Case study results

DELIVERABLE NO. D6.2

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No. 835896

Deliverable No.	D6.2	Work Package 6 (WP6)	
Work Package Title	Case Studies		
Status	Final		
Dissemination Level	PU		
Due date	2023.04.30	Submission date	2023.06.30
Deliverable version	Final		

History of Changes

Release	Date	Reason for change	Status
1	2023.04.30	Initial version	complete
3	2023.06.30	Final version	complete

Deliverable Contributors	Name	Organisation	Date
Deliverable Leader	Sandrine Charousset	EDF	
Work Package Leader	Sandrine Charousset	EDF	
Contributing Author(s)	Nadia Oudjane (CS1, 4, 5)	EDF	2023.03.09
	Ryan o'Reilly (CS1)	Energy Institute Linz	2023.03.09
	Pedro Crespo del Granado (CS1)	NTNU	2023.03.09
	Mostafa Barani (CS1)	NTNU	2023.03.09
	Sandrine Charousset (CS1, 4, 5, 7)	EDF	2023.03.09
	Theresia Perger (CS2)	TU Wien	2023.03.09
	Sebastian Zwickl-Bernhard (CS2, 3)	TU Wien	2023.03.09
	Hans Auer (CS2)	TU Wien	2023.03.09
	Luis Olmos (CS3)	Comillas	2023.04.26
	Andrés Ramos (CS3)	Comillas	2023.04.26
	Ingeborg Graabak (CS3)	SINTEF	2023.04.26
	Erik F. Alvarez (CS3)	Comillas	2023.04.26
	Philipp Härtel (CS4)	Fraunhofer IEE	2023.03.09
	Felix Frischmuth (CS4)	Fraunhofer IEE	2023.03.09
	Sebastien Lepaul (CS5)	EDF	2023.04.02
	Dimitri Pinel (CS3, 6)	SINTEF	2023.01.30
	Ove Wolfgang (CS3, 6)	SINTEF	2023.01.30
	Amos Schledorn (CS7)	DTU	2023.03.30
	Dominik F. Dominković (CS7)	DTU	2023.03.30
	Gokhan Kirkil (CS8)	KHAS	2023.06.27
	Emre Celebi (CS8)	KHAS	2023.06.27
	Ahmet Yucekaya (CS8)	KHAS	2023.06.27
	Franziska Holz (CS8)	DIW Berlin	2023.06.27
Reviewers	Luis Olmos (CS1)	Comillas	2023.04.20
	Dimitri Pinel (CS2)	SINTEF	2023.04.20
	Michael Belsnes (CS3)	SINTEF	2023.04.30
	Andrés Ramos (CS4)	Comillas	2023.04.20
	Theresia Perger (CS5)	TU Wien	2023.04.20
	Amos Schlechdorn (CS6)	DTU	2023.04.20
	Philipp Härtel (CS7)	Fraunhofer IEE	2023.04.20
	Michael Belsnes (CS8)	SINTEF	2023.06.20
Final review and approval	Ingeborg Graabak	SINTEF	2023.06.30

DISCLAIMER / ACKNOWLEDGMENT

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 835896.

Contents

Abstract

8 case studies were performed during the Open ENTRANCE project, as a real-size proof of concept of the project, covering the main topics of the energy transition. The main objectives of the case studies were:

- Show the adequacy and relevance of the Open ENTRANCE platform. For this purpose, the case studies have been using scenarios, assumptions and data developed within Work Package 3 "Scenario Building Exercises", and the suite of modelling tools supplied by Work Package 5 "Suite of Modelling tools".

- Show the ability of the proposed approach to answer specific questions related to the evolution of the energy system. This has been done with a specific focus on the effects of decentralisation, variability, the need for flexibility, real market functioning, integration of energy sectors, behaviour of individuals and communities of actors.

- Provide complementary inputs (data) to Work Package 3 "Scenario Building Exercises". This has taken place during the process of running the case studies, which conducted to a new version of the Scenarios in WP3.

In order to perform the case studies, simulations were run using the linked models developed within WP5 "Suite of Modelling tools" and the scenario dataset developed within WP3 "Scenario Building Exercises". As for the dataset, in order to ensure consistency among studies, supplemental data, which were needed on specific items, were added while performing the case studies. Therefore, it will be possible to easily re-run case studies or derive variants or challenge them by using other models/data.

Regarding the linkage of the data and models, it relied on the common Open ENTRANCE data format (see [3] as well as on the nomenclature which is defining the variables and regions names, as well as establishing rules for using them (see the open repository [1], and [2] for a detailed description of its organisation. The case studies are the following:

- Case study 1 is dedicated to Demand-Response from household consumers. It evaluates the flexibility potential when using load-control with household consumers and study its impact on the integrated European electricity system cost, operation and investments needs.

- Case study 2 is dedicated to behaviour of communities of actors. It studies shared energy management in different local energy community concepts, taking into account the individual preferences of the actors involved. Based on comprehensive modelling, the quantitative results have been up-scaled on country and European level.

- Case study 3 is dedicated to flexibilities and storage. It analyses how the uses of flexible hydropower and more generally of different kinds of storages (pumped-hydro, batteries, gas. . . .) can tackle some of the main challenges of the energy transition.

- Case study 4 is dedicated to cross-sector integration, with a specific focus on the flexibilities provided by electric vehicle owners to the electricity system. It also evaluates the impact of import hydrogen prices on the integrated system.

- Case study 5 compares different levels of geographic coordination for investment decisions, both at regional and European level, focusing on the topic of decentralisation. In particular regional decisions with local objectives were compared with European coordinated decisions with global targets.

- Case study 6 analyses the use of innovative technology in terms of underground rocks for seasonal storage of heat from summer to winter in a district in Oslo, Norway. The analyses show the impact on the energy system in the district.
- Case study 7 evaluates how the use of flexibilities from the heating sector at different time scales (short-time planning with hourly to 5 minutes resolution) may have an impact on the system operation costs and network expansion needs in Denmark.
- Case study 8 investigates the role of natural gas storage in current and future energy systems in Turkey.

Bibliography

[1] Open entrance nomenclature. https://github.com/openENTRANCE/openentrance.

[2] Olmos Luis Charousset-Sandrine Huppmann Daniel Graabak Ingeborg. Holz, Franziska. Illustrative case examples for the coordinated use of models. *Open ENTRANCE*, Deliverable D5.4, 2023. https://doi.org/10.5281/zenodo.7870715.

[3] Huppmann Daniel Charousset-Brignol Sandrine Camacho Luis Olmos Cohen Jed Galán Andrés Ramos Pisciella Paolo Boonman Hettie Perger Theresia Haertel Philipp Graabak Ingeborg Crespo del Granado Pedro Krey, Volker. Data exchange format and template. *Open ENTRANCE*, Deliverable D4.2, 2019. https://doi.org/10.5281/zenodo.5521098.

Chapter 1

Case Study 1: Demand response - behaviour of individuals

Contents

Abstract

The overall objective of Case Study 1 (CS1) is to estimate achievable-technical potentials for residential household Demand Load Control (DLC), from 2022 to 2050, and to evaluate their impact on the European electricity system, in terms of costs, investment decisions and operation, in a consistent way with the openENTRANCE Techno-FriendlyV2 scenario. The case study focuses on residential DLC flexibility, and it does not take into account DLC potentials from industrial and commercial sectors. Moreover, it only considers load shifting and not load curtailment meaning that the energy consumed by each flexible device is kept unchanged (on a given reference period) while the power consumption profile may change along the time.

The first step of CS1 consists of estimating the household DLC potential for the 27 countries of the European Union in addition to Great Britain, Norway, Switzerland, and Turkey. Ten electric-consuming devices were considered for this project because of their high-power demand and ability to be flexible with regard to their time of use such as electric air-to-air heat pumps and electric vehicles. One major novelty of this work is to take into account the willingness of people to participate in DLC programs when estimating the DLC potential. This is done by the introduction of a participation rate estimated from previous studies and residential DLC pilots based on recent observations of consumers behavior. For each of the ten considered devices, hourly profiles are generated at the NUTS2 level for the 31 countries considered in the study from 2022 to 2050. These estimates are based on the most recent empirical studies of usage patterns. For each region, the demand flexibility associated with a specific device is characterized by its maximum power consumption and maximum power reduction potentials. For 2022, the average hourly achievable DLC potential is estimated around 7 GW for load reduction and 51 GW for load increase. By 2050, the average hourly potential is estimated around 12 GW for load reduction and 67 GW for load increase.

In the second step of CS1, the objective is to evaluate the impact of the estimated DLC potentials on the European electricity system through two modelling tools, namely EMPIRE, and Plan4EU. EMPIRE focuses on the impact of DLC programs on long-term investment decisions, including various generation resources, energy storage devices, and transmission lines. It provides an optimal pathway for the transition of the European electricity system from 2022 to 2060. Although the EMPIRE modelling framework seeks to derive an optimal pathway for long-term capacity expansion planning, it also takes the short-term operation of the system into account. Four case studies with DLC — whereby different pathways of residential DLC programs are characterized — are studied. The results of these case studies are then compared with a base case that does not include DLC programs. The results of these four case studies show a decrease in the total costs, ranging from 0.26% to 0.99%, compared to the base case without DLC programs.

Plan4EU focuses on year 2050 and simulates the operation of all the flexibilities including generation plants, storage assets and DLC, with a granularity of one hour for fourteen countries (or aggregation of countries) in Europe, on 37 "stochastic scenarios" representing uncertainties on demand, renewable generation and inflows. Three cases are considered depending on the level of the participation rate considered: a reference case without use of DLC; a conservative case with partial use of DLC (assuming the population is willing to participate in DLC programs in 2050 has not increased w.r.t. 2020); an optimistic case with a full use of DLC (assuming 100% of participation to DLC programs in 2050).

Plan4EU evaluates the impact of DLC on the 2050 European Electricity system in terms of operation costs, marginal costs and energy generated per technology. We observe that the use of DLC induces a reduction of operation costs of 0.45 % in the conservative case and close to 2.5 % in the optimistic case. Similarly, household DLC allows both to reduce the average level of marginal costs and their dispersion. In terms of energy, it contributes to decrease photovoltaic curtailment allowing to increase the use of photovoltaic energy by almost 1% of the generated energy, while it reduces the use of small storages by 1.3 % of the generated energy.

1.1 Introduction

The present case study consists in analysing the Demand Load Control (DLC) potential allowing to shift a part of electricity demand and to assess the impact of this DLC flexibility on the operation and the resulting costs of the European electricity system. Data from real-life field-tests, recently carried out in several EU nations have been used. Such data directly reflect human behaviour and individual choices related to electricity consumption and contribute to an improved understanding of the potentials of DLC for the system and for individuals. The improved understanding of flexibility potentials has been used as input for the EMPIRE and plan4EU power system models to assess the system level impacts of flexibility under various scenarios and regimes. The models have been used in parallel as they focus their analyses on different aspects of the electricity system, with EMPIRE focused on capacity expansion and plan4EU focused on the operation of the electricity system with a detailed hourly model. Analyzing the outputs of the two models across various scenarios and assumptions of demand flexibility allows for a more holistic understanding of how demand flexibility can be considered in electricity system models and the consequences of this consideration.

The present report is organized as follows. Section 1.2 recalls the overall objectives of the case study. Then a brief explanation of the modelling frameworks used in this study, namely EMPIRE and plan4EU, is given in Section 1.3. Afterwards, Section 1.4 describes the DLC data set used in this study. Section 1.5 outlines the methodology of the employed modelling frameworks to incorporate DLC programs. Section 1.6 describes the input data used in this report. The results are provided in Section 1.7. This section is comprehensive and the results of the two modelling frameworks are discussed in detail. Section 1.8 then discusses the limitations of the employed modelling frameworks. Finally, Section 1.9 concludes the study.

1.2 Overall objective of the case study

The overall objective of this case study is to gain new insights into:

- What is the potential of DLC focusing on residential load shifting flexibility, including both technical aspects related to devices and behavioral aspects related to the willingness of consumers to participate in such programs?
- What are the impacts of DLC on the operation of the electricity system?
- What are the long-term system effects of DLC in the transformation of the electricity system?

1.3 Short summary of models used

This section briefly explains the two modelling frameworks used in this study with EMPIRE on the one hand and plan4EU on the other hand. Before describing this setting in details, let us underline that this case study only focuses on residential load shifting while load curtailment is not considered. Hence, demand flexibilities can be modelled in both tools as virtual short-term storages with two types of constraints:

- Power constraints imposing some maximum and minimum injection and withdrawal power constraints (allowing to limit the deviation of the power consumption profile of the device from its nominal consumption profile);
- Energy constraint imposing the state of charge of the battery to come back to its initial level after a fixed period (e.g. 2 hours) on which the load shifting flexibility can be operated.

No costs are associated to the use of DLC since the energy constraint is supposed to preserve the quality of service for the consumer.

1.3.1 EMPIRE Modelling Framework

The EMPIRE modelling framework is a linear multi-horizon stochastic programming model to derive long-term investment planning of a power system. The power system is presented as a network of nodes (representing a country or region) and arcs in the model where the decisions are made in two temporal scales (each representing one stage): investment time steps and operational time steps. In this regard, in EMPIRE, the investment decisions are subject to both long-term capacity expansion constraints and short-term operational constraints. The short-term uncertainties (i.e., variable production of renewable energy resources and load consumption) are taken into account through several stochastic scenarios. The object of EMPIRE is to optimize the long-term investment in generation resources, energy storage systems, and transmission lines by minimizing the total cost of the system. Therefore, the power market is assumed to be perfectly competitive in the model. The model was originally designed to analyze the decarbonization of the European power system with a focus on the supply side. The EMPIRE model was recently published as an open-source model [1].

To incorporate the responsive loads in the EMPIRE modelling framework, each category of residential appliances is modelled as an energy storage device through the DLC module which is already available in EMPIRE. The activation of responsive loads is considered to be free, meaning that no cost — neither operational nor investment — is associated with DLC programs in the model. The results will then reveal the highest benefit of implementing DLC programs which will be useful for making policies regarding the participation of responsive loads in direct load control programs.

1.3.2 Plan4EU modelling framework

Case study 1 makes use of the scenario valuation layer of plan4EU which allows to evaluate the operation costs of the electricity system by simulating the operation of the existing assets (power plants, storage etc.) on a typical period of one year with a granularity of one hour, taking into account uncertainties induced by demand, renewable generation and inflows. This layer contains two distinct models: the seasonal storage valuation model and the European unit commitment model. Those 2 models are 'hard-linked', meaning that the unit commitment model is used as the solver for evaluating sub-problems created within the seasonal storage valuation model.

The seasonal storage valuation model provides an accurate account of "the expected value" that seasonal storage (e.g. hydraulic reservoirs) can bring to the system. The actual use of the storage may in particular depend on uncertain adverse climatic situations (intense cold), but the ability to store the energy may in turn also depend on uncertain climatic conditions (e.g. draught). Such a vision of expected value should be transferred in an appropriate way to shorter time span tools, such as the unit commitment model. In turn computing an accurate value intrinsically depends on the value of substitution, and thus ultimately on the unit commitment tool as well.

The unit commitment model computes an optimal (or near optimal) schedule for all the system assets on a typical period of one year, with a typical granularity of one hour in order to satisfy demand (in this case study ancillary services are not taken into account) at the lowest cost with a deterministic approach for several chronicles modelling uncertainties on demand, renewable generation and inflows. It ensures that the given system is "feasible" in the sense that on each uncertainty chronicle, at each hour of the year, including peak hours, it is able to fulfil power demand supply (with a limited non served energy), transmission capacities limits and technical constraints of all assets.

1.4 Demand load control assumptions and approach

A quantitative prediction for residential electricity demand and the potential for direct load control (DLC) for Europe at a fine spatial scale for years 2022-2050 has been developed. To date only theoretical and spatially coarse measurements of this potential exist for a subset of technologies used in the residential sector. To fill this need, we generate hourly load profiles for the residential sector for key electricity consuming devices that take into account the most recent empirical studies of usage patterns, and of the cost and willingness of households to participate in DLC programs. Additionally, we extend the list of investigated technologies by the important classes of electric mobility and heat pumps for electric space heating. The Python and R scripts along with the input and final data for this work are freely available for external users. These resources are hosted on Zenodo (see O'Reilly et al. [8]). A detailed description of the methodology is also available in [8].

1.4.1 Demand Side Management: Demand Response vs Demand Load Control

Demand Side Management (DSM) operates as a set of implicit (Demand Response) and explicit control schemes (Demand Load Control) that can be used in conjunction or individually to reduce, increase, or shift the consumption of energy resources with respect to time [4] (for a historical overview of the field see [6]). [7] presents an overview of the types of control schemes along with their infrastructural, architectural, and operation criteria for DSM measures. Their work separates DSM into six control schemes: frequency-based, direct control over utility equipment, direct control over end-use equipment, price-based, market-based, and model-based predictive. The study notes that price-based control schemes that utilize static tariffs (e.g. time of use), dynamic tariffs (e.g. critical peak pricing), or real-time tariff (e.g. real time pricing) have seen increased attention but result in uncertain aggregate response. This is why the present study focuses on DLC and does not include Demand Response.

1.4.2 Load shifting vs load curtailment

One can distinguish two types of DSM flexibilities illustrated on Figure 1.1.

- Load shifting consists in advancing or delaying the power consumption of an electrical device but the total energy consumption over a reference period remains unchanged as illustrated on the left graph of Figure 1.1.
- Load curtailment consists in cancelling the use of an electrical device which results in a decrease of power consumption as illustrated on the right graph of Figure 1.1.

However, load curtailment often generates a "rebound effect" to compensate for the load reduction which may happen after or even before the load curtailment event. Load shifting integrates by construction this rebound effect by assuming a fixed energy consumption on a given reference period. This is why this study focuses on load shifting. Besides since the power consumption is unchanged, the quality of the service for the consumer can be supposed to be unchanged.

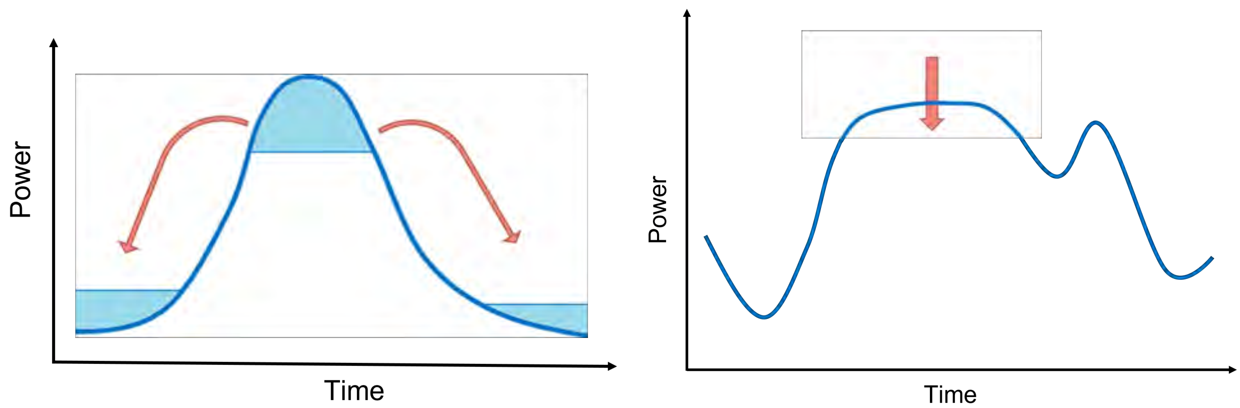


Figure 1.1: Load shifting (on the left graph) and load curtailment (on the right graph)

1.4.3 Demand load control model and data provided to Empire and PlanEU

We provide DLC potentials for 10 residential devices available for DLC from 2022-2050 in Europe. The potentials are based on achievable participation rates from previous studies and residential direct load control pilots. These estimates are provided for the NUTS2 level from 2022-2050 for the EU27, Turkey, Switzerland, Norway, and the United Kingdom. The electric consuming devices considered for this project are dishwasher (DW), washing machine (WM), tumble drier (TD), electric storage heater (SH), electric air-to-air heat pump (HP), electric water heater with storage capabilities (WH), heat circulation pump (CP), air conditioning (AC), refrigerators and freezers (Ref), and fully battery electric vehicles (EV). The devices were chosen because of their high-power demand and ability to be flexible with regard to timing of use. Annual demand profiles for each of these devices are generated on the NUTS2 level for the EU27, United Kingdom, Turkey, Switzerland, and Norway on an hourly granularity from 2020 to 2050 for a representative day for each month (i.e. 24 hours for an average day in each month). For each type of consumption device, we provide Empire and plan4EU with a simplified description of the associated demand flexibility in a given region (at the NUTS2 granularity) characterized by four features

- **Maximum reduction profiles** providing for each hour the (estimated) nominal consumption of the appliances when no DLC is applied provided for each target year from 2020 to 2050 for a representative day for each month;
- **Maximum dispatch profiles** providing for each hour the maximum power consumption of the appliances (it is also provided from 2020 to 2050 for a representative day for each month);
- **t.shift** defining how many hours the DLC event can take place recalling that the DLC event occurs when the effective consumption profile deviates from the Maximum reduction profile while the total consumed energy during the period is conserved;
- **Participation rates** coefficients between 0 and 1 determined for each appliance of each of the 31 considered countries determining the proportion of appliances which are participating in the DLC program (1 corresponds to a participation of all the appliances while 0 corresponds to the reference situation without DLC).

Maximum reduction and dispatch profiles determine for each hour the maximum potential for load increase or decrease. The “t.shift” allows to discretize the year into a collection of subperiods, $[t_i, t_{i+1}]$, with duration “t.shift” recovering the whole year. On each subperiod $[t_i, t_{i+1}]$ the controlled appliances are supposed to consume the same energy as the energy consumed by the maximum reduction profile on that subperiod.

Figure 1.2 shows the load reduction and increase potential estimated for each NUTS2 region for different target years. For 2022, the average hourly achievable DLC potential for the entire study area is estimated (for the whole Europe) around 7 GW for load reduction and 51 GW for load increase. By 2050, the average hourly potential is estimated around 12 GW for load reduction and 67 GW for load increase. Those figures may be compared to the mean European hourly demand (obtained by dividing the yearly final energy from the TechnoFriendlyV2 scenario by 8760): 445GW in 2018, 502GW in 2025 and 613GW in 2050.

1.4.4 Methods and parameters used to estimate the Participation rate

Theoretical potentials for residential Demand Load Control (DLC) exist on a European (EU) wide scale but potentials that account for consumer willingness to participate in DLC programs are limited [9]. The objective is here to provide achievable-technical residential DLC potentials. To that end, participation rates are introduced for each of the appliances and the countries considered in this study. It is calculated in two stages.

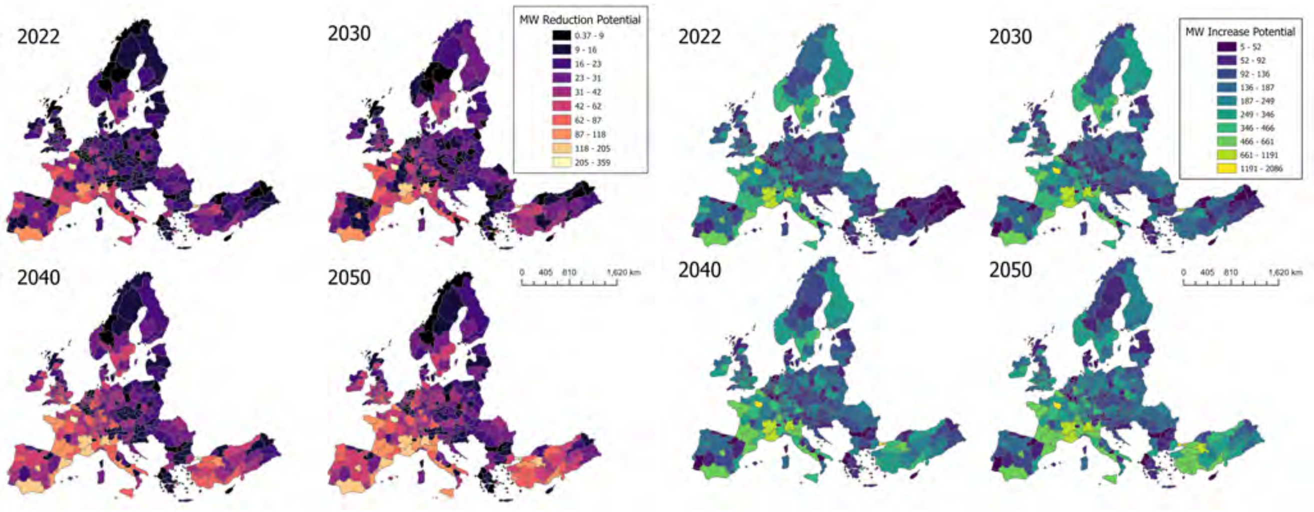


Figure 1.2: Average hourly reduction (on the left graph) and increase (on the right graph) potential by NUTS2 regions for selected years

First, for each type of device, a so-called "realistic" participation rate is calculated. Achievable participation rates are calculated by averaging participation rates provided from previous studies. Studies that were hypothetical, survey based, were multiplied by 0.45 to adjust for hypothetical bias. The coefficient allows the rate to pass from optimistic (hypothetical) to achievable participation rates on the differences observed between theoretical studies and residential load control pilots. The resulting achievable participation rates provide a conservative estimation of the DLC participation specific to each device, but it does not yet take into account the diversity of behavior between countries. In a second step, for each device considered, a specific participation rate is derived for each country. To do this, for each device, the participation rates obtained previously are multiplied by a country specific coefficient characterizing the willingness of a population in a given country to participate in a DLC program. These country specific coefficients are calculated on the basis of the survey [10] conducted in ECHOES H2020 project in 2018 across 31 European nations and over 18,000 respondents asking each individual whether he or she would agree to participate in a DLC program.

1.4.5 Methods and parameters used to estimate flexible loads

Following the methodology presented in Gils [4], the demand profiles for all devices but EV and HP, which were not included in the publication, were calculated using the equations and technical parameters provided in Gils [5]. A linear extrapolation was used to approximate values for years not shown in the publications. Updates to the Gils [5] study came from accounting for climate change for the NUTS2 heating and cooling degree days (HDD and CDD respectively) which are used to estimate the demand profiles for devices whose use are a function of outside temperature (i.e. AC, HP, SH, WH, and CP) [11]. The Gils [4] methodology follows a bottom up construction to estimate residential loads. The number of households, for each NUTS2 region, in a given year were estimated using Eurostat population expectations and average household sizes [3, 2]. Turkish and UK estimates were estimated using growth rates provided by Gils [5].

Most importantly, EV and HP are now included in the DLC potentials as both technologies are expected to play an important role in decarbonizing the residential sector. In the same spirit as the methodology presented in Gils [4] we have estimated the demand profiles for HP and EV, for NUTS2, on the period 2020-2050, relying on specific assumptions on the evolution of the share of HP in the heating sector for each country and on the transition to EVs in the transport sector. Details on these assumptions and methodology are provided in [**?**].

1.5 Methodology of case study, case study workflow, Effective linkages: what was done (compared to plans in D5.2)

In this study, two methodologies using two mathematical formulation problems have been used to investigate the impact of large-scale integration of Demand Load Control (DLC) programs. The responsive loads in both studies are the residential loads mentioned in Section 1.4.3. The employed approaches investigate the impact of DLC program integration from different angles. The focus of the first modelling tool — EMPIRE — is on long-term investment planning in the European electricity system. Although this model includes the system's short-term operation, it disregards some technical details for the sake of the tractability of the problem. The second modelling tool — plan4EU — focuses on analysing the impact of DLC on the European electricity system operation, considering specifically the related system expected costs, marginal costs, and distribution of energy generated per technology, using a detailed description of the system (integrating an hourly granularity, a detailed description of assets technical constraints and grid flows limits and representing the uncertainty affecting the main system operation input variables).

1.5.1 EMPIRE

This section gives an overall picture of how the openENRANCE Demand Load Control (DLC) data were used in the EMPIRE DLC module through a brief analysis. In EMPIRE, the responsive loads are modelled similar to storage systems. In order to use the provided DLC data in the EMPIRE model, a few adjustments are made to the data set. Then four case studies are developed to characterize various pathways toward the participation of responsive loads.

Classification of components

As mentioned in section 1.4, there are ten appliances in the provided DLC data set. The goal of this study is not to assess the impact of each appliance separately. Therefore, we aggregate the loads with similar shift times and direction of load shifts (i.e., delay and advance). In this regard, the loads are grouped into the following five categories:

1. **Cat1:** Air conditioning, refrigeration, and circulation pumps (only can be delayed up to two hours)
2. **Cat2:** Dryer, washing machine, and dishwasher (can be both delayed and advanced up to six hours)
3. **Cat3:** Storage heater and water heater (only can be advanced up to 12 hours)
4. **Cat4:** EV (only can be delayed up to four hours)
5. **Cat5:** Heat pump (only can be advanced up to two hours)

The DLC module in EMPIRE models these categories of responsive loads similar to energy storage devices.

Scenario Generation

On one hand, the loads that participates in DLC programs change each year but, except for a few appliances, they have a constant daily pattern throughout the year. On the other hand, the EMPIRE modelling framework considers every five years as one investment period, and a random scenario generation procedure is then adopted to generate the input data for volatile parameters such as per unit wind and PV generations. In order to effectively take the impact of DLC programs into account, we considered five scenarios and forced the scenario generation procedure to choose DLC data of each year in that investment period once while the choice of month and hour in that year is still according to the random procedure in the EMPIRE modelling framework. Although the EMPIRE modelling framework aggregates every five years as one investment period, through this method, we could consider the DLC data of all years in the simulation.

Case studies

In order to clearly discuss the impact of responsive loads on the energy transition in the European electricity system, four case studies were implemented through the EMPIRE modelling framework:

- **Base Case:** In this case, no DLC program was considered.
- **Case I:** In this case, the openENTRANCE DLC data set was used according to the assumptions provided together with the data set. Consequently, in this case, we assume that the participation rates — a rate that shows the willingness of loads to participate in DLC programs — of the loads remain constant for all years. Note that the participation rates have been provided for each country and load type. The input DLC data for each year is then calculated by multiplying the load profile of that year and the fixed participation rates of related countries and load types. However, the assumption that the participation rates remain constant may not be realistic. To this end, we also added **Case II**.
- **Case II:** In this case, we assumed that more loads become interested in participating in DLC programs. We assumed that 4% of new loads — loads that were not participating in DLC programs — decide to take part in DLC programs each year in addition to the previous loads. The average participation rate of all countries for various appliances and a few sample years are shown in Figure 1.3 for this case.
- **Case III:** In this case, we assume that all the residential loads are willing to participate in DLC programs. This case may not be realistic; however, through it, we can investigate the maximum impact of residential DLC programs on the transition of the European electricity system.
- **Case IV:** This case is the same as **Case II** with one change. The shift times were doubled in this case for two reasons. First, the techno-friendly storyline in openENTRANCE is based on the active collaboration of society, so we expect the participants to be more flexible in DLC programs. Second, in EMPIRE, the shift times are modelled through sequential time windows with the duration of shift times. With respect to this explanation, the loads cannot be shifted between these windows. Therefore, the results yield a lower bound of the impact of DLC programs, and increasing the shift times will compensate for this.

Note that the assumptions in cases **I** and **III** are the same as **PartFlex** and **FullFlex** in the plan4EU modelling framework, respectively.

1.5.2 Plan4EU

In this case study, plan4EU is used to provide the impact of DLC on the operation of the European electricity system. For this purpose, specific choices have been made according to the following points:

- simulation of the short-term integrated operation of all flexible assets of the pan-European electricity system is done on the target year 2050 with an hourly discretization, on 37 uncertainties chronicles (for temperature, demand, renewable generation, inflows etc.);

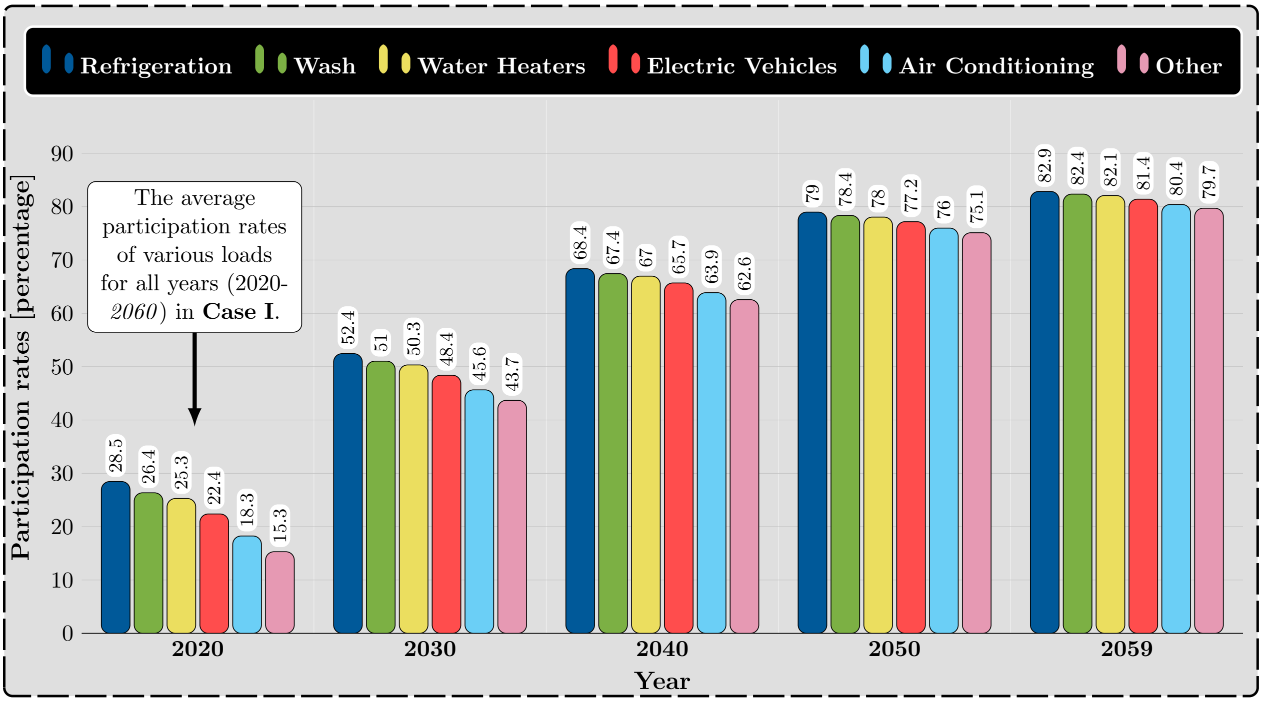


Figure 1.3: Average participation rates of various residential loads for some sample years in **Case II**.

- 14 regions are considered, each region corresponding to either a country or an "aggregation of countries": France, Germany, Italy, Switzerland, EasternEurope (Austria, Czech Republic, Hungary, Poland, Slovakia) , Benelux (Belgium, Luxembourg, The Netherlands), Iberia (Spain, Portugal), Britain (Ireland, United Kingdom), Balkans (non-EU-Balkans, Bulgaria, Croatia, Greece, Romania, Slovenia, North Macedonia), Baltics (Estonia, Latvia, Lithuania), Denmark, Finland, Sweden, Norway;
- Demand Load Control (DLC) flexibilities are limited to the residential electricity sector only (the ten types of DLC flexibilities enumerated at the beginning of Section 1.5 are considered). Each type of DLC flexibility at each node of the network is modelled as a short-term storage (battery), characterized by maximum and minimum volumes and power limits depending on time on the whole period, those parameters being calibrated in order to reproduce exactly the flexibility potential as described in Section 1.4 with the specific features **t.shift** and **Maximum reduction** and **Maximum dispatch** profiles.

As explained in Section 1.4, for each DR flexibility, a *participation rate* is calculated depending on the type of device and its location on the network. This participation rate is intended to represent the share of the population that is willing to provide flexibility to the system. In runs conducted with plan4EU, two cases have been analyzed considering different assumptions on the flexibility potential.

- **PartFlex** This first case considers conservative participation rates provided by the methodology described in Section 1.4.4 and implemented on current data reflecting the willingness of people in 2022 to participate in DLC programs;
- **FullFlex** This second case considers the very optimistic situation where the whole population is willing to participate so that all devices are providing flexibility.

1.6 Description of datasets and how they were created

1.6.1 Datasets used in plan4EU

Capacity mix in 2050

Plan4EU runs were conducted on a scenario close to the openENTRANCE Techno-FriendlyV2 scenario provided by Genesys-MOD in June 2022. However, running plan4EU with this scenario implied too much nonserved energy to be reasonably considered as feasible. So we created a new dataset for plan4EU based on Techno-FriendlyV2 scenario with some modifications allowing for feasibility. This adaptation has been done by running the capacity expansion lyer of plan4EU and by manually readapting the capacities so as to get a final mix feasible but still not too far away from the original Techno-FriendlyV2 scenario. The resulting modified scenario differ from the original Techno-FriendlyV2 scenario because of new capacities invested essentially in Gas, Nuclear, Hydrogen power plants, energy storage and slightly in biomass. With this new capacities we indeed obtain a mix allowing to ensure the balance between demand and generation with a reasonable probability.

Other data from Genesys-MOD

The following data (inputs or outputs) of Genesys-Mod were used for year 2050.

- For creating the electricity demand: 'Final Energy|Electricity', 'Final Energy|Electricity|Heat', 'Final Energy|Electricity|Transportation'
- For the interconnections: 'Network|Electricity|Maximum Flow'
- For creating the generation mix:
  - Thermal generation: 'Capacity|Electricity|' field for the following technologies 'Biomass|w/ CCS','Biomass|w/o CCS', 'Coal|Hard Coal|w/o CCS', 'Coal|Hard Coal|w/ CCS', 'Coal|Lignite|w/o CCS', 'Gas|CCGT|w/o CCS','Gas|CCGT|w/ CCS', 'Gas|OCGT|w/o CCS', 'Geothermal', 'Hydrogen|OCGT', 'Nuclear','Oil|w/o CCS']
  - Hydraulic generation (Hydro): 'Capacity|Electricity|Hydro|Reservoir' for the maximum power of reservoir generation in each region, and 'Secondary Energy|Electricity|Hydro|Reservoir' to adapt the hydro inflows; 'Capacity|Electricity|Hydro|Pumped Storage' for the maximum power of hydraulic pumped storage, 'Maximum Storage|Electricity|Hydro|Pumped Storage' for the reservoir volume of the pumped storage and 'Pumping Efficiency|Electricity|Hydro|Pumped Storage' for the pumping efficiency (maximum pumping being equal to -1×Capacity)
  - Renewable Energy Sources (RES): 'Capacity|Electricity|' fields for the following technos: Solar|PV', 'Wind|Onshore', 'Wind|Offshore', Hydro|Run of River'
  - For the costs: 'Variable Cost (incl Fuel Cost)|Electricity|', 'Fixed Cost|Electricity|', 'Capital Cost|Electricity| for all technologies where such costs are available.

For RES and Hydro, the Variable cost in plan4EU is set to 0.

Data from other sources

Data from OpenENTRANCE scenario are complemented with data from other sources:

Table 1.1: Improvement in total system cost for various cases with DLC with respect to the Base Case.

Total cost [€]	Improve percentage			
Base Case	**Case I**	**Case II**	**Case III**	**Case IV**
2.2×10^{12}	0.27%	0.58%	0.84%	0.99%

- To evaluate the share of cooling in the electricity demand, we used the value implemented in eHighway2050. Yearly electricity demand is separated into 4 categories (cooling, heating, Electric Vehicles, and the rest). Heating and EV parts are taken from the original openENTRANCE scenarios. The cooling part is computed using the cooling shares published by ehighway2050 (as cooling is not included in Genesys-MOD).
- The maximum volume of reservoir storages has been computed using the ENTSO-e database. This consists of historic values of the equivalent stored electricity in 'Reservoir' per country. We took the maximum value.
- Profiles come from Copernicus/C3S, where hourly scenarised profiles are available. These chronicles correspond to 37 climatic years which have been "readapted" to be consistent with the year 2050
  - Hourly demand profiles are generated by multiplying the yearly demand by hourly profiles from Copernicus/C3S energy (hourly profiles Electricity demand for heating; Electricity demand for cooling; 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 are computed by multiplying Copernicus/C3S scenarized profiles by the installed capacity.
- EDF has generated inflows to reservoir profiles, taking advantage of the historic data published by ENTSO-e.

1.7 Results of case study

1.7.1 EMPIRE

This section reports and analyzes the results obtained by the EMPIRE modelling framework. This section mostly focuses on the impact of residential DLC programs on long-term investment planning. However, the short-term operation of a few nodes, scenarios, and investment periods is also investigated at the end of this section.

Implementation of Direct Load Control Programs for Residential Sectors: The Benefit

The key finding of this study is summarized in Table 1.1. This table reports the improvements in total investment and operational costs in various case studies compared to the Base Case. **Case I**, in which the participation rates are fixed, yields the smallest improvement (i.e., 0.26%), and **Case IV**, with doubled time shifts and incremental participation rates, provides the largest improvement (i.e., 0.99%). Translating the percentages to euro, they range from 5.9 B€ to 20.2 B€. It should be mentioned that no cost was associated with DLC programs in the model — neither the cost of required equipment nor the payments to the participants. Therefore, the resulting values cannot be seen as the benefit of implementing DLC programs in residential sectors.

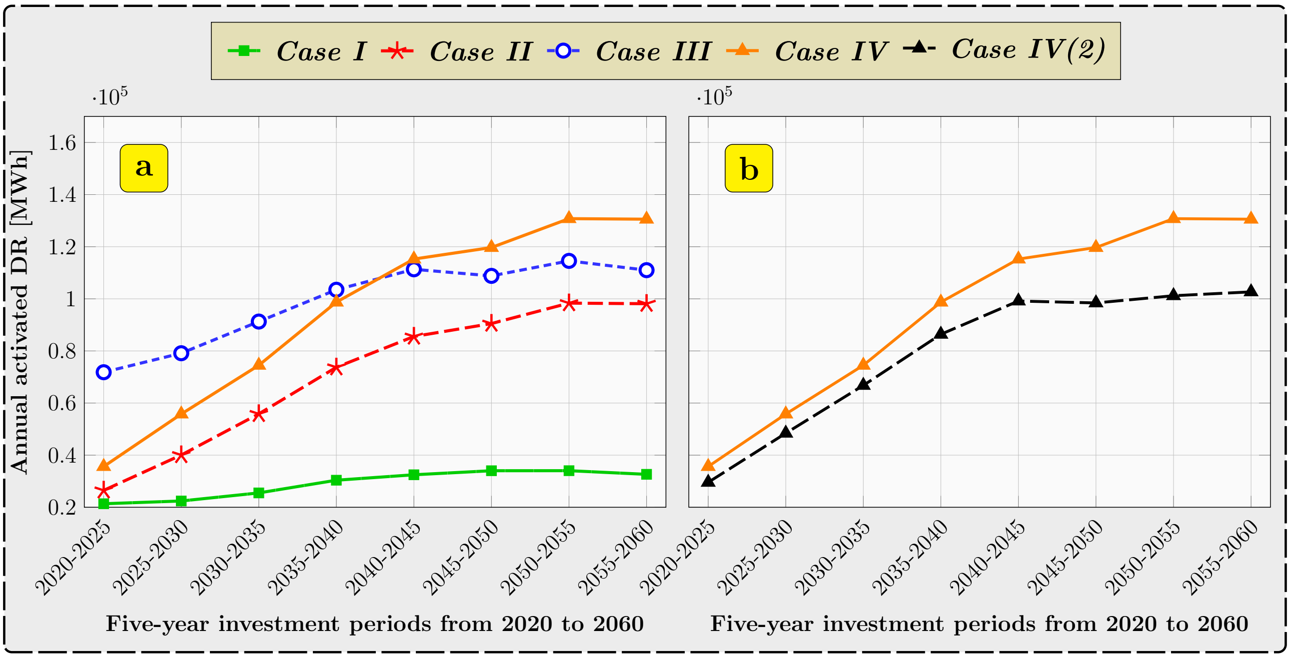


Figure 1.4: Activated DLC during all investment periods for each case study.

Activated DLC in Various Case Studies

This section compares the activated DLC in different cases and investment periods. The activated DLC refers to the responsive loads that have been either delayed or advanced.

Figure 1.4 shows the annual activated DLC during all investment periods and for all case studies. As can be seen in Figure 1.4.a, the annual activated DLC in each of the cases follows the trend of the DLC potential (input data) in the corresponding case. In **Case I**, the participation rates were assumed to remain fixed; therefore, the activated DLC, in this case, is not as large as in the other case studies. The increase in activated DLC in **Case I** is due to the increase in load demands over time. **Case II** and **Case IV** experiences a large increase in the Annual activated DLC over time. The reason is the increment in the participation rates over time. **Case III** — in which it was assumed that all the residential loads participate in direct load control programs — experiences the highest annual activated DLC during the first four investment periods. However, the annual activated DLC in **Case IV** overtook **Case III** during the fifth investment period (i.e., '2040–2045'). The participation rates in **Case IV** during this investment period is less than **Case III** (see Figure 1.3). However, the shift times considered doubled in **Case IV**. Comparing these two cases reveals the importance of the shift times.

As mentioned earlier, no cost was considered for the activation of responsive loads in the simulations. To this end, in some situations, the responsive loads may be activated without any benefit to the system. This, for example, may occur when the marginal prices are fixed for several hours. In such a situation, the responsive loads may be delayed or advanced without any benefit. In order to phase out this from the activated DLC, we assigned a very small cost (0.001 €/MWh) for the activation of responsive loads. Figure 1.4.b shows the results for **Case IV**. While the objective function remained almost the same, the annual activate DLC decreased largely. It is necessary to consider this small penalty if the value of the annual activated DLC will be used for post-analysis and policy making.

As a final point in this section, we have evaluated the ratio between the activated DLC and the total load in each node of the system. Figure 1.5 shows the ratio between activated DLC and the total load for all countries for two investment periods: a) investment period '2020–2025' in **Case I**, and b) investment period '2050–2055' in **Case IV**.

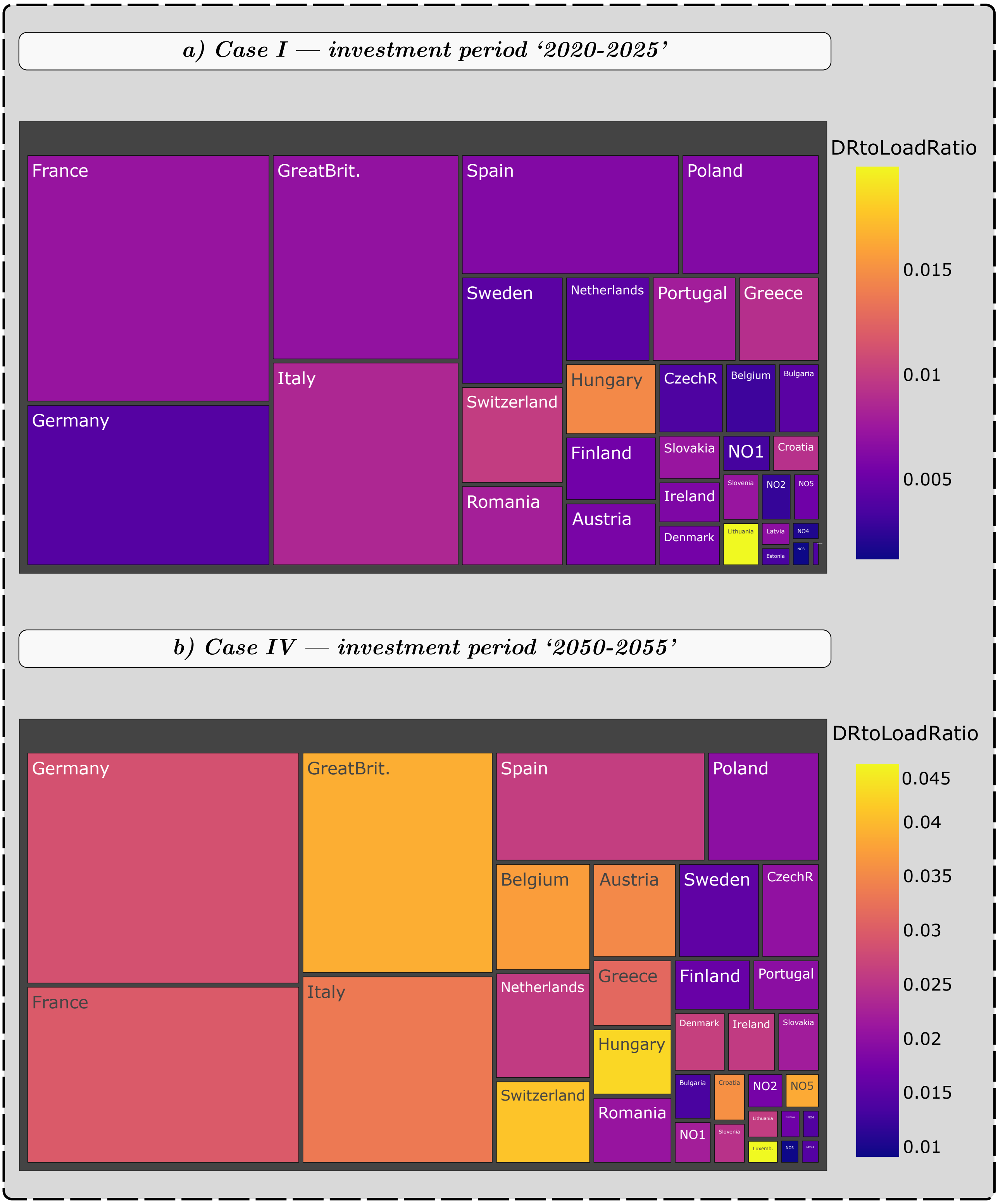


Figure 1.5: Annual activated DLC during two investment periods. The size of the boxes is a relative indication of the value of annual activated DLC in different countries. Various colours indicate the ratio between annual activated DLC and the total annual load in each country. Note that the activated DLC in Norway is shown for five regions.

Note that Bosnia and Herzegovina, Macedonia, and Serbia were excluded from this figure because no DLC data was available in the openENTRANCE DLC dataset for these countries. According to the results, France, Germany, Great Britain, and Italy have the highest activated DLC. This is consistent with the input DLC data. The activated DLC in Germany exceeds the activated DLC in France in **Case IV** in the investment period '2050–2055' while France has a higher share in **Case I** during the investment period '2020–2025' in **Case I**. This is justified by taking a look at the participation rates in these two cases. The participation rates of various appliances in France are higher in the provided data by the openENTRANCE project. However, each year a fixed share of loads — that has not been participating in DLC programs previously — decides to participate in DLC programs in **Case IV**. Therefore, the participation rates of the countries with lesser initial values grow faster. This explains the reason that the activated DLC in Germany exceeds France in **Case IV** during the investment period '2050–2055'.

Another important observation from Figure 1.5 is the ratio between DLC and total load. According to the results, the activated DLC reaches about 2% of the total load during the investment period '2020–2025' in **Case I** for only one node. This value increases to about 4.5% in **Case IV** during the investment period '2050–2055'. **Case IV** might be an ambitious storyline for direct load control programs. Even in this case, this rate exceeds 3% for a few countries which reveals a limitation of this study. The DLC dataset provided by openENTRANCE only includes the residential sector. Therefore, no conclusion can be made on the additional benefit of DLC potential from other load sectors.

Impact of Residential DLC Programs on Investments

In this section, we investigate the impact of DLC programs on the capacity expansion of generation resources during all investment periods. Note that the energy storage systems will be discussed later in a separate section.

Figure 1.6 shows the result of the EMPIRE modelling framework for the installed capacity of various generation resources in the European electricity system from 2020 to 2060 without DLC programs.

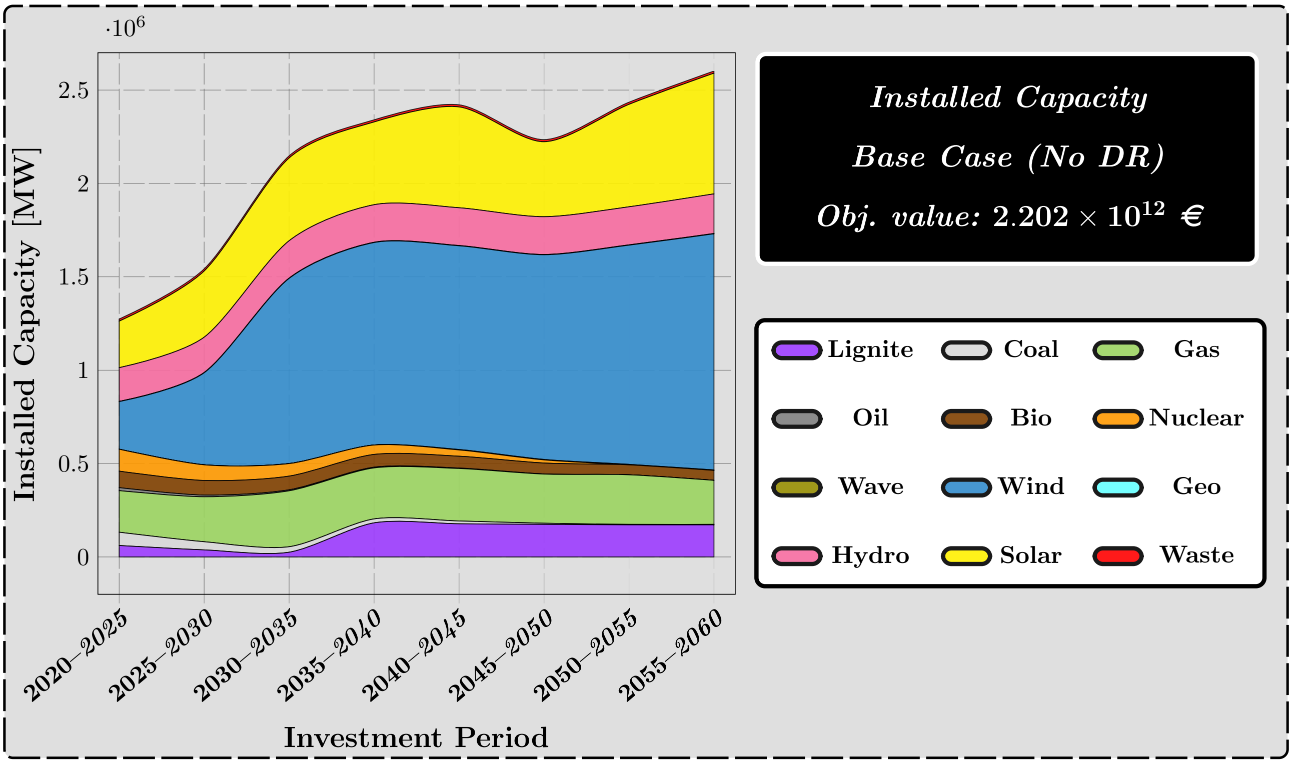


Figure 1.6: European energy transition: Installed capacity of various generation resources during 2020–2050

without residential DLC programs (**Base Case**).

The implementation of residential DLC programs makes no visible change in this figure. The same figure but for **Case IV** can be found in the appendix (Figure 1.22). In addition, the annual production of different power generation technologies can be found in the appendix in Figure 1.23.

In order to investigate the impact of residential DLC programs on the installed capacity of various resources, differences between all the case studies with DLC and the **Base Case** have been calculated and shown in Figure 1.7.a for the investment period '2050–2055'. In addition, Figure 1.7.b shows the differences between the cases with DLC and the Base Case regarding the annual production of various generation resources for the same investment period. Some generation resources including oil, nuclear, wave, and geo have been excluded from this figure since the differences for these resources were negligible. The most obvious observation from this figure is the replacement of a part of wind generation with PV production. This replacement increases as the potential of responsive loads increases from **Case I** to **Case IV**. The reduction in wind generation, especially in **Case IV**, is higher than the increase in PV generation in some cases. In addition, there is a reduction in lignite and gas-based power production. These reductions are compensated by coal, bio, and waste-based generation resources. Percentage-wise, the highest change belongs to coal-based power plants regarding both installed capacities and annual expected production in this investment period. However, as mentioned earlier, the overall change in installed capacities is small. The overall change is less than 0.5%.

Impacts of Residential DLC Programs on Investments in the Storage Systems

The EMPIRE modelling framework derives the optimal investments in generation resources, energy storage devices, and transmission lines. An important question is then "*Which of these elements is influenced the most by the implementation of residential DLC programs?*" The short answer is energy storage devices and to be accurate Li-Ion batteries. To justify the reason behind this, we only need to recall that the behaviour of responsive loads is very similar to energy storage devices. They shift

Figure 1.7: Changes in installed capacities and annual production of various generation resources in 7-th investment period (2050–2054).

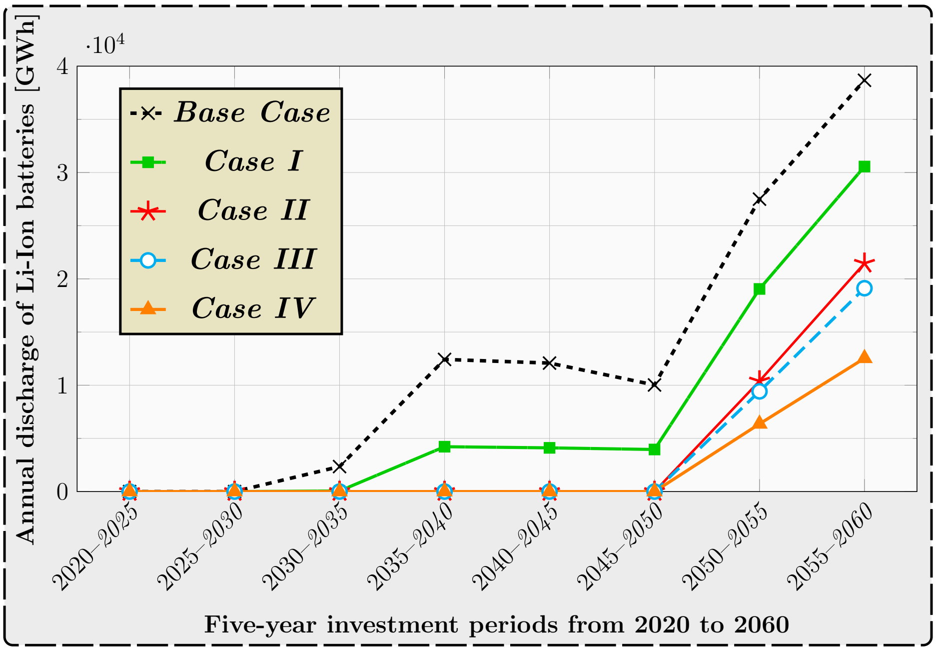


Figure 1.8: Annual expected generation of Li-Ion batteries.

loads from one time period to another time period. In the EMPIRE modelling framework, each category of responsive loads, mentioned in section 1.5.1, is modelled as an energy storage device. The storage discharge is then equivalent to load reduction and the storage charge is equivalent to load increase. Therefore, it can be expected that energy storage technologies incur the highest impact in the presence of DLC programs. Figure 1.8 depicts the annual expected discharge of Li-Ion batteries for all case studies during all investment periods. As can be seen in this figure, the implementation of residential DLC programs in the European electricity system decreases the usage of Li-Ion storage devices effectively. In three of the cases where DLC programs exist, the annual discharge of the Li-Ion storage devices is close to zero. Note that the installed capacity of Li-Ion storage systems also follows the same trend. During the last two investment periods, even **Case IV** — which includes an ambitious amount of available residential responsive loads — requires the installation of Li-Ion batteries since the penetration of variable renewable resources is very large.

Impact of Residential DLC programs on Hourly Marginal Costs

The value of lost loads is generally high: therefore the load interruption imposes a high cost on the system. In EMPIRE, the load shedding cost is 22000 €/MWh, meaning that the occurrence of load shedding in a particular hour increases the hourly marginal cost of the corresponding hour to 22000 €/MWh. Figure 1.9.b shows the hourly peak prices during each investment period for all case studies.

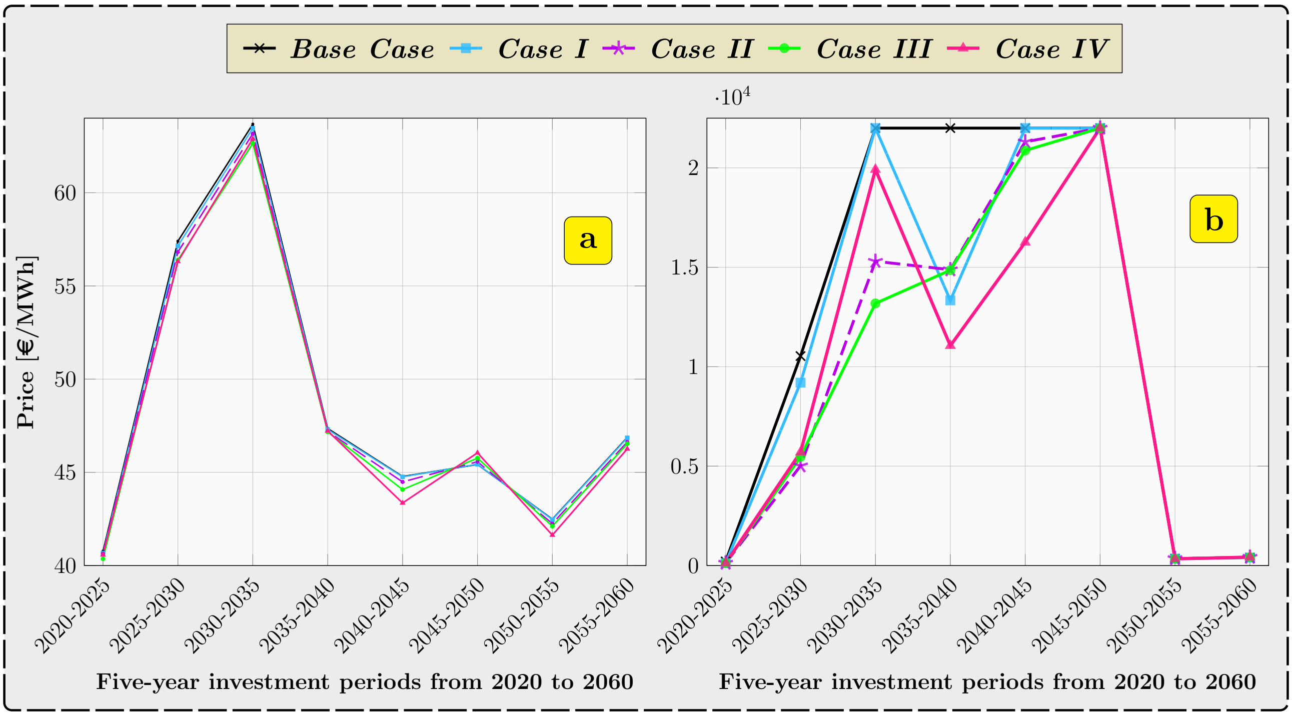


Figure 1.9: Impact of residential DLC programs on marginal prices: a) average price per MWh and b) hourly peak price during each investment period.

As can be seen in Figure 1.9.b, the maximum hourly marginal cost during periods '2030–2035', '2035–2040', '2040–2045', and '2045–2050' is equal to load shedding cost (22000 €/MWh), indicating that in these investment periods load interruption occurred. This is also confirmed in Figure 1.24 in the appendix. One interesting observation is the impact of DLC programs on the peak hourly marginal cost of these investment periods. As can be seen in Figure 1.9.b, in all cases, the implementation of DLC programs can effectively decrease the maximum hourly marginal cost of some periods. Obviously, **Case IV** performs better in this perspective and diminishes the peak marginal costs more effectively. Figure 1.9.a shows the average price per MWh for all case studies. According to the results, the implementation of the DLC programs does not guarantee a decrease in this metric (average price per MWh) for all investment periods. For example, **Case IV** has the smallest price per MWh for all investment periods except for the period '2045–2050'. During this period, **Cases II**, **III**, and **IV** have a higher average price per MW compared to the **Base Case** without DLC programs.

Analysis of Short-term Operation

As the final point regarding the result derived by the EMPIRE modelling framework, the short-term operation of the system is investigated through two sample weeks. Figure 1.10 shows the DLC activity and the hourly marginal prices of a Summer week in Austria during the investment period '2025–2030'. As can be seen in this figure, the activity of responsive loads follows the marginal prices in the system for most of the hours. Therefore, the activation of DLC could flatten the marginal prices to some degree. In this sample week, the mean of the hourly marginal prices decreases by 2.6% (**Case III**).

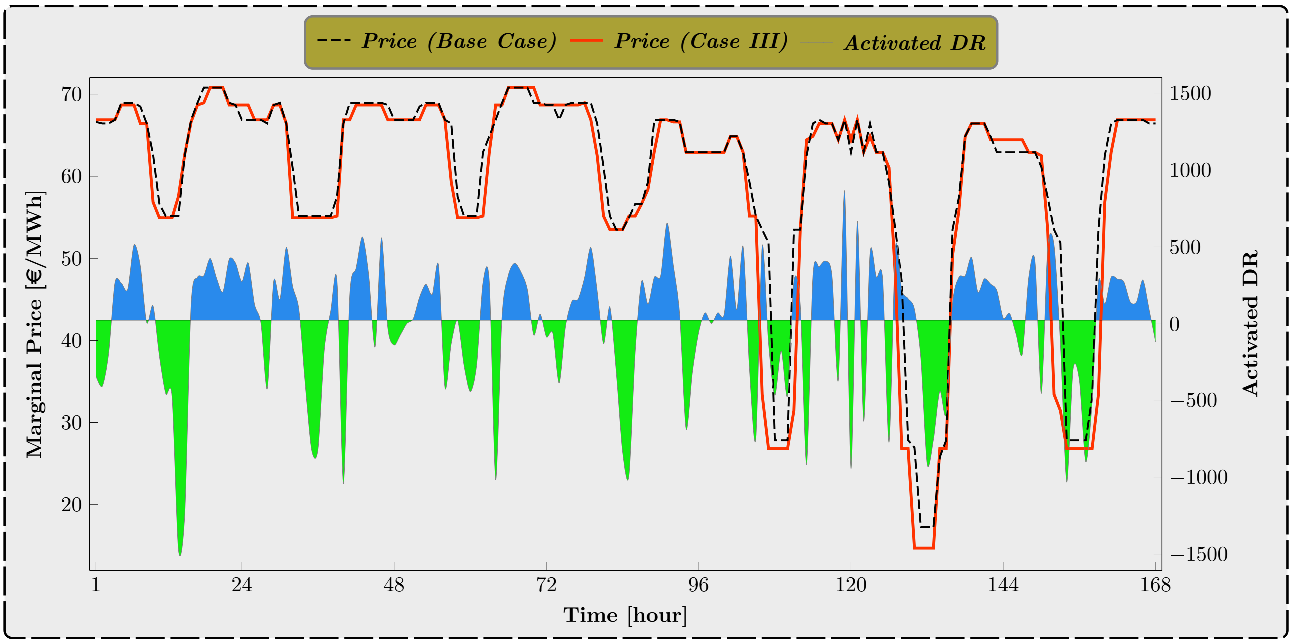


Figure 1.10: Shor-term activity of responsive loads in Austria during a Summer week in investment period '2025–2030' and **Case III**.

This is not always the case. The marginal prices in each of the nodes (representing a country or region) also depend on the other nodes. In addition, the marginal price may increase during the hours that the load increases due to load shifts. Therefore, some sample weeks in some nodes and scenarios may experience even an increase in the mean of the hourly marginal prices when DLC programs are included. As an example, Figure 1.11 shows another sample week belonging to a Spring week in Great Britain during the investment period '2050–2055'. During this week the mean of the hourly marginal prices increased by 3.3% when the residential DLC program was included (**Case IV**). In addition, as mentioned earlier, since no cost was assigned to the activation of responsive loads, the responsive loads may be activated without any benefit. This can be seen around the 48th hour in Figure 1.11.

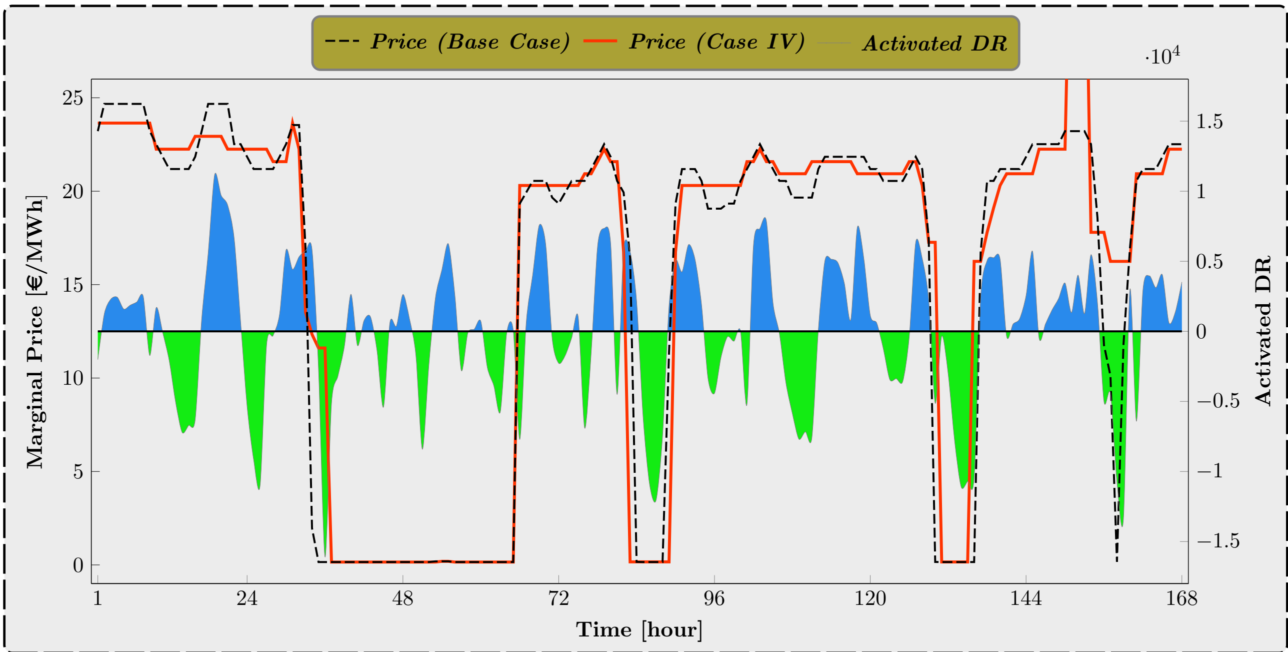


Figure 1.11: Shor-term activity of responsive loads in Great Britain during a Spring week in investment period '2050–2055' and **Case IV**.

1.7.2 Plan4EU

Plan4EU estimates the impact of demand flexibility in future scenarios of the European electricity grid in 2050 in terms of

- System Costs globally at the European level and more precisely for each region (country or "aggregation of countries");
- Marginal costs for each region;
- Energy generated per type of technology globally at the European level and more precisely for each region.

Operational costs

Figure 1.12 shows, for each considered region, the averaged variation of operational costs implied in year 2050 by the partial exploitation of flexible residential demand on the left graph (corresponding to the "PartFlex" case) and the full exploitation of flexible demand on the right graph (corresponding to the "FullFlex" case). The average is computed over the 37 chronicles considered to represent uncertainties on demand, renewable generation and inflows in year 2050. This cost variation is expressed as a percentage of the operational cost obtained with the reference case without exploitation of flexible demand (referred to as "Ref"). In both cases, we observe, as expected, a decrease in costs induced by the use of flexible demand. The level of decrease is different for each country, in particular, for Norway it is negligible due to very low operational costs (since the share of hydroelectricity is high in this region). For Europe as a whole, the observed cost reduction is greater than 0.4 percent for the PartFlex case and almost 2.5 percent for the FullFlex case.

In order estimate the impact of EVs alone (respectively Heat-Pumps alone) on the costs variation, we have implemented two specific versions of PartFlex case

1. PartFlexEV with only Electric Vehicles as flexible devices;

2. PartFlexHP with only Heat Pumps as flexible devices.

At the European level, we evaluated that in the PartFlex case, EVs alone are able to achieve 30 percent of the total costs decrease observed when using all the flexible devices while HPs alone are only able to achieve 5 percent of the total cost decrease. This show that EVs seems to represent a dominant part of the available flexibility when compared to HPs, at the european level. However, these rates are not equally distributed over countries since for instance in Germany EVs alone achieve 26% of the total costs decrease while HPs alone achieve 12.5% of the total cost decrease showing that in Germany HPs constitute an important source of flexibility.

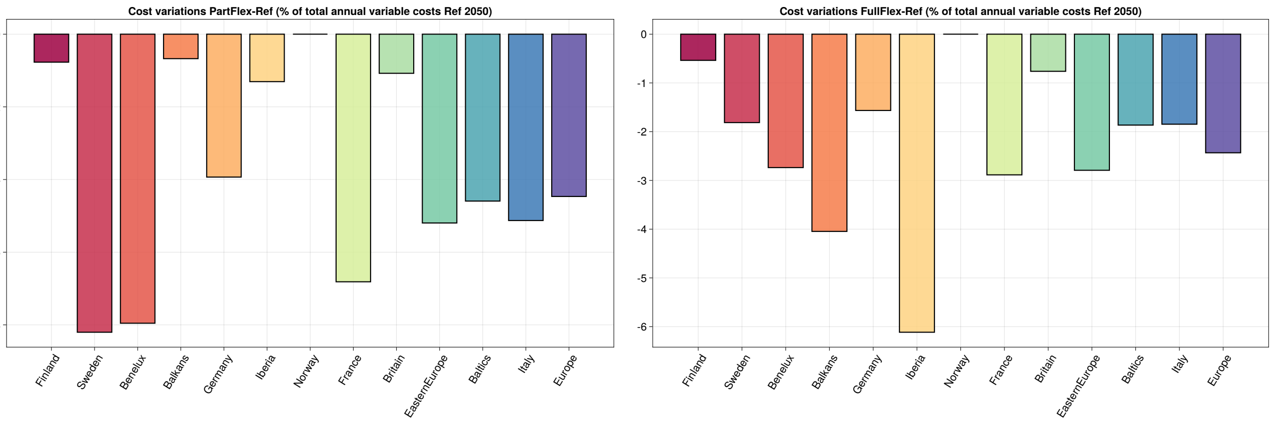


Figure 1.12: Percentage of variation of variable costs per region resulting from partial (on the left graph) or full (on the right graph) usage of flexibilities

Marginal costs

In this section, we analyze the impact on marginal costs of using flexible demand. Marginal costs are calculated as the dual variables of the supply-demand equilibrium constraint for each hour of year 2050 and for each of the 37 simulated chronicles. Four countries are considered for illustration purposes: Germany, Norway, Italy and France. Each graph below provides the average marginal costs over the 37 simulated chronicles and the associated dispersion on the average week (168 hours) of each season. The marginal costs corresponding to the reference case (without use of flexible demand) are represented in black, the marginal costs corresponding to the PartFlex case (with partial use of flexible demand) are represented in red and the FullFlex case (with full use of flexible demand) is represented in green. We can observe that the use of flexible demand allows on the one hand to reduce the average level of marginal costs, in particular by reducing the spikes and in the other hand to reduce the dispersion of the marginal costs.

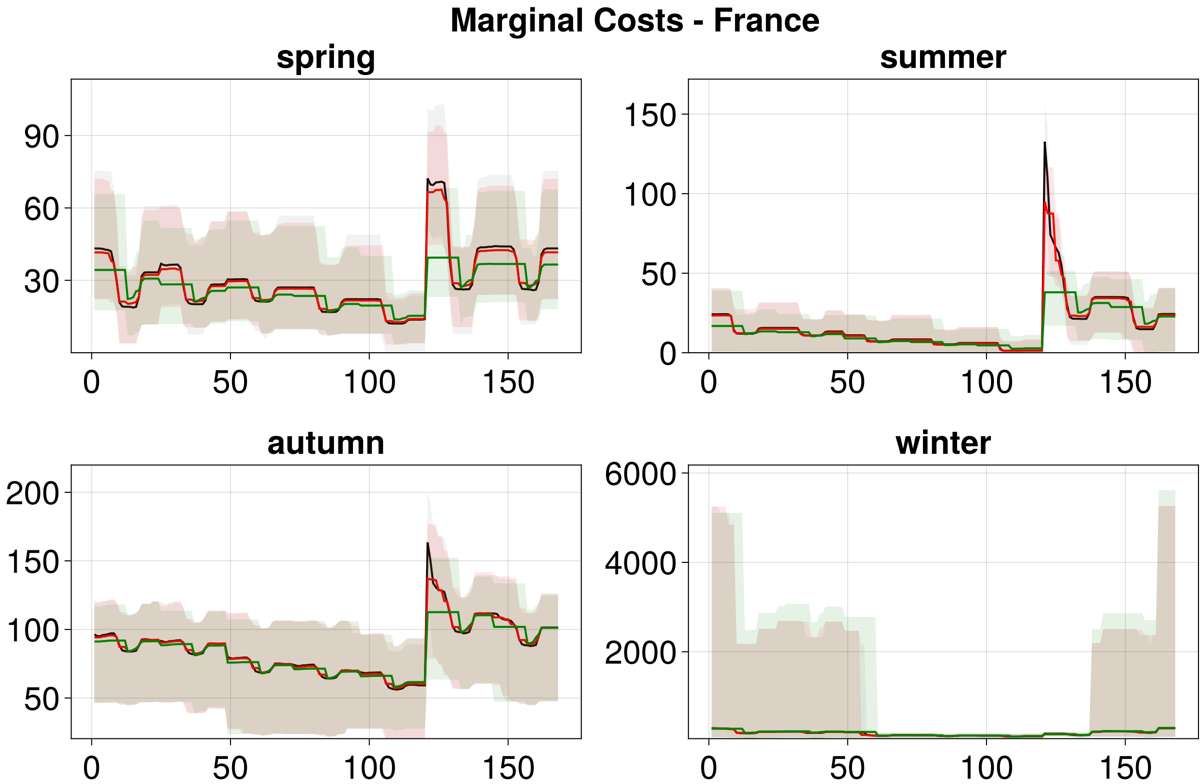


Figure 1.13: France Marginal costs average week per season average/min/max over 37 chronicles for reference (in black), PartFlex (in red) FullFlex (in green)

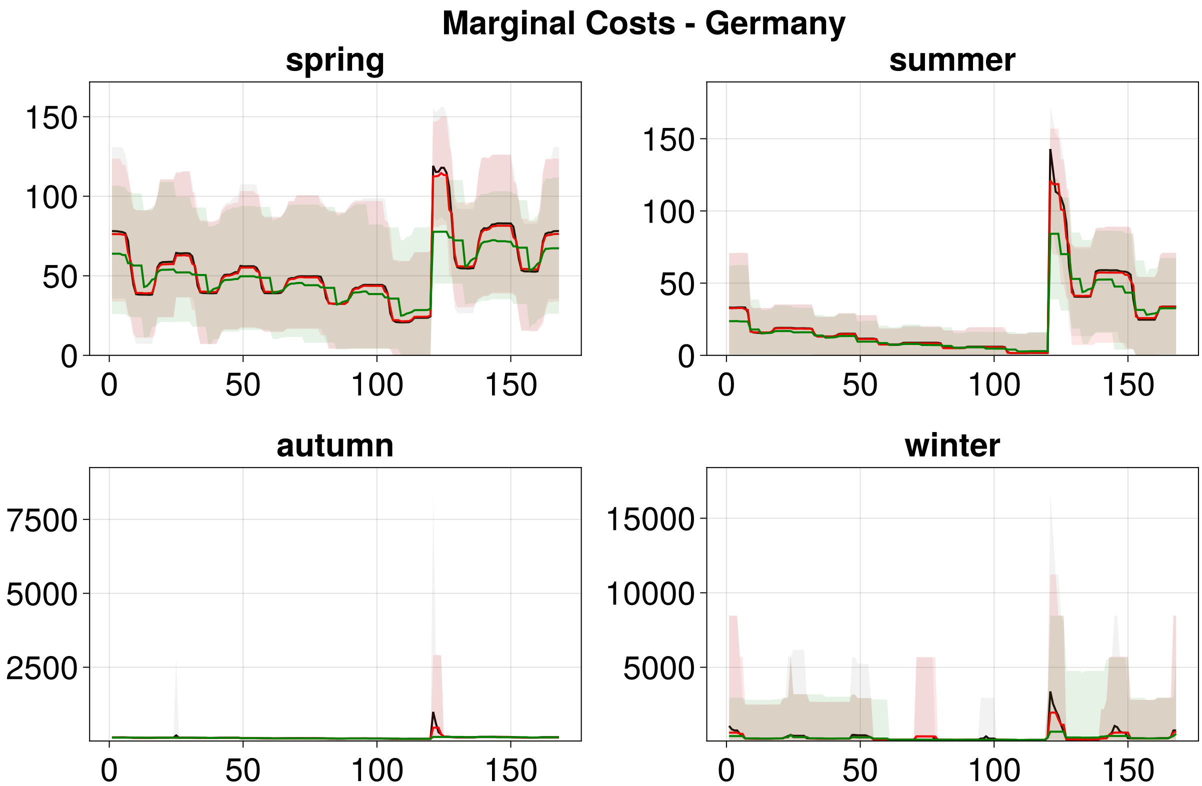


Figure 1.14: Germany Marginal costs average week per season average/min/max over 37 chronicles for reference (in black), PartFlex (in red) FullFlex (in green)

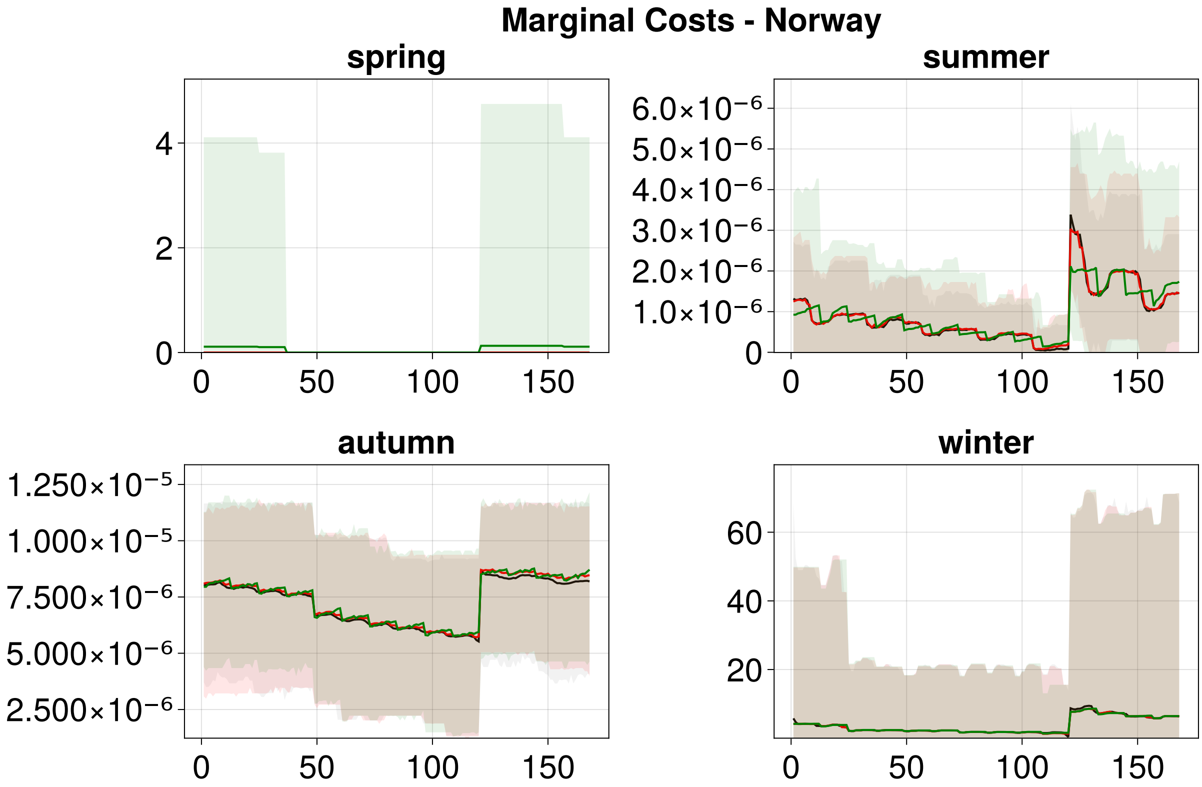


Figure 1.15: Norway Marginal costs average week per season average/min/max over 37 chronicles for reference (in black), PartFlex (in red) FullFlex (in green)

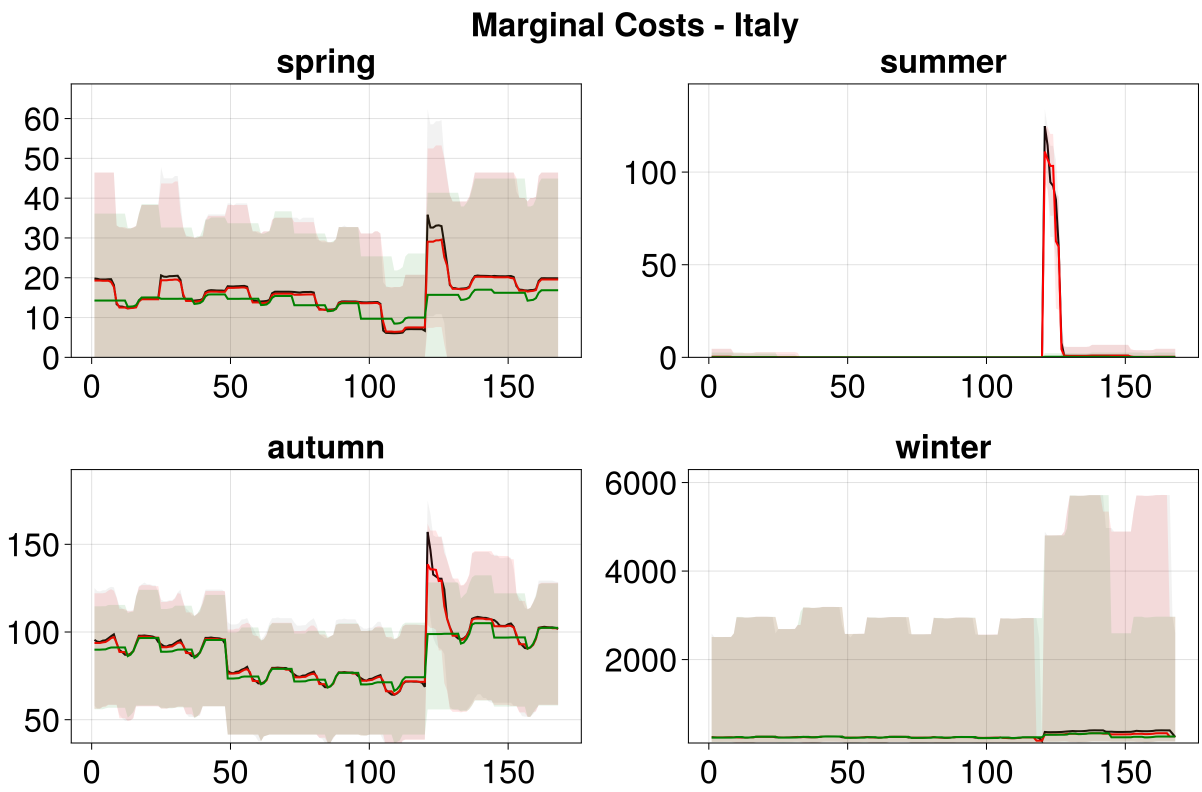


Figure 1.16: Italy Marginal costs average week per season average/min/max over 37 chronicles for reference (in black), PartFlex (in red) FullFlex (in green)

On Table 1.7.2 below, we observe that the use of DLC allows to reduce both the average value and the dispersion of marginal costs essentially during spring and summer.

	spring & summer	**autumn & winter**
	value | dispersion	value | dispersion
PartFlex	5% | 2%	1.5% | 4%
FullFlex	30% | 11%	2% | 0%

Table 1.2: Reduction of marginal costs values and dispersion averaged over countries

Distribution of energy generated per technology

In this section, we analyze the impact of using flexible demand on the management of generation and storage assets. We focus on the FullFlex case because the differences obtained in the PartFlex case are too small to be interpreted. On Figure 1.17, we have reported for each season and for each type of technology, the average variation of energy injected in the European grid implied by the full use of flexible demand as a percentage of the total energy generated over the year 2050 in the reference case. First, we can observe that the variations are greater in spring and summer than in autumn and winter. The use of flexible demand allows to increase the integration of photovoltaic energy into the grid by a quantity close to one percent of the generated energy while it reduces the use of small storages (including batteries and hydro pumps) by a quantity approximately equal to 1.3 percent the generated energy.

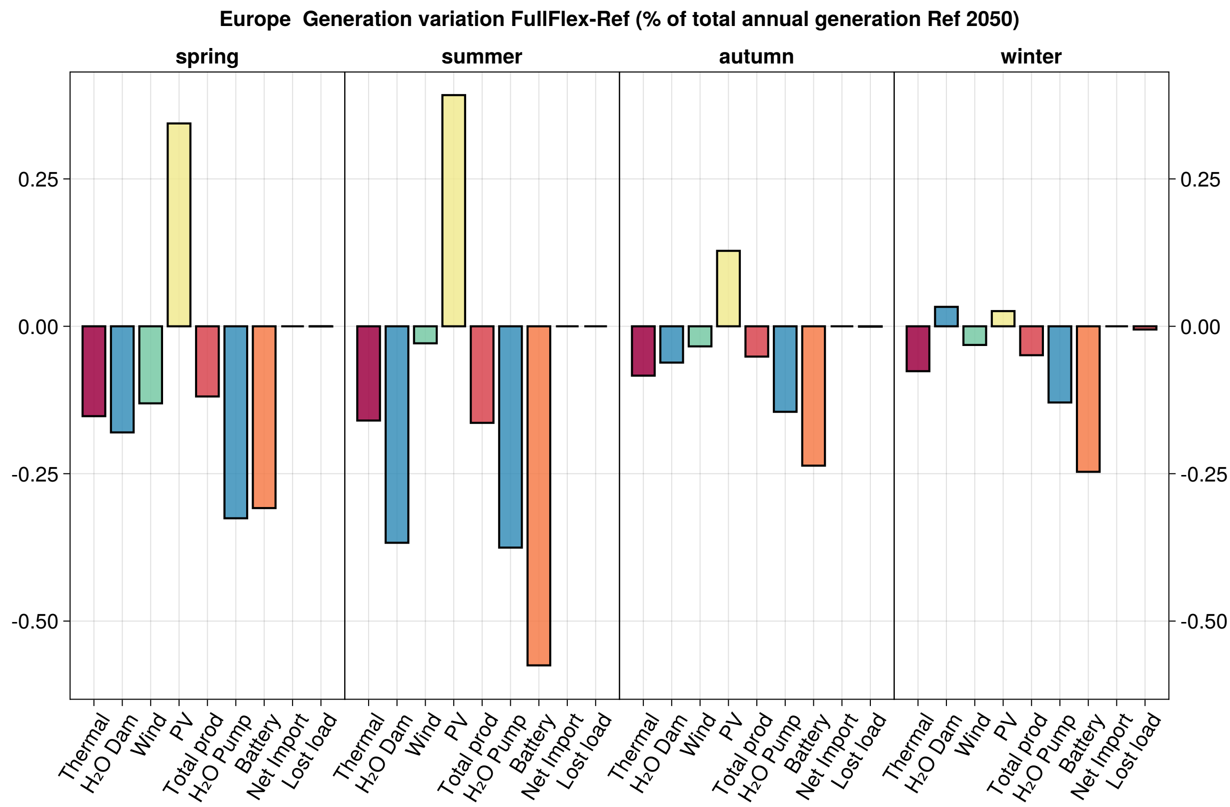


Figure 1.17: Variation of Europe energy generation per technology resulting from full usage of flexibilities

One can observe on Figure 1.17 that water from the seasonal storage is also less used, this may appear surprising since no operational costs are a priori associated to that water. However, this may be explained by the fact that some *artificial operational costs* are computed by the seasonal storage valuation tool in order to optimally decide within each week of the year, in the unit commitment tool, which unit should produce. However, to reduce the computational time, we have used, in the PartFlex and FullFlex case, the seasonal storage values computed for the reference case. This simplification induces a deviation from optimality that could explain this phenomena. On Figures 1.19 1.20 1.21 1.18, these results are specified for four particular regions: Germany, Norway, Italy and France. We have reported for each country, season and technology, the average variation of energy injected in the considered country induced by the full use of flexible demand as a percentage of the total energy generated in that country, in 2050, in the reference case. We can again observe that variations are always more important in spring and summer than in autumn and winter. On the other hand, the imports are reduced by approximately one to two percent. It seems that the impact of the flexible demand allows above all to absorb more photovoltaic energy and to reduce the need for small storages and importations.

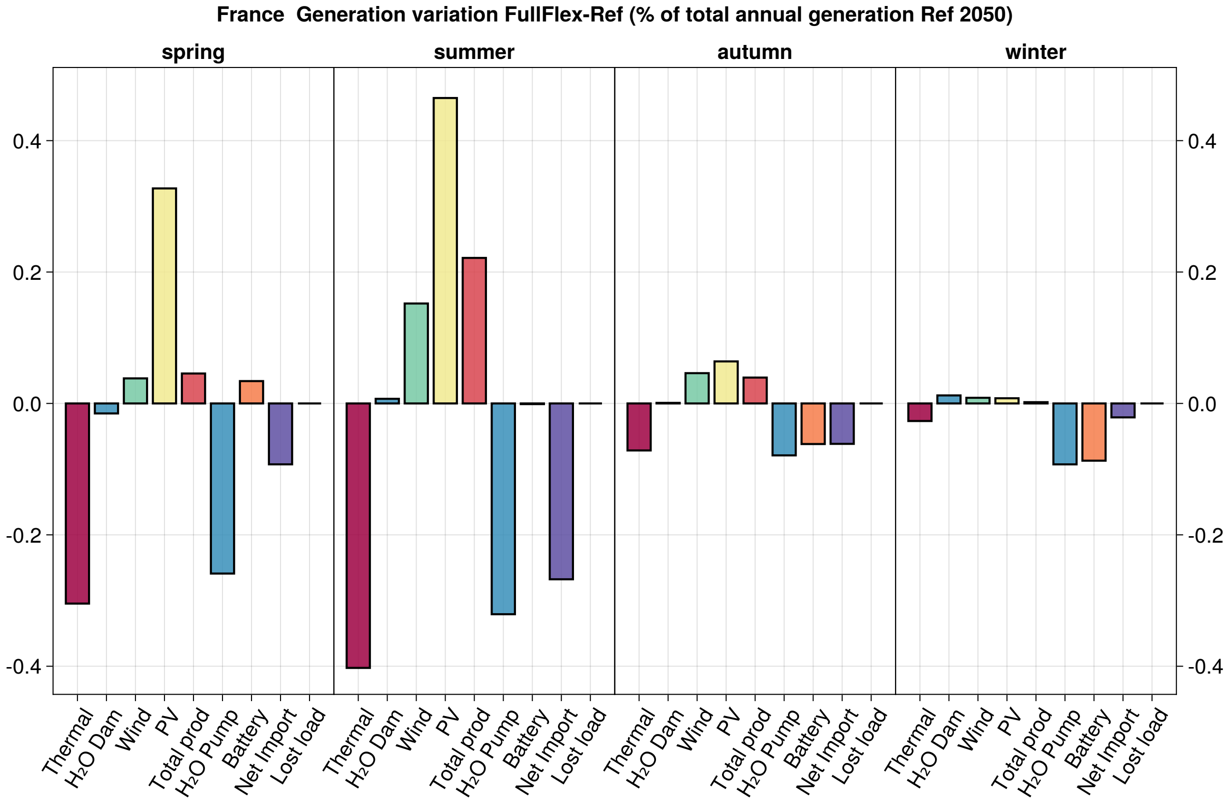


Figure 1.18: Variation of France energy generation per technology resulting from full usage of flexibilities

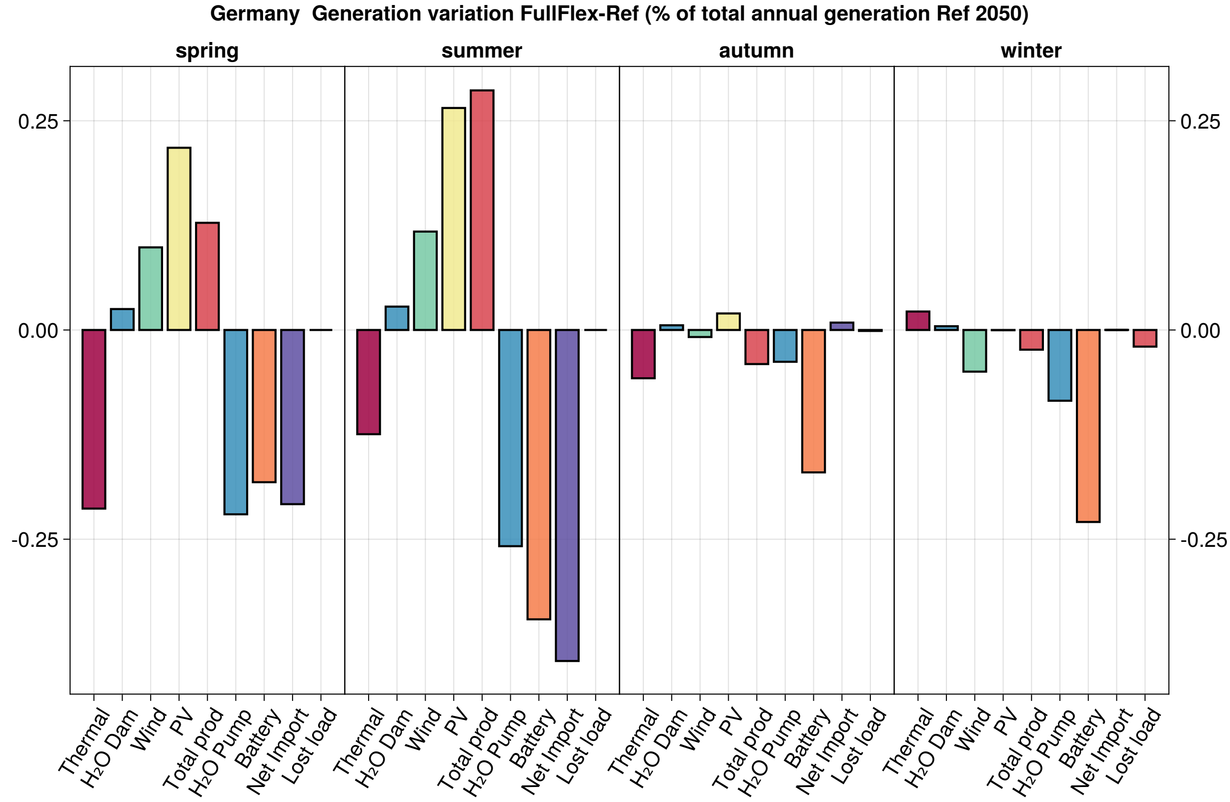


Figure 1.19: Variation of Germany energy generation per technology resulting from full usage of flexibilities

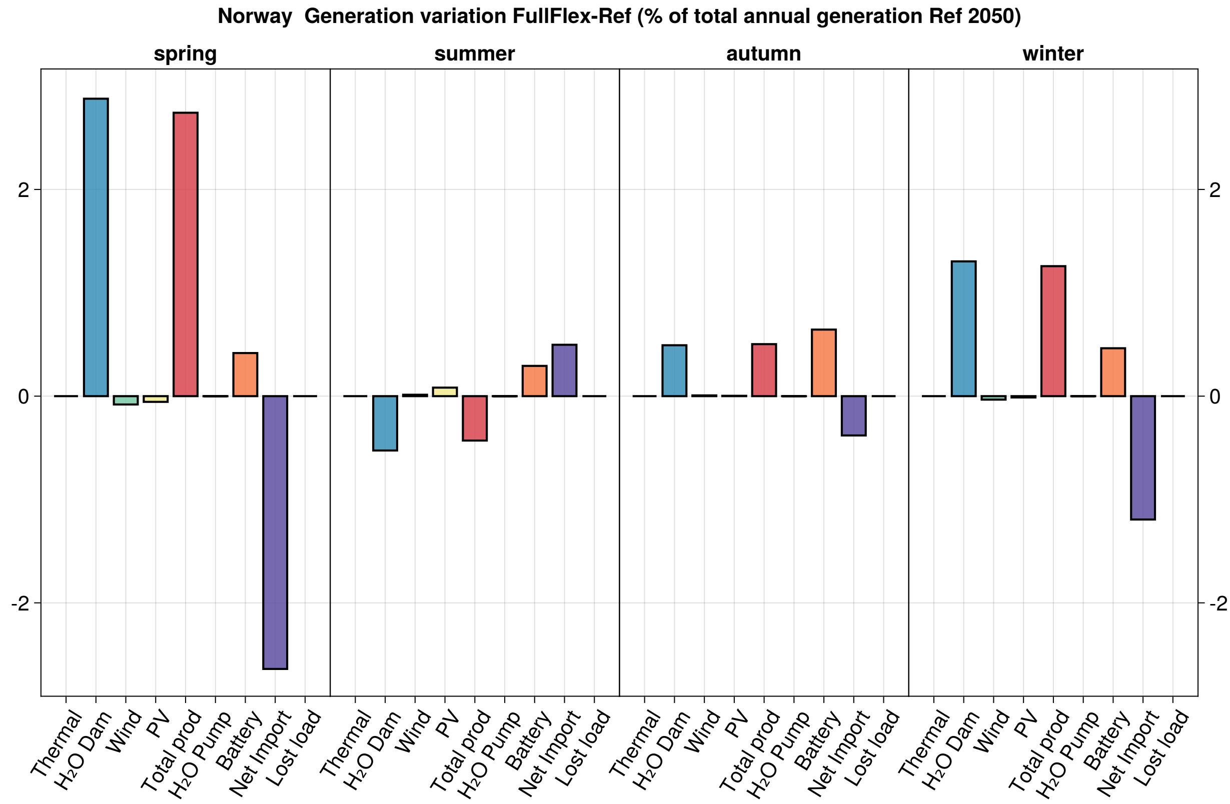


Figure 1.20: Variation of Norway energy generation per technology resulting from full usage of flexibilities

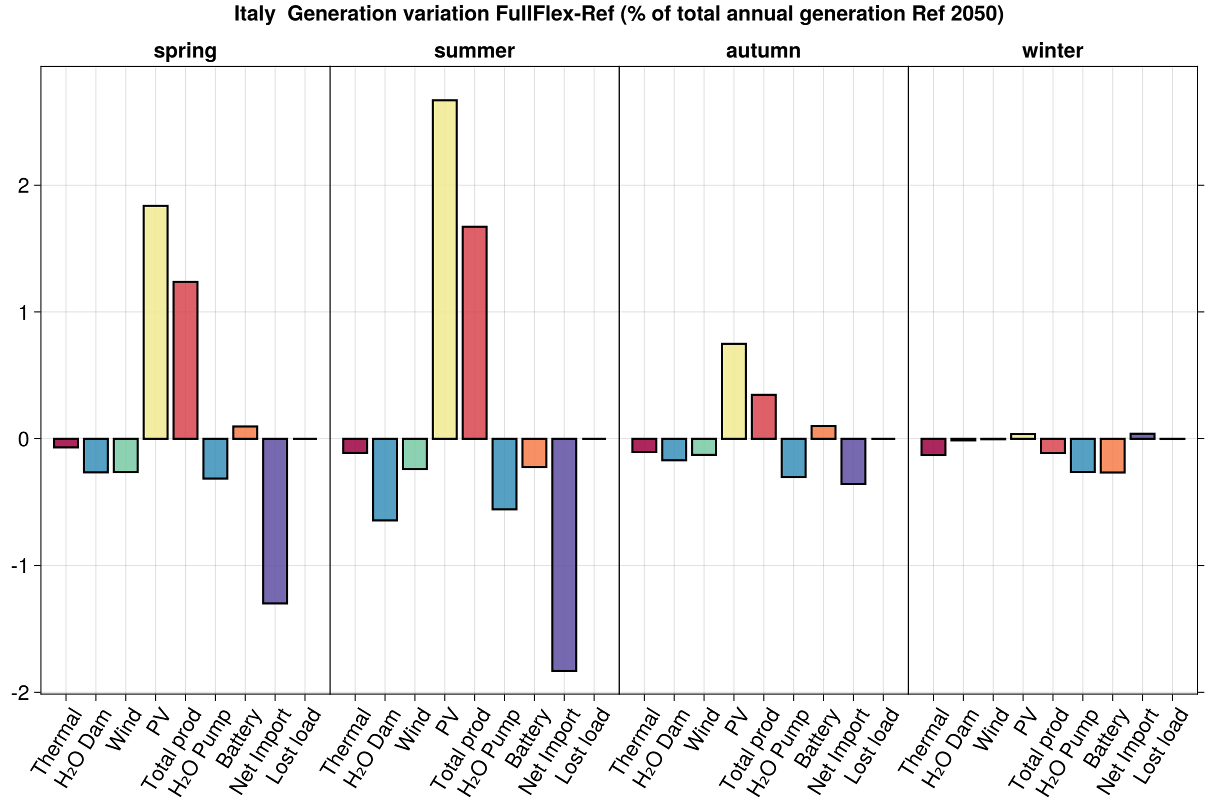


Figure 1.21: Variation of Italy energy generation per technology resulting from full usage of flexibilities

1.8 Limitations, potential extensions, future works

The limitations and the potential extensions of the current study can be assessed from three perspectives:

- DLC dataset :
  - A key limitation is that CS1 is only considering the DLC potential in the residential electricity sector while the commercial and industrial sector are certainly an important source of flexible consumption.
  - The conservative participation rate is estimated on the basis of pilot conducted in 2018 so their are not reflecting the willingness of people to participate in DLC programs in 2050.
  - The work relies on assumptions and simplifications that do not fully capture the heterogeneity in load profiles and technologies between countries and NUTS2 regions. Future efforts should focus on using improved data to capture the spatial heterogeneity.
  - We assumed conservative expectations for the usable life of electric vehicles and simplification of charging scenarios which could underestimate their future energy loads and corresponding flexibility potentials. To understand the full scope of benefits of controlled charging of electric vehicles, efforts should focus on establishing robust expectations for their usable life, integrating charging developments in highly urban settings, secondary applications for the batteries, and consider country dependencies for international used car import markets.
- Plan4EU
  - The power system is simulated on a single year (year 2050);

  - Hydro generation is aggregated (one lake by region);
  - seasonal storage values are computed in the reference case and re-used for the Partflex and FullFlex case inducing a deviation from optimality in these two latter cases;
  - The transmission network is simplified even if several nodes per region are considered, the model only considers nodes of the transmission network (without any representation of distribution grid). Besides, the power flow is approximated by a Net Transfer Capacity (NTC) model intended to represent commercial trades only, taking into account the capacity limits of the power lines, without any physical representation of the electrical power flows.

- EMPIRE
  - While the EMPIRE modelling framework is a stochastic problem and also considers short-term operational constraints, it makes some simplifying assumptions to yield a tractable model. It only includes the active power flows. In addition, each country is modelled as a bulk node, and various generation resources and loads are aggregated for these nodes.
  - The method that is used to model the shift time of responsive loads is another limitation of the EMPIRE model. In EMPIRE, the loads can only shift during fixed time windows which are placed one after another. The length of each shift window for each category of responsive loads is equal to its shift time. This gives a lower boundary of the impact of responsive loads. It may be viable to model the responsive loads without this limitation. This will be an important development of this work.
  - Another limitation of the study carried out by the EMPIRE model is the zero cost of DLC programs. The EMPIRE model has the capability of considering the costs associated with DLC programs — both the payments to responsive loads and the technological costs. However, since there was no input data, we considered the DLC model without any cost. This can be changed in future works.

1.9 Summary of main results, policy brief

- Plan4EU evaluates the impact of DLC on the 2050 European Electricity system in terms of operation costs, marginal costs and energy generated per technology. We observe that the use of DLC induces a reduction of operation costs of 0.45 % in the conservative case and close to 2.5 % in the optimistic case. Similarly, household DLC allows both to reduce the average level of marginal costs and their dispersion. In terms of energy, it contributes to decrease photovoltaic curtailment allowing to increase the use of photovoltaic energy by almost 1% of the generated energy, while it reduces the use of small storages by 1.3 % of the generated energy.

- EMPIRE: In this study, we used the EMPIRE modelling framework to estimate the impact of residential DLC programs on the long-term investment planning (2020–2060) of the European electricity system. In this regard, four case studies that included DLC programs were developed to characterize different pathways toward the participation of residential responsive loads in direct load control programs. The results were promising. In the best case, the result showed a 0.99% improvement in the total cost of the system. The impact participation of residential loads in direct load control programs was evaluated from various aspects, including long-term investment planning and short-term operation of the system. According to the results, implementing DLC programs will decrease the need for Li-Ion batteries to a high degree, decrease the electricity price per MW, and allows the higher penetration of PV plants. However, there is still room for improvement in this study. Particularly, it is necessary to continue this study in two directions. First, the other load sectors, including commercial and industrial sectors, should be included in the study. Second, the costs associated with DLC programs should be considered in the model.

1.10 Appendix

1.10.1 Results Related to EMPIRE Modelling Framework

Installed Capacity of All Available Technologies in Case IV

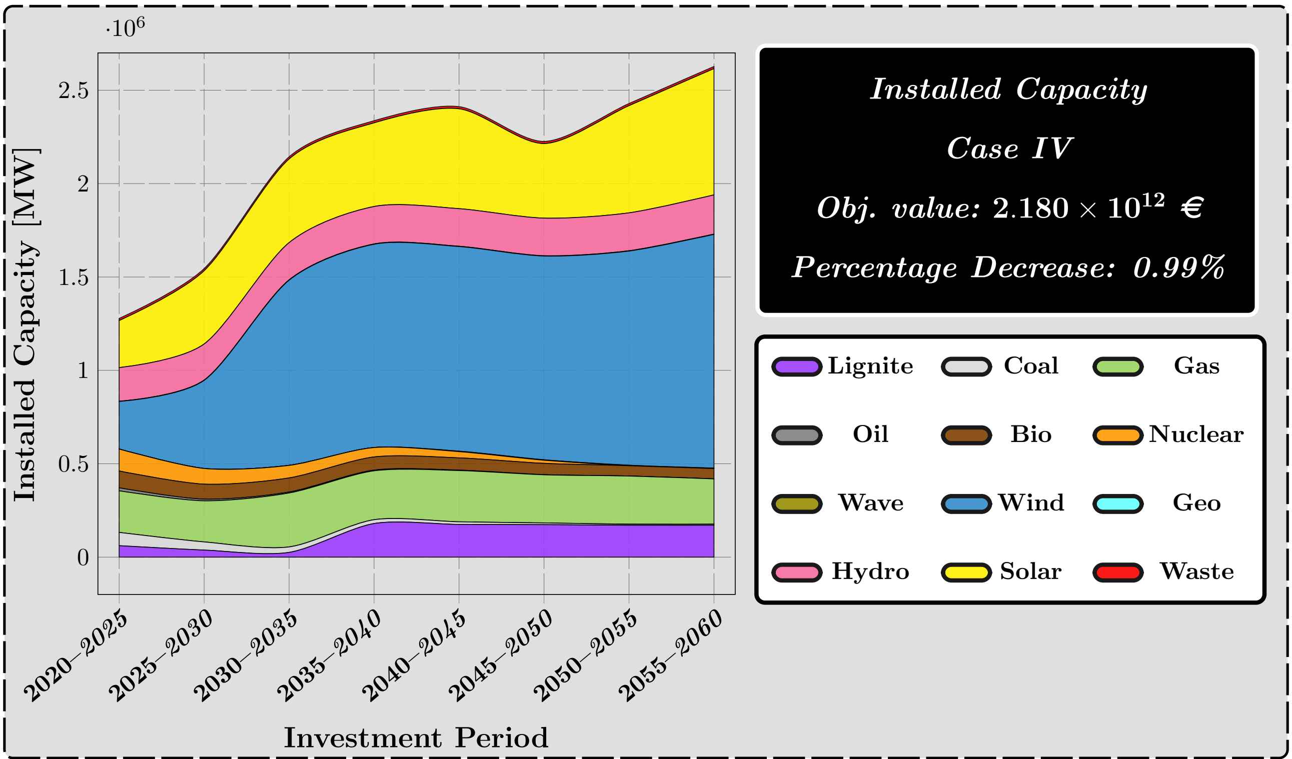


Figure 1.22: European energy transition: Installed capacity of various resources from 2020 to 2050 with residential DLC programs (**Case IV**).

Annual Expected Generation of all Available Technologies in the Base Case

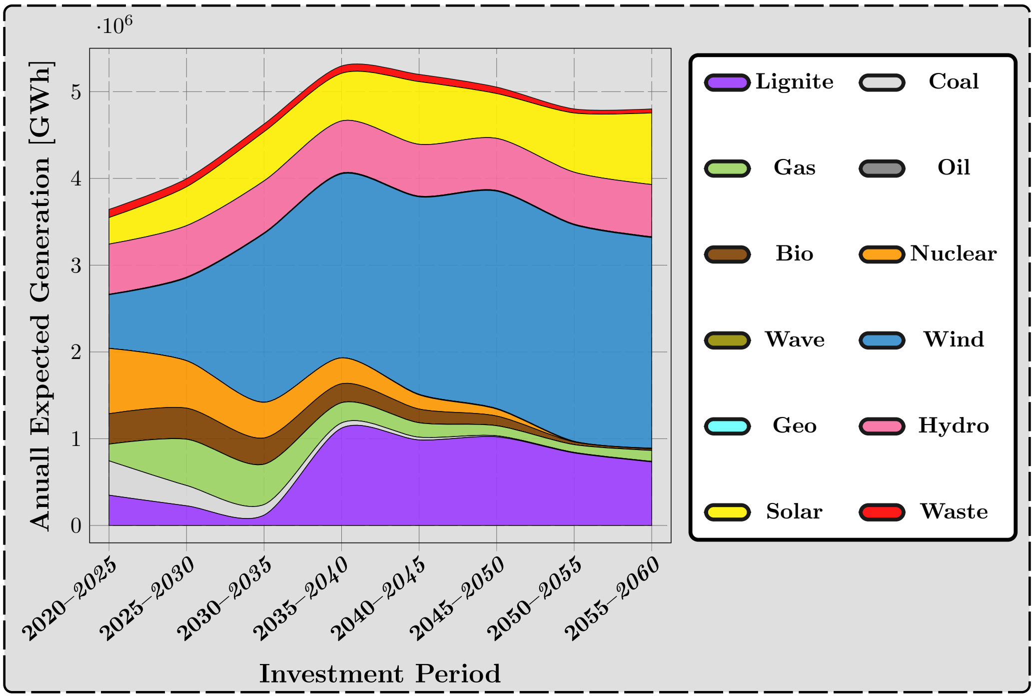


Figure 1.23: Annual Expected Generation of various resource in the **Base Case**.

Percentage of interrupted loads for all case studies in EMPIRE.

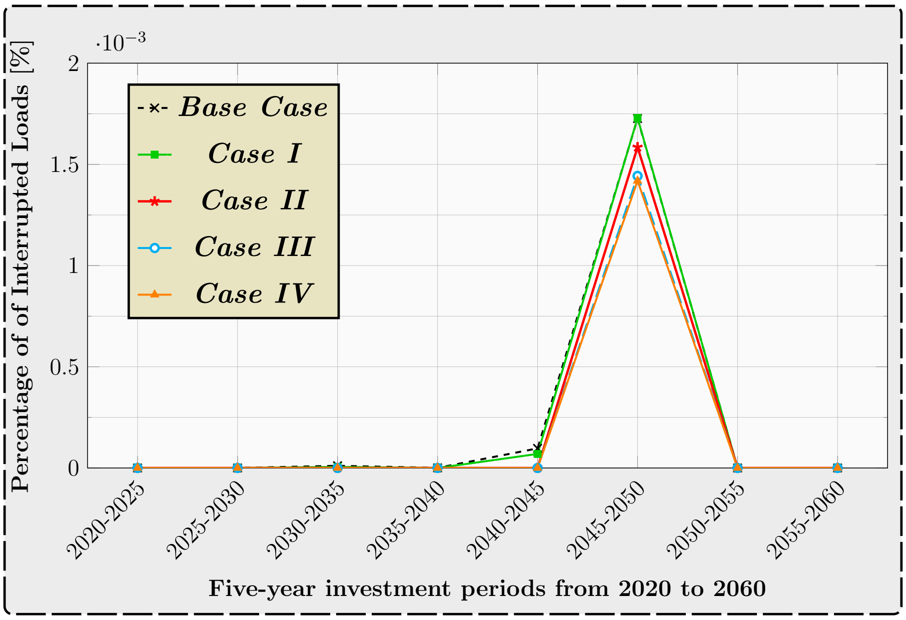


Figure 1.24: Percentage of interrupted loads for all case studies.

1.10.2 Average profiles of flexible DLC provided by plan4EU for France

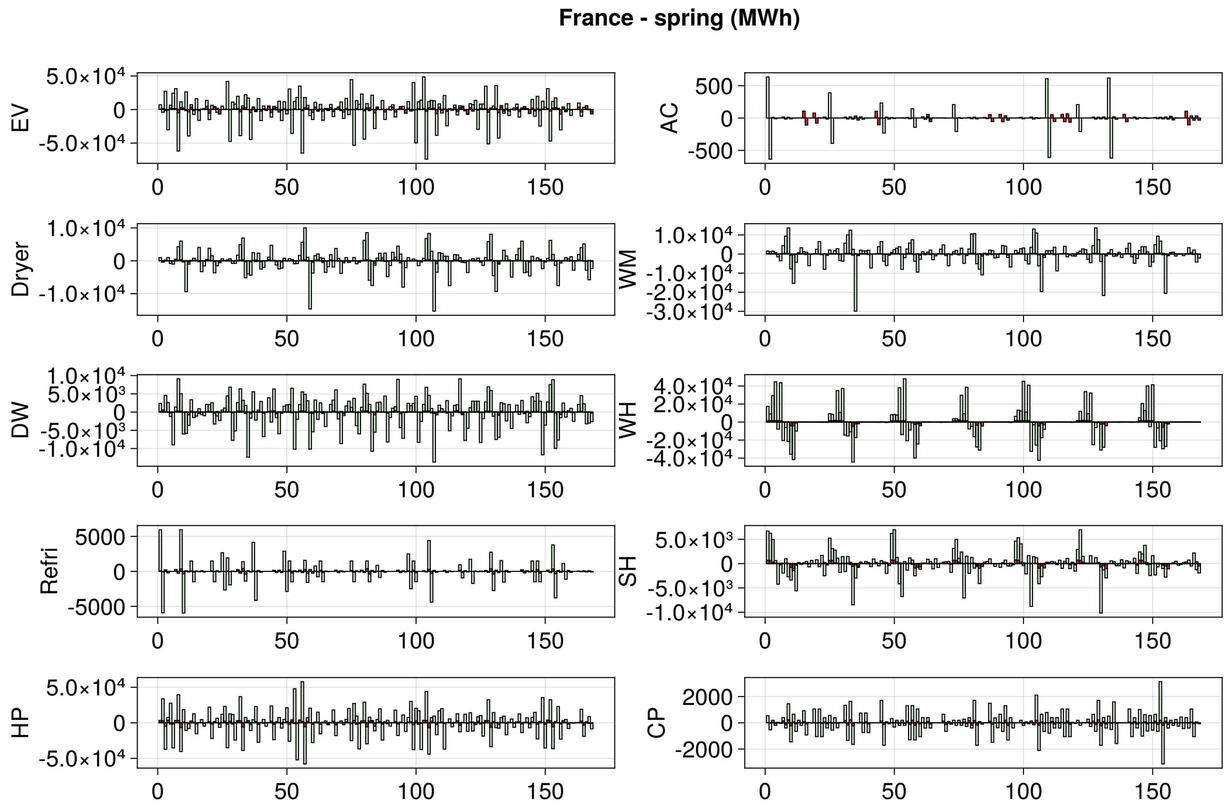


Figure 1.25: Average week per device (FullFlex in green and PartFlex in red)

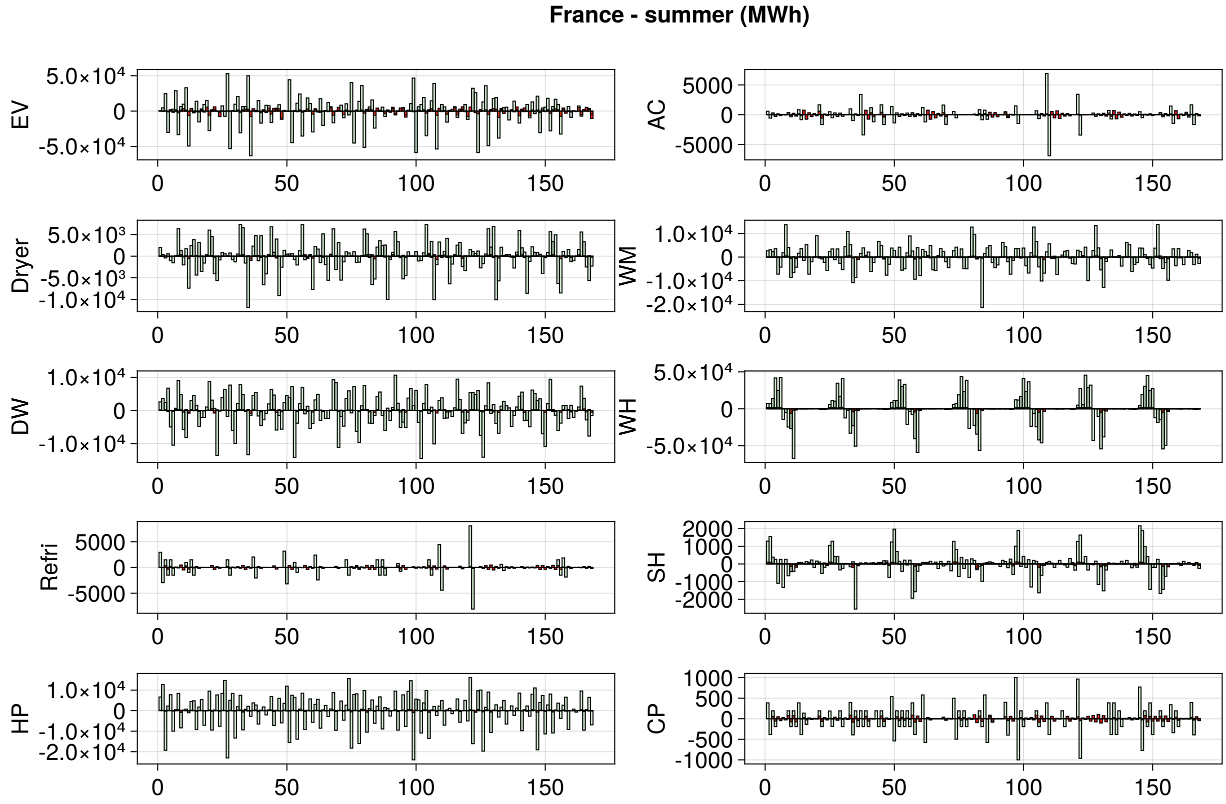


Figure 1.26: Average week per device (FullFlex in green and PartFlex in red)

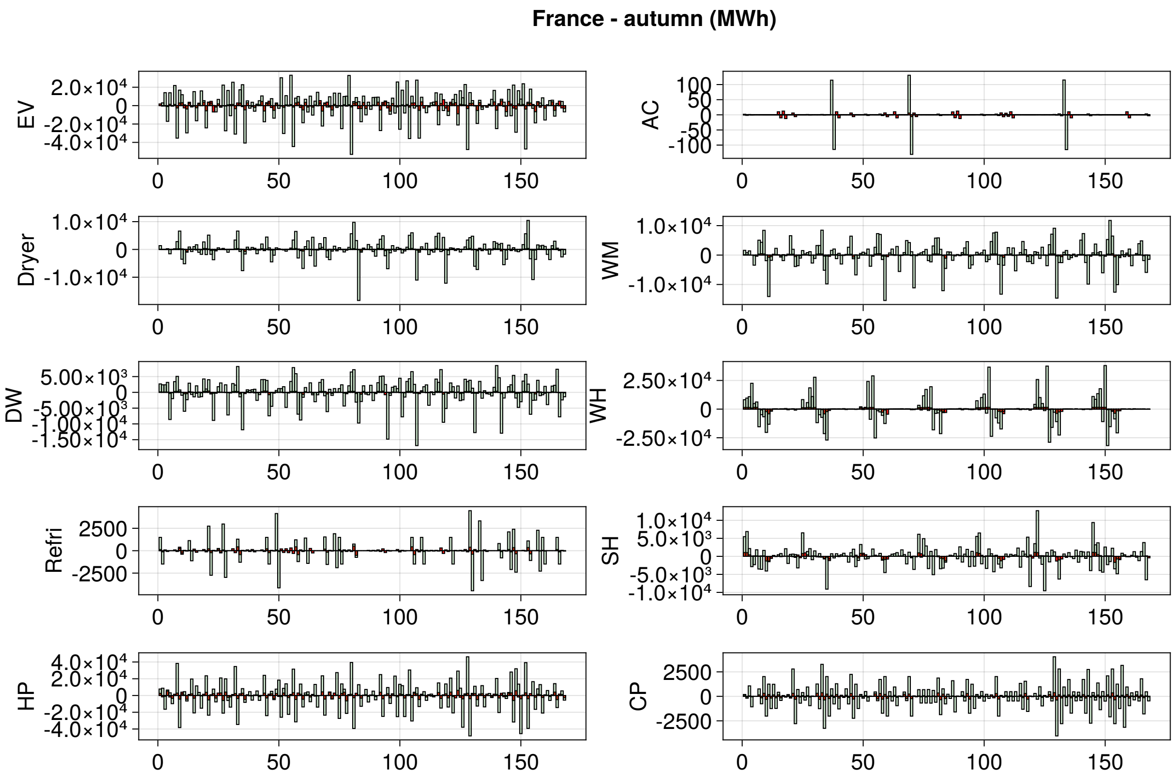


Figure 1.27: Average week per device (FullFlex in green and PartFlex in red)

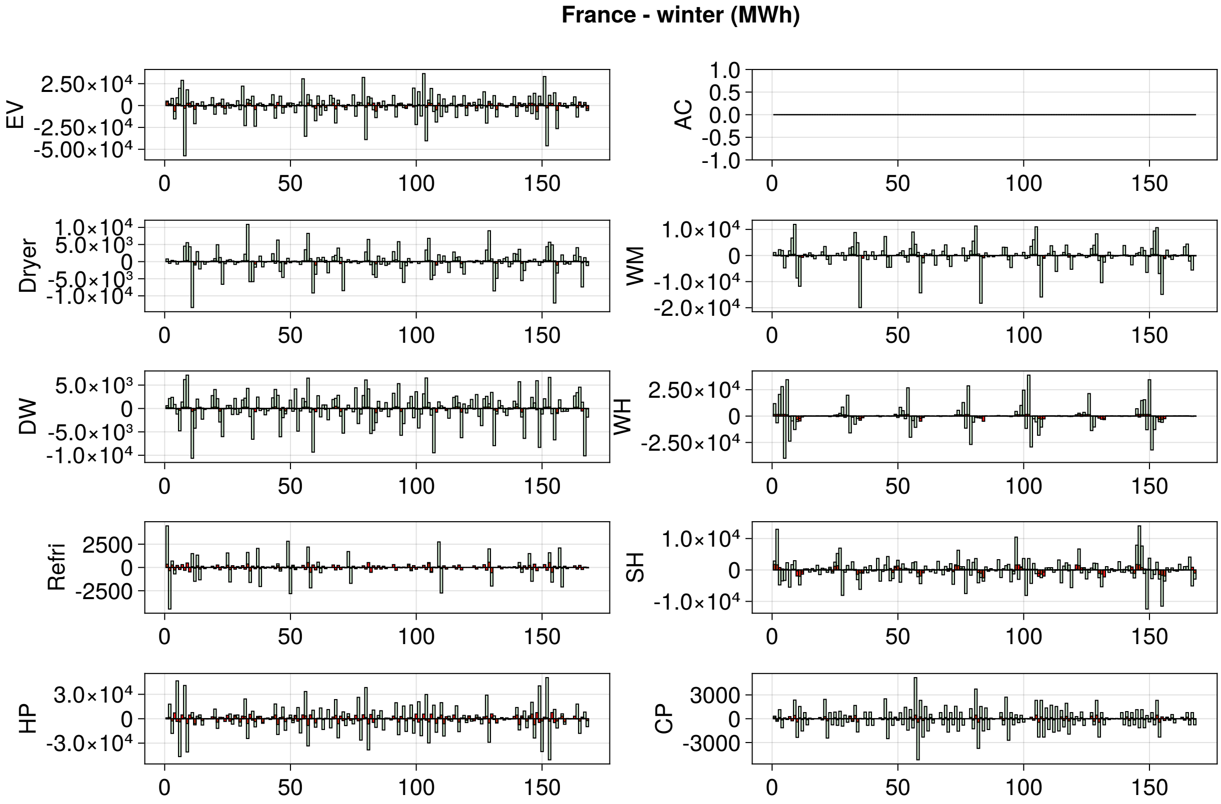


Figure 1.28: Average week per device (FullFlex in green and PartFlex in red)

1.11 References

[1] Stian Backe, Christian Skar, Pedro Crespo del Granado, Ozgu Turgut, and Asgeir Tomasgard. Empire: An open-source model based on multi-horizon programming for energy transition analyses. *SoftwareX*, 17:100877, 2022. https://doi.org/10.1016/j.softx.2021.100877.

[2] European Commission Eurostat. Average number of persons per household by household composition, number of children and age of youngest child, 2021. data retrieved from Eurostat `https://ec.europa.eu/eurostat/databrowser/view/lfst_hhantych/default/table?lang=en`.

[3] European Commission Eurostat. Population on 1st january by age, sex, type of projection and nuts 3 region, 2021. data retrieved from Eurostat `https://ec.europa.eu/eurostat/databrowser/view/proj_19rp3/default/table?lang=en`.

[4] Hans Christian Gils. Assessment of the theoretical demand response potential in europe. *Energy*, 67:1–18, 2014.

[5] Hans Christian Gils. Balancing of intermittent renewable power generation by demand response and thermal energy storage. 2015.

[6] Ioannis Lampropoulos, Wil L Kling, Paulo F Ribeiro, and Jan van den Berg. History of demand side management and classification of demand response control schemes. In *2013 IEEE Power & Energy Society General Meeting*.

[7] Ioannis Lampropoulos, Wil L Kling, Paul PJ van den Bosch, Paulo F Ribeiro, and Jan van den Berg. Criteria for demand response systems. In *2013 IEEE Power & Energy Society General Meeting*, pages 1–5. IEEE, 2013.

[8] Cohen Jed O'Reilly, Ryan and Johannes Reichl. openentrance - case study 1 - residential demand response - data and scripts [data set]. Technical report, 2022. Zenodo. https://doi.org/10.5281/zenodo.7871106.

[9] Bryony Parrish, Rob Gross, and Phil Heptonstall. On demand: Can demand response live up to expectations in managing electricity systems? *Energy Research & Social Science*, 51:107–118, 2019.

[10] Cohen Jed Kollmann Andrea Azarova Valeria Klöckner Christian Royrvik Jens Vesely Stepan Carrus Giuseppe Panno Angelo Tiberio Lorenza Fritsche Immo Masson Torsten Chokrai Parissa Lettmayer Gudrun Schwarzinger Stephan Reichl, Johannes and Neil. Bird. International survey of the echoes project (1.0.0.) [data set]. Zenodo, 2019. https://doi.org/10.5281/zenodo.3524917.

[11] Jonathan Spinoni, Jürgen V Vogt, Paulo Barbosa, Alessandro Dosio, Niall McCormick, Andrea Bigano, and Hans-Martin Füssel. Changes of heating and cooling degree-days in europe from 1981 to 2100. *International Journal of Climatology*, 38:e191–e208, 2018.

Chapter 2

Case Study 2: Behaviour of communities of actors

Abstract

The openENTRANCE case study two "Behavior of communities of actors" aims to analyze energy communities on a local level as well as on country and European level.

The overall objective includes studying a variety of energy community patterns and set-ups (incl. annual phase-in and phase-out of community actors resulting in frequent re-allocations of the default set-up), and upscaling the potential of energy communities for different European countries based on building stock, PV potential, electricity consumption. Subsequently, the quantitative potential of local energy communities is conducted for Europe as a whole.

The case study involves the energy community model FRESH:COM, which considers the electricity sector, and only at the local level. Communities of actors are, in particular, energy communities where prosumers are active participants in the energy system (actors) and members trade self-generated PV electricity with each other (peer-to-peer trading). The framework of the case study includes voluntary participation of prosumers in energy communities and the consideration of individual willingness-to-pay. Hence, we assume low entry barriers (no closed systems, but energy sharing within parts of the distribution network). As part of the case study, also dynamic phase-in and phase-out of members is analyzed. The local energy community model is then used to find the country-wide potential of energy communities in five European reference countries. Here, the potential of energy communities represents an estimated upper-bound for welfare gains that would result from a large-scale deployment of energy communities.

The main results include insights into electricity trading in energy communities, economic balances and emissions savings. Also, we derive the theoretical potential of energy communities for selected countries and the respective savings from consumer/prosumer point of view. We found that, in theory, approximately up to 11.5 million residential energy communities could be implemented in Europe. Depending on the settlement pattern structure of energy communities, self-consumption of PV generation in communities could increase by up to 70%.

Future extension of this work could include how "price cannibalism" could effect energy communities. Also, extensions to include sector coupling could be implemented in the energy community model.

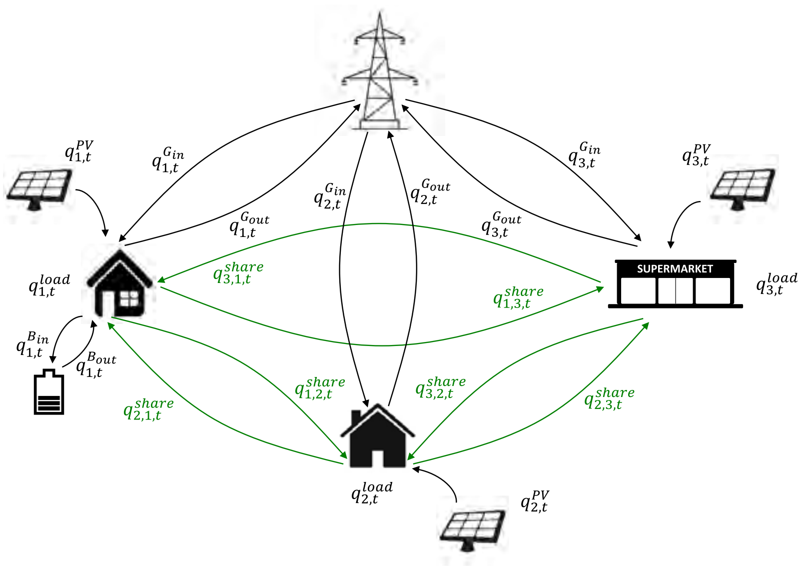


Figure 2.1: Sketch of electricity trading in an energy community

Contents

2.1 Introduction

2.1.1 Overall objective of case study

The concept of optimizing local PV self-generation and consumption on 'prosumers' level is already well established in many European countries. Recently, a further development of this concept beyond individual prosumer boundaries to neighbourhood and district levels has been triggered not least by the European Commission's "Clean Energy for all Europeans" package [5], where the establishment of energy communities and further democratization of the energy system is explicitly mentioned. Moreover, favorable amendment of legislation and regulations in this context have been made in some European countries (e.g., Germany, Austria).

In this case study, members/actors of the communities are characterized by an individual willingness-to-pay for local photovoltaic (PV) generation from the community. Participation is on a voluntary basis and the individual needs of the community members are considered (fully democratic participation). The actors involved can be regular households or small businesses (small and medium-sized enterprises – SMEs), with different demographic backgrounds and different individual objectives. The baseline of the analyses of this case study are energy communities of different structures, e.g., in terms of renewable technologies or system boundaries (building level, spatial extent, distribution grid anatomy, peer-to-peer matching/trading in a wider context, etc.), and self-sufficiency is not intended by the community.

In short, the objectives of the case study are:

- Studying a variety of energy community patterns and set-ups (incl. annual phase-in and phase-out of community actors resulting in frequent re-allocations of the default set-up).
- Upscaling the potential of energy communities for different European countries based on building stock, PV potential, electricity consumption, and subsequently the quantitative potential of local energy communities is conducted for Europe as a whole.

2.1.2 State of the art

2.1.2.1 Comparison of energy communities in Europe

Parts of the analyses in case study 2 are based on a net present value maximization for PV sharing in energy communities for four characteristic settlement patterns in Austria, which is performed in [19], and on [20], where a cost-optimal potential of energy communities in Austria as a whole is found. Building on different scenarios for the European energy system in 2030, [61] analyze the potential influence of local energy communities on the national energy system of three reference countries. The effects of energy communities on the European electricity and heating system are analyzed in [3]. The large scale roll-out of energy communities across Europe causes less capacity expansion across Europe and storage capacity expansion is decreased. Generation capacity expansion shifts from building heating capacity towards electricity production capacity. Focusing on Nordic countries, the implications of zero emission neighborhoods on the power system are analyzed in [2].

2.1.2.2 Recent developments in the field of energy communities in Austria, Greece, Norway, Spain, and England

Austria In Austria, the so-called *Erneuerbaren-Ausbau-Gesetz* (EAG, see [44]) defines renewable energy communities (Erneuerbare-Energie-Gemeinschaft) and citizen energy communities. Thereby, a renewable energy community is limited to a certain proximity of its participants. Austria offers lower grid tariffs to members of renewable energy communities, which strongly incentivizes the creation of new energy communities. [18] outline and discuss the transposition of European guidelines for energy communities into Austrian law.

Greece The concept of energy communities was established in the Greek Law in 2018 (L.4513/2018). An analysis of this law is provided by [8]. [46] critically review the Greek transposition of REDII into its legislative framework: unjustified administrative and regulatory barriers should be removed, and citizens should have access to finance and information facilitated. The ECOISM project ([58]) fosters the set-up and operation of energy communities in the small islands of Greece.

Norway [1] reviews the regulatory challenges regarding billing practices in Norway for zero energy communities or neighborhoods. A scenario calculator for smart energy communities is developed by [60] for the Norwegian use case.

Spain Analyzing the profitability of PV self-consumption, [14] put the Spanish regulatory framework into European perspective. Compared to other countries, the Spanish regulations lead to significantly lower net present value (NPV) for prosumers. The Royal Decree 244/2019 (see [26]) defines the regulatory development for creating energy communities. A recent study in [23] evaluates energy communities under this new Spanish regulatory framework on regional level, concluding that self-consumption is cost-effective. [31] investigates the impact of dynamic allocation coefficient and different electricity tariffs on the profitability of local energy communities in Spain.

England For the English case, [35] reviews business models for energy communities in a post-subsidies environment. [7] shows that support for grassroots, citizen-led action is reduced in favour of institutional partnerships and company-led investments in recent UK policy developments on decentralized energy, which has shifted from community energy to local energy.

2.1.2.3 Challenges beyond state-of-the-art

The challenges of case study 2 that go beyond state-of-the-art can be summarized as follows:

- Individual willingness-to-pay of different actors involved
- No closed system (the energy communities are part of the local distribution grid)
- Analyzing different settlement patterns and upscaling the potential for energy communities for a whole country
- Upscaling the community potential for Europe as a whole

2.2 Short summary of models used

The model FRESH:COM[1] developed in [38] is applied in case study 2 to optimally allocate PV electricity within an energy community via peer-to-peer trading. The model was made open-source during this project and is available on GitHub (see [54] and `https://www.github.com/tperger/FRESH-COM`). A short summary of the properties of the model is presented in the following:

- Members can be private households or small or medium-sized enterprises (SMEs)
- Participants have different reasons to join an energy community (economic or ecologic aspects)
- Fully democratic participation: voluntary participation, willingness-to-pay for renewable energy
- Renewable energy technologies: PV and battery storage
- Peer-to-peer trading via public grid

[1]FRESH:COM is an acronym for FaiR Energy SHaring in local COMmunities.

- Linear optimization model with the objective function to maximize the community's total welfare

There are three scientific publications related to the model FRESH:COM: [38], [37], and [39]. The model is implemented in Python using Pyomo and Gurobi.

2.3 Assumptions

For case study two, the following assumptions have been made:

- The energy community model FRESH:COM considers the electricity sector, and only at the local level.
- The case study considers communities of actors, hence energy communities where prosumers are active participants in the energy system (actors).
- Framework of energy communities:
  - Voluntary participation and consideration of individual willingness-to-pay
  - PV electricity sharing beyond the meter
  - Low entry barriers: No closed systems, but part of the distribution network
  - Dynamic phase-in and phase-out of members
- The results of the potential of energy communities in case study two are in line with the Societal Commitment story line. The potential of energy communities represents an estimated upper-bound for welfare gains that would result from a large-scale deployment of energy communities.

2.4 Methodology

2.4.1 Case study workflow

1. Defining the communities: The first step of this case study will be the definition of the different system boundaries of local energy communities, starting from a single prosumer. The different concepts include shared local energy management (matching renewable electricity self-generation and consumption, supported by battery storage) within a:
   - multi-apartment building,
   - a local neighbourhood/district,
   - a small village.

   The technology portfolio includes:
   - PV (rooftop, building integrated, small-scale ground mounted)
   - supported by small battery energy storage system (BESS)
2. Defining actors and settlement patterns: Set-ups in terms of actor portfolios, e.g.
   - tenant/owner structure multi-apartment building,
   - building/population/small businesses structure in a village

   Considering also diversity of settlement patterns in
   - dense cities,

- sub-urban and
- rural areas.

In addition, the individual objectives of the actors to join the community are determined (e.g. maximizing local self-generation, minimizing electricity purchase costs, avoiding emissions and/or externalities).

3. Determining the energy community potential for Austria: In terms of geographic coverage, a thorough quantitative assessment of the short- and long-term local energy community potential is planned for Austria (considering several important structural indicators necessary to describe the communities in a tailor-made metrics).
4. Determining the energy community potential for 4 reference countries in Europe: On higher aggregation level (in terms of empirical indicators necessary to describe the communities) additional 4 European 'reference countries' (representing e.g. the Iberian Peninsula, South-Eastern Europe, UK, Scandinavia) are also quantitatively analysed.
5. Finally, a quantitative upscaling of the short- and long-term local energy community potential is conducted for Europe as a whole, again using a metrics with a variety of country-specific structural and energy sector-related data. Matching this metrics with the countries where detailed quantitative results have been computed, accompanied by plausibility considerations, enable upscaling on European level.

2.4.2 Overall methodology

This Section describes the modeling approach of case study 2. First, we present the local energy community model FRESH:COM in Section 2.4.2.1, then our proposed method to derive the potential of energy communities in five European reference countries in Section 2.4.2.2, and finally we present the quantitative upscaling for Europe as a whole in Section 2.4.2.3.

2.4.2.1 FRESH:COM

In this Section, we explain the energy community model FRESH:COM in more detail.[2] The first part shows static participation in energy communities, i.e., when no members join or leave the community. In the second part, dynamic participation, we show the proposed method for adding new members to energy communities.

Static participation in energy communities For static participation, the model is applied to optimally allocate PV electricity within an energy community via peer-to-peer trading. The objective function of the linear program maximizes the community welfare (CW). CW is defined as following:

$$CW = \underbrace{\sum_{t\in\mathcal{T},i\in\mathcal{I}} p_t^{G_{out}} q_{i,t}^{G_{out}} - \sum_{t\in\mathcal{T},i\in\mathcal{I}} p_t^{G_{in}} q_{i,t}^{G_{in}}}_{\text{I}} + \underbrace{\sum_{t\in\mathcal{T},i,j\in\mathcal{I}} wtp_{i,j,t} q_{i,j,t}^{share}}_{\text{II}}. \tag{2.1}$$

Part I of community welfare measures the optimal resource allocation at the community level, maximizing the community's self-consumption as a whole. Part II optimally assigns PV generated electricity to each member in consideration of their individual willingness-to-pay; thus, part II represents peer-to-peer trading from one prosumer to another, $q_{i,j,t}^{share}$. The baseline of the willingness-to-pay is the retail electricity price, $p_t^{G_{in}}$, and an individual CO_2-price, w_j, is added on top that relates to the

[2]This Section is based on the methods presented in the publications [38] and [37].

prosumer's preference for reducing emissions from electricity consumption. In addition, there is also a preference between 0 and 1, $d_{i,j} \in [0,1]$, to buy more locally (i.e., buying from a prosumer with the shortest electrical distance). The willingness-to-pay of prosumer j at time t to buy from prosumer i, $wtp_{i,j,t}$, is defined as:

$$wtp_{i,j,t} = p_t^{G_{in}} + w_j(1 - d_{i,j}) \cdot e_t. \tag{2.2}$$

The emissions from the grid, e_t, are represented by a time series of the greenhouse gases from electricity generation. The local energy community is assumed to be a price taker in the wider electricity system. For this case study, we assigned individual carbon prices, w_j, between 0 EUR/tCO_2 to 100 EUR/tCO_2.

The objective function of the linear problem in (2.3a) maximizes community welfare. The equality constraints (2.3b) and (2.3c) ensure that prosumer i's electricity demand and PV generation are covered at all times. The state of charge of prosumer i's BESS is defined in Eqs. (2.3d) and (2.3e), and other battery constraints in (2.3f)-(2.3h). Non-negativity conditions are included in (2.3i).

$$\max_{Q_{i,t}} \sum_{t\in\mathcal{T},i\in\mathcal{I}} p_t^{G_{out}} q_{i,t}^{G_{out}} - \sum_{t\in\mathcal{T},i\in\mathcal{I}} p_t^{G_{in}} q_{i,t}^{G_{in}} + \sum_{t\in\mathcal{T},i,j\in\mathcal{I}} wtp_{i,j,t} q_{i,j,t}^{share} \tag{2.3a}$$

subject to:

$$q_{i,t}^{G_{in}} + q_{i,t}^{B_{out}} + \sum_{j\in\mathcal{I}} q_{j,i,t}^{share} - q_{i,t}^{load} = 0 \qquad \forall i,t \tag{2.3b}$$

$$q_{i,t}^{G_{out}} + q_{i,t}^{B_{in}} + \sum_{j\in\mathcal{I}} q_{i,j,t}^{share} - q_{i,t}^{PV} = 0 \qquad \forall i,t \tag{2.3c}$$

$$SoC_{i,t-1} + q_{i,t}^{B_{in}} \cdot \eta^B - q_{i,t}^{B_{out}}/\eta^B - SoC_{i,t} = 0 \qquad \forall i, t > t_0 \tag{2.3d}$$

$$SoC_{i,t=t_{end}} + q_{i,t_0}^{B_{in}} \cdot \eta^B - q_{i,t_0}^{B_{out}}/\eta^B - SoC_{i,t_0} = 0 \qquad \forall i, t = t_0 \tag{2.3e}$$

$$SoC_{i,t} - SoC_i^{max} \leq 0 \qquad \forall i,t \tag{2.3f}$$

$$q_{i,t}^{B_{in}} - q_i^{B_{max}} \leq 0 \qquad \forall i,t \tag{2.3g}$$

$$q_{i,t}^{B_{out}} - q_i^{B_{max}} \leq 0 \qquad \forall i,t \tag{2.3h}$$

$$-q_{i,t}^{G_{in}}, -q_{i,t}^{G_{out}}, -q_{i,j,t}^{share}, -q_{i,t}^{B_{in}}, -q_{i,t}^{B_{out}}, -SoC_{i,t} \leq 0 \qquad \forall i,t \tag{2.3i}$$

with $i,j \in \mathcal{I}$ and $t \in \mathcal{T}$.

For further information about the model see the publication in [38] and the GitHub repository in [54].

Dynamic participation in energy communities The following paragraphs discuss the extension of the linear optimization model FRESH:COM to a bi-level model for dynamic participation in energy communities. We start with an overview on the modeling approach. The flow chart in Figure 2.2 shows the process that is suggested to optimize dynamic participation in energy communities over a horizon of several years. For one year, the strategy is as follows:

- The starting point is the "old" community, where some members leave at the end of their contract period.
- The status quo of the remaining members is then captured. Previous analyses of peer-to-peer electricity trading under the consideration of prosumers' willingness-to-pay demonstrate two important characteristics for a community and its members: Overall community welfare[3], and the annual emissions and costs of each member. These indicators are obtained by solving the energy

[3] Community welfare comprises two parts: (i) producer welfare, which considers the community as a whole to maximize producer profits, and (ii) consumer welfare, which considers the individual demand functions (here, willingness-to-pay).

community model FRESH:COM to maximize community welfare of the original community configuration. The annual costs and emissions are then used as "benchmarks" for the optimization process.

- After decisions about leaving, staying, or joining the community are made by all existing and potential new members, a bi-level optimization problem is solved to determine the optimal configuration of new prosumers. The lower level problem is linear community welfare maximization that was applied to the original community in the previous step to obtain benchmarks. The upper-level problem determines which potential members are selected by the community, and subsequently, the new prosumers' parameters (annual electricity demand and peak capacity of the installed PV systems).[4]
- Finally, the new community is defined and the process repeats in the next year.

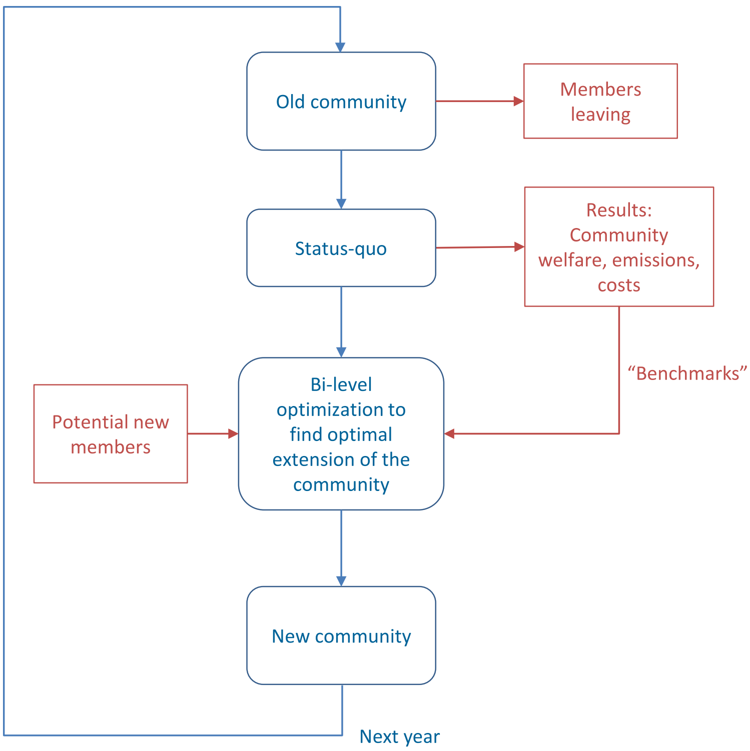


Figure 2.2: Flow chart of the proposed methodology for dynamic participation

Since dynamic participation is an extension of the original model FRESH:COM, we need to define a few mathematical details of the new model.

Prosumers' cost-emission function To evaluate the impact of new prosumers on original prosumers, the following functions are defined:

$$\Delta costs_i = costs_i - costs_{i,old}, \tag{2.4}$$

$$\Delta emissions_i = emissions_i - emissions_{i,old}. \tag{2.5}$$

[4]The proposed model calculates optimal BESS sizes as well; however, the focus of this work remains on annual demand and PV system size.

Equation (2.4) is the deviation of prosumer i's annual costs within the new community set-up compared to the previous status quo. Similar to Eq. (2.4), Eq. (2.5) represents prosumer i's annual emission increase or decrease. The cost-emission function CE is defined next.

$$CE = \sum_{i \in \mathcal{I}_{old}} \alpha_i \Delta costs_i + (1 - \alpha_i) \Delta emissions_i \tag{2.6}$$

Similar to Pareto-optimization, a weighting factor $\alpha_i \in [0, 1]$ is introduced for each prosumer to choose individually. Therefore, α_i determines whether more emphasis is placed on minimizing costs or emissions. By choosing an individual α_i, prosumers can express either a cost-saving or an emission-saving preference. Due to the absolute values of costs and emissions in Eq. (2.4) and (2.5), each prosumer's changes count equally. The cost-emission function CE is the objective to be minimized in the optimization problem.

The costs of each member i of the community over a certain period are calculated as follows:

$$\begin{aligned} costs_i = & \sum_{t \in \mathcal{T}} p_t^{G_{in}} q_{i,t}^{G_{in}} - \sum_{t \in \mathcal{T}} p_t^{G_{out}} q_{i,t}^{G_{out}} \\ & + \sum_{t \in \mathcal{T}, j \in \mathcal{I}} wtp_{j,i,t} q_{j,i,t}^{share} - \sum_{t \in \mathcal{T}, j \in \mathcal{I}} wtp_{i,j,t} q_{i,j,t}^{share}, \end{aligned} \tag{2.7}$$

where $\mathcal{T}$ is the respective time period. The emissions over a certain time are:

$$emissions_i = \sum_{t \in \mathcal{T}} e_t q_{i,t}^{G_{in}} \tag{2.8}$$

Only purchases from the grid are considered in the emissions calculations, because the production of PV electricity does not generate marginal emissions.

Bi-level-model The model solves two main problems: (i) selecting the optimal electricity demand and PV capacity of new prosumers to fulfill certain requirements set by original community members, and (ii) maximizing community welfare, given the new prosumers' parameters selected in (i). Subsequently, this problem can be formulated as a bi-level problem, wherein the leader anticipates the follower's reaction. In the upper-level problem, the *leader*, of the bi-level problem represents (i) and its lower level, the *follower*, (ii).

The leader minimizes the cost-emission function CE with the continuous decision variables $load_i$ and PV_i, and the binary decision variables b_i, for all $i \in \mathcal{I}_{new}$ (see Eq. (2.9a)). The decision variables have lower and upper bounds to ensure a reasonable solution of the model (see Eqs. (2.9b) and (2.9c)). We restrict the number of new members in Eq. (2.9d). The upper level problem is stated as follows:

$$\min_{\{load_i, PV_i, b_i, Q_{i,t}\}} \quad \sum_{i \in \mathcal{I}_{old}} \alpha_i \Delta costs_i + (1 - \alpha_i) \Delta emissions_i \tag{2.9a}$$

subject to:

$$b_i \cdot load_i^{min} \leq load_i \leq b_i \cdot load_i^{max} \quad \forall i \in \mathcal{I}_{new} \tag{2.9b}$$

$$b_i \cdot PV_i^{min} \leq PV_i \leq b_i \cdot PV_i^{max} \quad \forall i \in \mathcal{I}_{new} \tag{2.9c}$$

$$\sum_{i \in \mathcal{I}_{new}} b_i = n \tag{2.9d}$$

The lower level problem equals the linear problem for static participation, where community welfare is maximized, see Eq.s (2.3a)-(2.3i). The set of variables

$$Q_{i,t} = \{q_{i,t}^{G_{in}}, q_{i,t}^{G_{out}}, q_{j,i,t}^{share}, q_{i,t}^{B_{in}}, q_{i,t}^{B_{out}}, SoC_{i,t}\}$$

are the lower level primal decision variables. A very common approach to solving a bi-level optimization problem is the transformation to a mathematical program with equilibrium constraints (MPEC), see [45]. The lower level problem is reformulated by its corresponding Karush-Kuhn-Tucker (KKT) conditions, and can be classified as a mixed complementarity problem (MCP) or equilibrium problem, which is parameterized by the leader's decision variables ([6]). The resulting optimization problem is single-level, and it is linear except for binary variables and complementarity constraints. For the KKT conditions in detail please refer to [37]. The resulting complementarity conditions are then transformed into a mixed integer linear program (MILP) using the Fortuny-Amat method, also known as the "Big-M approach" ([22], [21], and [42]).

Clustering in the time domain Because MPECs are computationally expensive, an alternative approach is used to represent peer-to-peer trading within a community over a whole year. The input data that is available in hourly resolution for a whole year is transformed to three representative days using a k-means algorithm ([57]) of the Python *tslearn* package ([56]). The optimization model then determines the optimum using the three representative days considering the weight[5] of each day in both the upper and lower level objective functions.

2.4.2.2 Upscaling the potential of energy communities to country level

This Section explains how to calculate the potential of energy communities in a reference country. We explain the evaluation of the building stock, how the energy model FRESH:COM is used in the context, and we present the reference countries' parameter.

Overview on upscaling the potential of energy communities to country level Figure 2.3 shows a flow chart of the workflow for deriving the potential of energy communities in a country. We start with the selection of one of the following reference countries: Austria, Greece, Norway, Spain, or England. The building stock is assigned to different energy community types – so-called sample energy communities – according to settlement patterns (see settlement pattern algorithm below). With country specific data matching building stock and residential electricity consumption, the input data for each sample energy community is prepared. The energy community model FRESH:COM is applied to all sample ECs and the results are upscaled knowing the number of ECs per settlement pattern of the whole country. The following results are derived: the number of energy communities (theoretical potential) for each country, collective self-consumption, and the emissions and costs saved on a local level due to energy sharing within a community. The corresponding model is also available open-source on GitHub (see [55]) under the Apache 2.0 license.

Characteristics of settlement patterns The analyses of this study are to a large extent based on residential building stock data, which are found on national statistics websites of the five reference countries. Greek and Norwegian building data bases provide the highest spacial resolution (municipality level). Other countries, e.g. Spain, only provide data on NUTS 3 level. Each area includes different settlement patterns; hence, we need a method to divide the building stock into categories that summarize building types. Thereof, energy communities are formed, represented by sample ECs. The following definition of four different settlement patterns is adopted from [20]:

1. City areas (high population density)
    - Large apartment buildings (10 or more dwellings)
        - Aggregation of tenants' load profiles
        - Possibly with different types of businesses in the buildings (shops on the first floor, offices, ...)

[5] Each day represents a number of days of the year, which is then used to weight each representative day in the process of upscaling back to annual values; all three days represent the whole year. We choose this number of representative days due to computational constraints of the model.

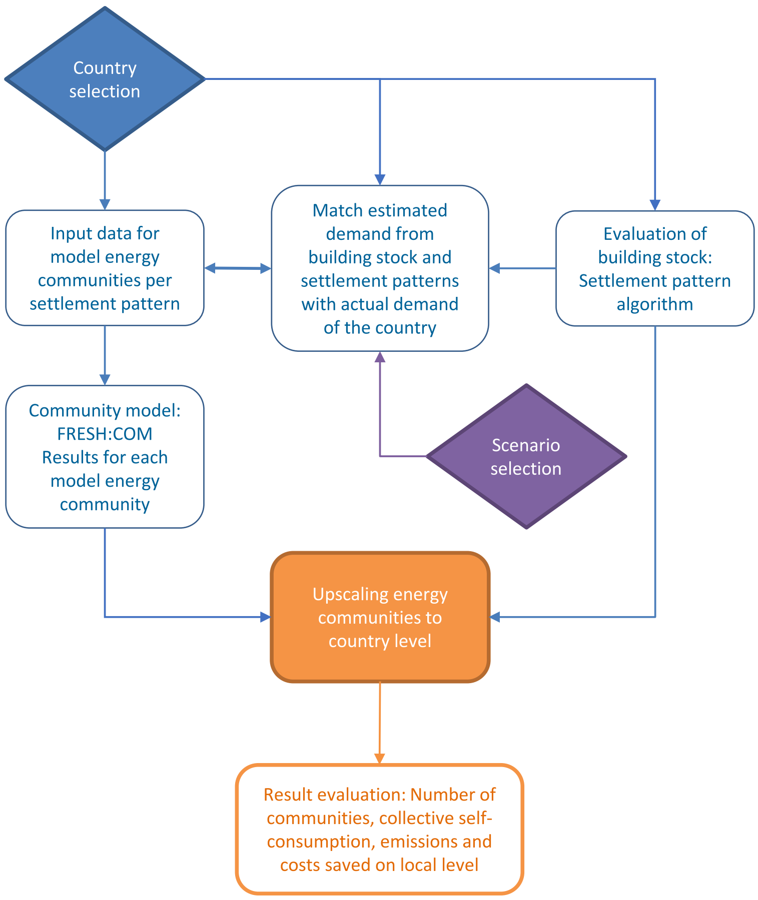


Figure 2.3: Flow chart of the up-scaling procedure

  - Limited rooftop area for PV systems

2. Town areas (medium population density)
   - Mostly small apartment buildings (3-9 dwellings)
   - Limited rooftop area for PV systems
   - Some businesses included (e.g., shops, bakery, ...)
3. Suburban areas (low-to-medium population density)
   - Mix of apartment buildings and single family houses
4. Rural areas (low population density)
   - Mostly single houses (1-2 dwellings)
   - Sufficient rooftop area available

With these definitions, we assign buildings to each of the samples ECs using a so-called *settlement pattern algorithm*:

1. City: 10 large apartment buildings ($LAB_{city} = 10$)
2. Town: 10 small apartment buildings ($SAB_{town} = 10$)
3. Suburban: 10 single houses + 2 large apartment buildings ($SH_{sub} = 10$ and $LAB_{sub} = 2$)
4. Rural: 10 single houses ($SH_{rural} = 10$)

[20] evaluate the ideal PV capacities and PV orientations for each settlement pattern. According to the paper, single houses in suburban and rural communities should have PV systems orientated South, while small and large apartment buildings in city and town communities should install PV systems facing different directions: East, South and West.

Settlement pattern algorithm The allocation of buildings to settlement patterns is performed individually for each area i (region or district depending on the granularity of the building stock data). Algorithm 1 shows the exact procedure: The allocation starts with the assignment of all small apartment buildings ($N_{i,SAB}$) to town ECs ($EC_{i,town}$). The following step divides large apartment buildings ($N_{i,LAB}$) into city and suburban ECs. If the percentage of LABs within the whole building stock $N_{i,total}$ is smaller than a specific threshold th_{city}, there are no city ECs in i, i.e., $EC_{i,city} = 0$. Else, the share of LABs allocated to suburban ECs is defined by the parameter $p_{sub/city}$.[6] There is a default value for $p_{sub/city}$; in some cases we need to decrease the value of $p_{sub/city}$ and assign more LABs to city ECs, because there are not enough single houses for the calculated number of sub-urban ECs using the default value of $p_{sub/city}$. The last step of each iteration assigns the remaining single houses ($N_{i,SH} - EC_{i,sub}SH_{sub}$) to rural communities ($EC_{i,rural}$).

Definition of sample energy communities Now that we determined how many energy communities per settlement pattern could (theoretically) exist in a country, we need to define the sample energy communities next. In the following, it is described how prosumers' electricity demand, PV generation profile, battery capacity, and willingness-to-pay are specified for each reference country and settlement pattern.

Hourly electricity demand profiles are calculated by the open-source tool LoadProfileGenerator (version 10.4.0; see [34] and [41]).[7] This way, different household characteristics, sizes, and demographics are represented. The demand profiles are normalized and then upscaled to country specific demand values: Electricity demand parameters are calculated separately for each country with the information provided by national statistic data bases. The average electricity demand per household D_{avg} is calculated from the total residential electricity demand and number of dwellings, $n_{dwellings}$, taking into account the proportion of permanently occupied dwellings, η_{occ}.

$$D_{total} = D_{avg} \cdot n_{dwellings} \cdot \eta_{occ} \tag{2.10}$$

$$n_{dwellings} = n_{SH} + n_{SAB} + n_{LAB} \tag{2.11}$$

Calculating the average electricity demand per dwelling in a single house, $D_{avg,SH}$, and in an apartment building, $D_{avg,AB}$, the following relation applies:

$$D_{avg} = x_{SH-AB} D_{avg,SH} + (1 - x_{SH-AB}) D_{avg,AB} \tag{2.12}$$

$$D_{avg,SH} = y_{SH-AB} D_{avg,AB} \tag{2.13}$$

x_{SH-AB} is the share of single house dwellings within the whole dwelling stock:

$$x_{SH-AB} = \frac{n_{SH}}{n_{SH} + n_{AB}} \tag{2.14}$$

$$n_{AB} = n_{SAB} + n_{LAB} \tag{2.15}$$

[6] Correspondingly, the share of LABs in city ECs is $1 - p_{sub/city}$.
[7] https://www.loadprofilegenerator.de/

Algorithm 1: Settlement pattern algorithm

---

for i *in areas* **do**

  $EC_{i,town} \leftarrow \left\lfloor \frac{N_{i,SAB}}{SAB_{town}} \right\rfloor$;

  if $N_{i,LAB}/N_{i,total} < th_{city}$ **then**

    $EC_{i,city} \leftarrow 0$;

    $EC_{i,sub} \leftarrow \left\lfloor \frac{N_{i,LAB}}{LAB_{sub}} \right\rfloor$;

  else

    if $\frac{N_{i,SH}}{SH_{sub}} < \left\lfloor \frac{p_{sub/city} \cdot N_{i,LAB}}{LAB_{sub}} \right\rfloor$ **then**

      $p_{sub/city} \leftarrow \frac{N_{i,SH}}{N_{i,LAB}} \frac{LAB_{sub}}{SH_{sub}}$;

    end

    $EC_{i,sub} \leftarrow \left\lfloor \frac{p_{sub/city} \cdot N_{i,LAB}}{LAB_{sub}} \right\rfloor$;

    $EC_{i,city} \leftarrow \left\lfloor \frac{N_{i,LAB} - EC_{i,sub} LAB_{sub}}{LAB_{city}} \right\rfloor$;

  end

  $EC_{i,rural} \leftarrow \left\lfloor \frac{N_{i,SH} - EC_{i,sub} SH_{sub}}{SH_{rural}} \right\rfloor$;

end

It is assumed that a household in a single house consumes on average around $y_{SH-AB} = 2.5$ times more electricity per year than a household in an apartment building (see [53], data from Austria in 2016). Next, the average number of dwellings per building type, $BT = \{\text{SH, SAB, LAB}\}$, is calculated:

$$n_{avg,BT} = \frac{n_{BT} \cdot \eta_{occ}}{N_{BT,occ}} \tag{2.16}$$

For some countries, only the total number of apartments, n_{AB}, is available, but not the exact numbers of n_{SAB} and n_{LAB}. We solve this problem by making an assumption on the average number of dwellings in either SABs, $n_{avg,SAB}$, or LABs, $n_{avg,LAB}$, and then we apply the following relation:

$$n_{avg,SAB} = \frac{n_{AB} \cdot \eta_{occ} - n_{avg,LAB} \cdot N_{LAB,occ}}{N_{SAB,occ}} \tag{2.17}$$

Each sample energy community consists of BT_{SP} buildings per building type. The annual electricity consumption of individual prosumers of a sample community are normally distributed with a mean value equal to the national average demand of building type BT. The parameters of the normal distribution $\mathcal{N}(\mu_{BT}, \sigma_{BT}^2)$ per BT are defined as following:

$$\mu_{BT} = D_{avg,BT} \cdot n_{avg,BT} \tag{2.18}$$

$$\sigma_{BT} = 0.3\mu_{BT} \tag{2.19}$$

The technology portfolio of the energy community members includes PV systems and battery energy storage systems (BESS). The PV generation profiles are obtained from the open-source tool renewables.ninja (year 2019, see [43], [40] and [48]). We use the generation profiles of the reference countries' capitals Vienna, Athens, Oslo, Madrid, and London, which are representative for the irradiation profiles of the whole country.[8] The installed capacities vary from $3\,\text{kW}_{\text{peak}}$ to $15\,\text{kW}_{\text{peak}}$, depending on the building types. Note that some members are consumers only and do not have their own PV system. Some prosumers own a BESS; the installed capacities vary from 3 kWh to 8 kWh.

Country data: 5 European reference countries Five reference countries are selected in case study 2: Austria, Greece, Norway, Spain, and England, see Fig. 2.4, to represent Central Europe, South-Eastern Europe, Scandinavia, Iberian Peninsula and Great Britain, respectively.

The case study results are based on building stock data of each country, obtained from the countries' national statistic websites. For details and references refer to Section 2.5. Table 2.1 compares population, spacial resolution, building and household data, and electricity consumption data. The population varies from 5.4 million in Norway to 56 million in England. The spacial resolution depends on the available building stock data: NUTS 3 in Spain and England,[9] Greece and Norway on municipality level (LAU), and political districts in Austria (below NUTS 3).

From the total building stock data, we only consider residential buildings which are either exclusively residential or mixed use with main purpose residential; other buildings are neglected. The occupancy rate of dwellings includes main residences, while empty dwellings and vacation homes are excluded. It can be noticed that Norwegian households have by far the highest electricity consumption due to the high degree of electrification in Norway.

[8] There are of course large inaccuracies especially in countries with large north-south expanses like Norway, but developing regional sample energy communities is beyond the scope of this case study. In addition, the northernmost areas of Norway, for example, are very sparsely populated or not populated at all.

[9] The English building stock data is available for single tier and county councils, which – not exactly, but more or less – represent NUTS 3.

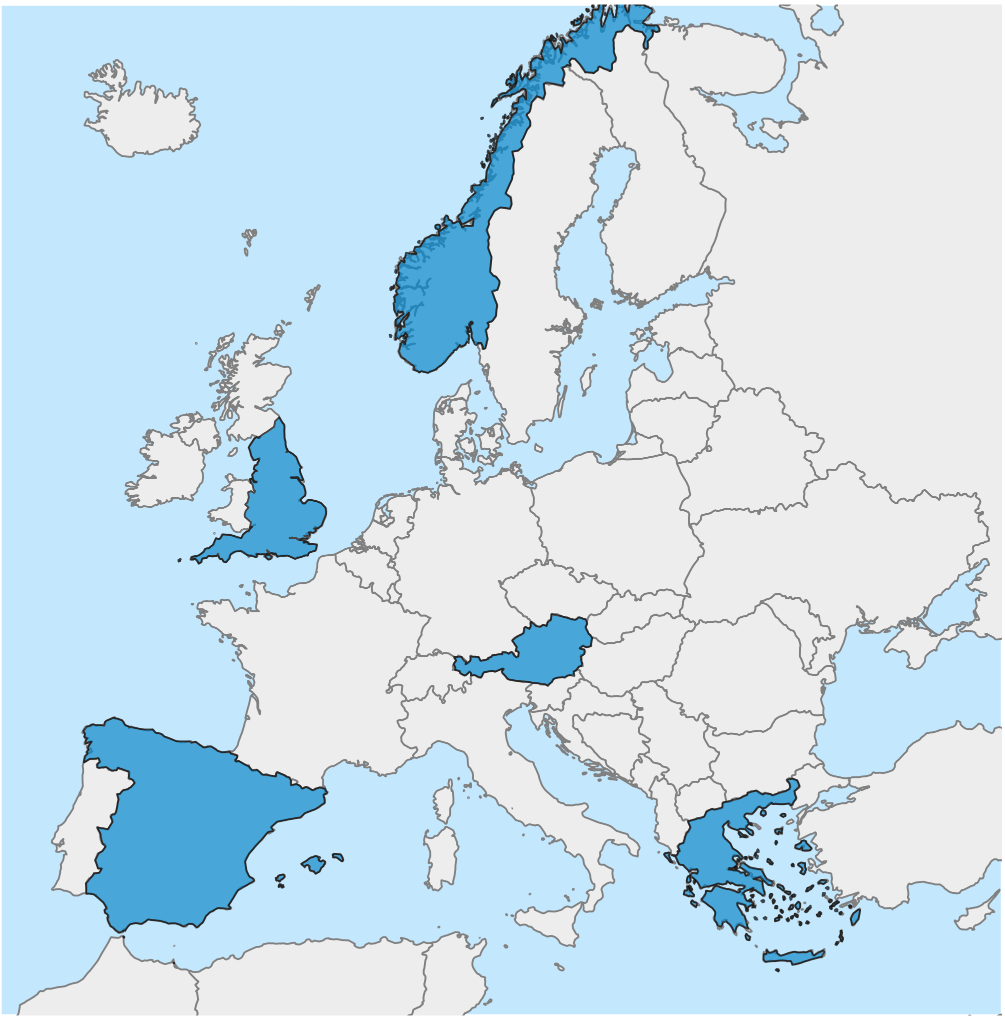


Figure 2.4: Austria, Greece, Norway, Spain, and England

2.4.2.3 Up-scaling to European level

Based on the evaluation of five reference countries, we want to estimate a theoretical potential for energy communities for Europe as a whole. The remaining European countries are each assigned to one of the reference countries (clusters) and the results are scaled considering population and residential electricity demand. In Figure 2.5, a map shows the allocation to reference countries. The allocation of countries to a certain cluster is mainly based on geographical indicators. Hence, the solar irradiation should be similar to the reference country, because PV generation strongly influences the results of an energy community. The other important factor, electricity demand, is considered for each country of a cluster separately.

The number of energy communities in total is derived using the following approach. For each cluster of countries represented by one of the five reference countries, the number of energy communities, $EC_{cluster}$, is

$$EC_{cluster} = EC_{ref.\,country} \frac{population_{cluster}}{population_{ref.\,country}}, \tag{2.20}$$

where $population_{cluster}$ is the total population of all countries assigned to the cluster, and $population_{ref.\,country}$ the population of the cluster's reference country. Similar, we calculate electricity savings of each cluster (the reduction of electricity trade between prosumers and the grid, the increase of collective local self

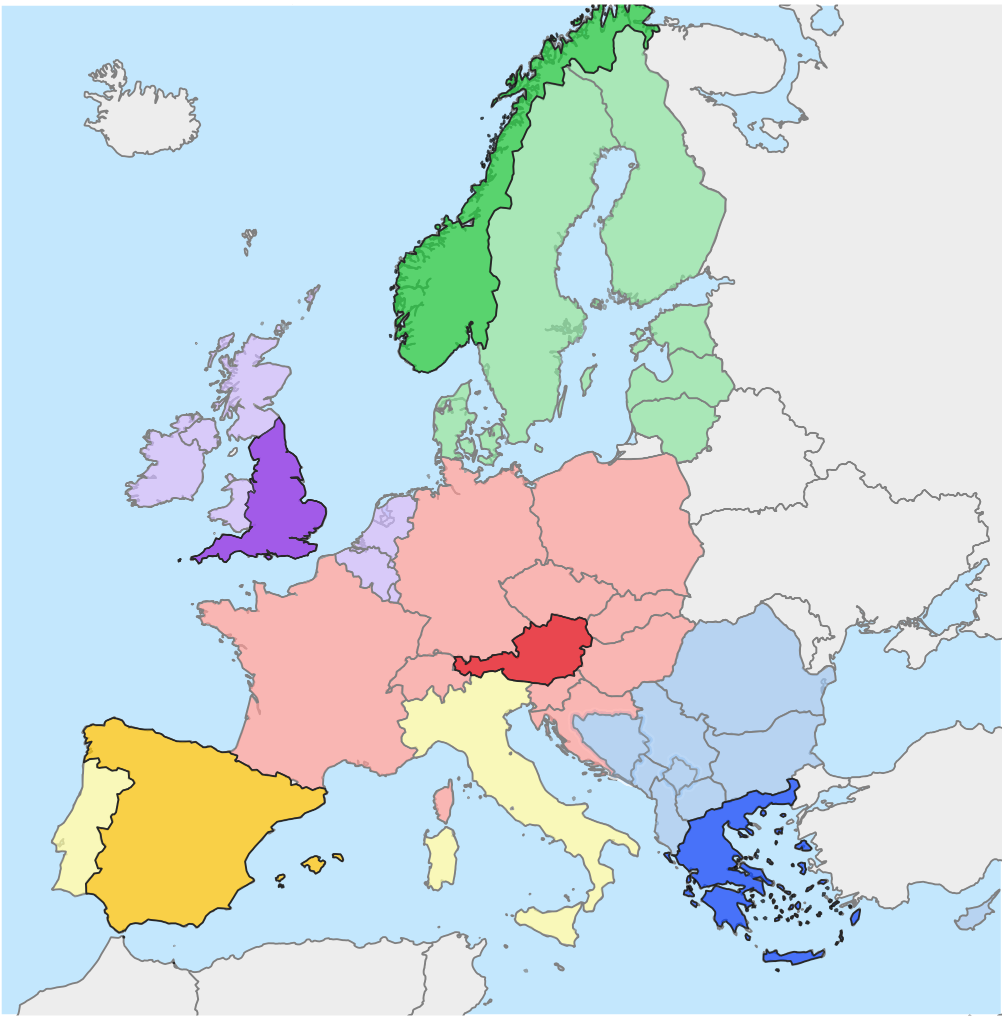


Figure 2.5: Overview of European countries assigned to the five reference countries (clusters)

consumption, and the decrease in battery storage utilization) using an upscaling factor $upscale_{cluster}$ defined as

$$upscale_{cluster} = \frac{demand_{cluster}}{demand_{ref.\,country}}, \tag{2.21}$$

where $demand_{cluster}$ is the total electricity demand of all countries assigned to the cluster, and $demand_{ref.\,country}$ the electricity demand of the cluster's reference country.

2.4.3 Linkages

The linkages of case study two are summarized as follows:

- The model is linked to the openENTRANCE project-internal database at `https://data.ece.iiasa.ac.at/openentrance-internal/#/workspaces`.
- The openENTRANCE common data format is used for input data.
- The openENTRANCE common data format is used for some selected output data.
- We use the open-source package pyam (see `https://pyam-iamc.readthedocs.io/en/stable/`) for data transformation.

Table 2.1: Relevant data for the case study of the selected countries

		Austria	Greece	Norway	Spain	UK (England)
Country data						
Population		8.9 Mio.	11.1 Mio.	5.4 Mio.	47 Mio.	56 Mio.
Spacial resolution		below NUTS 3	LAU	LAU	NUTS 3	NUTS 3
Number of areas		121 political districts	423 municipalities	357 municipalities	52 regions	152 single tier and county councils
Building and household data						
Total residential buildings		1.97 Mio.	3.25 Mio.	1.56 Mio.	9.73 Mio.	19 Mio.
Total number of dwellings		4.3 Mio.	6.4 Mio.	2.47 Mio.	25.85 Mio.	22.7 Mio.
Total number of households		3.96 Mio.	4.11 Mio.	2.47 Mio.	18.1 Mio.	22.1 Mio.
Occupied dwellings (%)		92%	64%	100%	72%	97%
	SH	1.2	1.4	1.1	1.1	1.0
Avg. Dwelling per building	SAB	5.5	4.0	1.8	6.2	3.6
	LAB	18.7	12.0	15.5	18.0	20.0
Electricity demand data						
Total demand households (TWh)		15.2	17.1	39.5	60.0	79.0
	SH	5652	5678	20830	5401	4108
Avg. demand households (kWh/yr)	AB	2261	2271	8332	2160	1643
	all	3848	4152	16000	3318	3582
Electricity prices and emissions						
Retail prices (cent/kWh)		22.16	16.8	18.26	23.23	21.8
Average Day Ahead price (EUR/MWh)		40.06	63.82	39.29	47.68	42.86
Average emissions (g/kWh)		132.25	434.04	10.43	164.06	213.32

2.5 Description of datasets and how they were created

This Section describes the data and assumptions of the case study in detail. We provide information on the datasets for the results of the energy community model FRESH:COM in Section 2.5.1 and for the calculation of the potential of energy communities in Europe in Section 2.5.2.

2.5.1 Datasets for the energy community model FRESH:COM

For the results of the energy community model and the corresponding datasets, we refer to our previous publication in [37], on which this section is based.

2.5.1.1 Model implementation

The model is implemented using Python (version 3.7.2; see [59]) using the Pyomo package (version 5.7.3; see [25] and [4]), and Gurobi (version 9.0.0; see [24]) as a solver. Gurobi is a commercial solver. Alternatively, the problem can be solved with the open-source solver GNU Linear Programming Kit (GLPK). The model is available open source on GitHub (*see Software availability*).

2.5.1.2 Input data

The electricity demand of each member is obtained from the open-source tool LoadProfileGenerator (version 10.4.0; see [41]), which generates artificial data. Different household types categorized by living situation and demographics (single working person, elderly couple, family, etc.) are included in this study. The PV generation data are obtained from a different open-source tool Renewables.ninja (version v1.3; see [40], and [48]). PV systems' irradiation data and electricity output are location-specific to Vienna, Austria. While the existing community is characterized by specific input parameters, standardized profiles for the new prosumers are used as input data:

- $q_{i,t}^{load}$ is a standardized load profile (H0 for household, G0 for standard business[10])), which is normalized to 1000 kWh/year. For example, a result of $load_i = 5$ means that the optimal prosumer has an annual demand of 5000 kWh/year. The possible range is between $2000 - 8000$ kWh/year.

- $q_{i,t}^{PV}$ is the generation profile of a 1 kW_{peak} PV system facing South; hence, the decision variable PV_i is a factor that upscales the PV system size. The possible range is between $0 - 5\,\text{kW}_{\text{peak}}$.

A summary of the prosumers' input data can be found in Table 2.2. The willingness-to-pay w_i is arbitrarily assigned between the prosumers to cover a range between 0–100 EUR/tCO_2. The electrical distance factors $d_{ij} \in [0, 1]$ are dummy values to represent electrical distances within a distribution network (the case study is artificial). The higher the value of d_{ij}, the further the electrical distance between prosumer i and j. Input data from the grid includes the following values: $p_t^{G_{in}} = 0.2$ EUR/kWh (the average value of the 2019 Austrian retail electricity price; see [16]) and $p_t^{G_{out}} = 0.04$ EUR/kWh (average Austrian spot market price of 2019; see [17]). Marginal emissions e_t are hourly values obtained from [47] (Austrian-German spot market).

2.5.2 Datasets for the potential of energy communities in Europe

2.5.3 Austria

- A list of buildings and apartments by type of (residential) building and political district (from 2011) can be found at [51].

[10] The synthetic load profiles of 2019 for household (H0 "Haushalt") and business (G0 "Gewerbe allgemein") are used. (See further: https://www.apcs.at/de/clearing/technisches-clearing/lastprofile

Table 2.2: Parameters of the prosumers of the community ("-" indicates that a technology type is not included). The willingness-to-pay w_i of the new prosumers (H0 and G0) is not optimized, but varied in a sensitivity analysis.

	Annual demand (kWh)	**PV orientation**	**PV peak output** (kW)	**Storage capacity** (kWh)	CO_2**-price** w_i (EUR/tCO2)
Prosumer 1	3448	-	-	-	100
Prosumer 2	8548	South	5	-	0
Prosumer 3	2403	West	3	-	90
Prosumer 4	3320	South	3	3	30
Prosumer 5	2521	-	-	-	50
Prosumer 6	2167	South	3	-	60
Prosumer H0	2000 – 8000	South	0 – 5	-	0/50/100
Prosumer G0	2000 – 8000	South	0 – 5	-	0/50/100

- Table *Durchschnittlicher Stromverbrauch eines Haushalts 2008, 2012 und 2016* at [53] shows the average electricity consumption per household according to parameters such as number of persons within the household, dwelling size, or number of dwellings within a building (1-2 dwellings versus 3 or more dwellings).
- The overall electricity demand for households in Austria was 15 222 GWh in 2021 [9].
- 3.955.761 private households and 8.753.667 inhabitants [52]

2.5.4 Greece

- Number of buildings [10] Table 4. Buildings by use (exclusive, mixed) and number of regular residences. Total Greece, large geographical areas, Decentralized Administrations, Regions, Regional Units, Municipalities.
  - (i) number of buildings for exclusive residential use, (ii) number of buildings for mixed use, but main use is residential, (iii) number of buildings for mixed use with main use other than residential. We use (i) and (ii)
- Empty dwellings [11] Table B18. Normal residences by state of residence. Regional Units, Municipalities.
- Households per SH, AB (only buildings with main use residential), [11] Table B13. Normal houses by building type. Regional Units.
- Electricity consumption: 4125 kWh/dwelling, see [36].

2.5.5 Norway

- Building stock for municipalities 2020 from [49].
  - SH: Detached house, house with 2 dwellings
  - SAB: Row house, linked house and house with 3 dwellings or more
  - LAB: Multi-dwelling building
- Dwellings: [50] (same structure as building stock)
- Electricity consumption [12]
- Electricity prices from: `https://ec.europa.eu/eurostat/databrowser/view/nrg_pc_204/default/table?lang=en`

2.5.6 Spain

- Number of buildings from [28]. Table: Results by Autonomous Communities and Provinces → Buildings by type of building by size and no. of dwellings.
  - Number of buildings according to: (i) total number of buildings, (ii) number of buildings mainly or exclusively used for housing, (iii) number of buildings for other purposes.
- Empty dwellings from [27]. Table: Province and Autonomous Communities results → Dwellings according to type of dwelling and construction year (added) of the building.
- Electricity consumption from [15]

2.5.7 United Kingdom

- Building stock, see [13].
- Number of dwellings, population density, number of households from [30] for all English single tier and county councils:
  - SH: Detached dwelling, semi-detached dwelling, terraced
  - SAB: Part of a converted or shared house
  - LAB: Purpose-built block:flats or tenement
- Househoulds, size of buildings, etc. [32]
- Residential electricity demand in the UK 103 825 GWh, see [29]; average electricity demand per household from [36]
- Emissions data see [33]

2.6 Results of case study

This section presents the results of case study 2. We start with the results of the energy community model FRESH:COM in Section 2.6.1, and continue with the potential of energy communities in five reference countries and in Europe as a whole in Sections 2.6.2 and 2.6.3, respectively.

2.6.1 Results of the energy community model FRESH:COM

2.6.1.1 Results for static participation

First we look into static participation in energy communities; i.e., when no members join or leave the community. The we analyze community consists of six households with consumers and prosumers. The annual results (kilowatt-hours of electricity bought and sold, marginal emissions, and costs) of all members are presented in Table 2.3. Figure 2.6 presents the peer-to-peer traded electricity (in kWh/year) in detail as a heat map; rows represent the amount a prosumer sells to each peer, and columns are the respective purchases.

Table 2.3: Summary of the results of peer-to-peer trading (original community set-up)

Prosumer	1	2	3	4	5	6	total
Buying grid (kWh)	1140.3	4871.6	1379.3	1080.4	1436.3	854.6	10762.6
Selling grid (kWh)	0	818.3	1680.0	573.5	0	2286.9	5358.8
Battery charging (kWh)	0	0	0	870.0	0	0	870.0
Battery discharging (kWh)	0	0	0	721.5	0	0	721.5
Self-consumption (kWh)	0	3341.5	1016.7	1400.7	0	1282.9	7041.9
Buying community (kWh)	2308.1	334.6	6.5	117.4	1084.5	29.6	3880.0
Selling community (kWh)	0	2300.8	274.3	1015.5	0	290.0	3880.0
Emissions (tCO_2)	0.6	2.6	0.7	0.6	0.8	0.5	5.8
Costs (EUR)	790.0	449.3	154.5	-8.2	527.7	24.0	1937.3

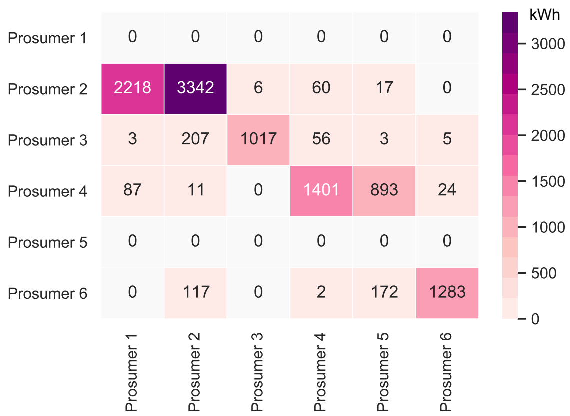


Figure 2.6: Heatmap of the peer-to-peer electricity trading between the prosumers in *static participation*. Rows represent prosumers selling electricity, columns buying electricity. The diagonal represents self-consumption.

Compared to all other participants, prosumer 1 buys the most from the community, with the highest share coming from prosumer 2, who is prosumer 1's closest peer and has a 5 kW_{peak} PV system installed. Prosumer 1 does not own a PV system and has the highest willingness-to-pay. Prosumer 3 has the second-highest willingness-to-pay; however, they also have their own PV system installed, and mostly consume their own generation. Prosumer 2 prefers to sell to prosumer 1, with a higher willingness-to-pay than prosumer 3. Prosumer 2 clearly has the highest electricity demand within the community; therefore, the highest annual (marginal) CO_2 emissions of the community, despite having large PV system capacities installed. Prosumer 5, who is a consumer only, prefers to buy from their closest peers, prosumers 4 and 6. Prosumer 6 has very low annual electricity costs due to high-self-consumption and being able to sell electricity to other members of the community. Prosumer 4 is the only participant with a BESS and is able to further minimize their electricity costs, achieving negative annual costs.

2.6.1.2 Results for dynamic participation

In this Section we show results for dynamic participation in energy communities. We consider again the same energy community ($\mathcal{I}_{old}$) as in the previous Section 2.6.1.1, which now wants to add a new member to the community.

Choosing optimal parameters The first set of results shows how the original energy community chooses optimal parameters of a potential new member depending on the community members' preferences.

(i) Minimizing emissions In the first case, it is assumed that all community members care about minimizing their annual emissions, but have no preference regarding cost savings; $\alpha_i = 0$ is set for all prosumers $i \in \mathcal{I}_{old}$. The result of the new prosumer's PV system size is not surprising. The PV capacity is set to its maximum $PV_{new} = PV_{new}^{max} = 5\,\mathrm{kW_{peak}}$. At the same time, the optimal electricity demand of the new prosumer is at its minimum $load_{new} = load_{new}^{min} = 2000\,\mathrm{kWh/year}$. The new annual peer-to-peer trading values are shown in Fig. 2.7. The annual results (kilowatt-hours of electricity bought and sold, marginal emissions, and costs) of all members are presented in Table 2.4.

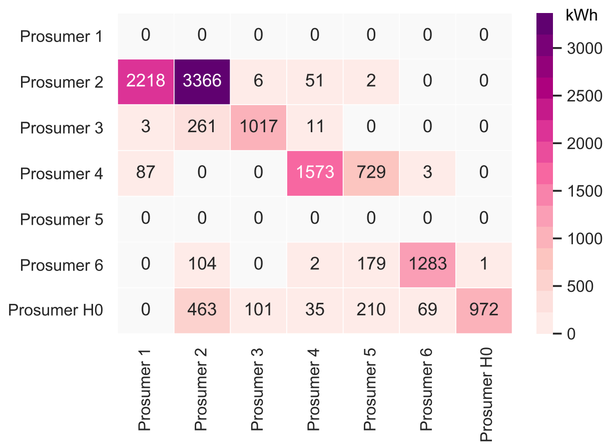


Figure 2.7: Heatmap of the peer-to-peer electricity trading between the prosumers – all $\alpha_i = 0$

Cost-wise, the newly added PV capacity can be seen as a competition with other members' PV systems. Part of the revenue from selling electricity to consumers transfers to the new prosumer instead of old members, whose earnings now decrease. Notably, the annual emissions of all prosumers involved are reduced. Due to the newly added PV capacity, prosumers are able to buy more electricity from the community. The electricity demand of the new prosumer is low, such that there is little competition in consuming PV electricity. The Sankey diagram in Figure 2.8 demonstrates that members of the original community ($\mathcal{I}_{old}$) cover their electricity demand through self-consumption, buying from other community members or buying from the grid. The left side represents the old community without the new prosumer, and the right side shows the new community. The new prosumer's PV generation primarily substitutes purchases from the grid, which is desirable if the common goal is to reduce

Table 2.4: Summary of the results of peer-to-peer trading – all $\alpha_i = 0$

Prosumer	1	2	3	4	5	6	H0
Buying grid (kWh)	1140.3	4354.7	1278.2	917.5	1401	812.6	1027
Selling grid (kWh)	0	818.3	1680	584.6	0	2291.6	4611
Battery charging (kWh)	0	0	0	882.6	0	0	0
Battery discharging (kWh)	0	0	0	731.4	0	0	0
Self-consumption (kWh)	0	3365.6	1016.7	1573.4	0	1282.9	972
Buying community (kWh)	2308.1	827.4	107.6	97.8	1119.8	71.6	0.9
Selling community (kWh)	0	2276.8	274.3	819.2	0	285.4	877.7
Emissions (tCO_2)	0.6	2.3	0.7	0.5	0.8	0.4	0.6
Costs (EUR)	790	449.5	158.1	-1.4	528.2	25.8	-165

emissions. Prior to adding the new prosumer, community members purchase 10 700 kWh from the grid. Adding a new prosumer with a 5 kW_{peak} PV system installed, this amount can be reduced by around 8%. Prosumer 4, who has battery storage installed, can also increase their self-consumption. The next Figure 2.9 presents the annual cost and emission increase (or decrease) of each prosumer of the original community, comparing Eqs. (2.4) and (2.5). Annual costs (left axis in red) increase slightly by a few EUR for most prosumers, whereas emissions significantly decrease, as desired.

Figure 2.8: Sankey diagram of the electricity consumption of prosumers

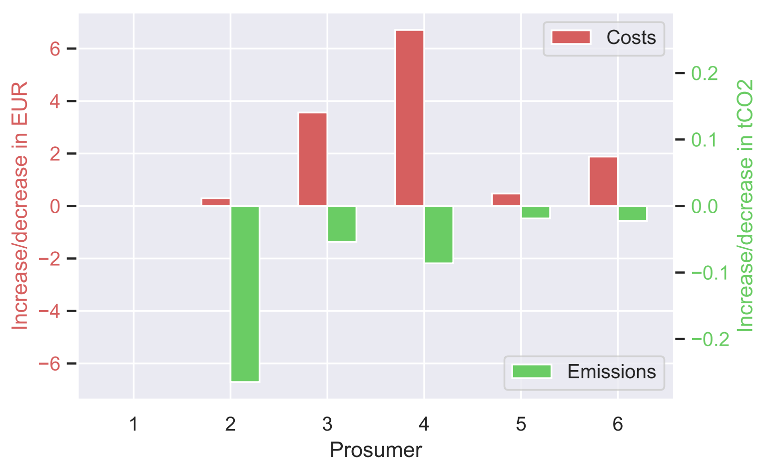


Figure 2.9: Cost- and emission balances of the prosumer of $\mathcal{I}_{old}$ – all $\alpha_i = 0$

(ii) Minimizing costs The other distinct case is setting all $\alpha_i = 1$, indicating that prosumers seek to minimize annual electricity costs. The optimal result of the bi-level problem is a prosumer with the maximum possible annual electricity demand $load_{new} = load_{new}^{max} = 8000\,\mathrm{kWh/year}$. At the same time, the new prosumer's optimal PV capacity is at its minimum $PV_{new} = PV_{new}^{min} = 0\,\mathrm{kW_{peak}}$; hence, the new member is a consumer, who buys PV electricity from the community, which generates additional revenue for the other members. The new annual peer-to-peer trading values are shown in Fig. 2.10. The annual results (kilowatt-hours of electricity bought and sold, marginal emissions, and costs) of all members are presented in Table 2.5.

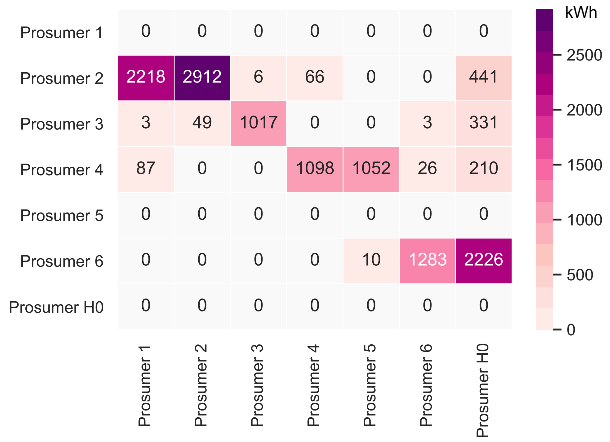


Figure 2.10: Heatmap of the peer-to-peer electricity trading between the prosumers – all $\alpha_i = 1$

Table 2.5: Summary of the results of peer-to-peer trading – all $\alpha_i = 1$

Prosumer	1	2	3	4	5	6	H0
Buying grid (kWh)	1140.3	5587.5	1379.3	1432.6	1459.1	854.6	4792.1
Selling grid (kWh)	0	818.3	1568.3	516.1	0	341.2	0
Battery charging (kWh)	0	0	0	870	0	0	0
Battery discharging (kWh)	0	0	0	723.6	0	0	0
Self-consumption (kWh)	0	2911.6	1016.7	1098.2	0	1282.9	0
Buying community (kWh)	2308.1	48.6	6.5	65.6	1061.7	29.6	3207.9
Selling community (kWh)	0	2730.8	386	1375.4	0	2235.8	0
Emissions (tCO_2)	0.6	3.0	0.7	0.8	0.8	0.5	2.6
Costs (EUR)	790	443.2	131.6	-25.8	527.6	-331	1663.1

The Sankey diagram in Figure 2.11 demonstrates that members can increase their income by selling a significant amount of their generation to the new prosumer, which was previously sold to the grid because the new prosumer's willingness-to-pay is higher than the remuneration for selling PV generation into the grid $wtp_{i,new,t} > p_t^{G_{out}}$.

In total, about 40% of the community's surplus PV production is sold to the new prosumer in this scenario, resulting in cost savings for prosumers with PV systems (see Figure 2.12). This is especially evident for prosumer 6, who is the closest neighbor of the new prosumer. The consumers of the community, prosumers 1 and 5 do not experience major changes. Emission balances offer another interesting result; the lower the willingness-to-pay (e.g., prosumer 2 with $w_2 = 0\,\mathrm{EUR/tCO_2}$), the higher the annual CO_2 emissions. Prior to adding the new member with a high electricity demand, higher amounts of PV generated electricity remained available for prosumers with low willingness-to-pay, which are now sold to the new member. Prosumer 6, the closest neighbor of the new prosumer, achieves the highest cost decrease.

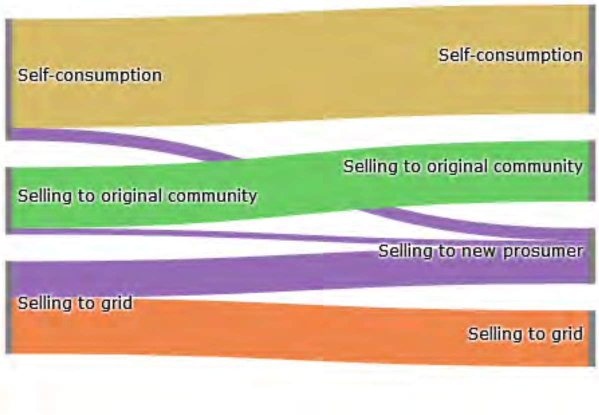


Figure 2.11: Sankey diagram of the electricity generation of prosumers

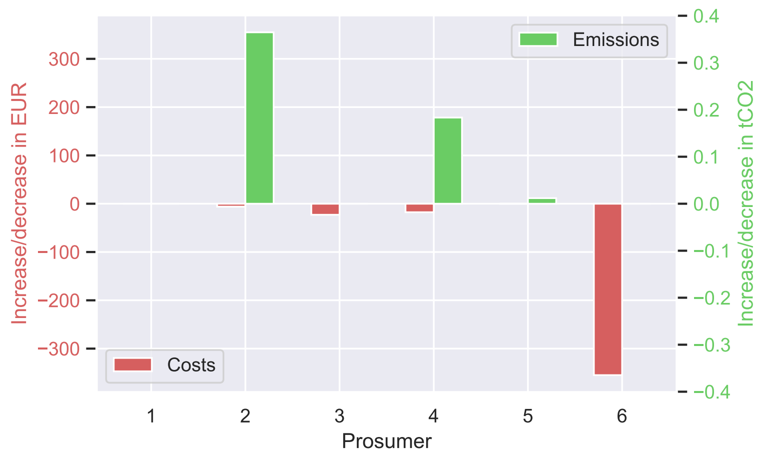


Figure 2.12: Cost and emission balances of the prosumer of $\mathcal{I}_{old}$ – all $\alpha_i = 1$

Mixed preferences While the prosumers' choices of α_i are uniform in both previous cases, we now introduce non-uniform values of α_i. There is a large number of possible combinations, many of which lead to the same results as before. Other combinations lead to different results; for example, $[\alpha_1, \alpha_2, \alpha_3, \alpha_4, \alpha_5, \alpha_6] = [1, 1, 0, 1, 1, 0]$, which is presented here The optimal parameters of the new prosumer are set by the model to maximum PV capacity and maximum annual electricity demand, $PV_{new} = 5\,\text{kW}_{\text{peak}}$ and $load_{new} = 8000\,\text{kWh/year}$, respectively. The detailed peer-to-peer trading in Figure 2.13 shows that the new prosumer trades electricity with the other members, but predominantly self-consumes their PV generated electricity due to their own high annual electricity demand. This differs from the first case, wherein the new prosumer has a low electricity demand and sells larger volumes of electricity to the other members, comparing Fig. 2.14 with Fig. 2.8.

Due to the high share of self-consumption in the mixed preferences case, the new prosumer buys only small volumes of electricity from the community (see Fig. 2.15). In general, there are less interactions/trades with the community, which is reflected in the annual cost-emission balances as well. Figure 2.16 shows very small deviations from the previous status quo. Annual emissions decrease for prosumers 3 and 6, which is congruent with their preferences on saving emissions ($\alpha_{3,6} = 0$). Annual cost differences are negligible (less than 2 EUR per year). The annual results (kilowatt-hours of electricity bought and sold, marginal emissions, and costs) of all members are presented in Table 2.6.

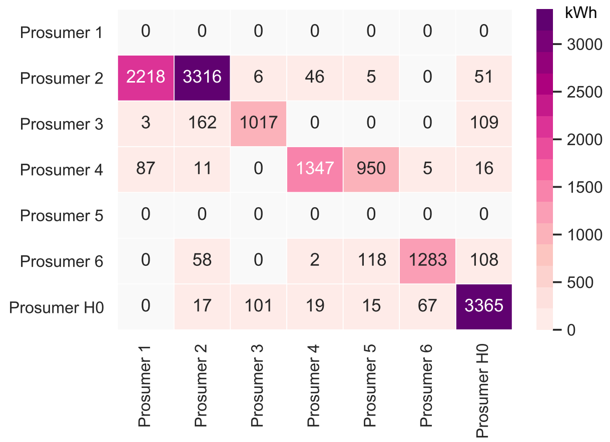


Figure 2.13: Heatmap of the peer-to-peer electricity trading between the prosumers – mixed α_i

Table 2.6: Summary of the results of peer-to-peer trading – mixed α_i

Prosumer	1	2	3	4	5	6	H0
Buying grid (kWh)	1140.3	4983.7	1278.2	1185.8	1432.9	812.6	4351
Selling grid (kWh)	0	818.3	1680	573.5	0	2291.6	2876.6
Battery charging (kWh)	0	0	0	870	0	0	0
Battery discharging (kWh)	0	0	0	720.1	0	0	0
Self-consumption (kWh)	0	3315.6	1016.7	1347.5	0	1282.9	3365
Buying community (kWh)	2308.1	248.4	107.6	66.6	1088	71.6	284
Selling community (kWh)	0	2326.7	274.3	1068.8	0	285.4	219.1
Emissions (tCO_2)	1	2.7	0.7	0.6	0.8	0.4	2.3
Costs (EUR)	790	448.8	156.3	-9.3	528	24.7	767.4

Figure 2.14: Sankey diagram of the electricity consumption of prosumers

Choosing between two new members Next, another potential new prosumer with the electricity demand profile of a standard business (prosumer G0) is compared to prosumer H0. The results remain unchanged when the model is run with prosumer G0 instead of H0; therefore, the binary decision variables are actively used in this step and the model is run with two potential new prosumers $\mathcal{I}_{new} = \{\text{prosumer H0}, \text{prosumer G0}\}$ to determine which prosumer type is preferred by the community.

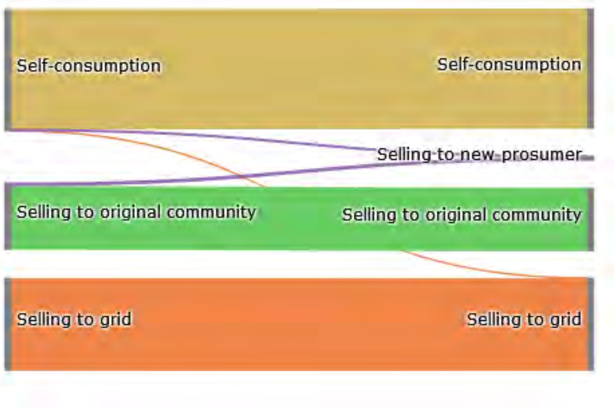


Figure 2.15: Sankey diagram of the electricity generation of prosumers

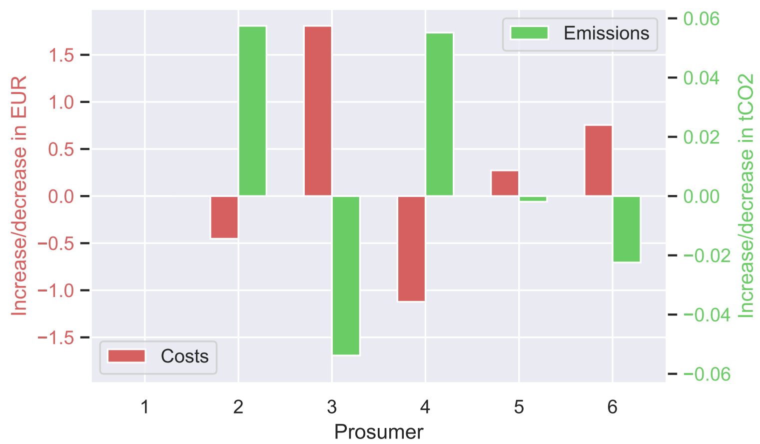


Figure 2.16: Cost- and emission balances of the prosumer of $\mathcal{I}_{old}$ – mixed α_i

There is only one possible choice:

$$\sum_{i \in \mathcal{I}_{new}} b_i = 1. \tag{2.22}$$

We start the analyses by minimizing the individual emissions again. The community prefers the household profile with the same parameters as before: PV_{new} =5 kW$_{\text{peak}}$ and $load_{new}$ = 2000 kWh/year. The annual peer-to-peer trading is shown in Figure 2.17 (left), wherein the business (prosumer G0) is not part of the community. The other cases, minimizing prosumers' costs and mixed preferences, lead to a different result. The business is a better match with PV generation profiles than the household and is, therefore, a better opportunity to sell surplus PV generation to. The business is a consumer only, with an annual electricity demand of 8000 kWh (see Figure 2.17, right). The results are summarized in Table 2.7.

Table 2.7: Choosing between different prosumer types H0 and G0

prosumer type	H0	G0
(i) individual emissions	✓	-
(ii) individual costs	-	✓
(iii) mixed α_i	-	✓

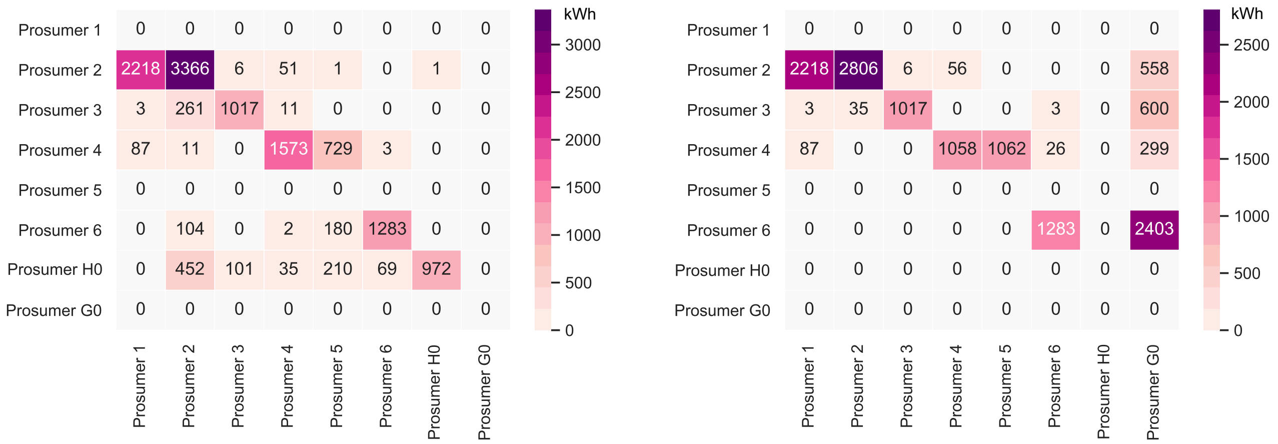


Figure 2.17: Choosing between prosumer types; $\alpha_i = 0$ (left) vs. $\alpha_i = 1$ (right)

Discussion and implications of the results The community's choice reflects well the different needs of the members. We can see that a community with environmental-oriented members opts for a prosumer with a large PV system, while profit-oriented choose a consumer with high electricity demand they can sell electricity to and thereby generate profits. Geographical distance and the new prosumer's willingness-to-pay also influence the decision. With mixed preferences, the needs of environment- and profit-oriented prosumers are balanced.

The model developed for dynamic participation presented here is only a basic model for dynamic participation, because it shows only one year of the selection process. It can be considered as a basis for dynamic participation over several years (annual phase-in and phase-out of members). Also, it helps an energy community to optimally select prosumers from a given portfolio without considering possible future developments of the community. To improve planning of the community, this matter is addressed in [39].

2.6.2 Potential of energy communities on country level

This Section presents the results of the theoretical potential of energy communities on country level. We start with a comparison of the total number of ECs per country in Section 2.6.2.1, then moving on to the potential savings due to energy sharing in the reference countries, first on country level in Section 2.6.2.2, then on prosumer level in terms of annual cost and emissions savings in Section 2.6.2.3.

2.6.2.1 Number of ECs in the reference countries

The evaluation of the results starts with a comparison of the total number of ECs per settlement pattern type, which is graphically displayed in Figure 2.18. It can be seen that in terms of numbers, rural ECs (green) are dominating. The highest number of ECs is found in England, which has by far the largest amount of buildings. In Spain, similar in population, there are about half as many residential buildings as England, because there are more apartment buildings rather than single houses. In the UK, even in larger cities, a big part of the population lives in singles houses (detached, duplex or row houses). Since the settlement pattern algorithm assigns single houses to rural or suburban areas, we can see that this assignment might not represent England as well as it represents the other reference countries, where a higher percentage of apartment buildings are found in cities. Therefore, the term "rural" can be misleading, as it really simply means single houses, both in rural and urban areas.

The three other reference countries are small in population and they have very similar numbers of

ECs. They all have a large share of rural areas, one large main metropolitan area, and a few smaller urban areas. The numbers are summarized in Table 2.8.

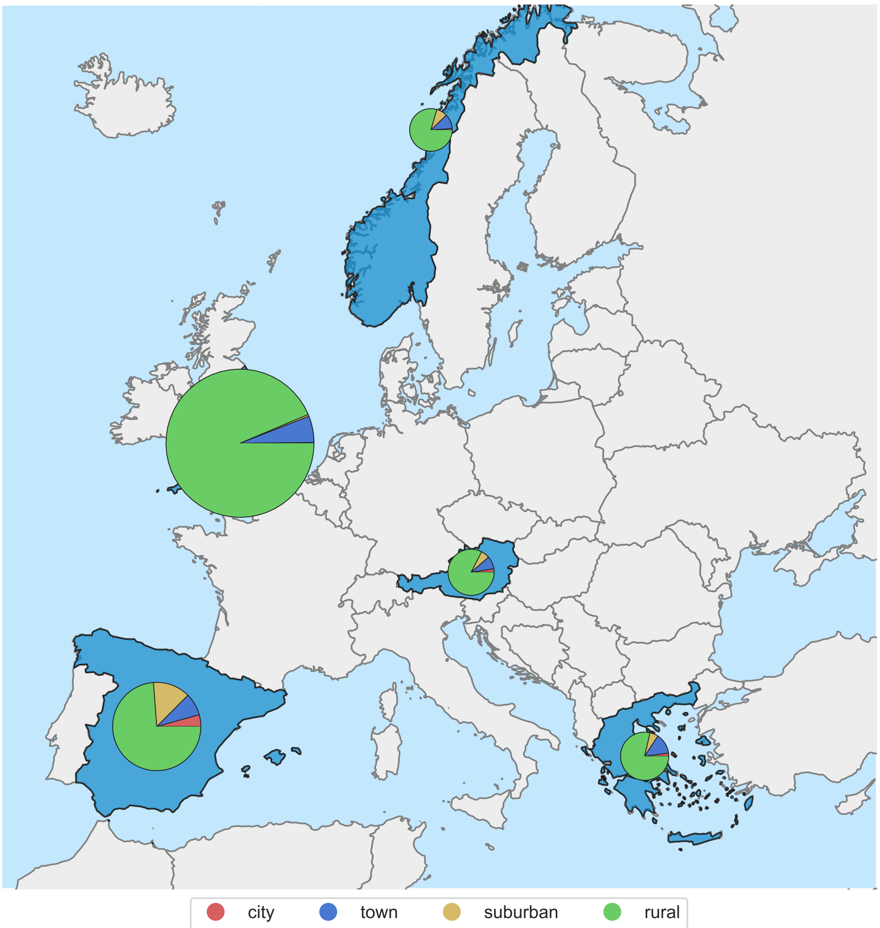


Figure 2.18: Number of energy communities in Austria, Greece, Norway, Spain, and England

Table 2.8: Total number of ECs per settlement pattern type and reference country

	city	town	suburban	rural
Austria	4353	16 123	10 734	148 107
Greece	4087	26 719	11 006	153 294
Norway	1587	17 062	12 753	121 641
Spain	28 170	53 865	89 516	483 401
UK (England)	2779	106 715	7490	1 728 185

2.6.2.2 Savings per country

The number of ECs is a representation of the building stock, but not yet represents the benefit and potential of energy communities for the energy system in each country. Electricity sharing/trading increases the PV self-consumption on community level and improves the exploitation of renewable resources. Figures 2.19-2.21 show the aggregated savings per country for Austria, Greece, and Spain, respectively. Per settlement pattern, savings are split into the following categories: buying from the grid (blue), selling to the grid (orange), shared self-consumption (own self-consumption plus purchases from the community - green), and BESS operation (red). In the figures, we see a repeating pattern, but with different quantitative numbers: Purchases and sales from the grid decrease due to the increased self-consumption of the community as a whole. Also, batteries are used less, which implies that prosumers can to some extent substitute battery size with increasing energy sharing with the community.

In particular, this means that electricity trading with the grid is reduced when prosumers are integrated into a local energy community: up to 25% less purchases from the grid in town settlement patterns in Greece and in rural settlement patterns in Spain, and up to 100% less sales to the grid in city energy communities in Norway. An increase of (shared) self-consumption within energy communities by up to 70% is apparent in towns and cities. In rural settlement patterns, up to 65% are possible. Battery utilization decreases by 10 % to 100 %.

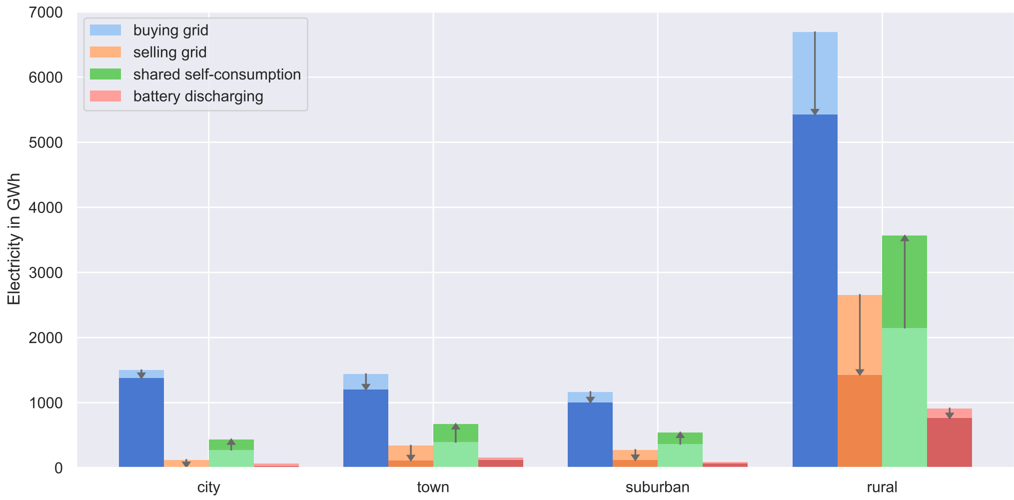


Figure 2.19: Impact of ECs on grid purchases, grid feed-in, shared self-consumption, and battery operation: Austria

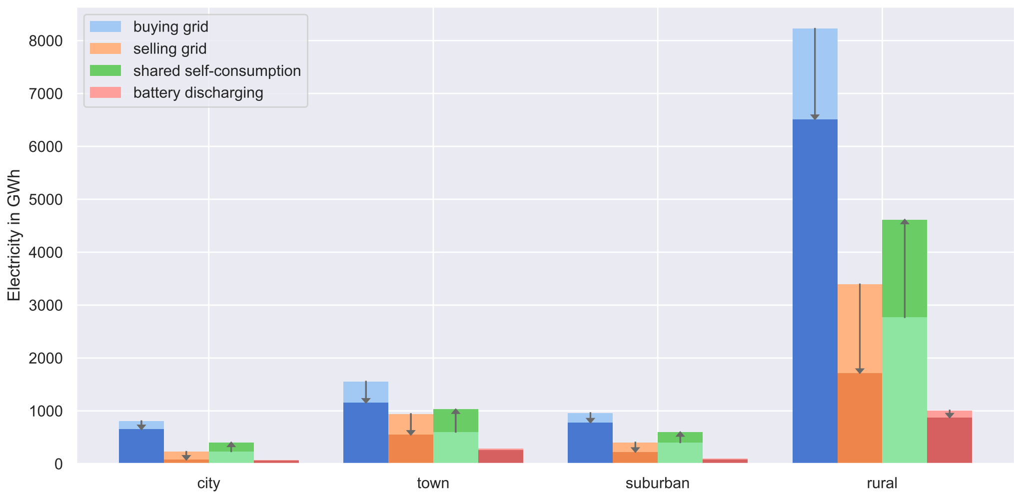


Figure 2.20: Impact of ECs on grid purchases, grid feed-in, shared self-consumption, and battery operation: Greece

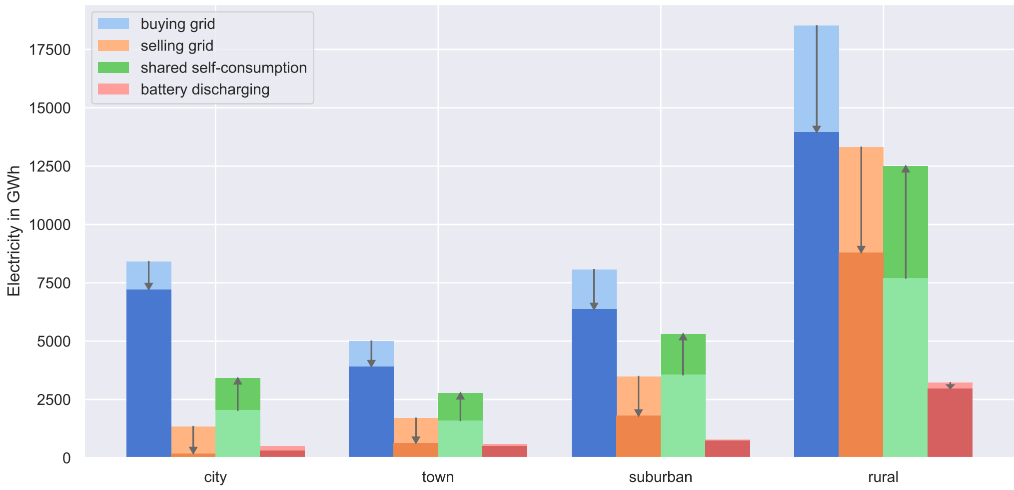


Figure 2.21: Impact of ECs on grid purchases, grid feed-in, shared self-consumption, and battery operation: Spain

2.6.2.3 Implications on prosumer level

Moving on from the results on country level, we are interested in how energy communities impact their individual members. We compare prosumers as community members and as stand-alone prosumers and derive the sharing potential of each settlement pattern and of each reference country. The main factors to evaluate are annual cost and emission savings per member. Apartment buildings are divided by the average number of dwellings per building such that we can compare savings per household. Below, we compare savings across settlement patterns and countries. Let's start with costs savings in Figure 2.22. The main factors leading to differences between countries are electricity prices for households and electricity generation from PV systems. Sharing electricity increases shared self-consumption, and the community saves money by maximizing its welfare, see Eq. (2.1). The influence of the electricity price becomes clear when comparing countries with similar solar irradiation, see Spain with high prices and Greece with low prices. Although consumers pay relatively high electricity prices in England, savings of English energy community members are at the lower end of the reference countries because of the country's low solar irradiation. Only Norwegian energy community members record lower savings. Comparing all four settlement patterns of the case study, cost savings are clearly highest in rural communities. In city ECs, which have the highest population density, self-consumption of individual members (buildings) already exploits the majority of the PV generation potential, leaving little room for further sharing with others. Rural ECs benefit primarily from members who do not own PV systems, but also from members with different load profiles. One interesting case is Norway, where cost savings in town ECs exceed savings in rural ECs. Since we assume that town settlements consist of SAB building types where the electricity demand per dwelling is much lower compared to single houses, and the average number of dwellings in Norwegian SABs is very low, much more PV electricity is available to community members.

The emission savings correspond to the emission intensity of the national electricity generation, see Figure 2.23. The most emission intense country (Greece) is about 42 times more emission intense than the least emission intense country (Norway). This is much more significant than the price difference, therefore the difference between the reference countries, which we can see in Figure 2.23, depends mainly on emission intensity rather than solar radiation. The difference between the settlement patterns can be explained in a similar way as the cost savings.

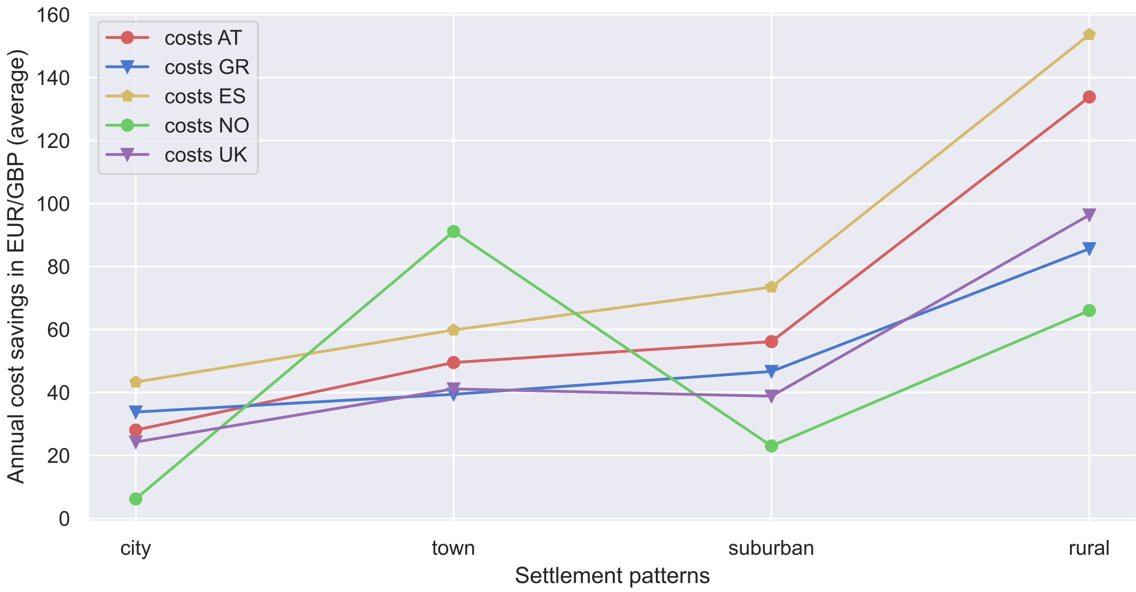


Figure 2.22: Impact of ECs on the average community member per settlement pattern: costs

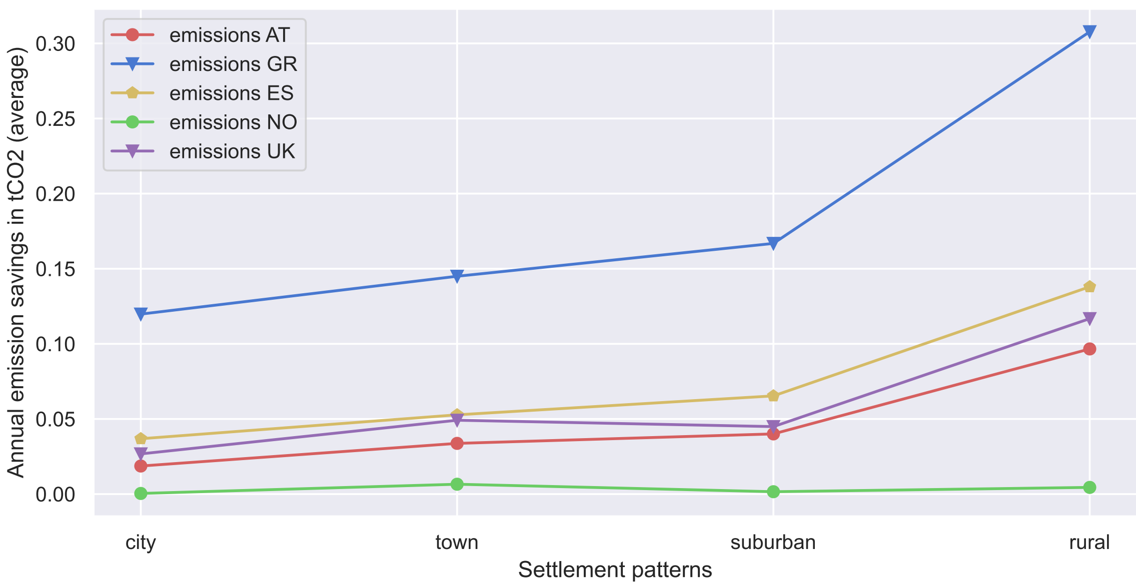


Figure 2.23: Impact of ECs on the average community member per settlement pattern: emissions

2.6.3 Potential of energy communities in Europe

As described in Section 2.4.2.3, the results from five reference countries are up-scaled to European level. The number of energy communities for each cluster of countries (as shown in Figure 2.5) is calculated according to Equation (2.20) and is presented in the following Table 2.9.

Table 2.9: Total number of ECs per settlement pattern type and cluster of countries

	city	town	suburban	rural
Austria	115,641	428,320	285,157	3,934,573
Greece	21,393	139,857	57,609	802,394
Spain	69,458	132,814	220,718	1,191,911
Norway	9,751	104,834	78,358	747,398
England	5,024	192,906	13,539	3,123,995
Europe total	221,266	998,730	655,381	9,800,271

Next, we display the savings per settlement pattern due to energy community participation similar to Section 2.6.2.2 within the following categories: buying from the grid (blue), selling to the grid (orange), shared self-consumption (own self-consumption plus purchases from the community - green), and BESS operation (red). Again, we use the results of each reference country to find the values of the respective cluster of countries, see Equation (2.21). To show the results for Europe as a whole (see Figure 2.24), all five clusters are added together. Expressed in percent, savings are highest in city and town settlement patterns, while in absolute terms, the greatest potential for savings is to be found in rural settlement patterns. Up to 20% less purchases from the grid in town settlement patterns, up to 85% less sales to the grid in city energy communities, up to 70% increase of shared self-consumption in towns, and finally, up to 50% fewer batteries are required (also in cities).

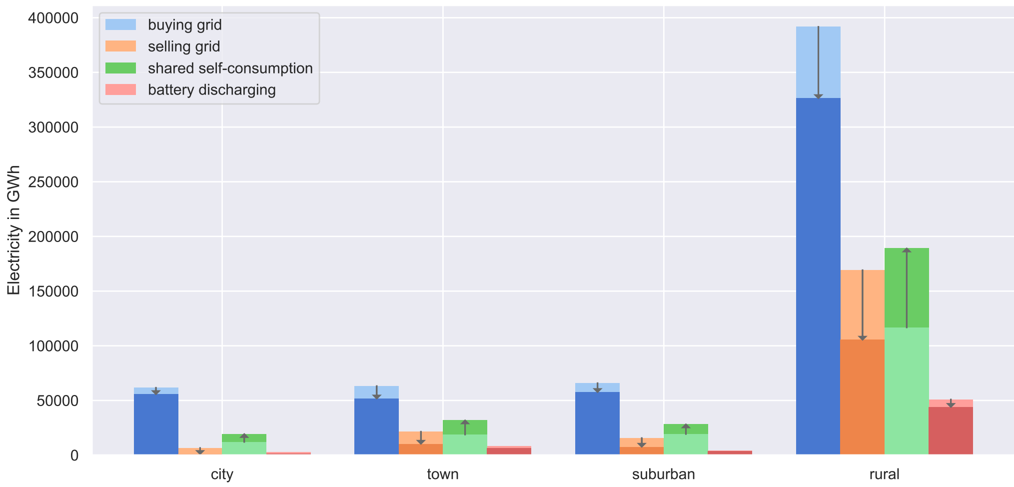


Figure 2.24: Impact of ECs on grid purchases, grid feed-in, shared self-consumption, and battery operation: Europe as a whole

2.7 Limitations and future extensions

Finally, we would like to point out the limitations of this case study and give an outlook on possible future extensions that could answer still open research questions. Since our energy community model FRESH:COM is limited to the electricity sector, a concept incorporating the ideas presented in this case study (especially individual willingness to pay and dynamic participation) could be created for holistic energy communities encompassing heating, cooling and other energy-related aspects such as transport, (waste) water or general waste management. It is also worth taking a closer look at the contractual agreements between energy communities as legal entities and their members, as the exact design of contracts depends on legal and regulatory aspects.

There are also a few limitations found in our analysis of the theoretical potential of energy communities in Europe. Based on five reference countries, case study 2 derives the number of energy communities according to the building stock and settlement patterns (city, town, suburban, and rural). An accurate data base of the residential building stock is key for this type of analysis. A high special resolution is desirable to correctly classify areas into settlement patterns. In this case study, we show results on country level only, then followed by a qualitative upscaling to Europe as a whole. Downscaling the results to regional level is possible, e.g., under consideration of settlement patterns and regions depending on the resolution of building stock data.

Participants of energy communities can cut down their annual electricity costs and emissions. Cost savings correlate with retail electricity prices, i.e. the higher the costs per kilowatt-hour, the higher the savings, and with the amount of PV electricity generated by the community in total. Due to an increasing consumption of (clean) PV electricity instead of the national power generation mix, emissions of prosumers participating in an energy community decrease. An interesting extension of this work would be to investigate whether "price cannibalism" plays a role due to the increased amount of self-consumed electricity, and if investments in PV and battery systems are incentivized.

Our work shows the "ideal" case with 100% of households in main residencies being energy community members. This is in contrast to voluntary participation, which is the underlying idea of the concept of communities of actors. However, based our results, it is easy to derive and analyze different levels of energy community penetration and to derive an upper bound for welfare gains due to energy communities in Europe.

The analyses are conducted from the perspective of the energy community and its prosumers, but not from the energy system point of view. For example, the impact of local energy communities on (possibly) reduced grid expansion needs is subject to future research. Our study limits each energy community to a specific settlement pattern, while energy communities across different settlement pattern types have the potential to further increase benefits for their members due to more diversity within the actors involved. Supported by the results of this case study describing the impact of energy communities on prosumers, we can assume that participation in energy communities will help to advance the energy transition from the perspective of citizens on individual level. In addition, citizen participation is likely to increase the acceptance of renewable technologies, which will advance the energy transition as a whole.

2.8 References

[1] Magnus Askeland, Stian Backe, and Karen Byskov Lindberg. Zero energy at the neighbourhood scale: Regulatory challenges regarding billing practices in norway. *IOP Conference Series: Earth and Environmental Science*, 352:012006, oct 2019.

[2] S. Backe, P. Crespo del Granado, A. Tomasgard, D. Pinel, M. Korpast, and K. B. Lindberg. Towards zero emission neighbourhoods: Implications for the power system. In *2018 15th International Conference on the European Energy Market (EEM)*, pages 1–6, 2018.

[3] Stian Backe, Sebastian Zwickl-Bernhard, Daniel Schwabeneder, Hans Auer, Magnus Korpås, and Asgeir Tomasgard. Impact of energy communities on the european electricity and heating system decarbonization pathway: Comparing local and global flexibility responses. *Applied Energy*, 323:119470, 2022.

[4] Michael L. Bynum, Gabriel A. Hackebeil, William E. Hart, Carl D. Laird, Bethany L. Nicholson, John D. Siirola, Jean-Paul Watson, and David L. Woodruff. *Pyomo–optimization modeling in python*, volume 67. Springer Science & Business Media, third edition, 2021.

[5] European Commission and Directorate-General for Energy. *Clean energy for all Europeans*. Publications Office, 2019.

[6] S. Dempe and F. Mefo Kue. Solving discrete linear bilevel optimization problems using the optimal value reformulation. *Journal of Global Optimization*, 68:255 – 277, 2017.

[7] Patrick Devine-Wright. Community versus local energy in a context of climate emergency. *Nature Energy*, 4:894–896, 2019.

[8] Ifigeneia Douvitsa. The new law on energy communities in greece. *Cooperativismo e Economía Social (CES)*, 2019.

[9] E-Control. Statistikbroschüre 2021. https://www.e-control.at/documents/1785851/1811582/E-Control-Statbro-2021.pdf/83442b63-df8c-a732-7152-8df34986c2c3?t=1636364279845, 2021. [Online; accessed 05-April-2022].

[10] ELSTAT - Greek statistical authority. Building inventory 2011. https://www.statistics.gr/el/census-buildings-2011, 2011. [Online; accessed 05-April-2022].

[11] ELSTAT - Greek statistical authority. Characteristics of houses - households / 2011. https://www.statistics.gr/el/statistics/-/publication/SAM05/2011, 2011. [Online; accessed 06-April-2022].

[12] Energy Facts Norway. Energy use by sector. https://energifaktanorge.no/en/norsk-energibruk/energibruken-i-ulike-sektorer/#households, 2022. [Online; accessed 06-April-2022].

[13] EPISCOPE. GB Great Britain / England - Country Page. https://episcope.eu/building-typology/country/gb/, 2014. [Online; accessed 12-April-2022].

[14] P. Escobar, E. Martínez, J.C. Saenz-Díez, E. Jiménez, and J. Blanco. Profitability of self-consumption solar pv system in spanish households: A perspective based on european regulations. *Renewable Energy*, 160:746–755, 2020.

[15] Eurostat. SECH PROJECT -SPAHOUSEC: Analyses of the energy consumption of the household sector in Spain. https://ec.europa.eu/eurostat/cros/system/files/SECH_Spain.pdf, 2011. [Online; accessed 06-April-2022].

[16] Eurostat. Electricity price statistics. https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Electricity_price_statistics, 2022. [Online; accessed 12-April-2022].

[17] EXAA Energy Exchange Austria, 2020.

[18] B. Fina and H. Fechner. Transposition of european guidelines for energy communities into austrian law: A comparison and discussion of issues and positive aspects. *Energies*, 14, 2021.

[19] Bernadette Fina, Hans Auer, and Werner Friedl. Profitability of PV sharing in energy communities: Use cases for different settlement patterns. *Energy*, 189:116148, 2019.

[20] Bernadette Fina, Hans Auer, and Werner Friedl. Cost-optimal economic potential of shared rooftop pv in energy communities: Evidence from austria. *Renewable Energy*, 152:217–228, 2020.

[21] Matteo Fischetti, Ivana Ljubić, Michele Monaci, and Markus Sinnl. A new general-purpose algorithm for mixed-integer bilevel linear programs. *Operations Research*, 65(6):1615–1637, 2017.

[22] José Fortuny-Amat and Bruce McCarl. A representation and economic interpretation of a two-level programming problem. *The Journal of the Operational Research Society*, 32(9):783–792, 1981.

[23] Cristobal Gallego-Castillo, Miguel Heleno, and Marta Victoria. Self-consumption for energy communities in spain: A regional analysis under the new legal framework. *Energy Policy*, 150:112144, 2021.

[24] Gurobi Optimization, LLC. Gurobi Optimizer Reference Manual, 2021.

[25] William E Hart, Jean-Paul Watson, and David L Woodruff. Pyomo: modeling and solving mathematical programs in python. *Mathematical Programming Computation*, 3(3):219–260, 2011.

[26] Eva Blasco Hedo. Real decreto 244/2019, de 5 de abril, por el que se regulan las condiciones administrativas, técnicas y económicas del autoconsumo de energía eléctrica. *Actualidad Jurídica Ambiental*, (90):68–71, 2019.

[27] Instituto Nacional de Estadística (INE). Population and Dwellinng Censuses 2011. Dwellings. https://www.ine.es/dynt3/inebase/index.htm?type=pcaxis&path=/t20/e244/viviendas/p01/&file=pcaxis&L=1, 2022. [Online; accessed 06-April-2022].

[28] Instituto Nacional de Estadística (INE). Population and Housing Census 2011. Buildings. https://www.ine.es/dynt3/inebase/index.htm?type=pcaxis&path=/t20/e244/edificios/p03/&file=pcaxis&L=1, 2022. [Online; accessed 06-April-2022].

[29] International Energy Agency. Data and statistics. https://www.iea.org/data-and-statistics/data-tables?country=UK&energy=Electricity&year=2019, 2022. [Online; accessed 14-April-2022].

[30] Local Government Association. Reports. https://lginform.local.gov.uk/, 2022. [Online; accessed 12-April-2022].

[31] Álvaro Manso-Burgos, David Ribó-Pérez, Manuel Alcázar-Ortega, and Tomás Gómez-Navarro. Local energy communities in spain: Economic implications of the new tariff and variable coefficients. *Sustainability*, 13(19), 2021.

[32] Ministry of Housing, Communities & Local Government. English Housing Survey. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/817286/EHS_2017-18_Households_Report.pdf, 2017. [Online; accessed 12-April-2022].

[33] National Grid ESO. Carbon Intensity API. https://carbonintensity.org.uk/, 2022. [Online; accessed 22-March-2022].

[34] Noah Pflugradt. LoadProfileGenerator. https://www.loadprofilegenerator.de/, 2021. [Online; accessed 08-February-2022].

[35] C. Nolden, J. Barnes, and J. Nicholls. Community energy business model evolution: A review of solar photovoltaic developments in england. *Renewable and Sustainable Energy Reviews*, 122:109722, 2020.

[36] Odyssee Mure. Electricity consumption per dwelling. https://www.odyssee-mure.eu/publications/efficiency-by-sector/households/electricity-consumption-dwelling.html, 2022. [Online; accessed 05-April-2022].

[37] T Perger and H Auer. Dynamic participation in local energy communities with peer-to-peer trading [version 1; peer review: 1 approved]. *Open Research Europe*, 2(5), 2022.

[38] Theresia Perger, Lukas Wachter, Andreas Fleischhacker, and Hans Auer. Pv sharing in local communities: Peer-to-peer trading under consideration of the prosumers' willingness-to-pay. *Sustainable Cities and Society*, 66:102634, 2021.

[39] Theresia Perger, Sebastian Zwickl-Bernhard, Antonia Golab, and Hans Auer. A stochastic approach to dynamic participation in energy communities. *e & i Elektrotechnik und Informationstechnik*, 2022.

[40] Stefan Pfenninger and Iain Staffell. Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. *Energy*, 114:1251 – 1265, 2016.

[41] Noah Pflugradt and Urs Muntwyler. Synthesizing residential load profiles using behavior simulation. *Energy Procedia*, 122:655–660, 2017. CISBAT 2017 International ConferenceFuture Buildings & Districts - Energy Efficiency from Nano to Urban Scale.

[42] S. Pineda, H. Bylling, and J. M. Morales. Efficiently solving linear bilevel programming problems using off-the-shelf optimization software. *Optimization and Engineering*, 19:187 – 211, 2018.

[43] Renewables.ninja. Renewables.ninja. https://renewables.ninja, 2019. [Online; accessed 06-April-2022].

[44] Republik Österreich. Bundesgesetz über den Ausbau von Energie aus erneuerbaren Quellen (Erneuerbaren-Ausbau-Gesetz – EAG) . https://www.ris.bka.gv.at/GeltendeFassung.wxe?Abfrage=Bundesnormen&Gesetzesnummer=20011619, 2022. [Online; accessed 21-August-2022].

[45] Carlos Ruiz, Antonio J. Conejo, J. David Fuller, Steven A. Gabriel, and Benjamin F. Hobbs. A tutorial review of complementarity models for decision-making in energy markets. *EURO Journal on Decision Processes*, 2:91 – 120, 2014.

[46] Heleen Schockaert. Development of energy communities in greece: Challenges and recommendations. *REScoop.eu*, 2021.

[47] Wouter Schram, Atse Louwen, Ioannis Lampropoulos, and Wilfried van Sark. The hourly emission factor profiles of Belgium, Spain, France, Italy, The Netherlands, Portugal, Germany and Austria for 2017, 2019.

[48] Iain Staffell and Stefan Pfenninger. Using bias-corrected reanalysis to simulate current and future wind power output. *Energy*, 114:1224 – 1239, 2016.

[49] Statistics Norway. 03175: Existing building stocks. Residential buildings, by type of building (M) 2001 - 2022. `https://www.ssb.no/en/statbank/table/03175/`, 2022. [Online; accessed 06-April-2022].

[50] Statistics Norway. 06265: Dwellings, by type of building (M) 2006 - 2021 . `https://www.ssb.no/en/statbank/table/06265/`, 2022. [Online; accessed 06-April-2022].

[51] Statistik Austria. Wohnungs- und Gebäudebestand. `https://www.statistik.at/web_de/statistiken/menschen_und_gesellschaft/wohnen/wohnungs_und_gebaeudebestand/022982.html`, 2011. [Online; accessed 05-April-2022].

[52] Statistik Austria. Haushalte. `http://www.statistik.at/web_de/statistiken/menschen_und_gesellschaft/bevoelkerung/volkszaehlungen_registerzaehlungen_abgestimmte_erwerbsstatistik/haushalte/index.html`, 2019. [Online; accessed 05-April-2022].

[53] Statistik Austria. Energieeinsatz der Haushalte. `https://www.statistik.at/web_de/statistiken/energie_umwelt_innovation_mobilitaet/energie_und_umwelt/energie/energieeinsatz_der_haushalte/index.html`, 2021. [Online; accessed 05-April-2022].

[54] T. Perger. FRESH:COM v2.0, 2021.

[55] T. Perger. ASCENDEMUS, 2022.

[56] Romain Tavenard, Johann Faouzi, Gilles Vandewiele, Felix Divo, Guillaume Androz, Chester Holtz, Marie Payne, Roman Yurchak, Marc Rußwurm, Kushal Kolar, and Eli Woods. Tslearn, a machine learning toolkit for time series data. *Journal of Machine Learning Research*, 21(118):1–6, 2020.

[57] Holger Teichgraeber and Adam R. Brandt. Clustering methods to find representative periods for the optimization of energy systems: An initial framework and comparison. *Applied Energy*, 239:1283–1293, 2019.

[58] The European Climate Initiative (EUKI). ECOISM project. `https://www.euki.de/en/euki-projects/energy-communities-greece/`, 2020. [Online; accessed 21-August-2022].

[59] Guido Van Rossum and Fred L. Drake. *Python 3 Reference Manual*. CreateSpace, Scotts Valley, CA, 2009.

[60] Harald Taxt Walnum, Åshild Lappegård Hauge, Karen Byskov Lindberg, Mads Mysen, Brita Fladvad Nielsen, and Kari Sørnes. Developing a scenario calculator for smart energy communities in norway: Identifying gaps between vision and practice. *Sustainable Cities and Society*, 46:101418, 2019.

[61] Sebastian Zwickl-Bernhard and Hans Auer. Citizen participation in low-carbon energy systems: Energy communities and its impact on the electricity demand on neighborhood and national level. *Energies*, 14(2), 2021.

Chapter 3

Case Study 3: Need for flexibility – storage

Abstract

Objective of the Case Study

This case study assesses the interplay among several storage technologies and the transmission grid in providing the flexibility required by the electricity system on its way to being fully decarbonized. Storage technologies whose flexibility contribution is determined include decentralized electricity storage within local energy communities (LECs), centralized storage in the form of pumped-storage hydro, utility-scale batteries, and hydrogen storage.

Scope and main features of the analysis

We address the CS objective by computing how the level of use of the rest of storage technologies and the expansion and use of the transmission grid is affected by the deployment of LECs within Norway and Spain. These are two paradigmatic countries due to the level of penetration of RES generation in them and the level of interconnection between them and the rest of the European system. In order to assess the impact of LECs on the electricity exchanges between Norway, Spain, and other countries, the rest of the European system is also represented in our analyses, though with a lower level of detail. The Norwegian and Spanish systems are represented considering between 8 and 11 grid nodes for each, as well as the energy related technologies deemed to be located in each of these nodes. Most of the rest of national systems are represented considering a single node. The time horizon considered for the analysis is 2030, which is the target year when the optimal operation of the system and expansion of the transmission grid is computed. Representing the operation of the system with a fine-enough resolution (hourly in our case) is crucial to assess the role of those technologies providing flexibility in each of several time-frames: 1) daily (utility-scale battery energy storage), 2) weekly (compressed-air energy storage and hydrogen storage), and 3) monthly, or seasonally, (pumped-storage hydro and hydrogen storage). Moreover, the variability of the output of VRES technologies (solar PV, Wind Offshore, and Wind Onshore) also needs to be represented with a high level of detail, since managing this variability is the main reason to mobilize flexibility in the system. Local energy communities are deemed to deploy and operate their energy resources according to the electricity price profile, in order to obtain economic benefits out of the system operation. Thus, the price profile largely affects the modifications to the net energy demand (demand net of variable RES output) in each node caused by LECs.

Workflow

The analyses in this Case Study are performed making use of three specialized and detailed models of the power system: a) EMPS-W, focused on the hydro scheduling, b) openTEPES, focused on the transmission expansion planning and operation, and c) GUSTO, focused on the deployment and operation of LECs. The interactions taking place among the models employed to compute results are illustrated in Figure 3.1. EMPS-W considers a multiplicity of climatic years and computes the optimal operation of the power system and, specifically, that of hydro resources, as well as the electricity prices. The operation of hydro technologies and the level of demand, considering it as elastic, computed by EMPS-W is taken as an input by openTEPES, which computes the optimal expansion of the transmission grid. This is then fed into EMPS-W to recompute the optimal operation of the system considering the expanded grid. The, the electricity prices computed by EMPS-W are used as an input by GUSTO to compute the optimal level of deployment and use of energy resources, including local storage, within LEcs. Based on these, GUSTO computes the changes to be made to the net demand profile of LECs, which are fed into EMPS-W, together with the expansion of the transmission grid computed by openTEPES, to recompute the operation of the system. After some iterations like this, convergence among the results provided by the three models is achieved.

Main results

Local energy communities in the two considered countries do not deploy a relevant amount of energy storage, due to limited price spread in both systems. Thus, the amount of flexibility they mobilize is also limited. On the other hand, they deploy relevant amounts of local variable generation, largely

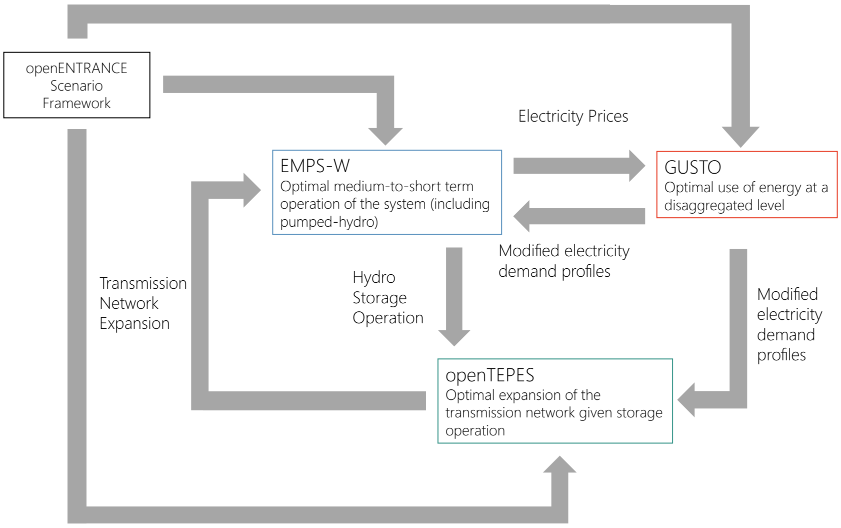


Figure 3.1: Workflow

PV, which tend to produce power in low price periods and, therefore, decrease the price in these periods. This results in an increase in the price spread among hours and, therefore, an increase in the need for flexibility of different types (daily, weekly and even seasonal, depending on the context). The limited amount of storage and flexibility mobilized by LEC is employed to shift energy from low-price periods to high-price ones and moderately reduce the price in the latter. The deployment of LECs affects differently the deployment of RES generation in different Norwegian areas. This causes differences in supply conditions among areas and additional power exchanges among them. On the other hand, LECs affect similarly the demand and generation pattern in all the areas in Spain, decreasing the complementarities among them. Then, the use of the transmission grid in Norway increases slightly due to the creation of LECs, while that of the Spanish transmission grid decreases moderately. As for the development of the grid, as aforementioned, LECs create a change in the pattern of flows in the Norwegian grid. Additional network investment are needed to host the new flows. Within Spain, the deployment of additional RES generation within LECs in those areas already featuring large amounts of this generation triggers a relevant increase in RES energy spillages within these areas. Partially avoiding these spillages involves building additional transmission interconnection capacity among areas. As a consequence, LECs cause an increase in the amount of transmission network investments both in Spain and Norway.

Future extensions

This work could be extended by considering the optimization of the expansion of storage technologies together with that of the transmission grid. Besides, the sensitivity of the results computed w.r.t. the level of penetration of LECs, that of deployment of electric vehicles within LEC, and that of CO2 and Gas prices, could also be determined.

Contents

3.1 Introduction

Electricity storage is one of the key supporting technologies of the energy transition, as it provides flexibility and thus is needed to facilitate the integration of renewable generation. Several technologies could be deployed in this context. Pumped-storage hydro is a mature technology with low investment costs for relatively large sizes but whose deployment is long and complex (in some cases, impossible). However, although significant hydro storage and pumped-hydro storage capacities are already installed in different regions across Europe, there is still potential to invest further and increase these capacities. In many cases, building new storage is not possible, but upgrades are potentially needed (e.g., adding a pumping mode to HS plants). Some projects are already on the PCI list (Projects of Common Interest). The maximum amount of energy that can be stored in the currently existing reservoirs in some European countries can be summarized as follows (all Numbers in TWh): Norway (85), Sweden (34), Spain (18.4), Switzerland (8.4), Austria (3.2) and France (9.8) [5]. Norway has hardly any pumping capacity in its system. However, a recent study has shown that it is possible, considering current regulations (water flows and reservoir levels), to install about 20 GW in the South-Western part of the country. Pumped-storage hydropower can contribute to balancing variable wind and solar power production in UK and Germany/Benelux if the transmission capacities are increased.

On the other side of the spectrum, batteries could offer an alternative to complement hydro with smaller (often at the scale of a single consumer) decentralized storage, albeit at a higher cost currently. In addition, the differing sizes of these technologies mean that they can be used at different time horizons and levels in the system. While pumping stations with large dimensions in energy content (capacities) could be used to shift loads over weekend periods or even seasons, the smaller batteries could only be used to store energy for several hours. In addition, smaller batteries would not be entirely controllable by the system operator and would instead respond to consumers' needs and behavior.

As seen, both technologies represent different options for storing electricity and shifting loads in different periods. On the one hand, batteries have traditionally been associated with smoothing short-term fluctuations in demand or renewable generation output. Their size is directly related to the scope of this smoothing: smaller batteries support a single consumer, while larger ones can minimize the local power excess or deficits of a community over extended periods. Therefore, battery storage supports the relative independence of prosumers and is linked to the development of decentralized structures in energy markets. On the other hand, large-scale pumped hydro can be used to balance renewables at the regional, country, and European levels. These two alternative uses of storage and schemes of centralization/decentralization will lead to diverging needs for market integration, which will be reflected in transmission network needs.

3.1.1 Overall objective of case study

This case study aims to assess the role of the following technologies: 1) centralized storage in the form of pumped-hydro storage, utility-scale batteries, and hydrogen storage, 2) decentralized storage deployed within local energy communities, and 3) the transmission grid. Some of these technologies can provide short-term flexibility, others medium-term flexibility, and some others long-term one within the Norwegian and Spanish systems. To carry out this assessment, we consider both the optimal level of deployment and use of each technology in the base case, not considering LEC, and how much the deployment of LECs impact the use of this technology, reflecting its optimal level of deployment, as well as the deployment of transmission capacity. The specific system variables monitored in this regard are listed next:

- At the whole European system level: the amount of CO2 emissions, and the amount of capacity deployed and the level of utilization of the interconnectors in each direction (exports and imports).

- At the Norwegian and Spanish systems level: the level of production and consumption of each storage technology, the level of production of generation technologies, the amount of energy curtailed for VRES technologies (Solar PV, Wind-offshore, and Wind-onshore), the amount of energy spilled by hydro-storage generation, the level of prices per zone and at country level, the level of utilization of the national grid, and the amount of transmission capacity deployed within the national grid.

3.1.2 State of the art

A number of previous studies focus on the potential of LECs for increasing the system's flexibility and RES-based generation penetration. However, the specific role LECs should play is still being assessed, and the trade-offs between them and the rest of flexible technologies are only beginning to be explored. Furthermore, most LEC studies focus on a relatively small region. Thus, large-scale benefits remain undetected. In this case study, we represent all the main critical technologies of the system and compute their operation with a high-enough level of detail so that their combined effects can be assessed as accurately as possible. The main aspects considered within the analysis conducted, which make its contributions different from those of previous works, follow:

- Synergies and possibilities for substitution between hydro storage, large-scale batteries, hydrogen storage, and LEC: both hydro storage technologies and LEC may bring flexibility to the system, albeit the specific role of each should be assessed to understand the interplay between both.
- Synergies and possibilities for substitution between the grid and LEC: all flexibility options could potentially compete with each other. As mentioned above, both grid infrastructure and LEC can provide flexibility. However, determining how both types of flexibility can be best combined remains largely unexplored territory. This should probably depend on the features of the system and the type of LECs deployed in it, the network topology, and the network congestion/bottlenecks. The LECs penetration level could also affect this trade-off.
- The effect of changes taking place at a local (LEC) level on the functioning of the system at bulk national and regional levels: we consider changes in the level of ambition of LEC deployment and calculate the impact of these at the national and European level. To be able to calculate these effects, we model our focus regions, where LECs are deemed to be deployed, in a detailed manner and represent at a more aggregate level the remainder of the EU power system.
- Contribution of decentralized DERs to the provision of short and long-term flexibility: based on the previous features of our analyses, we can draw relevant conclusions on the flexibility contribution of LECs in the several time horizons spanning hours to a year (seasonal flexibility). In order to appropriately determine the flexibility contribution of LECs in each time horizon, we accurately represent the operation profile of all the main flexible generation and storage technologies. Besides, we also employ a detailed model of the transmission network considering accurately the physics of power flows.
- Representation of the variability of climate conditions across years: to accurately determine the impact that these should have on the system's economic operation.

3.2 Short summary of models used

3.2.1 EMPS-W

This stochastic model is focused on the computation of the detailed operation of the power system in the medium to short-term considering the main sources of variability of the system conditions, largely related to the variability of primary energy resources: hydro inflows, but also wind and solar ones (More details in Appendix 3.8.1).

- Optimal dispatch considering stochastic weather-related variables: wind and solar gross output and inflows to hydropower reservoirs.
- Manages separately individual water reservoirs computing individual water values.
- Considers aggregate power flow constraints (at corridor level).

3.2.2 openTEPES

This model is focused on the computation of the expansion of the power system in the long term, with a special focus on the transmission grid (More details in Appendix 3.8.2).

- Network model with detailed granularity.
- Full representation of Kirchhoff laws and network losses.
- Suitable for analyzing the impact of the implementation of specific energy policies on the development of the transmission network.

3.2.3 GUSTO

This model is focused on modeling the energy management, including electricity, within local energy communities featuring the specific system features where they are deployed (More details in Appendix 3.8.3).

- Considers sector coupling (electricity, heating/cooling, and gas) at the energy community level.
- Optimal utilization of small batteries and flexible loads at the prosumer level.

3.3 Assumptions

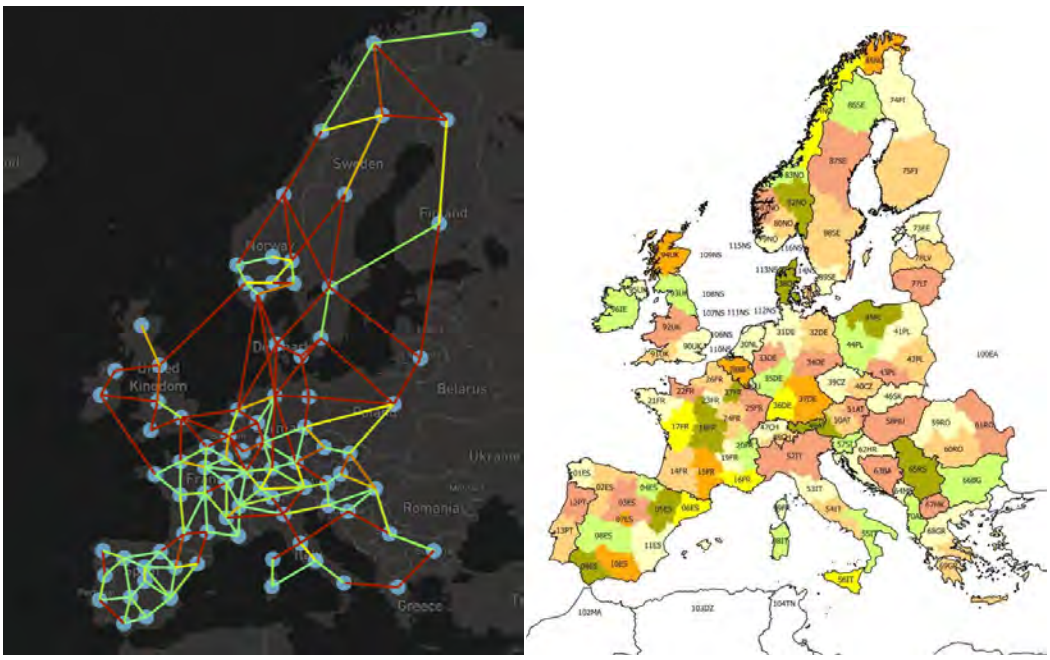
The study's main assumptions are related to the simplifications made when defining the detailed input data sets employed in the analysis of the scenario considered (Techno-Friendly) and when computing the system expansion planning and operation. When running each model, some abstraction of reality must be made. Besides, each model has multiple functionalities, some of which are not used for this case study. The simplifications made when running each specific model are described briefly in the following paragraphs.

3.3.1 Stochastic Hydro Scheduling and price simulations for climate years

The final results for the operation of the European power system are calculated by the EMPS-W model [7, 9]. Most of the input data fed into EMPS-W (generation capacities, generation costs) are GeneSys-Mod results computed for the Techno-friendly scenario. For other input data are based on those from the Sumeffekt project [1]. For hydropower, a detailed description is considered for Norwegian and Swedish areas. For other areas, all this hydropower is divided into reservoir hydropower, featuring one aggregated reservoir, and run-of-river. The operation of other energy storage types than reservoir hydropower is optimised for all areas. The following additional storage types are modelled: Pumped storage, batteries, and hydrogen. Hydrogen storage is considered only for Norway and Spain. For other countries, the electricity demand to produce hydrogen is modelled as fixed and included within the electricity demand. Additionally, some generation capacity to produce electricity from hydrogen at marginal cost is also considered. Weather variability concerning wind, solar radiation, temperatures, and reservoir inflows, for 57 climate years is simulated. All operating results have the resolution of 56 time-steps per week (3 hour resolution), 52 weeks, and 57 climate years. It is important to note that EMPS-W does not consider any uses of water that are not related to the generation of electricity. This means that including some ecological constraints can be particularly relevant for small units (i.e., run-of-the-river flows).

3.3.2 Expansion Planning of the European Transmission System

The expansion planning of the European-scaled transmission network in the case study is carried out using the openTEPES model [8]. The existing network, or starting point in the network expansion planning analysis, is presented in Fig. 3.2a. The expansion planning is computed only for a target year (2030). Thus, a static planning approach is adopted. Additionally, a single scenario is considered when representing the system evolution and the operation conditions. Then, the modelling approach followed is also deterministic. openTEPES determines the optimal network investment plan comprising reinforcements to supply the forecasted demand at minimum cost. The expansion plan is based on decisions that are carried out considering a set of expansion candidates predefined by the user. The



(a) European-scaled transmission network. (b) Map of the e-Highways' clusters

Figure 3.2: Transmission network and geographical distribution considered within the case study CS3.

expansion candidates comprise high voltage alternating and direct current (HVAC and HVDC) lines linking any pair of nodes across the European grid. These lines are predefined using the candidate discovery algorithm proposed in [6] and summarized here, see Algorithm 1. The algorithm identifies promising candidates based on the differences between the marginal supply costs in the grid nodes and the corresponding distances. For the promising expansion candidates, the following features are considered: line length, line capacity, resistance, reactance, voltage level, and investment cost. The set of expansion candidates considered is the same for all the openTEPES runs addressed within the CS. Note that the geographical distribution of the equivalent grid nodes considered in this case study is based on the node clustering analysis performed in the e-highways2050[1] project. This involved classifying NUTS3 regions (NUTS 2021 classification[2]) according to their features and merging similar regions making groups of interconnected ones, as can be appreciated in the Fig. 3.2b.

Algorithm 1: Candidate discovery algorithm

Data: Existing transmission network
Result: Reduced set of candidate lines
Initialization: Zero candidate lines (LC=0);
while *There is a new candidate line* ($PCI > 0$) **do**

1. Fix all the candidates as existing lines (LC)
2. Solve the economic dispatch (ED) problem
3. Search promising candidates as shown in [6]
4. Solve the relaxed problem (LP) considering all the promising candidates
5. Solve the discrete reduced problem (MIP)
    - It only considers the promising candidates that were invested in the previous step
6. Get the promising candidates who were invested: PCI
7. Add the PCI to the set of candidate lines: LC = LC + PCI

end
Solve the complete discrete problem (MIP). It considers all the promising candidates to get the final reduced set of candidate lines.

3.3.3 Deployment of Local Energy Communities in Norway and Spain

Here we briefly explain the main assumptions made about the penetration of local energy communities in Norway and Spain. Methodologically, we build on the studies in [4] and [10]. The main idea is to build representative types of energy communities based on settlement patterns from the existing building stock. In this work, we four different ones of communities(city, town, suburban and rural areas). GUSTO can then be applied to model and analyze local energy communities with the maximum level of detail possible. GUSTO enables a high resolution in the spatial and temporal dimensions. However, the clustering algorithm for both dimensions must abstract reality to limit calculation time. Thus, information on the energy community and at the country level is modeled with a limited level of detail. This approach has also been used in [2]. The main assumption here is that 15% of the potential for local energy communities (i.e., 15% of the total number of energy communities) will be implemented in the target year 2030. Thus, the penetration rate of local energy communities is 15%. The assumptions made in this case study align with those presented in case study 2, "Behavior of communities of actors." For a detailed description of these assumptions, including quantitative figures, we refer readers to that case study. In the interest of brevity, we will not provide further elaboration here.

[1] See: `https://docs.entsoe.eu/baltic-conf/bites/www.e-highway2050.eu/e-highway2050/`
[2] See: `https://ec.europa.eu/eurostat/web/nuts/background`

3.4 Methodology

3.4.1 Overall methodology

The analyses are conducted in the 2030 timeframe, i.e., having 2030 as the target year when the optimal development and operation of the system, and the impact on these of LECs, are assessed. They are focused on the Techno-Friendly scenario. The geographical scope of our analyses is the European power system. However, our focus is placed on the Spanish and Norwegian systems, where the deployment of LECs is considered and whose functioning is represented with a higher level of detail. These two systems are chosen because they are deemed paradigmatic ones. The two have a limited interconnection capacity with the bulk European power system. The availability of variable generation within the Spanish system is very high. Thus, this is expected to be a system with high flexibility needs. On the other hand, the Norwegian system is expected to host a large amount of flexible resources. Then, the latter could provide flexibility to the neighboring systems. Computing how the optimal mix of flexible resources, regarding their deployment and/or use, can be affected by the installation of decentralized, flexible resources represented by LECs in these two different contexts is of high interest. Pumped-storage hydro and the transmission grid have already been deployed to a large extent, while the opportunities to expand them further are limited. On the other hand, the potential for deployment of local energy communities remains largely unexploited. Using a soft-linking approach, the methodology involves the combined use of the models EMPS-W, openTEPES, and GUSTO (described in section 3.2). The case study workflow in the analyses conducted is discussed in section 3.4.2. As mentioned above, among those scenarios defined within the project, the analyses are conducted for the Techno-Friendly one. This implies that the development of the power system, including the amount of capacity deployed by most technologies, is that computed for this scenario in the global scenario analyses conducted within WP3 of the project. An exception to this is the capacity of the transmission grid, whose optimal development is determined within our CS analyses using model openTEPES, and, of course, the level of deployment of LECs, which is defined in our analysis as an input parameter. Most features of the technologies and relevant input parameters (like CO2 emission costs and fuel costs) are also made to coincide with those determined for the Techno-Friendly scenario in WP3. The rest of the data needed to run each model is collected from this own model database. Within our analyses, the optimal operation of the system and expansion of the transmission grid is computed both for a base case where LEC are deemed not to be deployed and for an alternative case where a 15% penetration level is considered for LEC. Then, the use made of each of the several flexibility sources considered, and, therefore, the optimal mix of amounts of flexibility mobilized by the several technologies, is determined for each of the two cases. Then, by comparing the results computed for both cases, the impact of LEC on the use of each flexible technology and the development of the transmission grid can be computed. A decrease in the use of a certain technology in the 15%LEC case with respect to that in the base case is an indication that the amount of capacity built for this technology should probably be lower the larger the penetration of LEC is. We should bear in mind that the impact assessed is that of the penetration of LEC in Spain and Norway only, not all over Europe. Thus, the most relevant results are those that have to do with the operation and development of these two national systems and with the interaction (and the development of the interconnections) between these two systems and their neighbors.

3.4.2 Case study workflow

This section presents the workflow of the use of models in our CS, as shown in Figure 3.3. The model EMPS-W calculates the optimal medium-to-short-term operation of the system for a multiplicity of climate years, which implies solving the hydrothermal coordination problem at the European level, considering a detailed model for the focus regions (that is, Spain and Norway) and an aggregate representation of the remaining countries. Then, the model openTEPES takes as an input the operation

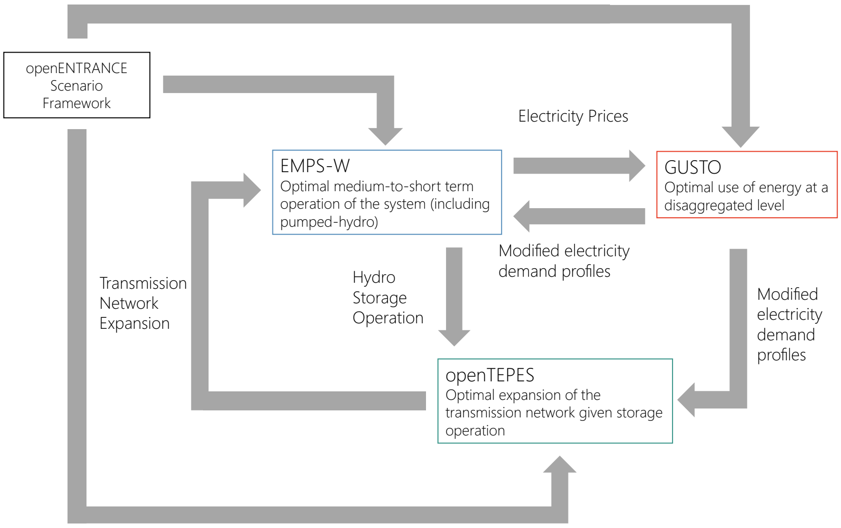


Figure 3.3: Workflow

of the hydro-related technologies and the estimate of the demand profile produced by EMPS-W for a specific climatic year that is close to the average, within those considered by EMPS-W. Considering all the climatic years jointly within the transmission expansion planning problem would be preferable. However, this is not feasible, given the huge size of the resulting problem. Just a single specific year can be considered by openTEPES when computing the expansion of the grid. Then, the climatic year to be considered for this should be as representative as possible of all the remaining ones. This is the case of those scenarios that are close to the average one. openTEPES computes the optimal expansion of the transmission network needed to provide additional flexibility in the form of an increase in the level of integration across markets. Subsequently, the new transmission network computed by openTEPES is fed back into EMPS-W, which recomputes the optimal operation of the system, and specifically hydro storage, as well as the electricity prices resulting from it. Then, the model GUSTO is employed to compute the optimal expansion and operation of DERs within LEC, taking as an input the electricity prices produced by EMPS-W for the same relevant climatic year considered by openTEPES. The deployment and operation of DERs within LEC result in some modifications to the demand level and profile. These modifications are considered for computing the basic demand profile for each climatic year taken by EMPS-W as an input, together with the latest expansion of the grid computed by openTEPES, to recompute the optimal operation of the system and prices for each climatic year. The new demand profile and hydro technologies operation computed by EMPS-W is taken as inputs by openTEPES to recompute the grid expansion and operation. This whole process, making a full iteration of runs of the models in the CS, is repeated until convergence is achieved in the results obtained. Convergence is deemed to be achieved when there are no relevant differences between the main results (operation computed by EMPS-W, demand changes computed by GUSTO, and network expansion and operation computed by openTEPES) computed in two consecutive iterations.

Obviously, in the case where LECs are not deemed to be deployed, GUSTO is not used in the analyses, and each iteration just includes one model run with EMPS-W followed by another one with openTEPES. In this case, the data exchanged among models only includes the hydro operation and the expansion of the transmission network.

Table 3.1 identifies the iterations and model runs conducted for the two main threads or cases (15% LEC and 00% LEC). The full workflow and exchanges of data for the 15% LEC case are also represented in Fig. 3.3 and 3.4.

Table 3.1: Sequence of model runs and numbering nomenclature

15% LEC	**00% LEC**
Iteration 1	*Iteration 1'*
1 - EMPS-W	1' - openTEPES
2 - openTEPES	2' - EMPS-W
3 - EMPS-W	
4 - GUSTO	
Iteration 2	*Iteration 2'*
3 - EMPS-W	3' - openTEPES
6 - openTEPES	4' - EMPS-W
7 - EMPS-W	
8 - GUSTO	
Iteration 3	*Iteration 3'*
9 - EMPS-W	5' - openTEPES
10- openTEPES	6' - EMPS-W
11- EMPS-W	
12- GUSTO	

3.4.3 Linkages

We use the openENTRANCE platform scenario explorer (openENTRANCE database) to manage the exchange of information among models. First, the common scenario data used by each model that is available within the dataset produced in the WP3 scenario analyses are uploaded onto the scenario explorer. Then, the missing data required to run each model is also uploaded on the explorer from the own databases of the models. To manage the exchange of information among models through the scenario explorer, two kinds of tools are needed: 1) tools for uploading/downloading data onto/from the scenario explorer, and 2) tools for converting data from each model format to the common openENTRANCE format (which can then be uploaded onto the Scenario Explorer) and vice-versa. These are used for exchanging information among models according to the workflow to carry out the CS analyses.

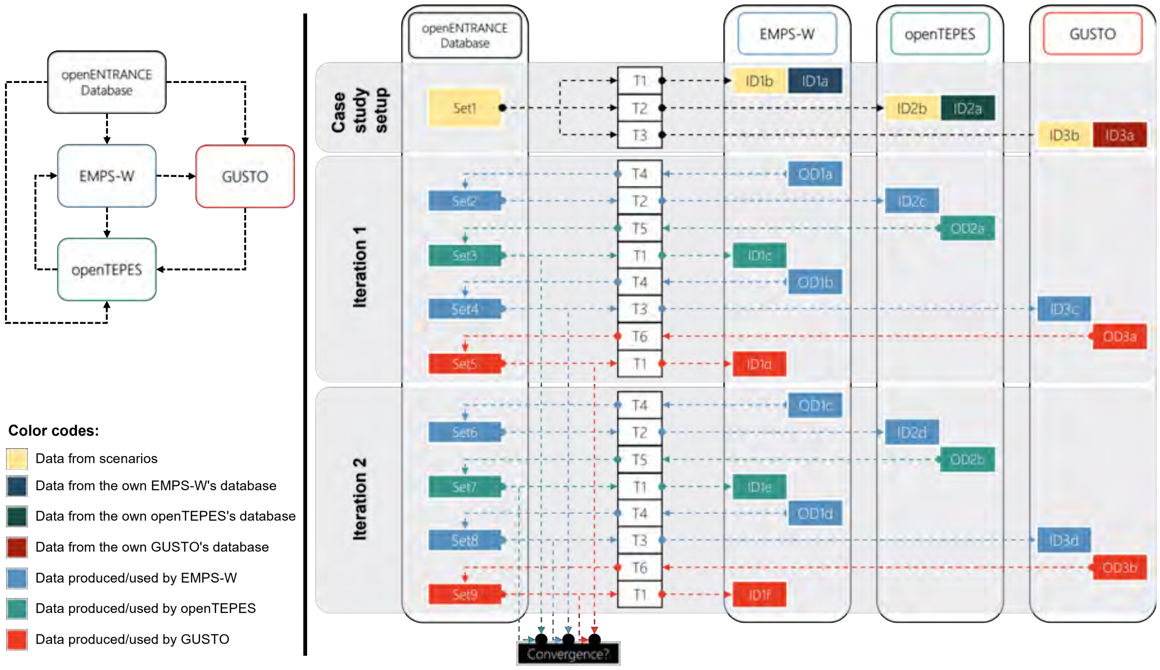


Figure 3.4: Data exchange among models

3.5 Description of the datasets and how they were created

The specificities of the data exchanged among models are discussed in this section. The workflow of the case study, determining the type of data to be exchanged, is described in section 3.4.2. To illustrate the workflow details and how the datasets are exchanged in a general and specific way, we use Figure 3.4, which displays the dataflow during the case study setup and in the first two iterations of runs for the thread with 15% LEC.

This figure comprises two parts: a) On the left-hand side, there is a general representation of the workflow, and b) On the right-hand side, a detailed representation is provided. Some relevant details from the figure are:

- The common data of the Techno-Friendly scenario to be used by the models are collected from the openENTRANCE database.
- The three models employed within CS3 make use of some data withdrawn from the openENTRANCE database and from third databases.
- Note that all the data exchanges among models take place through the openENTRANCE database (Scenario Explorer). There is a common format to be used for the exchange of data, called openENTRANCE common format, which is described in the nomenclature[3].
- There are tools (**T#**) for data conversion from the data format considered by each model to the openENTRANCE common format and vice-versa. In addition, these tools also include functionalities for uploading and downloading data to/from the Scenario Explorer[4].
- Dashed lines represent the flow of information.

The datasets can be classified into five types:

- Data withdrawn from the openENTRANCE's database (**Set1**), and converted into the data format considered by each model: EMPS-W (**ID1b**), openTEPES (**ID2b**), and GUSTO (**ID3b**).
- Data withdrawn from each models' own database (**ID1a**, **ID2a**, and **ID3a**).
- Data corresponding to some results produced by a model that is employed as input data by another model (**Set2**, **Set3**, **Set4**, **Set5**, **Set6**, **Set7**, **Set8**, and **Set9**).
- Data used as input to a model that is available in this models' format: EMPS-W (**ID1c**, **ID1d**, **ID1e**, and **ID1f**), openTEPES (**ID2c**, and **ID2d**), and GUSTO (**ID3c**, and **ID3d**).
- Data produced as output by a model that is available in this model's format: EMPS-W (**OD1a**, **OD1b**, **OD1c** and **OD1d**), openTEPES (**OD2a**, and **OD2b**), and GUSTO (**OD3a**, and **OD3b**).

Each of the relevant datasets is described next:

- **Set1:** The input data set from the openENTRANCE's database comprises the following:
  - Fuel and CO2 prices
  - Operation cost per technology and country
  - Electricity demand per country, whose annual values are shown in Fig. 3.5. This case study focuses on Norway and Spain; their combined value is slightly more than 500 TWh.

[3]See: `https://openenergymodels.net/a-common-format/`
[4]See: `https://openenergymodels.net/scenario-explorer/`

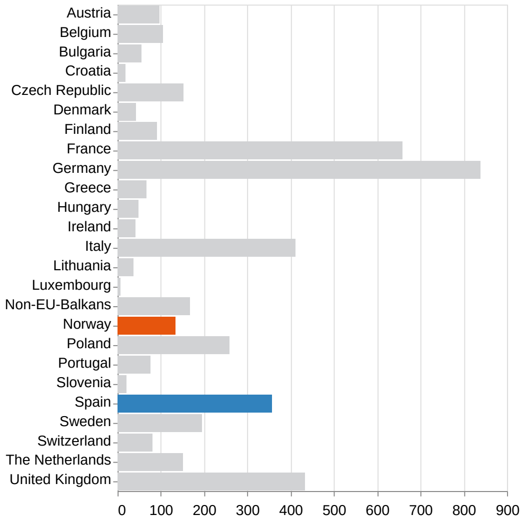


Figure 3.5: Electricity demand in TWh/year per country.

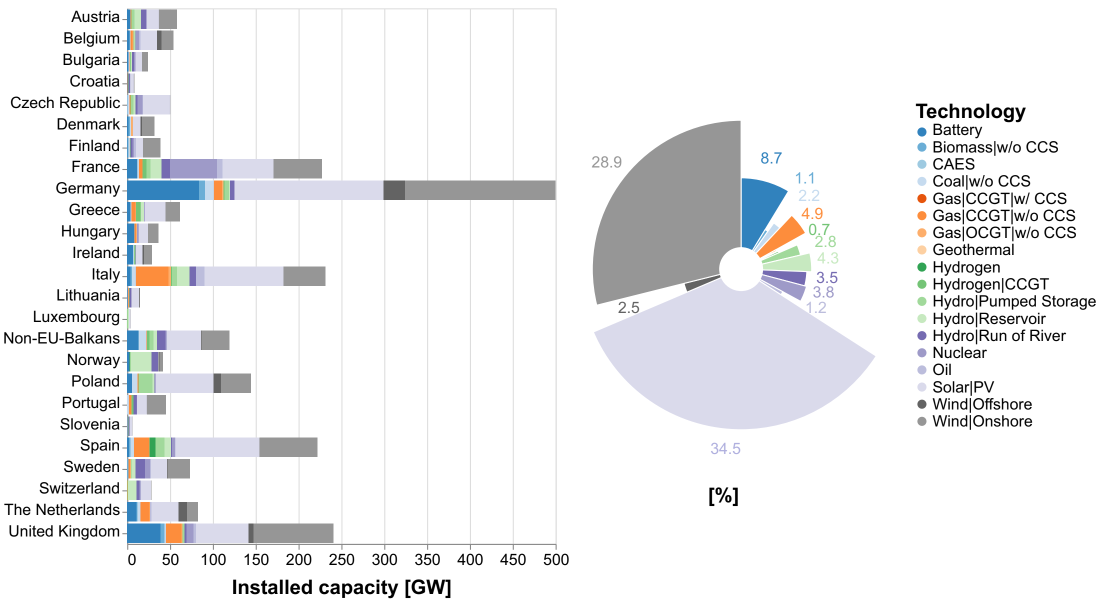


Figure 3.6: Installed generation capacity per country and technology.

– Installed capacities per technology and country, where almost 65% of the installed capacity corresponds to variable renewable energy (Solar PV and Wind), as can be appreciated in Fig. 3.6. Within Norway, more than 90% of the installed capacity corresponds to hydro technologies, while within Spain, almost 80% of the capacity corresponds to Solar PV and Wind.

All these are parameters corresponding to the techno-friendly scenario (can be obtained from the openENTRANCE's database or Scenario Explorer[5]).

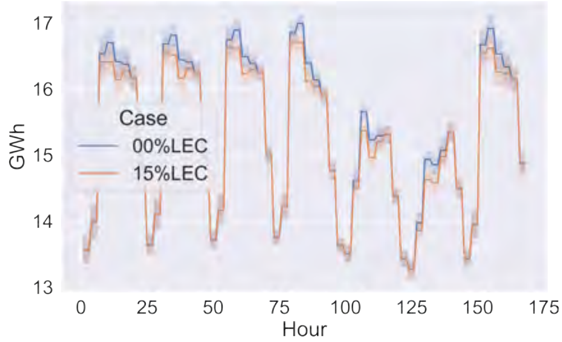
- **Set2:** Dataset comprising the EMPS-W's outputs to be used as input data by openTEPES. The type of data within this dataset are identified next:

  – Energy production and consumption (i.e., for Pumped-storage hydroelectricity) of the hydro generation units.

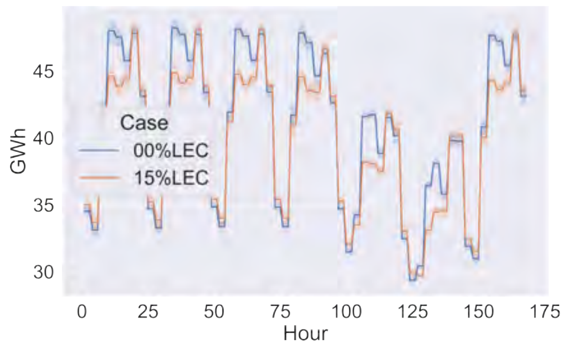
[5]See: `https://openenergymodels.net/scenario-explorer/`

- Electricity demand

- **Set3:** Dataset comprising the openTEPES' outputs to be used as input data by EMPS-W. The type of data within this dataset are identified next:
  - An expansion planning plan for the transmission network comprising HVAC and HVDC lines making either domestic or international interconnections.
- **Set4:** Dataset comprising those EMPS-W's outputs to be used as input data by GUSTO. The type of data within this dataset are identified next:
  - Electricity prices per Norwegian and Spanish area
  - Electricity demand
- **Set5:** Dataset comprising those GUSTO's outputs to be used as input data by EMPS-W. The type of data within this dataset are identified next:
  - Modified electricity demand considering the demand changes caused by a penetration of 15% of local energy communities (LEC). In Fig. 3.7, the reduction of the peak load levels can be appreciated even in the weekly average profile of the electricity demand in Norway and Spain.



(a) Norway



(b) Spain

Figure 3.7: Comparison of the average electricity demand in cases with 15% and 0% LEC.

The sets **Set6**, **Set7**, **Set8**, and **Set9** are equivalent to **Set2**, **Set3**, **Set4**, and **Set5**, respectively.

3.6 Results of case study

First, the main results computed in our Case Study are provided and discussed. Then, the main conclusions, or takeaways, drawn from them are identified.

3.6.1 Main results computed

The discussion of results is divided into those related to the modification of demand caused by LEC, those that have to do with the system operation, and those related to the system development.

Impact of LEC on Demand

The changes that the deployment of LEC has on demand in each of the two systems can be summarized as follows: (i) LECs trigger an increase in the amount of PV generation installed in Spain and, at least, some increase of this in some areas in Norway; (ii) almost no investments in local storage technologies take place within LECs, resulting in a limited contribution by them to the flexibility of the system; (iii) in Spain, LECs trigger the partial electrification of the heat demand. The overall impact of LECs on the system average demand profile for a typical week is displayed in Fig. 3.7.

Impact of LEC on the system operation

The assessment of the system operation is divided into two parts: one that is related to the use of the several technologies and another one related to the impact on prices. Regarding the impact of LEC on the system operation, Table 3.2 shows how the use made storage technologies increase moderately with the deployment of LEC, both in Spain and Norway. The increase taking place in the use of

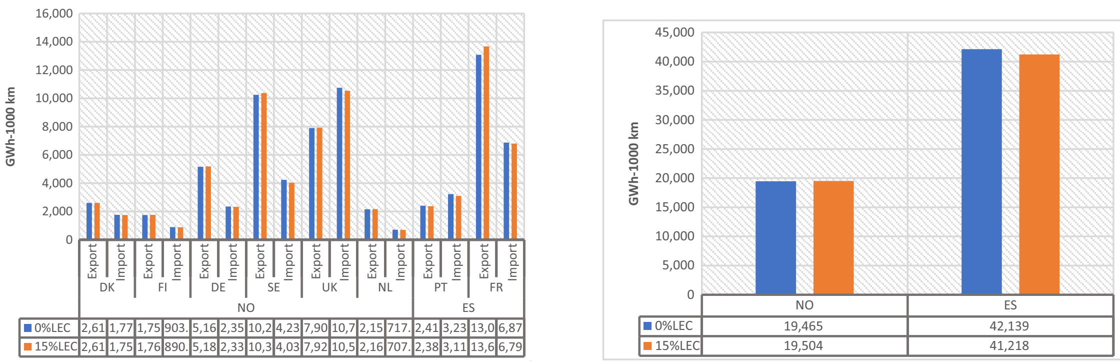
Table 3.2: Energy balances for Norway and Spain, GWh/year.

	Norway			Spain		
LEC	0%	15%	Delta	0%	15%	Delta
Technology						
Reservoir (Gross)	140452	140129	-323	27062	27068	6
RunOfRiver (Gross)	0	0	0	3675	3675	0
Wind (Gross)	17418	17418	0	150952	150952	0
PV (Gross)	81	81	0	183640	183640	0
Nuclear	0	0	0	19063	18720	-343
Bio	0	0	0	7241	7182	-59
Other Production	1301	1286	-15	0	0	0
Coal	0	0	0	118	181	64
Oil	0	0	0	1	1	0
CCGT	0	0	0	42196	41877	-319
OCGT	0	0	0	13	17	5
Sum Generation	159252	158914	-338	433961	433314	-646
Hydrogen Discharge	21	22	0	6194	6516	322
Battery Discharge	988	1017	29	2695	2712	17
Pumped Storage Discharge	0	0	0	27500	27859	359
Sum Gross Energy Produced	160262	159954	-308	470348	470401	53
Curtail./Spill. (Gross - Net prod.)	24	28	4	35101	39129	4027
Net Import	-23630	-24767	-1137	-24428	-26845	-2417
Available Net Energy	136608	135158	-1449	410819	404428	-6392
Consumption	133969	132467	-1502	356906	349194	-7713
Hydrogen Charge	53	54	1	16262	17108	846
Battery Charge	1137	1171	34	3095	3116	21
Pumped Storage Charge	1451	1466	15	34555	35010	455
ENS (non supplied load)	0	0	0	0	0	0
Total Energy Use	136610	135158	-1452	410819	404428	-6391

storage technologies in Spain with the deployment of LECs tends to be larger than that in Norway and, while, in Spain, the storage technologies increasing their use to a larger extent are the ones providing medium-to-long-term flexibility (weekly to seasonal), i.e., hydrogen storage and pumped storage hydro, in Norway, the storage technology featuring the most relevant increases in its use due to LECs are the batteries, which are providing short-term flexibility. Within Spain, the extra amount of PV generation deployed within LECs, which is producing electricity to a larger extent in summer, coupled with the electrification of heat demand in these communities, mainly existing in winter, gives rise to large opportunities to shift energy from summer to winter through the use of long-term storage options. In Norway, the electrification of heat demand is not taking place (heat demand is already largely arranged through heat pumps), while the deployment of PV generation is far less relevant than in Spains. This leaves little room for having some extra energy shifts across seasons due to LECs. Then, the additional electricity production from PV generation occurring in some Norwegian areas is employed within the same-day timeframe to ease supply conditions in peak hours. The deployment of PV generation within LECs is resulting in a decrease in the net demand (demand net of local generation with communities) in the system. Given that the amount of capacity of generation and storage technologies deployed has been deemed the same when LECs are deployed as when they are not, and despite the increase in the use made of flexible storage technologies, this decrease in net demand triggers an increase in the amount of energy spillages (hydro and RES generation based).

Since the amount of PV generation deployed within communities is much larger in Spain than in Norway, the decrease in the net demand and the increase in spillages is also much larger in the former. Together with this, the amount of energy produced by thermal technologies and nuclear in Spain decreases with LECs. Lastly, due to the decrease taking place in the net demand caused by LECs, the net exports of both countries, which originally are exporters already, increases. The reader should note that an increase in the level of use of certain technologies, namely the storage ones, probably indicates a need to increase the investments taking place for these.

As for the impact of LECs on the use of the transmission grid, we separately discuss the use of the internal grid within each country and that of the interconnection between each country and others, see Fig. 3.8. The impact of LECs on the use of the internal grid within Spain differs from that of LECs on the use of the internal grid within Norway. Within Spain, LECs result in some extra deployment of PV generation and an increase in heat electricity demand in all the areas. On the other hand, in Norway, these communities only result in an increase in PV generation in some areas while the electricity demand is barely affected by them. Besides, small amounts of storage and other flexibility resources are deployed within the LECs in both systems. Then, in the majority of periods, all the areas within Spain are similarly affected by the deployment of LECs. This decreases the complementarities existing among areas, and, therefore, the need to use the transmission grid to exploit these complementarities. As a result, the use of the Spanish transmission grid is reduced by the deployment of LEcs. On the other hand, LECs in Norway affect to a larger extent some areas than others. Those Norwegian areas where PV generation is deployed within LECs are those where there is already some PV generation. Then, LECs produce an increase in the exchange flows from those areas where PV generation concentrates to others. This results in a slight increase in the use of the grid within Norway triggered by LECs. LECs cause a decrease in the demand net of RES generation in both countries. In periods when a country is exporting electricity, this creates an increase in the exchange flows. In contrast, in those periods when a country is importing electricity, it creates a decrease in the exchange flows. Thus, export flows from both countries are increased by LECs, while import flows are decreased.



(a) Exports and imports

(b) National use

Figure 3.8: Network usage related to Norway and Spain in GWh - 1000 km.

The impact of LECs on the electricity prices, represented in Fig. 3.9, is much larger in the Spanish system than in the Norwegian one, though in both cases this impact is limited. Within the Spanish system, the lowest-price periods tend to be those when PV generation is at its maximum, given the relevance of this technology in Spain. The deployment of PV generation within LECs in Spain results in additional energy being produced at low-price periods, which results in a decrease in the price in these periods. At the same time, given the fact that the amount of flexibility deployed within LECs is small, the shift of energy from low-price periods to high-price ones made possible by this extra flexibility is also limited. Additionally, some partial electrification of heat demand within LEC in Spain takes place. All these, taken together, trigger an increase in the price spread among high and low-price periods occurring when LECs are deployed. This triggers the mobilization of additional flexibility already existing in the system to increase the energy shifts among periods. As a result of all this, the prices in high-price periods also decrease due to LECs, albeit to a lower extent than for low-price periods.

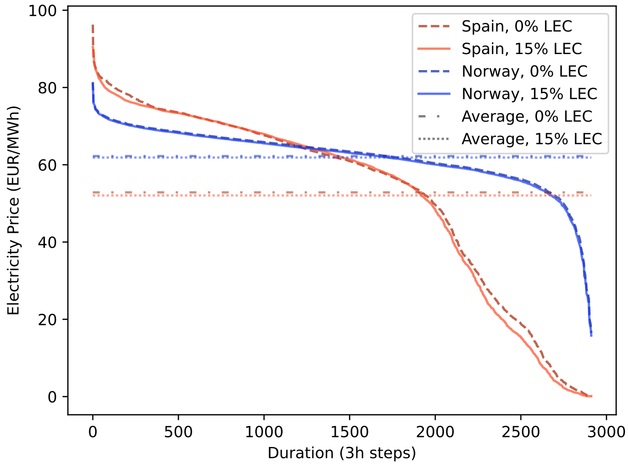


Figure 3.9: Average electricity prices for Norway and Spain.

Impact of LEC on the development of the transmission grid

Transmission capacity is developed to host those economic flows that exceed the capacity of transmission corridors. Within Norway, LECs affect differently the supply conditions in different areas. This results in changes in the pattern of exchange flows among areas, giving rise to new flows from areas where PV generation is abundant to others where it is not. Some of these flows cannot be hosted by the grid. Then, additional network investments within Norway are triggered by LECs. Within Spain, LECs affect all areas similarly. However, in those areas where an excess of PV generation already exists, the deployment of LECs further increases this excess and, therefore, the resulting RES generation curtailments. Avoiding part of this increase in curtailments justifies building extra transmission interconnection capacity between these areas and others. Then, LECs produce an increase in transmission investments also within Spain. See Fig. 3.10.

Regarding the expansion of cross-border interconnection capacity, as mentioned above, LECs result in an increase in exports and a decrease in imports for both national systems. Then, if export flows from Norway, or Spain, to a neighboring country are larger than import flows, LECs trigger an increase in the maximum exchange flows between both systems and, therefore, an increase in the corresponding interconnection capacity to be built. On the other hand, if import flows from a neighbor into any of the two systems are larger than export flows, LECs result in a decrease in the maximum exchange flows between both systems and, therefore, a decrease in the new capacity of the corresponding corridor to be built. See Fig. 3.10.

3.6.2 Main takeaways from the analyses conducted

The main takeaways that can be drawn from the analyses conducted follow:

- LECs deployed within two paradigmatic national systems, the Spanish and Norwegian ones, do not feature relevant amounts of local storage, since limited price spreads in these systems do not justify such investments.

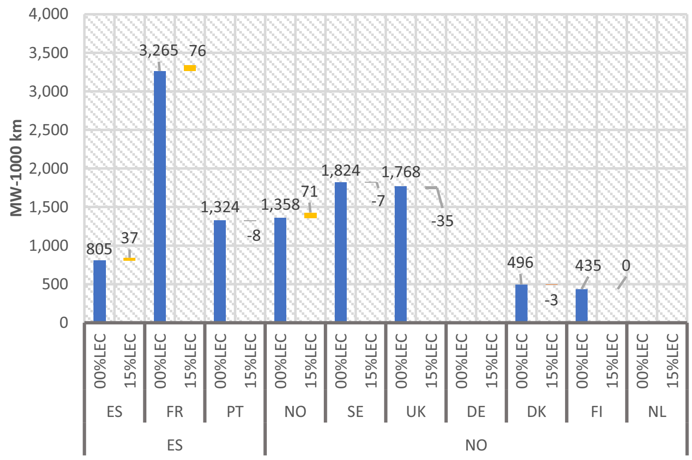


Figure 3.10: Network investment related to Norway and Spain in MW - 1000 km.

- The changes induced by LECs in the net demand of those consumers whose energy use they manage largely depend on the features of the system where they are deployed, especially its decentralized renewable potential. Relevant amounts of local variable generation are deployed within LECs in all the areas in Spain, exploiting the relevant local renewable potential existing in this system. These are much smaller in Norway, and unevenly distributed among the areas in the system, which also results in a much larger decrease in demand triggered by LECs in Spain than in Norway.

- In those countries with a large decentralized RES generation potential, LECs cause a decrease in prices in low-price periods, as well as a less significant decrease in prices in the highest-price periods. Thus, in the aforementioned countries, LECs cause a moderate increase in the price spread across periods of time, as well as a small decrease in the average level of prices in the system. The effect of LECs on prices in countries with limited distributed RES generation potential is negligible. LECs contribute a limited amount of flexibility in both types of systems. Besides, LECs cause an increase in the excess of primary energy resources available in low-price periods, especially in those systems with a high distributed RES generation potential, like Spain. This causes a decrease in prices in these periods. Due to the shift of energy from low-price periods, and the mobilization of the extra flexibility provided by LECs, the deployment of LECs also reduces peak prices.

- The use of storage technologies, to exploit the larger spread of prices across time created by LECs, increases both in Spain and Norway with the deployment of these communities. However, the impact of LECs in this regard also depends largely on the features of the system concerned. While, in Spain, the storage technologies increasing their use to a larger extent are the ones providing medium-to-long-term flexibility, in Norway, the storage technology featuring the most relevant increases in its use due to LECs are the batteries, which are providing short-term flexibility.

- The impact of LECs on the level of primary renewable energy spillages and curtailments also depends largely on the context. LECs tend to increase spillages and curtailments in all systems. However, these increases are much larger in countries with large distributed generation potential.

- The deployment of LEC tends to result in an increase in the use of the transmission grid (the flows within it) in those systems where LECs trigger an uneven deployment of distributed generation within them. In those other systems where the amount of DER deployed within LECs is similar in all areas, the use of the grid tends to decrease with the deployment of LECs. As for the use of interconnections among countries, given that LECs cause a decrease in the net demand in the system, they normally result in an increase in export flows and a decrease in import flows.

- LECs normally trigger an increase in the amount of transmission capacity built within a system. This is due to the uneven impact LECs have on the net demand across the areas of some systems, and to the increase in RES energy curtailments and spillages RES triggers in some other systems. Regarding the amount of cross-border interconnection capacity built, LECs in a country tend to create an increase in the capacity of those corridors where export flows from this country are dominant. On the other hand, LECs tend to decrease the amount of interconnection capacity built in those corridors where import flows are dominant.

3.7 Limitations and future extensions

Future extensions of the analyses conducted could include the ones that follow:

- The capabilities of the models involved in the CS could be extended to allow the optimal expansion of storage technologies to be computed, including utility scale batteries and those related to the use of hydrogen for storage, to be computed.
- Sensitivity analyses could be conducted related to several features of the analysis. Some of the follow:
  - the amount of Electric Vehicles deployed within LECs, in order to assess the impact of these. EVs should increase the demand within communities. The charging strategy considered could also largely impact the impact of these vehicles.
  - the level of CO2 prices, which could be higher (as well as that of Gas prices). Higher CO2 or Gas prices would probably result in larger price spreads and investments in storage in the LECs (and, probably, also a larger impact of LECs on the overall system functioning). Simultaneous increases in both CO2 and Gas prices could also be considered.
  - the penetration level of LECs, which could be higher or lower.
- Changes in the model workflow could be considered to assess the impact of computing the update of the grid before that of the system operation, instead of afterwards, as it is being done now.

3.8 Appendix

3.8.1 EMPS AND EMPS-W

EMPS [9] is an operational model for power systems. It minimizes the total costs of the modelled system, notably generation costs for thermal power, costs for flexible demand, and for energy not served. All capacities, e.g. for generation and transmission of power, and energy storages, are inputs to the model – which can be e.g. the current system or an assumed system of a future year such as 2030. The minimum time-resolution is one hour. The model run through a set of climate years, utilizing the corresponding input-data for the stochastic variables in the model – which are wind- and solar-power variability, hydropower inflow, and temperatures. The geographical coverage varies depending on the dataset. It could e.g. be the power system of the Nordic area, or whole Europe, divided into a set of areas that are connected by transmission lines. The model was originally developed for hydropower optimization, which is important for the Nordic area, and it is used by hydropower producers, TSOs, regulators, and other stakeholders in the Nordic area. Datasets typically include a detailed representation of river systems, reservoirs, generators etc. For hydropower, a stochastic dynamic optimization is needed due to varying hydropower inflows and the possibility to store water in reservoirs. In a first step (strategy calculation), water-values are calculated by stochastic dynamic programming. In the second step (simulation), water values are the marginal costs for hydropower when the model simulate each time-step. For hydropower, the optimized generation per area is allocated to the individual production modules by the draw down model. Heuristic methods are involved both for the water-value calculation and by the draw-down model to reduce computational time. Central outputs include power prices for all time steps within each climate year, water-values, reservoir levels, production, transmission, and economic surplus for producers and consumers in each area. If run in investment-mode, the model can optimize installed capacities for a set of investment options including wind/PV, thermal power generation and transmission lines. A separate version of the model includes DC power flow and optimal congestion management, accounting for more details in the transmission grid.

The EMPSW [7] is a power market simulator, similar to the detailed draw down simulator of the EMPS model. EMPSW has most of the same feature as the detailed draw-down simulation part of EMPS with two noteworthy differences: 1) While the simulation part of the EMPS is optimising hydropower on aggregated level and applying heuristics on a detailed level, EMPSW is based on formal optimisation, in the form of Linear Programming problems, representing the power system under study (with detailed hydropower). 2) The simulation part of the model, EMPS has only weekly values for reservoir levels and other energy storages. The optimized weekly production is then allocated to the different within-week time-steps. In EMPSW, energy storage constraints are specified for each time-step, which allow within-week optimization of included energy storages such as batteries, pumped storage, and hydrogen storages, depending on the within-week price variability.

3.8.2 openTEPES

openTEPES [8] is a planning model for power systems. It determines the investment plans of new facilities (generators, ESS, and lines) for supplying the forecasted demand at minimum cost. Tactical planning is concerned with time horizons of 10-20 years. Its objective is to evaluate the future generation, storage, and network needs. The main results are the future generation, storage, and transmission system structure guidelines. In this case study, the openTEPES model presents a decision support system for defining the transmission expansion plan (TEP) of a large-scale electric system at a tactical level, defined as a set of network investment decisions for 2030. The user pre-defined the expansion candidates, so the model determines the optimal decisions among those specified by the user. It automatically determines optimal expansion plans that simultaneously satisfy several attributes. Its main characteristics are:

- **Static:** the model scope corresponds to only one year (2030) with an hourly resolution for the system operation.
- **Deterministic:** only one planning and operation scenario that can influence the optimal generation, storage, and transmission expansion decisions is considered. This operation scenario is associated with renewable energy sources, energy inflows and outflows, operating reserves, inertia, and electricity demand.

The objective function incorporates the two main quantifiable costs: transmission investment cost (CAPEX) and expected variable operation costs (including generation, consumption, emission, and reliability costs) (system OPEX).

The operation model is a network constrained economic dispatch based on a tight and compact formulation with a DC power flow (DCPF). It considers different energy storage systems (ESS), e.g., pumped-hydro storage, battery, etc. It allows analyzing the trade-off between the investment in transmission and the use of storage capacity.

The main results of the model can be structured in these topics:

- **Investment:** investment decisions and cost
- **Operation:** unit output and aggregation by technologies (thermal, storage hydro, pumped-hydro storage, RES), RES curtailment, line flows, node voltage angles, ESS inventory levels
- **Emissions:** CO2 emissions by unit
- **Marginal:** Locational Short-Run Marginal Costs (LSRMC), water energy value
- **Economic:** operation, emission, and reliability costs and revenues from operation
- **Flexibility:** flexibility provided by demand, by the different generation and consumption technologies, and by power not served

3.8.3 GUSTO

The GUSTO model [10] is an open-source model that optimizes both the energy technology investment decision (portfolio optimization) and the energy technology dispatch on a local level. It is an extension of the existing OSM urbs by [3]. The expansion of the model's framework includes additional features and functionalities for analyzing local energy systems such as ECs. See the authors' previous publication in [11], [10], and recently in [2] for a detailed description of the model's extension.

Bibliography

[1] Sumeffekt project: New environmental restrictions – overall impact on the power system. `https://www.sintef.no/prosjekter/2020/nye-miljorestriksjoner-samlet-innvirkning-pa-kraftsystemet/`. Accessed: 2023-04-14.

[2] S. Backe, S. Zwickl-Bernhard, D. Schwabeneder, H. Auer, M. Korpås, and A. Tomasgard. Impact of energy communities on the european electricity and heating system decarbonization pathway: Comparing local and global flexibility responses. *Applied Energy*, 323:119470, 2022. doi: https://doi.org/10.1016/j.apenergy.2022.119470.

[3] J. Dorfner. *Open source modelling and optimisation of energy infrastructure at urban scale*. PhD thesis, Technische Universität München, 2016.

[4] B. Fina, H. Auer, and W. Friedl. Profitability of pv sharing in energy communities: Use cases for different settlement patterns. *Energy*, 189:116148, 2019. doi: https://doi.org/10.1016/j.energy.2019.116148.

[5] B. Lehner, G. Czisch, and S. Vass. Europe's Hydropower Potential Today and in the Future. *Europe*, 2000.

[6] S. Lumbreras, A. Ramos, and P. Sánchez. Automatic selection of candidate investments for Transmission Expansion Planning. *International Journal of Electrical Power and Energy Systems*, 59, 2014. ISSN 01420615. doi: 10.1016/j.ijepes.2014.02.016.

[7] B. Mo, O. M. Hansen, and L. E. Schäffer. Methods of aggregation and disaggregation-project results. *SINTEF Rapport*, 2020.

[8] A. Ramos, E. F. Alvarez, and S. Lumbreras. opentepes: open-source transmission and generation expansion planning. *SoftwareX*, 18:101070, 2022.

[9] O. Wolfgang, A. Haugstad, B. Mo, A. Gjelsvik, I. Wangensteen, and G. Doorman. Hydro reservoir handling in norway before and after deregulation. *Energy*, 34, 2009. ISSN 03605442. doi: 10.1016/j.energy.2009.07.025.

[10] S. Zwickl-Bernhard and H. Auer. Citizen participation in low-carbon energy systems: Energy communities and its impact on the electricity demand on neighborhood and national level. *Energies*, 14(2):305, 2021. doi: https://doi.org/10.3390/en14020305.

[11] S. Zwickl-Bernhard and H. Auer. Open-source modeling of a low-carbon urban neighborhood with high shares of local renewable generation. *Applied Energy*, 282:116166, 2021. doi: https://doi.org/10.1016/j.apenergy.2020.116166.

Chapter 4

Case Study 4: Need for flexibility – sector coupling

Abstract

Given the ongoing transformation of energy systems towards a climate-neutral and sector-integrated future, the case study is a sensitivity analysis based on openENTRANCE's *Techno-Friendly 1.5°C* pathway assessing the impact of three crucial determinants for the pan-European energy system development. These determinants cover electric vehicle charging flexibility in individual road transport sectors, cross-border exchange capacity for electricity trade between national markets, and prices of renewable hydrogen imports from outside of Europe for end-use demands that cannot be abated by direct use of renewable electricity. The coupling of the modelling frameworks SCOPE SD (Fraunhofer IEE) and plan4EU (EDF) together with input data from the GENeSYS-MOD (TU Berlin) demonstrates that both open and proprietary modelling frameworks can be linked via the openENTRANCE platform.

The case study shows that hydrogen import prices are responsible for the largest energy system changes in the climate-neutral system and determines Europe's energy import dependency. Low prices lead to higher hydrogen demand and a high share of imports from future global markets. Higher cross-border exchange capabilities and transport sector charging flexibility have moderate effects, i.e. they increase the direct use of renewable electricity and reduce the need for indirect electrification applications (i.e. hydrogen demand). Hydrogen import prices exhibit the strongest impact on regional electricity price distributions with cross-border trade and electric vehicle flexibility having only smaller effects on the volatility in the distribution tails.

All model-based analyses have to make assumptions when building the models and determining their parameters. The limitations of this case study include the representation of gas infrastructure, i.e. only pan-European fuel markets are considered without infrastructure restrictions, and pathway-dependencies are also only indirectly considered through openENTRANCE's storyline pathways. Moreover, the *Techno-Friendly 1.5°C* scenario features reduced electricity end-use demands for the conventional sectors (industry and households) when compared to other scenarios, e.g. the Ten Year Network Development Plan 2020 [1].

On a more general note, the linking of an integrated energy system model and power-sector-focused model provided additional insights. When combining integrated energy system models with power-sector-focused models, it is important to be aware of the interactions that are endogenous decisions in the integrated energy system model but become exogenous decisions in the power-sector-focused model. For instance, is the electrolyser demand considered as a fixed demand without or as flexible demand with a marginal value of hydrogen production — this will ultimately have impacts on the observed clearing prices in the modelling frameworks [2], [3].

A prominent challenge is the broadening integration of sectors, commodities, and markets, as well as more regional perspective required for the actual transformation of the system, which, in combination, increase both the complexity and uncertainty. Avenues for future research, therefore, include scalable planning approaches and their application to determine robust transformation pathways for the energy system development in Europe.

Contents

4.1 Introduction

In light of accelerated climate neutrality policies and a new lack of clarity, this case study investigates crucial determinants for the system development towards a clean energy system in Europe. The case study assesses the impact of system flexibility provided by the increasing integration and interaction of sectors at the pan-European level. While the case study initially set out to analyse available flexibility from individual road transport sectors, the scope was broadened during the openENTRANCE project to provide comprehensive coverage and a quantified assessment of the variety and range of future energy system configurations. Besides the transport sector flexibility offered by flexible electric vehicle charging, the extended case study scope incorporates sensitivities of available cross-border exchange capacities and renewable hydrogen (H_2) import prices from outside of Europe as two additional criteria for the system development. For the model-based analysis, the case study setup combines two separate models, a cross-sectoral capacity expansion planning model for developing integrated energy system scenarios in Europe (SCOPE SD, developed and maintained at Fraunhofer IEE) and a power-sector-focused unit commitment and market simulation model for European power markets (plan4EU, developed and maintained at EDF).

4.1.1 Overall objective of case study

Given the ongoing transformation of energy systems towards a climate-neutral and sector-integrated future, the case study objective is to asses the impact of three crucial determinants for the pan-European energy system development. These determinants cover (1) electric vehicle charging flexibility in individual road transport sectors, (2) cross-border exchange capacity for electricity trade between national markets, and (3) prices of renewable H_2 imports from outside of Europe for end-use demands that cannot be abated by direct use of renewable electricity. To that end, the case study simulates the expansion and operation of the pan-European energy system with the SCOPE SD and plan4EU modelling and optimisation frameworks.

The SCOPE SD model simulations feature a high sectoral and temporal resolution and a medium spatial resolution, i.e. sub-country regions for France and Germany as two major economies, and country-level resolution for the rest of Europe. Plan4EU focuses on the electricity sector with a high temporal and spatial resolution (sub-country regions), including models for aggregated distribution network constraints. SCOPE SD and Plan4EU are linked together via the openENTRANCE platform to run Plan4EU simulations based on inputs produced by the SCOPE SD modelling framework.

Case study characteristics and premise:

- Low-carbon energy systems in Europe need to be based on cross-sectoral integration to meet climate protection goals, i.e. electrification where possible and economically viable and indirect electrification (electrolytic H_2 or derived fuels) for hard-to-abate end-use demands.
- Cost-efficient coupling of the power with heat and transport sectors implies additional demands for renewable electricity but integrating technologies at the interfaces between those sectors may also provide a valuable source of flexibility
- Multiple studies have been carried out on a one-node-per-country level – but how does the integration of cross-sectoral technologies play out in the local but interconnected domain?
- Flexibility considerations also focus on the consumer behaviour perspective, by investigating a different willingness to provide flexibility for electric vehicle owners.

4.1.2 Case study challenges

By analysing the impact of a high electric vehicle penetration on the low-carbon electrical systems in Europe, the case study addresses an important challenge of increasing sectoral integration that can be characterised as follows:

- Comprehensive analysis of the impact on the electrical system of a high penetration of electric vehicles (allowing or not flexible charging) under the consideration of local/regional feasibility and dynamical constraints
- Explicit representation of vital cross-sectoral links and flexibility potential for low-carbon energy pathways, particularly hybrid technology configurations for industry, heat, and transport sector demand applications.
- Extending the one-node-per-country focus to better spatial granularity required to evaluate how flexibility plays out in the more detailed regional domain.
- Accounting for willingness to provide flexibility with a sufficient number of transport sector option instances to capture full technology range (niche applications).
- Concurrent analysis of hourly time-series data for multiple signals from the power sector (e.g. wind, solar PV, electricity demand, hydro inflow), building and industry heat sector (e.g. heat demand, heat pump coefficient of performance (COP) profiles), as well as the transport sector (e.g. transport demands, potential charging power, battery state of charge (SOC) limits).
- Providing regional data for German and French market areas by defining consistent market areas for power grid and other sector coupling technologies.

4.2 Short summary of models used

First, pan-European reference scenarios will be implemented from the GENeSYS-MOD in both model environments to determine further assumptions necessary for the detailed case study. Simulations will then be performed with SCOPE SD, including sensitivities regarding the share of flexible charging in all or selected European countries (i.e. uncontrolled versus system-friendly charging behaviour). Then, the flexibility information from SCOPE SD will be integrated into the plan4EU modelling framework to run more detailed simulations regarding the electricity sector. The approach is to run the SCOPE SD model focusing on the national level except for Germany and France where seven and fourteen nodes are included to represent sub-regions, and use these aggregate results as input for the Plan4EU model. In a second step, the Plan4EU model processes and disaggregates the country-specific input data to then perform the electricity market simulations in the more detailed regional domain. By increasing the spatial resolution in terms of multiple bidding zones per country, some limitations regarding internal transmission grid effects could be alleviated. A more detailed spatial resolution allows for a more accurate aggregation (i.e. not to the national but only regional level) of the transport sector flexibility parameters. The Plan4EU model can use the results from the SCOPE SD model with better assumptions on local potentials for flexibility in a second run. As a consequence, the two versions of running the models can be compared to provide insights into the impact of decentralised flexibility of electric vehicles on the grid and expansion planning. Further aspects to investigate in optional analyses include a refined modelling approach of the power flow in the Plan4EU model, i.e. using a DC power flow approximation instead of a transport model (NTC). Another aspect focuses on the capacity limits between distribution and transmission network, which is particularly relevant since large shares of renewable power generation as well as electric vehicle charging is connected to the distribution grid level.

4.3 Assumptions

The main input for this case study relay on the *Techno-Friendly 1.5°C* scenario from the openENTRANCE story-lines, see in the report 3.2 [4]. The assumption on the development of transmission capacities between the European countries are based on the results of the eHighway2050 project, see [5], [6]. The exogenous import price for green H_2 is based on the PtX Atlas, see [7], [8]. Figure 4.1 shows the combination of the three dimensions resulting in eighth scenarios for the model runs. Focusing on transport sector flexibility, cross-border integration, and H_2 import prices, the case study simulates the expansion and operation of pan-European energy systems in the two rather extreme shaping of every dimension. The electric vehicle flexible options are either 10 or 90 percent of all electric vehicles can charge optimal in the market in 2050, which is assumed to be are all passenger cars, see [4] *Techno-Friendly 1.5°C*. For the cross-border exchange capacities the higher scenario is based on the expansion until 2050 along the "Large Scale RES" scenario of the eHighway2050 project, see [5], while the lower scenario is based on the starting grid 2030. The higher H_2 import price is based on the world wide analyse of the PtX Atlas, see [7] as a mean import price for green H_2. The lower H_2 import price is based on openENTRANCE's *Techno-Friendly 1.5°C* storyline, which is considered as a very low price.

Criteria	**Sensitivities** (low and high)	
Cross-border electricity exchange (XB) capacity	**Low cross-border exchange capacity expansion (XB↓)** **Europe 118.5 GW** (w/o internal) DEU 101.1 GW (internal only) FRA 110.2 GW (internal only)	**High cross-border exchange capacity expansion (XB↑)** **Europe 229.9 GW** (w/o internal) DEU 108.2 GW (internal only) FRA 133.3 GW (internal only)
Share of electric vehicles (EV) with a flexible charging policy	**Low electric vehicle charging flexibility (EV↓)** **10%** of all electric vehicles (BEV, PHEV, REEV) allowed to charge in a system-friendly manner	**High electric vehicle charging flexibility (EV↑)** **90%** of all electric vehicles (BEV, PHEV, REEV) allowed to charge in a system-friendly manner
Import price for hydrogen (H_2) from global markets	**Low hydrogen import price (H_2↓)** **45.1 EUR/MWh$_{th}$** (~1.5 EUR/kg LHV)	**High hydrogen import price (H_2↑)** **85.0 EUR/MWh$_{th}$** (~2.82 EUR/kg LHV)

Figure 4.1: Low and high realisations of the investigated system development determinants, i.e. transport sector flexibility, cross-border exchange integration, and H_2 import prices, own illustration.

Following Figure 4.1, eight different scenario variants are analysed:

- XB↓_EV↓_H_2↓: low cross-border exchange capacities, low transport sector flexibility, low H_2 import price.
- XB↑_EV↓_H_2↓: high cross-border exchange capacities, low transport sector flexibility, low H_2 import price.
- XB↓_EV↑_H_2↓: low cross-border exchange capacities, high transport sector flexibility, low H_2 import price.
- XB↑_EV↑_H_2↓: high cross-border exchange capacities, high transport sector flexibility, low H_2 import price.
- XB↓_EV↓_H_2↑: low cross-border exchange capacities, low transport sector flexibility, high H_2 import price.
- XB↑_EV↓_H_2↑: high cross-border exchange capacities, low transport sector flexibility, high H_2 import price.

- XB↓_EV↑_H_2↑: low cross-border exchange capacities, high transport sector flexibility, high H_2 import price.
- XB↑_EV↑_H_2↑: high cross-border exchange capacities, high transport sector flexibility, high H_2 import price.

4.4 Methodology

4.4.1 Overall methodology

The methodology in this case study consist of two modelling frameworks.

4.4.2 SCOPE SD modelling and optimisation framework

The pan-European cross-sectoral capacity expansion planning framework SCOPE SD is a bottom-up techno-economic partial equilibrium model. Figure 4.2 illustrates the structure, components, and typical in- and output data of SCOPE SD (upper section) including the interactions of technology options (lower section) in the corresponding markets or policy instruments (middle section).

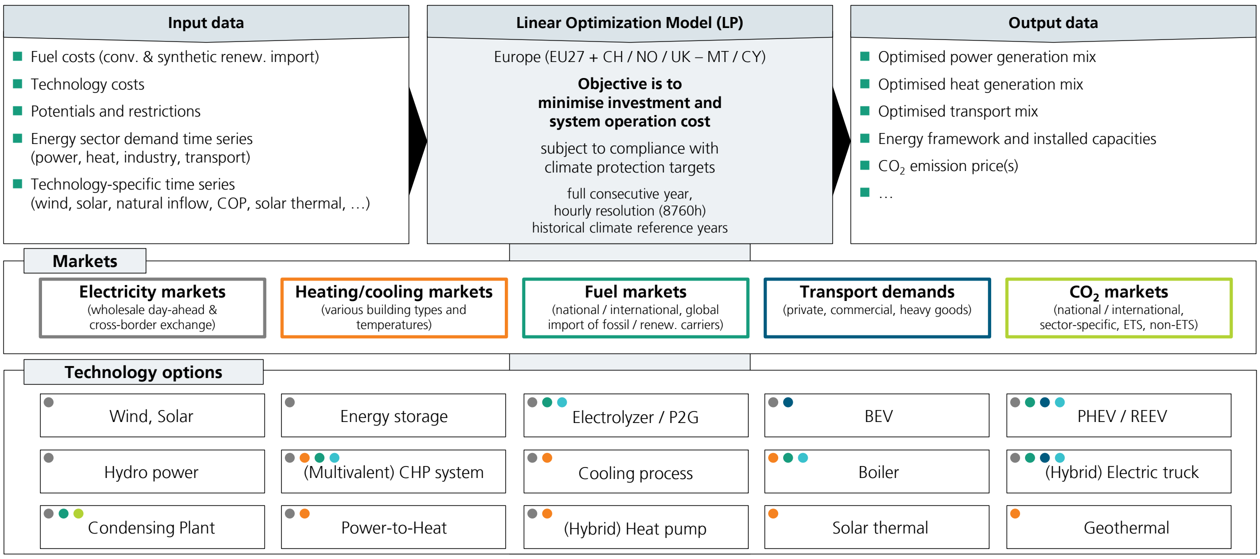


Figure 4.2: Schematic overview of the pan-European cross-sectoral capacity expansion planning framework SCOPE SD, own illustration. Note that the different dot colours of the technology options indicate the (multi-fold) participation of technology options in the corresponding markets or policy instruments.

The modelling and optimisation framework develops coherent long-term low-carbon energy system scenarios for Europe for a given target scenario year in the future. By minimising the generation, storage, and cross-sectoral consumer technology investment and system operation cost, this large-scale linear programming (LP) approach has representations for the traditional power system as well as for all relevant bi- and multivalent technology combinations at the sectoral interfaces with the building, industry, and transport sectors.

Each market area, i.e. every country in Europe, is represented by one node. All units (generation, storage, and cross-sectoral demand technology options), their most important parameters (costs, potentials, and operational characteristics), and their relevant interactions between each other are modelled in hourly resolution. By explicitly modelling national and pan-European fuel markets, it is possible to distinguish between the use of fossil fuels, on the one hand, and synthetic renewables, on the other hand, which are either imported from outside of Europe or produced domestically. In order to account for climate neutrality in future scenarios, national and international greenhouse-gas emission budgets are implemented as a driving force behind investments in low-carbon technologies.

Recent mathematical formulations and applications of SCOPE SD can be found in [2], [3], [9]–[11]. Therefore, only the formulations of the objective function and of the key constraints of the underlying optimisation model are given below.

4.4.3 Case study workflow

The results from GENeSYS-MOD are taken from the openENTRANCE platform as input for the SCOPE SD model. This includes the final energy demand for all power sector coupling technologies, covering the transport, building and industry sector. SCOPE SD than optimises the installed capacity of the power and heating sector for the target year 2050 in hourly granularity. In the end the plan4EU model analyses the dispatch by performing an unit commitment.

4.4.4 Linkages

The linkages in this case study is from the GENeSYS-MOD via the platform to SCOPE SD and from SCOPE SD to plan4EU, partially through the platform. Structural output data from SCOPE SD were in the IAMC format and unloaded to the platform, while time series result data were exchanged directly between the two models. Figure 4.3 describes the linkage and the case study workflow.

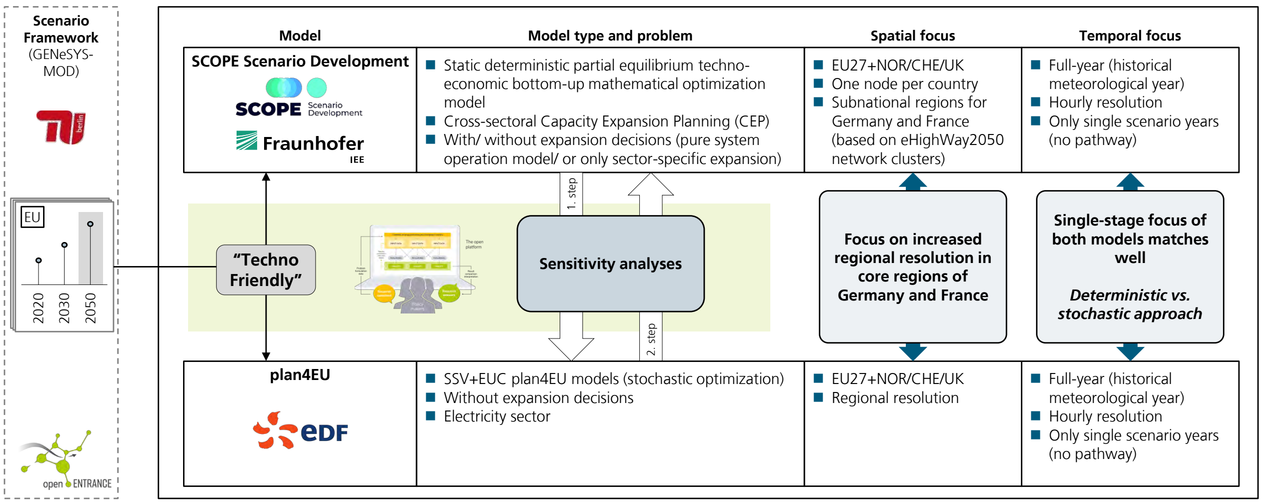


Figure 4.3: Methodological approach involves linking IEE's SCOPE SD and EDF's plan4EU modelling frameworks via the openENTRANCE platform to use its *Techno-Friendly 1.5°C* pathway as a basis, own illustration.

4.5 Description of data sets and how they were created

The input data sets for SCOPE SD, which are on a country level, were regionalised for Germany and France. To divide Germany in seven and France in 14 sub-regions, the definition of the eHighway2050 project [6] were used. Figure 4.4 and Figure 4.5 show the geographical details of the SCOPE SD input data. All in all 39 market areas were considered, including seven in Germany and 14 in France. Figure 4.4 shows the regionalisation of the conventional electricity demand, the renewable production potentials and capacity factors, the time-dependent coefficients of performance for heat pumps, the potential for centralised and district heating solutions and the hydropower input data.

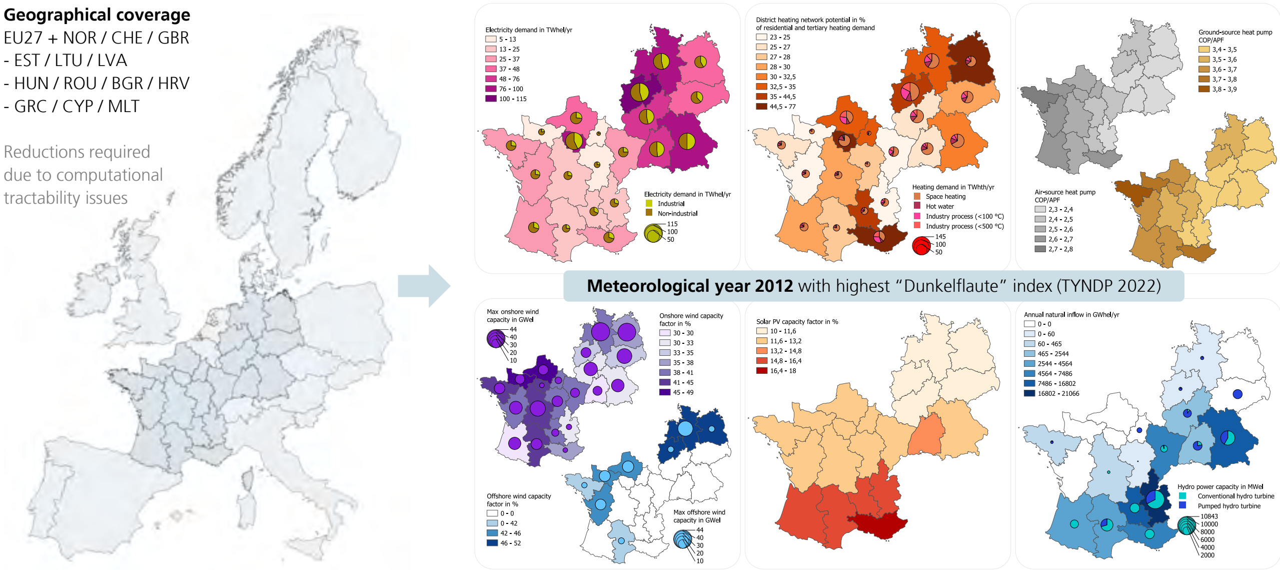


Figure 4.4: Geographical coverage with increased focus on grid regions in Germany and France

The transport sector is divided into individual transport and heavy-duty transport, see Figure 4.5. For the regionalisation of the individual transport sectors, Eurostat was used as data source [12]. The achieved number of cars per region was divided through the total amount of cars per country to get a relative distribution key for the individual transport sectors, which can be applied to the existing input data for the SCOPE SD modelling framework. For the heavy-duty transport sector and its corresponding input data, a spatial distribution for Germany was available from data surveyed by automatic permanent counting stations on motorways and federal roads [13]. France was split according to the length of highways per region and the information as to which toll company the street belongs. Then, for the companies the numbers for the freight transport were at hand [14], [15].

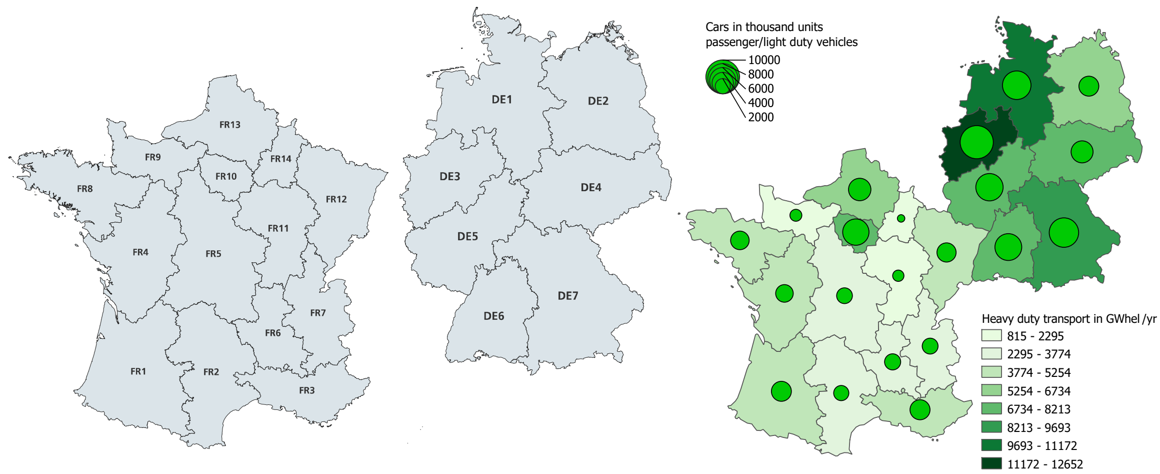


Figure 4.5: Results of the transport sector regionalisation for Germany and France, own illustration based on own computations.

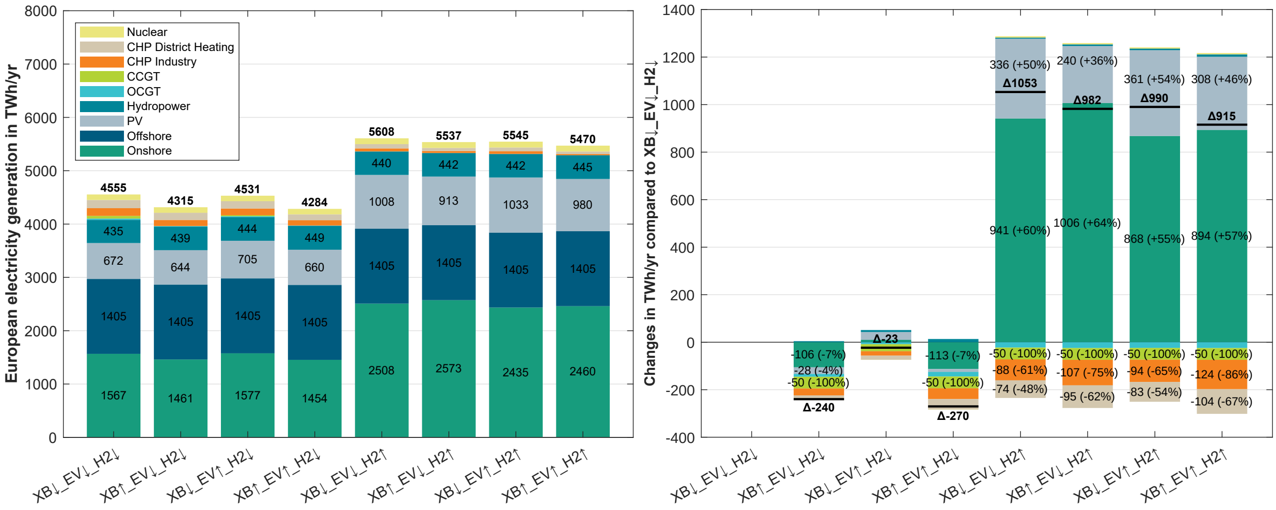
4.6 Case study results

4.6.1 Impacts on pan-European system development and electricity prices

The results focus on two aspects. On the one hand on the resulting electricity balance of the optimised integrated energy systems at the European level to highlight the largest system development impacts. On the other hand the wholesale market clearing price distributions expose the impacts of low and high materialisations of future transport flexibility, cross-border exchange, and H_2 import prices. Here follows the main results from the case study:

- Case study is a sensitivity analysis based on openENTRANCE's *Techno-Friendly 1.5°C* pathway, looking into low and high materialisations of future transport flexibility, cross-border exchange, and H_2 import prices
- Coupling of GENeSYS-MOD (TU Berlin) SCOPE SD (Fraunhofer IEE) plan4EU (EDF) demonstrates that both open and proprietary modelling frameworks can be linked via the openENTRANCE platform
- H_2 import price is responsible for the largest energy system changes in the climate-neutral system and determines Europe's energy import dependency – low prices lead to higher H_2 demand and high share of imports from global markets
- Higher cross-border exchange capabilities and transport sector charging flexibility have moderate effects, i.e. they increase direct use of renewable electricity and reduce need for indirect electrification applications (i.e. H_2 demand)
- H_2 import prices exhibit strongest impact on regional electricity price distributions –Cross-border trade and electric vehicle flexibility rather affect the volatility in the distribution tails
- *Techno-Friendly 1.5°C* scenario features reduced electricity end-use demands for conventional sector (industry and households), e.g. about 900 TWh_{el}/yr less than in parallel scenarios – other issues to follow-up on are German offshore deployments
- General limitations include gas infrastructure representation (only pan-European fuel markets considered w/o infrastructure) and pathway dependencies (partly alleviated through openENTRANCE's pathway development)

To substantiate the impacts on the European electricity system and markets, Figure 4.6 shows the optimised (net) electricity generation balances in Europe. For each scenario, the absolute figures in TWh_{el}/yr are given in Figure 4.6(a) while Figure 4.6(b) indicates the absolute and relative changes in the various scenarios compared to $XB{\downarrow}\_EV{\downarrow}\_H_2{\downarrow}$. Note that the $XB{\downarrow}\_EV{\downarrow}\_H_2{\downarrow}$ scenario is considered as the reference scenario, which all other scenarios are compared against.

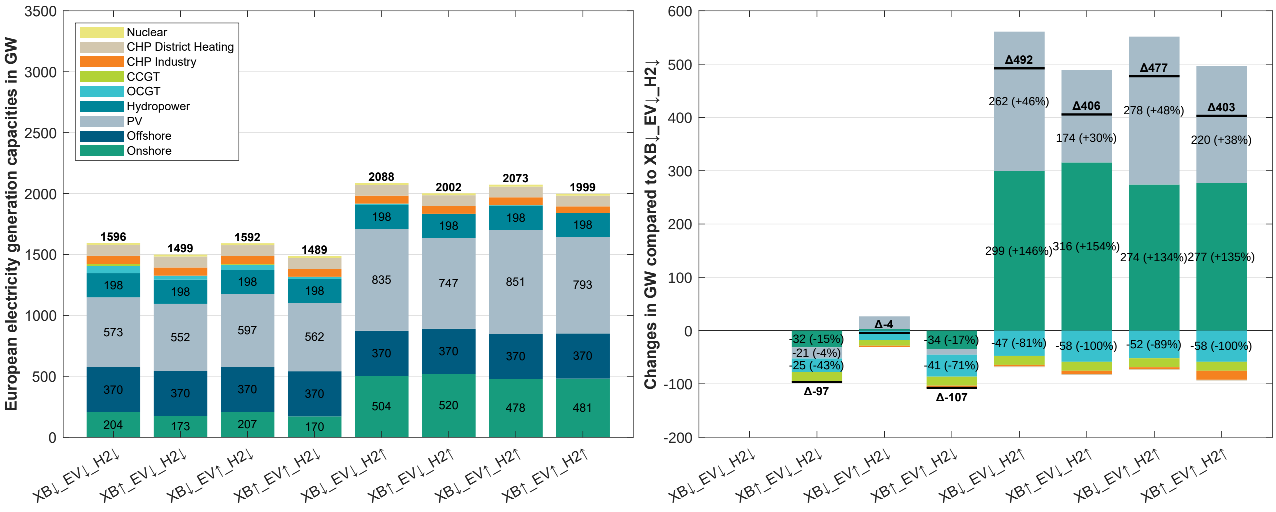


(a) Absolute values (b) Changes w.r.t. XB↓_EV↓_H$_2$↓

Figure 4.6: Electricity generation balance in Europe for each considered scenario variant, own illustration based on own calculations.

The results show that a high H_2 import price leads to increased renewable build-outs due to wide electrification of end-use demands and domestic H_2 production. Low cross-border integration and low H_2 import prices drive up H_2-based thermal generation, affecting both CHP and non-CHP thermal units. With reduced flexibility from electric vehicle charging, thermal production increases even more.

Besides the European electricity generation balance, it is also worth looking into the capacity expansion decisions for each scenario in Figure 4.7. Again, for each scenario, the absolute figures in GW_{el} are given in Figure 4.7(a) while Figure 4.7(b) indicates the absolute and relative changes in the various scenarios compared to XB↓_EV↓_H$_2$↓.

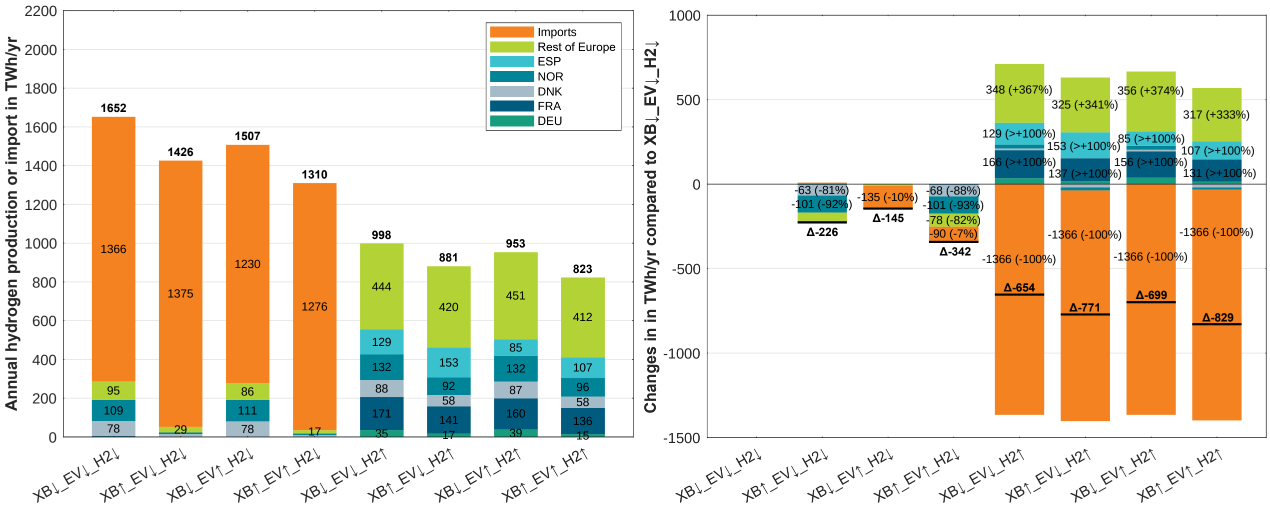


(a) Absolute values (b) Changes w.r.t. XB↓_EV↓_H$_2$↓

Figure 4.7: Electricity generation capacities in Europe for each considered scenario variant, own illustration based on own calculations.

Similar to Figure 4.6, H_2 import prices demonstrate the strongest effect on European electricity generation. For renewable generation, changes directly correspond to the optimised capacity expansion decisions.

Given the case study setup and indicated by the results from Figures 4.6 and 4.7, a key question is the origin of H_2 or derived renewable fuels in the modelled market areas, i.e. the trade-off between importing green H_2 from outside of Europe and producing green H_2 with domestic electrolysers. Figure 4.8 shows the annual H_2 production and import balance for the considered energy system in Europe. For each scenario, the absolute figures in $\mathrm{TWh_{th}}$/yr are given in Figure 4.8(a) while Figure 4.8(b) indicates the absolute and relative changes.



(a) Absolute values

(b) Changes w.r.t. XB↓_EV↓_H₂↓

Figure 4.8: Domestic hydrogen (H_2) production by region and H_2 imports from outside of Europe for each considered scenario variant, own illustration based on own calculations.

The balances of annual domestic H_2 production and imports make the observed impacts on electricity generation levels and the capacity investments in Figures 4.6 and 4.7 explicit. The model responses to the considered low and high realisations of a future H_2 import price show that it is a very sensitive parameter for the future system development. It decides whether Europe relies on the domestic production of electricity-based H_2 or imports from outside of Europe become a vital option. With high import prices, all direct electrification options are drawn by the model, reducing the overall demand for H_2. Cross-border electricity exchange capabilities and more flexible transport sector lead to a more efficient energy system, reducing the overall H_2 consumption.

Figures 4.9 and 4.10 show the market clearing price results obtained from the individual SCOPE SD model runs for Germany and France, respectively. Note that the dual variable of the market clearing constraint is used as a proxy for the electricity clearing price.

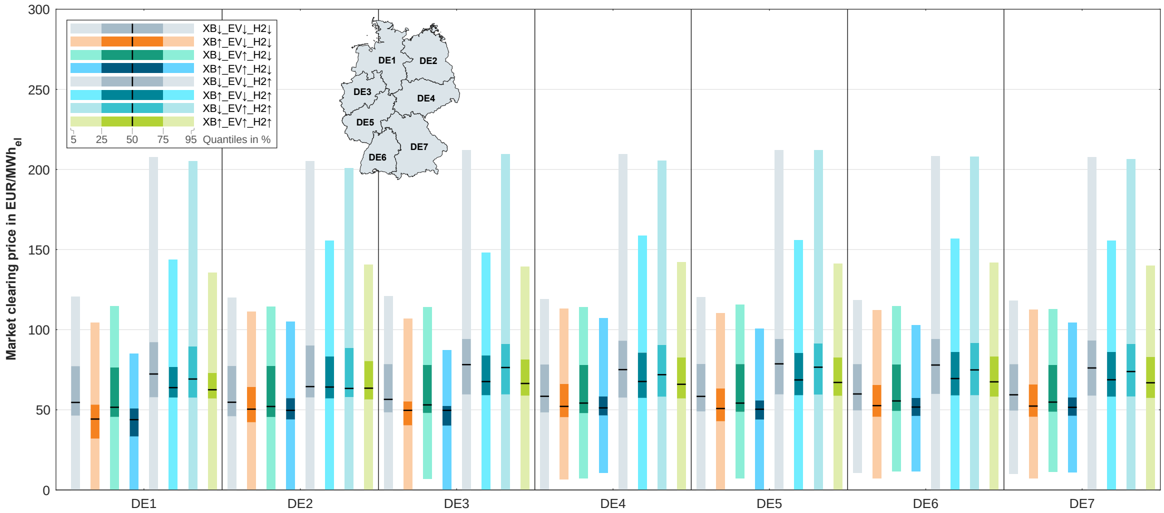


Figure 4.9: Market clearing price distributions for the German sub-regions in all eight considered scenario variants, own illustration based on own computations.

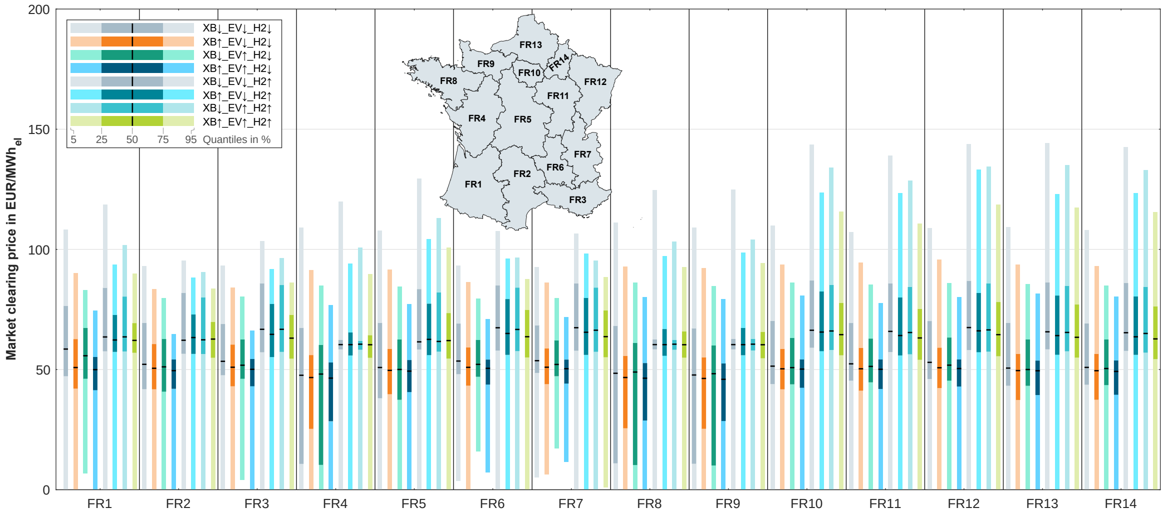


Figure 4.10: Market clearing price distributions for the French sub-regions in all eight considered scenario variants, own illustration based on own computations.

Germany's wholesale market clearing prices show substantial impacts of high H_2 import price scenarios. The volatility primarily depends on the availability of cross-border exchange capacity. Flexible charging of electric vehicles in the transport sectors only plays a secondary role. French prices show a more heterogeneous picture with similar impacts of different criteria. The observed prices are generally lower than German prices. In the Northeastern regions of France, it can be seen that prices from neighbouring bidding zones permeate the French market areas.

4.6.2 Focus on the electrical system operation

In this section, plan4EU is used to more precisely assess the impact of the different considered variants on the operation of the European electrical system in terms of

- Energy generated per type of technology globally at the European level and more precisely for each zone (region or country);

- Marginal costs for each zone;
- System costs globally at the European level and more precisely for each zone.

We consider more specifically the two extreme cases XB↑EV↑H_2↑ and XB↓EV↓H_2↓. For each of these two variants, we consider an alternative variant without EV flexibility, meaning that the EV demand is not optimized by plan4EU model but set to the value previously optimized by SCOPE SD model. Finally, this results in considering the four following variants

- XB↑EV↑H_2↑;
- XB↑EV0H_2↑ similar to XB↑EV↑H_2↑ except that there is no EV flexibility;
- XB↓EV↓H_2↓;
- XB↓EV0H_2↓ similar to XB↓EV↓H_2↓ except that there is no EV flexibility.

Impact of EV flexibility on the operation of the electrical system

In this section, we analyse the impact of using EV flexibility on the management of generation and storage assets. On Figure 4.11 and respectively on Figure 4.12, we have reported for each season and for each type of technology, the average variation of energy injected in the European grid implied by the use of EV flexibility in the variant XB↑EV↑H_2↑ (resp. XB↓EV↓H_2↓) compared to the reference XB↑EV0H_2↑ (resp. XB↓EV0H_2↓) as a percentage of the total energy generated over the year 2050 in the reference case XB↑EV0H_2↑ (resp. XB↓EV0H_2↓). We can observe that the variations are slightly greater in spring and summer than in autumn and winter. Besides, the use of EV flexibility allows to increase the integration of photovoltaic energy and decrease the quantity of lost load while it reduces the use of small storage units (including batteries and hydro pumps).

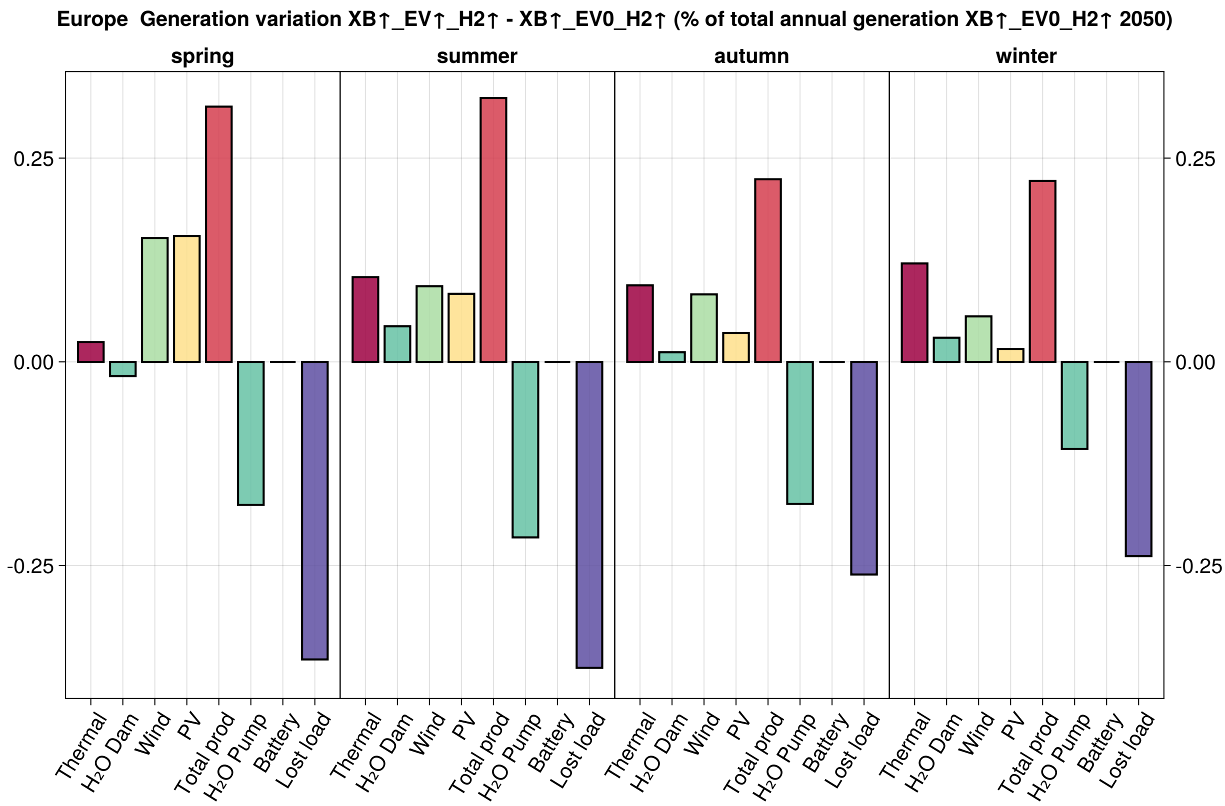


Figure 4.11: Variation of European energy generated per technology with EV flexibility in XB↑EV↑H_2↑

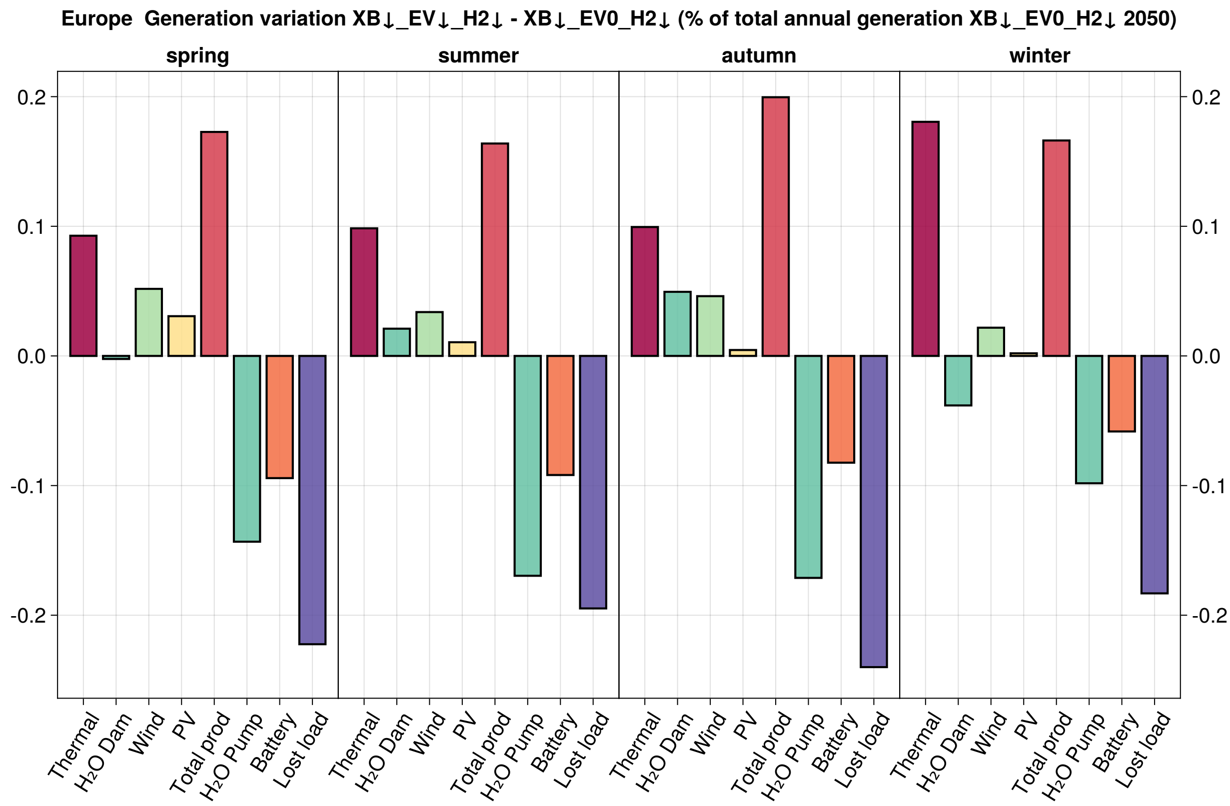


Figure 4.12: Variation of European energy generated per technology with EV flexibility in XB↑EV↑H_2↑

On Figures 4.13 and 4.14 these results are specified for Germany and France. We can again observe that variations are always more important in spring and summer than in autumn and winter. On the other hand, the imports are reduced. It seems that the impact of EV flexibility allows above all to absorb more photovoltaic energy and to reduce the need for small storages and importations.

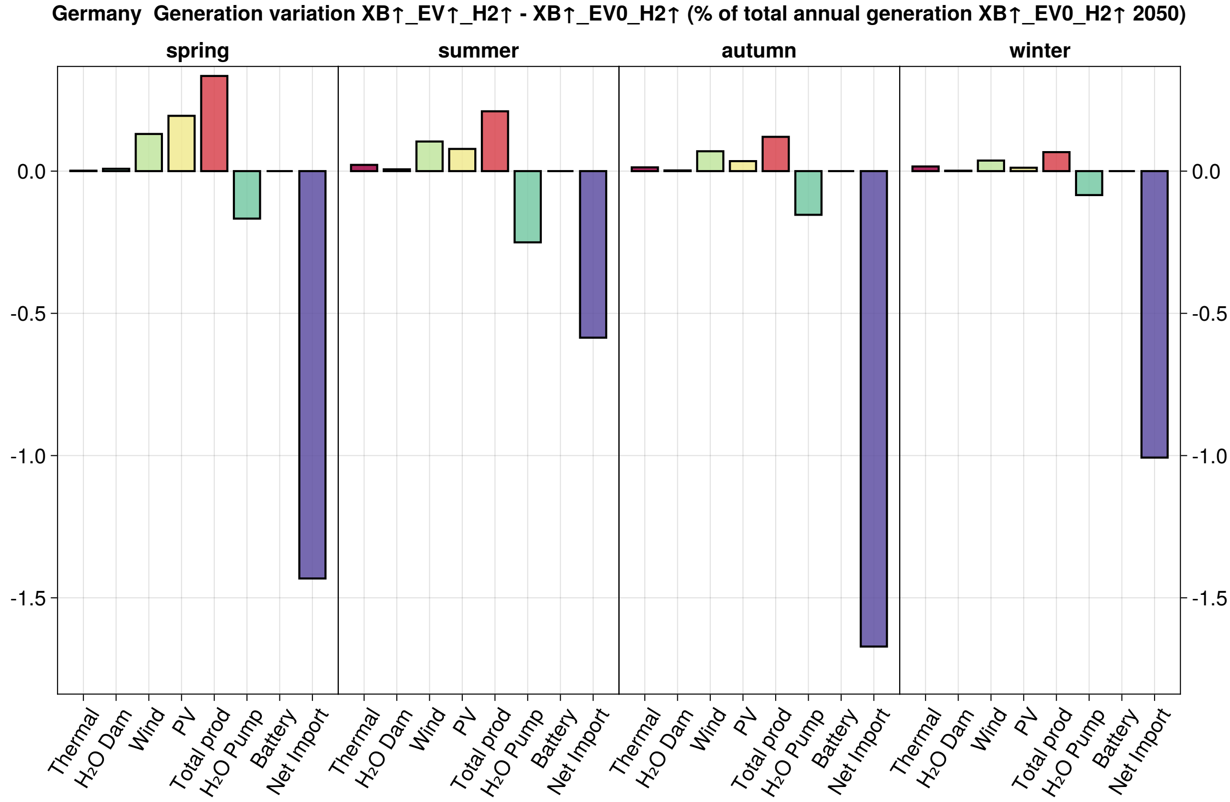


Figure 4.13: Variation of Germany energy generation per technology with EV flexibility

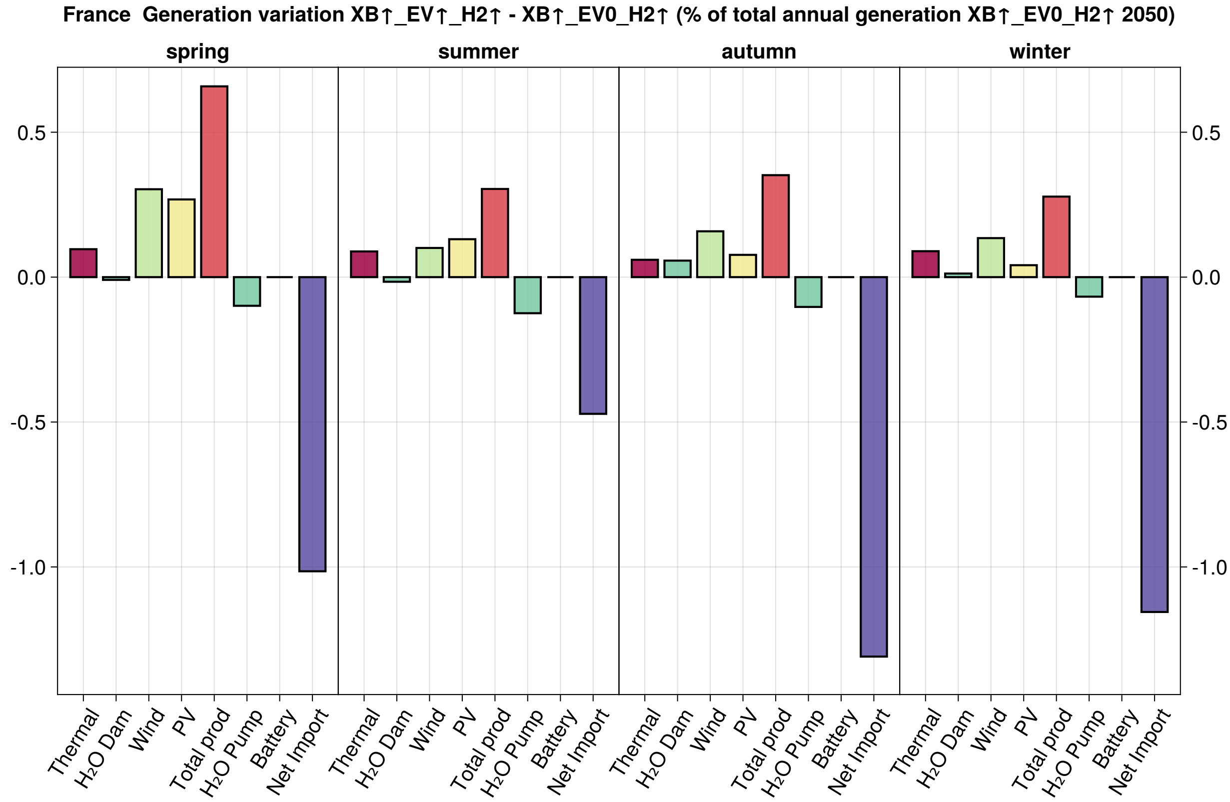


Figure 4.14: Variation of France energy generation per technology with EV flexibility

We have re-conducted the same study with a refined regional model for France and Germany:

instead of using a single node for each country, we have used a node per region of each country. We can observe on Figures 4.15 and 4.16 that the results are qualitatively similar but slightly more pronounced showing that the refined model allows to assess a better value of EV flexibility for the electrical system.

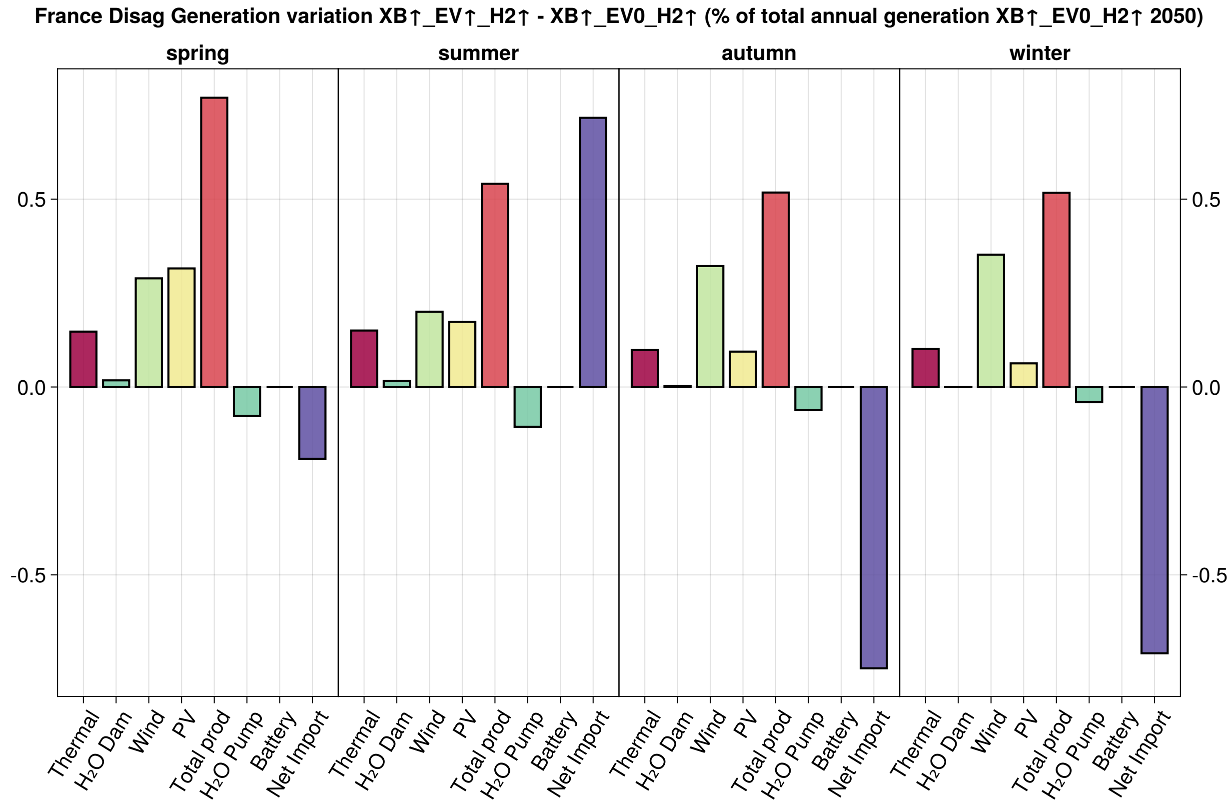


Figure 4.15: Variation of France energy generation per technology with EV flexibility using a refined regional model for Germany and France

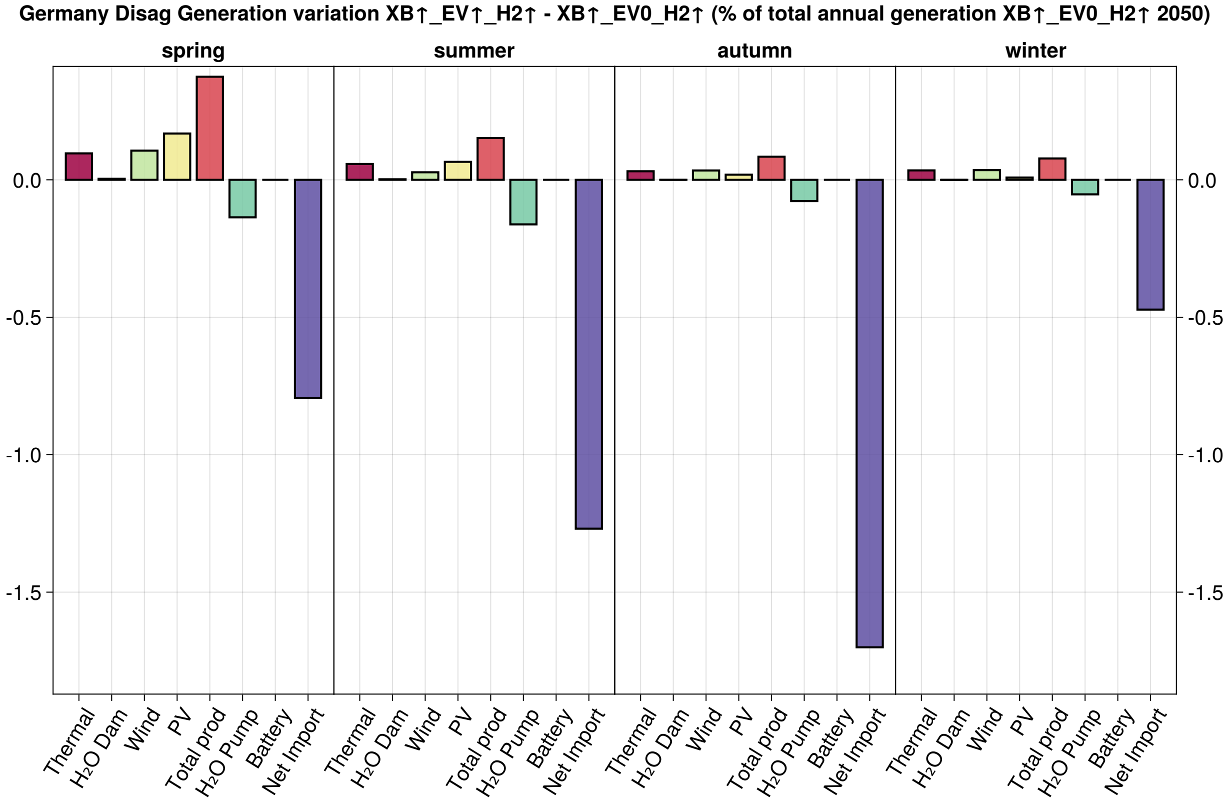


Figure 4.16: Variation of Germany energy generation per technology with EV flexibility using a refined regional model for Germany and France

We analyse the impact of EV flexibility on marginal costs, calculated as the dual variables of the supply-demand equilibrium constraint for each hour of the year 2050 and for each of the 37 simulated chronicles considered by plan4EU representing uncertainties on demand, renewable generation and inflows in year 2050. We focus on Germany and France in the specific case XB↑EV↑H_2↑ vs. XB↑EV0H_2↑ but the results obtained for the other case (XB↓EV↓H_2↓ vs XB↓EV0H_2↓) are similar. We computed the average marginal cost over the 37 simulated chronicles and the associated dispersion with and without EV flexibility. The use of EV flexibility allows, on the one hand, to flatten the trajectory of marginal costs, in particular by reducing the spikes, on the other hand, to reduce the dispersion of the marginal costs over the 37 chronicles of uncertainties .

Impact of hydrogen prices on the operation of the electrical system

In this section, we analyse the impact of import prices of H_2 on the management of generation and storage assets by comparing the two variants XB↑EV↑H_2↑ and XB↓EV↓H_2↓. On Figure 4.17, we have reported for each season and for each type of technology, the average variation of energy injected in the European grid by comparing the variant XB↑EV↑H_2↑ w.r.t. XB↓EV↓H_2↓ taken as a reference, as a percentage of the total energy generated over the year 2050 in the reference case XB↓EV↓H_2↓. As expected one can observe that the higher prices of H_2 implies a reduction of thermal plants production which is compensated by a better integration of renewable production.

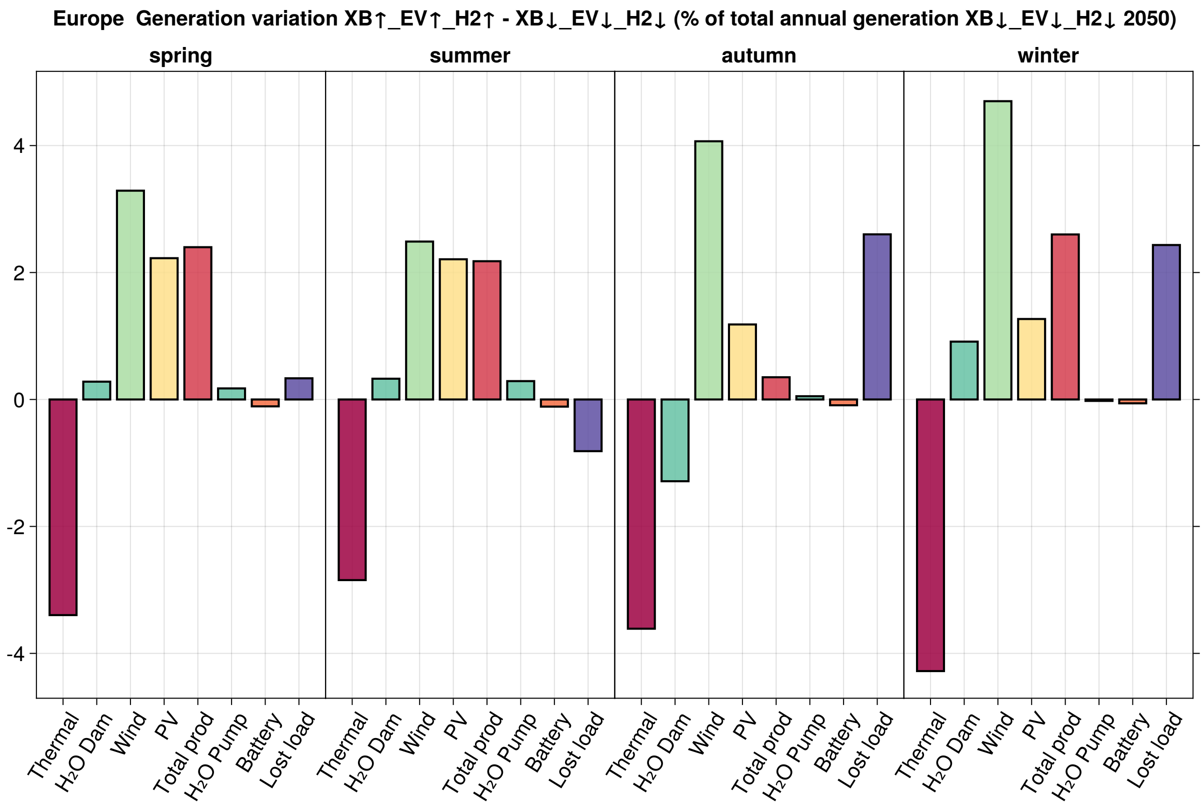


Figure 4.17: Variation of European energy generated per technology in XB↑EV↑H_2↑ w.r.t. the reference XB↓EV↓H_2↓

Concerning marginal costs, we obtain that a higher price of H_2 implies an upper translation of marginal costs. Finally, on Figure 4.18 we have reported for each considered country, the averaged variation of operational costs implied in year 2050 by the variant XB↑EV↑H_2↑ compared to the variant XB↓EV↓H_2↓ considered as a reference. The average is computed over the 37 chronicles considered in plan4EU to represent uncertainties on demand, renewable generation and inflows in year 2050. This cost variation is expressed as a percentage of the operational cost obtained for each country with respect to the reference. Globally, at the European level, we observe surprisingly a decrease of operational costs induced by higher import H_2 prices. This is due to investment decisions in the capacity mix, made in the variant XB↑EV↑H_2↑ allowing to avoid using H_2 plants.

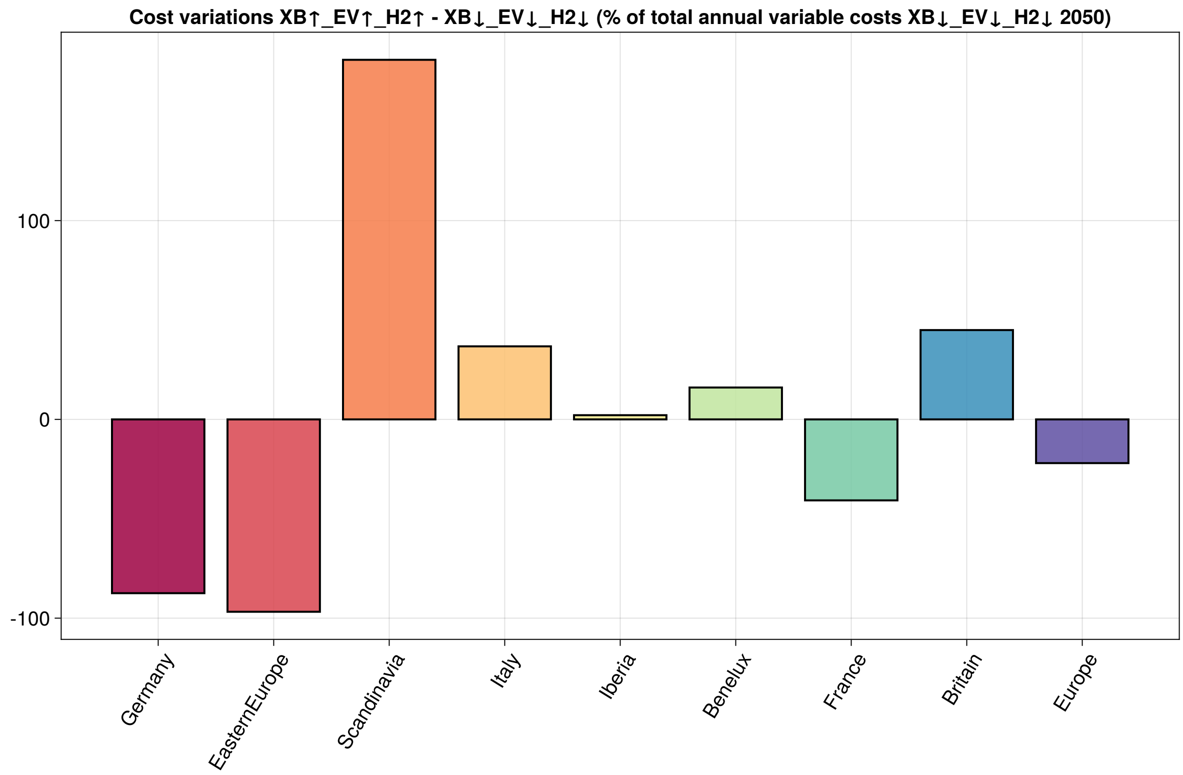


Figure 4.18: Percentage of variation of variable costs per country between variant XB↑EV↑H_2↑ and the reference XB↓EV↓H_2↓ relatively to the variable costs obtained for each country in the reference variant

Besides, the effect is different for each country depending on the evolution of the gas units installed capacity (provided by SCOPE SD model) between the reference XB↓EV↓H_2↓ and the variant XB↑EV↑H_2↑ as reported on Figure 4.19 and 4.20. First, we should emphasise that operational costs in Scandinavia are very low (due to the high share of hydro) so that an increase of operational costs close to 200% is not so important in absolute value. Moreover, in Scandinavia the gas units installed capacity decreases slightly compared to Germany for instance implying that the variable costs related to energy produced in Scandinavia are much more exposed to the H_2 price explaining why we observe such an increase. This interpretation is confirmed by the energy flows reported on Figure 4.21.

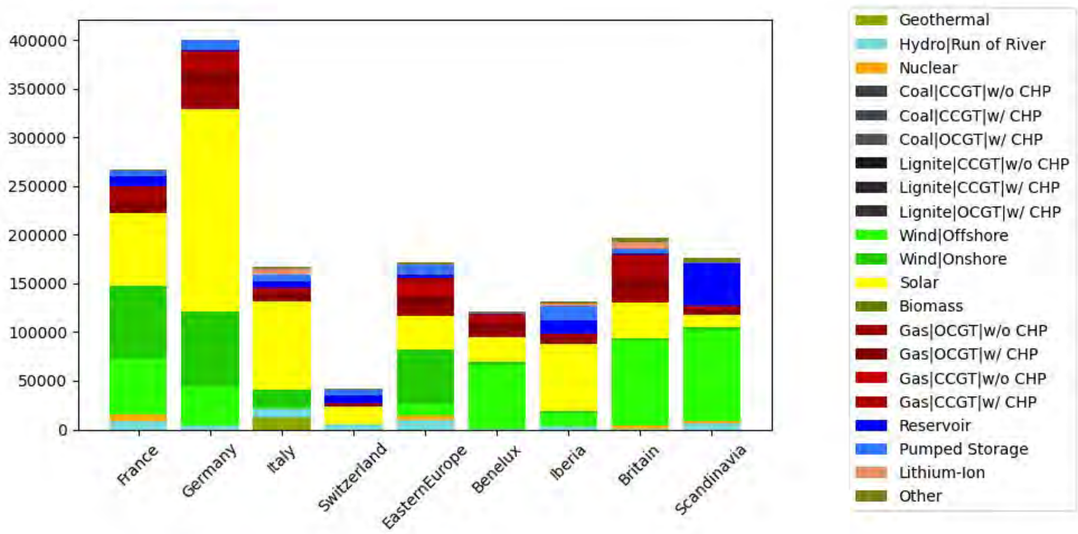


Figure 4.19: Installed capacities for the variant XB↓EV↓H_2↓ (reference)

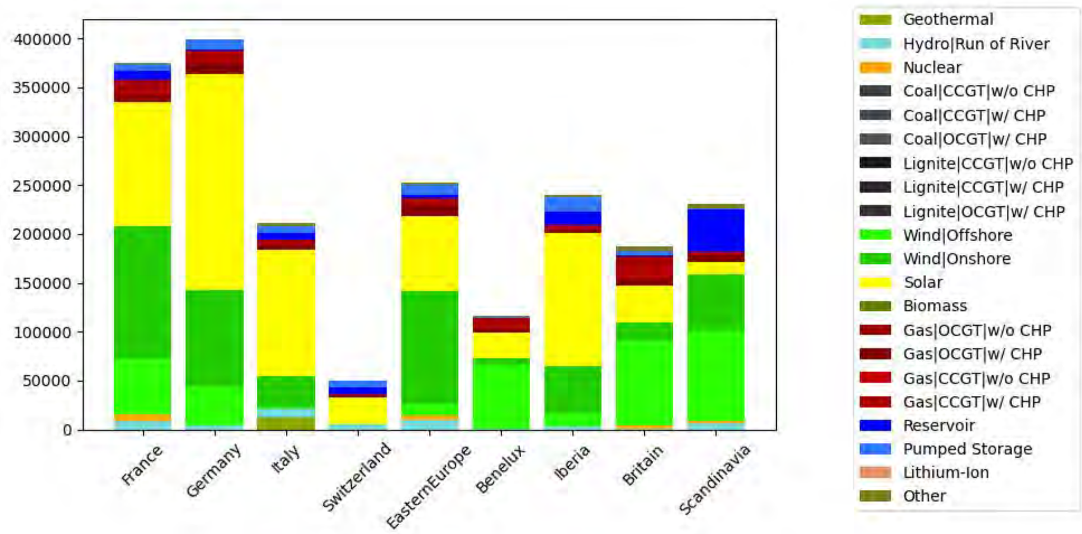


Figure 4.20: Installed capacities for the variant XB↑EV↑H_2↑

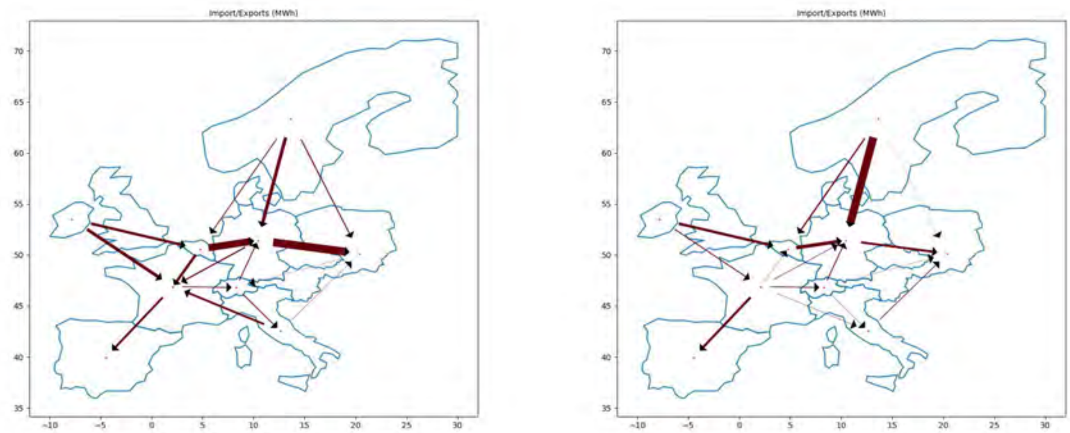


Figure 4.21: Average energy flows for the reference XB↓EV↓H_2↓ (on the left graph) and for variant XB↑EV↑H_2↑ (on the right graph)

4.7 Summary

Given the ongoing transformation of energy systems towards a climate-neutral and sector-integrated future, the case study is a sensitivity analysis based on openENTRANCE's *Techno-Friendly 1.5°C* pathway assessing the impact of three crucial determinants for the pan-European energy system development. These determinants cover electric vehicle charging flexibility in individual road transport sectors, cross-border exchange capacity for electricity trade between national markets, and prices of renewable hydrogen imports from outside of Europe for end-use demands that cannot be abated by direct use of renewable electricity. The coupling of the modelling frameworks SCOPE SD (Fraunhofer IEE) and plan4EU (EDF) together with input data from the GENeSYS-MOD (TU Berlin) demonstrates that both open and proprietary modelling frameworks can be linked via the openENTRANCE platform.

The case study shows that hydrogen import prices are responsible for the largest energy system changes in the climate-neutral system and determines Europe's energy import dependency. Low prices lead to higher hydrogen demand and a high share of imports from future global markets. Higher cross-border exchange capabilities and transport sector charging flexibility have moderate effects, i.e. they increase the direct use of renewable electricity and reduce the need for indirect electrification applications (i.e. hydrogen demand). Hydrogen import prices exhibit the strongest impact on regional electricity price distributions with cross-border trade and electric vehicle flexibility having only smaller effects on the volatility in the distribution tails.

Numerical results of both modelling frameworks emphasise the crucial role of flexibility in the transition to a climate-neutral energy system. By modelling the cross-sectoral interactions in high detail, it is shown that different types of operational flexibility play different roles in the system. More specifically, we see that the impacts on the system development choices, unit dispatch, and the resulting electricity prices are strongly influenced by the multi-fuel flexibility and, less so, by the direct temporal flexibility [11]. When combining integrated energy system models with power-sector-focused models, it is important to be aware of the interactions that are endogenous decisions in the energy system model but become exogenous decisions in the power-sector-focused model. For instance, is the electrolyser demand considered as a fixed demand without or as flexible demand with a marginal value of hydrogen production — this will have impacts on the observed clearing prices in the modelling frameworks [2], [3].

4.8 Limitations and future work

In the analysis, we made a number of assumptions that may partly affect our results. The limitations of the case study and the models are listed below:

- Modelling the power system on a single year operation (e.g. 2050 horizon).
- Uncertainty consideration (SCOPE SD model), particularly long-term uncertainty.
- SCOPE SD does not feature intrazonal grid congestions as it is only a market-based capacity expansion planning model
- Modelling of hydro generation is aggregated (equivalent hydropower valleys in SCOPE SD [16]; one lake by country/region, no hydro valleys in plan4EU).
- Modelling of transmission network is simplified (clustering).
- Modelling of distribution network is limited to the reinforcement's costs and global constraints at each node of the transmission network (maximum amount of power injected into the distribution network at each hour).
- Aggregation of heterogeneous vehicles storage into a single representative storage per node (plan4EU).
- Short-term uncertainties are not taken into account (everything is supposed to be known within a day): arrival and departure of electric vehicles to the parking station are not taken into account, variable renewable generation are not taken.
- Network model: the primary implementation of the case study entails a simplified modelling of the network. Even if several nodes per country will be considered, the model will only consider nodes of the transmission network. Besides, the power flow will be approximated by a Net Transfer Capacity (NTC) model intended to represent commercial trades only, taking into account the capacity limits of the power lines, without any physical representation of the electrical power flows.

Future extensions should address uncertainty in the assumption and path dependent investment decisions to have robust insight into optimal decisions. Moreover, during the case study it became clear, that linking a multi sector model (SCOPE SD) with an power-sector-focused model (plan4EU) is challenging. In particular, the representation of CHP units is hard by not considering the heating part of this unit.

4.9 References

[1] ENTSO-E and ENTSO-G, *TYNDP 2022 Scenario Report*, 2022. [Online]. Available: https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP2022_Joint_Scenario_Full-Report-April-2022.pdf.

[2] P. Härtel and M. Korpås, "Demystifying market clearing and price-setting effects in low-carbon energy systems," *Energy Economics*, vol. 93, p. 105 051, 2021, ISSN: 01409883. DOI: 10.1016/j.eneco.2020.105051.

[3] D. Böttger and P. Härtel, "On wholesale electricity prices and market values in a carbon-neutral energy system," *Energy Economics*, vol. 106, p. 105 709, 2022, ISSN: 01409883. DOI: https://doi.org/10.1016/j.eneco.2021.105709.

[4] openENTRANCE, *Quantitative scenarios for low carbon futures of the european energy system on country, region and local level*, 2022. [Online]. Available: https://openentrance.eu/wp-content/uploads/openENTRANCE-D3.2_final.pdf.

[5] ENTSO-E, *e-Highway2050 project*, 2015. [Online]. Available: https://docs.entsoe.eu/baltic-conf/bites/www.e-highway2050.eu/results/,%20https://docs.entsoe.eu/baltic-conf/bites/www.e-highway2050.eu/fileadmin/documents/Results/e-Highway_database_per_country-08022016.xlsx.

[6] Thomas Anderski, Yvonne Surmann, Simone Stemmer, Nathalie Grisey, Eric Momot, Anne-Claire Leger, Brahim Betraoui, Peter van Roy, *Modular development plan of the pan-european transmission system 2050: European cluster model of the pan-european transmission grid: D 2.2.* [Online]. Available: https://docs.entsoe.eu/baltic-conf/bites/www.e-highway2050.eu/results/ (visited on 10/20/2020).

[7] Fraunhofer Institute for Energy Economics and Energy System Technology, *Global PtX Atlas. Fraunhofer IEE*, 2022. [Online]. Available: https://maps.iee.fraunhofer.de/Global%20PtX-Atlas/.

[8] M. Pfennig, D. Böttger, B. Häckner, *et al.*, "Global gis-based potential analysis and cost assessment of power-to-x fuels in 2050," 2022. DOI: https://doi.org/10.48550/arXiv.2208.14887.

[9] D. Böttger, M. Jentsch, T. Trost, N. Gerhardt, M. von Bonin, and J. Eschmann, "Cost-optimal market share of electric mobility within the energy system in a decarbonisation scenario," *2018 15th International Conference on the European Energy Market (EEM)*, pp. 1–5, 2018. DOI: 10.1109/EEM.2018.8469846.

[10] P. Härtel and D. Ghosh, "Modelling heat pump systems in low-carbon energy systems with significant cross-sectoral integration," *IEEE Transactions on Power Systems*, vol. 37, no. 4, pp. 3259–3273, 2020, ISSN: 0885-8950. DOI: 10.1109/TPWRS.2020.3023474.

[11] F. Frischmuth and P. Härtel, "Hydrogen sourcing strategies and cross-sectoral flexibility trade-offs in net-neutral energy scenarios for europe," *Energy*, vol. 238, p. 121 598, 2022, ISSN: 03605442. DOI: 10.1016/j.energy.2021.121598.

[12] eurostat, *Stock of vehicles by category and nuts 2 regions*. [Online]. Available: https://ec.europa.eu/eurostat/databrowser/view/TRAN_R_VEHST/default/table (visited on 04/09/2021).

[13] Bundesanstalt für Straßenwesen (BASt), *Automatische Zählstellen 2021*, 2021. [Online]. Available: https://www.bast.de/DE/Verkehrstechnik/Fachthemen/v2-verkehrszaehlung/Aktuell/zaehl_aktuell_node.html.

[14] Geofabrik, *France: Download openstreetmap data for this region:* 2021-04-09. [Online]. Available: https://download.geofabrik.de/europe/france.html (visited on 04/09/2021).

[15] ASFA, *Le rapport des chiffres clés 2020*, 2020. [Online]. Available: https://www.autoroutes.fr/fr/publications/chiffres-cles.htm (visited on 04/09/2021).

[16] P. Härtel and M. Korpås, "Aggregation methods for modelling hydropower and its implications for a highly decarbonised energy system in Europe," *Energies*, vol. 10, no. 11, p. 1841, 2017. DOI: 10.3390/en10111841.

Chapter 5

Case Study 5: Decentralisation

Abstract

The main issue of case study 5 (CS5) is to evaluate the impact of decentralization of investment decisions compared to centralized decisions on power systems, in a consistent way with the Open ENTRANCE Techno-FriendlyV2 scenario. More specifically, the centralized framework is viewed here as the least cost case and is considered as a baseline. All resources are supposed to be exploited in a common objective taking advantage of geographical disparities. On the other hand, decentralization is the natural trend we are following because, it allows to enhance acceptance and active participation of communities in fully exploiting the potential of local flexibilities involving distributed renewable generation, heat, mobility or demand side management. The objective of CS5 is then to quantify the impact of decentralization of investment decisions in order to provide some insights on relevant coordination mechanisms to recover efficiency in a partially decentralized system.

Two geographical scales are considered: a global level for the entire system under consideration and a local level defining the mesh at which decentralized decisions are made. More specifically, we consider Europe as a global level and countries (or aggregations of countries) as local levels. The objective is to define a generation mix with a minimum percentage of the available energy generated coming from *decarbonized* sources (i.e. without any CO2 emissions). Four variants were implemented ranging from a completely centralized system to a fully decentralized system. Each variant is formalized as a specific mathematical problem.

- The first variant is the ”fully centralized case”, with a centralized target. In this setting, a central operator is minimizing the investment and operation costs of the whole system such as to satisfy the supply/demand balance at each node of the grid together with a *decarbonization* constraint applying globally for the whole Europe.
- The second variant called “centralized decisions with decentralized targets” corresponds to the same optimization problem except that the *decarbonization* constraint is considered at the level of each country in order to ensure that each country is able to produce in average enough *decarbonized* energy on the whole year. Even though each region has to fulfill the *decarbonization* constraint at its national level, it may rely on energy coming from neighbouring regions for fulfilling the generation demand balance.
- The third variant called “fully decentralized” corresponds to a situation where each country considers its own capacity expansion problem independently of other countries, that is to say that when considering investment decisions, each country does not rely on the interconnection with its neighbours. Each country also defines its generation mix, considering its own *decarbonization* constraint at the national level.
- Finally the fourth variant is in between second and third: it corresponds to the same problem as the third variant, but with a unique *decarbonization* constraint at the European level. This variant is purely theoretical.

Each of the four variants corresponds to a specific optimization problem that is solved using the plan4EU modelling suite -implemented in the plan4Res H2020 project- to optimize power systems investments and operation decisions for the target year 2050.

Two important limitations of this case study should be underlined. First, plan4EU does not provide a pathway of investments decisions from 2022 to 2050 because the optimization tool is only able to consider a target year (here 2050). More importantly, CS5 is limited to computing investments in power systems only, without explicitly modelling interactions in both directions between the electrical system and other sectors as heat or transport for instance.

The results obtained show that the decentralization of decisions as well as the decentralization of targets at the level of European countries leads a priori to a significant increase in costs both in terms of CAPEX and OPEX. On the other hand, a relevant approach to decentralize the decarbonization efforts in the European electrical system could be to build country-specific decarbonization targets from the results of a fully centralized optimization at the European level, taking into account both the exchange capacity offered by the grid and the specific characteristics of each country in terms of renewable energy capacity and generation.

Contents

5.1 Introduction

5.1.1 Overall objective of case study

The objective of CS 5 is to assess the (modelled) impact of decentralization on investment decisions. Decentralization can be interpreted as:

- Decentralization of targets: for instance each country has a specific target for the share of Renewable Energy vs. a single target at the European level. This case study focuses in particular on a *decarbonization* target (that will be precisely described in Section 5.3.3). Mathematically, this situation still implies a single optimization problem relating all the countries but some specific local constraints are replacing the global constraint in the optimization problem.

- Decentralization of decisions: each country has its own decision variables in order to optimize its own objective with its own constraints. In full generality, the objective of a given country depends on the decisions of the other countries so that this type of problems should fall into the complex mathematical framework of game theory. Here, to simplify, we consider the situation where each country considers a specific optimization problem independent of other countries decisions, by supposing fixed exchanges with other countries, considering in particular the extreme situation where exchanges are fixed to zero.

In this case study, the four following variants are compared:

1. "Centralized decisions and centralized *decarbonization* targets (CC or fully centralized case): this case focuses on a single objective function representing investment and operation costs at the European level and constraints related to technical constraints as well as a global target in terms of share of *decarbonized* available energy which is formulated at the European level;

2. "Centralized decisions with decentralized *decarbonization* targets" (CD): this setting corresponds to an optimization problem with the same objective function and technical constraints as above, except that targets on the yearly *decarbonized* available energy share are local to each country;

3. "Decentralized decisions with decentralized *decarbonization* targets" (DD or fully decentralized case): this framework differs from the previous ones because it involves as many optimization problems as countries since each country aims at minimizing its own costs under technical constraints. However, we have to make assumptions on potential exchanges between countries and we consider the extreme situation where each country has no exchange with other countries when optimising its generation mix expansion (practically, we consider within the capacity expansion tool, that there are no interconnection capacities between countries). Regarding the *decarbonization* target, it applies individually to each country. We then have to independently solve one problem per country for the capacity expansion problem. Simulations are then ran at European level, with a representation of interconnections.

4. "Decentralized decisions with centralized *decarbonization* targets" (DC): this framework corresponds to the previous one except that the *decarbonization* target applies globally at the European level. This means that although each country solves its own problem, as the last constraint is coupling countries together, the problem has to be solved as a single optimization problem. This framework is purely theoretical and allows to evaluate separately the impact of decisions decentralization with the impact of target decentralization.

Variants CC and CD perform the role of fictional central planners with all information and making investment decisions at the global level with global targets (variant CC) or local targets (variant CD) in order to minimize the system costs, while in variants DD and DC each country performs independently its own decisions. Those variants are mathematically described in Section 5.3.3.

This case study should then illustrate to what extent different decision levels (country or continent) with specific objectives may lead to different investment decisions. Note that in the case of decentralized decisions, even if the investment decisions are taken individually in each country, the simulation of the system operation is always done at European level, taking into account the interconnection capacities.

5.1.2 State of the art

In [4, 10], the impact of decentralization of investments and operation decisions in power systems is investigated at different geographic scales: continental, national, regional, and municipal. In particular, the authors compare the three following situations at the European level:

1. system with European energy supply and power balancing with all the decisions optimized at the European scale, where the demand supply equilibrium is satisfied taking full benefit of the network allowing for exchanges between countries;

2. system with national energy supply and European power balancing, where each country in Europe generates sufficient energy annually to satisfy national demand, but all countries can still trade within a year to balance their net demand profiles fluctuations;

3. system with national energy supply and national power balancing, where each country is supposed to be completely self sufficient, assuming no exchanges between countries (no network capacities between countries).

Of course the first case is less expensive that the second case which is less expensive than the third one. However, they evaluate quantitatively the system costs in each case and show that the difference between the two first cases is small w.r.t. the difference with the third one meaning that self-sufficient systems have high cost mainly because they cannot access the grid.

Both studies consider zero-carbon systems, ie. systems which are able to produce 100% of *decarbonized* energy. The first one focuses on the United States while the second one focuses on Europe.

The present study focuses on the European system and considers a less ambitious target. Indeed, the share of *decarbonized* energy in the total amount of available energy, taking into account load factors associated with variable RES generation, is required to be greater than 70%. This means that the system is required to be able to produce at least 70% of *decarbonized* energy.

5.2 plan4EU model

Plan4EU simultaneously optimizes investment decisions and hourly dispatch over the course of one year (2050) relying on two modelling layers. The **capacity expansion layer** computes a better or ideally optimal set of assets including electric generation plants, storages and interconnection capacities between clusters, for the considered time horizon (the year 2050). Here optimal means, providing the least-cost (including CAPEX and OPEX) set of assets, while accounting at best for the modelled constraints in order to satisfy the demand on the target year (here 2050). The **scenario valuation layer** evaluates the investment decisions from the capacity expansion model by means of modelling the operation of the existing assets in the energy system on one target year with an hourly granularity, on several scenarios representing uncertainties on demand, renewable generation potential and inflows to hydro-reservoirs. This layer contains two distinct models, the first model, referred to as the seasonal storage valuation model, and the second model called the European unit commitment model. The objective of the seasonal storage valuation model is to provide an accurate account of “the value” that seasonal storage can bring to the system. Indeed, such seasonal storage (e.g., cascaded reservoir systems) can be used to store energy over large spans of time and use this “stored” energy when most needed. The actual use may in particular depend on adverse climatic situations (intense cold), but the ability to store the energy may in turn also depend on climatic conditions (e.g. draught). It is therefore clear that such a vision of the 'water' value should be transferred in an appropriate way to shorter time span tools, such as the unit commitment model. In turn computing an accurate value intrinsically depends on the value of substitution, and thus ultimately on the unit commitment model tool as well.

plan4EU was implemented within the SMS++ framework. SMS++ is a set of C++ classes intended to provide a system for modeling complex, block-structured mathematical models (in particular, but not exclusively, single-real-objective optimization problems), and solving them via sophisticated, structure-exploiting algorithms (in particular, but not exclusively, decomposition approaches and structured Interior-Point methods). More details about SMS++ can be found here https://gitlab.com/smspp/smspp-project.

The algorithms included in plan4EU are described in the following papers [8, 3, 2, 12, 11].

More details about the plan4EU modelling suite can be found in [6, 7, 5, 9].

5.3 Assumptions and methodology

5.3.1 Base Case

The main assumption of this study is that the base case corresponds to the electric mix in year 2050 of the Open ENTRANCE TechnoFriendly scenario, which is described in [1].

5.3.2 Geographical scale

14 regions are considered, each region corresponding to either a country or an "aggregation of countries": France, Germany, Italy, Switzerland, EasternEurope (Austria, Czech Republic, Hungary, Poland, Slovakia), Benelux (Belgium, Luxembourg, The Netherlands), Iberia (Spain, Portugal), Britain (Ireland, United Kingdom), Balkans (non-EU-Balkans, Bulgaria, Croatia, Greece, Romania, Slovenia, North Macedonia), Baltics (Estonia, Latvia, Lithuania), Denmark, Finland, Sweden, and Norway.

5.3.3 Description of the four cases: CC, CD, DD, DC

The four cases presented in Section 5.1.1 are written below.

1. **Centralized decisions with centralized targets (CC)**
   For the sake of simplicity we do not include in the equations the investment of interconnections expansions, which is indeed included in the model. The problem consists in choosing the capacity mix κ such as to minimize the sum of annualized CAPEX $C_z^{capex}(\kappa)$ associated with the mix κ and OPEX $C_z^{opex}(\kappa)$ induced by satisfying the demand on the given target year (2050) with the mix κ:

$$\begin{cases} \min_\kappa \sum_{z\in Z} \left[C_z^{capex}(\kappa_z) + \underset{s\in S}{\mathbf{E}} C_z^{opex}(\kappa_z) \right] \\ \text{such that demand is satisfied on each zone } z \\ \text{taking account of exchanges through the network.} \end{cases} \tag{5.1}$$

   where

   - Z is the set of regions (ie countries or aggregations of countries),
   - I is the set of available technologies,
   - $\kappa = (\kappa_{i,z})_{i\in I, z\in Z}$ is the vector determining the capacity mix resulting from investment decisions, with components $\kappa_{i,z}$ denoting the number of assets of technology i in region z, and we make use of the notation $\kappa_z = (\kappa_{i,z})_{i\in I}$
   - $\{s \in S\}$ is the set of uncertainty scenarios,

- $C_z^{capex}(\kappa)$ is the annualized investment cost in region z,
- $C_z^{opex}(\kappa)$ the operation cost of region z on the target year 2050.

The global *decarbonization* target constraint (a minimum share of the available energy comes from decarbonized sources) is written as follows:

$$\mathop{\mathbf{E}}_{s\in S}\left[\sum_t\sum_z\sum_{i\in I_{NoCO_2}}\kappa_{i,z}P_{i,t,z}^{\max}\alpha_{i,t,z,s}\right]\geq\rho\mathop{\mathbf{E}}_{s\in S}\left[\sum_t\sum_z\sum_{i\in I}\kappa_{i,z}P_{i,t,z}^{\max}\alpha_{i,t,z,s}\right] \tag{5.2}$$

with

- I_{NoCO_2} the set of available technologies that do not induce CO_2 emissions,
- $\alpha_{i,t,z,s}\in[0,1]$ the availability of technology i at time t for the uncertainty scenario s in region z (for variable renewables -PV, WindPower or run-of-river- it represents the load factor, for thermal power it includes the unplanned failures);
- $P_{i,t,z}^{\max}$ the maximum power of technology i at time t in region z (which in particular includes planned maintenance);
- we assume that the duration of a timestep is 1 hour, which allows us not to include the timestep duration in the equation, which indeed represents an amount of energy, and not a capacity.

This represents a *decarbonization* constraint, aiming at creating a generation mix in which the available decarbonized energy (taking into account the load factors associated with variable RES generation) accounts for a minimum share $\rho\in[0,1]$ of the total available energy. The experiments of the present study are conducted with $\rho=70\%$.

2. **Centralized decisions with decentralized targets (CD)**
   The problem remains unchanged apart from the *decarbonization* constraint which is now written:

$$\forall z\in Z,\ \mathop{\mathbf{E}}_{s\in S}\left[\sum_t\sum_{i\in I_{NoCO_2}}\kappa_{i,z}P_{i,t,z}^{\max}\alpha_{i,t,z,s}\right]\geq\rho^z\mathop{\mathbf{E}}_{s\in S}\left[\sum_t\sum_{i\in I}\kappa_{i,z}P_{i,t,z}^{\max}\alpha_{i,t,z,s}\right] \tag{5.3}$$

   where $\rho^z\in[0,1]$ denotes the target share of decarbonized energy for region z. The experiments of the present study are conducted with $\rho^z=\rho=70\%$.

3. **Decentralized decisions with decentralized targets (DD)** (implying self sufficiency for balancing): this is an extreme case since it requires that each region is able to supply its own demand, without any connection to other regions, and to fulfil a target in terms of decarbonized energy. Equations (5.1) is transformed into:

$$\forall z\in Z,\ \begin{cases}\min_\kappa\left[C_z^{capex}(\kappa_z)+\mathop{\mathbf{E}}_{s\in S}C_z^{opex}(\kappa_z)\right]\\ \text{such that demand is satisfied on zone } z\\ \text{without exchanges through the network.}\end{cases} \tag{5.4}$$

   with local target constraint (5.3) unchanged.

4. **Decentralized decisions with centralized targets (DC)**
   This consists of the local problem (5.4) associated to the global constraint (5.2).

Four runs have been conducted corresponding to the four variants described above. In each case the penalty corresponding to the value of loss load is tuned in order to ensure in average three hours per year where the supply demand constraint is not served. The results obtained in each of the above cases have been compared in terms of

- installed capacity,
- system costs including investments and operation costs,
- marginal costs, which are computed as the dual value of the supply demand constraint,
- power flows between regions,
- generated energy.

5.3.4 Importance of the reference generation mix

Remark 1 *The runs were performed with the scenario data provided in June 2022. Some updates have been done since then which could not be included to the current results. Part of the results have been readapted to account for these updates (in particular regarding costs). Nevertheless, we believe that the conclusions of this case study would not be changed.*

An important point to emphasize in this study is that all investments are made starting from a given reference generation mix, κ^{ref}. Because it is not equivalent to invest or dis-invest (in terms of costs or constraints), the starting point κ^{ref} strongly impacts the optimal decisions. In other words the investment costs $C_z^{capex}(\kappa_z)$ depends implicitly on the reference generation mix κ^{ref} and should be noted $C_{z,\kappa^{ref}}^{capex}(\kappa_z)$.

Section 5.5.1 thoroughly describes how the reference generation mix is built from Open ENTRANCE Techno-FriendlyV2 scenario 2050. Indeed κ^{ref} is obtained by a modification of Open ENTRANCE Techno-FriendlyV2 scenario 2050 in order to obtain a reasonable generation mix in the sense that it allows to ensure the balance between supply and demand in most cases with an acceptable level of failure. This step is necessary because the data that we used, in particular the electricity demand load factors show very high demand peaks in some cases.

Starting from this reference generation mix, κ^{ref}, we compare different ways of coordinating investments at the European level in order to reach a target in terms of share of decarbonized energy w.r.t. the total available energy. To this end we consider the four different optimization problems CC, CD, DD and DC previously described.

The reference generation mix is of major importance in these optimization problems. Indeed, if for example, in the reference mix, each country is already close to self-sufficiency (or decarbonization) then little investment is needed to make each country generation mix self-sufficient (resp. decarbonized) so that the DC case will be close to the CC case (resp. the DC case will be close to the CC case). The results are therefore very dependent on the reference generation mix (i.e. on Open ENTRANCE Techno-FriendlyV2 scenario and on the way it has been re-adjusted) and cannot be considered as absolute.

An interesting study (left for future investigations) would be to consider the current generation mix in 2023 as the reference.

5.3.5 Case study workflow

CS5 considers decentralization of investment decisions of Europe to the level of countries. A wide perspective of the workflow is represented by the diagram 5.1 below.

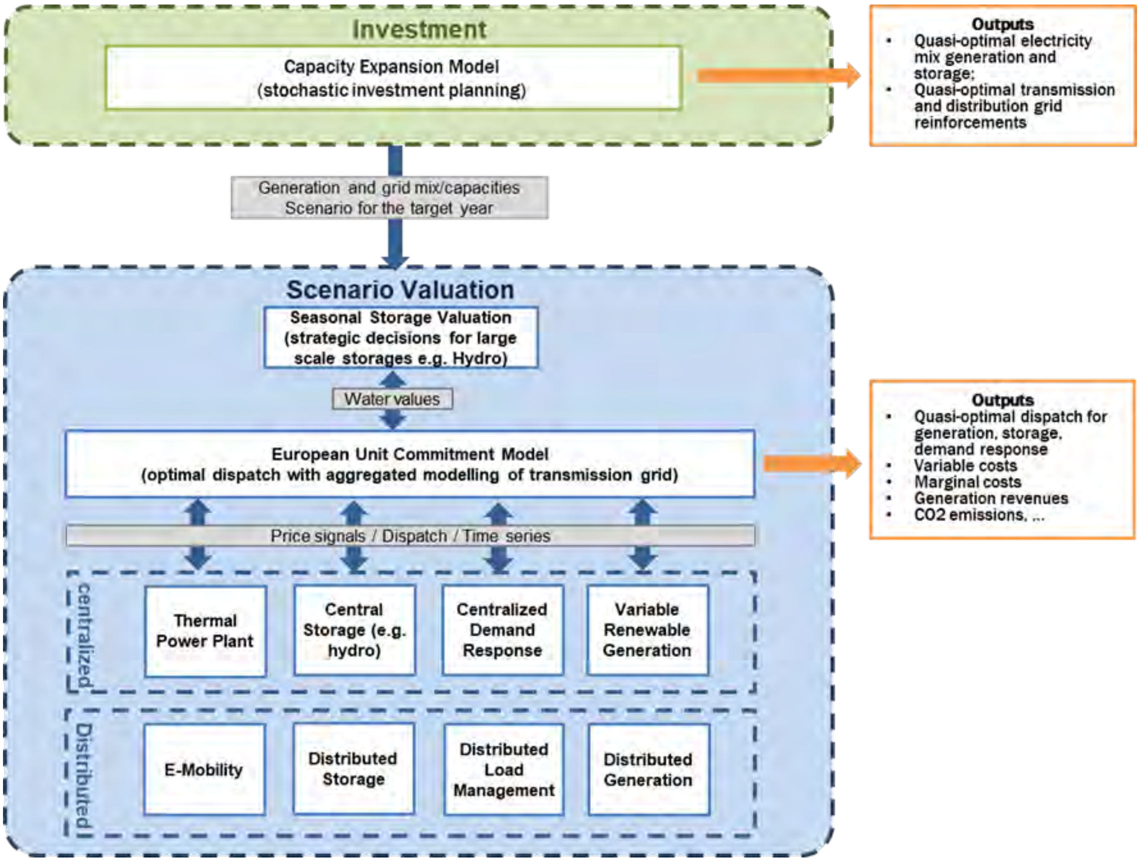


Figure 5.1: plan4EU: Interaction between the capacity expansion layer and the scenario valuation layer

5.4 Description of datasets and how they were created

The names of variables used in the following sections are defined in the Open ENTRANCE nomenclature. (see https://github.com/openENTRANCE/openentrance)

5.4.1 Data from GENeSYS-MOD

Plan4EU runs were conducted on the Open ENTRANCE Techno-FriendlyV2 scenario provided by GENeSYS-MOD in June 2022. The following data (inputs or outputs) of GENeSYS-MOD were used for the year 2050.

- For creating the electricity demand: Final Energy|Electricity, Final Energy|Electricity|Heat, Final Energy|Electricity|Transportation
- For the interconnections: Network|Electricity|Maximum Flow
- For creating the generation mix:
  - Installed capacity: Capacity|Electricity| for the following technologies Biomass|w/ CCS, Biomass|w/o CCS, Coal|Hard Coal|w/o CCS, Coal|Hard Coal|w/ CCS, Coal|Lignite|w/o CCS, Gas|CCGT|w/o CCS,Gas|CCGT|w/ CCS, Gas|OCGT|w/o CCS, Geothermal, Hydrogen|OCGT, Nuclear,Oil|w/o CCS, Hydro|Reservoir, Hydro|Pumped Storage, Solar|PV, Wind|Offshore, Wind|Onshore, Hydro|Run of River
  - for adaptating the inflows profiles: Secondary Energy|Electricity|Hydro|Reservoir

  - for the storages: Storage|Electricity|Hydro|Pumped Storage and Pumping Efficiency|Electricity|Hydro|Pumped Storage
  - For the costs: Variable Cost (incl Fuel Cost)|Electricity|, Fixed Cost|Electricity|, Capital Cost|Electricity| for all technologies where such costs are available.

For RES and Hydro, the Variable cost in plan4EU is set to 0.

5.4.2 Data from other sources

Data from Open ENTRANCE scenario are complemented with data from other sources:

- To evaluate the share of cooling in the electricity demand, we used the value implemented in eHighway2050. Yearly electricity demand is separated into 4 categories (cooling, heating, Electric Vehicles and the rest). Heating and EV parts are taken from the Open ENTRANCE Techno-FriendlyV2 scenario. The cooling part is computed using the cooling shares published by eHighway2050 (as cooling is not included in GENeSYS-MOD).
- The maximum volume of reservoir storages has been computed using the ENTSO-e database. This consists in historic values of the equivalent stored electricity in 'Reservoir' per country. We took the maximum value.
- Scenarised Hourly Profiles for RES potentials and electricity demand per uses come from Copernicus/C3S. Scenarios correspond to climatic years which have been "readapted" to correspond to the year 2050
  - Hourly demand profiles are generated by multiplying the yearly demand by hourly profiles from Copernicus/C3S energy (hourly profiles Electricity demand for heating; Electricity demand for cooling; Electricity demand for electric mobility; (deterministic) electricity demand for other uses).
  - PV, offshore, Onshore wind-power and run-of-river generation profiles. The hourly maximum generation is computing by multiplying these profiles by the installed capacity
- EDF has generated inflows to reservoir profiles, taking advantage of the historic data published by ENTSO-e.

5.5 Results of case study

5.5.1 Feasibility assessment of TechnoFriendly2050 scenario

Feasibility assessment means that the simulation layer of plan4EU was ran on the TechnoFriendly scenario completed with the hourly profiles described in Section 5.4. The installed capacities regarding electricity generation are shown in Figure 5.2. The scenarised electricity demand is shown in Figure 5.3.

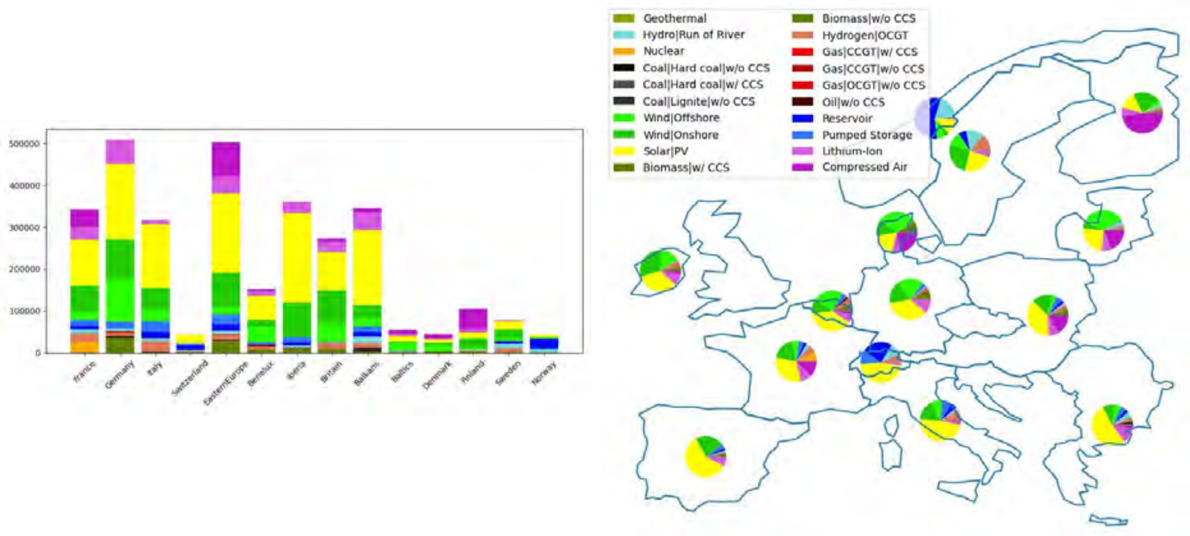


Figure 5.2: TechnoFriendly scenario 2050: Installed Capacity in Europe (Reference) (MW)

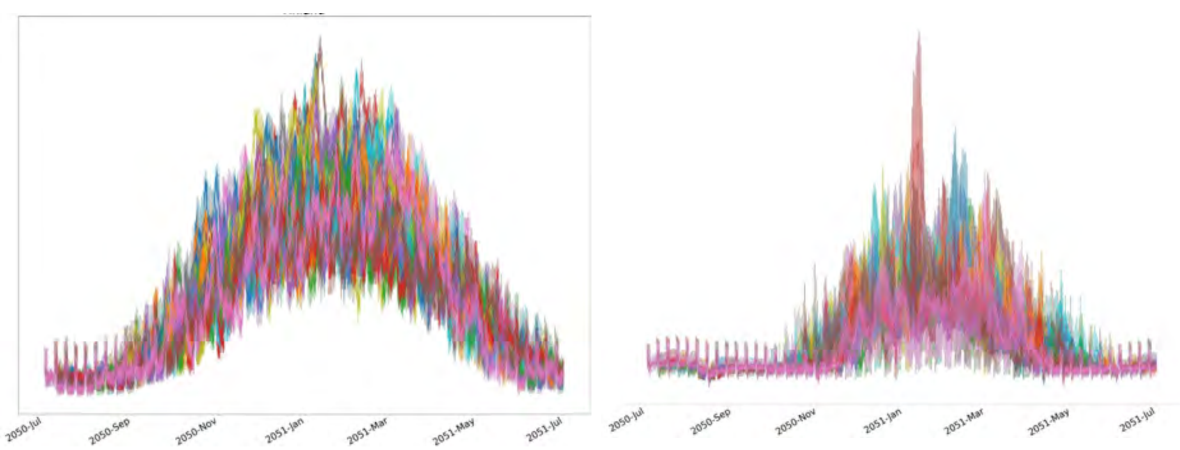


Figure 5.3: Demands variability for 2 examplary regions

We can see in Figure 5.3 that as demand scenarios are created based on meteorological historic years, a high variability between scenarios can be observed, as well as huge demand peaks, sometimes for quite a long duration (up to 10 days, corresponding to long very cold periods).
The operation simulation shows that this reference case is not feasible from the point of view of the electricity system, mainly because of the very accurate and dynamic representation of demand and renewable generation. An other limitation of the study is that the timeseries used for computing the demands were created in 2017 within the Copernicus C3SEnergy project. A new C3S project has recently started whose aim is to update these time series, while accounting for lessons learnt and errors found. Moreover we have used those timeseries in an extreme case, as we have applied energy per uses coming from different sources, which may not be fully consistant. Some of the demand peaks which appear in extreme scenarios may then be too high.

Table 5.1 shows the number of hours with non served energy over the simulated year in the different regions.
Non-served energy occurs mainly when the demand is high and the renewable capacity is low. In particular in this base case, the rate of PV power in the generation mix is quite high, and in winter demand peaks occur at a time when PV generation is zero (eg after 5pm in winter when it is dark). In the cases of long periods with high demands, all the short term storages were optimised to be full

Table 5.1: Number of hours with non-served energy

	Mean Number of Hours	Max Number of Hours
France	0	0
Germany	7.864864865	60
Italy	2.513513514	93
Switzerland	0	0
EasternEurope	0	0
Benelux	1.162162162	32
Iberia	0.216216216	4
Britain	49	366
Balkans	9.27027027	93
Baltics	1027.567568	2178
Denmark	0.189189189	4
Finland	53.75675676	231
Sweden	0.027027027	1
Norway	0	0

before the peak, but they were not sufficient to last the whole duration of the demand peak (or the 'off-peak' periods were not long enough to allow filling the storages). Moreover, demand peaks often occur simultanously in neighbouring countries, as well as eg. low wind periods, which increases the difficulty of the scenario. As plan4EU includes in its modelling the intercorrelations between demand and renewable generation potentials, it can be used to evaluate unfeasibility in a given scenario.
Following this analyses, the plan4EU capacity expansion model was ran in order to get a new reference generation mix, which would prove to be closer to feasibility. Only Thermal power and Batteries were allowed to be added in this adaptation run.
Figure 5.4 shows the deviation between the adapted reference and the initial reference.

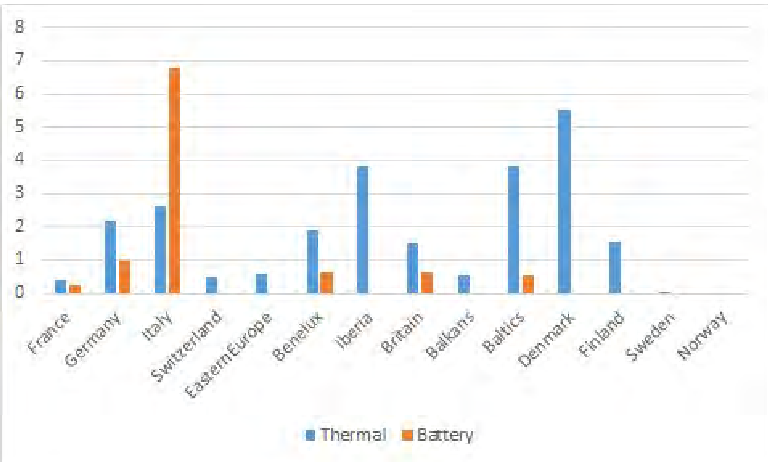


Figure 5.4: Adapted generation mix: deviations from reference, %

From now on, we will denote "Reference" the adapted generation mix.

5.5.2 Impact of decentralization of decisions

In the following we will denote:

- REF: the reference optimised case,

- CC: case with centralized decisions and centralized *decarbonization* constraint,
- CD: case with centralized decisions and decentralized *decarbonization* constraint,
- DD: case with decentralized decisions and decentralized *decarbonization* constraint,
- DC: case with decentralized decisions and centralized *decarbonization* constraint.

Installed capacity

The following Figure 5.5 shows the installed capacity in the 4 variants (CC, CD, DD, DC)

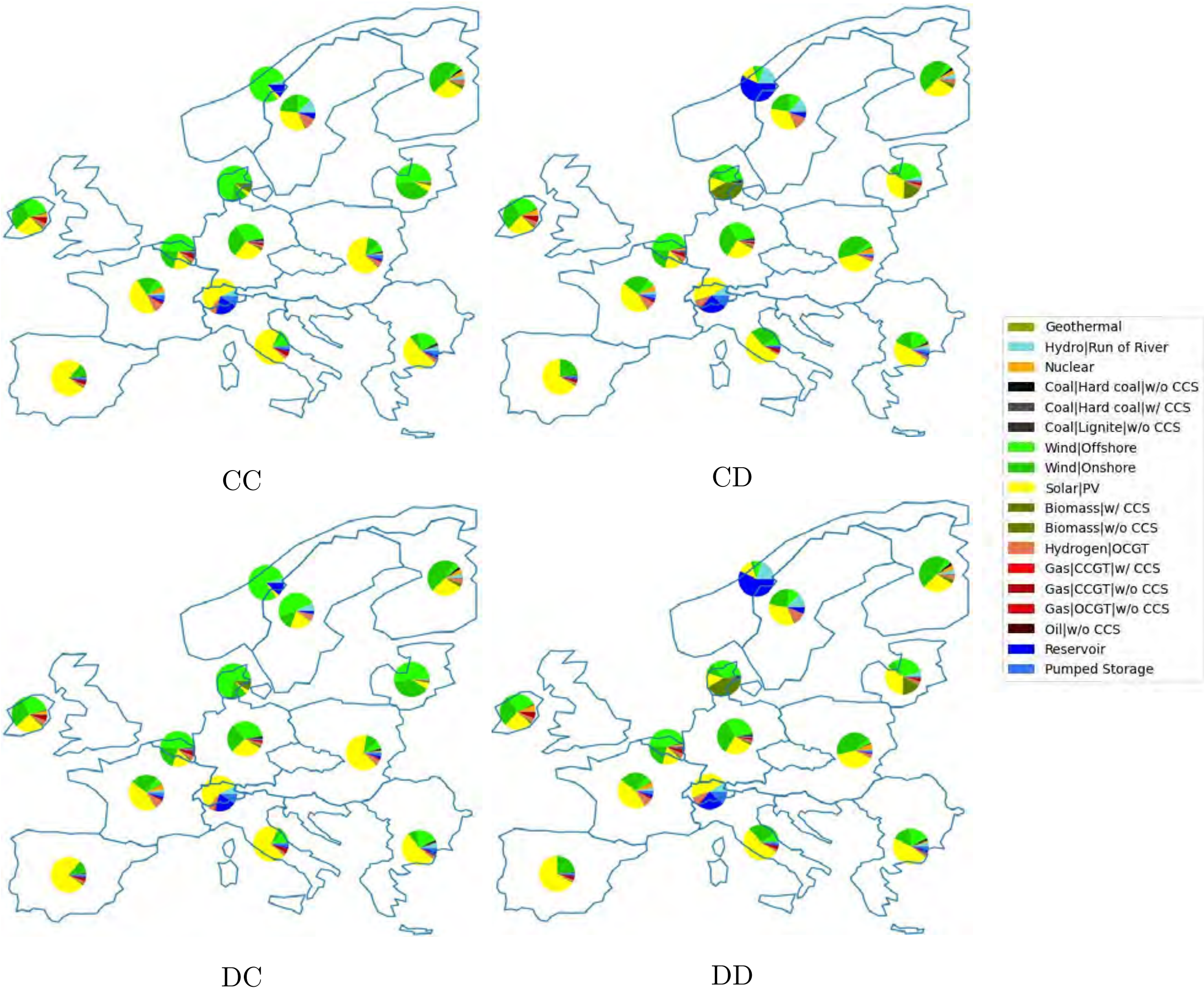


Figure 5.5: Installed capacity shares per technology in centralized/decentralized variants

The differences in the installed technologies are highlighted in Figure 5.6.

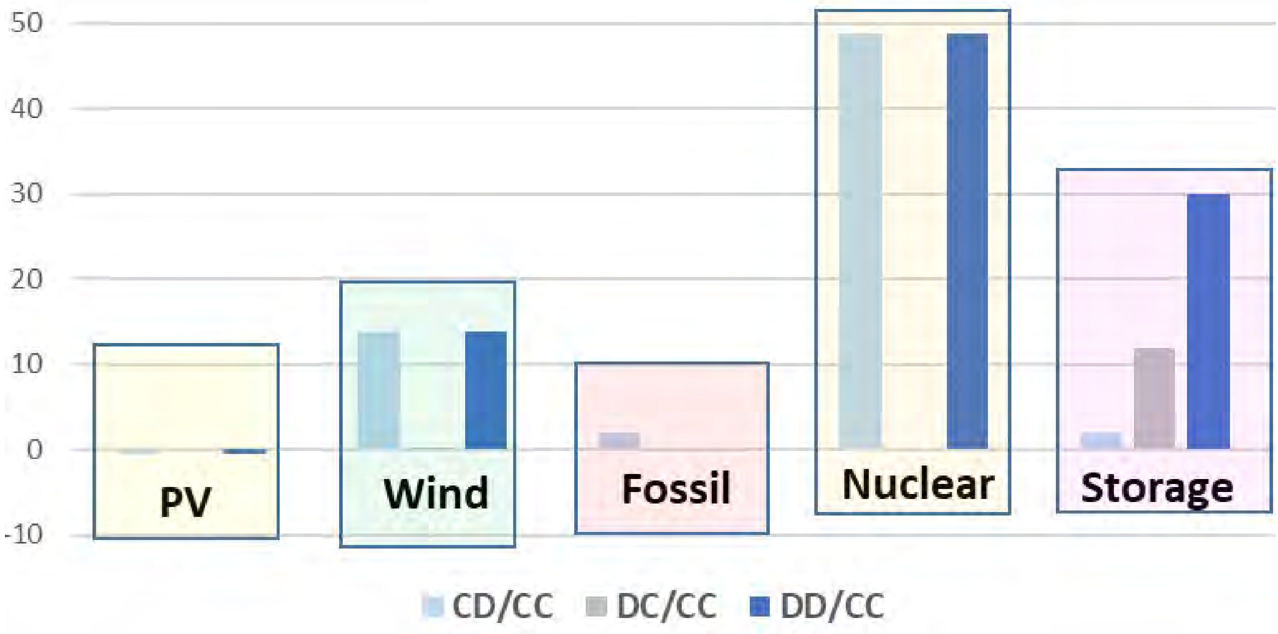


Figure 5.6: Installed capacity: deviations from the CC variant (%)

We can see that in total for Europe, decentralising decisions induces an increasing need in short-term storage and fossil plants while decentralising targets increases the need for Nuclear and Wind-Power, and slightly decreases the need for PV.

Generated energy

Figure 5.7 shows the amount of energy generated over the year per technology in all countries. One can observe that the differences between the fully centralized case CC with case CD (centralized decisions but decentralized targets) seems small w.r.t. to cases DC and DD involving decentralized decisions. In particular, decentralizing decisions implies an increase in the use of gas and coal thermal units.

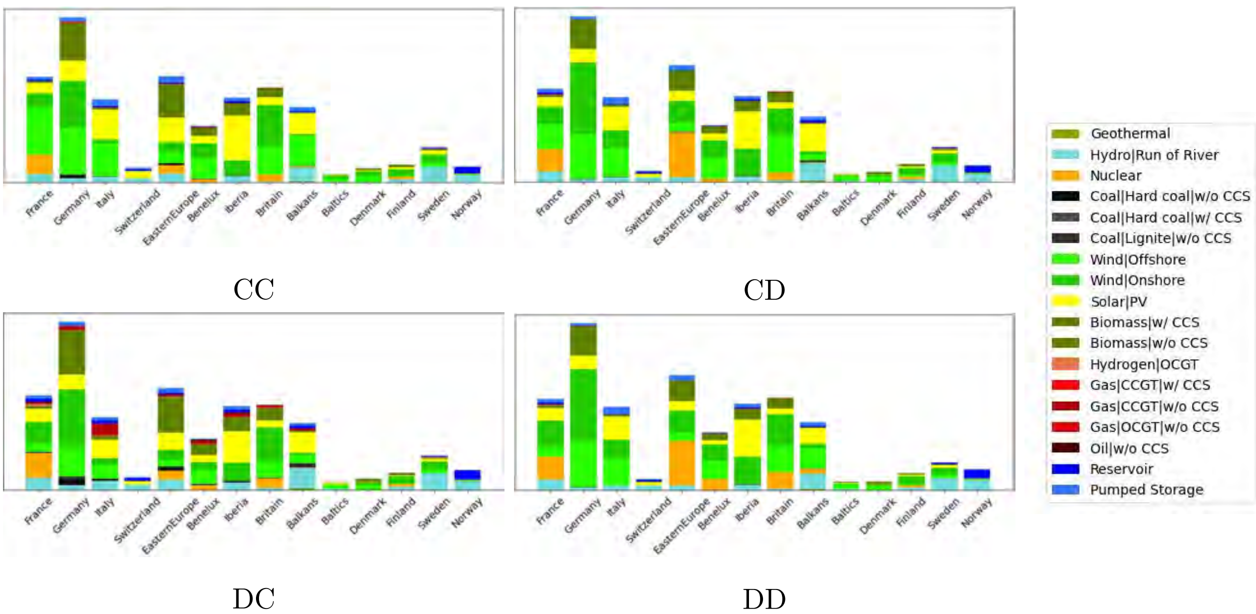


Figure 5.7: Yearly energy in centralized/decentralized variants (MWh)

That observation is confirmed on Figures 5.8, 5.9, and 5.10 where we have reported for each season and for each type of technology, the average variation of energy injected in the European grid in each variant CD, DC, and DD compared to the fully centralized case CC as a percentage of the total energy generated over the year 2050 in case CC. One can observe that decentralizing decisions only (DC) implies that the use of fossil units increases by more that 8% of the total energy while the use of PV and Wind energy decreases in the same proportion (corresponding to more curtailments). However, the use of storage is kept unchanged even if the installed capacity is increased. This is due to fact that investments are made assuming sel-sufficiency while the system is operated taking into account exchanges between countries. On the other hand, the use of fossil and PV energy decreases in the both cases where targets are decentralized (CD and DD) while the use of Nuclear and wind is increased. Besides, one can observe that deviations with case CC are mainly observed during winter and autumn especially in the DC case. We can also observe a 'strange' behavior in the case of Norway: Norway has already enough decarbonised energy (100%), but given the constraints on potentials in other regions, the model choses to invest in WindPower in Norway to fullfill the decarbonization constraint in the centralised targets cases (CC and DC) although this energy is not required, and not used as we can see in Figure 5.7.

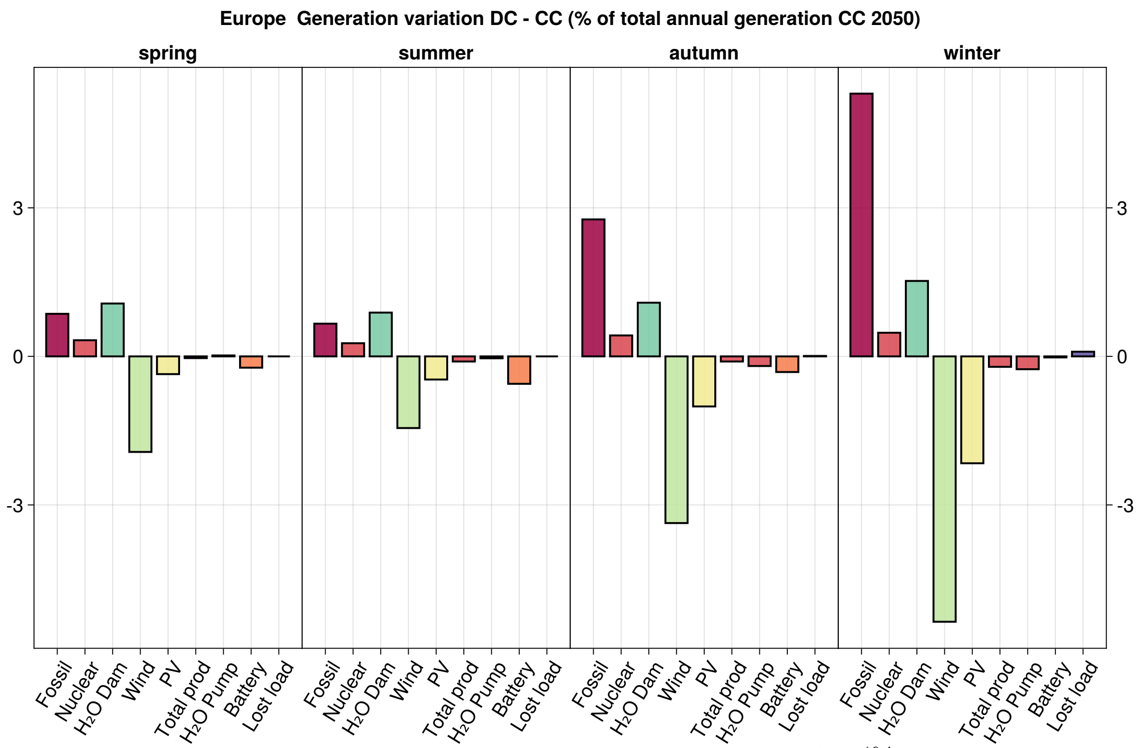


Figure 5.8: Energy generation deviation per season in case DC w.r.t. CC (% of total energy generated in Europe in case CC in year 205)

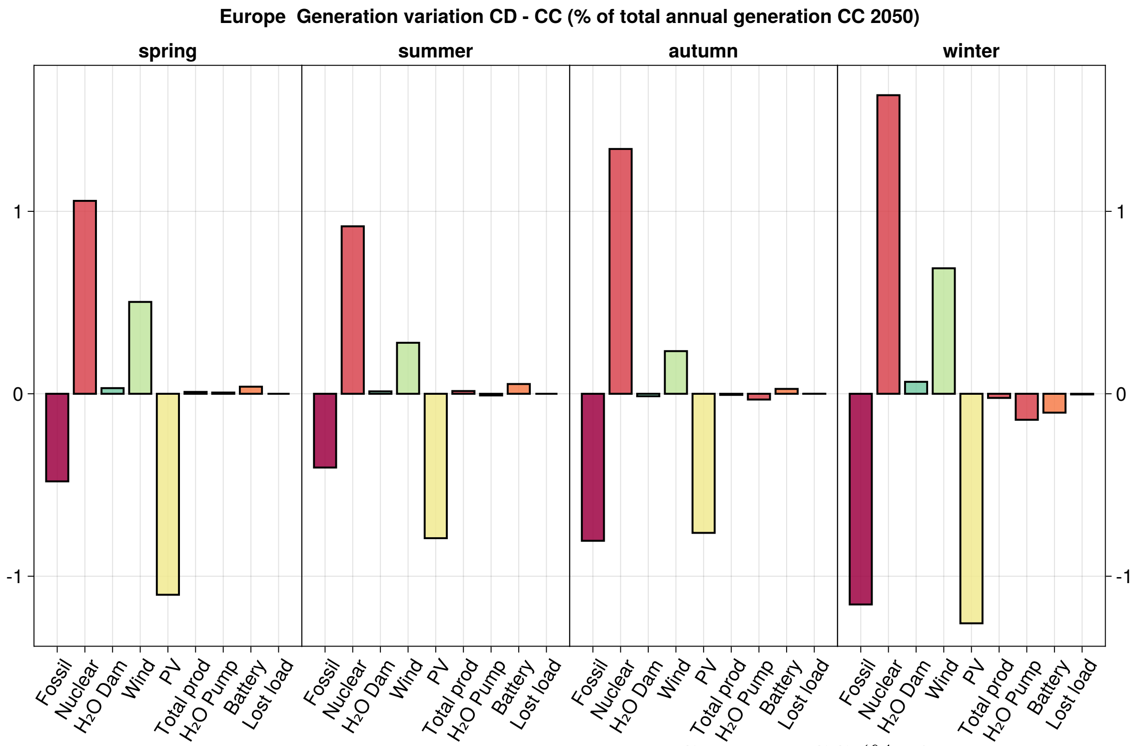


Figure 5.9: Energy generation deviation per season in case CD w.r.t. CC (% of total energy generated in Europe in case CC in year 205)

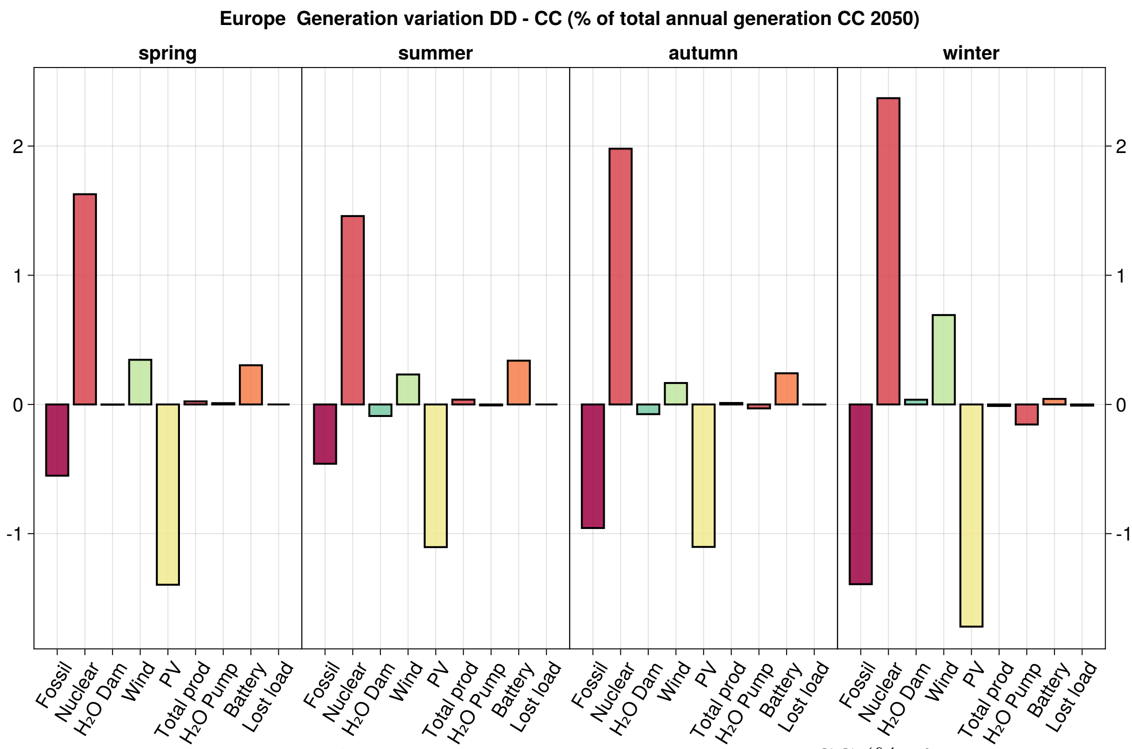
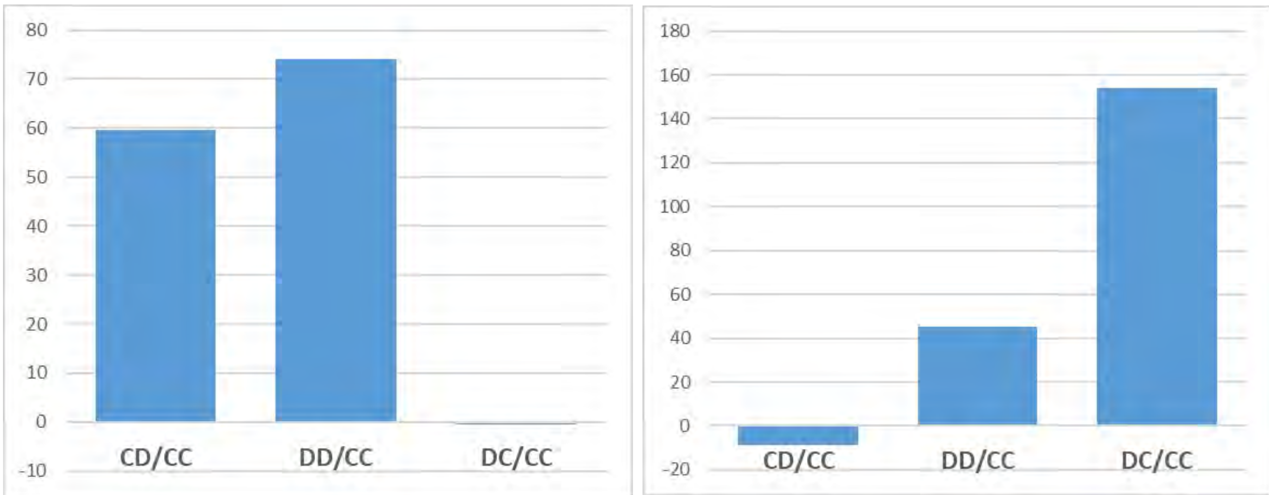


Figure 5.10: Energy generation deviation per season in case DD w.r.t. CC (% of total energy generated in Europe in case CC in year 205)

Costs

Figure 5.11 shows the difference in percentage from the full centralized case CC, for investment and operation costs. The operation costs reported on Figure 5.11 include the variable cost of technologies generating energy as well as the 'cost' of water turbined by dams (as computed with the seasonal valuation layer of plan4EU).



Investment Cost

Operation Cost

Figure 5.11: Yearly investment and operation costs variation, compared to the CC case (%)

We can see that the more decentralized the system is, the more costly investments are. More precisely, it seems that decentralizing the *decarbonization* target has much more impact than decentralizing decisions on investment costs which represent the most significant part of the total costs. Besides, on Figure 5.12 we have reported for each considered country, the averaged variation of operational costs obtained in each variant CD, DC, DD and CC for year 2050. We can observe that operation costs are much higher in the cases with decentralized decision process. Indeed, the extreme DC and DD cases have much less *decarbonized* energy and must then rely on thermal technologies (inducing high operation costs) to fulfill their equilibrium. On the other hand, the case with centralized decisions and decentralized targets (CD) has the lowest operation costs, which is obviously explained by the fact that the mix includes a higher renewable share (inducing low operation cost), as decentralization forced countries with a low *decarbonization* rate to increase it much more than in the centralized option.

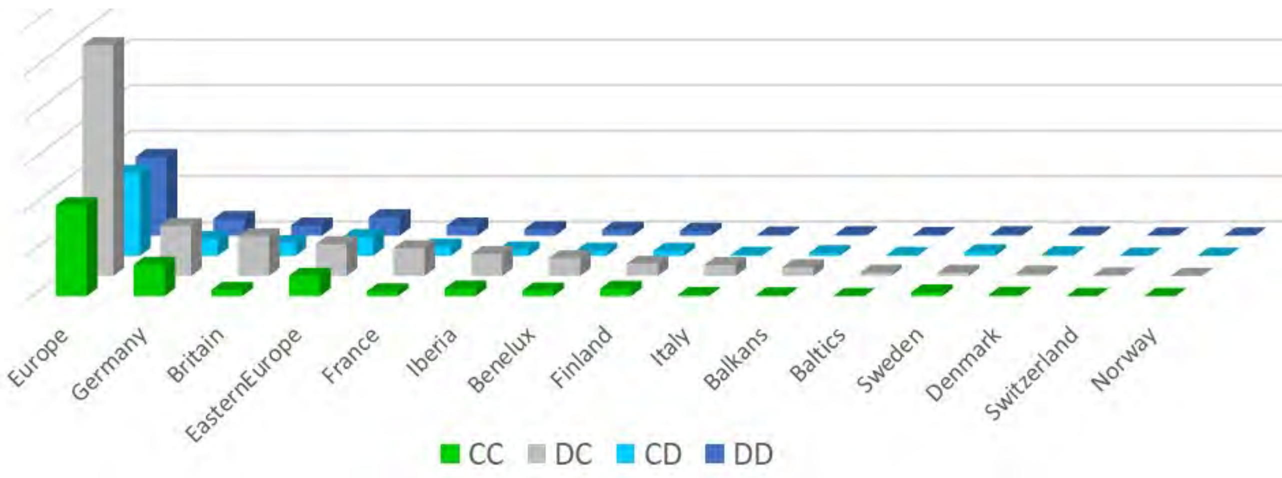


Figure 5.12: Operation costs per countries

Marginal costs

For each of the variants, we have computed the mean marginal cost over all uncertainty scenarios and all hours of the year 2050, for all countries. Figure 5.13 shows the deviation between the fully centralised variant and the others. We can see that the marginal costs decrease in the decentralised targets cases, for regions with lowest initial decarbonised shares, and increase for other regions - apart from Norway for which marginal costs are very close to zero in all cases -. This can be obviously explained by the fact that decentralised targets force those countries to have higher decarbonised share in their generation mix. On the contrary, the countries with initial higher decarbonised shares invest less in the case of decentralised targets than with a centralised one.

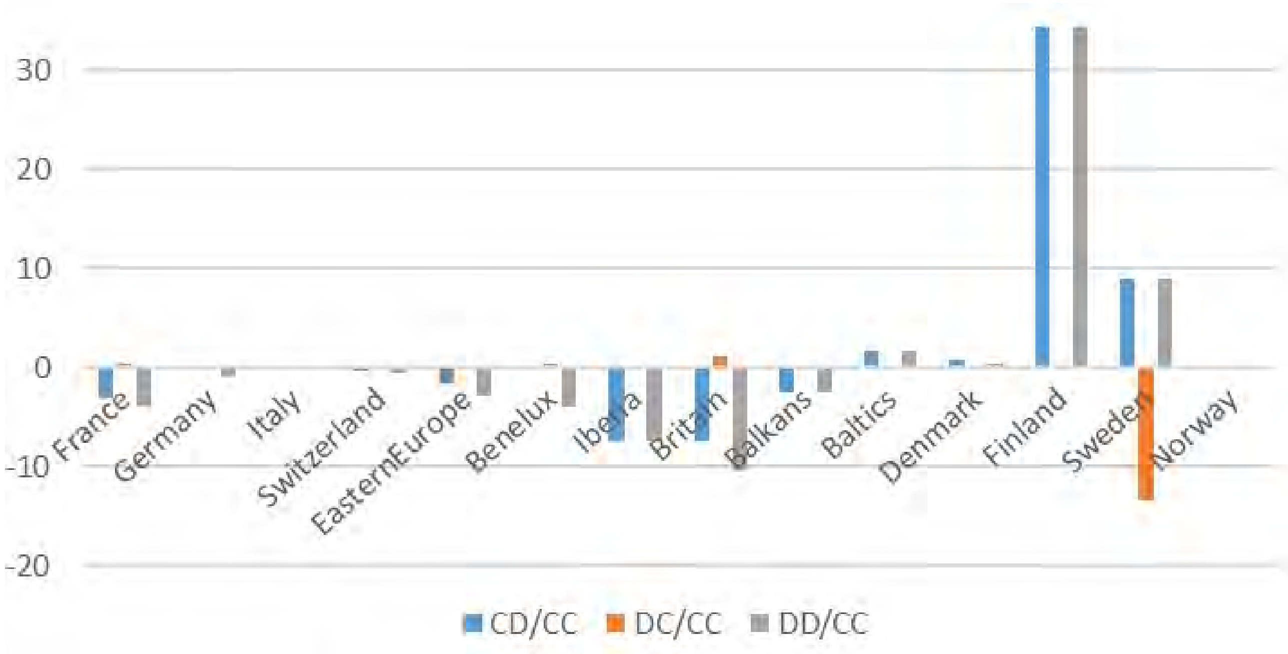


Figure 5.13: Mean marginal costs per countries, deviation compared to CC case

Flows

The following Figure 5.14 shows the flows between regions, depending on the variant considered.

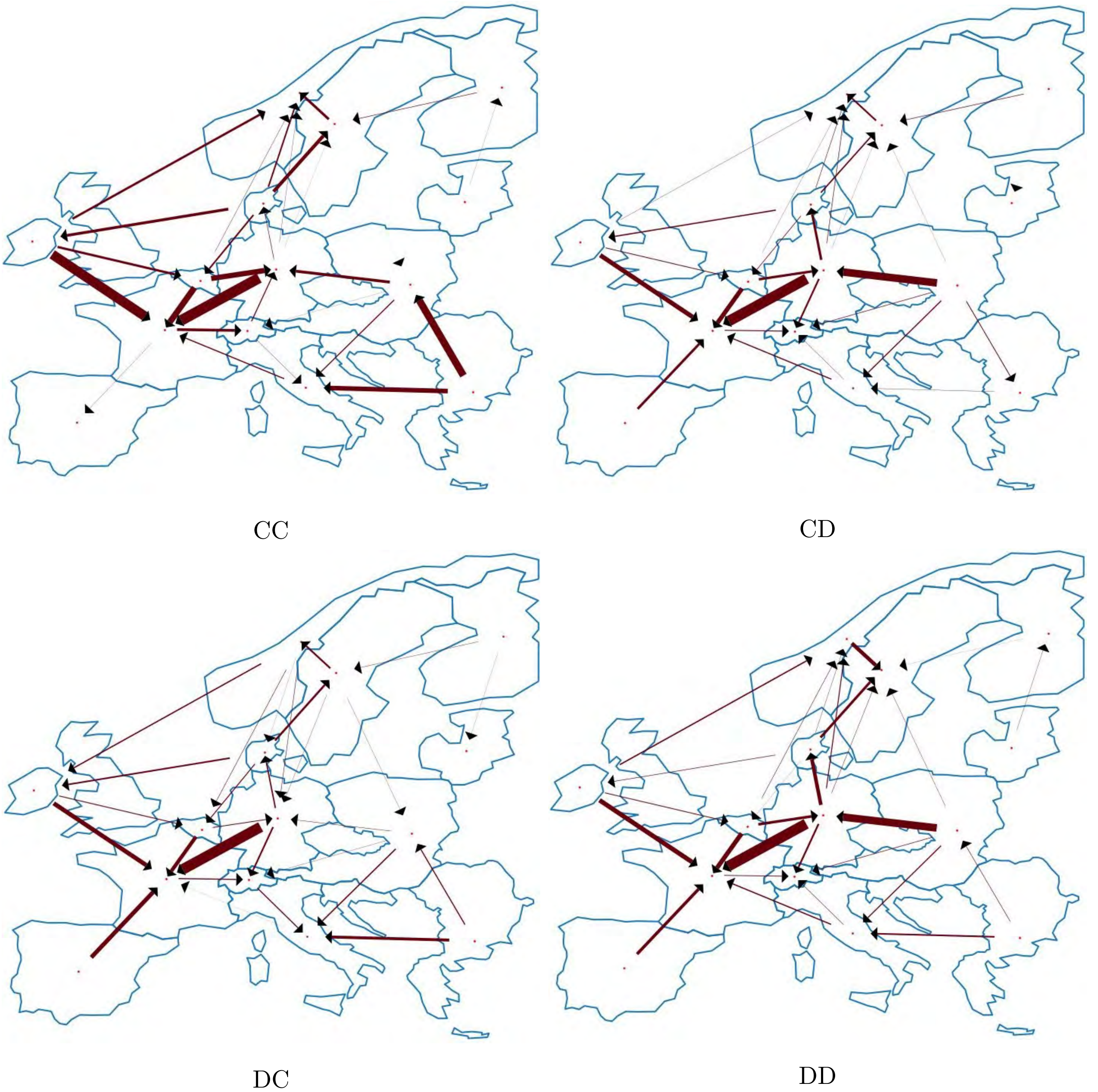


Figure 5.14: Flows between regions depending on variants - the thicker the arrow is, the bigger the flow is

Decarbonized **shares**

The share of *decarbonized* installed capacity in the generation mix with a $\rho = 70\%$ target on the available yearly energy is shown in Figure 5.15. Here we also included the REF case, which is corresponding to the adapted mix from Open ENTRANCE technofriendlyV2 scenario (see 5.5.1). Figure 5.16 shows the corresponding shares in terms of yearly available *decarbonized* energy (which is not the *decarbonized* energy generated but the energy which could be generated if all *decarbonized* assets were producing at maximum level).

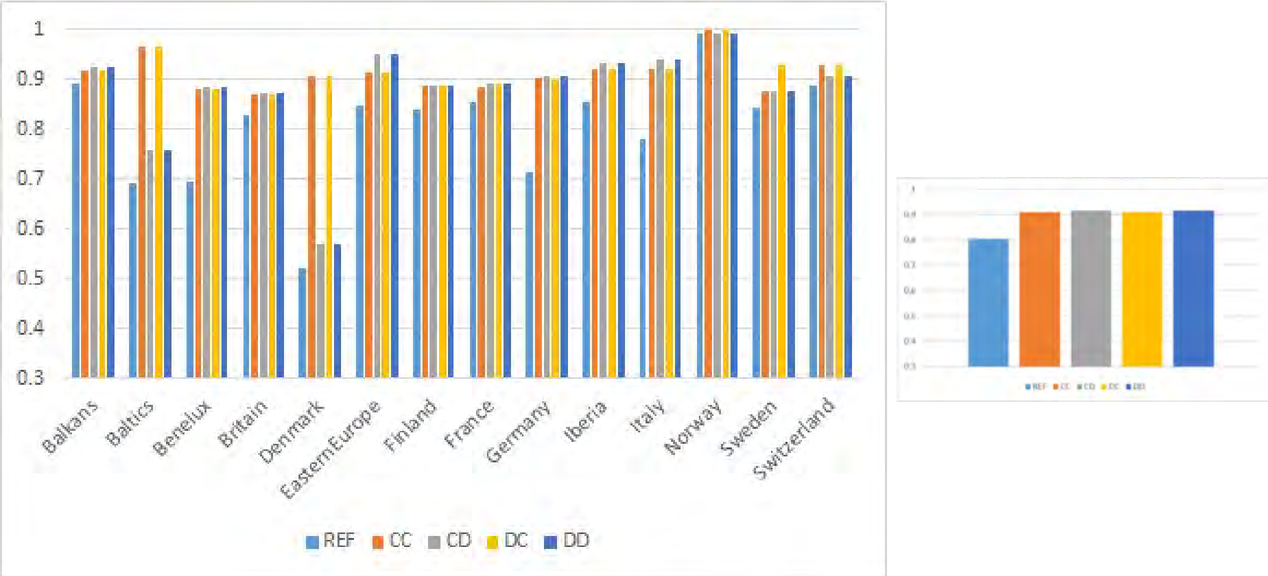


Figure 5.15: *Decarbonized* installed capacity shares in centralized/decentralized variants

Figure 5.16 shows the corresponding shares in terms of yearly energy.

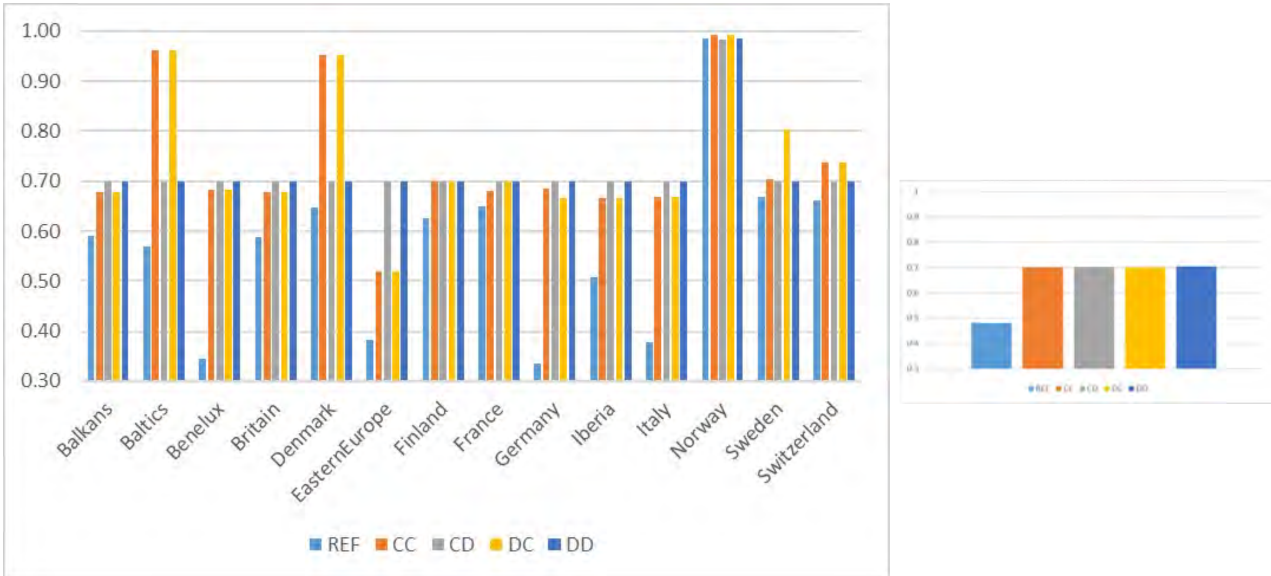


Figure 5.16: Yearly *decarbonized* available energy share in centralized/decentralized variants

We can note that:

- In the fully centralized (CC) case, with a global target of 70% *decarbonized* available energy, the shares of *decarbonized* available energy per country are highly dependent of the initial situation of each country as well as of the potential of each country.
- the *decarbonized* shares in terms of installed capacity are very different from the shares of available *decarbonized* energy, this because of the existence of load profiles for renewable energy (eg PV produces 0 at night).
- As expected in decentralized targets cases (CD and DD) the energy target is fulfilled for each country while it may not be fulfilled for some countries in cases CC and DC.

- Some regions are investing massively in *decarbonized* energy, even if they do not need it, because this is required to fullfull the centralised targets and bounds are reached in other regions which may have been able to use this energy. This is a limitation of the approach.

5.5.3 Optimised targets per countries

Exploiting the results in terms of *decarbonized* energy shares, we have ran a fifth variant, which corresponds to the fully decentralized case DD, but in which the targets ρ^z are differentiated per country z, and are exactly the *decarbonized* available energy shares of each country obtained in the fully centralized case CC (see Figure 5.16).
Figure 5.17 shows the investment costs per country and at European level in all 5 variants, including the new one, which we name DDTargetCC.

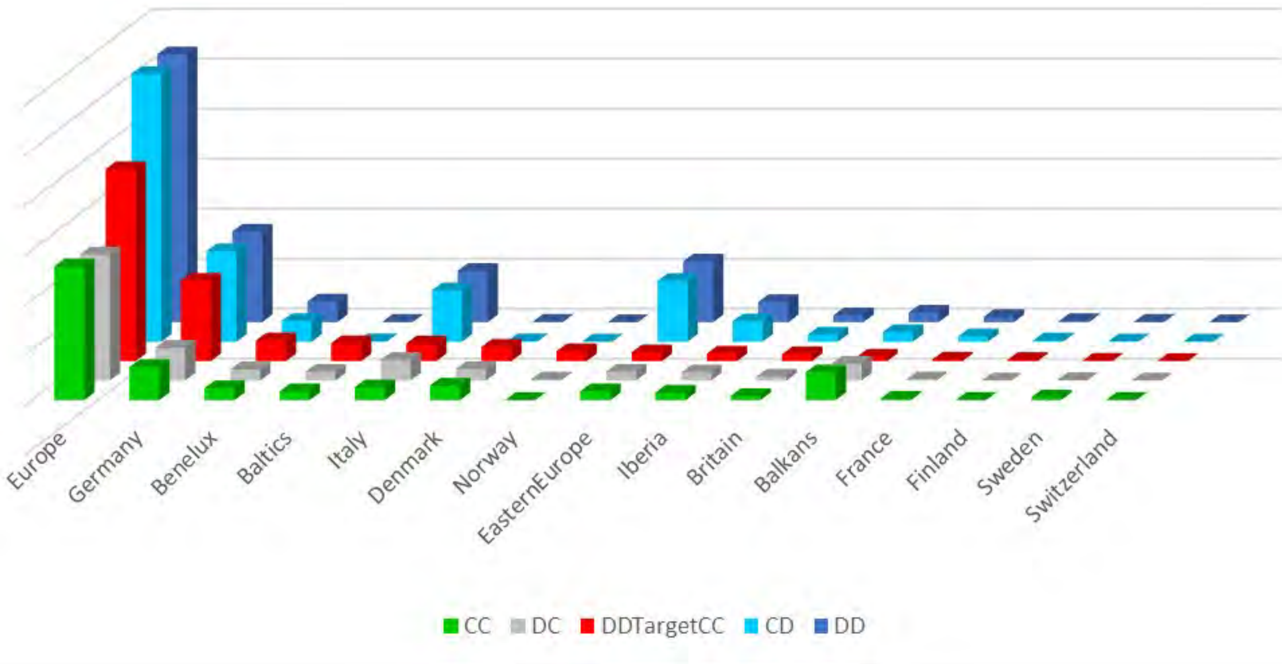


Figure 5.17: Investment costs in all variants

We can see that the investment cost within this fully decentralized variant with targets obtained from the fully centralized case are very close (of course still slightly higher) to the investment costs within centralized schemes. Note that if we set the individual targets ρ^z to the value obtained in the DC case the resulting variant DDTargetDC would of course coincide with the DC variant.
Figure 5.18 shows the variable costs per country and at European level in all 5 variants.

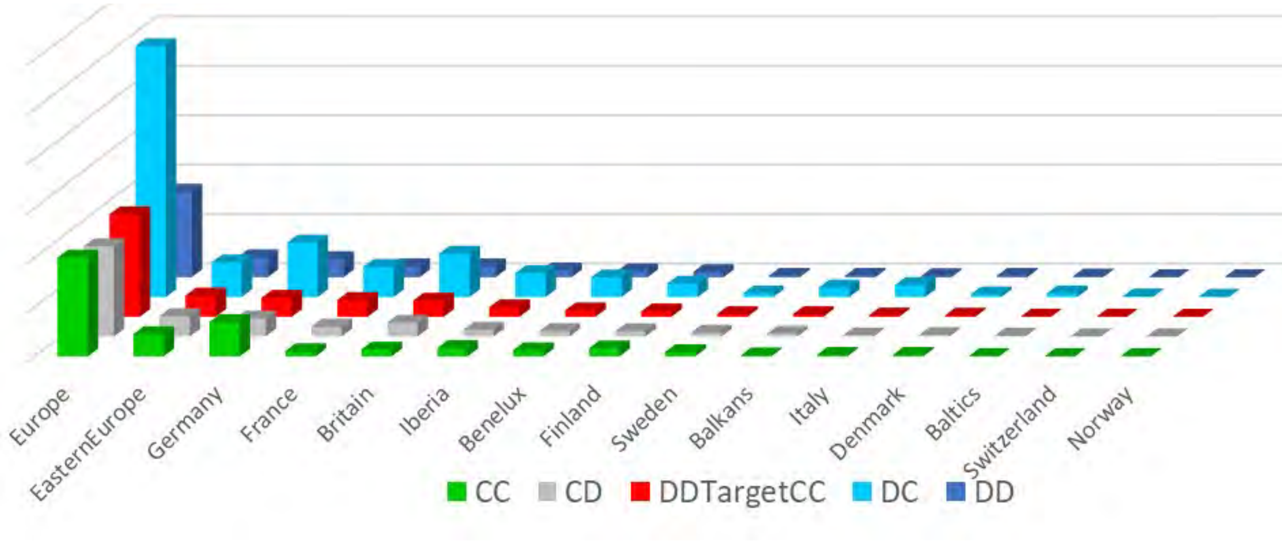
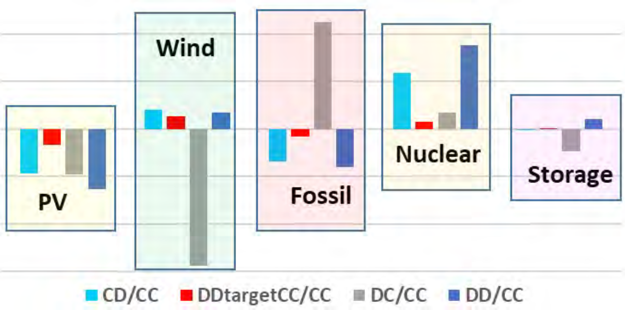


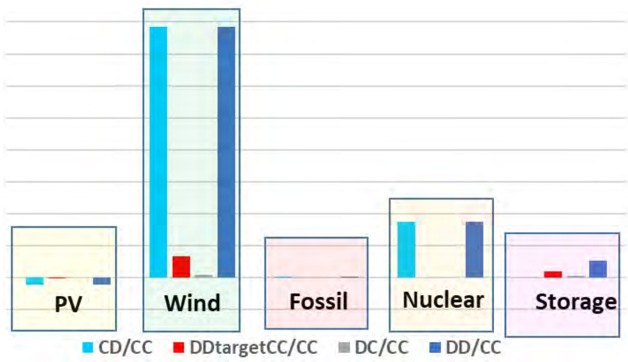
Figure 5.18: Operation costs in all variants

We can see that the variable cost within this fully decentralized variant with targets obtained from the fully centralized case are much higher as the variable costs within centralized schemes, but slightly lower than those with decentralised scheme.

Figure 5.19 shows the deviations from the fully centralised case (CC) in terms of installed capacity and yearly energy.



Generation deviation in %



Installed Capacity deviation in %

Figure 5.19: Yearly generation and installed capacity variation, compared to the CC case (%)

We understand that the operation cost deviation is due to increased use of thermal generation in all decentralised cases.

5.6 Conclusion and perspective

This study on the decentralization of investment decisions shows that decentralizing *decarbonization* targets or even decentralizing decisions (by letting each actor make arbitrary assumptions on its exchanges with others) induces significant additional costs on the power system, which impact both investment costs and operational costs. When *decarbonization* targets are roughly decentralized by country (by requiring the same target share $\rho = 70\%$ to all countries), we lose the exploitation of the fact that the installation and generation potentials of renewable energies are not equally distributed over European countries. This leads to a significant increase in the investment costs to reach the

decarbonization target. When investment decisions are decentralized, (considering the extreme case where decisions are taken assuming no exchange with neighbors), then we lose the potential offered by the grid in the balancing. Hence, investment costs are increased with in particular an increase in the share of thermal power plants (gas and coal). This decentralization of decisions then also leads to an increase in operational costs due to the use of thermal plants.
Nevertheless, we show that it is possible to obtain quite efficient decentralized decisions (i.e. inducing a reasonable increase of system costs w.r.t. the fully centralized case) by requiring to each country a specific *decarbonization* target consistent with its own potentials (of RES installation and generation and exchange with other countries). In particular, a reasonable option seems to choose for each country as a specific *decarbonization* target the share of *decarbonized* energy effectively obtained when implementing the "fully centralized" strategy.
Hence this study opens the way to the proposal of some organization schemes in order to coordinate efficiently the decarbonization of the electrical system at the European level.

5.7 Limitations and future extensions

The main limitations of the case study are listed below

- Modelling the power system only without a fully multi-energy and inter-sectoral approach;
- Assumptions considered on renewable energies investment potentials for each country in 2050 are questionable;
- The choice of the reference generation mix has a strong impact on the results and could be modified (for instance choosing the actual mix in 2023 could yield different though interesting results);
- Modelling the power system on a single year operation (2050 horizon), without providing any pathway to reach the final electricity mix;
- Aggregation of hydro generation (one reservoir by country/region, no detailed representation of hydro valleys);
- the transmission network is aggregated without AC or DC optimal power flow and no model of the distribution grid;
- Operation costs related to the transmission network are neglected;
- Ancillary services, system inertia or transient stability are not modelled.

5.8 References

[1] Hans Auer, Pedro Crespo del Granado, Daniel Huppmann, Pao-yu Oei, Karlo Hainsch, Konstantin Löffler, Thorsten Burandt, Philipp Härtel, Felix Frischmuth, and Ingeborg Graabak. Quantitative scenarios for low carbon futures of the pan-european energy system. *Zenodo*, https://doi.org/10.5281/zenodo.5521160, 2020.

[2] T. Bacci, A. Frangioni, and C. Gentile. Lagrangian methods and dynamic programming based mip formulations for the unit commitment problem. *Optimization Techniques – Theory and Practice*, 2023. under submission.

[3] T. Bacci, A. Frangioni, C. Gentile, and K. Tavlaridis-Gyparakis. New minlp formulations for the unit commitment problem with ramping constraints. *Operations Research*, 2023. under submission.

[4] Patrick R Brown and Audun Botterud. The value of inter-regional coordination and transmission in decarbonizing the us electricity system. *Joule*, 5(1):115–134, 2021.

[5] Sandrine Charousset-Brignol, Wim van Ackooij, Dominique Daniel Nadia Oudjane, Slimane Noceir, Utz-Uwe Haus, Alfio Lazzaro, Antonio Frangioni, Rafael Lobato, Ali Ghezelsoflu, Niccolò Iardella, Laura Galli, Enrico Gorgone, Mauro dell'Amico, Spyros Giannelos, Goran Strbac Alex Moreira, Stefan Borozan, Paula Falugi, Danny Pudjianto, Lothar Wyrwoll, Carlo Schmitt, Marco Franken, Daniel Beulertz, Henrik Schwaeppe, Dieter Most, Inci Yüksel-Ergün, and Janina Zittel ana Thorsten Koch. Synergistic approach of multi-energy models for a european optimal energy system management tool. *The Project Repository Journal*, 9:113–119, 2021.

[6] Beulertz D., Charousset S., Giannelos S. Most D., and Yueksel-Erguen I. Development of a modular framework for future energy system analysis. *UPEC*, 2019.

[7] Beulertz Daniel, Franken Marko, Oudjane Nadia, van Ackooij Wim, Konstaltelos ioannis Schweiger Jonas, Djapic Pedrag, and Pudjianto Danny. plan4res deliverable 3.1: Description of model interconnections. 2020.

[8] A. Frangioni. Standard bundle methods: Untrusted models and duality. *Numerical Nonsmooth Optimization: State of the Art Algorithms*, pages 61–116, 2020.

[9] Dieter Most, Spyros Giannelos, Inci Yueksel-Erguen, Daniel Beulertz, Sandrine Charousset-Brignol Utz-Uwe Haus, and Antonio Frangioni. A novel modular optimization framework for modelling investment and operation of energy systems at european level. *ZIB Report*, 20(08), 2020.

[10] Tim Tröndle, Johan Lilliestam, Stefano Marelli, and Stefan Pfenninger. Trade-offs between geographic scale, cost, and infrastructure requirements for fully renewable electricity in europe. *Joule*, 4(9):1929–1948, 2020.

[11] W. van Ackooij and A. Frangioni. Incremental bundle methods using upper models. *SIAM Journal on Optimization*, 28(1):379—-410, 2018.

[12] W. van Ackooij, I. Danti Lopez, A. Frangioni, F. Lacalandra, and M. Tahanan. Large-scale unit commitment under uncertainty: an updated literature survey. *Annals of Operations Research*, 271(1):11–95, 2018.

Chapter 6

Case Study 6: Innovative technologies

Abstract

This case study aims at increasing the understanding of an innovative technology the use of is still limited in local energy systems. This innovative technology is the seasonal storage of heat, in particular, in underground boreholes. Such technologies would allow for a better utilization of excess heat, for instance from waste incineration in the summer that is otherwise lost. In addition, in the context of Norway, where the heating system is highly electrified, or other countries where the energy transition leads to an increased electrification of heating, seasonal thermal storage could reduce constraints on the electric grid and allow to reduce or delay investments, as well as provide additional flexibility to the system.

We consider this technology in Furuset, a neighborhood of Oslo, Norway, which is planned to be further developed with additional residential and commercial buildings towards 2050. The energy system of this neighborhood is modeled in the Integrate model, an optimization based tool allowing to carry out techno-economic analysis of the design and planning of multi-energy systems. We compare three alternatives for the energy system, direct electric heating, a connection to the nearest existing district heating network and a seasonal thermal storage in addition to the connection to the district heating network.

This modeling framework has limitations. We only model a single area in a particular context, limiting somewhat the scope of the results. The modeling framework also does not allow for a very detailed modeling of the seasonal thermal storage, in part due to the use of representative periods.

The results show some potential for the technology depending on the context. Generally, connecting to an existing district heating network is sufficient to reduce electricity peak demands in the winter. However, the seasonal thermal storage allows to increase the utilization of waste heat and reduce emissions by replacing other peaking units in the district heating network. It does not impact future investment in grid capacity in an area such as Furuset, with ample overhead capacity, but it can delay or reduce the need for grid investment in more constrained grids. Finally, it allows to hedge against high variability in electricity prices for only a small increase in cost (3% annuity increase) as higher electricity prices increase considerably the profitability of this technology.

Such techno-economic analysis should be replicated in the context of different countries and different cities to increase the understanding of the potential of this technology. A similar study

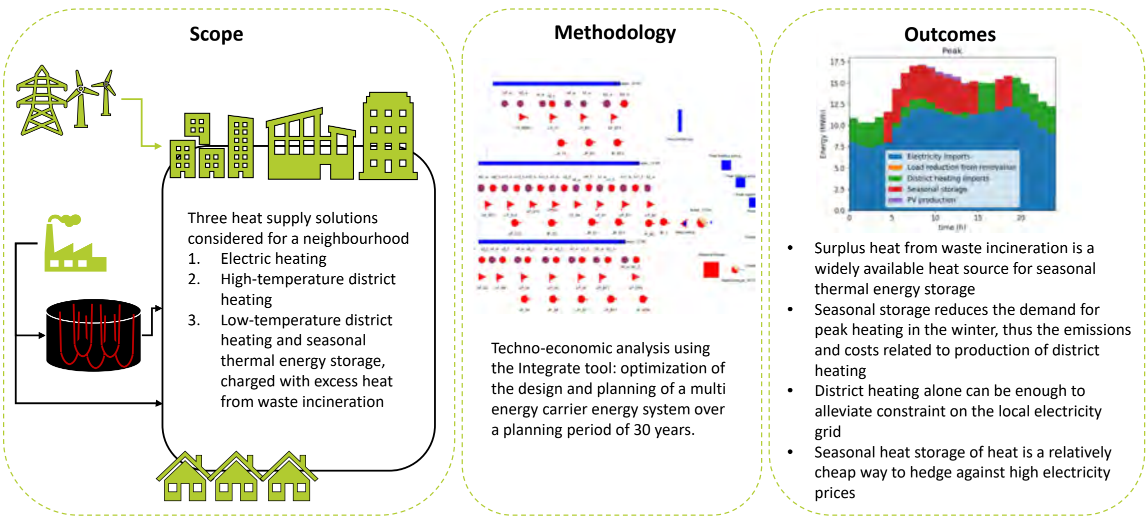


Figure 6.1: Graphical abstract of the case study

Contents

6.1 Introduction

6.1.1 Overall objective of case study

The main objective of this case study is to investigate and develop a better understanding of the potential of seasonal storage of heat in a local micro energy system. This case study aims to quantify how seasonal heat storage can reduce the surplus heat in the district heating system as well as from solar heating during summer. Furthermore, it seeks to quantify the potential of thermal seasonal storage to cover peak loads in heat demand during winter and thereby reduce the need for investment in heating infrastructure, both for the current and the future system. The case study will also include a cost/benefit analysis for the application of the uncommon storage technology as well as offer insight on how this technology can be relevant on a European level. This will be done through a qualitative discussion of the relevance of the results on the European level. The case study will also identify drivers as well as barriers for investment into this novel heat storage technology. In particular, the case study will focus on the district Furuset in Oslo and evaluate the innovative technology of seasonal storage in underground rocks in this particular setting. The interactions between the district heating (DH) system of the city of Oslo and the local heating grid will be investigated with hindsight to the impacts especially on the energy system at Furuset. In the light of Europe's ambition to decarbonize its energy system, ever more intermittent energy sources will penetrate the energy market. It is likely that in many parts of Europe there will be an excess of energy supply during periods in the summer months from both solar and wind power[1, 2, 3, 4]. Short term storage challenges might well be solved by the deployment of batteries on a large scale but for seasonal storage other technologies will be needed. With pumped storage being very limited to specific geographical conditions and hydrogen production and storage facing efficiency issues, there is a clear need to assess other options. The results of this case study will give qualitative insights into what role local, seasonal heat storage can play on a pan-European scale in the transition to a decarbonized energy system. It will furthermore inform the Norwegian national research centre on zero emission neighbourhoods in smart cities (ZEN), as well as the government in Oslo on the potential and benefits of seasonal thermal storage in connection with local energy system solutions across the country. The model that will be used for the analysis is the energy investment model Integrate (formerly eTransport) [5, 6]. A representation of the micro energy system of Furuset, created in the ZEN centre will be adapted to incorporate a module to represent the planned seasonal thermal energy storage unit [7]. This adapted version will serve as the baseline scenario and will be compared to a micro energy system without such a storage unit.

6.1.2 State of the art

Energy storage solutions are not limited to batteries. Thermal energy storages (TES) also have an important role to play in providing flexibility and helping incorporate a larger share of renewable energy sources (RES) in the power system. In addition, they can be less costly and more efficient than batteries [8]. An important challenge for integrating RES in the energy system is the mismatch between the RES availability and energy demand on a seasonal level. Seasonal Thermal Energy Storage (STES) has a great potential in enabling the storage of heat produced in the summer for use in the winter. Various STES designs exist, using aquifers, boreholes, tanks or pits [9]. Each technologies has its set of advantages and drawbacks, for example specific geological conditions. Borehole thermal energy storage is scalable and has fewer geological constraints than some of the other technologies and is a good solution for supplying neighborhoods and communities.

Boreholes STES already exist in neighborhood applications [9, 10, 11], often in combination with solar thermal collectors or PV panels. This increases the investment cost of the system and can reduce the profitability of the investment [12]. An other source of heat for the STES can be from municipal waste incineration, which is a common heat source in DH systems in the Nordics, covering 20 % of the heat supply for DH systems in Sweden [13] and Denmark [14], 14 % in Finland [15], and 48 % in

Norway [16]. This source of heat is quite consistent due to the constant flow of waste. On the other hand, heat demand is highly seasonal. STES is thus a good candidate to make use of large quantities of heat that is otherwise wasted. This can also replace more costly and carbon-intensive sources in the winter. An emission reduction potential of 86 % was estimated in a study of borehole STES for a new residential area in Finland [17].

Energy system modeling is an important tool for improving the design and performance of urban energy systems with multiple energy sources, and a wide range of tools and approaches exist for this purpose [18]. [19] have applied a techno-economic optimization tool to study the optimal location, size and operation of TES in a DH system, but have not considered STES. Some models, as in [20] and [21], include STES for district system planning but focus exclusively on the heating system. It is difficult to balance model complexity (and solution time) and modelling details. Trade-offs have to be made between the level of details of the technologies representation, spatial and temporal representation, and the number of technologies considered, for instance. Some models use a multi-layer representation of the heat storage such as [22] and [23] while others have a single layer. The temporal resolution also varies with a common solution being the use of representative periods (days/weeks) within a year. This complicates storage modelling as the time periods are no longer continuous. An approach to modelling storage despite the loss of continuity between time-periods is proposed by [24].

6.2 Short summary of models used

The Integrate model [5] is an optimization model for the planning of local energy systems where different energy carriers and their interaction are considered. The model considers investments in the infrastructure related to those energy carriers and for conversion between them. Some of the main energy carriers include: electricity, district heating, cooling, hydrogen, waste and biomass. The model minimizes cost for investing and operating the energy system and also considers the environmental consequences. It combines mixed integer linear programs for the operational optimizations and a dynamic programming (DP) for the investment planning. Representative periods are used for the operation, while the investment planning spans across longer periods of several years. The DP approach allows the model to consider the best timing of investment. The model provides the optimal solution and a user defined number of near-optimal solutions.

6.3 Assumptions

The Integrate model considers the local energy system in Furuset and takes a central planner perspective. It does not model the interest of the different actors inside the neighborhood. The model considers socio-economic costs that do not necessarily correspond to cost seen by consumers. For instance the cost of the heat from the district heating is a marginal cost based on fuel costs and efficiencies and not the cost consumer would see, which is a regulated cost, with taxes and tariffs.

We consider the Societal Commitment and Techno-Friendly storylines of the OpenENTRANCE scenario pathways[1]. The main differences in the storylines for our modelling are in the amount of residential-scale PV in NO1, the bidding zone where Furuset is located, which we scale to the area we study. The Techno-Friendly storyline does not see any investment in residential PV while Societal Commitment does. We thus refer to the cases as PV for Societal-Commitment and ~~PV~~ for the Techno-Friendly storyline.

The assumptions related to input data are presented in Section 6.5.

6.4 Methodology

[1] https://openentrance.eu/2022/07/06/quantitative-scenarios-for-low-carbon-futures-of-the-european-energy-system

6.4.1 Overall methodology

The structure of the model is represented in Figure 6.2. The existing energy system is represented in the model as the starting point. Possible investments to the energy system are also added and conditions on their investment can be specified. For example, one can specify that a technology can become available only if another has previously been installed. An optimization of the operation of the energy system is then conducted for all possible energy system configurations (base system and combinations of possible investments) for all periods. The minimum cost of each alternative is then used in the DP algorithm to find the optimal pathway as well as near optimal ones.

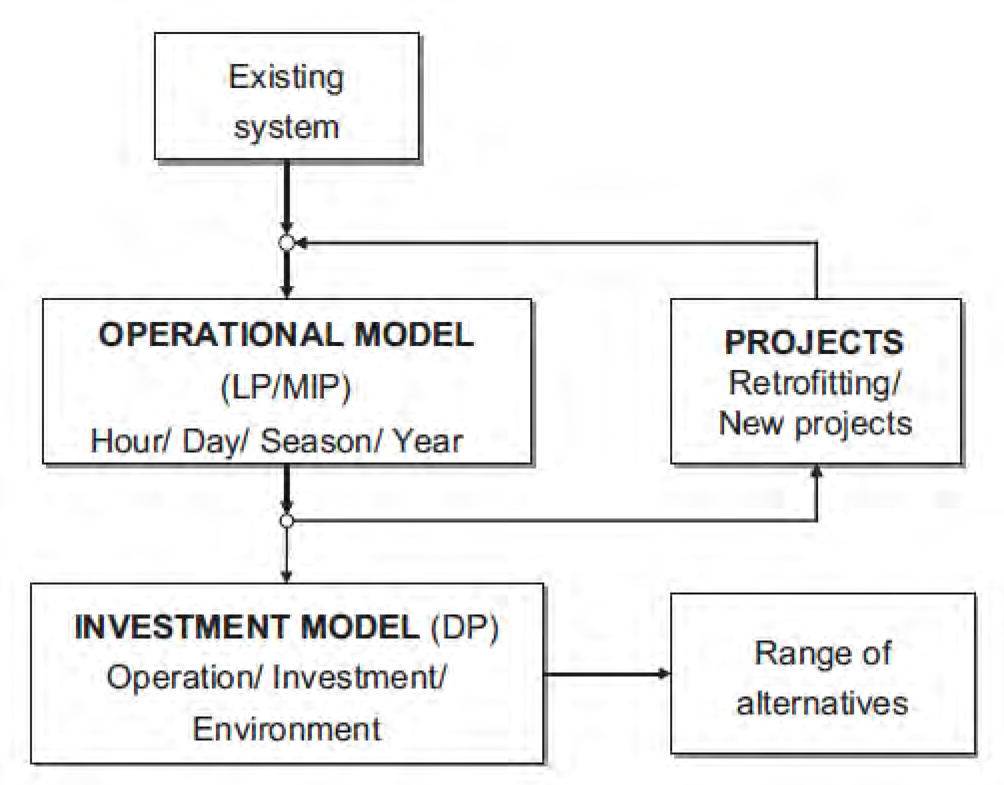


Figure 6.2: Schematic structure of the Integrate Model

We consider the existing energy system of Furuset. The energy needs of the existing buildings are estimated based on their floor area and the type of the buildings. A significant number of new buildings are expected in this area, consisting of both residential and commercial, and the expected energy needs of these buildings are also estimated.

The following model description is taken from [25].

Description of the operational optimization

The operational model presented in this section corresponds to the case investigated in the present study. The operational optimization is performed for a selected number of representative days in a year with hourly resolution. The optimization is carried out in the first stage for all the possible combinations of technologies and for all investment periods. Many of the modules available in Integrate were not used in this study, and their contributions to the objective function and constraints are thus not presented here. With the modules used in our case study, the objective function is:

$$min\ c^{ope}_{S_\pi,\pi} = \sum_{\xi} \sigma_\xi \Bigg(\sum_{t_\xi} \Big(P^{el}_{t_\xi} \cdot y^{el,imp}_{t_\xi} + \sum_{b} \Big(P^{el,def}_{t_\xi,b} \cdot y^{el,def}_{t_\xi,b} + P^{DH,imp}_{t_\xi} \cdot q^{DH,imp}_{t_\xi,b}$$

$$+ P^{SH,def}_{t_\xi} \cdot q^{SH,def}_{t_\xi,b} + P^{DHW,def}_{t_\xi} \cdot q^{DHW,def}_{t_\xi,b} \Big) + C^{DH}_{\xi} \Big) \Bigg) \tag{6.1}$$

where S_π are identifiers for the possible combinations of investment options (system states) in period π and $c^{ope}_{S_\pi,\pi}$ is the operational cost of the given state in the given period. Each period has several segments ξ, corresponding in our case to seasons, and several time steps t_ξ within each segment. $P^{el}_{t_\xi}$ and $y^{el,imp}_{t_\xi}$ are respectively the cost and amount of electricity imports; $P^{el,def}_{t_\xi}$, $y^{el,def}_{t_\xi,b}$ the penalty cost and amount of deficit of electricity in building b. Similarly, $P^{DH,imp}_{t_\xi}$ and $q^{DH,imp}_{t_\xi,b}$ are the cost and amount of DH imports, and $P^{SH,def}_{t_\xi}$, $q^{SH,def}_{t_\xi}$, $P^{DHW,def}_{t_\xi}$ and $q^{DHW,def}_{t_\xi,b}$ are the penalty cost and amount of deficit for space heating (SH) and domestic hot water (DHW). C^{DH}_{ξ} are the penalty costs associated with the district heating grid, presented in section 6.4.1.

Each building is represented by its electrical, SH and DHW load and its load balance: $\forall b \in \mathcal{B}, \forall t_\xi$

$$y^{el,imp}_{t_\xi,b} + y^{el,def}_{t_\xi,b} = L^{el}_{t_\xi,b} \tag{6.2}$$

$$y^{SH,imp}_{t_\xi,b} + y^{SH,def}_{t_\xi,b} = L^{SH}_{t_\xi,b} \tag{6.3}$$

$$y^{DHW,imp}_{t_\xi,b} + y^{DHW,def}_{t_\xi,b} = L^{DHW}_{t_\xi,b} \tag{6.4}$$

In addition to the energy balances of the loads, each component of the network within the modeled area has an energy balance as well. Those balances represent the flow of energy within and in between the networks (and their components).

The import of electricity and DH are limited: $\forall t_\xi$

$$y^{el,imp}_{t_\xi} \leq Y^{max}_{t_\xi} \tag{6.5}$$

$$q^{heat,imp}_{t_\xi} \leq Q^{max}_{t_\xi} \tag{6.6}$$

where $Y^{max}_{t_\xi}$ is the maximum electricity import from the grid and $Q^{max}_{t_\xi}$ the maximum heat import. In our case, the investment in a larger transformer is an investment option, so the maximum electricity import will be different in the operational optimizations for the different system states needed in the investment layer.

Description of the investment optimization

The investment part finds the optimal investment plan based on the available options' investment costs and the operating costs of all the combinations of technologies resulting from the operational optimization. The number of possible combinations increases exponentially with each additional investment option. In order to limit this number, different investment logics can be defined:

- **Mutually exclusive alternatives:** the default investment logic; two investment alternatives are mutually exclusive, i.e. only one of them can be chosen at a time.
- **Time window for investments:** defines the periods in which a given alternative can be chosen.
- **Dependent alternatives:** some alternatives require another alternative to be invested in during the same or a previous period.

- **Necessary alternatives:** a set of investment alternatives where at least one of the alternatives must be carried out within a specified year. Several sets for necessary alternatives can be defined for each year.

The objective of the DP is minimizing the discounted present value of all costs, minus the scrap value of new investments. For all investment periods π except the last one we have:

$$C^*_\pi(S_\pi) = min\left\{\delta^{\pi-\Pi_{start}}\left(\sum_{\tau\in\{1,...,\Pi_{step}\}}\delta^{\tau-1}c^{ope}_{S_\pi,\pi} + \sum_{d\in D}c^{inv}_d I_{d\pi}\right) + C^*_{\pi+1}(S_{\pi+1})\right\} \tag{6.7}$$

where the investment periods are defined by a starting year Π_{start}, end year Π_{end} and a number of years in each period Π_{step}. C^*_π is the minimum net present value in period π. δ is the annual discount factor defined as $\frac{1}{1+r}$, where r is the rate of return. c^{inv}_d is the investment cost of investment option d, $I_{d\pi}$ is a binary parameter which identifies if the investment is performed in the given period and system state.

In the last investment period, we need to account for the residual values of the investments ϕ:

$$C^*_\pi(S_\pi) = min\left\{\delta^{\pi-\Pi_{start}}\left(\sum_{\tau\in\{1,...,\Pi_{step}\}}\delta^{\tau-1}c^{ope}_{S_\pi,\pi} + \sum_{d\in D}c^{inv}_d I_{d\pi}\right)\right.$$
$$\left. - \delta^{\Pi_{end}+\Pi_{step}-\Pi_{start}}\phi + C^*_{\pi+1}(S_{\pi+1})\right\} \tag{6.8}$$

In addition, for the possible combinations of investment options (system states) we have:

$$\phi = \sum_{\pi\in[\Pi_{start},\Pi_{end}]}\sum_{d\in D}c^{inv}_d I_{d\pi} max\left\{0; 1 - \frac{\Pi_{end}-\pi+\Pi_{step}}{\lambda_d}\right\} \tag{6.9}$$

where λ_d is the lifetime of investment option d. The residual values of the investments ϕ is calculated linearly based on the remaining lifetime

$$C^*_{\Pi_{end}+1} = 0 \tag{6.10}$$

$$S_{\Pi_{Start}} = 0 \tag{6.11}$$

The DP algorithm progresses backwards through all periods and possible system states within a period to find the optimal investment plan. Once at the starting period, the optimal investment plan is the path with the lowest net present value. Additional "sub-optimal" investment plans can be found, as many as defined by the user, by running the DP algorithm again with an additional constraint stating that the state in the last period of the investment plan with directly higher rank is infeasible.

Relevant modules

District heating module The DH module in Integrate is described in more detail in [26] and [**?**], and here only the main features are given. The DH module includes production points for heat input, junction points, and load points, as well as pipelines connecting the network points. A pipeline contains both the supply and return flow, and reversal of the flow direction is also allowed. The total heat load in the network consists of the SH and DHW loads attached to load points, and heat losses.

The objective of the DH module is to satisfy the demand with minimum heat deficit. In addition to heat deficit at production points and loads, dumping of heat at the production points is penalized. The contribution to the overall objective function is then:

$$C^{DH}_\xi = \sum_{p,t_\xi} q^{DH,dump}_{p,t_\xi}\cdot P^{DH,dump}_{p,t_\xi} + \sum_{p,t_\xi} q^{DH,def}_{p,t_\xi}\cdot P^{DH,def}_{p,t_\xi} + \sum_{b,t_\xi} q^{DH,def}_{b,t_\xi}\cdot P^{DH,def}_{b,t_\xi} \tag{6.12}$$

where $q^{DH,dump}_{p,t_\xi}$ is dumped heat, $q^{DH,def}_{p,t_\xi}$ / $q^{DH,def}_{b,t_\xi}$ is heat deficit at production/load points; and $P^{DH,dump}_{p,t_\xi}$, $P^{DH,def}_{p,t_\xi}$ and $P^{DH,def}_{b,t_\xi}$ are the corresponding penalty costs.

At the production points p, the module imports heat from the surrounding energy system and available heat sources, depending on the demand. The demand is defined by the variable q_{less} containing both the heat demand of all the load points connected to the network, as well as the heat losses. The required heat import at each production point p is summed over all the pipes connected to that point:

$$q^{heat,imp}_{t_\xi,p} = \sum_{(i,j)\in DH_{pipes} if i=p} q_{less,[i,j,"back","this",t_\xi]} \tag{6.13}$$

where "back" denotes the return line and "this" the end of the pipe closest to the production point.

The heat losses are calculated for supply flow only, and added to the q_{less} variable at the end of each pipe connecting two network points (i,j):

$$q_{less[i,j,"out","far",t_\xi]} = q_{less[i,j,"out","this",t_\xi]} + l_{pipe[i,j]} \cdot (T_{supply} - T_{ground}) \cdot k_{loss[i,j]}; \tag{6.14}$$

where "out" denotes the supply line and "this"/"far" denote the pipe ends closest/farthest away from the production point, respectively. $l_{pipe[i,j]}$ is the pipe length, T_{supply} is the supply temperature and T_{ground} the ground temperature, and $k_{loss[i,j]}$ is a heat loss factor.

The heat load $L_{t_\xi,b}$ (SH or DHW) is added to the the q_{less} variable at the far end of each pipe connected to a load point (building) b:

$$\sum_{(i,j)\in DH_{pipes}|j=b} q_{less[i,j,"back","far",t_\xi]} = \sum_{(i,j)\in DH_{pipes}|j=b} q_{less[i,j,"out","far",t_\xi]} + L_{t_\xi,b} \tag{6.15}$$

where "back" denotes the return line, and DH_{pipes} is the set of pipelines in the network. The returning flow in the pipes thus contains the accumulated heat losses from the supply pipes, as well as the requested heat load at the load points noted $L_{t_\xi,b}$.

To preserve linearity, the supply and return temperatures are set as parameters, while the volume flow of water is a variable. The supply and return temperatures are however allowed to have different values in different seasons to enable a more realistic calculation of heat losses and pumping power. The following constraint makes sure that the water flow is sufficient to cover the demand of load b, at the given supply and return temperatures:

$$q_{less[i,b,"out","far",t_\xi]} + L_{t_\xi,b} + y^{def}_{t_\xi,b} \leq C_p \cdot (T_{supply} - T_{return}) \cdot v_{i,b,t_\xi}, \tag{6.16}$$

where v is the volume flow of water in the pipe (i,b), C_p is the specific heat capacity, and T_{return} is the return temperature.

The required pumping power depends on the pressure drop at the customer substations and in pipes. Pumping power due to pressure drop in pipes has a cubic dependency on the volume flow, and to be able to represent this in Integrate, a piece-wise linear approximation using non-dimensional variables was applied, explained in detail in [26]. The pumping power is represented as an electrical load in the system, located at the the production points, representing the heat central(s) in the system.

The module does not consider the temperature levels for heat exchange at the customer substations or at the heat supply points, but only the amount of energy requested by and supplied into the network. This applies also to TES units attached to the network.

Seasonal thermal energy storage module Including the operation of seasonal energy storage in optimization models in order to study its techno-economic feasibility can be complex. Energy systems, especially systems including renewable energy sources, require at least an hourly resolution while the energy planning problem calls for a long time horizon, resulting in unreasonably long computation times. Different approaches, such as clustering have been presented to deal with this issue [24].

In Integrate, the STES is modeled by assuming a certain required amount of heat to be charged, and certain allowed amount of heat to be discharged in the different seasons, taking into account heat losses. The allowed amount of heat to be charged/discharged per representative day is thus obtained by dividing the amount of heat available per season by the number of days belonging to the season.

The daily allowed amount of heat flow to/from a storage unit s is determined by parameter $Q_{s,daily}$, which is negative for discharging and positive for charging, and given as a share of the total storage capacity $Q_{s,tot}$. The total amount of heat charged and discharged over a 24-hour period is then defined by

$$\begin{aligned} \sum_{t_\xi} \left(q_{charge,s,t_\xi} + y^{def}_{t_\xi,s} - y^{dump}_{t_\xi,s} \right) &= \max\left(0, Q_{daily,s} \cdot Q_{s,tot}\right) \\ \sum_{t_\xi} \left(q_{discharge,s,t_\xi} + y^{dump}_{t_\xi,s} \right) &\leq \max\left(0, -Q_{daily,s} \cdot Q_{s,tot}\right) \end{aligned} \tag{6.17}$$

where $y^{def}_{t_\xi,s}$ represents deficit of heat, and $y^{heat,dump}_{t_\xi,s}$ dumping of heat. q_{charge,s,t_ξ} and $q_{discharge,s,t_\xi}$ are the charging and discharging rates, respectively, with certain allowed maximum values. The storage is charged via a connection to a heat source, and discharged to a heat network or directly to a load. A more detailed description of the STES module in Integrate can be found in [7].

6.4.2 Case study workflow

In this case study, Integrate is the only tool used. There is therefore no workflow.

6.4.3 Linkages

In this case study, Integrate is the only tool used. There is therefore no linkages.

6.5 Description of datasets and how they were created

We consider the existing energy system of Furuset to model the base year and also considers different technologies for the future investment options. This requires various input data which are described in this section.

Energy Demand The energy needs of the existing buildings (Domestic Hot Water, Space Heating and Electric specific) are estimated based on their floor area and the type of the buildings. Significant developments are expected in this area, consisting of both residential and commercial buildings, and the expected energy needs of these buildings are also estimated at fixed intervals corresponding to the periods used in our Integrate modeling. The method used to estimate those loads timeseries is introduced in [27].

The data is using representative periods. In this case study we use 5 representative days at hourly resolution (4 seasons and peak) sampled from the yearly hourly data.

The other data necessary for the model is related to: the connection to the electric grid, the evolution of the electric demand related to the increasing share of electric vehicles and the investment options: PV panels, district heating (high and low temperature options) and seasonal heat storage. The existing buildings are using direct electric heating to supply their heat demands and do not require specific data.

Connection to electricity grid The connection of the electric grid to the area is set to 22.6MW based on discussion with the distribution grid operator. The electricity price is set using the spot prices in the area between 2004 and 2018, taken from Nordpool. An average year is computed and used to calculate an average day per season at hourly resolution. The grid tariff is also added but the taxes and charges are not considered. For example the part of the tariff dedicated to grid investment is left out, since the investment in additional grid capacity is included in the model. We include the possibility to upgrade the grid connection size with an extra 10MW.

District heating The neighborhood is, in the base year, not connected to the existing district heating network of Oslo. We consider the connection to the district heating as an investment option. This includes local piping network, connection to the main DH network (about 3km away) and customers substations.

Two alternatives are considered for the local DH network, a high temperature (supply temperature between 90 and 110°C depending on time of the year and return between 50 and 60°C) or a low temperature variant (supply 70°C and return of 50°C). The heat loss factor was set at 0.75 W/(mK).

The cost of the heat from DH is calculated based on the mix of generators in use throughout the year based on a dialogue with the district heating operator. The main heat generation units include waste incineration, electric boilers, heat pumps, as well as boilers using pellets, biodiesel and gas. In the summer, excess heat from waste incineration is exclusively used.

STES The STES is considered with 390 boreholes, 200 m deep, giving a total storage capacity of 13GWh. We assume 5GWh of heat losses annually. We assume the storage is charged exclusively during summer from excess heat from waste incineration. Table 6.1 shows the allowed charging and discharging of the STES per season in the base case. The maximum heat flow rate for charging/discharging was set to 4.27/4MW based on input from the DH supplier.

Table 6.1: Charge and discharge pattern of the STES per season

	Spring	Summer	Autumn	Winter	Peak
Charge(+), discharge(-) per season/day [MWh]	-500/-9.6	13 000/102.4	-1 400/-22.6	-6 050/-49.2	-50/-50.0

PV panels We considered an investment in PV panels as an option in the model. The capacity of PV in this option is set based on results from the GENeSYS-MOD in the Societal Commitment storyline and disaggregated to Furuset. This corresponds to a PV capacity of 5.5MW and an annual production of 5.26 GWh in 2050. The PV profiles are obtained from the renewables.ninja website which is based on [28, 29].

Additional load from electric vehicles The additional load coming from electric vehicles has been estimated for the different periods by considering the increasing share of electric vehicles in Norway. The total number of cars and number of electric cars in Norway in 2019 from national statistics (Statistics Norway(SSB)) is used as a starting point. The sale of internal combustion engine vehicles will be banned in Norway from 2025, so we assume a linear increasing of the sale of EVs from 2019 to 2025. This allows us to estimate the number of electric cars in Norway until 2050. We use the Norwegian population and a projection of its future evolution toward 2050 (main alternative of the national population projection from SSB) to calculate the number of electric cars per inhabitants in Norway. We then use the expected population of Furuset in different years to find the number of electric cars in the area. A charging profile from [30] is used to find the additional load profile from electric vehicles in the area. We also consider the impact of seasonal variations on the load profiles [31].

Building Retrofit We consider the option to retrofit part of the existing building stock in Furuset, corresponding to around a quarter of the building mass or 15GWh annually. This investment was estimated to reduce the annual heat demand by 9.8GWh/year (30% reduction). We assume this demand reduction is evenly distributed and the cost of renovation to be around 900€/m^2.

Investment alternatives The investment options and their cost are summarized in Table 6.2. The PV system is not considered as an investment option but separate runs are performed in a system with and without the PV. Investment in infrastructure inside the buildings (hydronic system, individual electric heaters) are not considered. We define three alternatives, investments that have to be performed. The alternatives are called: Electric heating, HTDH and LTDH. The costs related to the DH and STES system were obtained from the DH operator. For the STES, it includes the boreholes and the heat central but potential government subsidies are not considered.

Table 6.2: Investment costs and lifetimes for the different alternative technologies, and which technologies need to be invested in each heat supply solution (HTDH - high-temperature DH, LTDH - low-temperature DH). Technologies that are fixed are marked with X while technologies that are optional are marked with (X).

	Costs [M€]	**Lifetime [y]**	**Electric heating**	**HTDH**	**LTDH and STES**
New transformer	1.0	40	(X)	(X)	(X)
Local heating network	1.9	30		X	X
STES	7.2	60			X
Connection to DH network	3.9	30		X	X
Upgrading existing buildings	97	30	(X)	(X)	(X)

6.6 Results of case study

The results of the case studies have been published in [25]. The main results are summarized here.

The annuity of all cases run in this case study are summarized in Fig. 6.3 but we will go in more details into each of the runs in the rest of the section.

The annuity of each of the cost-optimal solutions for each alternatives, in the case with and without PV (PV and ~~PV~~ respectively) is presented in Table 6.3. In both cases, the solution with direct electric heating is more cost-effective. The existing overhead in the grid connection is enough and no extra investment in the grid is required, contributing to making this option the cheapest. As seen in Fig. 6.3, the case with investment in the increased grid connection is also more cost effective than the DH alternatives, though unnecessary. The grid in Furuset is not constrained enough for the DH to make a difference on the electric grid.

We can look at the energy balances and the operation of the system in the different seasons in the case with and without PV.

6.6.1 with PV

Table 6.4 presents the annual and peak demand of heat and electricity in the different alternatives in the case with PV. Going from a fully electric heating system to the use of DH reduces the annual electric demand by 26 %. The peak power is also reduced by 28 %. The annual heat delivered varies

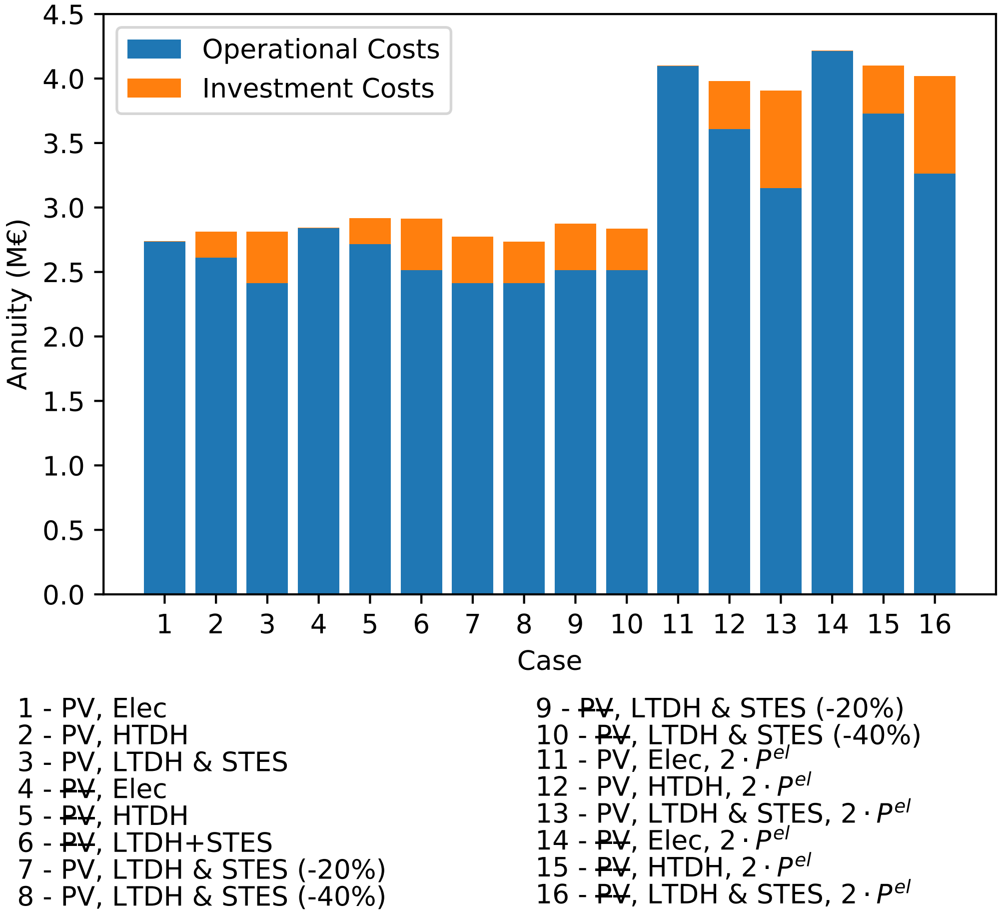


Figure 6.3: Graphical summary of the results presented in tables 5, 9 and 11.The base cases are numbered 1 to 6; the sensitivity on the investment cost of the STES (with the percentage reduction in parenthesis) are 7 to 10; and the sensitivity on the electricity price (double cost in winter and peak period) are 11 to 16.

between the case with the low temperature and high temperature heat network. The higher losses in the low temperature cases due to the losses in the STES increases the energy use by 28 % but the operation of the STES also allows a reduction the peak load by 31 %.

Figure 6.4 shows the operation of the system in the three alternatives, aggregating the heat and electric supply. In the summer, PV has a substantial contribution to the energy needs of the area. In the LTDH alternative, the import of heat in the summer to charge the STES represent an important energy need.

On the peak day, in the direct electric heating alternative, the peak power consumption is high due to the additional heating demand. In the HTDH alternative, the DH network takes part of the strain away by supplying heat to the buildings. In the LTDH alternative, the STES covers the heat demand in the hours with the highest DH prices reducing the demand on the main DH network.

6.6.2 Without PV

Table 6.5 presents the annual and peak demand of heat and electricity in the different alternatives in the case without PV (~~PV~~). The absence of PV leads to higher electricity imports of 8.6 % and 11.6 % respectively in the electric heating and DH cases. The peak electricity imports and imports of heat stay the same or close to the same.

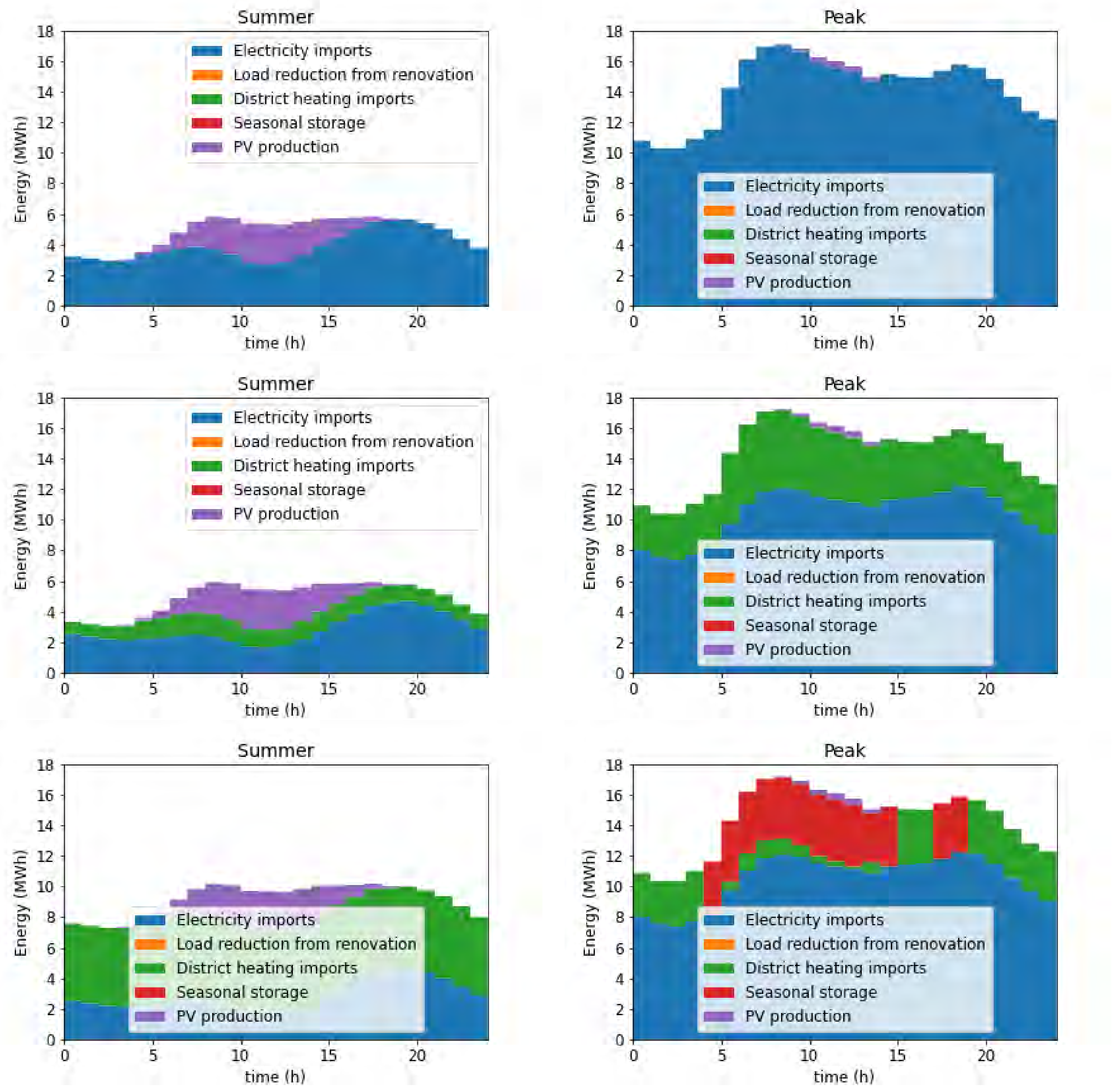


Figure 6.4: Energy supply from the different sources in the representative days for summer (left) and peak (right panel), for the investment alternatives of direct electric heating (top row), high-temperature DH (middle row) and low-temperature DH with STES (bottom row) in the PV scenario.

Table 6.3: Investment and operational costs from the Integrate runs (M€).

	PV			**~~PV~~**		
	Operation	**Investments**	**Total**	**Operation**	**Investments**	**Total**
Electric heating	2.736	0.000	2.736	2.841	0.0	2.841
HTDH	2.612	0.199	2.812	2.717	0.199	2.917
LTDH and STES	2.414	0.399	2.813	2.516	0.399	2.915

Table 6.4: Total annual and peak energy demand for electricity and DH in the PV scenario.

	Electricity		DH	
	Energy [GWh/year]	Peak [MWh/h]	Energy [GWh/year]	Peak [MWh/h]
Electric heating	59.2	17.0	0.0	0.0
HTDH	44.0	12.2	16.2	5.22
LTDH and STES	44.0	12.2	20.9	3.61

6.6.3 Heat losses and pumping power

The low temperature DH network has the advantage of smaller losses compared to the high temperature system. Annual heat losses in the HTDH system are 1.14 GWh (7.5 % of the total heat demand) versus only 0.85 GWh (5.6 % of the total heat demand) in the LTDH system. On the other hand, the LTDH system requires twice as much energy for pumping than the HTDH system (due to the higher flow rates needed to transfer the same amount of energy), but pumping represents a negligible amount of energy (0.031 GWh in LTDH, 0.014 GWh in HTDH) compared to the heat losses.

6.6.4 Levelized cost of heat

We calculate the levelized cost of heat for the different alternatives using DH with the following formula:

$$LCOH = \frac{I_0 + \sum_{t=1}^{n} \frac{C_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{6.18}$$

where I_0 is the total initial investment, C_t is the annual operational costs (i.e., the energy costs), E_t is the annual amount of heat delivered by the heat central, n is the number of years of operation, set to 30 years, and r is the discount rate, set to 3 %.

The resulting LCOH were found to be 51.9 and 51.5€/MWh for the HTDH and LTDH cases respectively. Those values are lower than the average LCOH for DH in Norway in 2020 but slightly higher than the spot price of electricity in the same year (note however that this year had particularly low electricity prices). These values can also be compared with values from the literature. [17] found the LCOH of a borehole STES using excess waste heat to be 10.5 and 23.5€/MWh(excluding taxes). Different assumptions between the present study and [17] can explain this discrepency. In particular, the investment cost of STES assumed in this study are 37% higher; the storage volumes, efficiencies and share of waste heat are also somewhat different. It should be noted that this case study considers only connecting the new buildings planned in Furuset(corresponding to 47% of the total) to the DH system. Increasing the share of buildings connected to the DH system with future developments or retrofitting of the older building stock would decrease the LCOH further.

Table 6.5: Total annual and peak energy demand for electricity and DH in the ~~PV~~ scenario.

	Electricity		DH	
	Energy [GWh/year]	Peak [MWh/h]	Energy [GWh/year]	Peak [MWh/h]
Electric heating	64.3	17.1	0.0	0.0
HTDH	49.1	12.2	16.2	5.22
LTDH and STES	49.2	12.2	20.7	3.91

6.6.5 Sensitivity analyses

STES heat availability

In the results presented in the previous sections, the heat availability in the STES was based on assumptions. In practice, depending on the moment in the season, the temperature in the storage might be lower and not be able to provide as much heat. In [32], dynamic simulations were used to study the the operation of the borehole planned in Furuset. That study allowed to estimate the outlet temperatures of the STES to the local DH network throughout the discharge season and the demands of heat for charging the STES with different strategies. An analysis is conducted using our model in a setup with limited heat availability during peak periods and winter based on these results to consolidate the results presented in the previous section.

Table 6.6: The allowed charging and discharging of the STES per season and day with reduced availability in winter and peak periods.

	Charge(+) or discharge(-) per season/day [MWh]	Share of demand covered by STES
Spring	-596 / -11.5	63 %
Summer	13 000 / 102.4	–
Autumn	-2 108 / -34.0	98 %
Winter	-5 271 / -42.9	81 %
Peak	-24 / -24	30 %

This setup results in only minimal changes, with 2.415 M€ for operational costs and 0.40 M€ for investment costs, and 2.81 M€ in total costs; the same value as previously. Despite the lower heat availability, the storage can still provide enough heat to cover the hours with the highest DH cost (Figure 6.5). The impact on the peak demand for heat is larger however with a value of 5.11 MWh/h or about the same as without the STES.

STES investment costs

A certain level of uncertainty is associated with the investment cost of the STES system. To find the cost at which it becomes more cost-efficient than direct electric heating, several runs are performed. Table 6.7 summarizes the results of these runs. For cases with and without PV, the cost reduction necessary from the base case to make the STES cost optimal is of a bit under 40%.

Despite the size of the planned storage reducing the cost with economies of scale compared to other existing projects [33], the STES is not competitive with direct electric heating in a grid with no particular grid constraints such as Furuset (Table 6.3). The cost reduction affects the LCOH and reduces it to below the average power prices for 2020 in Norway (meaning that it becomes more cost effective than direct electric heating). The LCOH with a 20% investment cost decrease becomes

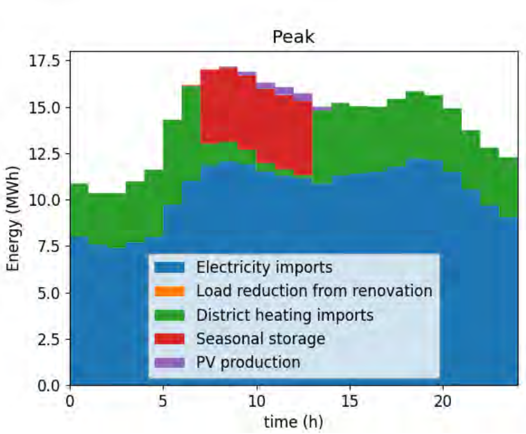


Figure 6.5: Energy supply from the different sources on the peak day with low-temperature DH and STES, with reduced availability of heat during winter and peak periods.

Table 6.7: Annuity of investment and operation resulting from a given reduction in the STES investment cost in both the PV and ~~PV~~ scenarios in M€. "Base" represents the cost assumption used in the main analysis.

	PV			~~PV~~		
	Operation	Investments	Total	Operation	Investments	Total
Base	2.414	0.399	2.813	2.516	0.399	2.915
−20%	2.414	0.359	2.773	2.516	0.359	2.875
−40%	2.414	0.319	2.733	2.516	0.319	2.835

46.7 €/MWh and 41.8 €/MWh for a cost reduction of 40%.[2]

Reduced grid capacity

The results presented previously show that the existing grid infrastructure in Furuset is enough to accept the future growth of the building mass in the area and is not representative of the situations of other neighborhoods. We conduct a sensitivity analysis on the starting grid capacity to see how STES could be applied to areas with less grid connection overhead. The grid capacity is reduced with between 3 and 15 MW (corresponding to a 13 to 66% reduction) and the results are presented in Table 6.8.

Here, we compare the operational, investment and total costs of a system with reduced grid capacity connection in the electric heating alternative and the LTDH + STES alternative. There is no major difference in the cases with and without PV, apart from the reduction in operational costs that the PV provides. In the direct electric heating case, the operational cost increases as the number of hours of load not served (due to the penalty for not delivering energy) increases due to the reduced grid connection size. LTDH + STES becomes more profitable than direct electric heating for a reduction of 9 MW of the grid capacity in the ~~PV~~ case and slightly above 9 MW in the PV case. A further reduction to 12 MW significantly increases the operational costs (54% in PV case and 80% in ~~PV~~) in the direct electric heating case while the increase is kept small in the LTDH+STES alternative. Further reducing the grid by a total of 15 MW leads to large amount of non-served energy and penalties in the direct electric heating case. The LTDH and STES are not enough to compensate the effect of a

[2]This comparison is done only as a simple indication on the competitiveness of the STES compared to direct electric heating. More parameters should be accounted for: heat pumps can be used, requiring less electricity to provide the same amount of heat; 2020 was a year with very low spot prices and is not representative of typical spot prices.

Table 6.8: Annuity of investment and operational costs resulting from a given reduction in the grid capacity in both the PV and ~~PV~~ scenarios in M€. The second column contains the grid connection reduction from the base value.

		PV			~~PV~~		
		Operation	Investments	Total	Operation	Investments	Total
Electric heating	$-3MW$	2.735	0	2.735	2.841	0	2.841
	$-6MW$	2.737	0	2.737	2.843	0	2.843
	$-9MW$	2.805	0	2.805	2.915	0	2.915
	$-12MW$	4.321	0	4.321	5.263	0	5.263
	$-15MW$	34.40	0	34.40	38.06	0	38.06
LTDH + STES	$-3MW$	2.414	0.399	2.813	2.516	0.399	2.915
	$-6MW$	2.414	0.399	2.813	2.516	0.399	2.915
	$-9MW$	2.414	0.399	2.813	2.516	0.399	2.915
	$-12MW$[1]	2.343	0.571	2.914	2.445	0.571	3.016
	$-15MW$[1]	4.661	0.571	5.232	5.858	0.571	6.429

[1] Here investment in DH in 2019 and STES in 2029

15 MW grid reduction and see an increase in operating costs due to unserved loads. In the case of 12 and 15 MW reduction, the investment in the LTDH and STES happens in 2019 while it is only done in 2029 for lower grid reductions.

Higher winter electricity prices

Particularly high electricity prices have occurred in the last years in many parts of Europe due to a combination of various factors: the consequences of the war in Ukraine on the supply of gas, rebound of activity after the ease of COVID-19 restrictions, dry conditions affecting reservoir levels and troubles with an ageing french nuclear fleet, to name a few. The increasing penetration of renewable energy sources in the future energy system could also lead to higher level of variability of the electricity prices. We study the sensitivity of the results to the price of electricity by considering a case where the electricity prices are doubled in the winter and peak periods. The corresponding change in the DH cost are also accounted for. The results of this case are presented in Table 6.9.

Table 6.9: Investment and operational costs from the Integrate runs with doubled electricity costs in the winter and peak (M€).

	PV			~~PV~~		
	Operation	Investments	Total	Operation	Investments	Total
Electric heating	4.098	0.000	4.098	4.216	0.0	4.216
HTDH	3.609	0.372	3.981	3.728	0.372	4.099
LTDH and STES	3.152	0.755	3.907	3.265	0.755	4.020

As a results of the higher electricity costs, the alternative with DH and STES becomes cost optimal, followed by the high temperature DH. An important takeaway is then that despite it not being the cost optimal solution in the base case, the LTDH and STES system allows to hedge against extreme electricity prices for only a 2.8% increase in total cost, with the large potential savings in the case of extreme events.

6.6.6 Emission reduction due to implementation of STES

In addition to cost consideration, it is important to consider the impact of the change from direct electric heating to STES on emissions of greenhouse gases. Indeed, the STES allows a reduction of the use of peak heating boilers in the main DH network in the winter and to utilize waste heat that otherwise would be lost. We estimate the emissions of the system with the different alternatives in the period 2039-2049 based on the emission factors of electricity and of fuels used in the DH system and the shares of each technology in the DH system. The emission factor considered are: 277 kg/MWh for gas, 50 kg/MWh for biodiesel, 40 kg/MWh for wood pellets and 17 kg/MWh for electricity based on [34]. The results are presented in 6.10.

Table 6.10: Annual emissions for the energy system considered with the different investment alternatives from electricity and DH (*ton* CO_2/*year*)

	PV			~~PV~~		
	El.	DH	Total	El.	DH	Total
Electric heating	1007	0	1007	1094	0	1094
HTDH	748	182	930	835	182	1017
LTDH and STES	748	46	794	836	44	880

Connecting the neighborhood to the DH network reduces emission by 7-8% compared to the direct electric heating case while the addition of the STES leads to a 20% reduction.

6.7 Limitations and future extensions

The case study presented in this report has limitations. It is considering the use of a particular type of STES in a particular location and does not completely represent the potential of STES. A major limitation when it comes to the modelling is the representation of the seasonal aspect of the storage. In this work, seasonal constraint on the charge and discharge have been used (and validated using dynamic models), due to the constraint arising from using a low number of representative periods associated with the complexity of the model. This could be improved by increasing the number of representative periods or their lengths but it comes at the cost of computational time. Increasing the number of representative periods would however also increase the quality of the representation of other elements such as loads and electricity prices for example. The model is based on DP for the investment optimization, which has the advantage of studying the investment timing but require the capacities of the technology options to be fixed. A linear program would allow to optimize the sizing of the components in the system. In this study, the sizing of the components is based on the plans for area but checking if this sizing is optimal and impacts the profitability of the alternatives could be additional work.

Extensions of this work are possible and could address some of those limitations. New case studies considering STES in different context would allow a better understanding of the profitability of STES. The Integrate model is for example being used on a caste study of a neighborhood in Trondheim in the research center on zero emission neighborhood in smart cities (FME ZEN) financed by the Norwegian Research Council. There, the modules developed for Integrate are being used and a longer representative periods are used. More work is also needed more generally on the topic of the integration of flexibility from the heating system in the power system. It could be an important flexibility asset for integrating larger share of renewable generation but there needs more knowledge of the flexibility potential at different scales and their aggregated impact on the power system.

Bibliography

[1] J. Goop, M. Odenberger, and F. Johnsson, "The effect of high levels of solar generation on congestion in the european electricity transmission grid," *Applied Energy*, vol. 205, pp. 1128–1140, 2017. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0306261917311601

[2] L. Bird, D. Lew, M. Milligan, E. M. Carlini, A. Estanqueiro, D. Flynn, E. Gomez-Lazaro, H. Holttinen, N. Menemenlis, A. Orths, P. B. Eriksen, J. C. Smith, L. Soder, P. Sorensen, A. Altiparmakis, Y. Yasuda, and J. Miller, "Wind and solar energy curtailment: A review of international experience," *Renewable and Sustainable Energy Reviews*, vol. 65, pp. 577–586, 2016. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S1364032116303161

[3] H. C. Gils, Y. Scholz, T. Pregger, D. Luca de Tena, and D. Heide, "Integrated modelling of variable renewable energy-based power supply in europe," *Energy*, vol. 123, pp. 173–188, 2017. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0360544217301238

[4] L. Mehigan, B. Ó Gallachóir, and P. Deane, "Batteries and interconnection: Competing or complementary roles in the decarbonisation of the european power system?" *Renewable Energy*, vol. 196, pp. 1229–1240, 2022. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0960148122010539

[5] B. H. Bakken, H. I. Skjelbred, and O. Wolfgang, "etransport: Investment planning in energy supply systems with multiple energy carriers," *Energy*, vol. 32, no. 9, pp. 1676–1689, 2007. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0360544207000175

[6] M. L. Kolstad, S. Backe, O. Wolfgang, and I. Satori, "Software tools for local energy system operation and expansion," ZEN Report, Tech. Rep. 6, 2018. [Online]. Available: https://ntnuopen.ntnu.no/ntnu-xmlui/handle/11250/2594308

[7] H. Kauko, "eTransport Modules for Diurnal and Seasonal Heat Storage," *ZEN Memo*, 2019.

[8] H. Lund, P. A. Østergaard, D. Connolly, I. Ridjan, B. V. Mathiesen, F. Hvelplund, J. Z. Thellufsen, and P. Sorknæs, "Energy storage and smart energy systems," *International Journal of Sustainable Energy Planning and Management*, vol. 11, p. 3–14, Oct. 2016. [Online]. Available: https://journals.aau.dk/index.php/sepm/article/view/1574

[9] T. Yang, W. Liu, G. J. Kramer, and Q. Sun, "Seasonal thermal energy storage: A techno-economic literature review," *Renewable and Sustainable Energy Reviews*, vol. 139, p. 110732, 2021. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S1364032121000290

[10] L. Gao, J. Zhao, and Z. Tang, "A review on borehole seasonal solar thermal energy storage," *Energy Procedia*, vol. 70, pp. 209–218, 2015, international Conference on Solar Heating and Cooling for Buildings and Industry, SHC 2014. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S1876610215002398

[11] L. Mesquita, D. McClenahan, J. Thornton, J. Carriere, and B. Wong, "Drake landing solar community: 10 years of operation," 01 2017, pp. 1–12.

[12] J. Hirvonen, H. ur Rehman, and K. Sirén, "Techno-economic optimization and analysis of a high latitude solar district heating system with seasonal storage, considering different community sizes," *Solar Energy*, vol. 162, pp. 472–488, 2018. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0038092X18300732

[13] G. Schweiger, J. Rantzer, K. Ericsson, and P. Lauenburg, "The potential of power-to-heat in swedish district heating systems," *Energy*, vol. 137, pp. 661–669, 2017.

[14] T. Fruergaard, T. H. Christensen, and T. Astrup, "Energy recovery from waste incineration: Assessing the importance of district heating networks," *Waste Management*, vol. 30, no. 7, pp. 1264–1272, 2010.

[15] Energiateollisuus, "Energiavuosi 2020 - Kaukolämpö," https://energia.fi/files/5650/Kaukolampovuosi_2020_netti_kj_paivitetty_20210318.pdf, 2021, accessed: 2021-10-28.

[16] Norsk Fjernvarme, "Fjernvarme - Energikilder 2020," https://www.fjernkontrollen.no/, 2021, accessed: 2021-10-28.

[17] J. Hirvonen and R. Kosonen, "Waste incineration heat and seasonal thermal energy storage for promoting economically optimal net-zero energy districts in finland," *Buildings*, vol. 10, no. 11, pp. 1–19, 2020.

[18] D. Connolly, H. Lund, B. V. Mathiesen, and M. Leahy, "A review of computer tools for analysing the integration of renewable energy into various energy systems," *Applied energy*, vol. 87, no. 4, pp. 1059–1082, 2010.

[19] A. Bachmaier, S. Narmsara, J.-B. Eggers, and S. Herkel, "Spatial distribution of thermal energy storage systems in urban areas connected to district heating for grid balancing—A techno-economical optimization based on a case study," *Journal of Energy Storage*, vol. 8, pp. 349–357, Nov. 2016.

[20] D. Romanchenko, E. Nyholm, M. Odenberger, and F. Johnsson, "Impacts of demand response from buildings and centralized thermal energy storage on district heating systems," *Sustainable Cities and Society*, vol. 64, p. 102510, Jan. 2021.

[21] D. Buoro, P. Pinamonti, and M. Reini, "Optimization of a Distributed Cogeneration System with solar district heating," *Applied Energy*, vol. 124, pp. 298–308, Jul. 2014.

[22] D. Steen, M. Stadler, G. Cardoso, M. Groissböck, N. DeForest, and C. Marnay, "Modeling of thermal storage systems in MILP distributed energy resource models," *Applied Energy*, vol. 137, pp. 782–792, Jan. 2015.

[23] T. Schütz, R. Streblow, and D. Müller, "A comparison of thermal energy storage models for building energy system optimization," *Energy and Buildings*, vol. 93, pp. 23–31, Apr. 2015.

[24] P. Gabrielli, M. Gazzani, E. Martelli, and M. Mazzotti, "Optimal design of multi-energy systems with seasonal storage," *Applied Energy*, vol. 219, no. May 2017, pp. 408–424, 2018. [Online]. Available: https://doi.org/10.1016/j.apenergy.2017.07.142

[25] H. Kauko, D. Pinel, I. Graabak, and O. Wolfgang, "Assessing the potential of seasonal thermal storage for local energy systems: Case study for a neighborhood in norway," *Smart Energy*, vol. 6, p. 100075, 2022. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S2666955222000132

[26] K. Kvalsvik and H. Kauko, “Linear optimization of district heating systems: Description of an upgraded district heating module for eTransport,” *ZEN Report No. 9*, 2018. [Online]. Available: https://fmezen.no/wp-content/uploads/2018/12/ZEN-Report-no-9_optimisation-district-heating.pdf

[27] K. B. Lindberg, S. J. Bakker, and I. Sartori, “Modelling electric and heat load profiles of non-residential buildings for use in long-term aggregate load forecasts,” *Utilities Policy*, vol. 58, pp. 63–88, 2019.

[28] S. Pfenninger and I. Staffell, “Long-term patterns of european pv output using 30 years of validated hourly reanalysis and satellite data,” *Energy*, vol. 114, pp. 1251–1265, 2016. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0360544216311744

[29] I. Staffell and S. Pfenninger, “Using bias-corrected reanalysis to simulate current and future wind power output,” *Energy*, vol. 114, pp. 1224–1239, 2016. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S0360544216311811

[30] Åse Lekang Sørensen, K. B. Lindberg, I. Sartori, and I. Andresen, “Residential electric vehicle charging datasets from apartment buildings,” *Data in Brief*, vol. 36, p. 107105, 2021. [Online]. Available: https://www.sciencedirect.com/science/article/pii/S2352340921003899

[31] C. H. Skotland, E. Eggum, and D. Spilde, “Hva betyr elbiler for strømnettet,” NVE, Tech. Rep., 2016.

[32] M. Jokiel, D. Rohde, H. Kauko, and H. T. Walnum, “Integration of a high-temperature borehole thermal energy storage in a local heating grid for a neighborhood,” in *BuildSIM-Nordic 2020*. SINTEF Academic Press, October 2020.

[33] A. Kallesøe and T. Vangkilde-Pedersen (eds), “Underground thermal energy storage (utes) – state-of-the-art, example cases and lessons learned.” GEOTHERMICA – ERA NET Cofund Geothermal, Tech. Rep., 2019, HEATSTORE project report.

[34] D. Pinel, M. Korpås, and K. B. Lindberg, “Impact of the co2 factor of electricity and the external co2 compensation price on zero emission neighborhoods’ energy system design,” *Building and Environment*, vol. 187, p. 107418, 2021.

Chapter 7

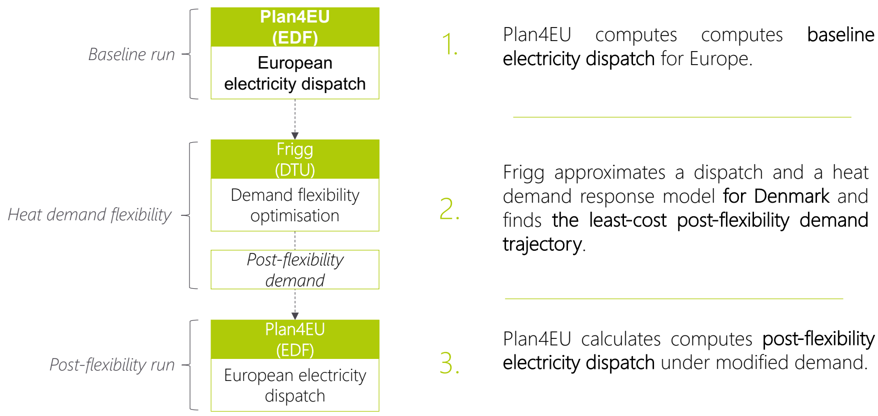
Case Study 7: Integration of electricity and heating sector

Case study 7

Abstract

Decarbonising the European energy system requires large-scale electrification across sectors combined with the utilisation of different sources of energy system flexibility, such as through cross-border power exchange, smart charging of electric vehicles, energy storage and demand response. Such flexibility is particularly relevant for the Danish energy system due to its role as an electricity transit hub for power exchange between its neighbours alongside its significant wind power potentials.

In this case study, we analyse the role of demand-flexible electrified heating (heat storage and end-consumer demand response from district heating piping water and residential building envelopes) in the Danish electricity system of 2050. For this analysis, we apply Frigg, a novel modelling approach for integrating demand response models in energy system analysis. Traditionally, large-scale energy system modelling assumes demand response as shifting load between different time steps or as energy storage, meaning as a direct control problem. Frigg's underlying paradigm is that demand response is rather an indirect control problem, where consumers react to time-varying prices of energy, those prices being the control variable of the problem. Frigg is used to couple Plan4EU, an electricity dispatch model for Europe, with the flexibility function that models power-to-heat demand response in Denmark. Frigg also determines cost-optimal heat storage capacities .



Our results suggest Danish electrified heat demand flexibility to influence both the Danish and European electricity dispatch notably, though the relative effect on a continental level being minor. Demand response might slightly decrease Danish electricity costs, mainly through lower priced imports and higher priced exports. The effect of heat storage is even more significant, decreasing (already negative) domestic (operational) electricity cost by 1.3 EUR/MWh in comparison to a reference case. Power-to-heat demand flexibility substantially supports Danish power system operation, also mostly through more efficient cross-border trade.

The modelling framework of this study comes with some limitations that could be addressed in two main lines of future research: Firstly, the Danish building stock and heating system could be modelled at higher detail. That includes representing individual and district heating individually and estimating demand response parameters from data. Secondly, our proposed modelling approach could be evaluated against other modelling methods and against real-world observations.

Contents

7.1 Introduction

This case study analyses the role of demand-side flexibility in electrified heating (consumer demand response and heat storage) in the Danish energy system of 2050. We assume a Danish energy system (installed generation capacities and aggregated demand levels) as computed in the OpenEntrance Techno-Friendly scenario. Specifically, we quantify the cost savings potential through demand response from the electricity demand for heating. This includes all power-to-heat technologies, such as heat pumps and electric boilers, for both individual and district heating. The economic potential of demand flexibility is understood as the savings in operational cost when utilising demand response in comparison to the baseline (unresponsive demand) under time-varying prices that are optimal from a system point of view.
We compute this potential by soft-linking Plan4EU and the Flexibility Function via Frigg. Firstly, Plan4EU solves a baseline electricity dispatch for Europe. Then, Frigg finds demand levels for heating after application of indirect demand response, simulated by the Flexibility Function. These demand levels are then passed back to Plan4EU to compute the electricity dispatch under electricity demand flexibility in the heating sector. The modelling approach is described in detail in sections 7.2 and 7.4.

7.1.1 State of the art

The Danish government aims at 70% emission reduction in comparison to 1990 by 2030 and climate neutrality by 2050 [12]. This is expected to come along with significantly higher electrification rates in the heating sector [6]. The OpenEntrance transition pathway, which this case study is based on, suggests an electrification rate in the EU building sector of more than 60% in 2050 in the Techno-Friendly scenario [13]. While this increases total demand for electricity, utilising the flexibility potential of the heating sector can ease the transformation to a decarbonized power sector substantially [23] by helping to maintain the supply-and-demand equilibrium, which needs to be ensured very closely in order to maintain system stability, with demand being driven by consumer behaviour [18].

Demand response, meaning consumption levels responding to the state of the system, across various sectors has been analysed for the Danish case. Examples include the study in [16], who investigate demand response from refrigerators in a Danish case study and find them to show an average response time of 24s and ramping rate of 63% per minute. [22] estimate the demand response potential of the Danish power system based on the output of several other studies as a "total potential peak load reduction" to be 704-1409 MW, of which 85-172 MW stem from residential water and space heating. The authors of [17] study demand response from electrified heating on the island of Bornholm, Denmark. They find that demand response reduces social cost by 5.4% and increases RES uptake by 8.6%. [11] analyse optimal heat pump capacities in a local district heating system under varying wind power capacities in the electricity sector finding a positive correlation between power-to-heat capacities and wind power share. The role of cross-sectoral units in electricity markets is analysed in [14].

7.2 Modelling tools

Electricity generation capacities and marginal costs are given by Genesys-mod. Plan4EU is used as a dispatch model for Denmark being interconnected to neighbour states. Demand response is modelled through a set of ordinary differential equations, where demand responds to time-varying prices [10, 20].

7.2.1 Plan4EU

Plan4EU [5, 2] is a modelling tool for the electricity sector of the EU and some additional countries. It allows for capacity expansion, seasonal storage modelling and unit commitment. In this study, it is applied as an electricity dispatch model on an hourly resolution. It finds a (near-)optimal optimal dispatch schedule for electricity generators across Europe under consideration of short and long-term as well as cross-border trade. Plan4EU takes uncertainty in input data into account by applying demand and variable renewable energy sources (VRES) load factors based on 36 different climatic years.

7.2.2 Flexibility function

Consumers heat demand response to time-varying heat prices is modelled through the flexibility function used in [10], with all parameters chosen as in [10] if not indicated otherwise (see section 7.5). The flexibility function returns demand as a function of price (fig. 7.1). It incorporates dynamics of demand response, captured by a state variable X, which functions similarly to energy storage: An increase in demand compared to baseline levels leads to an increase in X, making consumers less responsive to high prices in the future (and vice versa).

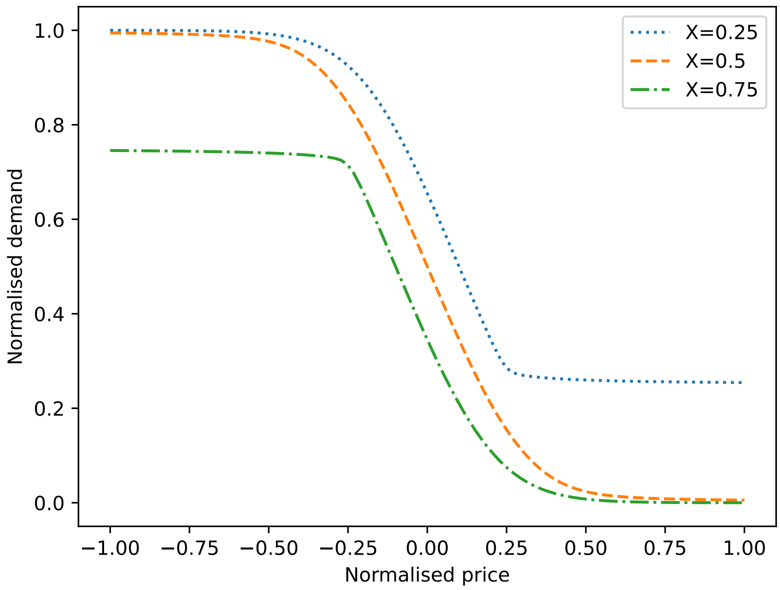


Figure 7.1: Normalised demand against normalised price as flexibility function output under varying initial states X. Values of $X > 0.5$ ($X < 0.5$) indicate that consumers have increased (decreased) their demand compared to baseline levels.

7.2.3 Frigg

Frigg is a soft-linking framework for flexible energy systems. The aim of that framework integrating low-level operational problems in large-scale energy system planning and analysis. Frigg is in early-stage development at the department for applied mathematics and computer science of the Technical University of Denmark. In this study, we use Frigg for soft-linking a dispatch model of the European electricity system, Plan4EU (section 7.2.1), with a demand response model of the Danish heating system, the flexibility function (section 7.2.2).

Problem formulation

Traditionally, large-scale electricity system models formulate the problem of when to dispatch which assets in an electricity system as a (mixed-integer) linear program. The optimal dispatch per time step is computed based on demand levels as well as generator capacities and costs. Both costs and capacities can be time-varying (for example capacities of intermittent energy sources and costs of electricity imports or combined heat-and-power generation). Electrified heat demand response and heat storage can help integrate more intermittent energy generation. However, single-sector electricity dispatch models do not solve a heat dispatch problem, and thus consider neither of the two. Integrating heat demand response and storage in an electricity dispatch problem poses challenges, both mathematical (potentially non-linear demand response models (see section 7.2.2), and practical (reformulating established modelling tools and changing their implementation).

Both challenges can be tackled by a soft-linking approach (section 7.4.1), where demand trajectories after application of demand response and heat storage are computed and then passed to the energy system/dispatch model. Frigg solves this problem by soft-linking the flexibility function and Plan4EU. We refer to load factors after application of demand response and heat storage dispatch, i.e. the output of Frigg, as post-flexibility load factors.

Solution approach I: dynamic programming

The above problem is not only non-linear, but also, potentially, large in size due to the intertemporal constraints (storage and state of demand response). In the absence of these constraints, the problem would be fully decomposable and could be solved individually for each time step $t \in \mathcal{T}$.

We have introduced a solution approach for solving heat storage for a local district heating system in [20] using dynamic programming. That leads to fewer intertemporal constraints, or, in control engineering jargon, fewer state variables, the only remaining state being the state of demand response X. In that study, we found that demand response can reduce heating costs substantially, but falls short of the operational savings achieved by investments in an optimally-sized heat storage unit (fig. 7.2).

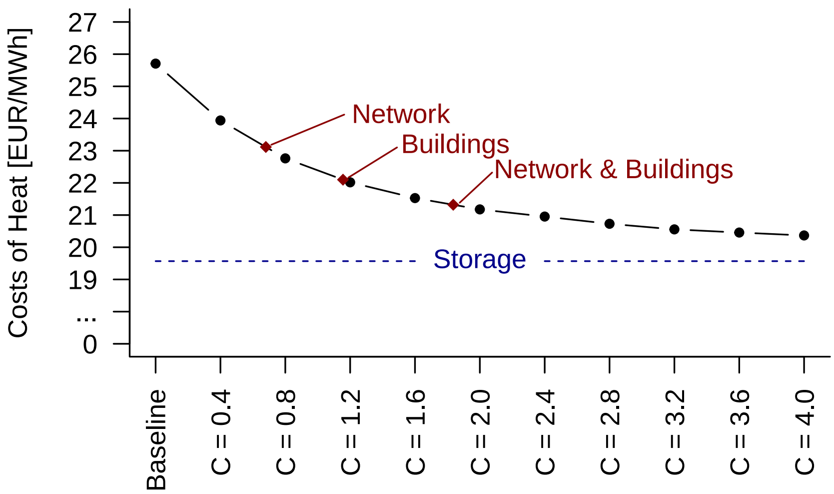


Figure 7.2: Costs of heat across cases compared. The straight dashed line indicates the system costs, including investment costs, under optimal storage sizing. Previously published in [20].

Solution approach II: mixed-integer programming

(Piece-wise) linearisation of Demand Response In this study, both heat storage and demand response need to be included. The additional state variable makes a solution via dynamic programming more challenging. Thus, the flexibility function is approximated with a piece-wise linear model and a slightly modified heat dispatch (c.f., e.g., [21]) problem is solved. This dispatch problem treats demand as a variable, which is indirectly controlled via a price signal. Hence, the energy balance equation features both demand response and heat storage. For this study, we extend the dispatch model to include heat storage investments as a decision variable. A piece-wise linear model is fitted to simulated data prior to solving the dispatch problem using the implementation of [3]. The approximation is plotted in fig. 7.3 for a neutral baseline demand and state variable.

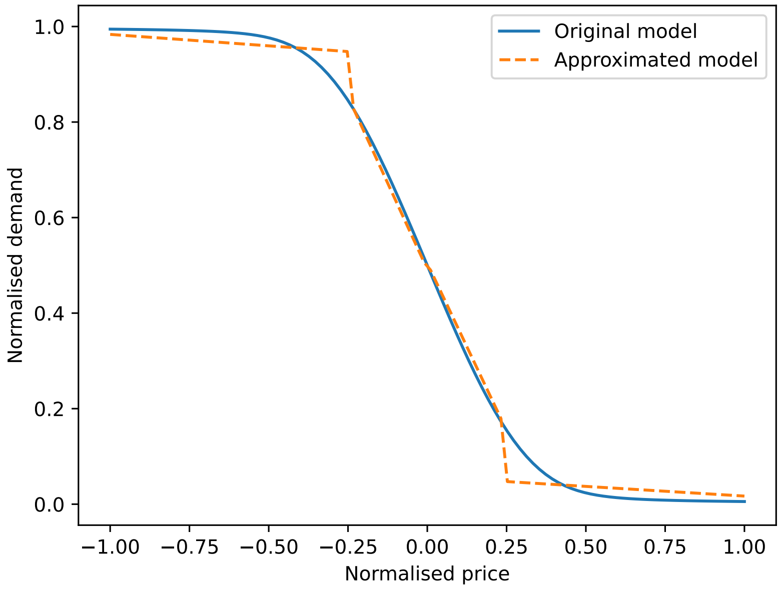


Figure 7.3: Example of piece-wise approximation of flexibility function for neutral baseline demand and neutral state (2-d projection for $X_t = B_t = 0.5$; Note that a higher-level projection would explain the “elbows“ around $u = \pm 0.25$). For illustrative purposes only: The actual approximation can take different shapes depending on model configurations.

7.3 Assumptions

Denmark is modelled as a one-node system. We assume the Danish electricity system to be a ”copper plate” system, where neither transmission losses nor bottlenecks occur, as we do not introduce any spatial resolution in the Danish system. We also aggregate the entire Danish electrified heating sector (district and individual heating) to a single demand and supply node and aggregate its demand response potential as well as storage capacity accordingly. This simplification is a strong one, since heat is usually not transported over long distances but brings computational benefits (by reducing problem size).

The total water in the Danish district heating system and residential building envelopes are assumed to have similar characteristics as today and constitute the demand-flexible mass in the system. The thermal capacity of demand response is based on [20]: We assume the total water in the Danish district heating system in 2050 to be the same as today. We also assume constant thermal characteristics of residential as today, based on [19].

Constant coefficient of performance in heat dispatch. All electrified heat generators (heat pumps and electric boilers) share a common and constant conversion factor between electricity and heat (see section 7.5). Note that in making this simplification, we do not account for seasonal fluctuations in heat pump performance, which is likely to be higher in summer than winter.

Heat storage sizing varies across climatic years. Our analysis is based on a number of climatic years to increase the robustness of our results (see section 7.5. Heat storage sizing, used to compute post-flexibility (demand response and storage) electrified heating load factors (see section 7.2.3), is done independently for each climatic year, resulting in varying capacities across climatic years.

Common individual and district heating. Frigg does not distinguish between individual and district heating, since neither Plan4EU nor GENeSYS-MOD make that distinction. This results in a common heat dispatch and storage investments for the entire electrified heating sector. Note that this aggregation simplifies the operation of the Danish heating sector. For instance, district-level storage is assumed able to compensate for demand fluctuations in individually-heated homes and vice versa.

Flexibility function parameters are not estimated on data. The flexibility function (see section 7.2.2) can be estimated as stochastic differential equations based on observed data. Since no observations are available, we assume the same parameters as in [10], where an analysis of their variations is made. We also do not consider demand response from other sources than the piping water in the district heating sector and residential houses, the latter sharing the same characteristics as estimated in [19] and applied in [20].

Insensitive electricity import prices in Frigg. In Frigg, we only model the Danish system and thus treat electricity imports and exports as generators with fixed capacities and time-varying costs (negative for exports). Prices for imports and exports are assumed insensitive to Danish electricity demand. Please note that Plan4EU does not make this assumption, as also the electricity dispatch for Denmark's neighbours is computed. Thus, this simplification holds only for the computation of post-flexibility load factors.

7.4 Methodology

This study investigates the impact of flexibility from electrified Danish heating on the Danish power dispatch of 2050. Our case is based on the OpenEntrance project's Techno-Friendly scenario [1]. Plan4EU (section 7.2.1) is the main model for this case study. The model is run twice (with and without heat sector flexibility). Frigg (section 7.2.3) is executed to determine load factors for electrified heating in Denmark in 2050, which form the basis of the second Plan4EU run.

7.4.1 Case study workflow

Specifically, Plan4EU uses installed electricity generation capacities and aggregated demand as determined in the OpenEntrance scenarios by GENeSYS-MOD. Hourly load factors for VRES generation and electricity demand from the Plan4RES project [4] are used together with that data to generate a baseline electricity dispatch for Europe.
The same input data that was used for Plan4EU, only solely for Denmark, is used in Frigg to solve an electricity dispatch problem for Denmark. This problem is simplified in the sense that cross-border trading takes place at fixed import/export prices (marginal generation costs per time step and country

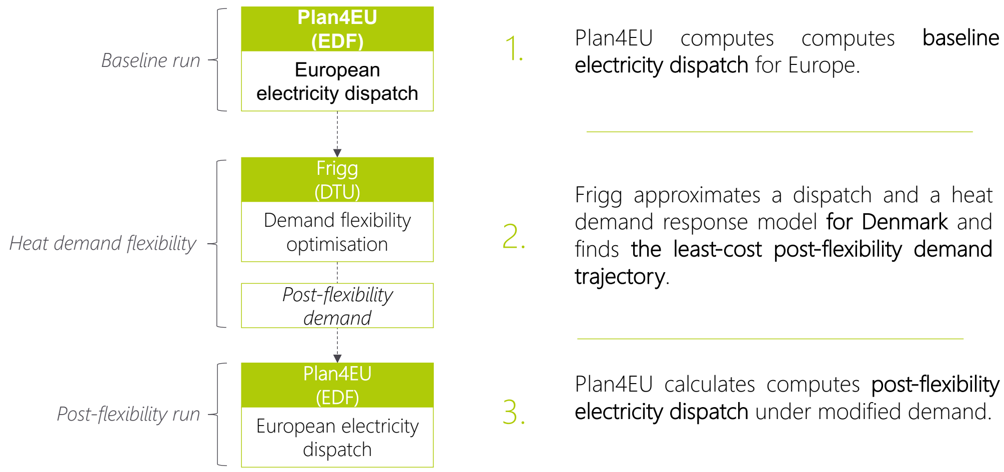


Figure 7.4: Case study workflow.

determined in case study 1). However, Frigg includes an indirect demand response model and heat storage (sections 7.2.2 and 7.2.3). Solving this dispatch problem yields cost-optimal, "controlled" electricity demand for heating, after application of demand response and heat storage. Note that Frigg is solely used for the computation of these load factors, thus all final dispatch results are based on Plan4EU.
Finally, Plan4EU is run on these "post-response" load factors for electrified heating. A comparison with the reference case allows analysing the role of added heat sector flexibility on the Danish power system.

7.4.2 Linkages

In Frigg, generation capacities and sub-sector-wise electricity demand are disaggregated to an hourly resolution based on demand and VRES load factors. Aggregated data is read from the Scenario Explorer, whereas time series inputs are handled offline as CSV files. In particular, the following data inputs are used:

- Generation capacities and costs (GENeSYS-MOD)
- Aggregated annual electricity demand per sub-sector (GENeSYS-MOD)
- Climatic Scenario (Plan4EU)
- Demand and VRES load factors (Plan4EU)
- Parameters of the flexibility function (demand response model)

Plan4EU does not receive modified input data in the `Baseline` scenario. In all other scenarios, modified load factors generated by Frigg are used as data input.

Table 7.1: Installed electricity generation capacities (Denmark). *disregarded in Frigg due to small capacity

	Generation capacity [GW]
Biomass (CCS)	3.02
Biomass (no CCS)	0.62
Hard coal (no CCS)*	0.02
Natural gas (CCS)	0.25
Hydro*	0.01
Solar	8.00
Wind (Offshore)	13.79
Wind (Onshore)	5.79

Table 7.2: Variable electricity generation costs for Denmark. [4]

Technology	**Variable costs [EUR/MWh]**
Biomass (CCS)	42.8
Biomass (no CCS)	38.3
Natural gas (CCS)	54.1
Hard coal (no CCS)	4.03

7.4.3 Scenarios

We analyse two scenarios with varying degrees of power-to-heat demand flexibility, which are compared to a `Baseline` scenario:

- `Baseline`: Reference case without consideration of power-to-heat demand flexibility
- `Demand response`: Power-to-heat demand response in the Danish energy system assuming the thermal mass of district heating piping water and residential building envelopes to be flexible
- `Heat storage`: Cost-optimally sized heat storage in the Danish heating system

7.5 Input data

Electricity generation capacities and variable generation costs. The Danish electricity generation portfolio corresponds to the Techno-Friendly scenario for 2050 as an output of GENeSYS-MOD [1] (table 7.1). The system is largely decarbonized with wind power being the largest source of electricity.

Load factors for time series data. Our analysis is run for 38 climatic years (scenarios), based on historical data from 1982 onward at uniform probability. That data includes hourly load factors for electricity demand across sub-sectors and renewable generation profiles [4].

Heat dispatch. The thermal capacity of demand response (i.e., parameter C in the flexibility function (c.f. [15]) is calculated as the sum of the thermal capacity of all network water in the Danish district heating system today (1 billion liters [9]) and the thermal capacity of the residential building sector. We assume temperature deviations of $\pm$3.5K for network water and $\pm$1K for building envelopes. The computations are given in [20] and are scaled to size for this case study (to the entire country and normalised by the maximum demand in the respective climatic year).
We convert between power and heat at a fixed ratio of 3.905. This is equal to the ratio of heat

produced by electricity in Denmark in 2050, as given by the GENeSYS-MOD pathway results [1] and the power consumed to produce that heat. Thus, we assume a constant coefficient of performance for the combination of heat pumps and electric boilers.

Heat storage capacities are determined within Frigg. We assume annualised investment costs of 151.57 EUR/MWh. This is the result of a discount rate of 4% [7] and investment cost of 3000 EUR/MWh at a lifetime of 40 years [8].

Temporal resolution. Both Plan4EU and Frigg operate on an hourly resolution. The flexibility function, for the sake of simulating and approximating post-response demand, runs on 1000 time steps per hour, i.e., 3.6s.

7.6 Results

Electricity mix

On a European level, the `Baseline` electricity mix is dominated by renewable energy sources, with small amounts of nuclear and gas capacity remaining (table 7.3). With the application of power-to-heat demand response in the Danish energy system, no significant change can be observed. When adding heat storage to the Danish system instead of demand response, the uptake of hydro, wind and solar power increases slightly, while the remaining thermal generation decreases.

Table 7.3: European Union (EU) electricity mix across scenarios [TWh] (Difference to `Baseline` scenario). Electricity sources contributing less than 0.1% of the total electricity demand have been removed.

	`Baseline`	`Demand response`	`Heat storage`
Hydro	668.63 (±0.0%)	668.82 (+0.03%)	669.05 (+0.06%)
Nuclear	342.67 (±0.0%)	342.56 (-0.03%)	342.34 (-0.1%)
Wind	1817.5 (±0.0%)	1817.53 (±0.0%)	1818.47 (+0.05%)
Solar	1092.88 (±0.0%)	1092.39 (-0.04%)	1093.73 (+0.08%)
Biomass	240.76 (±0.0%)	240.64 (-0.05%)	240.21 (-0.23%)
Hydrogen	143.43 (±0.0%)	143.32 (-0.07%)	142.79 (-0.44%)
Gas	205.36 (±0.0%)	205.34 (-0.01%)	205.12 (-0.12%)

On a Danish level, we can observe a similar pattern compared to the European level (table 7.4). Again, the sole introduction of power-to-heat demand response yield a significant change compared to the `Baseline`. Heat storage investments decrease the remaining fossil generation, with biomass and coal-fired generation decreasing by 43% and 58% respectively. Generation from wind and solar power is 0.94% and 2.7% higher than in the `Baseline`.

Cross-border trade

With its location between different electricity systems, electricity trade plays a particularly prominent role in the Danish power system. In the baseline scenario, electricity imports amount to 29.07 TWh, equivalent to 45% of the annual domestic demand (table 7.5), exports being 16.47 TWh higher, making Denmark a net-exporter of electricity (table 7.6). Germany, Sweden, Netherlands and the UK are net-importers of Danish electricity, whereas Denmark's imports from the Norwegian power system exceed

Table 7.4: Danish electricity mix across scenarios [TWh] (Difference to Baseline scenario). Electricity sources contributing less than 0.1% of the total electricity demand have been removed.

	Baseline	Demand response	Heat storage
Hydro	0.05 (±0.0%)	0.05 (+-0.0%)	0.05 (+0.79%)
Coal	0.05 (±0.0%)	0.05 (+1.19%)	0.05 (-2.74%)
Wind	59.5 (±0.0%)	59.47 (-0.04%)	60.06 (+0.94%)
Solar	5.39 (±0.0%)	5.4 (+0.23%)	5.53 (+2.66%)
Biomass	0.11 (±0.0%)	0.1 (-5.53%)	0.06 (-43.15%)
Gas	0.01 (±0.0%)	0.01 (-13.02%)	0.01 (-57.65%)

its exports. In the Demand response scenario, total imports increase slightly, as do exports. In the Heat storage scenario, imports are 1.14% lower and exports 0.69% higher than in the Baseline.

Table 7.5: Danish electricity imports across scenarios [TWh] (Difference to Baseline scenario)

	Baseline	Demand response	Heat storage
GER	6.85 (±0.0%)	6.83 (-0.34%)	6.42 (-6.21%)
NOR	9.68 (±0.0%)	9.74 (+0.55%)	10.03 (+3.57%)
SWE	6.91 (±0.0%)	6.94 (+0.38%)	6.75 (-2.38%)
NL	0.75 (±0.0%)	0.74 (-1.37%)	0.65 (-13.37%)
UK	4.87 (±0.0%)	4.88 (+0.29%)	4.89 (+0.29%)
Total	29.07 (±0.0%)	29.13 (+0.21%)	28.74 (-1.14%)

Costs of electricity

In the Baseline scenario, OPEX on a European and Danish level stand at 7.23 and -8.7 EUR/MWh (table 7.7). Note that the Danish cost include electricity imports and exports, and are thus negative. The Demand response scenario allows for slightly lower cost, both on a continental and domestic level. Again, Heat storage exceeds the savings made with the introduction of power-to-heat demand response at cost reductions of 0.23% and 15.1%. In the interpretation of these numbers, it is important to note here that the cost structure of largely VRES-based electricity systems, such as the one analysed here, is dominated by CAPEX rather than OPEX.

The Danish cost savings appear to be mainly related to the combination of lower import costs and higher export revenues, rather than a reduction in dispatch cost (table 7.8). Note that the achieved relative cost savings exceed the changes in import and export quantities significantly across scenarios. That suggests heat storage and demand response to shift electrified heating demand towards periods of favourable prices in the neighbouring electricity systems, allowing imports at lower and exports at higher per-unit prices.

It should be noted that the numbers presented here heavily depend on the approach for calculating import costs and export revenues from a Danish perspective. Here, we assume both to be priced at the marginal generation costs of the respective interconnected electricity system. Alternatively, one

Table 7.6: Danish electricity exports across scenarios [TWh] (Difference to `Baseline` scenario)

	Baseline	Demand response	Heat storage
GER	17.9	17.99	18.37
	(±0.0%)	(+0.51%)	(+2.63%)
NOR	4.11	4.07	3.77
	(±0.0%)	(-1.03%)	(-8.17%)
SWE	11.57	11.56	11.67
	(±0.0%)	(-0.04%)	(+0.87%)
NL	5.26	5.27	5.34
	(±0.0%)	(+0.11%)	(+1.58%)
UK	6.7	6.7	6.7
	(±0.0%)	(-0.1%)	(-0.09%)
Total	45.54	45.58	45.85
	(±0.0%)	(+0.09%)	(+0.69%)

Table 7.7: OPEX across scenarios [EUR/MWh] (Difference to `Baseline` scenario). Danish numbers assume electricity imports and exports to be priced at the marginal generation costs in the respective neighbour country.

	Baseline	Demand response	Heat storage
DK (per MWh)	-8.7	-8.9	-10.01
	(±0.0%)	(-2.29%)	(-15.1%)
EU (per MWh)	7.23	7.23	7.21
	(±0.0%)	(-0.04%)	(-0.23%)

could also apply marginal costs of electricity flows on the interconnectors or use marginal generation costs in Denmark.

Table 7.8: Danish electricity cost structure across scenarios [M EUR] (Difference to `Baseline` scenario)

	Baseline	Demand response	Heat storage
Domestic generation	5.56	5.22	3.15
	(±0.0%)	(-6.12%)	(-43.3%)
Import costs	256.67	251.53	216.02
	(±0.0%)	(-2.0%)	(-15.84%)
Export revenues	826.88	834.33	869.08
	(±0.0%)	(+0.9%)	(+5.1%)
Total	-564.65	-577.58	-649.91
	(±0.0%)	(-2.29%)	(-15.1%)

Heat storage investments

Table 7.9 shows heat storage capacities and annualized investment costs across scenarios, with the `Demand response` scenario not featuring heat storage. In the `Heat storage` scenario, Frigg chooses to invest in 342.7 GWh-heat of storage, corresponding to roughly 45 hours of average annual electrified heat load.

7.7 Limitations and future research

This case study analyzes the role of power-to-heat demand flexibility (end-consumer demand response and heat storage) on the Danish electricity system of 2050 based on the Techno-Friendly scenario. We have developed an extension of Frigg, a soft-linking framework for integrating non-linear price-based demand response models in large-scale energy system analysis. Our modelling approach allows for a more realistic large-scale analysis of demand response than most existing tools. Frigg was applied to

Table 7.9: (Electrified) heat storage capacities and investment cost across scenarios

	Baseline	Demand response	Heat storage
Capacity [GWh]	-	-	342.70
Annualized investment cost [M EUR]	-	-	51.94

couple Plan4EU, a dispatch model of the European energy system, with a flexibility function modelling Danish heat demand response.

Our numerical results suggest significant cost savings and increased VRES uptake with the introduction of power-to-heat demand flexibility. Here, both cost savings through demand response and heat storage are significant highlighting the importance of the Danish heating sector as a source of energy system flexibility.

Given that our results are based on several assumptions outlined in section 7.3, we recommend the following lines of future research in particular:

- Further improvements of the soft-linking approach and the approximations it makes.
- Evaluating our approach of modelling demand response as an indirect against assuming it a direct control problem.
- Modelling the Danish heating sector in greater detail: This could include the separation of individual and district heating, a higher spatial resolution and time-varying heat pump performance.
- The inclusion of non-electrified heating flexibility and a more detailed modelling of the Danish heating sector and building stock.
- The addition of a capacity expansion model to analyse the impact of power-to-heat flexibility on energy system investments.

7.8 References

[1] Hans Auer et al. *Quantitative Scenarios for Low Carbon Futures of the European Energy System on Country, Region and Local Level*. Tech. rep. 2022. URL: `https://openentrance.eu/2022/07/06/quantitative-scenarios-for-low-carbon-futures-of-the-european-energy-system-oncountry-region-and-local-level/`.

[2] Daniel Beulertz et al. "Development of a Modular Framework for Future Energy System Analysis". In: *2019 54th International Universities Power Engineering Conference, UPEC 2019 - Proceedings* (Sept. 2019). DOI: `10.1109/UPEC.2019.8893472`.

[3] Marco Cearliani. *linear-tree: A python library to build Model Trees with Linear Models at the leaves*. URL: `https://github.com/cerlymarco/linear-tree`.

[4] Sandrine Charousset et al. *plan4res public dataset for case study 3 "Cost of RES integration and impact of climate change for the European Electricity System in a future world with high shares of renewable energy sources"*. URL: `https://zenodo.org/record/3802550#.Y_O-si8Q1QI`.

[5] Sandrine Charousset-Brignol et al. "Synergistic approach of multi-energy models for a European optimal energy system management tool". In: *The Project Repository Journal* (Apr. 2021). URL: `https://opus4.kobv.de/opus4-zib/frontdoor/index/index/docId/8570`.

[6] Danish Energy Agency. *Denmark's Climate and Energy Outlook 2020*. Tech. rep. 2020. URL: `https://ens.dk/sites/ens.dk/files/Basisfremskrivning/deco_2020_27082020.pdf`.

[7] Danish Energy Agency. *Finding your Cheapest Way to a Low Carbon Future: The Danish Levelized Cost of Energy Calculator*. Tech. rep. URL: `https://ens.dk/sites/ens.dk/files/contents/material/file/vejledning_lcoe_calculator.pdf`.

[8] Danish Energy Agency. *Technology Data for Energy storage*. Copenhagen, 2019.

[9] Dansk Fjernvarme. *Fakta om fjernvarme*. URL: `https://www.danskfjernvarme.dk/presse/fakta-om-fjernvarme`.

[10] Dominik Franjo Dominković et al. "Implementing flexibility into energy planning models: Soft-linking of a high-level energy planning model and a short-term operational model". In: *Applied Energy* 260.December 2019 (2020), p. 114292. ISSN: 03062619. DOI: `10.1016/j.apenergy.2019.114292`. URL: `https://doi.org/10.1016/j.apenergy.2019.114292`.

[11] Hrvoje Dorotić et al. "Impact of wind penetration in electricity markets on optimal power-to-heat capacities in a local district heating system". In: *Renewable and Sustainable Energy Reviews* 132 (Oct. 2020). ISSN: 18790690. DOI: `10.1016/j.rser.2020.110095`.

[12] Folketinget. *Lov om klima*. 2020.

[13] Karlo Hainsch et al. "Energy transition scenarios: What policies, societal attitudes, and technology developments will realize the EU Green Deal?" In: *Energy* 239 (2022). ISSN: 03605442. DOI: `10.1016/j.energy.2021.122067`.

[14] Philipp Härtel and Magnus Korpås. "Demystifying market clearing and price setting effects in low-carbon energy systems". In: *Energy Economics* 93 (Jan. 2021). ISSN: 01409883. DOI: `10.1016/j.eneco.2020.105051`.

[15] Rune Grønborg Junker et al. "Stochastic nonlinear modelling and application of price-based energy flexibility". In: *Applied Energy* 275 (Oct. 2020). ISSN: 0306-2619. DOI: `10.1016/J.APENERGY.2020.115096`.

[16] Venkatachalam Lakshmanan et al. "Provision of secondary frequency control via demand response activation on thermostatically controlled loads: Solutions and experiences from Denmark". In: *Applied Energy* 173 (July 2016), pp. 470–480. ISSN: 03062619. DOI: `10.1016/j.apenergy.2016.04.054`.

[17] Henrik Lund et al. "Energy Storage and Smart Energy Systems". In: *International Journal of Sustainable Energy Planning and Management* 11 (2016), pp. 3–14. ISSN: 22462929. DOI: `10.5278/ijsepm.2016.11.2`.

[18] F. Moeller Andersen et al. *Analyses of demand response in Denmark*. Risø DTU - National Laboratory for Sustainable Energy, 2006. ISBN: 8755035299. URL: `https://inis.iaea.org/search/search.aspx?orig_q=RN:38013867`.

[19] Jaume Palmer Real et al. "Characterisation of thermal energy dynamics of residential buildings with scarce data". In: *Energy and Buildings* 230 (2021), p. 110530. ISSN: 03787788. DOI: `10.1016/j.enbuild.2020.110530`. URL: `https://doi.org/10.1016/j.enbuild.2020.110530`.

[20] Amos Schledorn et al. "Frigg: Soft-Linking Energy System and Demand Response Models". In: *Applied Energy* 317 (2022). DOI: `https://doi.org/10.1016/j.apenergy.2022.119074`.

[21] Amos Schledorn et al. "Optimising block bids of district heating operators to the day-ahead electricity market using stochastic programming". In: *Smart Energy* 1 (2021), p. 100004. ISSN: 26669552. DOI: `10.1016/j.segy.2021.100004`. URL: `https://doi.org/10.1016/j.segy.2021.100004`.

[22] Lennart Söder et al. "A review of demand side flexibility potential in Northern Europe". In: *Renewable and Sustainable Energy Reviews* 91 (Aug. 2018), pp. 654–664. ISSN: 18790690. DOI: `10.1016/j.rser.2018.03.104`.

[23] Georg Thomaßen, Konstantinos Kavvadias, and Juan Pablo Jiménez Navarro. "The decarbonisation of the EU heating sector through electrification: A parametric analysis". In: *Energy Policy* 148.February 2020 (2021). ISSN: 03014215. DOI: `10.1016/j.enpol.2020.111929`.

Chapter 8

Case Study 8: The role of natural gas storage for flexibility

Contents

Abstract

As the world continues to shift towards cleaner and more sustainable energy, various technologies and strategies are being explored and developed for energy storage and supply. The power-to-gas technology has been highlighted as a promising way to address the current energy crisis due to its high storage capacity and long lifetime compared to other systems. Recent studies have shown that achieving a zero emissions target by 2050 is possible through aggressive policies focusing on promoting clean fuels with fewer emissions. In this case study, we explored power-to-gas and storage technologies further, and their potential impact on meeting future energy demands sustainably. Advancements in technology, including intelligent dispatching through advanced storage solutions like power-to-gas technology, are presenting new ways to store and supply energy efficiently and in a flexible way. One idea is to produce green hydrogen through electrolysis and blend and store it together with natural gas (up to 20%), as in Turkey natural gas storage facilities and their capacity have been increasing steadily. One can also continue using green hydrogen and further produce and store synthetic methane in underground storage facilities. Both cases (hydrogen and synthetic methane storage for Turkey) are studied in this case study, which provides an overview of how natural gas storage solutions can provide flexibility for natural gas import dependent countries like Turkey by 2050. This case study investigates the role of natural gas storage in the current and future Turkish energy systems in transition. It is shown that the use of power-to-gas technology for producing hydrogen and/or methane can enhance flexibility in energy supply systems, particularly during the transition to low-carbon energy system. The result of the case study will promote the use of renewables and therefore lead to a low-carbon energy system. The impact of carbon pricing and decreasing cost of renewables as well as the natural gas storage availability will allow policy makers to make decision about renewables.

8.1 Introduction

Until the recent strengthening of European climate ambitions in the framework of the "Green Deal", the role of natural gas in the decarbonising European energy system was unclear and many expected a long-term role as "bridge fuel" [9]. Facing an increasing global demand for energy and, at the same time, the need to drastically and rapidly reduce carbon dioxide emissions, green gases have gained increasing attention for tackling the various challenges of the energy transition. In this context, the production of green hydrogen, either for direct use or for further processing to, e.g., green methane, plays a crucial role. Yet, as of 2019, about 95% of global hydrogen production is based on fossil fuels, mainly steam reformation of natural gas, causing large amounts of CO_2 emissions. The remaining 5% are a by-product from chlorine production (water electrolysis employing the current electricity mix). So far, there exist hardly any (green) hydrogen production based on renewable electricity.

For the large-scale implementation of green, renewables-based gases, several competing strategies are possible and currently discussed. First, a direct shift from natural gas to green hydrogen with parallel infrastructure in the short to medium run. Second, the production of green synthetic methane which can be used within the existing natural gas infrastructure. Third, the blending (mixing) of green hydrogen with natural gas within the existing natural gas infrastructure.

Each of these strategies to integrate green gases has specific strengths and weaknesses. For instance, methanation of green hydrogen and subsequent injection in the existing natural gas framework suffers from a low overall efficiency of only about 40% with respect to electricity input in production. By contrast, while overall efficiency is higher when directly using green hydrogen, a shift away from natural gas requires substantial investments in new hydrogen-ready infrastructure or in the adaption of existing infrastructure. Finally, blending green hydrogen with natural gas may appear as the optimal solution for a gradual transition at first glance. Yet, (seasonal/variable) blending is likely to be only feasible for relatively low shares of hydrogen and may cause problems when gas purity is required (chemical industry) or when a constant stream of energy is necessary. One must keep in mind that the energy content per volume (at ambient pressure) is higher for natural gas than for hydrogen.

Thus, the choice of the optimal transformation strategy depends on country-specific conditions like the availability of renewable (surplus) electricity generation but also on techno-economic parameters like process-efficiency and current and expected future investment costs. This case study report sheds some light on these questions and provides results for the Turkish case. By evaluating different strategies to green gas supply in Turkey, lessons for the rest of Europe can be drawn.

The Turkish energy system is in transition towards to more renewable, but the role of natural gas is still important and will be considerable in future. Although its role is expected to be important, the level of demand is also expected to change due to dynamic conditions in energy system. The cost of renewables is decreasing, the carbon pricing becomes important and a low carbon energy system is desired. A more secure, flexible, sustainable, and reliable energy supply is preferred. The energy storage capacity and means are developing and expected to be more common in future. The policy makers need long term analysis to make decision for the future energy system.

This case study investigates the role of natural gas storage in the current and future Turkish energy systems in transition. The result of the case study will promote the use of renewables and therefore lead to a low-carbon energy system. The impact of carbon pricing and decreasing cost of renewables as well as the natural gas storage availability will allow policy makers to make decision about renewables.

Power-to-gas provides a new level of flexibility in the energy supply system by producing hydrogen and/or synthetic methane. Renewable gas from the power-to-gas conversion of surplus renewable electricity can be stored in natural gas storage either in the form of partially blended hydrogen (thru electrolysis) with natural gas or fully blended synthetic gas (thru electrolysis and methanation) with natural gas. Additionally, the study emphasizes the need for decarbonized sources of natural gas, to ensure the long-term viability of natural gas storage as an option for the energy transition.

The study also examines the potential for integrated energy systems that deeply interconnect electricity and natural gas infrastructure. Moreover, the study highlights the importance of using decarbonized natural gas (i.e. synthetic methane) and power-to-gas technology (i.e. electrolizers) to ensure the sustainability and viability of storage as an option for transitions to low-carbon energy. The use of power-to-gas technology for producing hydrogen and/or methane can significantly enhance flexibility in energy supply systems, particularly during the transition to low-carbon energy. Through the conversion of surplus renewable electricity to renewable gas, natural gas storage can be used as an ideal option for storing this energy. However, in order to ensure long-term viability and sustainability of natural gas storage as an option for energy transition, the use of decarbonized natural gas and power-to-gas technology is crucial.

Additionally, integrating natural gas infrastructure in integrated energy systems can further enhance flexibility within the energy supply system. This "Case Study 8 Report" underscores the importance of natural gas storage in contributing to the integration of intermittent renewable energy, providing flexibility within energy supply systems, and potentially playing a significant role in the future energy system.

Under the light of the presented situation, the research questions can be summarized as below.

- Is it possible to develop a long term model to integrate power-to-gas infrastructure to the current Turkish energy system considering the increasing share of renewables and demand for natural gas?
- What will be the model outputs in each scenario when the long term energy system is analyzed and run using GENeSYS-MOD-Turkey?
- What will be the natural gas, synthetic methane and hydrogen production and use in each scenario as well as storage dispatch and possible takeouts from these results?
- What should be the natural gas storage capacity in future energy system of Turkey?

8.2 Background

8.2.1 Background: Turkish energy system

The energy system in Turkey still heavily relies on fossil fuels, and the country is not considered rich in terms of fossil fuel resources. Almost all of the oil and natural gas resources are imported as well as the important share of the coal. According to the latest reports, the electricity generation in 2022 is provided from coal (34.6%), natural gas (22.2%), hydro (20.6%), wind (10.8%), solar (4.7%), geothermal (3.3%) and other resources (3.7%). As of April 2023, the installed electricity capacity is 104 496 MW while hydro (30.2%), natural gas (24.3%), coal (20.9%), wind (11%), solar (9.5%), geothermal (1.6%) and other (2.5%) are the main capacity components. Another report shows that the primary energy consumption in Turkey is 6 163 petajoules (147.2 Mtoe) in 2020 and solid fuels (27.6%), oil and derivatives (28.7%), natural gas (27%), and renewables (16.7%) are the main resources. [18].

Turkey is located in the middle of Caucasian and Middle Eastern countries, which are natural gas exporting countries. The country is located on the crossroads of pipeline networks and aims to be an energy hub, and transmission corridor to Europe. Hence, storage capacity is important for this objective. Figure 8.1 shows the main components of the oil and gas infrastructure whereas Figure 8.2 shows the natural gas network in Turkey [18]. .

Figure 8.1: Turkish Oil and Gas Infrastructure (Source:[4]

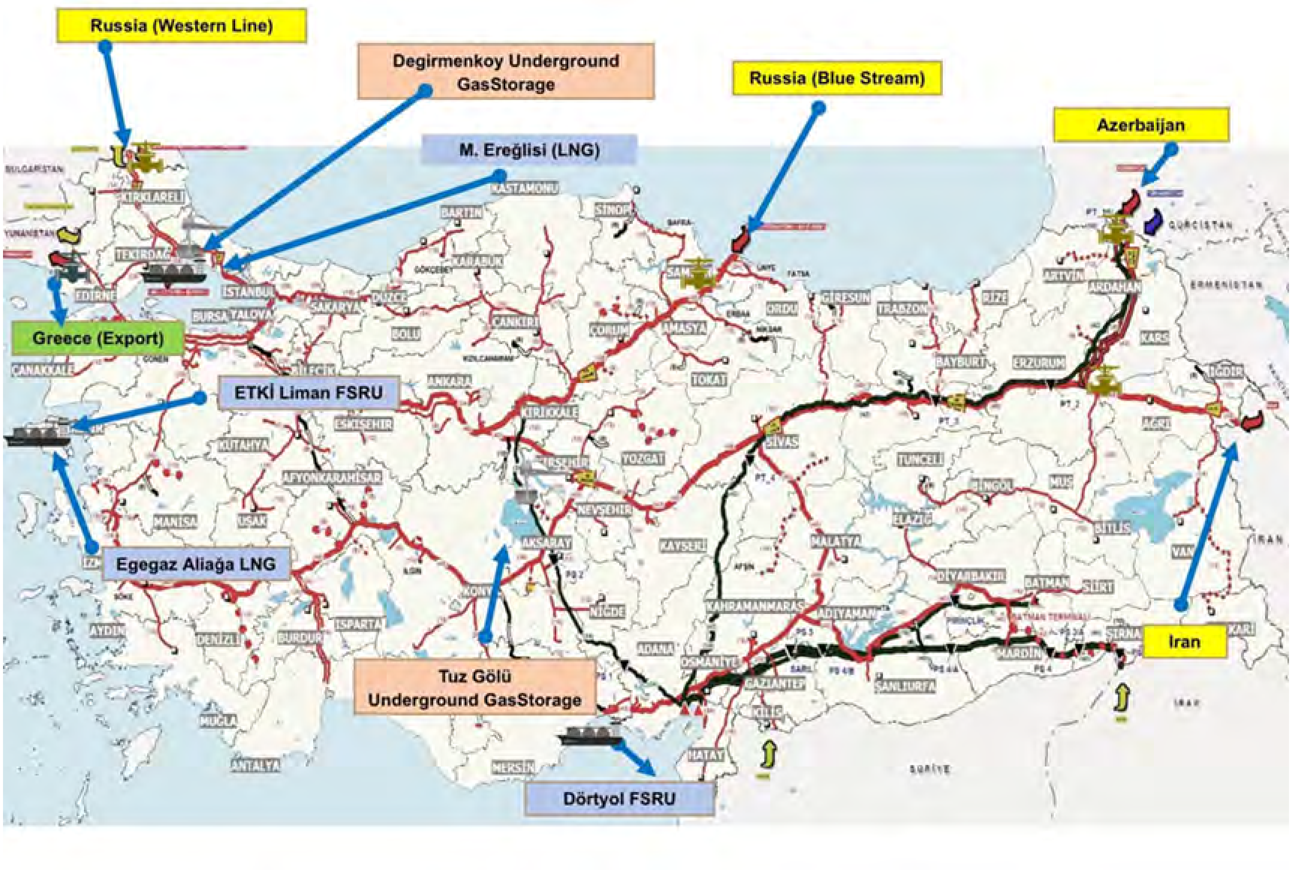


Figure 8.2: Natural gas network of Turkey (Source:[4]

In Turkey, procurement, distribution, tariff determination, and wholesale of natural gas are managed by the main supplier company, Petroleum Pipeline Corporation (BOTAS). Figure 8.3 summarizes the natural gas supply network structure in Turkey[1].

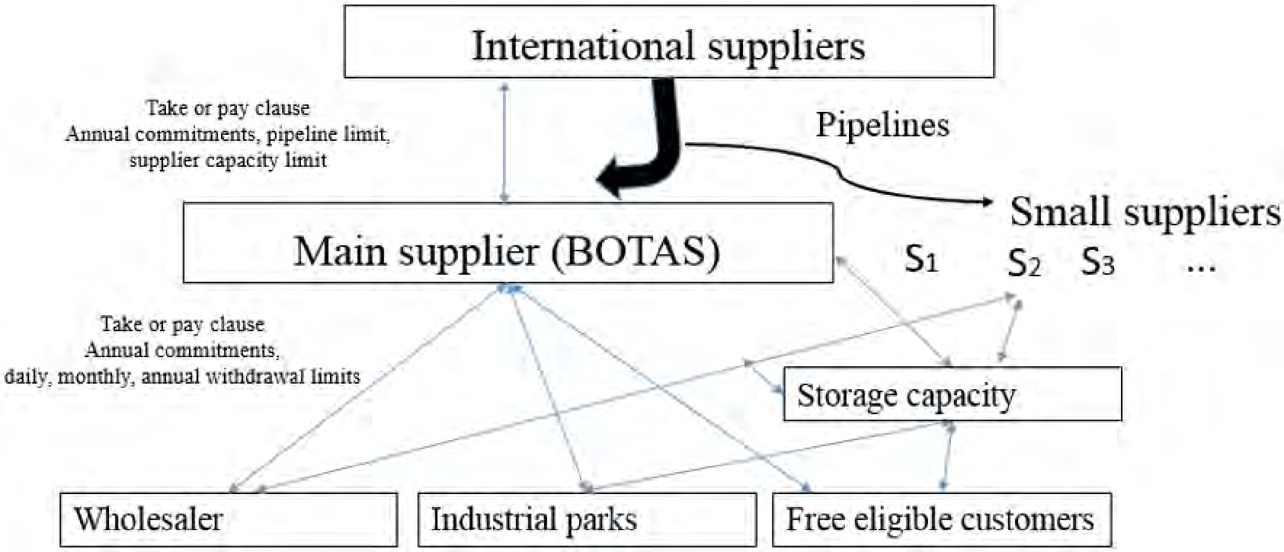


Figure 8.3: Natural gas supply chain of Turkey

The objective of the market mechanism in Turkey is to reach a reliable, minimum cost, competitive supply, a transparent market, and supply security. Storage operations can be useful in managing demand fluctuations in the market, sudden demand increases, seasonal changes, and supply security. An adequate storage capacity is essential for such purposes. The storage of natural gas is currently limited in Turkey with a total capacity of 6.28 billion cubic meters (bcm), which is around 10% of the annual demand in Turkey [18].

Turkey has increased its natural gas storage capacity in recent years to help the supply and demand balance. The natural gas can be stored in the Silivri, Kuzey Marmara, Değirmenköy and Salt lake natural gas underground natural gas storage facilities, as seen in Figure 8.2. Especially Salt lake facility has added a significant capacity to this storage and the amount of capacity that is available in this facility is increased for eligible natural gas suppliers and consumers. A supplier and consumer may apply for a storage capacity and the natural gas can be stored, injected and withdrawn to the national pipeline upon request. On the other hand, natural gas can be stored as LNG in several facilities that belong to BOTAŞ. Power-to-gas, on the other hand, provides an opportunity for the Turkish energy system to produce gas (either through natural gas blended with hydrogen or production/storage of synthetic methane).

8.2.2 Technology background: The power-to-gas value chain

Green hydrogen, that is, the water-electrolysis based production of hydrogen with renewable electricity, is potentially an important substitute for natural gas in many applications.[1] Yet, a rapid transition from natural gas to green hydrogen is unlikely and will probably take place earlier in some sectors than in others. Thus, for a rolling transition, the question arises whether it is possible to (partially) use existing infrastructure for hydrogen or, alternatively, to which extent natural gas can be blended with green hydrogen.

[1] Other ways to produce emission-free hydrogen, e.g., steam-methane-reformation with or without carbon capture and storage are not considered here.

Figure 8.4 shows the methodology that will allow the utilization of hydrogen or synthetic methane after methanation.

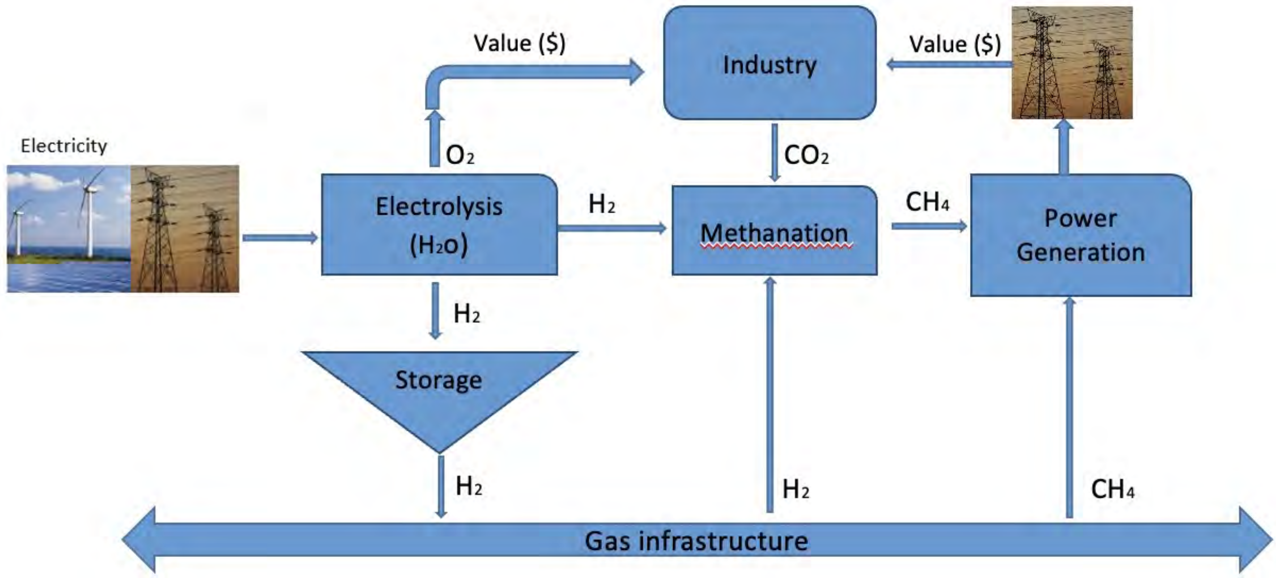


Figure 8.4: Power-to-gas infrastructure

Limits to blending hydrogen with methane

Independently of the level of admixture of hydrogen, the blending of natural gas is only possible in cases where natural gas is not used as raw material (feedstock) which would require a high degree of purity of the methane. Apart from that, blending of up to 20% in natural gas pipelines is found to be feasible with only minor modifications [13]. Yet, the maximum feasible degree of blending and associated adaption costs depends highly on the specific application. This must be assessed on a case-by-case basis. Figure 8.5 shows that the limitations to blending in various cases.

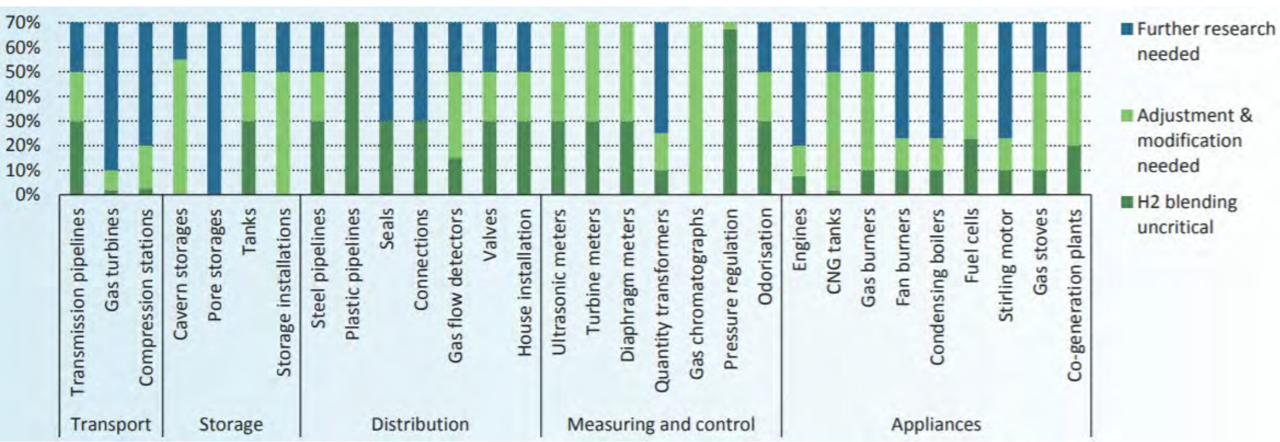


Figure 8.5: Limitations to blending (Source: [11])

Further possible obstacles to blend a high share of hydrogen in natural gas pipelines are:

- The lower energy density of hydrogen that requires higher energy flows (e.g., for a 20% blend of H2 or 15% higher flow rates are required), implying larger compression energy demand.

- When pure hydrogen or natural gas is needed, hydrogen and natural gas must be separated, which requires additional infrastructure near the pipeline exit point or the demand site and leads to additional costs.

Underground hydrogen storage

Underground storage has three main advantages: large volume, low costs, and operational safety. Different kinds of porous rocks (depleted oil and gas fields, aquifers) and (artificial) underground spaces (salt caverns, disused mines) are used for natural gas storage and have been considered in the literature for underground hydrogen storage. However, as highlighted by [23], there is yet only a little experience with underground storage of hydrogen. To date, there are only a few demonstration projects with hydrogen.

According to the International Energy Agency, in 2018, several hundred underground natural gas storage facilities with a working gas capacity of 2377 bcm (billion cubic meters) were in operation worldwide, of which 1057 bcm were located in Europe [12] (including Turkey and the Balkan, but excluding Ukraine and Belarus, excluding storage at LNG import terminals). The distribution of underground storage facility working gas capacity by type of geological structure in Europe is given in Figure 8.6. The majority of underground storage capacity in Europe still is in depleted oil and gas fields (almost 80%), but the share of salt caverns has increased substantially in the last two decades to more than 15%.

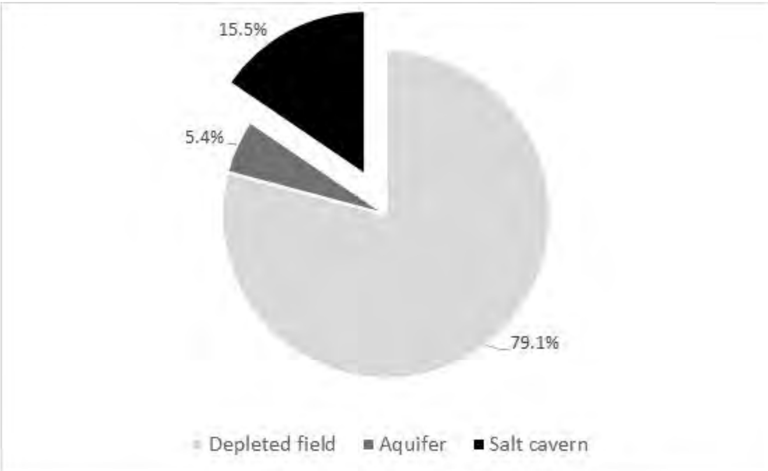


Figure 8.6: Working gas capacity by storage type in 2018 (Source: [12])

Each geological structure has specific advantages and disadvantages for storing hydrogen, which is systematically summarized in the Table in Figure 8.7. For each of the three types of geological structures, capital investment costs (CAPEX) mainly comprise compression, purification, and dehydration infrastructure. Moreover, for new salt caverns, dissolution, i.e., creating storage volume, can entail substantial further costs. The literature also points out that the necessity of cushion gas (30-50%) to provide a minimum pressure incurs further costs. The following values are given for total CAPEX [23]:

- depleted hydrocarbon deposits (1.23 USD/kg of stored hydrogen)
- aquifers (1.29 USD/kg)
- salt caverns (1.61 USD/kg)
- hard rock caverns (2.77 USD/kg)

While these CAPEX costs give a first impression, they may largely depend on the specific storage site. A precise accounting of costs also requires to include variable (operational) costs (OPEX), like electricity inputs for compression etc. [23, 22].

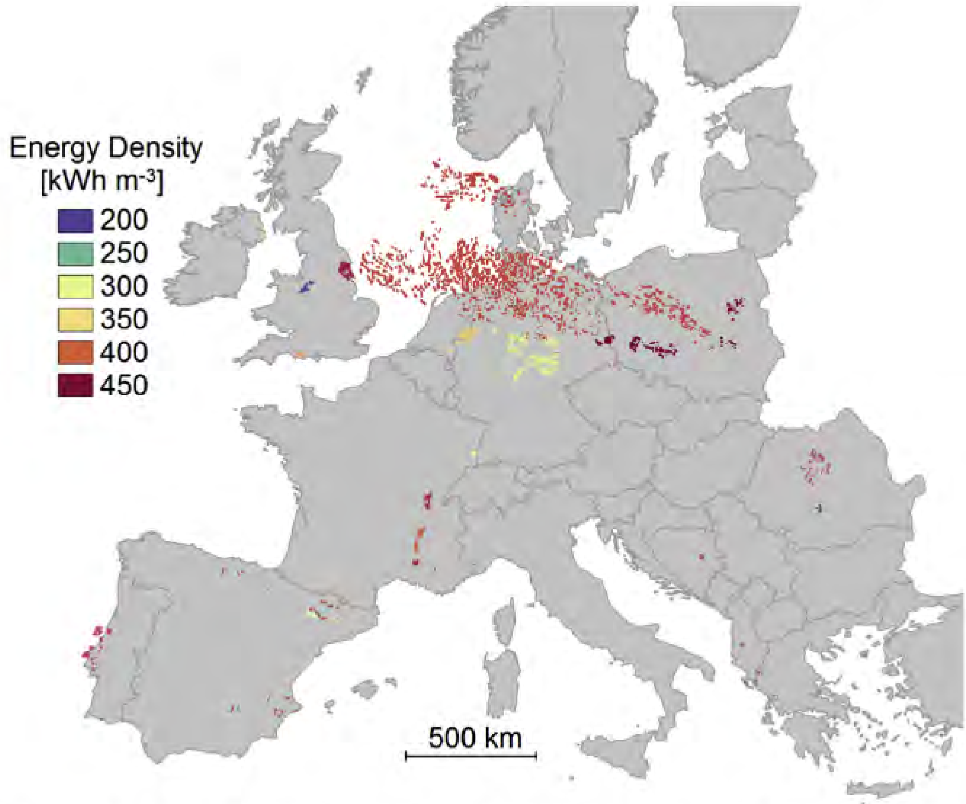
Relevant geological, technical, environmental, health and cost aspects of various options for underground hydrogen storage.

	Deep aquifers	Depleted oil and gas fields	Salt caverns
Occurrence	Prevalence in all sedimentary basins	Traps accumulating hydrocarbons	Prevalence in many sedimentary basins
The depth of deposits	Various depths, optimally up to 2000 m	Various depths, optimally up to 2000 m	Various depths, optimally up to 1500 m
Lithology of site storage and caprock	Reservoir rocks with high porosity and high permeability, roof rocks providing seal, not cracked	Reservoir rocks with high porosity and high permeability, roof rocks providing seal, not cracked	Thick salt deposits; salt beds seem most appropriate
Recognition	Low. Recently recognised in Europe in the context of assessing the potential for CCS	Geology well recognised	Well recognised salt formations in Europe
Geological tightness	The tightness of aquifer initially unknown, a low risk of gas leakage	The existence of gas deposits confirms their tightness	The tightness is assured by favorable properties of the salt rock
Recent experience throughout the world	No experience with storage of pure hydrogen. Numerous underground stores of natural gas working successfully	No experience with storage of pure hydrogen. Numerous underground stores of natural gas working successfully	Positive experience with storage of hydrogen and other gases
Injection and withdrawal cycles	One, maximum two cycles of injection and withdrawal per year	One, maximum two cycles of injection and withdrawal per year	Possibility of multiple (up to 10) cycles of injection and withdrawal of gas per year
Flexibility of cycling	Used for seasonal storage	Used for seasonal storage	Possible use for storage more frequent than seasonal
Impurities in withdrawn gas	Undesirable reactions producing gases such as H_2S and CH_4 with loss of hydrogen	Undesirable reactions producing gases such as H_2S and CH_4 with loss of hydrogen, mixing of residual hydrocarbons with hydrogen in the case of depleted oil fields	Impurities caused by undesirable reactions between hydrogen and interbeddings other than rock salt
Cost of construction and operation	The costs higher than the cost of storage in salt caverns or hydrocarbon deposits	The lowest storage costs for the use of depleted natural gas deposits, higher for oil fields	Higher than in depleted hydrocarbon fields

Figure 8.7: Relevant geological, technical, environmental costs of various options for underground storage (Source: [23])

In the literature, salt caverns are largely considered the most promising type of underground hydrogen storage [23, 5], due to their lower cushion gas requirement (30%), and most importantly their impermeability and advantages with respect to potential contamination of stored hydrogen [5]. Moreover, salt caverns can be operated relatively flexibly with several injection/withdrawal cycles per year. [17] point out that, in contrast to depleted gas fields, availability of salt caverns may be limited in some places. However, salt caverns are man-made structures and can potentially be constructed in many more places than where they currently exist.

[5] find a total technical storage potential of 84400 TWh of salt caverns (LHV, working gas, i.e., already accounting for cushion gas), 27% (23.2 PWh) of which are onshore. Potential indicates that salt caverns need to be leached (i.e. constructed) first to create storage capacity. Realizable potential, accounting for economic and ecological limitations, may be substantially lower. If the maximum distance to the shore (to allow for easy brine disposal) is constrained to below 50 km, onshore potential reduces to 7300 TWh. The distribution of storage capacities across Europe with the respective energy density (which accounts for storage pressure) is given in Figure 8.8. Country-specific storage capacities are given in Figure 8.9. In Turkey, one salt cavern facility has been under construction in the last years, Lake Tuz. It is reported to reach a capacity of up to 5.4 bcm (billion cubic meters) by 2023, with pressures up to 210 bar. Assuming a maximum pressure of 160 bar during operation and 30% cushion gas, this amounts to about 1790 TWh hydrogen storage capacity.



Distribution of potential salt cavern sites across Europe with their corresponding energy densities (cavern storage potential divided by the volume).

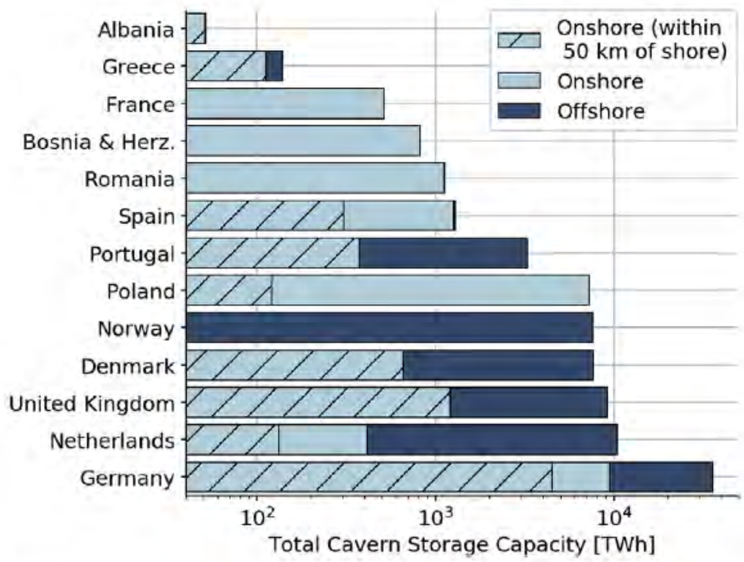
Figure 8.8: Distribution of potential salt caverns across Europe (the graphic partially covers Turkey) with corresponding energy density (Source: [5])

Reassignment of Natural Gas Pipelines (100% hydrogen)

Research in the last years has increasingly focused on the introduction of pure hydrogen in the energy system instead of admixing. To avoid stranded investments, the possibility to reassign natural gas transport infrastructure, especially pipelines, for pure hydrogen, plays a key role in the discussions. The costs of natural gas pipeline reassignment are investigated in [6] and [19]. Four competing reassignment methods of gas pipelines must be distinguished:

- Use of pipelines without substantial modifications while managing hydrogen-induced material degradation (e.g., higher maintenance frequency),
- Admixture of inhibitors to the hydrogen stream,
- Inner coating of pipelines,
- Implementation of an additional pipeline within existing ones.

The main challenge in reassigning natural gas pipelines for pure hydrogen is to avoid material failure, especially fracturing of metal (so-called hydrogen embrittlement). Thus, most of the four reassignment methods tackle fatigue crack propagation of X42 and X70 steel, which is commonly used for natural gas pipelines, by minimizing contact/reactions between steel and hydrogen. Table 8.1 summarizes the strengths and weaknesses of each pipeline reassignment method. As pipe-in-pipe and



Total cavern storage potential in European countries classified as onshore, offshore and within 50 km of shore.

Figure 8.9: Total cavern storage potential in Europe classified as onshore, offshore and within 50km of shores (Source: [5])

coating potentially require large costs due to excavation of pipelines, [6] focus on the two options to either use gas pipelines without further modifications or with admixture of inhibitors.

Table 8.1: Strengths and weaknesses of pipeline reassignment alternatives (Source: [6] and references therein)

Reassignment alternative	Strengths	Weaknesses
Pipeline without modification	Few modifications are required Limited material fracturing under static load	Increased material degradation
Coating	Specific protection layer against H_2 embrittlement Developed industrial process on metal surfaces	No known on-site coating procedures Excavation of pipelines probably required
Inhibitors (O_2, CO, SO_2)	Limited modifications are required Protection layer undermining hydrogen permeation	Toxicity and security risks Purity requirements of H_2 processing and of fuel cells
Pipe-in-pipe	Combined benefits from inner and outer pipeline	Additional material required Excavation of pipelines probably required

As highlighted in [6], without further modifications, the use of existing gas pipelines for pure hydrogen may result in crack growth that would be accelerated by a factor of up to 5-15 (compared to regular natural gas operations), thereby inducing higher operational and maintenance costs (OPEX) as well as a reduced pipeline lifetime. Moreover, a shift to hydrogen additionally requires new infrastructure for hydrogen compression and pressure regulation.

For inhibitor admixture, costs depend largely on the used inhibitor (O_2, SO_2, CO). Again, compressor stations and pressure regulation infrastructure must be replaced/adapted to hydrogen. Moreover, post-transportation purification and re-compression may cause a further rise in CAPEX and OPEX. In a scenario for Germany, [6] obtain additional costs for pipeline reassignment as shown in Figure 8.10. Importantly, [6] find that total costs of pipeline reassignment using inhibitors are in general higher than building new hydrogen pipelines. In contrast, despite higher OPEX, using existing natural gas pipelines without modification is about 60% cheaper than building new hydrogen pipelines. Consequently, only the use of existing pipelines without large modifications is seen as a feasible reassignment method while the admixture of inhibitors is rejected due to high costs. While the costs depicted in Figure 8.10 give a first impression, they may largely depend on the specific pipeline material. A precise identification of costs thus requires the direct implementation of reassignment-induced CAPEX and OPEX changes as outlined in Figure 8.11.

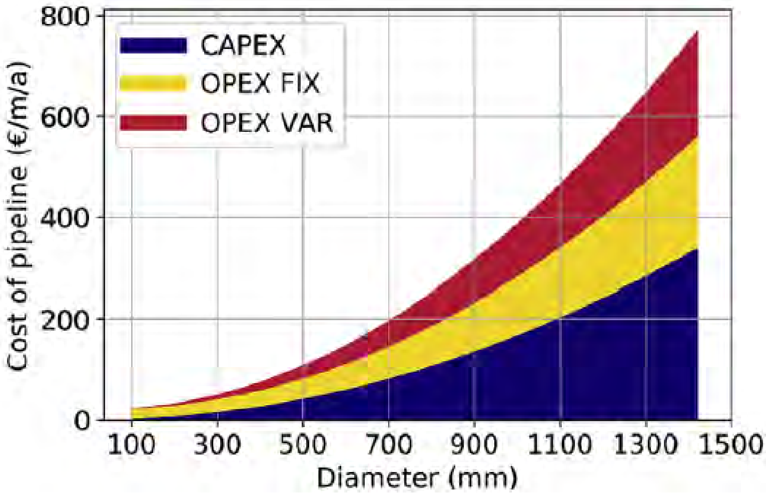
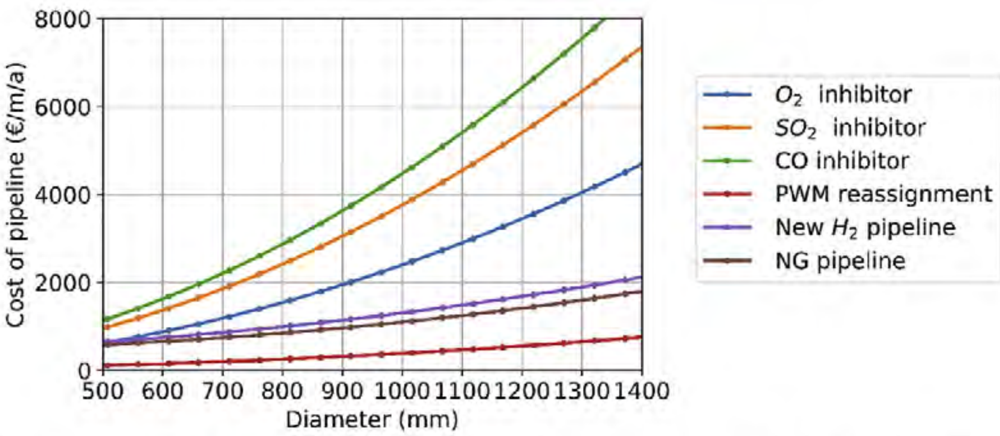


Figure 8.10: Additional costs of using gas pipelines without modifications for hydrogen, for different pipeline diameters (Source: [6])



Cost comparison of the pipeline reassignment alternatives and new H_2 pipelines.

Figure 8.11: Cost comparison of pipeline reassignment alternatives and new hydrogen pipelines (Source: [6])

Electrolysis and methanation

The costs of water-electrolysis technologies are expected to decrease rapidly in the future. Table 8.2 presents data for costs, lifetime, and efficiency of the two most common water-electrolysis technologies, alkaline water electrolysis (ALK) and proton exchange membrane water electrolysis (PEM). Following [21], OPEX, lifetime, and efficiency are assumed to remain unchanged over time and are based on [22] for both 2015 and 2030. According to [21] and [24], CAPEX of both water electrolysis technologies will decline further after 2030 and are expected to fall to or even below 500 $€/kW_el$ by 2050.

Table 8.2: Parameters for the two electrolysis technology types ALK (alkaline water electrolysis) and PEM (proton exchange membrane water electrolysis) (Sources: 2015 [21]; 2030: [22])

	2015		2030	
	ALK	PEM	ALK	PEM
CAPEX (€/kW_el)	1100	2090	550	724
OPEX (%)	1.5	1.5	1.5	1.5
Lifetime (years)	10	10	10	10
Efficiency (%)	66	71	66	71

As [24] points out, the costs for synthetic methane production are substantially higher than natural gas prices were on average in the past years (i.e., except for the strong gas price rise in 2022). Costs of biological methanation (i.e., production of biomethane which is a high-methane concentration variant of biogas) are about one third higher (1200 €/kW_el) than chemical methanation as presented in Table 8.3. Chemical methanation involves the combination of hydrogen with carbon dioxide. Until 2030, [24] expect the costs of biological methanation to decrease to 300 €/$kWel$ while that of chemical methanation may potentially decrease even further to 130-400 €/kW_el. In the case of synthetic methane production, CAPEX also includes the capacity costs of electrical power generation for the electrolyzer necessary to feed the methanation plant (but does not include electrolyzer costs itself).

Table 8.3: Cost parameters for methanation of hydrogen in 2015 (based on an overall average efficiency of 41% and an electrolysis efficiency of 77%) (Source: [24])

Parameter	Parameter value
CAPEX (€/kW_el)1	800
OPEX (%)	2
Lifetime (years)	15
Efficiency (%)2	53

An open, yet important question with respect to the scope of large-scale methanation is the availability of (pure) CO_2. As [2] point out, with ongoing decarbonization, CO_2 captured from large-scale combustion processes may become a scarce resource, leaving recovery of CO_2 from ambient air (direct air capture, DAC) as the only option. The costs of DAC are expected to be non-negligible, currently ranging from 94-232 USD per ton of CO_2. Projections indicate that costs may decline to 60$/t by 2040 [13]. Further processes are necessary during the production of hydrogen or synthetic methane, e.g., compressors, small-scale storage etc. and their costs have to be included in a comprehensive assessment [22].

8.3 GENeSYS-MOD-Turkey model

GENeSYS-MOD, a custom-designed global energy solution system for long-term energy models, was used in this case study. GENeSYS-MOD, is a full-fledged energy system model originally based on the open-source energy modeling system, called OSeMOSYS [15, 16]. The model uses a system of linear energy system equations to search for the lowest-cost solutions for a secure energy supply, given externally defined constraints on greenhouse gas (GHG) emissions. In particular, it takes into account increasing interdependencies between traditionally segregated sectors, e.g., electricity, transportation, and heating. OSeMOSYS itself is used in a variety of research to provide insights about regional energy systems and their transition towards renewable energies. GENeSYS-MOD model is extended and additional functionalities are implemented, e.g., a modal split for the transportation sector or relative investment limits for the single model periods. Both the model and the data used by GENeSYS-MOD are open-access and freely available to the scientific community[15, 16]. This model's importance lies in its ability to provide insights about regional energy systems and their transition toward renewable energies. [2]

A stand-alone GENeSYS-MOD-Turkey model, which isolates Turkey from the rest of EU countries, is used for this study [14]. The reason is to investigate the impact of flexibility options of gas storage by excluding the imports of hydrogen or synthetic methane.

In this case study, GENeSYS-MOD v3.1 model [3] is used, but there are several modifications to it. Firstly, only a single node model (aggregated Turkish region) is used, i.e., all regions, except TR region, are excluded from the model's regions set. Although, a disaggregated model for Turkey is available in Deliverable 3.2 of OpenENTRANCE project [3], gas infrastructure data (e.g., gas flow or daily/monthly pipeline capacities) for sub-regions are not available nor accessible through Petroleum Pipeline Corporation (BOTAŞ). Secondly, there was an issue within the GAMS model, regarding storage variable/parameter/equation definitions and relations. This has been corrected by the GENeSYS-MOD developer team (by late November 2022). Thirdly, the data for Turkish energy system is updated, as described in Section 8.5. Major parameters of the GENeSYS-MOD model are kept the same as in the European model version, i.e,. only capacity and input/output activity ratios of natural gas storage are modified. As there is significant natural gas storage capacity in Turkey; creating new ways in GENeSYS-MOD-Turkey to store renewable hydrogen and synthetic methane in these storage facilities generated results that are specific and significant to the Turkish energy system.

8.4 Assumptions and methodology

This case study aims to investigate the potential for gas (including natural gas and synthetic methane) storage to provide additional flexibility to the energy system. In order to explore flexibility options related to natural gas and green gases (hydrogen, synthetic methane), we consider four cases:

- **No limits on natural gas imports:** In this case, we have no limitations on natural gas imports, i.e. the capacities of import pipelines and LNG (liquified natural gas) import terminals are assumed to be unlimited. Natural gas and hydrogen storage are both possible. This is used as a hypothetical base (reference) case.
- **No H_2 blending:** This case limits the natural gas imports in certain time periods (i.e., from December to March), hence a need for natural gas storage can emerge. We have selected these time periods based on monthly natural gas demand between 2018-2022, as highlighted in Figure 8.12.

[2]See https://www.iamcdocumentation.eu/index.php/GENeSYS-MOD and references therein.

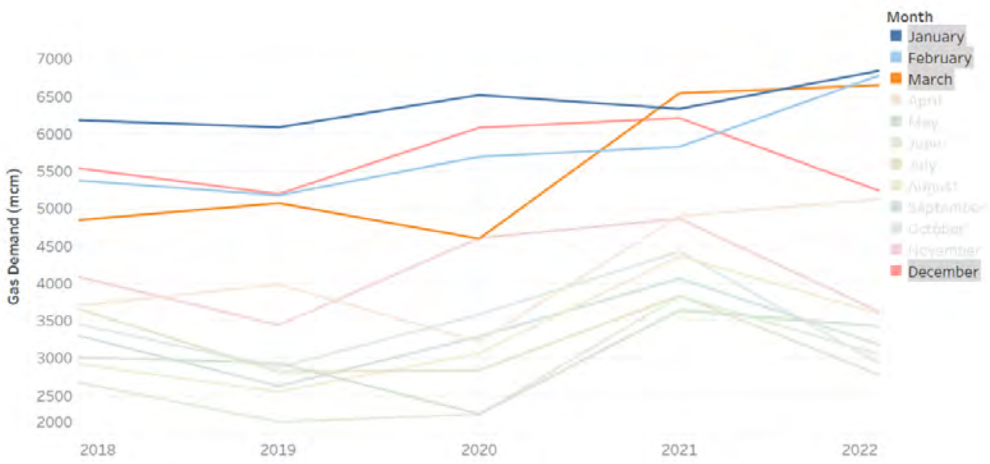


Figure 8.12: Monthly Turkish Gas Demand in 2018-2022 (Source: [7])

- **H_2 blending:** In this case, hydrogen can be blended into natural gas storage, as opposed to "No H_2 blending" case. This is achieved through modifying the model parameter,"Input Activity Ratio" of natural gas storage gradually, from 100% natural gas and 0% hydrogen in 2018 to 80% natural gas and 20% hydrogen by 2030. This 20% hydrogen blending into natural gas storage strategy by 2030 is a target of the Turkish energy system as discussed in [20].
- **Synthetic methane storage:** In addition to the "H_2 blending" case, this case considers the storage of synthetic methane in natural gas storage from 2040 to 2050. In this case study, under all cases and scenarios, natural gas use ends before 2040 (except GD scenarios which ends before 2045) and synthetic methane production through methanation takes place as early as 2040 (except GD scenario which takes place after 2045). Therefore, we have assumed that natural gas can be replaced by synthetic methane after 2040. In order to model this in GENeSYS-MOD GAMS model, we have modified the "Input Activity Ratio" as well as "Output Activity Ratio" parameters in the model in order to replace natural gas by synthetic methane from 2040 to 2050 (for GD scenarios, 2045 to 2050).

Although Turkey has a natural gas storage capacity of 6.28 billion cubic meters (bcm), we assume that the storage can be increased in future. The proposed model assumes that the storage capacity is available (10 bcm by 2025 and stays constant until 2050), and hence finds the amount of natural gas to be stored. The technical details of the storage, whether it is a cavern or another geological structure depends on future research and necessities. The long term energy system is analyzed based on the model results for scenarios, the outputs are analyzed to extract useful information for decision making for the future of the Turkish energy system.

Same technological scope of GENeSYS-MOD-Europe [15], namely electricity, heat and trasportation was used when running GENeSYS-MOD-Turkey for this case stıdy. Available technologies, their costs, capacities, availabilities and efficiencies, demand profiles, emission costs were kept same as well. We have carefully checked the changes in the costs of methanation and electrolysis in the input file and we found they agreed with the literature. We have updated the natural gas storage amounts and their charging and discharging rates in GENeSYS-MOD-Turkey. The time step of the simulations were 73 hours which was smaller than the one used to run GENeSYS-MOD-Europe scenarios. We have also used same four openENTRANCE pathways (scenarios) that the GENeSYS-MOD-Europe uses, namely

Gradual Development (a 2°C scenario), Techno-friendly, Societal Commitment and Direct Transition (all 1.5°scenarios).

In light of this, the case study report presents analyses and shows that a comprehensive analysis of natural gas storage facilities is necessary to ensure economic viability for an energy system. The report stresses the important role of renewable energy technologies, such as power-to-gas facilities, in the low-carbon energy transition. Without careful consideration of these factors, investment in natural gas storage facilities may result in stranded assets and have negative economic impacts. The case study report does not include the following operational, economical and technical details that was mentioned in Deliverable 5.2, such as hourly dispatch of storage, cost-benefit analysis of natural gas storage, the change in the use of methanation and electrolysis when market prices change and comparison of salt cavern storage with other storage types (e.g., batteries, EVs, hydropower). The current version of GENeSYS-MOD is not capable of modeling, for example, the change in the use of methanation when market prices change.

8.5 Data Collection

By selecting four pathways from recent studies, the implementation of the four scenarios in GENESYS-MOD is completed [3]. Called OpenENTRANCE pathways, they contribute to understand the drivers, uncertainties, strategies and consequences of the energy transition. The calculated carbon costs to reach 1.5/2.0 degree targets and their corresponding developments are one of the main distinctions between these four scenarios. Directed Transition (DT), Gradual Development (GD), Societal commitment (SC), and Techno Friendly (TF) scenarios assume different political, technological and societal sets and hence the carbon prices and its pathways in the future differ [2]. The carbon price is implemented exponentially, with a low price in the early model periods and a high price in the latter model periods, for the GD, SC, and TF scenarios. In contrast, the DT scenario assumes that the price of carbon will increase linearly. This results in substantially higher carbon prices in the time period between 2025 and 2040 compared to all other scenarios, due to the strong policy measures put in place. Overall, in 2050 SC scenario requires the highest carbon price to reach its 1.5°C compatible pathway goal with 1275€/tCO_2 (mostly due to the absence of carbon dioxide removal technologies being available making complete carbon neutrality challenging), followed by DT scenario with a required carbon price of 1000€/tCO_2.

GENeSYS-MOD-Turkey is a stand-alone (only Turkish energy system) version of the pan-EU GENeSYS-MOD v3.1, but includes updates for Turkish energy data from various sources. Detailed energy input data for Turkey is available in the model:

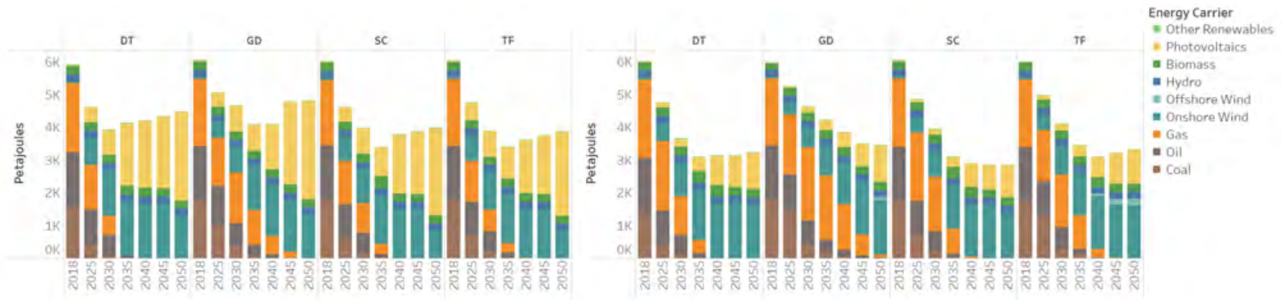
- Gas storage capacity of Turkey (10 bcm in 2025 from Petroleum Pipeline Corporation (BOTAS))
- Hourly generation profiles, hourly load profiles (available in current GENeSYS-MOD v3.1 database)
- Energy demand (updated for Turkey model from Ministry of Energy and Natural Resources [18] for power, but heat demand from GENeSYS-MOD v3.1 database)
- Transportation data (from several sources, such as statistics from Ministry of Transport and Infrastructure, Ministry of Environment, Urbanisation and Climate Change)
- Installed capacities and generation/production mix per technology and sector (from the transparency platform of Energy Exchange Istanbul (EXIST)) [8]
- Energy balances (from Ministry of Energy and Natural Resources)[18]
- Generation/production costs (available in current GENeSYS-MOD v3.1 database)
- Minimum storage requirements (assumed as 10% of overall storage capacity)

- Seasonal variations in natural gas imports (specifically between December & March, based on monthly variations as depicted in 8.12
- 73-hour steps for all scenarios (as described in [15], one can use $24n + 1$, where $n = 3$ allows equal day/night time slices)
- Hydrogen blending rates of 5, 10, and 20 % of which 20 % is the final blending target until the year 2030 and beyond (as discussed in [20]). Once H_2 is blended into the natural gas (CH_4) system, we consider it as CH_4 and do not envisage later separation of the blended H_2 from the CH_4 stream.

The details about the data, model files can be found in GENeSYS-MOD-Turkey GitHub page [14] The next section discusses the results of the cases among scenarios.

8.6 Results of case study

GENeSYS-MOD-Turkey model results are extensive and they can be used for many different aspects. In order to illustrate the model results, they are grouped under four cases (namely, No limits on natural gas imports, No H2 blending, H2 blending, and Synthetic methane storage). The results for each case are also classified for all four scenarios (e.g., DT, GD, SC and TF).



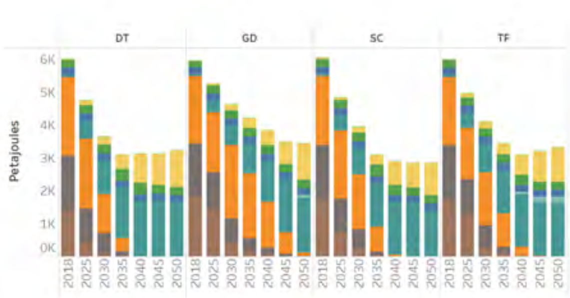
(a) D3.2 results for TR only (b) CS8: No limits on natural gas imports [15]

Figure 8.13: Primary energy production in D3.2 Results vs. Case Study 8

Figure 8.13 compares the primary energy for Turkey from Deliverable 3.2 (referred as D3.2 thereafter) of OpenENTRANCE project [3] and this case study's "No limits on natural gas imports"(referred as CS8 thereafter). As clearly seen, there is quite difference in results for solar as energy carrier. In D3.2, import/export among EU allows countries such as Turkey and Spain to be net hydrogen and synthetic methane exporters (see section 3.3.1 and Figure 3-4 in [3]). Hence there is an increasing requirement for solar resources in hydrogen (and therefore synthetic methane) production. But, in CS8, there is no such requirement. Since, the focus is on flexibility options of natural gas storage facilities and their impact on the Turkish energy system in the future by excluding the imports/exports of hydrogen or synthetic methane.

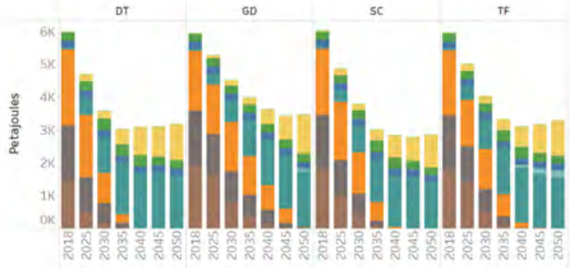
Figure 8.14 provides the primary energy by energy carrier for all cases. The natural gas is significantly reduced by 2040in line with the strong increase of CO_2 prices which evict fossil, CO_2-intensive energy carriers from the energy system. Not surprisingly, coal disappears from the system even earlier, in most scenarios during the 2030s.

Among the renewable technologies, onshore wind takes the largest role with about half of primary energy production in 2050. But solar PV also contributes a large share to the primary energy production (about 1/3 by 2050).

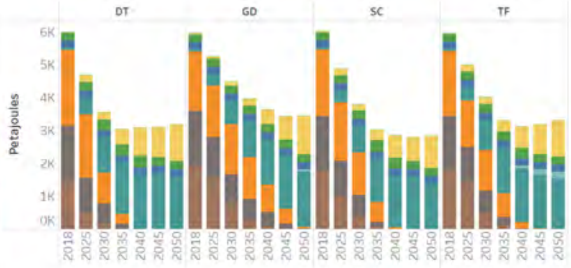


(a) No limits on natural gas imports

(b) No H_2 blending

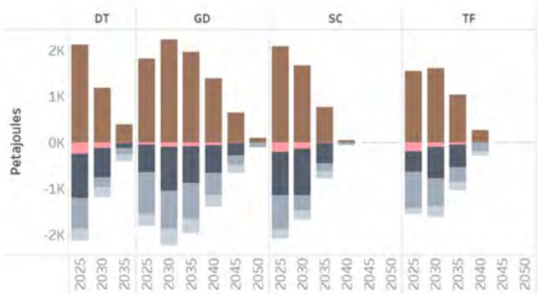


(c) H_2 blending

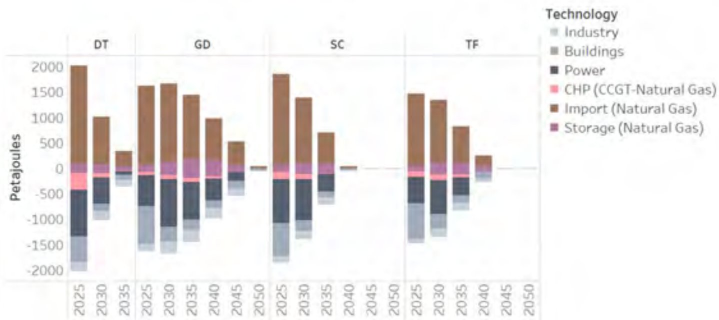


(d) Synthetic methane storage

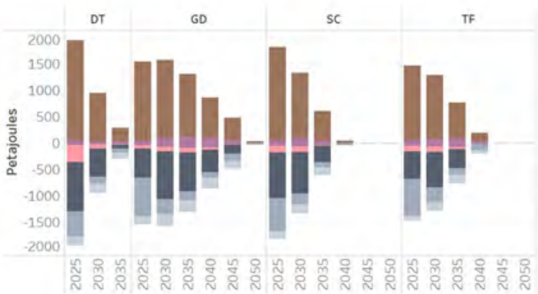
Figure 8.14: Primary energy production in all cases



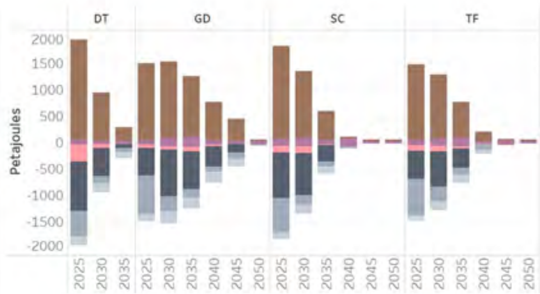
(a) No limits on natural gas imports



(b) No H_2 blending



(c) H_2 blending



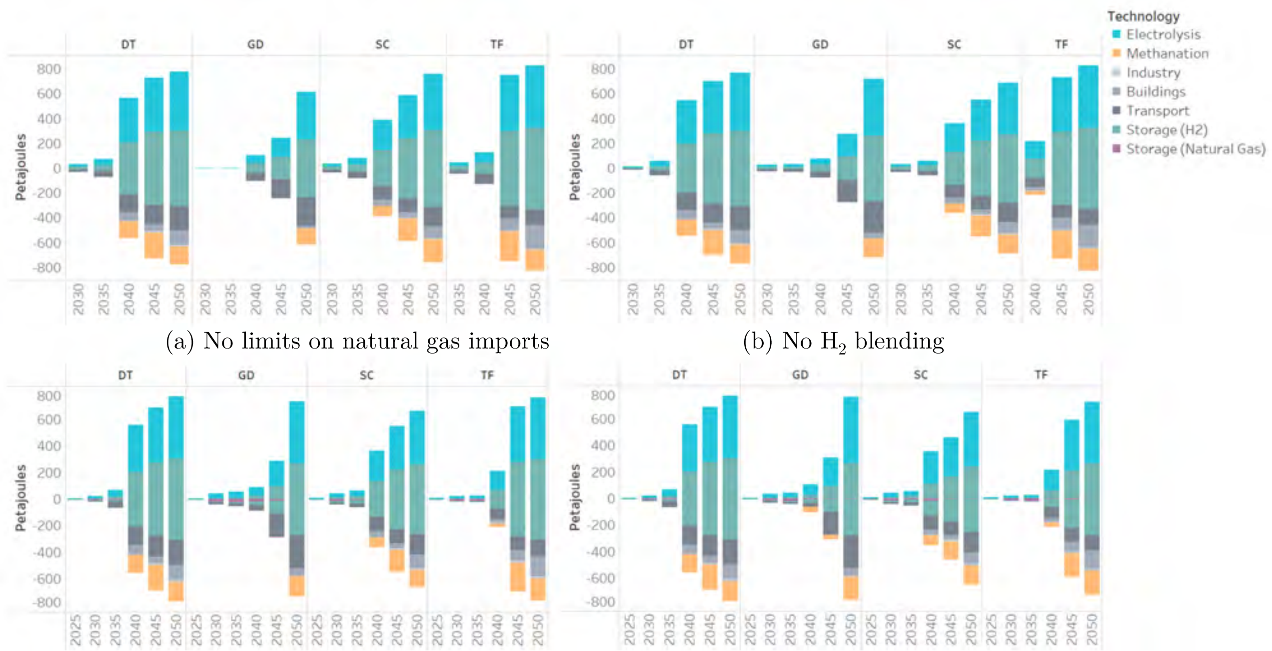
(d) Synthetic methane storage

Figure 8.15: Natural gas production and use

Figure 8.15 shows natural gas production and use in all cases. Natural gas supply (upper part of the diagrams) is almost zero in all scenarios after 2040. The imported natural gas is continuously decreasing in the next decade. At the same time, the use of natural gas declines after 2025 (in the 1.5°C scenarios DT, SC, and TF) and 2030 (in the 2°C scenario GD).

Today, natural gas is used for a large variety of uses in Turkey such as power generation but also heat production, both as final energy consumption (i.e., direct use of natural gas in buildings) as well as in combined heat and power generation (CHP). Industrial use (mostly in high-temperature heat processes) is relatively small compared to other European countries. In the absence of carbon capture and storage (CCS) technologies available [10], these uses are replaced by different technologies in a future decarbonized energy system [25]. In the power sector, renewable electricity generation (mainly solar and wind) replaces the base-load generation and carbon-free flexibility options such as hydropower, batteries and H_2 electrolysis take over gas power's role in balancing the electricity grid. In heat provision, electrified solutions such as heat pumps of different scales take over the role of natural gas (both in buildings and replacing CHPs). In industry, some processes can be replaced by electrified processes, others must be converted to green gases (H_2, synthetic CH_4).

Natural Gas storage option is not used in the scenario in which we assume unlimited, fully flexible imports. In the other scenarios, it is quite interesting to see that the storage is increasing until 2035 and starts to decrease afterward. In all cases with storage (i.e. with and without hydrogen blending and synthetic methane cases) the storage provides flexibility to energy system and reduces the natural gas imports. This effect is more pronounced in the case of synthetic methane storage, as storage facilities are continued to be used until 2050 in all scenarios.



(a) No limits on natural gas imports

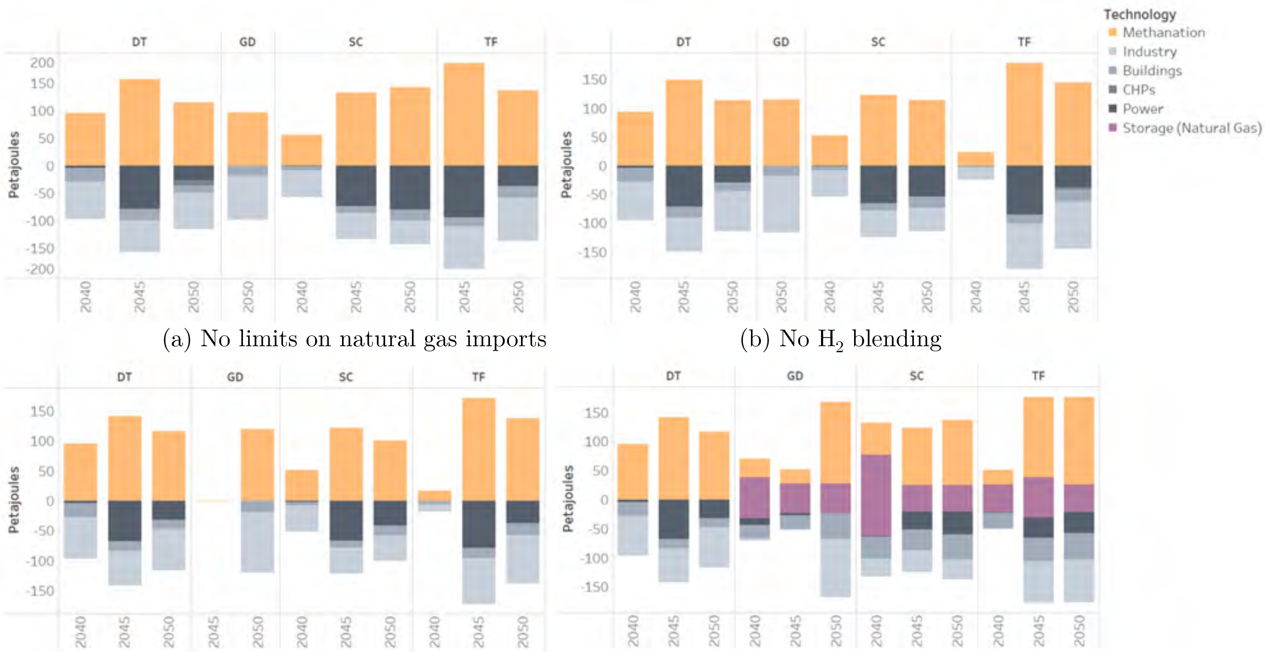
(b) No H_2 blending

(c) H_2 blending

(d) Synthetic methane storage

Figure 8.16: Hydrogen Production and Use

Figure 8.16 shows the production and use of hydrogen (if there is no production and use of hydrogen in that year, it is not shown in the figure). The total supply and use of hydrogen is similar between the different Turkey cases and reaches almost 800 PJ by 2050 in all cases. However, there are large variations to observe between the openENTRANCE scenarios. Most notably, total hydrogen supply and use is smaller in the Societal Commitment (SC) scenario where it stays below 700 PJ in 2050 because energy efficiency options (i.e., conservation) are more widespread used in this scenario than in the other scenarios. Another striking results in line with the openENTRANCE assumptions is the larger use of H_2 use in the transport sector in the Gradual Development (GD) scenario where a larger variety of technologies is employed because the emissions target is less stringent than in the other three scenarios. Interestingly, in the other three scenarios (DT, SC, TF) the hydrogen use in the buildings sector is higher than in the GC scenario and reaches up to 25% of the total use (use excluding storage, but including methanation). Methanation, that is the further processing of H_2 with CO_2 to synthetic CH_4, is the largest use of hydrogen in all the 1.5°C scenarios (DT, SC, TF) and close to being the largest in the 2°C scenario GD.



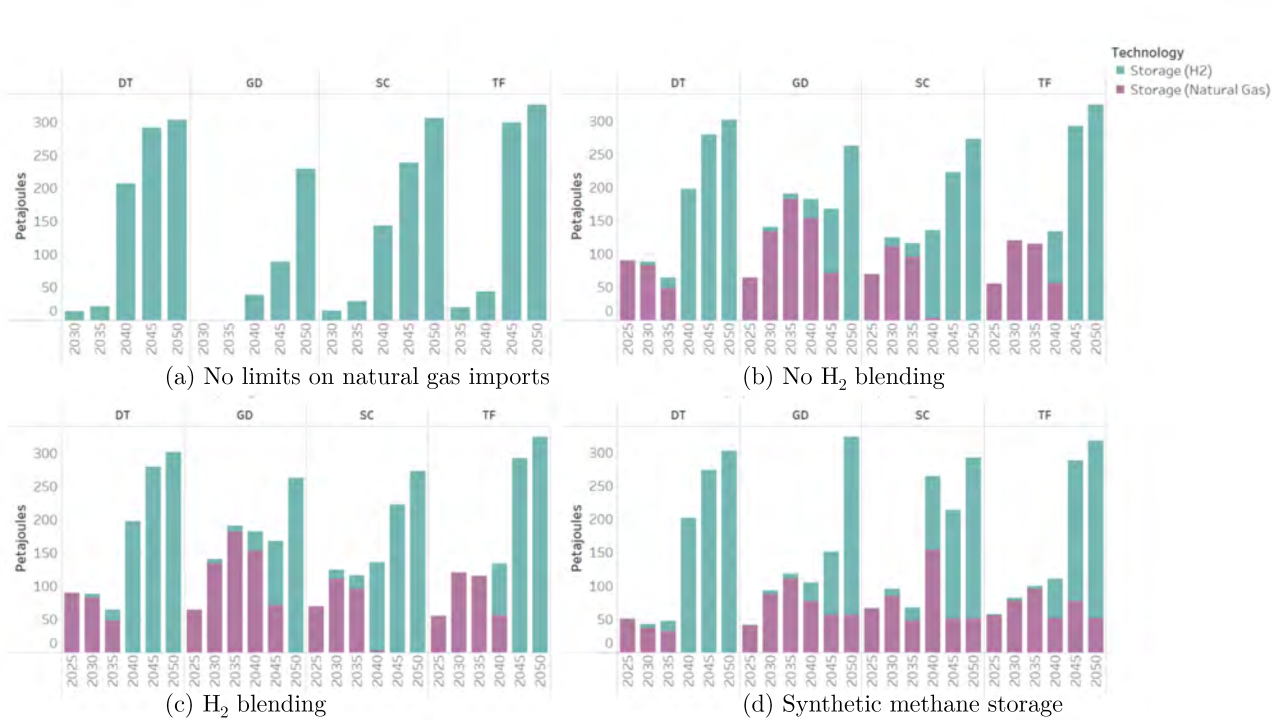
(a) No limits on natural gas imports (b) No H_2 blending

(c) H_2 blending (d) Synthetic methane storage

Figure 8.17: Synthetic methane production and use

Figure 8.17 shows synthetic methane production and use in all openENTRANCE scenarios and our four case study scenarios. If there is no production and use of synthetic methane in that year, it is not shown in the figure, e.g., for years before 2040 (and years before 2045 for GD scenarios). Due to the technical challenges and high current costs, methanation only becomes relevant from 2040 onwards. Indeed, synthetic methane has the advantage that it can be used in the same infrastructure for storage but also transportation as natural gas today because it is the same gas. This is contrast to hydrogen which is a gas with different properties than natural gas and reassignment of infrastructure is still in research (see Section 8.2.2).

Comparing our four case study scenarios, we find that, as expected, synthetic methane production and use is more significant when synthetic methane storage is allowed. In this case, synthetic methane storage helps providing inter-seasonal flexibility in the energy system. On the use side, we see that the majority of the synthetic methane replaces natural gas in the industrial sector (between 50% and 74% in 2050, depending on the scenario). In the 1.5°C scenarios (DT, SC, TF), synthetic methane also plays an important role in the power sector as fuel for backup gas turbines when renewable generation is low. In the 2°C scenario (GD), which allows for slightly higher greenhouse gas emissions, natural gas is used as backup in the power sector. The use of synthetic methane in buildings is low because electrification of heat supply is cheaper than using methanized hydrogen.



(a) No limits on natural gas imports

(b) No H_2 blending

(c) H_2 blending

(d) Synthetic methane storage

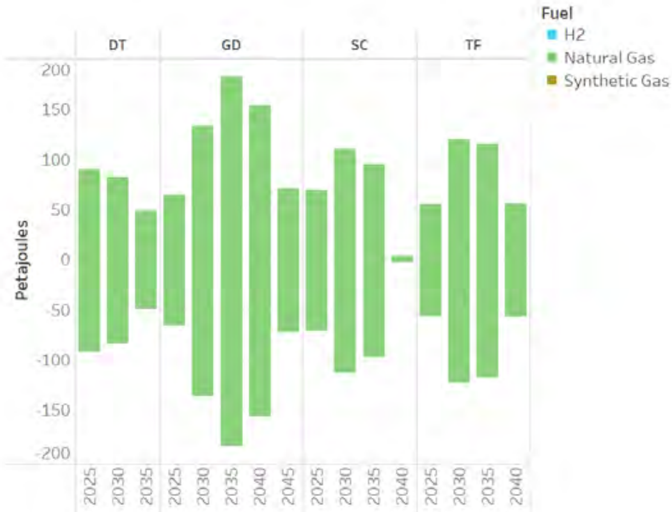
Figure 8.18: Storage use by storage facility type

Figure 8.18 shows use of hydrogen storage and natural gas storage facilities among scenarios and cases. When natural gas imports are limited by import infrastructure capacities, natural gas storage facilities are used to store natural gas. This means, in turn, that in the base (reference) case. "No limits on natural gas imports", there is no natural gas storage usage because imports react flexibly to the changes in consumption during the year. Hydrogen storage in all cases is increasing until 2050 and provides flexibility as well. Whenever natural gas storage facilities are available to store additional hydrogen in the form of hydrogen blending and synthetic methane storage; the amount of hydrogen can shift between hydrogen storage and natural gas storage, especially in GD and SC scenarios. In all other cases, natural gas storage provides inter-seasonal flexibility by balancing gas supply and demand. Natural gas consumption in the Turkish household sector typically fluctuates during the year due to the high use for space heating in the winter months (see **??**).

With decarbonization advancing over time, natural gas use and storage is phased out until 2050 in almost all scenarios. Only in the case with synthetic methane storage, this "synthetic natural gas" is stored for longer, i.e. until 2050 in all openENTRANCE scenarios except DT scenario (which places a focus on hydrogen). Clearly, storage provides a much-needed inter-seasonal flexibility to balance intra-year demand fluctuations, in particular from the household sector. At the same time, gas storage capacity is increasingly used to storage hydrogen which starts in all scenarios during the 2030s. The rationale for hydrogen storage goes beyond today's summer-winter balancing. Indeed, underground storage can also balance other supply-demand, e.g. hydrogen from a period with high renewables production that is later used in hydrogen-fueled power plants to generate electricity in low-renewables periods. This flexibility role of hydrogen increases with the higher share of renewables over time. By 2050, the hydrogen storage use even surpasses the methane storage usage in any previous model year.

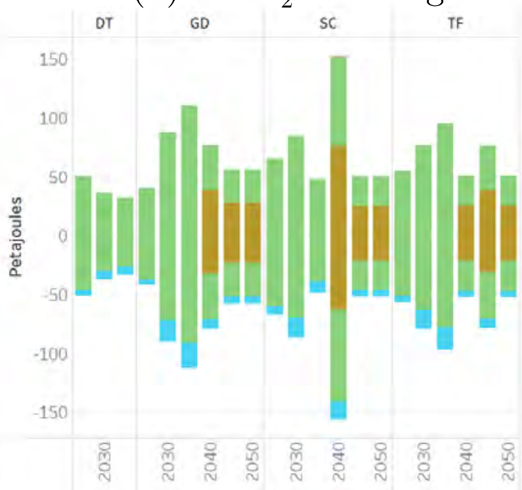
Storage capacity is NOT used in this case.

(a) No limits on natural gas imports



(b) No H_2 blending

(c) H_2 blending



(d) Synthetic methane storage

Figure 8.19: Natural gas storage use by fuel type

Figure 8.19 shows use of natural storage facilities by fuel type (natural gas, synthetic methane and hydrogen). Natural gas storage use is the largest in the less stringent climate scenario, i.e. in the 2°C scenario GD (Gradual Development). In this scenario, natural gas plays a role for longer in the energy system than in the other, 1.5°scenarios. Yet, natural gas storage use stops in 2050 in this scenario, too, in order to reach climate targets.

With hydrogen blending, hydrogen is stored together with natural gas and with synthetic methane storage (cases (c) and (d)), per our model assumptions. We do not model a case in which hydrogen is stored separately from (natural or synthetic) methane in natural gas storage. Synthetic methane storage is included as option only in case (d). Synthetic methane storage only starts after 2040 and is then stored along with hydrogen and natural gas in natural gas storage facilities. Synthetic methane storage does not start earlier because the – costly – synthetic methane production only becomes part of the energy supply when decarbonization targets become very stringent and CO_2 prices rise accordingly.

(a) No limits on natural gas imports (b) No H_2 blending

(c) H_2 blending (d) Synthetic methane storage

Figure 8.20: Power capacity (total and new) by source

The previous figures reflected the higher share of renewables over time by the higher use of renewable gases. Figure 8.20 shows directly the total and new power capacity installed. Indeeed, the new capacity additions are mainly renewables such as solar and wind. However, there are also some minor natural gas capacity additions until 2035, especially in the 2°C scenario GD. Capacity additions for solar are also highest in the GD scenario while wind is mainly preferred in DT and TF. Wind is primarily onshore wind in Turkey, with very little offshore wind capacities foreseen. At the same time, new capacity investments for renewables and hydrogen production through electrolysis increase strongly until 2050 in all cases and scenarios. There is hardly any variation between the cases which favor natural gas use more (cases (a) and (b)) and those cases which favor synthetic gases (hydrogen or methane) more (cases (c) and (d)). In other words, the long-term inter-seasonal flexibility provided by gas has less influence on the design of the energy system than have other factors such as the CO_2 price included in the openENTRANCE scenarios.

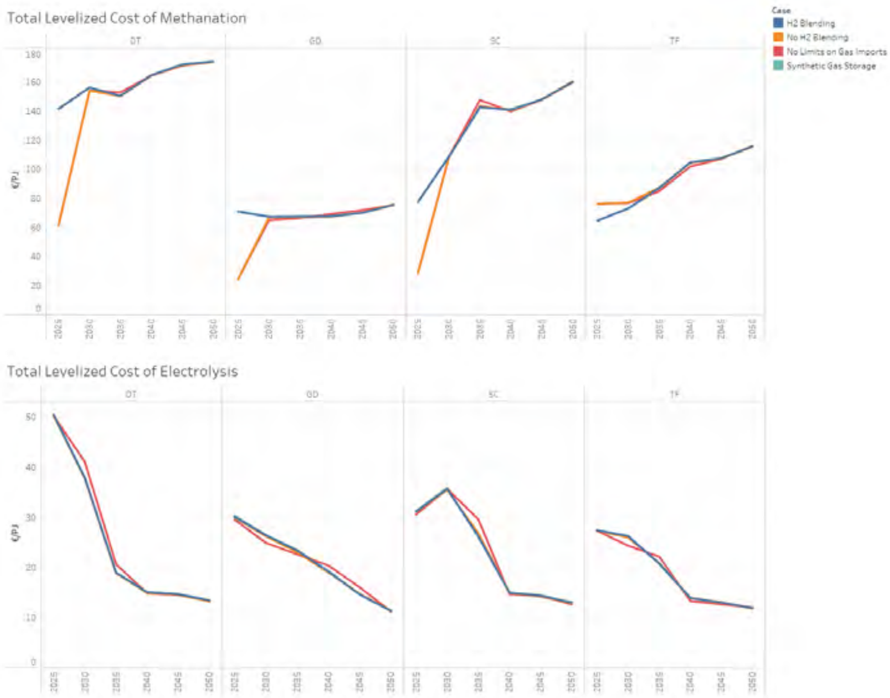


Figure 8.21: Total levelized costs of methanation and electrolysis

Figure 8.21 shows the levelized costs of electrolysis and methanation technologies. Among the four cases, there is only minor differences. The differences in levelized costs of methanation in early years can be attributed to difference between current and future natural gas and electrolysis costs. The levelized cost of electrolysis decrease until 2050, as expected, however the levelized cost of methanation increase over time because the levelized costs include the emission costs (CO_2 price). Synthetic methane (CH_4) is a carbon-emitting fuel – just as natural gas (methane) – so that a CO_2 price has to be paid when it is combusted. However, despite this increasing cost in synthetic methane's levelized costs, the technology cost decreases and the increasing benefit from inter-seasonal flexibility lead to the future use of synthetic methane in the Turkish energy system.

8.7 Summary and conclusions

The current status of the Turkish energy system is heavily fossil fuel based and has played an increasing role in the last decade. In this case study, a long term energy model that integrates power-to-gas infrastructure to the current system is developed and run using GENeSYS-MOD-Turkey. The share of renewables is increasing and it is expected that the capacity addition will play an important role in future energy system.

The model parameters are set for four different openENTRANCE scenarios, namely DT, GD, TF, and SC and the results are analyzed for each scenario. Most importantly, the openENTRANCE scenarios have ambitious emission reduction targets which are included in the model with strongly increasing CO_2 prices. This case study investigated the role of natural gas storage in the future Turkish energy systems in transition. It is shown that the use of power-to-gas technology for producing hydrogen and/or synthetic methane and then stored in underground natural gas storage facilities of Turkey can enhance flexibility in Turkish energy supply systems, particularly during the energy transition until 2050. Both cases (hydrogen and synthetic methane storage in existing natural gas storage facilities of Turkey) are studied in this case study, which provides an overview of how natural gas storage solutions can provide flexibility for natural gas import dependent countries like Turkey by

2050. We focus on the model outputs for natural gas, synthetic methane, and hydrogen production and use in each scenario as well as the storage activity. In all scenarios, natural gas storage provided some extra flexibility to the energy system. The model results show that the share of natural gas is decreasing mainly due to renewable capacity while the synthetic gas is mainly used by industry in future. The required underground gas storage capacity is expected to be increased in Turkey and the model results show that the capacity will be sufficient in the future. Turkey has recently signed Paris Agreement and announced its first NDC contributions. The National Hydrogen Strategy plan was also announced recently which targets 70 GW electrolyzer installations by 2053. Our model results also support this target, as in the hydrogen blending case, for example, we will need 10-20 GW of installed electrolyser capacity in all OpenEntrance pathways.

In conclusion, we have estimated that a 200 PJ (around 5.6 bcm) natural gas storage is sufficient for Turkish energy system with OpenEntrance storylines under different cases, as depicted in Figure 8.18. Hydrogen blending in natural gas storage and synthetic methane storage from 2040 to 2050 further declines this storage capacity requirement to 150 PJ (4.17 bcm), i.e., about a 25% decrease. .

8.8 Limitations and future extensions

Since there is no data available for the network infrastructure in any NUTS level disaggregation in Turkey, the model cannot analyse the impacts of gas network infrastructure. A more thorough spatial study should be examined in future research.

Although the model results provide quite useful and interesting insights for the future energy system, the limitations in data availability prevent some more outputs to be obtained. The proposed system does not consider a natural gas storage system in which the natural gas is injected and withdrawn hourly or daily. Hence, operational constraints such as efficiency, daily limits, maximum charge/discharge, installed capacity, and operational costs are not considered. It is assumed that the capacity is or will be available whenever necessary and the model results are obtained. The impact of market price on power generation, electricity use for electrolytes, and natural gas storage is not also modeled in this system. In fact, another solution methodology other than GENeSYS-MOD might be required to run such a system with operational constraints as the GENeSYS-MOD is a long-term energy modelling system. Such work can be a good topic to work on for future study. We will also continue to investigate new ways of storing green hydrogen by modeling new technologies into the Genesys-mod-Turkey model like local residential electrolysis and then local storage of hydrogen to be used either in hydrogen vehicles (transportation) and/or for residential and electric vehicle demand.

8.9 References

[1] E. Aktunc, E. Yukseltan, A. Yucekaya, and A. H. Bilge. Managing natural gas demand for free consumers under uncertainty and limited storage capacity. *Journal of Natural Gas Science and Engineering*, 79, 2020.

[2] H. Auer, P. Crespo del Granado, P.-Y. Oei, K. Hainsch, and L. Konstantin. Development and modelling of different decarbonization scenarios of the European energy system until 2050 as a contribution to achieving the ambitious 1.5 C climate target—establishment of open source/data modelling in the European H2020 project openENTRANCE. *e & i Elektrotechnik und Informationstechnik*, 137:346–358, 2020.

[3] H. Auer, K. Löffler, K. Hainsch, T. Burandt, I. Graabak, S. Schmidt, A. Yucekaya, E. Celebi, G. Kirkil, S. Zwickl-Bernhard, P. Härtel, and F. Frischmuth. Quantitative scenarios for low carbon futures of the european energy system on country, region and local level. *Deliverable 3.2*, 2022. Accessed: June 01, 2022.

[4] BOTAŞ. Natural gas and crude oil pipeline map. https://www.botas.gov.tr/pages/natural-gas-and-crude-oil-pipeline-map/416, 2022. Accessed: May, 04, 2022.

[5] D. G. Caglayan, N. Weber, H. U. Heinrichs, J. Linßen, M. Robinius, P. A. Kukla, and D. Stolten. Technical potential of salt caverns for hydrogen storage in Europe. *International Journal of Hydrogen Energy*, 45(11), 2020.

[6] S. Cerniauskas, A. J. Chavez Junco, T. Grube, M. Robinius, and D. Stolten. "Options of natural gas pipeline reassignment for hydrogen: Cost assessment for a Germany case study. *International Journal of Hydrogen Energy*, 45(21), 2020.

[7] Energy Market Regulatory Authority (EMRA). Yearly natural gas sector reports, 2018-2022. https://www.epdk.gov.tr/Detay/Icerik/3-0-94/yillik-sektor-raporu. Accessed: April 15, 2023.

[8] Turkish Energy Market Operator (EPIAS). Day-ahead and Intra-day Turkish Energy Market Data Platform. https://https://seffaflik.epias.com.tr/transparency/. Accessed: June 01, 2022.

[9] Franziska Holz, Philipp M. Richter, and Ruud Egging. The role of natural gas in a low-carbon europe: infrastructure and supply security. *The Energy Journal*, 37(Sustainable Infrastructure Development and Cross-Border Coordination):33–59, 2016.

[10] Franziska Holz, Tim Scherwath, Pedro Crespo del Granado, Christian Skar, Luis Olmos, Quentin Ploussard, Andrés Ramos, and Andrea Herbst. A 2050 perspective on the role for carbon capture and storage in the European power system and industry sector. *Energy Economics*, 104, 2021.

[11] IEA. *Technology Roadmap - Hydrogen and Fuel Cells*. International Energy Agency, Paris, 2015.

[12] IEA. *Natural Gas Information*. International Energy Agency, 2019.

[13] IRENA. *Hydrogen: A renewable energy perspective*. International Renewable Energy Agency, Abu Dhabi, 2019.

[14] KHAS. GENeSYS-MOD-Turkey –Disaggregated at NUTS level 1, i.e., 12 regions. https://github.com/celebiemre/GENeSYS-MOD-Turkey. Accessed: June 01, 2022.

[15] K. Löffler, K. Hainsch, and T. Burandt. GENeSYS-MOD public. https://git.tu-berlin.de/genesysmod/genesys-mod-public. Accessed: June 01, 2022.

[16] K. Löffler, K. Hainsch, T. Burandt, P.-Y. Oei, C. Kemfert, and C. Hirschhausen. Designing a Model for the Global Energy System—GENeSYS-MOD: An Application of the Open-Source Energy Modeling System (OSeMOSYS). *Energies*, 10:1468, 2017.

[17] D. Mignard, M. Wilkinson, and A. Amid. Seasonal Storage of Hydrogen in a Depleted Natural Gas Reservoir. *International Journal of Hydrogen Energy*, 41(12), 2016.

[18] Republic of Turkey Ministry of Energy and Natural Resources. Energy balances of turkey. https://enerji.gov.tr/eigm-raporlari. Accessed: April 15, 2023.

[19] M. Reuß, T. R. M. Grube, P. Preuster, P. Wasserscheid, and D. Stolten. Seasonal storage and alternative carriers: A flexible hydrogen supply chain model. *Applied Energy*, 200, 2017.

[20] D. Saygın, E. Gencer, and B. Sanlı. Priority areas for a national hydrogen strategy for turkey. https://shura.org.tr/wp-content/uploads/2021/02/SHURA-2021-02-Priority-Areas-for-a-National-Hydrogen-Strategy-for-Turkey.pdf, 2021. Accessed: August, 21, 2022.

[21] O. Schmidt, A. Gambhir, I. Staffell, A. Hawkes, J. Nelson, and S. Few. Future cost and performance of water electrolysis: An expert elicitation study. *International Journal of Hydrogen Energy*, 42, 2017.

[22] Fabian Stöckl, Wolf-Peter Schill, and Alexander Zerrahn. Optimal supply chains and power sector benefits of green hydrogen. *Scientific Reports*, 11(1), 2021.

[23] R. Tarkowski. Underground hydrogen storage: Characteristics and prospects. *Renewable and Sustainable Energy Reviews*, 105, 2019.

[24] M. Thema, F. Bauer, and M. Sterner. Power-to-Gas: Electrolysis and methanation status review. *Renewable and Sustainable Energy Reviews*, 112, 2019.

[25] Georg Zachmann, Franziska Holz, Alexander Roth, Ben McWilliams, Robin Sogalla, Frank Meißner, and Claudia Kemfert. *Decarbonisation of energy: Determining a robust mix of energy carriers for a carbon-neutral EU*, volume 175 of *Politikberatung kompakt*. DIW Berlin, 2021.