Future electricity mix and the role of natural gas in Western Europe's carbon-free transition

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CHAPTER 1

ABSTRACT

This thesis studies the optimal electricity mix to be implemented by 2050 in six Western European countries (Belgium, Luxembourg, France, the Netherlands, Germany, and Great Britain), interconnected by electricity and gas grids, enabling their electricity demand to be met under the climate constraint of net carbon neutrality across the entire system.

This system is modelled using the optimisation language GBOML (Graph-Based Optimisation Modelling Language), which allows writing mathematical problems. Several scenarios aim to best estimate the future of the electricity mix in 2050 by imposing realistic limits on the installation capacity of renewable technologies, as well as the future of nuclear power in Europe, while observing the fluctuating prices of natural gas. The main objective is to determine under which conditions gas-fired power plants can still contribute to a zero-carbon electricity system by analysing their economic competitiveness despite ecological constraints and exploring the use of alternative low-carbon fuels such as hydrogen.

The results obtained demonstrate the necessary use of gas-fired power plants, even in scenarios with a high renewable energy penetration rate or scenarios with significant limitations regarding nuclear power, serving as backup generation sources during high electricity demand or low renewable electricity production. Conversely, in the most limited scenarios with restrictive limits on renewable capacities or without nuclear power plants, gas-fired power plants therefore play a role as an essential component for the system's electricity production and no longer simply as a backup solution. However, their economic profitability depends heavily on the purchase price of natural gas. In a system constrained both by the renewal of the existing nuclear fleet in 2019 and by the imposition of limits on the installation of renewable capacities, the economic tipping point at which the system uses hydrogen to fuel gas-fired power plants instead of natural gas is reached from a natural gas price of 145 €/MWh. In another configuration in which the system is devoid of nuclear production capacities but accepts double the maximum installation of renewable power sources compared to the previous case, this threshold is pushed back to 155 €/MWh.

CHAPTER 2

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"Hang in there, and above all, help yourself and heaven will help you." — Mamy Geneviève

CHAPTER 3 INTRODUCTION

3.1 Context & objectives

The energy transition is one of the major challenges of the 21st century, aimed at drastically reducing greenhouse gas emissions and limiting climate change and its consequences. To address this issue, the European Union (EU) has committed to achieving carbon neutrality by 2050 [1] with the main strategy of electrifying sectors dependent on fossil fuels that emit greenhouse gases, in particular transport, heating and certain industrial processes, combined with decarbonised or low-carbon electricity production. This strategy poses major challenges for the electricity production sector, which must therefore replace the 35.9% [2] of its electricity mix produced from fossil fuels in 2019 within the EU and develop its production resources in the face of increasing electricity demand. This decarbonised production is therefore supported by renewable power sources such as solar, wind, hydroelectric, etc. These technologies already accounted for 42.2% [2] of the EU's electricity generation capacity in 2019, producing 32% of the country's electricity. One of the major concerns with these technologies is their dependence on weather conditions, making them intermittent and uncontrollable. If these technologies are highly integrated into the electricity mix, that can lead to difficulties in balancing between electricity demand and production.

To ensure this balance of supply, gas-fired power plants are an excellent candidate. Their controllable source of production, their fast ignition and load variations, and their low-carbon properties, emitting fewer greenhouse gases than any other combustion power plants, allow them to quickly and efficiently balance the electricity grid, making them indispensable. Added to this is the possibility of synthesising their fuel, natural gas, which is mainly composed of methane, by combining hydrogen, ideally produced by electrolysis powered by decarbonised electricity, and carbon dioxide, which can be captured in the power plant's chimneys or directly from the air. This synthesis can make gas-fired power plants sustainable and carbon neutral.

It is essential to study the economic competitiveness of using gas-fired power plants combined with carbon dioxide capture and storage systems compared to other solutions enabling the management of the intermittency of renewable power sources, such as over-sizing renewables combined with storage systems to return electricity to the grid during high demand, for example. This thesis will therefore aim to explore this question. To this end, a study conducted over six countries in Western Europe, Belgium, Luxembourg, France, the Netherlands, Germany, and Great Britain, interconnected by electricity and gas networks is being conducted to determine the optimal electricity mix for this system to meet the electricity demand of these countries while respecting the European climate constraint by 2050. The study is limited to the electricity generation sector. It will aim to observe which configurations allow these objectives to be achieved through various scenarios trying to best represent the future energy mix by taking into account the energy policies and resources available in each country while paying particular attention to the role of gas-fired power plants in these configurations, as well as to know under what conditions the possible alternative fuels become competitive.

3.2 Related works

The *Ten-Year Network Development Plan* (TYNDP) 2024 report [3], co-authored by ENTSO-E (European Network of Transmission System Operators for Electricity) and ENTSO-G (same but for gas), proposes scenarios studying the development of the European energy system by 2030 and 2050 in order to meet the carbon neutrality objectives set by the European Union. Three scenarios were developed: *Distributed Energy*, *Global Ambition* and *National Trends+*. These scenarios differ in the level of collaboration between ENTSO-E member countries[1], the centralisation of production means and their technological approach, but all converge towards a massive electrification of the energy sectors with a very significant use of renewable power sources. The model they use is multi-sectoral, studying electricity demand and gas demand by detailing the interactions between consumption sectors such as agriculture, industry, heating and electricity use. Each country is modelled as an aggregated system without internal geographical granularity, with an annual representation at hourly time steps. The results obtained by their model indicate that, in 2050, according to the Distributed Energy and Global Ambition scenarios, electricity consumption represents 49% and 40% of the total energy consumption of the system, respectively. This electricity is produced from 96% and 93% renewable power sources, respectively, the vast majority (more than nine tenths) of which comes from solar energy (photovoltaic panels) and wind energy (wind onshore and offshore). The use of gas-fired power plants, fuelled by hydrogen or e-methane, remains marginal and serves as a backup resource producing only a few tenths of a percent of the system's electricity.

The article by J. Mbenoun et al. [4] presents the study of the integration of offshore wind turbines into the Belgian energy mix by 2050 by evaluating the different means of transport

[1]The member countries of ENTSO-E are : Albania (AL), Austria (AT), Bosnia and Herzegovina (BA), Belgium (BE), Bulgaria (BG), Switzerland (CH), Cyprus (CY), Czech Republic (CZ), Germany (DE), Denmark (DK), Estonia (EE), Spain (ES), Finland (FI), France (FR), United Kingdom (GB) (sometimes abbreviated as 'UK' by abuse of language but geographically, it is indeed the geographical area of Great Britain which is taken into account, composed of England, Scotland, Wales and Northern Ireland.), Greece (GR), Croatia (HR), Hungary (HU), Ireland (IE), Iceland (IS), Italy (IT), Lithuania (LT), Luxembourg (LU), Latvia (LV), Montenegro (ME), Republic of North Macedonia (MK), Northern Ireland (NI), The Netherlands (NL), Norway (NO), Poland (PL), Portugal (PT), Romania (RO), Serbia (RS), Sweden (SE), Slovenia (SI), and Slovak Republic (SK).

(power lines, or conversion to hydrogen and pipeline transport). The interesting part of this article is the open-source model they used to represent the Belgian energy mix. The model created in this article is formulated using the GBOML (Graph-Based Optimization Modelling Language) modelling language and is based on a techno-economic approach applied at an hourly resolution over a full year. The Belgian energy system is decomposed into 3 geographical zones: the offshore zone, the coastal zone and the inland zone, interconnected by power lines and gas pipelines. Each zone has a set of assets representing conversion, storage, flexibility and transport technologies. The model studies 3 energy vectors: electricity, methane and hydrogen, necessary to cover a certain energy demand which has been sectorised into 5 demands: residential, tertiary, industrial, transport and others. The study focuses on 2 scenarios which are distinguished by the penetration rate of renewables in the electricity production mix with both the objective of achieving an optimal overall system cost under the constraint of neutral carbon emissions. The cost of the overall system in the conservative scenario in terms of renewable capacity allocated to the model is 20.47 G€/year while that with a high penetration rate of renewables is 19.88 G€/year

The article by H. Scharf and D. Möst studies the future role of gas-fired power plants in the European electricity mix, particularly by 2050. The authors used a model called "ELTRAMOD", which is a bottom-up model covering the entire years of 2030, 2040 and 2050 with an hourly resolution. The countries studied are all the countries of the European Union as well as the United Kingdom, Norway and Switzerland. It is based on the existing electricity production fleet in 2017 and is projected for the future years studied, and future investments are determined endogenously, that is to say that the model receives the technical and economic data of each technology and it is the optimisation that will determine the technologies to be used and therefore the investments to be made. The model focuses on Germany, representing individual installations, while for other countries, it aggregates installations by type to provide a more general representation of Europe. This article considers a total of nine scenarios, comparing three trajectories of renewable energy penetration in Germany with three trajectories of future electricity demand, all aiming for carbon neutrality by 2050. In addition, the authors also consider the impact of an early coal phase-out by 2030.
In the short term, by 2030, the results show an increase of up to 38.3% in the installed capacity of European gas-fired power plants, implying an increase in electricity generation from natural gas of up to 32.8% compared to 2017, depending on the scenario. They observe a high dependence of Germany on natural gas in all scenarios, despite an 80% penetration rate of renewables in the electricity generation mix. The early phase-out of coal in the German electricity mix will lead to a near-total replacement of this generation by gas-fired power plants.
In the long term, between 2040 and 2050, the use of gas-fired power plants will show a downward trend across Europe, although Germany will see an increase in the share of its electricity generation from natural gas, up to 51%. The need for reactive generation technologies such as gas-fired power plants is essential to cope with the fluctuating production peaks of renewable power sources. The use of decarbonised fuels such as e-methane becomes economically viable for the 2050 study, which is considered to cost 100.79 $€_{2017}$/MWh. They conclude that gas-fired power plants remain an essential component of the fully decarbonised European electricity mix.

This thesis is a continuation of the work exploring the European energy transition by 2050 to meet the carbon neutral emissions ambitions imposed by the EU through a strong electrification of the energy sectors and a high penetration rate of renewables. This study focuses on 6 Western European countries: Belgium, Luxembourg, France, the Netherlands, Germany and Great Britain, interconnected by power lines and gas pipelines where each country is modelled as an aggregated entity without internal meshing. It considers a set of assets to model the energy park of these countries as conversion, flexibility, storage and transport technologies necessary to meet the electricity demand of each country provided through various energy vectors: electricity, natural gas and hydrogen. The model, formulated using GBOML, uses a technical-economic approach with an hourly time step over a full year, with partially endogenous operating and investment decisions to analyse the future role of gas-fired power plants in the electricity mix. More specifically, the impact of natural gas prices on their participation in the optimal energy mix is studied, while respecting carbon neutrality objectives. The study also explores the potential of hydrogen as an alternative low-carbon fuel to power these plants.

CHAPTER 4

BACKGROUND

This chapter introduces the key concepts involved in modelling the problem and understanding in general the subject of this thesis. The purpose of these theoretical explanations is not to go into the subject in depth but to provide the information needed to understand the model.

4.1 GBOML

GBOML (Graph-Based optimisation Modelling Language) [5] is a mathematical modelling language designed to facilitate the formulation of optimisation problems, particularly in the energy sector. GBOML differs from traditional modelling languages by introducing an object-oriented approach to optimisation modelling and by using the notion of a hypergraph. A hypergraph corresponds to a set of nodes (e.g. a power plant, a transmission network, an energy storage facility) linked by hyperedges that define the interactions between the nodes (e.g. mass balances). In practical terms, mass and energy balances will be used to represent these links between the sub-systems. This representation makes it possible to build a modular model in which each block of the system is defined separately, with its own parameters, variables, constraints and objectives.

More technically, GBOML is designed to formulate linear (LP) and mixed integer linear programmes (MILP). It is suitable for modelling discrete dynamics over a finite time horizon. This language is based on a hierarchical structure, i.e. the model is a large hypergraph whose nodes are themselves sub-hypergraphs representing sub-problems. This structure enables modular and scalable modelling by decomposing the system into interconnected components. Each node has a set of internal and external variables, where internal variables are linked to a specific node and can not be accessed by others and external variables are shared variables that can be used by other nodes to ensure inter-node consistency. Local constraints governing the dynamics of the node and a local objective function that will contribute to the overall objective of the model. Hyperedges are used to determine the relationships between nodes via constraints on external variables.

GBOML is both algebraic, like traditional modelling languages, and object-orientated, like programming, making it easy to reuse modelling blocks, write models clearly, analyse results and interface with high-performance optimisation solvers such as one of the most well-known and widespread which is used in this case, *Gurobi*. The tool is coded in Python and offers both a command-line interface and a Python API, making it easy to integrate into simulation or research environments.

In short, GBOML is a language designed to model complex systems in a clear, modular and efficient way. Particularly well suited to energy planning over a discrete time horizon, especially for modelling an energy mix optimisation problem involving a large number of interconnected sub-systems, as is the case in this thesis.

4.2 Linear Programming and Mixed-Integer Linear Programming

As already formulated in the previous section, GBOML is a mathematical modelling language designed to facilitate the formulation and resolution of linear and mixed-integer linear programmes. It interfaces with several solvers such as *Gurobi*[1], which are software tools designed to compute the optimal solution of mathematical programming problems (More information about what a solver is can be found at the end of this section). In this chapter, the theoretical description of Linear Programming (LP) and Mixed-Integer Linear Programming (MILP) will be detailed.

Linear programming means that the objective function to be solved is linear and that the set of constraints imposed on the model are also linear. The mathematical description of a standard LP problem is given below:

$$
\begin{aligned}
\text{minimize:} \quad & c^\top \cdot x \ ; && (4.1)\\
\text{under constraints:} \quad & A \cdot x \leq b \ ; && (4.2)\\
& x \in \mathbb{R}^n \ ; && (4.3)
\end{aligned}
$$

where

- x is the vector of decision variables,
- c is the vector of coefficients of the objective function,
- A is the matrix of constraint coefficients,
- b is the vector of constant terms of the constraints.

In order to solve a linear problem, efficient methods such as the *simplex algorithm* or *interior point methods* can be used. These methods are implemented in Gurobi, offering optimal per-

[1]Mathematical optimisation solver specialising in fast, efficient solutions to linear, mixed and non-linear problems.

formance for a wide range of LP problems.

Mixed-integer linear programming complicates linear programming by introducing integer variables resulting in the addition of integrality constraints on these binary decision variables, which has the effect of considerably increasing the combinatorial complexity and the difficulty of the calculations, thus impacting the problem resolution time. A standard MILP problem can be mathematically formulated as:

$$
\begin{aligned}
\text{minimize:} \quad & c^\top \cdot x \ ; && (4.4)\\
\text{under constraints:} \quad & A \cdot x \leq b \ ; && (4.5)\\
& x_j \in \mathbb{Z} \ , \qquad \forall j \in \mathcal{I} \ ; && (4.6)\\
& x \in \mathbb{R}^n \ ; && (4.7)
\end{aligned}
$$

where $\mathcal{I} \subseteq \{1, \ldots, n\}$ is the set of indices for variables that are integers.
MILP problems are generally solved using methods such as *branch-and-bound*, *branch-and-cut* or *branch-and-price*. These methods are also implemented in Gurobi, which offers advanced features to improve the efficiency of MILP problem solving. MILP problems have a long solution time due to the combinatorial nature of the integer or binary variables involved. Linear problems have a continuous and convex solution space, whereas MILP problems require the exploration of a discrete and often non-convex solution space, which greatly complicates the search for an optimal solution and has a direct impact on computation time.
A solver, such as Gurobi, is designed to solve mathematical optimisation problems by taking a model formulated in a modelling language (GBOML in this case) as input and applying numerical algorithms to find an optimal solution. Numerous resolution methods are implemented in the solver and it chooses which one to use to find the optimal solution. The choice is based on the structure of the problem, such as the size of the system, the presence of integer variables, the density of the constraint matrix, etc. The solver acts like a black box that analyses a problem and chooses the most suitable methods to speed up convergence towards an optimal solution.

4.3 The Big M method

When writing the mathematical model, certain constraints may depend on the value taken by a binary variable, resulting in a logical condition. In the case of this thesis, this situation arises when trying to integrate the minimum output power constraint of certain electricity production technologies. A binary variable is used to indicate that if the power plant is used, it must operate at a minimum power fixed by a ratio of the maximum power while allowing this power plant to shut down. Expressing this type of relationship directly can lead to the multiplication of two variables, making the problem non-linear. In this case, the two variables are the binary decision variable and the capacity of the newly installed plant. A non-linear problem is all the more complex to solve, strongly impacting the resolution time. Add to this that the current version of GBOML does not support non-linear optimisation problems. To mitigate this issue we can use a method that separates the constraint in order to eliminate the multiplication of variables between them. The *Big M method* introduces a large constant, M, to linearise the constraint. This method is widely used for constraints involving binary variables such as :

$$y \cdot (a^\top \cdot x) \leq b \ , \tag{4.8}$$

where y is a binary variable, a is the vector of constraint coefficients, x is the vector of decision variables, and b is the vector of constant terms of the constraints. This naive way of writing leads to non-linearity because of the product between y and x, which are two variables. In order to linearise this constraint, the constant M will be introduced as follows:

$$a^\top \cdot x \leq b \ , \tag{4.9}$$

$$a^\top \cdot x \leq M \cdot (1 - y) \ . \tag{4.10}$$

M is a sufficiently large constant to make the constraint inactive when $y = 0$, thus releasing the constraint when the condition is not verified. Conversely, when $y = 1$, the initial stress is restored. The choice of constant M must be judicious. M must be large enough to guarantee the validity of the relaxation while taking care not to set the value too high, as this could degrade the numerical stability and performance of the solver. A value of M that is too large can significantly slow down the resolution time or even lead to approximation errors.

4.4 Technologies studied

In order to meet the electricity demand of the countries studied, conversion, storage and transport technologies will be modelled. For the year 2019, the technologies used are given in the ENTSO-E report [2] which is an annual report providing the information needed to understand the state of the energy park in the ENTSO-E member countries in the power generation sector, including data relating to power stations and electricity exchanges. While for the year 2050, other technologies that are not yet widely used will be added on the basis of their known technological advances and their interesting potential in the future energy mix for electricity generation. It should be noted that this list of technologies is an arbitrary choice, and the list of useful technologies may be extended to study their usefulness in the energy mix, such as whether they are economically competitive and efficient.
The technologies mentioned below are those used and modelled for the year 2019. Those considered in addition for the year 2050 are included in Subsection 4.4.7.

4.4.1 Photovoltaic panels

Photovoltaic panel are a technology invented in the 1950s to generate electricity from solar radiation. This technology quickly became widely available and is used worldwide. In 2019, 98.236 GW of solar panels were installed in ENTSO-E member countries, representing 3.74% of the total production of the member countries of ENTSO-E [2]. They offer a zero-carbon solution to electricity production[2] and low installation and operating costs. However, their dependence on sunshine means that storage solutions are needed to overcome the problem of intermittence.

[2]without looking at its manufacture

4.4.2 Wind turbines

The role of a wind turbine is to convert the mechanical energy of the wind into electrical energy. This is not a recent invention that dates back to 1888. It wasn't until the 1970s and the first oil crisis that it really took off. This technology offers a zero-carbon source of electricity production[2], but, like solar panels, they suffer from intermittence due to weather conditions.
In this work, two types of wind turbines are considered: **onshore wind turbines** and **offshore wind turbines**. The difference lies in their location. The first is implemented on land, while the second is installed at sea, attached to the seabed. Offshore wind turbines are therefore more expensive to install and maintain but benefit from more constant winds at sea because they are not disturbed by the topography. In addition, it is becoming difficult for onshore wind turbine manufacturers to obtain building permits due to the lack of space in densely populated countries such as Belgium and the reluctance of citizens to have a massive construction close to their homes.
Around 160 GW of onshore wind turbines were installed in the ENTSO-E countries, producing 11.08% of the total electricity production, making them the leading source of renewable production in Europe, compared with 20 GW of offshore wind turbines, producing 1.92%.

4.4.3 Hydropower

Hydroelectricity is a technology that transforms the potential energy of water into electricity by rotating a turbine. Two technologies can be distinguished, and their use is very different.

Run-of-river and water reservoir

Run-of-river power stations are turbines installed along rivers. This technology is therefore limited by the weather, which influences the flow and height of the water in the river, and thus the energy generated by the turbine, creating problems of intermittency. Water reservoirs rely on the storage of water in large dams coming from rivers, ice melting, and rain. This water can be released through turbines to ensure load following on the grid, offering more flexibility and control than run-of-river stations. The electrical production still depends on the level of stored water, which in turn depends on seasonal factors due to its water supply sources mentioned shortly before.
In 2019, ENTSO-E estimates that 59.4 GW were installed for run-of-river power stations and almost 102 GW were installed for water reservoir power stations, representing 5.49% and 8.44% of carbon-free production respectively.

Hydro-pump-storage

Pumped-storage stations are an energy storage solution that does not create a positive electricity production balance. This technology relies on two basins located at different heights. When the network produces an electrical surplus, the turbine acts as a pump, bringing water from the lower basin to the upper basin. The cycle is then reversed, functioning as a turbine to return energy to the network during periods of high consumption. The efficiency of the cycle is not 100% due to losses, which is why this technology is not considered as a source of electricity production but as a means of storage.
According to the ENTSO-E report for the year 2019, 53 GW were installed.

4.4.4 Combustion power plants

Combustion power stations operate on a common principle: the combustion of a fuel (such as coal, gas or biomass) heats a circuit of water. This heat transforms the water into steam under pressure. The steam is then directed at high speed towards a turbine, setting it in motion. Coupled with an alternator, the turbine converts the mechanical energy of the movement into electricity. The main difference between combustion power plants is the type of fuel used as the primary energy source. Depending on the fuel characteristic, in particular its moisture content, physical state or chemical composition, the fuel influences the treatment technologies required before combustion (such as dehumidification or processes to reduce SO_x[3] and NO_x[4] emissions). It also determines the way in which it is burnt and the treatment required for the flue gases at the end of the cycle. These specific features have a direct impact on the model that will be created by modifying costs, yields and CO_2 emissions, which justifies different modelling for each type of fuel.
These different technologies are listed below.

Biomass-fired power plant

Biomass combustion power plants use different sources of organic matter as fuel such as wood in the form of logs, forest chips, pellets or sawmill residues, agricultural residues such as straw or corn stalks, organic waste from organic bins or even garden waste (lawn mowing, tree and bush pruning, etc.) or even solid organic waste from the food industry as well as dried sewage sludge. These various sources allow a diversified supply of the plant but also impact its efficiency depending on the specific energy of this organic mix. This technology differs from other combustion plants in that its primary energy is made up of organic matter, which is considered renewable due to the rapid growth of this primary source, unlike coal or oil, which are formed over millions of years. It is also considered to be carbon-neutral in theory, as the organic matter absorbs CO_2 as it grows, which is then released during combustion. The problem is that the quantity of biomass required is large, around 555.56 t/GWh_{el}[5], and so the demand for organic matter can compete with the use of land for food and forestry. In addition, burning biomass creates local pollution from fine particles and NO_x.
In 2019, almost 24 GW of biomass power plants were installed in all ENTSO-E member countries, representing 3.04% of total production.

Gas-fired power plant

Gas-fired power stations are power stations supplied with fuel in the form of gas. There are currently 2 main types of gas used in Europe: *natural gas* and *gas from coal gasification*. This technology has the enormous advantage of being highly reactive, enabling it to follow fluctuations in demand with ease.
There are two main types of technologies used for generating electricity from gas combustion: *Open-Cycle Gas Turbines* (OCGT) and *Combined-Cycle Gas Turbines* (CCGT). The former

[3] SO_x refers to sulphur oxides, primarily sulphur dioxide (SO_2), which are formed when sulphur-containing fuels such as coal and oil are burnt. These gases contribute to acid rain and air pollution.

[4] NO_x refers to nitrogen oxides, a group of harmful gases composed mainly of nitric oxide (NO) and nitrogen dioxide (NO_2), which are produced during combustion processes.

[5] Considering an efficiency of 40% [6] with a specific energy content of $4.5 \cdot 10^{-3}$ GWh/t [7]

has a simple gas cycle, with the exhaust gases from combustion replacing the steam cycle that directly drives the turbine, while the latter combines a gas cycle and a steam cycle in parallel, powered by the residual heat from the exhaust gases. Connecting a second cycle in parallel increases the efficiency of the plant but reduces its startup speed and therefore its ability to rapidly vary its output power, which is one of the key properties of this type of power plant. Due to the lack of information on what type of technology is used to produce electricity from gas, CCGT technology will be considered since the model under consideration studies large-scale power plants which explains the installation of CCGTs being more abundant than OCGTs in terms of installed capacities [8]. OCGTs are generally used for small installations to provide electricity during peak consumption periods.
Regarding power plants running on coal-derived gases, the Danish catalogue (see SECTION 6.1 for more information on this catalogue and source) shows a technology with a CO_2 capture system at the combustion chamber inlet to limit emissions at the turbine outlet. This additional step, not taken into account in the calculation of the mass of CO_2 produced by the power plant, has the effect of increasing the price of this type of power plant initially and not considering a reduction in CO_2 at the chimney outlet. This node will then be doubly impacted economically following the carbon tax. These divergences must be taken into account when analysing the model.
The electrical production in 2019 for the gas-fired power plants supplied with natural gas or with gas from coal gasification corresponded, respectively, to 18.53% and 0.33% for an installed capacity of 221.2 GW and 2.5 GW in all ENTSO-E countries.

Coal-fired power plant

Coal-fired power plants are simple but effective technologies that have been in use for a long time. Thanks to their rapid startup and high load-following capabilities, they offer significant grid flexibility. However, the pollution emitted by these plants, such as CO_2, fine particles, NO_x, and SO_x, calls into question their use in a carbon-neutral future, as does their non-renewable primary energy source, meaning coal reserves are not eternal.
The ENTSO-E report distinguishes three types of coal: brown coal, hard coal, and peat. Their carbon content and moisture content impact their specific energy content and therefore the efficiency and cost of power plants.
In 2019, the installed capacity of these power plants across all ENTSO-E member countries was 58.7 GW, 92.5 GW and 1.5 GW for brown coal, hard coal and peat power plants respectively, each producing 8.35%, 6.69% and 0.19% of total electricity production.

Oil-fired power plant

Oil-fired power plants operate in a similar way to coal-fired power plants and have the same advantages and disadvantages. These plants can run on different petroleum by-products, such as heavy fuel oil for large plants, which benefit from cheaper fuel costs, or diesel and gasoline for smaller plants.
ENTSO-E differentiates between two types of oil sources: crude oil and oil shale. The former is extracted in a liquid state from a natural underground well formed from the decomposition of organic matter under high pressure and heat over millions of years, while the latter is a solid rock rich in organic matter from which liquid oil can be extracted by pyrolysis (high-

temperature heating without oxygen). This additional step makes oil shale less economically attractive compared to crude oil. However, with the scarcity of oil reserves, this source is becoming attractive.
Electricity production in 2019 covered 0.57% of total production for a total capacity of 17.8 GW in the electricity mix of ENTSO-E member countries for crude oil while the production for oil shale is 0.13% for almost 2 GW installed mainly in Estonia.

Waste-fired power plant

Waste-to-energy power plants convert non-recyclable waste into electricity. The waste used is residual household waste, non-hazardous industrial waste, bulky waste and sewage sludge (in dry form). It is sorted to eliminate hazardous elements and recyclable materials before combustion. This technology makes it possible to recover non-recyclable waste, but it also releases a large number of pollutants (CO_2, NO_x and fine particles). Its efficiency is highly dependent on the type of waste used, which is an uncontrollable variable. In 2019, only 4.5 GW were installed, covering 0.4% of production.

4.4.5 Nuclear

Nuclear power plants generate electricity through nuclear fission: a uranium nucleus (often uranium-235) is bombarded by neutrons, causing it to split into two lighter nuclei, releasing a large amount of heat. This heat is fed into a steam circuit that drives a turbine coupled to an alternator, generating electricity. Invented in the early 1950s, this technology developed in Western Europe from the 1970s onwards, a period marked by the need for energy independence and the first oil crises. The advantages of this technology are its very low CO_2 emissions during the operating phase, its ability to produce electricity continuously as a base load, and the high energy density of the fuel (960 MWh/kg [9] compared with 15.4 kWh/kg [7] of natural gas). The major disadvantages are the management of radioactive waste, the risk of nuclear accidents and its low load-following ability.
122 GW were installed in 2019, producing almost 11.5% of the electricity generated within ENTSO-E, making this source the second most important energy source behind gas.
Some countries, such as Germany, have already decided to withdraw from nuclear energy, while others, such as Belgium, are hesitating, depending on the government in power. For example, in 2003, Belgium drew up a law setting shutdown dates for its nuclear reactors. However, following the arrival of the new government, this law was repealed and the new government extended the lifespan of its newest reactors and is studying the possibility of building new reactors [10]. This is a complex public debate, which has led to the choice of several scenarios, with or without nuclear power in the European energy mix.

4.4.6 High voltage lines

High-voltage lines are necessary to model electrical exchanges between countries. Historically, this electrical transmission has mainly been done in Alternating Current (AC) because it allows the output voltage of power plants to be easily increased using transformers before being transported over long distances in these lines. The increase in voltage is very important in order to limit the losses by Joule effect, caused by the electrical resistance of the line and

proportional to the square of the current intensity, by increasing the voltage for the same power delivered, the current intensity decreases. However, this alternating current transmission has certain limitations: losses related to the capacitance and inductance of the lines, the difficulty of synchronising two independent electrical networks (to connect 2 networks together, perfect synchronization of phase and frequency is required.), the potential instability in energy flows and the constraints related to distance in an underwater environment. Following numerous technological advances, direct current is now gaining popularity. Indeed, the advent of power electronics allowing easy switching from alternating current to direct current and vice versa and varying the voltage in order to be transported increases the general interest in this type of transmission. HVDC lines allow electricity to be transported over long distances with fewer losses (beyond a certain distance called "break-even distance", HVDC lines are cheaper and more efficient than HVAC lines. This distance is between 600 and 800 kilometres.), to connect non-synchronized networks such as Great Britain with the European continent (Great Britain has chosen to fix its alternating current network at 60 Hz while Europe has chosen a frequency of 50 Hz), to cross difficult areas (mountains, seabeds, etc.) saving on rights of way (a single line against three for alternating current representing the three phases of three-phase current) and alleviating network congestion by imposing a direction of electricity flow.
In order not to make this thesis too long by presenting all the complex aspects of electrical networks, [11] explains in detail the ins and outs of these two technologies.

4.4.7 Technologies of tomorrow

Batteries

Batteries allow storing electrical energy in a chemical form. This process can be reversed, offering an interesting solution to the intermittent nature of renewable energy sources by storing surplus electricity from the grid when demand is low before returning it to the grid when demand is high.
As part of this research, two types of batteries will be considered among the multitude of existing batteries: **lithium-ion batteries**, invented in 1991 and which have since conquered the world market, and **sodium-ion batteries**, invented in 1970. This older technology has been marginalised compared with lithium-ion batteries due to its lower energy density, but since 2021 it has been attracting growing interest from industry, particularly because of its lower price and ecological impact.
Recently, battery farm projects have appeared in several European countries, including the battery farms developed by TotalEnergies in Antwerp and Feluy (Belgium), Carling, Dunkerke and Grandpuits (France) and Dahlem (Germany) [12]. This idea of battery farms is fairly recent in the European energy landscape, which is why this technology will be studied for future scenarios.

Fuel cells

Fuel cells are electrochemical devices that directly convert, through a redox reaction, the chemical energy of a fuel (often hydrogen) and an oxidant (typically atmospheric oxygen) into electricity, without combustion and producing no pollution (only electricity, heat, and water). The principle of this technology dates back to 1839, practical applications only emerged during

the 1960s, notably within the American space programme.
A wide variety of fuel cell technologies have since been developed, each with specific characteristics adapted to particular uses. For example, PEMFCs (Proton Exchange Membrane Fuel Cells) are compact and well suited for low-power and mobile applications, while SOFCs (Solid Oxide Fuel Cells) or AFCs (Alkaline Fuel Cells) serve better in specialised industrial or controlled environments. However, given the fixed and stationary nature of the system studied in this thesis, the focus was redirected to a single technology: the **MCFC** (Molten Carbonate Fuel Cell).
MCFCs operate at high temperatures (around 600–700°C) and use a molten carbonate salt as the electrolyte. This allows them to accept a wider range of fuels, including biogas or natural gas, without requiring high hydrogen purity. Their high efficiency—especially when combined with heat recovery, makes them attractive for decentralised and industrial-scale stationary power generation. Moreover, their tolerance to CO_2 in the fuel stream is a significant advantage in carbon-constrained scenarios.
Despite their promise, MCFCs still face technical and economic challenges, including high material costs and limited lifespan due to thermal and chemical degradation. Nonetheless, their scalability, efficiency (up to 70%), and potential for low-carbon operation justify their selection for modelling in this study.

Electrolysers

Electrolysers are devices that use electricity to split water molecules into hydrogen and oxygen through an electrochemical reaction. This process, known as water electrolysis, is central to the production of low-carbon hydrogen when powered by renewable electricity. While the principle of electrolysis has been known since the 19th century, its deployment at an industrial scale has regained strategic importance with the global push for decarbonisation.
Several types of electrolysers have been developed, each based on a different electrolyte and operating conditions, which determine their efficiency, responsiveness, durability, and cost. In this work, the analysis focuses on three key technologies: **AEC** (Alkaline Electrolyser Cell), **PEMEC** (Proton Exchange Membrane Electrolyser Cell), and **SOEC** (Solid Oxide Electrolyser Cell). These technologies are introduced into the model in competition with each other in order to assess, under specific system constraints, which is the most suitable for large-scale hydrogen production.

- AECs are the most mature and widely used technology. They operate with a liquid alkaline electrolyte (usually KOH[6]) at moderate temperatures (60–90°C). They are relatively inexpensive and robust but have slower dynamic response and lower current densities compared to newer technologies.
- PEMECs use a solid polymer membrane as the electrolyte and operate at similar temperatures to AECs. They offer faster load response and can operate at higher pressures, making them suitable for integration with intermittent renewable energy sources. However, they rely on scarce and expensive materials such as platinum-group metals and fluorinated membranes, which raise costs and environmental concerns.
- SOECs are high-temperature electrolysers (typically 600–850°C) that use a solid ceramic

[6]Potassium hydroxide

electrolyte. Thanks to the elevated temperature, they require less electrical energy per unit of hydrogen produced and can directly use waste heat or heat from renewable sources (e.g., solar or geothermal). This leads to very high theoretical efficiencies. However, SOECs are still in development and face challenges related to durability, thermal cycling, and system complexity.

These three technologies have been selected for the model due to their complementary profiles and different levels of technological maturity. Their integration in a competitive framework enables an evaluation of their respective roles and economic relevance within a decarbonised energy system.

Carbon capture and storage

The main carbon capture technologies studied here are:

- **PCCC (Post-Combustion Carbon Capture)** : this technology captures CO_2 directly from the flue gases of power plants using chemical solvents. It is suitable for existing infrastructure and reduces emissions without modifying existing industrial processes.
- **DAC (Direct Air Capture)** extracts CO_2 directly from ambient air, independently of emission sources. It acts as a kind of large vacuum cleaner that separates CO_2 from the air.

The first research on carbon capture dates back to the 1970s, but pilot projects have only recently emerged, notably the industrial-scale Northern Lights project (Norway), with a capacity of 1.5 million tonnes per year in its first phase [13]. The captured carbon can then be stored in the soil or reused to produce e-methane by combining hydrogen and CO_2 for reuse in various sectors, including CCGT.
In this model, captured CO_2 is assumed to be stored underground in geological formations, such as depleted oil and gas reservoirs or deep saline aquifers. This approach reflects the most mature and widely considered option for large-scale carbon sequestration. The reuse or valorisation of CO_2, for example to produce synthetic fuels or materials, is beyond the scope of this thesis. However, this represents a promising avenue for future research and a potential axis of model extension, where CO_2 could be integrated as a feedstock in circular carbon processes with various industrial applications.
European carbon storage capacity is estimated at 131 767 million tonnes of CO_2 [14]. Looking at the countries studied in this model, this capacity for each country represents: 199 Mt for Belgium and Luxembourg combined, 8 692 Mt for France, 17 080 Mt for Germany and 14 610 Mt for Great Britain and Ireland combined. No data are provided for the Netherlands and will therefore be considered zero.

CCGT feed with hydrogen

A promising emerging technology that could play a role in the decarbonised energy systems of tomorrow is the gas turbine power plant partially or fully fuelled with hydrogen. Its main advantage lies in its potential to produce electricity without any direct CO_2 emissions, provided that the hydrogen used is generated from renewable sources.
In this study, hydrogen-fuelled CCGT are included as a flexible and dispatchable solution to

complement variable renewable energy. Unlike conventional gas turbines that rely solely on natural gas, these systems offer the possibility of gradually integrating hydrogen into the fuel mix, enabling a progressive transition towards low-carbon electricity generation without needing to overhaul the entire infrastructure from day one.
Recent technological advances have shown encouraging results. A notable example is the EU-funded HYFLEXPOWER project, which successfully demonstrated a complete “power-to-hydrogen-to-power” loop using 100% green hydrogen. Initial trials with a 30% hydrogen mix were followed by successful operation with pure hydrogen, proving the technical feasibility of flexible hydrogen combustion in gas turbines [15].
While still at the demonstration stage, this type of system represents a viable pathway to decarbonise sectors where continuous and controllable power generation is needed. In the context of this model, such hydrogen-compatible turbines are evaluated for their potential role in the energy mix. Their inclusion allows for assessing under which conditions they could become competitive and contribute meaningfully to emissions reduction targets, particularly in stationary and industrial-scale applications.

Hydrogen pipes

Since both gas and hydrogen will be studied in the 2050 model, gas pipelines will be modelled. Several studies such as [16] have demonstrated the possibility of introducing up to 20% hydrogen into the current gas network, allowing an exchange between gas and hydrogen production countries.

4.5 European carbon emissions market

To limit greenhouse gas emissions and achieve its climate objectives, in 2005 the European Union introduced a system for setting an emissions cap, i.e. a total quota of CO_2 emitted is imposed on all participants in the system. Each carbon-emitting participant must buy emission allowances for each tonne of CO_2 emitted that exceeds its cap. Conversely, a participant that does not reach its cap can sell its excess carbon emission allowances to other participants. These allowances are therefore bought and traded on a market called the European Union Emissions Trading System (EU ETS), which means that the price fluctuates because it is a market. The price of an EU ETS allowance, quoted in €/t_{CO_2}, therefore acts as a carbon tax.

This mechanism is one of the main instruments of European climate policy for encouraging participants to reduce their greenhouse gas emissions. The participants are mainly power stations producing electricity, power stations producing heat and heavy industry (e.g. the steel sector, cement works, oil refineries, etc.) with a capacity of more than 20 MW, covering 36% of the EU’s greenhouse gas emissions [17].

CHAPTER 5

MODELLING

5.1 Objective

The main aim of the model developed in this thesis is to analyse the role that natural gas could play in the European electricity system in order to achieve carbon neutrality by 2050. More specifically, this work investigates under which conditions natural gas remains economically competitive for electricity generation while ensuring system stability in a context of high renewable energy penetration. The construction of this model aims to answer multiple questions such as:

- With the addition of carbon capture and storage units, are gas-fired power plants still competitive with other electricity generation solutions ?
- To what extent does natural gas play a flexible role in supporting intermittent renewable power sources ?
- How does this role change depending on the presence of nuclear power in the electricity mix ?
- What is the extent of the competition between gas-fired power stations and electricity storage units in order to respond to the problems of intermittence and security of electricity supply ?

To answer these questions that aim to achieve the objectives of this thesis, a model is built to model the energy system of 6 Western European countries: Belgium, Luxembourg, France, the Netherlands, Germany and Great Britain. This model integrates electricity production technologies (wind turbines, gas-fired power plants, etc.), electrical and storage means (chemical batteries and pumped storage plants), transmission infrastructures (power lines and pipelines) as well as CO_2 capture and storage technologies. Each technology is defined using parameters such as its costs, efficiency and technical constraints. Cross-border interconnection is modelled to take into account the interconnection impacts on the overall balance and allows us to study the question of the need to increase these capacities with the penetration of renewables in the electricity mix. The constraint of net zero emissions in 2050 is imposed on the entire modelled system. To find the most cost-effective energy configuration for the system, an optimisation model is built. The objective is to minimise total costs, including investment, operation, and fuel, while ensuring that demand is met and technical and environmental constraints are respected.

5.2 Overall system configuration

The general architecture of the model is based on a multi-cluster representation in which each modelled country represents a cluster. In the article from which this thesis is inspired [4], the author J. Mbenoun studies the penetration of electricity production from offshore wind turbines and how this energy is repatriated and integrated into the Belgian energy mix. To do this, he divides Belgium into 3 clusters representing the offshore, the coast and the inland of the country. This thesis differs from that article by simplifying the model and grouping these 3 geographical areas into a single cluster representing the country as a whole. Since the objective of this thesis is not to study the means of connection between offshore and inland, this allows us to focus on the exchanges between the different countries. The countries considered are: Belgium, Luxembourg, France, the Netherlands, Germany and Great Britain. Each national cluster integrates its own production, storage and energy conversion technologies as well as its specific electricity demand. These technologies are represented using generic nodes that can be classified by type: conversion nodes representing technologies that transform one commodity into another (e.g. CCGT, electrolyser, etc.), flexibility nodes representing storage technologies, transport nodes modelling technologies enabling cross-border trade, demand nodes representing the country's energy needs and central nodes, the clusters. The interconnections within a single cluster of all these technologies are represented in Figure 5.1.

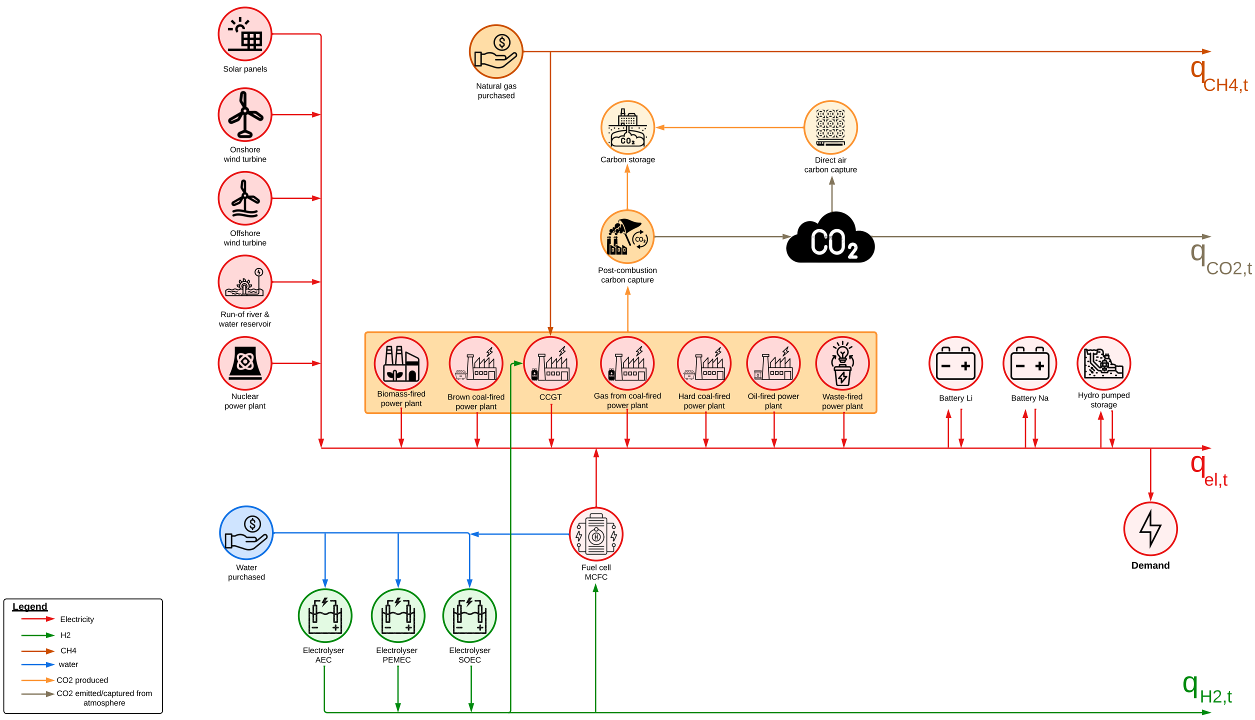


Figure 5.1: Schematic representation of a generic cluster.

Then, each national cluster is connected to neighbouring clusters by two types of infrastructure: AC or DC power lines allowing electricity exchanges and pipelines allowing the transport of gas which can be a mixture of natural gas and hydrogen. The cross-border connections between countries are represented in FIGURE 5.2.

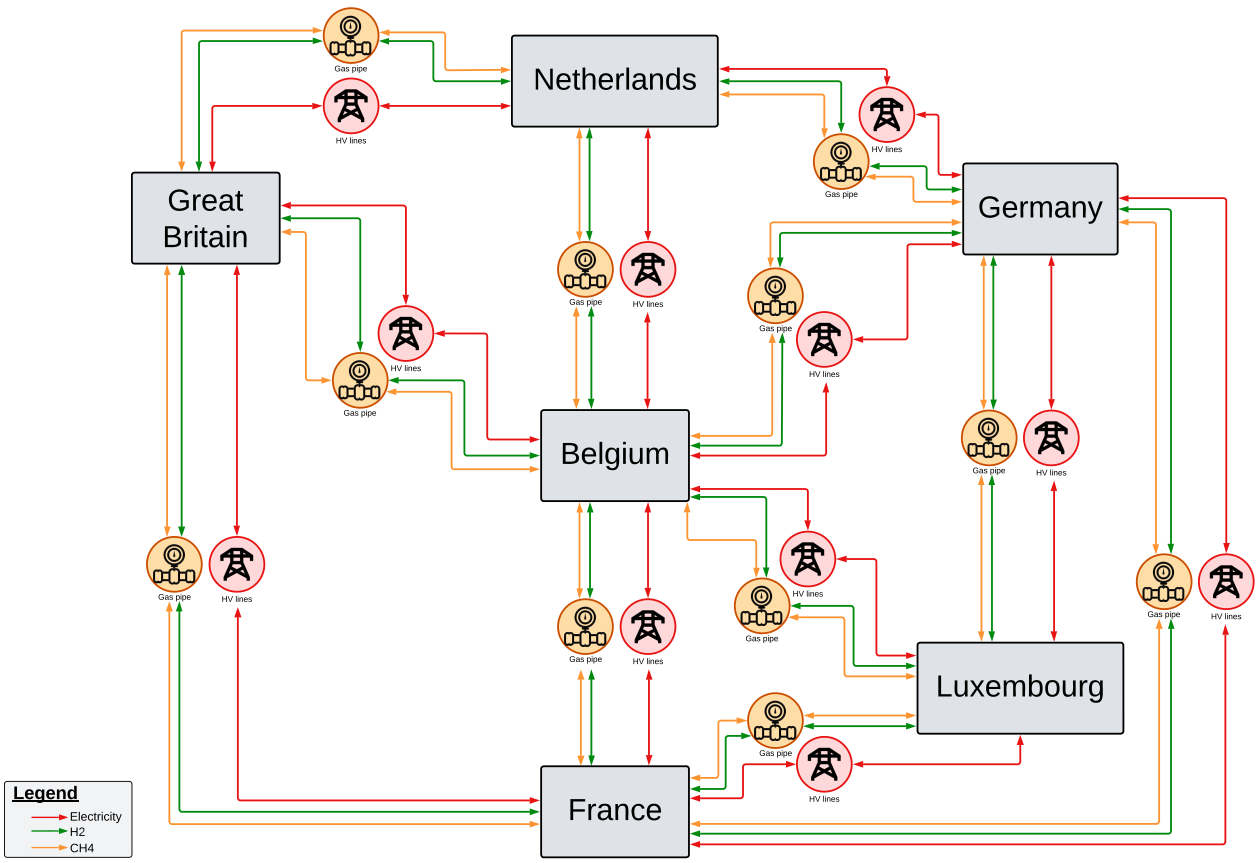


Figure 5.2: Schematic representation of the interconnections between clusters.

The model considers several energy vectors: electricity, natural gas, hydrogen and carbon dioxide. Each vector can be transported and stored depending on the technologies available in each cluster. CO_2 emissions from combustion can be captured using capture units such as PCCCs and DACs before being stored underground in natural reservoirs to meet the constraint of net zero carbon emissions by 2050. This multi-cluster modelling makes it possible to analyse the interactions between countries, the complementarities between technologies and the choices between decarbonised but often intermittent production, storage capacity and modular backup technologies such as gas-fired power plants.

5.3 Modelling language

The language used to formulate the problem is GBOML (Graph-Based Optimisation Modelling Language), already presented in detail in Section 4.1. This language is used in combination with the Gurobi solver, a powerful optimisation solver, to solve the problem efficiently. The entire model has been implemented in Python using the GBOML API, which allows seamless integration into the research environment and easy manipulation of the input data and results.

5.4 Modelling assumptions

A single entity is assumed to be responsible for decision-making about financing the entire system, planning, management and operation, having perfect knowledge and foresight, and assuming that all aspects of the technical, economic, meteorological and demand profiles are known.
A static investment model assumes that assets are immediately available, and investments are considered irreversible once made at the beginning of the time horizon. Operational decisions are made using hourly time steps. Operational and investment decisions are co-optimised in a linear programming or mixed-integer linear programming (LP or MILP) problem aiming to minimise total system cost. This means that the model only seeks to minimise the total cost of the system without taking into account the real functioning of an electricity market or the exchanges between the different players in this market. The size, defined by capacity[1], and operation of an asset are modelled by simple mathematical constraints between input and output, such as mass or energy balances. Storage technologies are approximate without taking into account complex dynamics by describing the evolution of the system based on its current state. In contrast, some assets are modelled with additional operational constraints, such as ramp-up and ramp-down limits, to reflect their slower responsiveness and inertia, which influence their short-term flexibility.
The time horizon of the model is a natural integer representing the number of time periods considered. The time horizon chosen covers a full calendar year with an hourly time step enabling the representation of daily and seasonal fluctuations in electricity demand and generation.

5.4.1 Asset assumptions

In order to model the different assets of the model and define their technical and economic parameters, many assumptions had to be made due tu uncertainty about this parameter. These assumptions are listed below:

- A financial metric called WACC (Weighted Average Cost of Capital) determines the weighted average cost of capital for a business. It stands for the lowest rate of return that a business needs to produce to appease its creditors and shareholders. The assumption of a uniform WACC set at 7% for all technologies and for all countries considered, making it possible to cover the funds assumed to be borrowed on the financial markets.
- Due to a lack of time to model the potential energy of the many rivers existing in the considered system throughout the year, the capacity factor will be considered constant and equivalent to 22% [6] throughout the year. This assumption eliminates the intermittent nature of these stations by considering constant production.
- Due to the complexity of modelling a hydroelectric power plant with a dam (water reservoir) due to the lack of time to model the many sources that allow this reservoir to be filled with water and the lack of data relating to its costs and technical parameters, water

[1] Capacity is the maximum power that a production, storage, or transmission technology can produce, store, or transport at a given time. In this thesis, capacity is expressed in kilotons per hour (kt/h) for gas capture, transmission, and storage technologies and in gigawatts (GW) for others. Capacity is used to define the size of an infrastructure in the energy sector.

reservoirs will be merged with run-of-river power plants, thus assuming the strong hypothesis that the costs are the same. This hypothesis is quite strong because it implies the loss of the property of controlling electrical production replaced by a constant production throughout the year as well as an underestimation of costs. Due to its imposing dams, a water reservoir certainly does not have the same costs as a run-of-river power plant.

- The fuel prices for combustion plants for the year 2050 (C_{2050}) are derived from the costs of the year 2019 (C_{2019}) to which an average value of inflation ($r = 2.2412\%$) calculated between the years 1991 and 2024 was added via [18] by the following formula where N is the number of years separating the years studied: $C_{2050} = C_{2019} \cdot (1+r)^N$. The hypothesis is that only inflation will have an impact on the price of these fuels, ignoring the problems of scarcity and political-economic issues.
- Fuel costs, water costs and the carbon tax are assumed to be constant throughout the year and uniform across all countries studied in the model. This implies underestimating seasonal fuel price variations when heat demand is higher, thus increasing fuel prices while also neglecting market effects. Except for the price of natural gas, which is obtained by considering the profile of the natural gas price curve according to the TTF (Title Transfer Facility) index associated with the cost of natural gas in the European market, which has been scaled by the annual average of the cost of natural gas in each country to take into account the taxes linked to the transport and consumption of natural gas specific to each country. The precise calculation of these costs is explained in SECTION 6.1.
- The storage capacity of the CO_2 storage node is assumed to be infinite. In practical terms, this storage capacity is calculated from the flow capacity to be installed, which is based on the maximum CO_2 emissions by all the nodes in the model multiplied by the time horizon. This ensures a sufficiently large storage capacity and enables an analysis to be made comparing what the model needs to store 1 year's production with the storage capacity of each country. This will also make it possible to observe whether countries with insufficient storage capacity need to be connected to CO_2 pipelines.
- Due to a lack of data, some charge and discharge efficiencies for storage nodes are calculated by taking the square root of the round-trip efficiency considering a perfectly symmetrical efficiency.
- The conversion factor between storage capacity and flow capacity of hydro-pumped storage was calculated using data from the largest installations (> 1GW) in each country. As the smaller plants do not communicate their installed capacity or the data needed to calculate it, it is not possible to know the exact capacity for 2019 or to estimate a factor close to reality. Based on the largest power plants, this factor may be distorted and probably overestimated. This will mean that the model will have greater storage capacity than in reality, enabling it to store more energy.
- The economic and technical data relating to the all-hydrogen pipe are unknown. Sources indicate that the maximum hydrogen content that can be injected into current natural gas pipelines is 20% to avoid any risks [16]. This model assumes that these pipelines can contain 100% hydrogen in order to model fully hydrogen pipelines. Therefore, the data relating to the already present and well-known natural gas pipes are used. This

will have the impact that the transport costs related to hydrogen will be the lower limit and it must be understood that the reported cost will be higher than the ordinary cost of a conventional natural gas transport system given that it is not subject to the same conditions as hydrogen which, due to its atomic size which is one of the smallest in the entire chemical table of elements, is subject to losses requiring the use of expensive coatings. Added to this is the need for higher pressure to transport the same amount of energy more quickly because hydrogen has a lower volumetric energy density than natural gas and, in addition, stricter safety regulations given the greater risk of flammability. All this explains the higher cost of hydrogen pipes than natural gas pipes.

5.5 Notations and abbreviations

The notations are governed by the following rules: Greek letters represent parameters (e.g., the efficiency of a technology), uppercase Latin letters represent sizing variables (such as capacity) while lowercase Latin letters represent operating variables (e.g., energy production).

Nomenclature

$a^n_{r,t}$	Binary variable associated with the commodity r at time t representing if node n is used ($a^n_{r,t} = 1$) or not ($a^n_{r,t} = 0$)
$\alpha^n \in [0, 1]$	Fraction of time that node n is shutdown due to planned outage
$\text{CAPEX}^n \in \mathbb{R}_+$	Capital expenditure of the node n
γ^n	Big M parameter of the Big M method of node n
$\mathcal{C}$, c	Set of clusters and cluster index
$\Delta^n_{i,+} \in [0, 1]$	Maximum ramp-up rate for flow i and conversion node n (frac. of capacity per unit time)
$\Delta^n_{i,-} \in [0, 1]$	Maximum ramp-down rate for flow i and conversion node n (frac. of capacity per unit time)
$\delta t \in \mathbb{R}_+$	Duration of each time period
$d^n_{i,t} \in \mathbb{R}_+$	Aggregated demand for the commodity i at time t in the node n
$\mathcal{E}$, e	Set of hyperedges and hyperedge index
$E^n \in \mathbb{R}_+$	Stock capacity of storage node n
e_r, e_w	Tail and head of hyperedge $e \in \mathcal{E}$
$e^n_t \in \mathbb{R}_+$	Inventory level of storage node n at time t
$\overline{e}^n \in \mathbb{R}_+$	Maximum stock capacity of storage node n
$\underline{e}^n \in \mathbb{R}_+$	Existing stock capacity of storage node n
$\epsilon^n_{i,t} \in \mathbb{R}_+$	Energy over produced of the node n of the commodity i at time t
$\varepsilon^n_{i,t} \in \mathbb{R}_+$	Energy not served of the node n of the commodity i at time t
$\mathcal{G}$	Hypergraph with node set $\mathcal{N}$ and edge set $\mathcal{E}$

Nomenclature - cont.

$\zeta^n \in \mathcal{R}_+$	Annualised investment cost of node n
$\eta_+^n \in [0,1]$	Charge efficiency of storage node n
$\eta_-^n \in [0,1]$	Discharge efficiency of storage node n
$\eta_s^n \in [0,1]$	Self-discharge rate of storage node n
$\eta_t^n \in [0,1]$	Efficiency of transport node n
$\theta_f^n \in \mathbb{R}_+$	Fixed Operation and Maintenance cost
$\theta_v^n \in \mathbb{R}_+$	Variable Operation and Maintenance cost
$\vartheta_f^n \in \mathbb{R}_+$	Stock component of the FOM cost of storage node n
$\vartheta_v^n \in \mathbb{R}_+$	Stock component of the VOM cost of storage node n
$\mathcal{I}^n$, i	Set of external variables at node n, and variable index
$\widetilde{\mathcal{I}} \subset \mathcal{I}$, $\tilde{i}$	Set of commodity that a cluster can purchased, and variable index
J_t^n	Used flow capacity of node n at time t
$K^n \in \mathbb{R}_+$	Flow capacity of node n
$\overline{\kappa}^n \in \mathbb{R}_+$	Maximum flow capacity of technology n
$\underline{\kappa}^n \in \mathbb{R}_+$	Existing flow capacity of technology n
$LHV_{\mathrm{H_2}} \in \mathbb{R}_+$	The Lower Heating Value of hydrogen
$l_t^n \in \mathbb{R}_+$	Cost related to the CO_2 captured from or released to the atmosphere by node n
$\lambda \in \mathbb{R}_+$	The carbon emission tax
$\lambda_{i,s,t}^n \in \mathbb{R}_+$	Demand for commodity i from time-series s at time t
$M_{\mathrm{H_2O}} \in \mathbb{R}_+$	The molar mass of pure water
$M_{\mathrm{H_2}} \in \mathbb{R}_+$	The molar mass of hydrogen
$\mu^n \in [0,1]$	Minimum operating level of conversion node n (in fraction of capacity)
$\mathcal{N}$, n	Set of nodes and node index
$\nu \in \mathbb{N}$	The number of years spanned by the optimisation horizon
$\nu_{\mathrm{H_2}}^{\mathrm{H_2O}} \in \mathbb{R}_+$	The stoichiometric coefficient between the water and hydrogen produced or consumed
$\xi^n \in \mathbb{R}_+$	Factor linking the stock capacity to the flow capacity of storage node n
$\pi_t^n \in [0,1]$	(Operational) availability of conversion node n at time t
$q_{i,t}^c \in \mathbb{R}_+$	Flow of commodity i at cluster c and time t
$q_{i,t}^n \in \mathbb{R}_+$	Flow of commodity i at node n and time t
$q_{r,t}^n \in \mathbb{R}_+$	Flow of the reference commodity r at node n and time t
$q_{z,t}^n \in \mathbb{R}_+$	Flow of the chemical element z forming part of the fuel flow at node n and time t
$q_{i_f,t}^n \in \mathbb{R}_+$	Forward flow of commodity i at node n and time t
$q_{i_r,t}^n \in \mathbb{R}_+$	Reverse flow of commodity i at node n and time t
$q_{i_f,t}^{n,z} \in \mathbb{R}_+$	Forward flow chemical element z forming part of the fuel flow at node n and time t

Nomenclature - cont.

$\rho^n \in [0,1]$	Charge-to-discharge ratio of storage node n
$\varrho_t^n \in \mathbb{R}_+$	Cost of the amount of energy over produced at node n at time t
$\sigma^n \in [0,1]$	Minimum state of charge of storage node n
$\sigma_t^n \in \mathbb{R}_+$	Cost of the amount of energy not served at node n at time t
$\sigma_{\tilde{i}} \in \mathbb{R}_+$	Cost of the amount of commodity $\tilde{i}$ purchased by a cluster
$\varsigma^n \in \mathbb{R}_+$	Stock component of the annual investment cost of storage node n
$\mathcal{T}$, t	Set of time periods which is equal to $\{0, 1, ..., T-1\}$ where T is the time horizon of the model and time index
$\phi_i^n \in \mathbb{R}_+$	Conversion factor between reference flow r and flow i for conversion node n
$\phi_{z,t}^n \in \mathbb{R}_+$	Share of the element z at time t in the mix that composes the fuel flow of the node n
$\overline{\phi_z^n}$	Maximal share of element z in the mix of the fuel flow of node n
$\phi_{\mathrm{CO_2}}^n \in \mathbb{R}_+$	Conversion factor between carbon dioxide produced and flow i for conversion node n
$\varphi^n \in \mathbb{R}_+$	Production (resp. consumption) of water per unit of hydrogen consumed (resp. produced)
$\chi_i^n \in \mathbb{R}_+$	Cost of the commodity i consumed by the node n
$\Psi_i^n \in [0,1]$	Percentage of the commodity i that need to be self-consumed in the node n for its operation
$w^n \in [0,1]$	Weighted Average Cost of Capital of node n
$\mathcal{Z}^n$, z	Set of chemical elements that compose the fuel used in the node n and element index

5.6 Formalisation

5.6.1 Conversion nodes

Technologies

Conversion nodes are nodes in which a commodity such as energy, a molecule, or others is transformed into another commodity using a process or asset. These nodes include: photovoltaic panels (PV), wind onshore and wind offshore turbines (WON and WOFF), hydroelectric power plant (combination of run-of-river and water reservoir [2]), combustion power plants such as biomass-fired power plants (BIO), brown coal turbines (BCT), combined-cycle gas turbines (CCGT), gas from coal turbines (GFCT), hard coal turbines (HCT), oil turbines (OT) and waste-fired power plants (WA), nuclear power plants (NK), alkaline electrolyser cells (AEC), proton exchange membrane electrolyser cells (PEMEC) and solid oxide electrolyser cells (SOEC), molten carbonate fuel cells (MCFC), CO_2 capture facilities such as direct air capture (DAC) and post-combustion carbon capture (PCCC). These technologies are described in SECTION 4.4.

[2]Named "run-of-river" in the model (ROR)

Mathematical formulation

The conversion of one commodity into one or more commodities (e.g. from raw material to electricity, heat and to carbon emissions) using a technology is done with a certain efficiency coefficient. Equation 5.1 describes this conversion in which n is a conversion node among the $\mathcal{N}$ nodes, each commodity is modelled as a variable and indexed by an index $i \in \mathcal{I}^n$ where $\mathcal{I}^n$ is the set of external variables, r is the reference commodity chosen arbitrarily among the set of commodities of the node $r \in \mathcal{I}^n$, $q^n_{r,t}$ is the flow of the reference commodity of node n at time t, $q^n_{i,t}$ is the flow of all other commodities of $\mathcal{I}^n$ except r and $\phi^n_i \in \mathbb{R}_+$ is the conversion factor. This equation simply expresses the fact that, taking the example of a fuel cell, the electricity produced at output is equal to the hydrogen input multiplied by a certain efficiency percentage. If there are multiple input flows, The Eq. 5.1 is applied separately for each input stream

$$q^n_{r,t} = \phi^n_i \cdot q^n_{i,t} \ , \qquad \forall i \in \mathcal{I}^n \backslash \{r\},\ \forall t \in \mathcal{T} \ . \tag{5.1}$$

The consumption or production of the reference commodity is less than the maximum capacity of the technology which is reflected in Eq. 5.2 where K^n is the flow capacity of technology n and $\pi^n_t \in [0,1]$ is a utilisation factor at time t. This factor can be the load factor of a wind turbine which is zero when there is no wind or the maximal rate of carbon capture of a PCCC unit.

$$q^n_{r,t} \leq \pi^n_t \cdot K^n \ , \qquad \forall t \in \mathcal{T} \ . \tag{5.2}$$

The variable K^n must be bounded by the existing capacity $\underline{\kappa}^n \in \mathbb{R}_+$ (the capacity already installed of this technology) and the maximum capacity $\overline{\kappa}^n \in \mathbb{R}_+$ of technology n that can be installed. This is shown in Eq. 5.3.

$$\underline{\kappa}^n \leq K^n \leq \overline{\kappa}^n \ . \tag{5.3}$$

Some conversion technologies have a minimum load, which means that when the plant is running it operates between the minimum load, which is a percentage of the maximum capacity, and the maximum capacity. This constraint is expressed by imposing a minimum flux on a commodity $q^n_{r,t}$ as a function of the capacity K^n using a coefficient denoted $\mu^n \in [0,1]$. Initially, this constraint will be neglected by imposing no minimum output power. Then, this constraint will be considered by introducing a binary variable $a^n_{r,t}$ to ensure that the plant does not operate at this minimum load throughout the year. This variable must also be included in Eq. 5.2. Integrating a binary variable into the model implies that the model is no longer a Linear Programming (LP) problem but becomes a Mixed-Integer Linear Programming (MILP) problem. The specificities of these two types of problems are detailed in SECTION 4.2. This leads to:

$$q^n_{r,t} \geq \mu^n \cdot a^n_{r,t} \cdot K^n \ , \qquad \forall t \in \mathcal{T} \ ; \tag{5.4}$$

$$q^n_{r,t} \leq a^n_{r,t} \cdot K^n \ , \qquad \forall t \in \mathcal{T} \ . \tag{5.5}$$

If the binary variable is zero, the only solution for the flow of the reference commodity is to be also null while if the binary variable is equal to 1, the flow of the reference commodity is bounded by a minimal and a maximal value given by a proportion of K^n and K^n itself.
The problem is that this involves multiplying 2 variables (the binary variable $a^n_{r,t}$ and the flow capacity of the installation K^n) with each other, which is forbidden in MILP. To solve this

linearity problem, an auxiliary variable J_t^n representing the total flow capacity effectively used by node n at time t is introduced. First, Eq. 5.6 is used to constraint J_t^n below the total available flow capacity K^n to ensure that used flow capacity remains within physical limits. Then, J_t^n is linked to the binary variable $a_{r,t}^n$ using the Big M method thanks to Eq. 5.7 where γ^n is the parameter M of the Big M method shown in Eqs. 4.9 and 4.10 of the node n. γ^n is a suitably chosen parameter, ideally close to or equal to $\overline{\kappa}^n$. This constraint ensures that when $a_{r,t}^n = 0$, the effective flow capacity used J_t^n is forced to zero, and when $a_{r,t}^n = 1$, J_t^n is unconstrained up to γ^n, which matches K^n if the value is chosen appropriately. This decouples the product $a_{r,t}^n \cdot K^n$, thus recovering linearity. Finally, the flow of the reference commodity is linked to this auxiliary variable thanks to Eq. 5.8 and Eq. 5.9 which restores the original logic explained earlier.

$$J_t^n \leq K^n \ , \qquad \forall t \in \mathcal{T} \ ; \tag{5.6}$$
$$J_t^n \leq a_{r,t}^n \cdot \gamma^n \ , \qquad \forall t \in \mathcal{T} \ ; \tag{5.7}$$
$$q_{r,t}^n \leq J_t^n, \qquad \forall t \in \mathcal{T} \ ; \tag{5.8}$$
$$q_{r,t}^n \geq \mu^n \cdot J_t^n, \qquad \forall t \in \mathcal{T} \ . \tag{5.9}$$

For technologies such as CCGTs, where the fuel used is a combination of 2 or more elements noted $q_{z,t}^n \in \mathbb{R}_+$ for $z \in \mathcal{Z}^n$ that may vary in proportion in the mix, the mathematical formulation is:

$$q_{z,t}^n = \phi_z^n \cdot \sum_{j \in J} q_{z,t}^n, \qquad \forall j \in \mathcal{Z}^n, \ \forall t \in \mathcal{T} \ ; \tag{5.10}$$
$$\phi_{z,t}^n \leq \overline{\phi_z^n}, \qquad \forall j \in \mathcal{Z}^n, \ \forall t \in \mathcal{T} \ ; \tag{5.11}$$
$$\sum_{j \in J} \phi_{z,t}^n = 1, \qquad \forall z \in \mathcal{Z}^n, \ \forall t \in \mathcal{T} \ ; \tag{5.12}$$

where $\mathcal{Z}^n$ is the set of element composing the fuel, $q_{z,t}^n$ is the flow of the element z at time t, $\phi_{z,t}^n \in \mathbb{R}_+$ is the share of the element z in the flow mix of the fuel which is bounded between 0 and the maximal share of this element in the fuel mix, i.e. $\overline{\phi_z^n}$ and where the sum of all element flows $q_{z,t}^n$ is equal to the fuel flow in the plant.
The ramping constraint is the constraint that expresses the capability of a flow of a commodity $r \in \mathcal{I}^n$ to increase or decrease. For example a gas-fired power plant is suitable to follow demand variation due to its ability to quickly modify its electricity output unlike nuclear power plants that have more inertia. The change in flow is calculated as the difference between the value at time t and the value at the previous time $t-1$. This difference is limited by a portion of the maximum capacity K^n, represented by the $\Delta_r^n \in [0,1]$ parameter. The variation can be ramped up or ramped down, leading to equations 5.13 and 5.14 expressing the ramp-up and ramp-down constraints respectively.

$$q_{r,t}^n - q_{r,t-1}^n \leq \Delta_{r,+}^n \cdot K^n \ , \qquad \forall t \in \mathcal{T} \backslash \{0\} \ ; \tag{5.13}$$
$$q_{r,t}^n - q_{r,t-1}^n \geq -\Delta_{r,-}^n \cdot K^n \ , \qquad \forall t \in \mathcal{T} \backslash \{0\} \ . \tag{5.14}$$

Some technologies require maintenance, necessitating a planned shutdown of the power plant. This is known as a planned outage. This forced and planned outage implies a new constraint represented by Eq. 5.15 in which $\alpha^n \in [0,1]$ represents the fraction of time during which the plant n is not usable and therefore cannot produce any output. This constraint allows the model to determine at what time of year this shutdown is most optimal to cause the least loss of money, which is actually done by the plant manager.

$$\sum_{t\in\mathcal{T}} q^n_{r,t} \leq (1-\alpha^n)\cdot \sum_{t\in\mathcal{T}} K^n \ . \tag{5.15}$$

The objective function is a mathematical equation that the optimiser must minimise or maximise. In this model, the aim is to minimise the overall cost of the system by minimising the cost of each node. The cost of a technology is specific to that technology. In the case of this model, these costs are represented by cost functions. The first cost function takes into account the installation cost and the operation and maintenance costs as follows:

$$F^n = \nu \cdot (\zeta^n + \theta^n_f)\cdot (K^n - \underline{\kappa}^n) + \sum_{t\in\mathcal{T}} \theta^n_v \cdot q^n_{r,t}\cdot \delta t \ , \tag{5.16}$$

where $\nu \in \mathbb{N}$ is the number of years spanned by the optimisation horizon, $\zeta^n \in \mathbb{R}_+$ describes the annualised investment cost given by Eq. 5.17, $\theta^n_f \in \mathbb{R}_+$ represents the cost associated with Fixed Operation and Maintenance (FOM), expressed in function of the capacity, includes the cost of regular servicing, maintenance equipment, etc., $\theta^n_v \in \mathbb{R}_+$ represents Variable Operation and Maintenance (VOM), expressed in function of production, includes the cost of wear and tear due to the use of the plant, the cost of the input commodity (the cost of gas from a CCGT plant, for example), etc.
The annualised investment cost given by Eq. 5.17 depends on CAPEX^n which is the capital expenditure of the node n or more simply the initial investment, w^n is the Weighted Average Cost of Capital (WACC)[3] and L^n is the lifetime of node n.

$$\zeta^n = \text{CAPEX}^n \cdot \frac{w^n}{1-(1+w^n)^{-L^n}} \ . \tag{5.17}$$

The VOMs obtained from the various sources ([6, 19]) indicate that the cost of fuel is not taken into account, which means that a second cost function needs to be created to take it into account. This second cost function is added to the objective to minimise.

$$F^n_i = \chi^n_i \cdot \sum_{t\in\mathcal{T}} q^n_{i,t}\cdot \delta t \ , \tag{5.18}$$

with $\chi^n_i \in \mathbb{R}_+$ the price of the commodity i and $\delta t \in \mathbb{R}_+$ the duration of each time period. This equation can also be used to model the objective function on carbon emissions where χ^n_i is the carbon taxes and $q^n_{i,t}$ is the carbon emission. As the carbon tax is assume to be the same in all countries and for all nodes, let note it as λ to avoid confusion between the carbon tax and the fuel cost in tables. It should be noted that a carbon tax is fixed for the year 2019 and is assumed to be equal to 24.88 €/t_{CO_2} based on the annual average of the European Emissions Trading System (EU ETS) given by [20]. For the model of 2050, no carbon tax is fixed but a quota of carbon emissions is imposed and the solution returned by the solver allows obtaining the price of carbon emissions.

[3] The discount rate used to assess the profitability of a project, taking into account the cost of borrowed capital (debt) and equity (capital). It reflects the average cost to the investor of financing the plant over its lifetime and therefore has a strong influence on long-term investment decisions.

Nodes modelling

Each conversion node is modelled with one variable representing the newly installed plant capacity which is constrained using Eq. 5.3 and other variables representing commodities and are all subjected to the same objective defined by Eq. 5.16.

Renewable intermittent technologies such as wind turbines, solar panels and hydroelectric power plants are modelled using Eq. 5.2 where π_t^n is a time series obtained via [21] for the nodes PV, wind onshore and offshore while the time series for the hydroelectric nodes is a constant equal to 22% which is the efficiency given by [6]. The choice of a constant load factor rather than hourly load factor values had to be made in view of the lack of data concerning the many run-of-river installations. For PV nodes, wind onshore nodes and wind offshore nodes, the difference between $\pi_t^n \cdot K^n$ and $q_{r,t}^n$ is the electricity curtailed when there is to much production on the grid while there is no electricity curtailed for hydroelectric node leading to replace the sign "$\leq$" by an equality sign. As there is no fuel, there is no cost associated with it and so Eq. 5.18 is not used for those nodes.

Combustion power plants and nuclear power plants are all modelled on the same basis. Eq. 5.6 to Eq. 5.9 are used to bound the electricity produced between the maximal power of the installation and its minimal external power while leaving the possibility of the power plant being shut down. Eq. 5.13 and Eq. 5.14 are used to limit variation of electricity produced between two time steps to represent the dynamics of the installations. These data come from [4]. Eq. 5.15 is used to represent the time that the plant cannot produce electricity due to forced outage. Finally, Eq. 5.1 is used to evaluate the quantity of carbon emission where ϕ_i^n is the specific carbon emission of the primary energy used and this equation is also used to compute the quantity of fuel needed. For the CCGT node, other constraints are needed to modelled the possibility of the plant being fed with a mixture of hydrogen and natural gas which is made by Eqs. 5.10 to 5.12. Fuel costs are obtained from different sources which are reported in SUBTABLE 5.1c and so Eq. 5.18 is used. This equation is re-used to model the carbon taxes due to CO_2 emissions of those power plants.

Fuel cells and electrolyser cells are modelled using the same equations as combustion power plants but the flow of the reference commodity is the hydrogen production for electrolysers instead of electrical production and is the same for fuel cells. Any carbon is emitted and the hydrogen consumed by the fuel cells is produced by the electrolysers leading to not using Eq. 5.18 while the electrolyser nodes need water which is recovered from fuel cells if they are used and bought so Eq. 5.18 is needed to model the cost of this purchased water. Eq. 5.1 is used to compute the water consumed by the electrolysers (resp. produced by the fuel cells) where ϕ_i^n can be obtained through the following parameter:

$$\varphi^n = \nu_{\mathrm{H_2}}^{\mathrm{H_2O}} \cdot \frac{M_{\mathrm{H_2O}}}{M_{\mathrm{H_2}} \cdot LHV_{\mathrm{H_2}}}, \tag{5.19}$$

where $\nu_{\mathrm{H_2}}^{\mathrm{H_2O}}$ is the stoichiometric coefficient between the water and the hydrogen which is equal to 1 for AEC, PEMEC, SOEC and MCFC due to their respective chemical equation, $M_{\mathrm{H_2O}}$ is the molar mass of H_2O and is equal to 18 g/mol while M_{H_2} is the molar mass of H_2 which is equal to 2 g/mol and LHV_{H_2} is the Lower Heating Value of hydrogen which is equal to 33.3 GWh/kt$_{H_2}$) given that $\varphi^n = 0.27$ kt$_{H_2O}$)/GWH$_{H_2}$) for all of those nodes. Then this value must be reversed to express it in function of the reference flow for ECs and must then be multiplied by the efficiency of the plant to obtain the conversion factor related to the flow of the reference commodity in the case of the MCFC.

Carbon capture nodes are modelled with Eq. 5.2 where the flow of the reference commodity is the amount of CO_2 that is captured by the plant and π_t^n is replaced by a constant representing the maximal rate of carbon capture of the plant. The same equation can be used to determined the amount of carbon that is released by taking the inefficiency to capture CO_2 (which is equal to 1 minus the maximal rate of carbon capture) and the total amount of carbon passing through this node is the sum of these two variables. Eq. 5.1 is used to obtain the electrical consumption of the plant from the amount of carbon captured, where ϕ_i^n is the amount of electricity required per mass of carbon captured.

Node parameters

Table 5.1 is an example over the year 2019 of the technical and economical parameters used in the model. $\underline{\kappa}^n$ and $\overline{\kappa}^n$ are not given as they vary depending on the scenario studied and on the country, so they will be given later. Parameters for the year 2050 are given in Appendix A.1.

n	Commodity r	α^n -	μ^n -	Δ_+^n/Δ_-^n -	Source
PV	Electricity	0	0	-	[4]
WON	Electricity	0	0	-	[4]
WOFF	Electricity	0	0	-	[4]
ROR	Electricity	0	0	-	[4]
BIO	Electricity	3/52	0.45	0.25/0.3	[4]
BCT	Electricity	2.3/52	0.45	1.0/1.0	[4, 19]
CCGT	Electricity	2.3/52	0.4	1.0/1.0	[4, 19]
GFCT	Electricity	2.3/52	0.4	1.0/1.0	[4, 19]
HCT	Electricity	2.3/52	0.23	1.0/1.0	[4, 22]
OT	Electricity	2.3/52	0.2	1.0/1.0	[4, 19]
WA	Electricity	1.8/52	0.2	0.25/0.3	[4]
NK	Electricity	3/52	0.0	0.01/0.01	[4]
AEC	H_2	11/365	0.1	1.0/1.0	[4, 19]
PEMEC	H_2	11/365	0.1	1.0/1.0	[4, 19]
SOEC	H_2	11/365	0.1	1.0/1.0	[4, 19]
MCFC	Electricity	0.1/52	0.1	1.0/1.0	[4, 19]
DAC	CO_2	0	0	-	[19]
PCCCC	CO_2	0	0	-	[19]

(a) Technical parameters.

n	Unit of r $\star$	ϕ_{el} $\star/GWh_{el}$	ϕ_{H_2} $\star/GWh_{H_2}$	ϕ_{CH_4} $\star/GWh_{CH_4}$	ϕ_{CO_2} $\star/kt_{CO_2}$	ϕ_{H_2O} $\star/kt_{H_2O}$	ϕ_{fuel} $\star/GWh_{fuel}$ or $\star/kt_{fuel}$	Source
BIO	GWh_{el}	-	-	-	0.35/0.41	-	0.35	[6, 7]
BCT	GWh_{el}	-	-	-	1/0.28	-	0.37	[6, 7]
CCGT	GWh_{el}	-	0	0.57	1/0.18	-	0.57	[7, 19]
GFCT	GWh_{el}	-	-	-	1/0.168	-	0.35	[6, 23]
HCT	GWh_{el}	-	-	-	1/0.37	-	0.38	[6, 7]
OT	GWh_{el}	-	-	-	1/0.26	-	0.39	[7, 19]
WA	GWh_{el}	-	-	-	0.33/1	-	0.33	[6, 24]
NK	GWh_{el}	-	-	-	0	-	0.38	[6]
MCFC	GWh_{el}	-	0.68	-	0	2.516	-	[6]
AEC	GWh_{H_2}	0.577	-	-	-	3.7	-	[19]
PEMEC	GWh_{H_2}	0.526	-	-	-	3.7	-	[19]
SOEC	GWh_{H_2}	0.66	-	-	-	3.7	-	[19]
DAC	kt_{CO_2}	0.5	-	-	1.0	-	-	[19]
PCCCC	kt_{CO_2}	1/0.863	-	-	0.9	-	-	[19]

(b) Conversion factors.

n	$CAPEX^n$ M€/GW or M€/kt/h	θ_f^n M€/Gw-yr or M€/(kt/h)-yr	θ_v^n M€/GWh or M€/kt	χ_i^n M€/MWh or M€/kt	L^n years	Source
PV	560	11.3	0	0	35	[19]
WON	1 105.514	16.397	$2.11 \cdot 10^{-3}$	0	27	[19]
WOFF	2 780.229	44	$4.41 \cdot 10^{-3}$	0	30	[19]
ROR	2 450	8.9	0	0	50	[6]
BIO	2 000	47.5	$3.56 \cdot 10^{-3}$	$43.8 \cdot 10^{-3}$	40	[6, 25]
BCT	1 800	32.5	$3 \cdot 10^{-3}$	$22.89 \cdot 10^{-3}$	40	[6, 26]
CCGT	935.768	31.157	$4.68 \cdot 10^{-3}$	$18.196 \cdot 10^{-3}$	25	[6, 27, 28]
GFCT	3 550	69.8	$7.74 \cdot 10^{-3}$	$21.06 \cdot 10^{-3}$	30	[6, 29]
HCT	1 600	25.6	$2.4 \cdot 10^{-3}$	$28.77 \cdot 10^{-3}$	40	[6, 26]
OT	404.082	0	0	$74.75 \cdot 10^{-3}$	25	[6, 26]
WA	2 030	52.3	$0.82 \cdot 10^{-3}$	0	20	[6]
NK	5 300	120	$6.4 \cdot 10^{-3}$	$4.443 \cdot 10^{-3}$	60	[6, 30]
AEC	1 100	44	0.205	0.19	25	[19, 31]
PEMEC	1 200	24	0.205	0.19	25	[19, 31]
SOEC	1 800	180	0.205	0.19	25	[19, 31]
MCFC	4 447	66.7	$1.04 \cdot 10^{-3}$	-	20	[6]
DAC	6 500	260	0	-	20	[19]
PCCCC	4 100	120	$2.5 \cdot 10^{-3}$	-	25	[19]

(c) Economical parameters.

Table 5.1: Technical and economical parameters of conversion nodes associated with the year 2019.

5.6.2 Flexibility nodes

Technologies

Flexibility nodes are important to render the system to maintain a balance between production and demand. The rise of renewable energy plants produces a low-carbon solution to electricity production, but these technologies generally suffer from intermittency, often depending on weather conditions. Flexibility technologies make it possible to store energy when there is a production surplus so that it can be discharged back to the grid when there is a production deficit. The flexibility nodes considered in this model are lithium-ion and sodium-ion batteries (LI-BAT and NA-BAT), hydraulic pumped storage power stations (HPS) and carbon storage (CS).

Mathematical formulation

To evaluate the state of charge of a storage technology $n \in \mathcal{N}$, Eq. 5.20 is used to compute the state of charge at the next time step, i.e. $e^n_{t+1} \in \mathbb{R}_+$, where $e^n_t \in \mathbb{R}_+$ is the state of charge of the asset at time t, $\eta^n_S \in [0,1]$ is the self-discharge, $q^n_{i,t} \in \mathbb{R}_+$ is the incoming flow which enters the storage asset, $\eta^n_+ \in [0,1]$ is the charging efficiency, reduced by the outgoing flow $q^n_{j,t} \in \mathbb{R}_+$ is the outgoing flow that leaves the storage node and $\eta^n_- \in [0,1]$ the discharging efficiency of the storage node n.

$$e^n_{t+1} = (1-\eta^n_S) \cdot e^n_t + \eta^n_+ \cdot q^n_{i,t} - \frac{1}{\eta^n_-} \cdot q^n_{j,t} \ , \qquad \forall t \in \mathcal{T} \backslash \{T-1\} \ . \tag{5.20}$$

The storage capacity E^n must be bounded by the constraint expressed at Eq. 5.21 where $\underline{e}^n \in \mathbb{R}_+$ is the storage capacity already installed and $\overline{e}^n \in \mathbb{R}_+$ is maximal storage capacity.

$$\underline{e}^n \leq E^n \leq \overline{e}^n \ . \tag{5.21}$$

Then, the storage capacity is used to limit the storage level at time t through:

$$e^n_t \leq E^n \ , \qquad \forall t \in \mathcal{T} \ . \tag{5.22}$$

The storage capacity could have a minimum value to not exceed which is expressed by Eq. 5.23 where σ^n is the minimal rate of the storage level:

$$e^n_t \geq \sigma^n \cdot E^n \ , \qquad \forall t \in \mathcal{T} \ . \tag{5.23}$$

The flow into and out of the node is also limited by the flow capacity K^n of the node n. This limit is described by Eq. 5.24 and Eq. 5.25 where ρ^n is the maximum charge-to-discharge ratio used when the maximum commodity in- and out-flows are asymmetric.

$$q^n_{i,t} \leq \rho^n \cdot K^n \ , \qquad \forall i \in \mathcal{I}^n, \forall t \in \mathcal{T} \ ; \tag{5.24}$$

$$q^n_{j,t} \leq K^n \ , \qquad \forall j \in \mathcal{I}^n, \forall t \in \mathcal{T} \ . \tag{5.25}$$

In the case of carbon storage, as it is used as an underground burial node of the captured carbon, the amount of the output stream is set to zero via Eq. 5.26. In a future perspective where this carbon would be used to transform it into e-fuel, this constraint would have to be removed in order to use Eq. 5.25.

$$q^n_{j,t} = 0 \ , \qquad \forall j \in \mathcal{I}^n, \forall t \in \mathcal{T} \ . \tag{5.26}$$

The flow capacity K^n may be bound by the constraint 5.3 or can be linked to the stock capacity which is expressed by:

$$K^n = \xi^n \cdot E^n \ , \tag{5.27}$$

where $\xi^n \in \mathbb{R}_+$ is the flow-to-stock ratio capacity of node n.
A constraint associated with $t = 0$ is used to initialise the inventory level dynamics in order to avoid edge problems at the last time step. Eq. 5.28 gives this initial constraint, where $q^n_{i,T-1}$ and $q^n_{j,T-1}$ are the commodity in- and out-flows at the last time step of the optimisation, i.e. $t = T - 1$. For the carbon storage node, the initial value of the storage level is zero.

$$e^n_0 = (1 - \eta^n_S) \cdot e^n_{T-1} + \eta^n_+ \cdot q^n_{i,T-1} - \frac{1}{\eta^n_-} \cdot q^n_{j,T-1} = e^n_{T-1} \ . \tag{5.28}$$

In order to charge a storage system, it may be necessary to bring in a new flow of energy, denoted $l \in \mathcal{I}^n, l \neq i, j$, such as using electricity to power the pump of a hydraulic pumped storage plant. This new dependency is written as follows:

$$q^n_{l,t} = \phi^n_i \cdot q^n_{i,t} \ , \tag{5.29}$$

where ϕ^n_i is, as for the conversion nodes, a conversion factor between the two commodities. Among the equations that can be taken from the conversion nodes, the equations allowing planned outages to be taken into account are defined in the same way for the input and output flows by Eqs. 5.30 and 5.31 respectively.

$$\sum_{t \in \mathcal{T}} q^n_{i,t} \leq (1 - \alpha^n) \cdot \rho^n \cdot \sum_{t \in \mathcal{T}} K^n \ , \qquad \forall t \in \mathcal{T} \ , \tag{5.30}$$

$$\sum_{t \in \mathcal{T}} q^n_{j,t} \leq (1 - \alpha^n) \cdot \sum_{t \in \mathcal{T}} E^n \ , \qquad \forall t \in \mathcal{T} \ , \tag{5.31}$$

where $\rho^n \in \mathbb{R}_+$ is the maximum charge-to-discharge ratio.
The cost function of storage node n to be minimised is defined by:

$$\begin{aligned} F^n = & \left(\nu \cdot (\varsigma^n + \vartheta^n_f) \cdot (E^n - \underline{e}^n) + \sum_{t \in \mathcal{T}} \vartheta^n_v \cdot e^n_t \cdot \delta t \right) \\ & + \left(\nu \cdot (\zeta^n + \theta^n_f) \cdot (K^n - \underline{\kappa}^n) + \sum_{t \in \mathcal{T}} \theta^n_v \cdot q^n_{i,t} \cdot \delta t \right) \ , \end{aligned} \tag{5.32}$$

where $\varsigma^n \in \mathbb{R}_+$ and $\zeta^n \in \mathbb{R}_+$ are respectively the stock and the flow component of the annual investment cost. Those parameters are computed thanks to Eq. 5.17 forζ^n. and the equation for ς^n is exactly the same by using the CAPEX^n associated with the stock. $\vartheta^n_f \in \mathbb{R}_+$ and $\theta^n_f \in \mathbb{R}_+$ are respectively the stock and the flow component of FOM cost while $\vartheta^n_v \in \mathbb{R}_+$ and $\theta^n_v \in \mathbb{R}_+$ modelled the VOM costs of stock and flow.

Nodes modelling

All equations listed above from Eq. 5.20 to Eq. 5.31 are used in each storage node except for Eq. 5.26 which is used only for the carbon storage and Eq. 5.28 which is not used for this same storage node as already mentioned.

Node parameters

All technical and economical parameters used in storage nodes are reported in Table 5.2 for the year 2019 except for the parameters associated with the pre-installed capacity and maximum capacity of both flow and storage capacity which depend on the country and on the scenario and so will be given later. Parameters associated with the year 2050 are reported in Appendix A.1.

n	η_S^n	η_+^n	η_-^n	σ^n	ρ^n	ξ^n	ϕ_{el}^n GWh$_{el}$/GWh$_{CO_2}$	α^n	Source
LI-BAT	0.0042	0.98	0.97	0	0.5	3	-	0.2/52	[4, 19]
NA-BAT	0	0.911	0.911	0	50/300	50/300	-	0	[4, 19]
HPS	0	0.866	0.866	0	1	-	-	0	[4, 19]
CS	0	1	1	0	1	$1/T$	50/3600	0	[4, 19]

(a) Technical parameters.

	BE	LU	FR	NL	DE	UK	Source
ξ^{HPS}	1/5	0	1/21	0	1/6	1/5	[32]

(b) Conversion factors.

n	$\text{CAPEX}_{\text{stock}}^n$ M€/GWh or M€/kt	$\text{CAPEX}_{\text{flow}}^n$ M€/GW or M€/kt/h	ϑ_f^n M€/GWh or M€/kt	θ_f^n M€/GW or M€/kt/h	ϑ_v^n M€/GWh or M€/kt/h	θ_v^n M€/GW or M€/kt	L^n years	Source
LI-BAT	246.728	140.3688	0	0.574	0	$2.127 \cdot 10^{-3}$	20	[19]
NA-BAT	319.02	435.994	0	5.2638	0	$1.91 \cdot 10^{-3}$	19	[19]
HPS	0	4 253.6	0	8.5072	0	0	50	[19]
CS	$2.36 \cdot 10^{-3}$	0	$0.87 \cdot 10^{-3}$	0	$1.24 \cdot 10^{-3}$	0	30	[19]

(c) Economical parameters.

Table 5.2: Technical and economical parameters of storage nodes associated with the year 2019.

5.6.3 Transport nodes

Technologies

Electricity, natural gas and hydrogen will be the only three commodities that can be imported or exported. Electricity can be transmitted from a cluster (a country) to another through high-voltage lines. As described in Subsection 4.4, there are two types of lines: Alternating Current lines (HVAC) and Direct Current lines (HVDC). In order to transport gas from one cluster to another, a pipe node must be created.

Mathematical formulation

Each transport node n supports flow in both forward and reverse paths indicating the direction in which the commodity is transferred. The forward direction is noted as f while the reverse direction is noted as r. Each transport node can receive and send a commodity. To annotate this, $i \in \mathcal{I}^n$ will be the index indicating the import/inflow of the commodity while $j \in \mathcal{I}^n$ will be the index indicating the export/outflow of the commodity. The maximal forward inlet flow $q^n_{i_f,t}$ can be obtained via Eq. 5.33 while the associated forward outlet flow $q^n_{j_f,t}$ is computed through the forward inlet flow multiplied by an efficiency representing the losses in the transport node noted $\eta^n_t \in [0,1]$:

$$q^n_{i_f,t} \leq K^n \ , \qquad \forall t \in \mathcal{T} \ ; \tag{5.33}$$

$$q^n_{j_f,t} = \eta^n \cdot q^n_{i_f,t} \ , \qquad \forall t \in \mathcal{T} \ ; \tag{5.34}$$

where K^n is bounded by Eq. 5.3. The same equations can be written for the reverse flows $q^n_{i_r,t}$ and $q^n_{j_r,t}$ such as:

$$q^n_{i_r,t} \leq K^n \ , \qquad \forall t \in \mathcal{T} \ ; \tag{5.35}$$

$$q^n_{j_r,t} = \eta^n_t \cdot q^n_{i_f,t} \ , \qquad \forall t \in \mathcal{T} \ . \tag{5.36}$$

In the case of the gas pipeline, the gas transmitted in it can be a mixture of 2 or more elements. Let note $z \in \mathcal{Z}^n$ the element considered in the set of element composing the commodity transmitted, the forward inlet flow of the element z composing the commodity transported by the transport node n, i.e. $q^{n,z}_{i_f,t} \in \mathbb{R}_+$ can be linked to the total amount of the commodity transported $q^n_{i_e,t}$ with the following equation:

$$q^{n,z}_{i_f,t} = \phi^n_{z,t} \cdot q^n_{i_f,t} \ , \qquad \forall z \in \mathcal{Z}^n, \forall t \in \mathcal{T} \ . \tag{5.37}$$

The outlet forward flow of the element z can be computed with Eq. 5.34 by taking the flow of element z and not the total commodity flow. Same equations are used for the reverse flows of the element z. The share of the element in the mix of the commodity $\phi^n_{z,t} \in \mathbb{R}_+$ is bounded by the following formula:

$$\phi^n_{z,t} \leq \overline{\phi^n_t}, \qquad \forall z \in \mathcal{Z}^n, \forall t \in \mathcal{T} \ . \tag{5.38}$$

The sum of each share at each time t must be equal to 1, as already expressed in Eq. 5.12. The outlet forward flow of the element z, $q^{n,z}_{j_f,t}$, composing the commodity outlet forward flow, $q^n_{j_f,t}$ is computed through the node efficiency given by:

$$q^{n,z}_{j_f,t} = \eta^n_t \cdot q^{n,z}_{i_f,t} \ , \qquad \forall z \in \mathcal{Z}^n, \forall t \in \mathcal{T} \ . \tag{5.39}$$

Eq. 5.37 and Eq. 5.39 can be used for the in- and outlet reverse flow of the element z by just modifying the index f by an index r.
The final constraint on transport nodes is an equation linking the flow of one commodity to the use of another commodity, such as the power consumption of a pump that circulates gas in a pipeline. This additional commodity will be indexed by the index $l \in \mathcal{I}^n, l \neq i,j$ where $q^n_{l,t} \in \mathbb{R}_+$. The constraint linking these commodity flows is given by:

$$q^n_{l,t} = \phi^n_l \cdot (q^n_{i_f,t} + q^n_{i_r,t}) \ , \qquad \forall i,j,l \in \mathcal{I}^n, \forall t \in \mathcal{T} \ . \tag{5.40}$$

The cost function to minimise of the transport node n is obtained via:

$$F^n = \nu \cdot (\zeta^n + \theta_f^n) \cdot (K^n - \underline{\kappa}^n) + \sum_{t \in \mathcal{T}} \theta_v^n \cdot (q_{i_f,t}^n + q_{i_r,t}^n) \cdot \delta t \ , \tag{5.41}$$

where $\zeta^n \in \mathbb{R}_+$ is the annualised investment cost computed thanks to Eq. 5.17 and θ_f^n, $\theta_v^n \in \mathbb{R}_+$ are, respectively, the FOM cost and VOM cost.

Nodes modelling

Eqs. 5.33 to 5.41 are used to model HVAC and HVDC transmission lines except for Eqs. 5.37, 5.38 and 5.39 which are used to model the hydrogen content that can be transported in pipelines containing a mixture of hydrogen and natural gas where the maximum hydrogen content in the pipe can reach a maximum value of 20% before causing safety and loss concerns but in this thesis, in order to model hydrogen pipes, this value will be set to 100%.

Node parameters

Table 5.3 shows the technical and economic parameters used to model these transmission nodes for the year 2019. Tables 5.3b and 5.3c show the lengths considered for HVDC lines and gas pipes. For the 2019 model, only electricity production and exchanges are studied, explaining the zeros in the lengths matrix for the pipes as well as the zeros present in the matrix of lengths of HVDC lines indicating that there are no lines present in 2019. The lengths of the lines present in 2019 come from [33]. The costs considered for the year 2019 are based on the prices of future line installation projects listed by ENTSO-E [34]. More details on this assumption are given in Section 6.1.
Concerning the year 2050, the possibility of installing HVDC lines between countries that do not yet have an HVDC connection is forbidden except for lines between Great Britain and its neighbours for which the length of existing line and future project line is considered. For the lengths of the pipes, it is different from the high-voltage lines which connect to a pre-existing network. Since only hydrogen pipelines are modelled in this model, the network does not exist and the current network serving natural gas can only accommodate 20% hydrogen at most, it must be built from scratch. The length of the network to be constructed is based on the length joining the centroids[4] between each country. The geographic coordinates of the centroids are obtained via [35] and the length between 2 geographic coordinates is calculated via [36].

n	η^n	$\overline{\phi_{H_2}}$	ϕ_{el}^n GWh_{el}/GWh_{gas}	Source
HVAC	0.93	-	-	[4]
HVDC	$0.9801\text{-}2.940\ 3 \cdot 10^{-5} \cdot$ length	-	-	[4]
Gas pipe	$1\text{-}2.2 \cdot 10^{-5} \cdot$ length	0	0.015	[4]

(a) Technical parameters.

[4]A centroid is the geographic centre of a country for which the length between this point and any point on the border of the country considered is equidistant.

	BE	LU	FR	NL	DE	UK
BE	-	0	0	0	0	140
LU	0	-	0	-	0	-
FR	0	0	-	-	0	72
NL	0	-	-	-	0	245
DE	0	0	0	0	-	-
UK	140	-	72	245	-	-

(b) Length matrix in km for HVDC.

	BE	LU	FR	NL	DE	UK
BE	-	0	0	0	0	0
LU	0	-	0	-	0	-
FR	0	0	-	-	0	0
NL	0	-	-	-	0	0
DE	0	0	0	0	-	-
UK	0	-	0	0	-	-

(c) Length matrix in km for pipes.

n	CAPEX^n M€/GW	θ_f^n M€/GW	θ_v^n M€/GWh	L^n years	Source
HVAC	422.48	0.015·CAPEX^n	10^{-6}	70	[4, 34]
HVDC	5.226·length	0.015·CAPEX^n	10^{-6}	40	[4, 34]
Gas pipe	0.201·length	0.015·length	10^{-6}	40	[4]

(d) Economical parameters.

Table 5.3: Technical and economical parameters of transport nodes associated with the year 2019.

5.6.4 Demand nodes

Energy carriers

In this thesis, only the demand for electricity and the way in which this electricity is produced are studied. Consequently, there will be only one demand node, which will be electricity demand. For the 2019 model, ENTSO-E has published hourly data on electricity demand for all its member countries. It is therefore possible to extract a time-series for each country. For the 2050 model, it is not possible to predict hourly consumption. In order to know the hourly electricity demand, the 2019 time series are scaled by a factor that takes into account the increase or decrease in electricity demand. This factor is obtained by dividing the forecast annual electricity demand over the year 2050 by the annual electricity demand in 2019. This forecast of annual electricity demand in 2050 was the subject of a study carried out in collaboration between ENTSO-E and ENTSOG, which are respectively the managers of the European electricity and gas transmission networks. In this report, entitled *Ten-Year Network Development Plans* (TYNDP) 2024 [3], these managers study future gas and electricity requirements according to 3 scenarios in order to determine what future investment is needed to ensure that we are always able to meet this demand. Each scenario provides predictions of the annual demand in 2030, 2040 and 2050 that is expected to meet the net zero carbon emission target by 2050. In the *Global ambition* scenario, whose assumptions are similar to those of this thesis, such as an energy transition initiated at European or national level, a strong increase in renewable power sources replaced by low-carbon sources, a focus on large-scale technologies, integration of carbon capture and storage, justifying the choice of this scenario as the reference, the estimated annual electricity demand is 3 616 TWh compared to a demand of 2 660 TWh in 2019 given by the ENTSO-E report [2] across all ENTSO-E countries giving a scale factor of 1.359 which will be applied to each time step of the time-series of electricity demands for the year 2019 in order to keep realistic hourly profiles.

Two additional variables related to the electrical demand are added to the model to allow more flexibility and in particular to ensure the existence of a solution. These variables are called "Energy Not Served (ENS)" and "Energy Over Produced (EOP)" and represent respectively the quantity of energy that the model cannot provide at a time t because of an excessive demand at that moment and the quantity of energy that the model produces in excess at a time t compared to the electrical demand at that moment.

Mathematical formulation

Let $n \in \mathcal{N}$ be a demand node, $\lambda^n_{i,s,t}$ be the demand for commodity i from time-series s at time t, then the aggregated demand for commodity i at time t, $d^n_{i,t}$ is given by:

$$d^n_{i,t} = \sum_{s \in \mathcal{S}^n_i} \lambda^n_{i,s,t} - \varepsilon^n_{i,t} + \epsilon^n_{i,t} \ , \qquad \forall i \in \mathcal{I}^n, \forall t \in \mathcal{T} \ , \tag{5.42}$$

where $\mathcal{S}^n_i$ is the set of all time-series considered for the demand of commodity i, $\varepsilon^n_{i,t}$ is the energy not served for commodity i at time t and $\epsilon^n_{i,t}$ is the energy over produced for commodity i at time t. The cost function of the node to be minimised is:

$$F^n = \sum_{t \in \mathcal{T}} \sigma^n_t \cdot \varepsilon^n_{i,t} \cdot \delta t + \varrho^n_t \cdot \epsilon^n_{i,t} \cdot \delta t \ , \tag{5.43}$$

where σ^n_t and ϱ^n_t are the costs associated with the amount of energy not served and overproduced, respectively, which is assumed to be both equal to 3 000 €/MWh [4] which is 70 times higher than the average cost of electricity in 2019 [37].

5.6.5 Clusters

To represent the geographical areas considered in the model, clusters are central nodes each containing a set of all previously detailed nodes. These clusters have their own set of nodes and hyperedges, as well as their own parameters, variables and constraints. These variables represent the net production of the various commodities produced or consumed. Each cluster representing a country uses 5 variables: electricity production, hydrogen production, natural gas production, CO_2 production and water production. These balances can be computed following Eq. 5.44 in which $q^c_{i,t}$ is the net production (resp. consumption) of the cluster $c \in \mathcal{C}$ of the commodity i at time t given by the sum of the production (resp. consumption) of all nodes producing (resp. consuming) the commodity i at time t minus the sum of all nodes consuming (resp. producing) the commodity i at time t. This difference between production and consumption can not be seen in the equation but is implied through the sign of $q^n_{i,t}$.

$$q^c_{i,t} = \sum_{n \in \mathcal{N}} q^n_{i,t} \ , \qquad \forall t \in \mathcal{T} \ . \tag{5.44}$$

In each cluster, a constraint links the amount of CO_2 captured by PCCCs and DACs to the amount of CO_2 stored in the soil in each cluster.

Objective functions are also added at the cluster level. Let $\widetilde{\mathcal{I}} \subset \mathcal{I}$ be the set of commodities that a cluster can purchase according to the needs of its nodes, in the case of this model these commodities are pure water and natural gas, let $q^c_{\tilde{i},t}$ also be the net production of the commodity purchase, which in this case is actually a consumption, of this commodity by cluster c at time t obtained via Eq. 5.44, the objective function is then given by:

$$F^c_{\tilde{i}} = \sum_{t \in \mathcal{T}} \sigma_{\tilde{i}} \cdot q^c_{\tilde{i},t} \cdot \delta t \ , \tag{5.45}$$

where $\sigma_{\tilde{i}}$ is the cost of the commodity $\tilde{i}$ that is assumed to be constant over the year and does not depend on geographical location as it is in the real world. The cost of pure water is assumed to be equal to 0.19 €/kg in 2019 [31], and, assuming that only inflation will have an impact on its cost, pure water is assumed to be purchased at 0.378 €/kg, assuming inflation of 2.2412% [18]. The same assumption is taken for the future cost of natural gas which is equal to 18.196 €/MWh in 2019 (see Chapter 6.1 to know this cost was obtained) and, taking the impact of inflation on its cost, the natural gas cost is assumed to be equal to 36.173 €/MWh in 2050.

5.6.6 Conservation hyperedges

Hyperedges are links between nodes and clusters expressed through production/import and consumption/export balance equations for each traded commodity. The model describes 3 equations that fix the links between electricity, natural gas and hydrogen exchanges. To ensure that net CO_2 emissions are zero, i.e. that all the CO_2 emitted by a power plant is captured and stored, an additional constraint is added. The hyperedges connecting the clusters are shown in Figure 5.2.

5.6.7 Objective function

The global objective function is a sum of all the local objective functions. Let $\mathcal{N}$, be the set of nodes, whether they are flexibility conversion, transport or demand nodes, and $\mathcal{N}_i \subset \mathcal{N}$ representing the set of conversion nodes, the global objective can be written as :

$$\min \quad \sum_{n \in \mathcal{N}} F^n + \sum_{n \in \mathcal{N}_i} F^n_i + \sum_{c \in \mathcal{C}} F^c_{\tilde{i}} \ , \tag{5.46}$$

where F^n is the cost function of node n given in Eqs. 5.16, 5.32, 5.41 and 5.43, F^n_i is the cost function associated with the fuel consumption of conversion nodes given in Eq. 5.18 and $F^c_{\tilde{i}}$ is the cost of purchased commodities.

CHAPTER 6

WEST EUROPEAN MODEL FOR 2019

In order to determine the quality of the model and its limitations, an analysis over the year 2019 will be carried out. The choice of this year over more recent years is motivated by the time elapsed since then, which has allowed ENTSO-E to collect, verify, and consolidate data that closely reflects actual conditions. Added to this is the presence of Great Britain in the European Union in 2019. After that year, their withdrawal means that the UK TSOs will no longer be members of ENTSO-E, and due to the absence of a similar platform offering free access to this information, key data such as installed capacity, electricity production and consumption are no longer shared, which prevents the precise modelling of this country. What's more, 2019 comes before the COVID-19 crisis and the war in Ukraine, which had a major impact on the electricity and gas markets that is still being felt today.

During this chapter, the sources allowing to obtain the data allowing to model the technical-economic parameters of the model as well as the processing which had to be carried out on these data will be presented with a presentation of the ENTSO-E data which will serve as a basis for comparison for the results. Finally, 3 experiments will be conducted. The first is a base case and the other 2 are attempts to improve the model carried out by the addition of constraints which allows studying the impact of certain assumptions on the model. A discussion will close this chapter allowing to bring a conclusion.

6.1 Data

6.1.1 Installed capacities, annual production and exchanges of electricity

Installed capacity by country and technology is provided in the ENTSO-E annual report [2], as is the energy produced by each of these technologies and annual cross-border electricity exchanges for 2019. TABLE 6.1 shows the Belgian example of the data extracted from the ENTSO-E report (Data for other countries are included in APPENDIX A.2 so as not to overburden this report). In this table, only the values for the technologies selected for the model are reproduced.

Technologies	Installed capacity [GW]	Electricity produced [TWh]	Share [%]
Nuclear	5.943	41.4	47.18
Fossil brown coal	0	0	0
Fossil coal derived gas	0	0	0
Fossil gas	6.642	23.5	26.78
Fossil hard coal	0	0	0
Fossil oil	0.242	0	0
Hydro pumped storage	1.308	0.9*	1.03
Waste	0.362	2	2.28
Wind offshore	1.548	4.7	5.36
Wind onshore	2.248	3.4	3.87
Solar	3.369	3.5	3.99
Biomass	0.619	2.4	2.73
Run-of-river	0.172	0.2	0.23
Others	\	5.742	6.54
Total		87.742	

* Net production (production - consumption) = 0.9 - 1.1 = -0.2 TWh.

Table 6.1: Installed capacities, electrical production and share in the electrical mix for each technology used to produce electricity in Belgium in 2019 according to ENTSO-E.

The data relating to the "others" line allows us to model two types of electrical production that are not taken into account by the model: the first type of production relates to assets that have not been selected by the model and the second type relates to productions that seem to be poorly listed by the report, seeing that the production added to the electrical exchanges is not strictly equal to the electrical consumption of each country.
Indeed, some assets listed in the report have not been taken into account in the model, such as fossil oil shale, fossil peat, other non-renewables, geothermal, marine and other renewables, due to a significant lack of data that does not allow these assets to be modelled. In total, this amounts to not modelling the production of 5.7 TWh in Belgium, 35.1 TWh in the Netherlands, 4.8 TWh in Germany and 0.8 TWh in Great Britain (the amount of energy produced by the technologies not considered in France is not reported in the article). Adding to this, some energy productions are reported such as the energy produced by waste-fired power plant in France equivalent to 1.7 TWh and the energy produced by the fossil coal-derived gas of Germany which is equal to 2 TWh, which cannot be modelled as the installed capacity of those technologies is not given. These values are not insignificant, particularly for the Netherlands, which represents 33% of their production.
In addition to this, the data in the report show that when the total net production of a country is added together (i.e. taking the net electricity production of the pumped storage hydroelectric plant) and the net imports of that country, the result is less than the consumption of that country, indicating that there are missing production data. This represents 0.042 TWh for Belgium, 0.075 TWh for Luxembourg, 2.969 TWh for France, 4.341 TWh for the Netherlands,

18.152 TWh for Germany and 26.983 TWh for Great Britain.
So that the model is not poisoned by this missing and unmodelled data, this energy will be modelled under the name 'others' in tables 6.1 and A.4 to A.8 and, in concrete terms in the model, this energy will be added in the form of constant production over the time horizon. This method allows not to consider the losses by the electrical distribution circuit since the added value allows to exactly equalise the production to the consumption both in reality and in the model. This also allows the model not to be impacted by this missing production allowing a better comparison of annual productions between the model and the ENTSO-E values.

The capacity of the high-voltage lines enabling the transmission of this electricity is provided by Ember[1] [38], who, in their report, listed the electricity transmission capacity between each country for the year 2023. The electricity transmission capacity is based on their figures, from which the transmission capacity built between 2019 and 2023 is deducted. As this file dates from 2023 and not 2019, care should be taken to ensure that no lines have been built during this period, for example the line linking Belgium and Germany, which was inaugurated in 2020, and the IFA 2 line linking France and the UK, which was inaugurated in 2021. The capacity associated with these lines must be subtracted from the installed exchange capacity between the countries considered. TABLE 6.2 shows the installed capacity for each country in the model. The name of the line is made up of 3 particles separated by a '_'. The first particle indicates the type of line (AC = Alternating Current or DC = Direct Current), while the second and third particles give the code for the countries connected. For DC lines, the length of the line is important in calculating the cost and efficiency of the line, and this information can be obtained via [33]. The ENTSO-E report also shows a map of annual cross-border electricity exchanges. These exchanges are also shown in TABLE 6.2.

Line name	Installed capacity [GW]	Length [km]	Annual exchange [TWh] * (forward)	(reverse)
HVAC_BE_LU	0.68		0.184	0.092
HVAC_BE_FR	2.8		3.229	6.011
HVAC_BE_NL	2.4		4.494	5.423
HVDC_BE_UK	1.0	140.0	5.487	0.126
HVAC_LU_DE	2.3		0	4.033
HVAC_FR_DE	3.0		14.832	1.719
HVDC_FR_UK	2.0	72.0	12.023	0.704
HVAC_NL_DE	3.95		2.946	9.142
HVDC_NL_UK	1.0	245.0	6.202	0.347

* The annual exchange in forward mode means that the first country appearing in the line name is the exporting country while the second one is the importing country. In reverse mode, it's the opposite.

Table 6.2: Installed capacities, lengths and annual exchanges of high-voltage cross-border transmission lines between the countries studied in 2019 according to ENTSO-E.

Another source of unmodelled disturbance is that associated with the model boundary. Countries at the boundary of the model are deprived of connections with countries outside the model

[1]Ember is a company dedicated to helping global policies move toward decarbonising the energy sector to accelerate the global energy transition by providing reports and studies based on open data analysis.

with which they used to exchange electrical energy. In order to reduce this disturbance, the sum of net exports (sum of annual export minus the sum of the annual import) is evaluated for each country, giving the following results: 30.255 TWh for France, -0.847 TWh for the Netherlands, 37.036 TWh for Germany and -0.182 TWh for Great Britain. In the same way as above, these values are modelled as a constant hourly export or import depending on the sign. As the model does not study a large number of countries, its limits are quickly reached and this allows not to impact the comparison between the results of the model and those of ENTSO-E, even if considering constant imports/exports and production is not realistic.

6.1.2 Economical parameters

The economic parameters of the nodes are taken from the Danish Energy Agency [19] or the European Energy Commission report [6]. Priority is given to the first source, which is more recent (perpetual modification of their data), over the second source, which dates from 2018. The Danish Energy Agency is a public body attached to the Danish Ministry of Climate, Energy and Public Utilities. It regularly publishes detailed catalogues of technical and economic data on energy installations, including investment and operating costs, efficiencies, lifetimes, and much more, which are evaluated over various time horizons by estimating future changes in these data. These data are updated regularly and enable analyses necessary for Danish energy policy. The methodology and transparency of their assumptions make them a reliable source. The second source is a European Commission report, entitled *"Technology Pathways in Decarbonization Scenarios"* containing an assessment of the costs and performance of numerous energy technologies. This report is produced by an internal scientific service of the Commission, the Joint Research Centre (JRC). This report also estimates these parameters for future years, which is very useful for this thesis.

The prices of primary fuels are mainly taken from [26] providing the price of primary fuels on the European market. Not all primary energy prices are provided, such as that of enriched uranium which comes from [30] which is a report provided by Sia Partners[2], the cost of gas from coal mine gasification comes from an article by a team of researchers from the University of North Dakota who conducted a study on a specific case [29], the cost of biomass comes from [25] which is a report provided by Valbiom[3] and the cost to produce pure water comes from a report [31] by ELGA LabWater (Veolia)[4].

The HVAC and HVDC line installations are used to model cross-border transmission. To have a practical model that does not deviate too much from reality, it is important to use realistic prices of installation. But the CAPEX considered for high-voltage lines and cables is difficult to generalise depending on the nature of each project. Thus, an average based on projects submitted by the various national organisations responsible for electrical transmission (TSOs[5]) and listed by ENTSO-E was calculated. The projects were classified into 3 categories:

[2]Sia Partners is an international energy consulting firm that has conducted in-depth studies on the socio-economic impact of the renewal of the French nuclear fleet.

[3]Valbiom is a Belgian association with a reference role in the bio-sourced economy, regularly publishing analyses on the evolution of the prices of wood fuels of all types.

[4]ELGA LabWater is a brand of Veolia Water Technologies specialising in water purification technologies for laboratories, which is a world leader in the production of pure water.

[5]Transmission System Operators

submarine HVDC cable installation projects, terrestrial HVDC line installation projects and HVAC line installation projects. Projects related to mixed installations and the improvement of existing lines are excluded. In the model, onshore high-voltage lines are used to connect two neighbouring countries sharing a land border. These lines connecting the two electrical substations attached to the electricity grid of each country do not therefore cover long distances justifying the exclusion of projects involving excessive distances that serve to connect two points that are spatially very distant, such as projects linking northern Germany to southern Germany, for example. The averages obtained, evaluated in millions of euros per installed capacity expressed in GW and per length expressed in kilometres, are: 3.732 M€/GW/km for submarine HVDC cables, 5.631 M€/GW/km for terrestrial HVDC lines, and 2.364 M€/GW/km for terrestrial HVAC lines.
Given the greater price of terrestrial HVDC lines, it can already be stated that the model will never choose this technology to connect two countries with a land border. Furthermore, the choice to install HVDC lines also depends on strategic choices, such as the desire to relieve congestion in a geographical area by imposing a direction of electricity flow that can be carried out using direct current. Since these strategic choices are not modellable in this model and given the higher price of this technology over short distances, terrestrial HVDC lines will not be modelled and only HVAC lines will be used to transmit electricity between two countries connected by a land border.
In order to standardise the length to connect 2 countries, the average distance of projects aiming to connect 2 countries by HVAC line was calculated giving a length of 92.857 km thus allowing the calculation of the CAPEX of HVAC lines in M€/GW which is therefore 219.543 M€/GW.

The price of gas was obtained from the TTF[6] European Gas Index, which is a daily index of the price of natural gas traded on the TTF market, a virtual trading hub located in the Netherlands. It serves as a benchmark for gas futures contracts in Europe. This index, obtained via [27], quoted in €/MWh, does not take into account the cost of transporting natural gas, the cost of storing it, the marketing costs that enable the supplier to take its margin, and other costs. This explains why a company in one country does not pay exactly the price indicated by the TTF index. The source [28] provides the average prices that European companies paid in 2018 for gas supplies. As the price is from 2018, it needs to be related to 2019. To do this, the average of the TTF index for 2018 has been calculated and is worth 22.33 €/MWh. Next, the percentage of "taxes" that a company in a country pays on average was calculated from the average of a European company (resp. a national company in a specific country) and the average of the TTF index. Finally, this "tax" is assumed to be the same for the year 2019 and by adding it to the average of the TTF index for 2019, which was worth 14.57 €/MWh, the average price of gas paid by a European company (resp. a national company in a specific country) in 2019 is obtained.
Thus, the average cost of gas paid by a European company in 2019 was 18.196 €/MWh. In more detail, national companies purchased their gas in 2019 at the following prices: 17.54 €/MWh for Belgium, 18.33 €/MWh for Luxembourg, 24.16 €/MWh for France, 16.78 €/MWh for the Netherlands, 17.08 €/MWh for Germany, and 16.87 €/MWh for Great Britain. The price differences highlight some key points of the European gas market. The Netherlands and Great Britain have a lower cost of natural gas than their neighbouring countries because

[6]Title Transfer Facility

they are themselves natural gas producers, giving them direct access to the resource without transport taxes, right of way, etc. Belgium has a price that is certainly higher than the two countries mentioned above but lower than France and Luxembourg thanks to its role as a European gas hub. Indeed, Belgium has numerous natural gas terminals, notably in Zeebrugge, combined with a vast, efficient transport network operated by Fluxys, making this country a gas distributor for its neighbouring countries, which explains the price difference between Belgium and neighbouring countries, which pay a higher price in order to take into account Belgian transport, infrastructure and logistics. Germany is directly connected to producing and exporting countries such as the Netherlands, Norway and Russia by pipeline, it benefits from more advantageous prices than France and Luxembourg.
Similarly to the national load demand time-series, an hourly time-series of natural gas prices can be obtained by starting from the TTF index, which is a daily time-series. Its transformation into an hourly time-series is done by assuming that the given price is that of the day indicated at midnight and by evaluating the hourly indices via a linear interpolation between 2 days. Finally, by adding the "tax" calculated previously, the gas prices paid by a European (resp. national) company are obtained.

The price of the carbon tax is obtained via [20] which gives the cost of the EU ETS which is the European carbon emissions market. How this market works is explained in SECTION 4.5. In the first two experiments, an annual cost will be considered by taking the average of the daily time-series of the EU ETS over the year 2019 which is worth 24.88 $€/t_{CO_2}$. For the third experiment, a time-varying price will be used requiring the creation of an hourly time-series of the carbon tax price. To do this, the daily time-series of the EU ETS is added and the hourly point is created by linear interpolation between 2 points obtained by the daily time-series informed by [20] considering that the daily price displayed is that corresponding to the first hour of the day, i.e. midnight.
In the model, a uniform carbon tax is applied to all CO_2-emitting power plants, regardless of their type. This approach is a simplification, as in reality, not all plants are subject to the same carbon pricing mechanisms. Indeed, only large installations are subject to these quotas. Some power plants, depending on their type, have free allocations meaning that part of their quotas are allocated to them for free. This free allocation is granted in particular to biomass combustion plants that theoretically have a neutral carbon footprint or to waste combustion plants that receive a partial free allocation depending on the quantity of organic waste incinerated. Furthermore, in the model each tonne of CO_2 emitted is taxed, thus not taking into account the quantity of CO_2 freely allocated to each participant from the maximum annual quota. These assumptions must be taken into account when analysing the results.

6.1.3 National time-series

The aim of the model is to determine which technologies should be used and installed to cover a given demand. As the time step chosen is hourly, it is necessary to know the hourly electricity demand of the countries studied. The data for the year 2019 can be obtained from the ENTSO-E website [39]. However, some data are missing. To solve this problem, a Python script analyses the file. If an hour is missing, a data point is added with an electrical demand evaluated by linear interpolation using the value of the previous hour and the following hour. If the missing date is an edge of the time vector, the points used for interpolation will be the next two or the previous two, depending on which edge of the vector the date is missing from.

As for intermittent renewable generation technologies such as solar, wind and hydro, their production depends on weather conditions. This dependence is taken into account via the capacity factor, which varies over time between 0 and 1, reflecting the proportion of electricity produced as a function of installed capacity. For solar and wind power, the *Renewables.ninja website* [21] provides these values by country for 2019. These figures are calculated on the basis of installed capacity at that time and MERRA-2[7], a climate database produced by NASA[8] using weather stations, satellite data and sounding balloons. As these values are based on imperfect weather models, it should be noted that they are subject to a certain degree of error. As there are no missing dates, the data obtained did not need to be modified.

6.2 Experiments

This section will present the results obtained by the model. All the experiments conducted have a common basis. The pre-installed capacities, $\underline{\kappa}^n$, and the maximum capacities, $\overline{\kappa}^n$, are equivalent, allowing the model to be prevented from installing new additional capacities and are set to the values provided by ENTSO-E. The costs considered are those reported in the economic tables in SECTION 5.6. The experiments differ in the assumptions made, which will be given in the introduction to each experiment.

6.2.1 Exp. 1 - Base case

In this base case, the cost of gas will be set by the annual average calculated over the entire model and worth 18.196 €/MWh for all countries in the model. The price of the carbon tax imposed identically on CO_2-emitting production units is also an equivalent annual average for all countries in the system and worth 24.88 €/t. Power plants are assumed to be able to operate at any power, thus not considering a minimum external power.

Given that the installation of new capacity is prevented, the only components that will vary the objective, which is an economic objective, will be the variable costs represented by VOM, the costs of primary energy and carbon taxes. It is therefore possible to predict the behaviour of the model by calculating the cost of producing 1 MWh for all the technologies and ranking them, which gives the following list of the cheapest technologies to produce 1 MWh in ascending order: solar panels, run-of-river & water reservoirs and hydro pumped storage are on a par with 0 considered marginal cost of production, then come onshore wind turbines, then offshore wind turbines, nuclear power stations, and lastly combustion power stations, which are, in order of fuel type, gas-fired, gas from coal-fired, brown coal-fired, waste-fired, hard coal-fired, biomass-fired and oil-fired. In order to achieve a minimum target while ensuring that electricity demand is met, the model should make maximum use of renewable power sources according to their production potential. In order to ensure constant production, it should use nuclear power, which is very cheap. Finally, combustion power plants will be used in order to provide a load-following solution. Let's see if these predictions are correct.

[7] Modern-Era Retrospective analysis for Research and Applications, Version 2

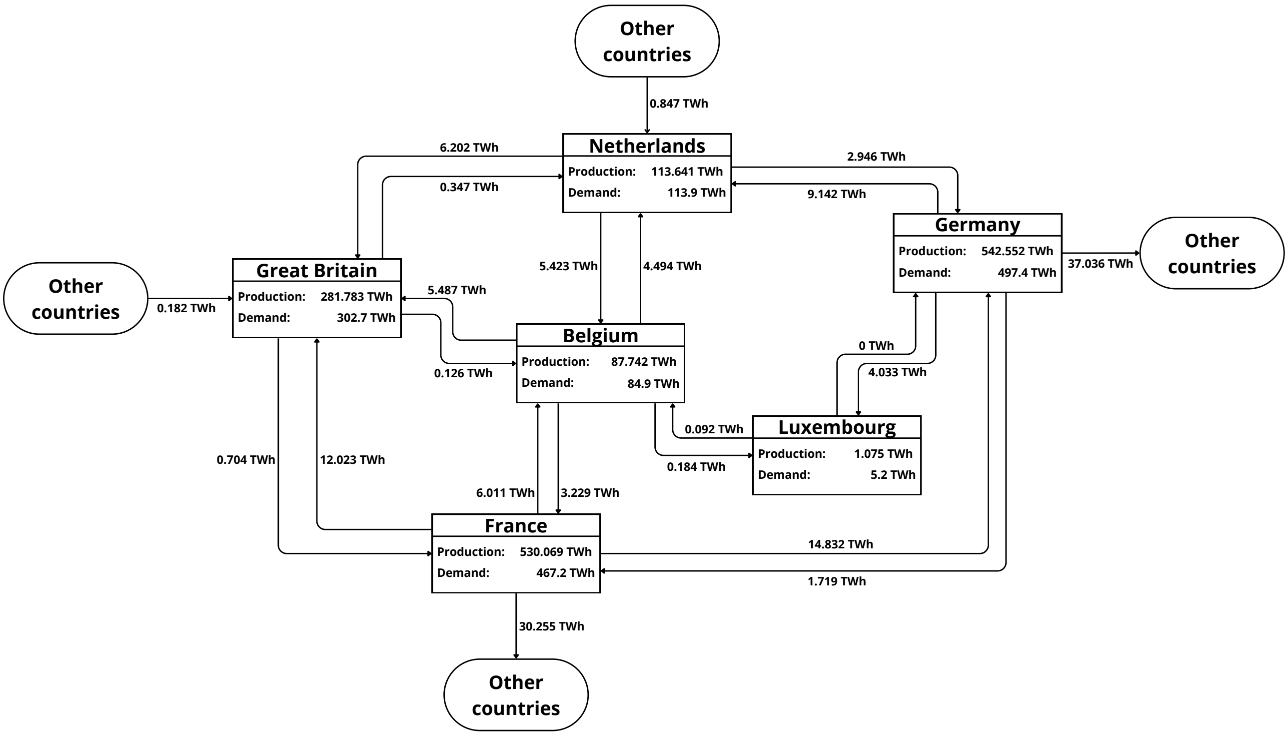
[8] National Aeronautics and Space Administration

TABLE 6.3 shows the annual production of each technology for Belgium, as obtained by the model, as well as the share of each technology in total Belgian production. The results for the other countries are shown in APPENDIX A.3. TABLE 6.3 and TABLES A.9 to A.13 coupled with FIGURE 6.1, summarising the production, demands and electricity exchanges of each country according to ENTSO-E and according to the model and a diagram allowing to observe the differences in production in TWh between the model and reality, allow to understand the dynamics of the model in order to understand why a country produces more or less than in reality and what allows to evacuate this surplus of production or to fill this lack of production.

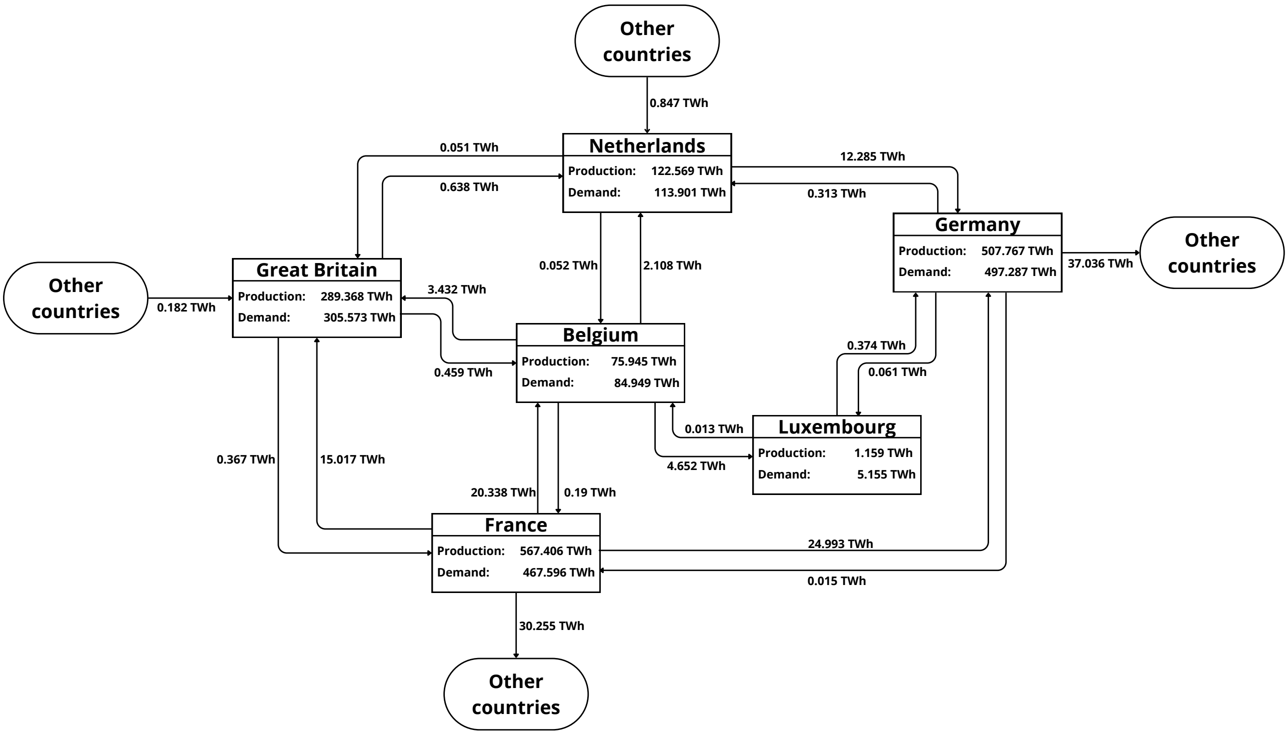
Technologies	Electricity produced [TWh]	Share [%]	Difference* [%]
Nuclear	49.057	64.6	+17.41
Fossil brown coal	0	0	+0.0
Fossil coal derived gas	0	0	+0.0
Fossil gas	7.883	10.38	-16.4
Fossil hard coal	0	0	+0.0
Fossil oil	0	0	+0.49
Hydro pumped storage	0.027 **	0.04	-0.99
Waste	0	0	-2.28
Wind offshore	4.202	5.53	+0.18
Wind onshore	4.958	5.53	+2.65
Solar	3.744	4.93	+0.94
Biomass	0	0	-2.73
Run-of-river	0.331	0.44	+0.21
Others	5.742	7.56	+1.02
Total	75.945		

* Compute as the difference in the share obtained by the model and the share given in the ENTSO-E report.
** Net production (production - consumption) = 0.027 - 0.036 = -0.009 TWh.

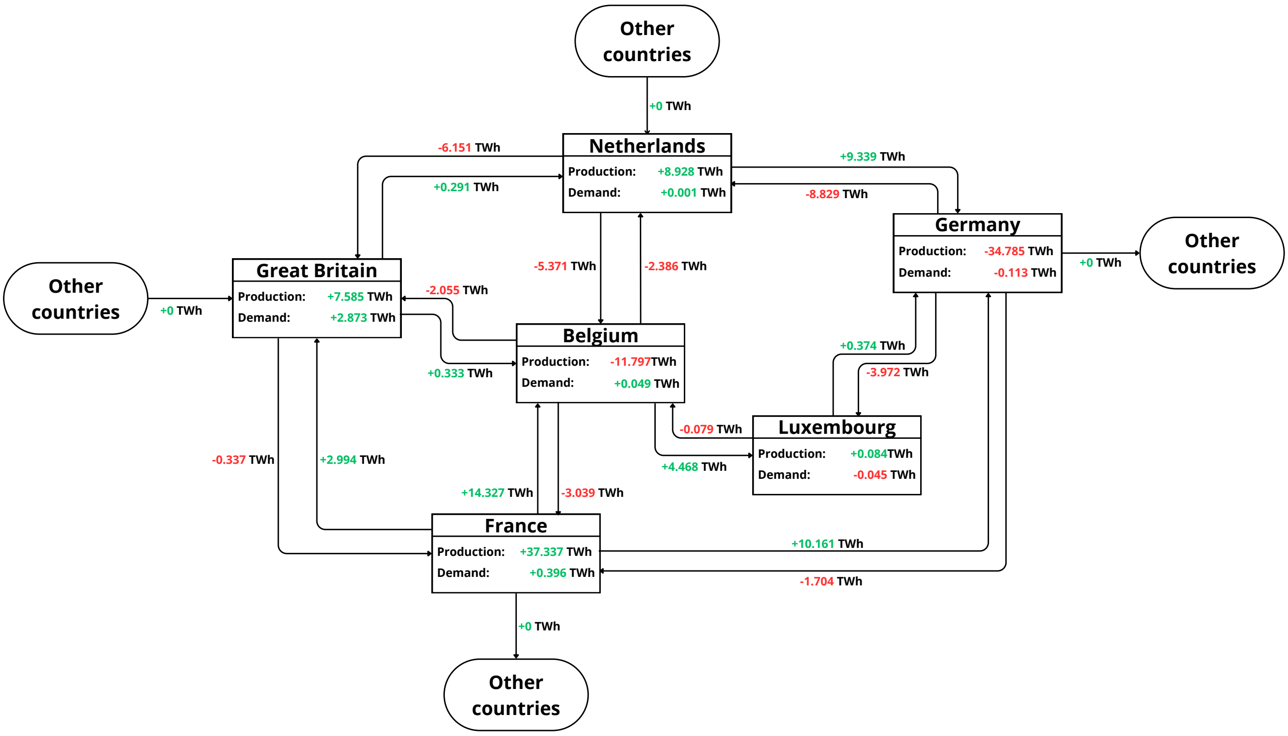
Table 6.3: Electrical production and share in the electrical mix for each technology used to produce electricity in Belgium in 2019 according to the model as well as the variation in the production shares of technologies between the model and reality.



(a) ENTSO-E data.



(b) Model results.



(c) Differences between the model and the reality.

Figure 6.1: Scheme of the electrical production (with hydro-pumped storage production), electrical demand (without the hydro-pumped storage consumption) and cross-border electricity exchanges (without considering losses in lines) in TWh over the year 2019.

The model behaves as expected, and Belgium is a perfect example. The model maximises renewable energy by never curtailing it, then maximises nuclear production, justifying the increase in this energy in the Belgian energy mix. The share of gas-fired power plants decreases because the model uses trade with neighbouring countries to manage its load following by exporting surplus nuclear production, particularly to Luxembourg, and importing surplus production from France.

France and Great Britain have similar behaviour. France is significantly increasing its nuclear power generation to fill the gap in run-of-river power generation due to the modelling assumptions of this technology to significantly reduce the share of natural gas in its electricity mix and ensure the supply of cheap electricity to neighbouring countries, particularly Belgium and Germany. Great Britain, for its part, does not play the role of exporter to its neighbouring countries. It is increasing its nuclear power generation to replace fossil fuels such as natural gas, hard coal, and biomass. The France - Great Britain link allows Great Britain to benefit from France's low-cost electricity generation. To ensure its load following, Great Britain retains a significant share of electricity generation from CCGTs.

Luxembourg, a small country with very low demand compared to its neighbours and therefore very low production, was already largely dependent on electricity imports. Previously supplied by Germany, the model's results show that these imports now come from Belgium in order to

benefit from the cheap electricity generated by nuclear power plants.
The Netherlands, not having a large nuclear electricity production capacity and not being neighbours with a country with large nuclear electricity production capacities like France, uses its renewable power sources to the maximum and ensures the rest of its production no longer by combining the use of coal-fired power plants and gas-fired power plants but relies solely on gas-fired power plants, as they are more economically viable. To manage the surplus generated by its high renewable electricity production, the Netherlands - Germany power line is increasingly used to export this excess energy.
Finally, Germany is a country with an electricity demand equivalent to France but has chosen a completely different electricity mix. Due to its energy policy and particularly its decision to phase out nuclear power, it does not have a significant nuclear fleet and makes up for this low-carbon, constant and inexpensive electricity production by strengthening the penetration of renewables, notably onshore wind turbines and solar panels. The rest of its mix is made up of fossil fuels, notably natural gas and coal (brown and hard), covering 37.8% of production according to ENTSO-E. The model, which favours low-carbon sources and those with no or low marginal costs, prioritises renewable energy production and also makes extensive use of nuclear power, which, despite its higher capital costs and ramp-up constraints, remains a controllable and low-emission technology. The rest of the electricity demand is met by importing cheap energy from French nuclear power or Dutch renewable power sources and the remainder is provided by combustion plants. Since natural gas is cheaper in the model than coal (brown and hard), this energy source replaces the other two previously mentioned, explaining the sharp increase in the German energy mix of natural gas. A small share of production from brown coal is always retained, allowing an electricity supply during high demand, thus serving as a backup source.

The model is efficient in modelling the electricity production of intermittent renewable power technologies by maximising their cheap production. The deviations from reality are due to the lack of data related to hydrology leading to an assumption of constant production which works quite well for most countries except France, which has a large share of production associated with the water reservoir which is not constant and can be controlled. The deviations related to photovoltaic panels and wind turbines are due to meteorological inaccuracies in the calculation of capacity factors, combined with the use of national averages and the absence of detailed market interactions in the model. In reality, renewables are often curtailed first in cases of overproduction, as they have no ramp-up constraints and are easy to disconnect from the grid, which is not fully captured in the model. However, these deviations are not too significant. In addition, the model maintains the hierarchy of choice of production units to use by using nuclear power plants, when there are any, as a production base, by maximising renewable production coupled with export or hydraulic storage in case of surplus, and by using combustion plants as a backup source. On the other hand, the model favours nuclear energy a little too much, coupled with an increase in cross-border trade, thus disfavouring combustion plants, leading to significant deviations from reality, as shown in FIGURE 6.2, which summarises all the deviations between the share of each technology in the electricity mix of each country obtained by the model and compared to reality. In addition, the model strongly favours natural gas and almost no longer uses other fossil fuels from combustion plants.

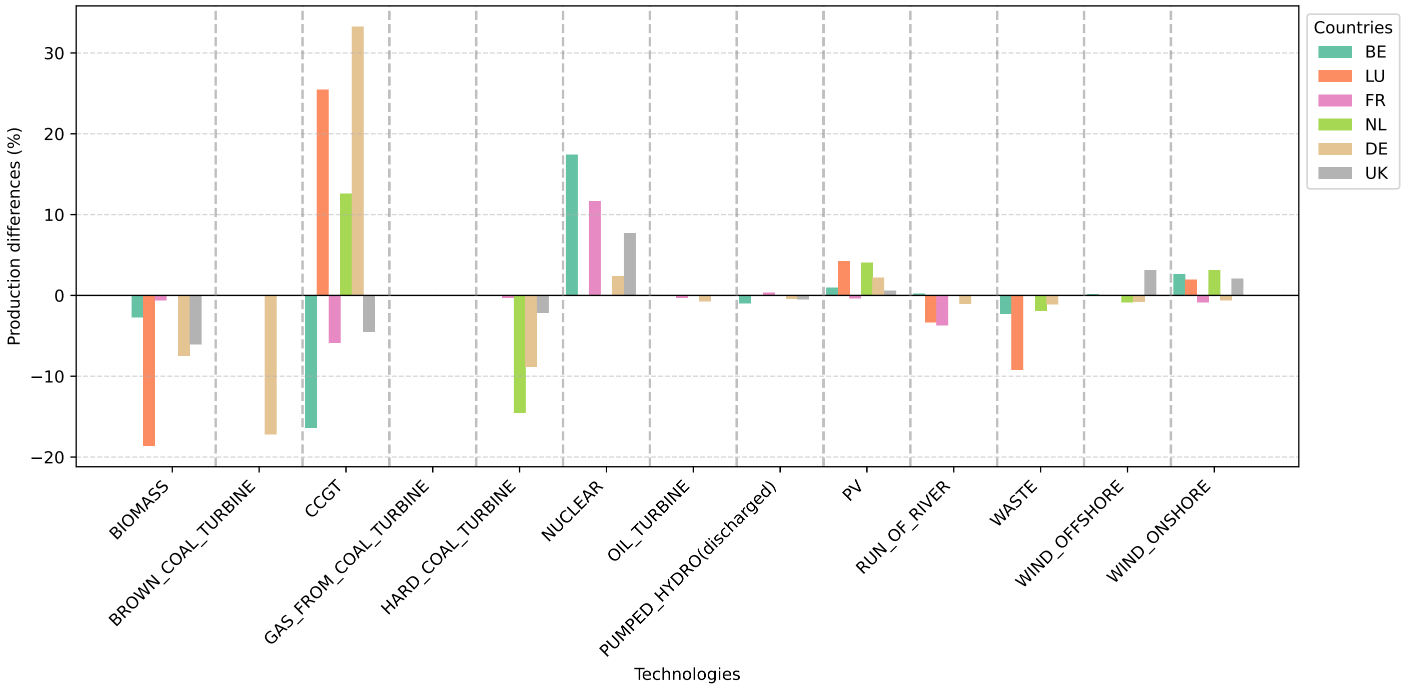


Figure 6.2: Differences in the shares of each electricity generation technology for all countries between the results obtained by the theoretical model and the actual data communicated by ENTSO-E.

In this experiment, the maximum observed deviation is between [-18.6, +33.23]%. The significant deviations associated with Luxembourg are due to the fact that the model must optimise the production of large quantities of energy while Luxembourg has a production scale significantly smaller than the entire model. A small variation of 0.1 TWh therefore quickly leads to a significant deviation. The deviations associated with renewables (WON, WOFF, PV and ROR) are less than 5%, demonstrating the efficiency of the model for these production sources.

Given the observed discrepancies between the results of the base case and the ENTSO-E data, it appears that most deviations stem from the overuse of nuclear energy and natural gas, which are economically favoured in the model, to the detriment of other combustion technologies such as coal or biomass. It is therefore necessary to test the model to see if these discrepancies stem from the assumptions made. The following experiments thus attempt to get as close as possible to the real data by constraining the advantages model.

6.2.2 Exp. 2 - Consideration the minimal external power of power plants

This experiment aims to test whether the origin of these deviations is caused by the assumption made regarding minimal external power. Indeed, the previous experiment neglects the minimal external power of combustion plants.

In order to take them into account while leaving the possibility for the plant to shut down (without this, combustion plants would have a constant production instead of being stopped, strongly impacting the model because combustion plants would no longer ensure their role as a source of backup energy), the problem will now have to be written using binary variables, transforming the problem that was originally linear into a mixed integer linear problem (MILP). Therefore, Eqs. 5.4 and 5.5 are used and Eqs. 5.6 to 5.9 representing the *Big M method* are not useful for the 2019 model since the variable K^n representing the sum of the pre-installed capacity and the capacity that the model instals in addition, can be substituted by simply the pre-installed capacity being a parameter thus avoiding the multiplication of 2 variables between them. This can be done because for the 2019 model, no capacity can be added by the model, it can only use what is already present.

FIGURE 6.3 shows the gaps obtained between the share of production of each technology in each country between this improved model and the data provided by ENTSO-E representing reality. The maximum gap observed in the previous model was [-18.6, +33.3]% becomes [-18.6, +33.18]% with this improved model, showing a slight improvement in the gaps. Concerning trade between countries shown in FIGURE 6.4, the values obtained do not approach those of reality with for certain lines a widening of the gap. The time required for the solver to find an optimum with the previous model, which, as a reminder, was an LP, was of the order of a minute. With this MILP model, the calculation time increases drastically requiring nearly 19 hours of calculation time. This increase in calculation time is explained by the fact that for each binary variable, the solver must study 2 "branches". Having 7 nodes with binary time variables multiplied by the 6 countries studied and the study being conducted over 8760 hours, this means that the solver could be led to explore 2^{367920} fields of possibilities. Fortunately, thanks to the resolution methods integrated into the solver, it does not explore all these fields of possibilities, thus reducing the computation time which remains very long. In view of the low added value brought by the addition of this constraint and the enormous impact on resolution time, this constraint will now be definitively neglected in order to return to LP and maintain a correct resolution time.

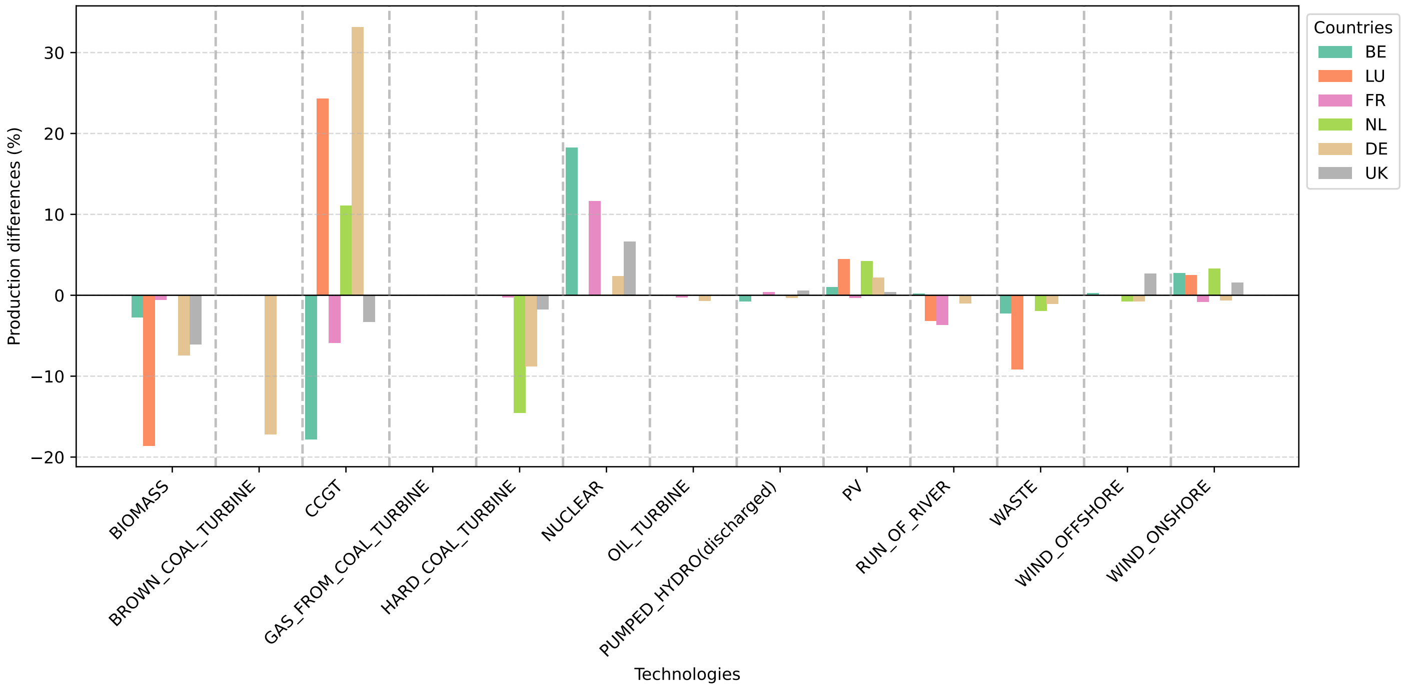


Figure 6.3: Differences in the shares of each electricity generation technology for all countries between the results obtained by the theoretical model considering the minimum external power constraint and the actual data communicated by ENTSO-E.

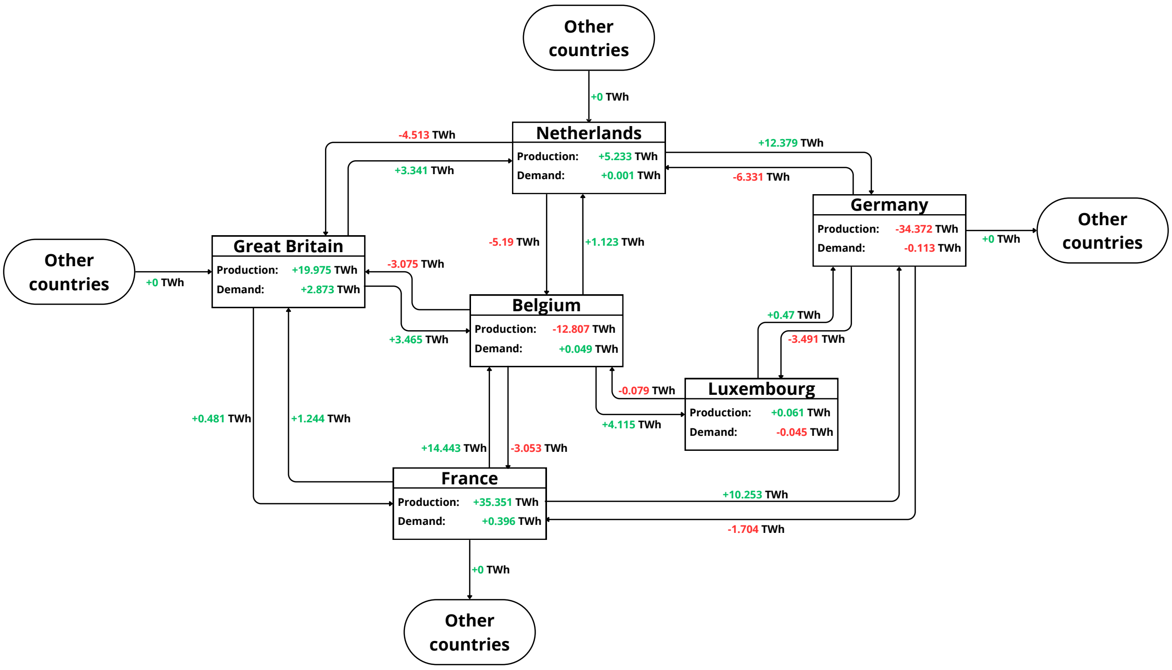


Figure 6.4: Scheme of the differences between the model considering the minimum external power constraint and the reality of the electrical production (with hydro-pumped storage production), electrical demand (without the hydro-pumped storage consumption) and cross-border electricity exchanges (without considering losses in lines) in TWh over the year 2019.

6.2.3 Exp. 3 - Consideration of a country-specific, time-varying gas price and a time-varying carbon tax

Given the small improvement in results brought by the previous experiment, a new experiment is conducted. This aims to verify the hypothesis of a gas price that was assumed to be uniform across the entire system and invariant over time by considering an annual average, now considering it on an hourly basis and different for each country. Similarly, the cost of the carbon tax, which was based on an annual average, is now also time-varying by considering a uniform hourly time-series across all countries in the system. This improvement of the model aims to represent market fluctuations more accurately. Indeed, gas prices have an upward trend during the winter months linked to the increase in demand for natural gas to heat buildings due to cold weather, which then decreases in summer for the opposite reasons. The price differences between countries can be explained by multiple reasons such as: the producing nature of the country - for instance, the Netherlands and Great Britain being European producers of natural gas, they logically benefit from reduced prices - the availability and development of infrastructure, as is the case for Belgium, which has numerous natural gas terminals and a vast pipeline network, benefiting from reduced prices due to the flexibility that this entails or geographical proximity to major sources of supply. Unfortunately, the prices associated with other primary energy sources cannot be subject to similar treatment in order to observe their fluctuations during the year, having only annual average values.

Figure 6.5 shows the evolution of the cost to produce 1 MWh of electricity for each production technology, taking into account the VOM, the carbon tax and the efficiency of the plant. The figure shows that at the beginning of the year, the cost of gas was higher, leading to French natural gas being more expensive than gas from coal and brown coal for a few dozen hours. Since these two technologies are not used by France, this will not have a major impact. Since waste combustion plants have a significant specific carbon emission rate, their production cost is strongly impacted by the EU ETS course. As the gas price curve was relatively stable during 2019, the seasonal impact was only slightly felt and was not sufficient to justify the more abundant use of other fossil fuel sources in reality.

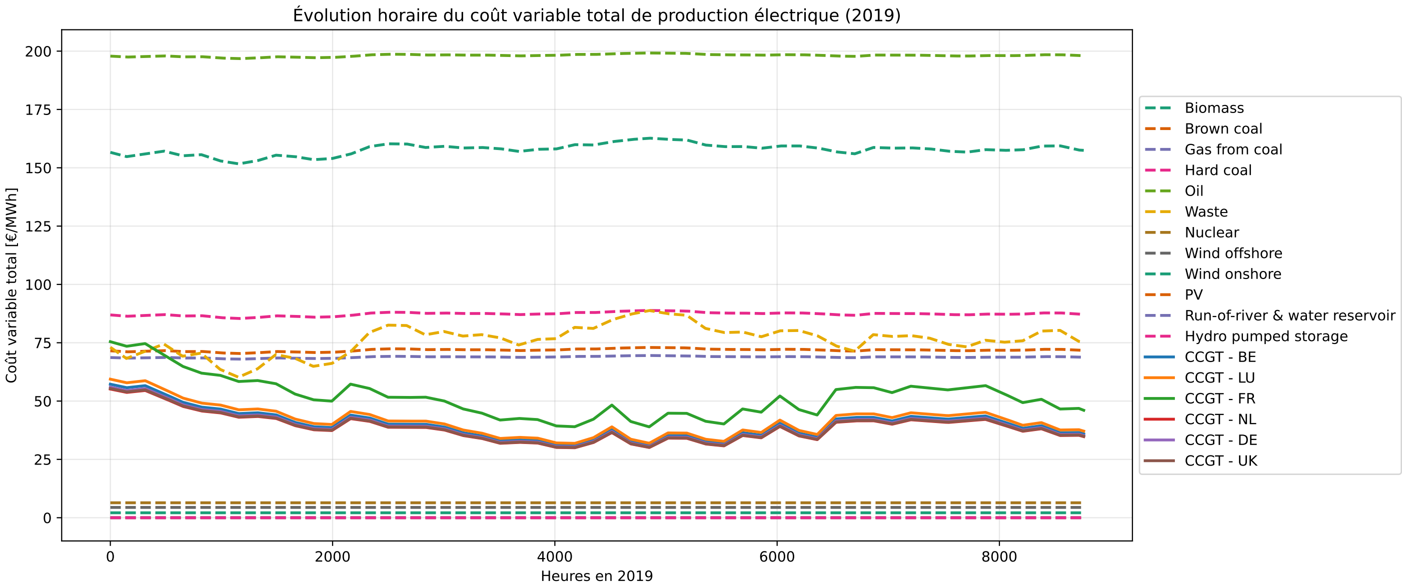


Figure 6.5: Evolution of the cost to produce 1 MWh of electricity for each technology composed of the VOM cost, the fuel cost and the carbon tax for each country for the year 2019.

As expected, the results do not show clear improvements in the results as shown in Figure 6.6 representing the gaps in the share of each technology in the electricity mix of its country between the results of the model and those of ENTSO-E as well as Figure 6.7 showing the difference between the quantity of electricity produced by the model for each country and the quantity produced according to ENTSO-E as well as the differences between the quantities of electricity exchanged during the year. The maximum observed deviation goes from [-18.6, +33.3]% for the original model to [-18.6, +33.22]% bringing only a very small change in the deviations. The difference in quantities of electricity exchanged improved by only a few tenths of a TWh also bringing a very small improvement. Having considered an average price of natural gas and carbon tax over a year as stable as 2019 therefore does not have a big impact on the model but it could have been with years much more volatile in terms of the market.

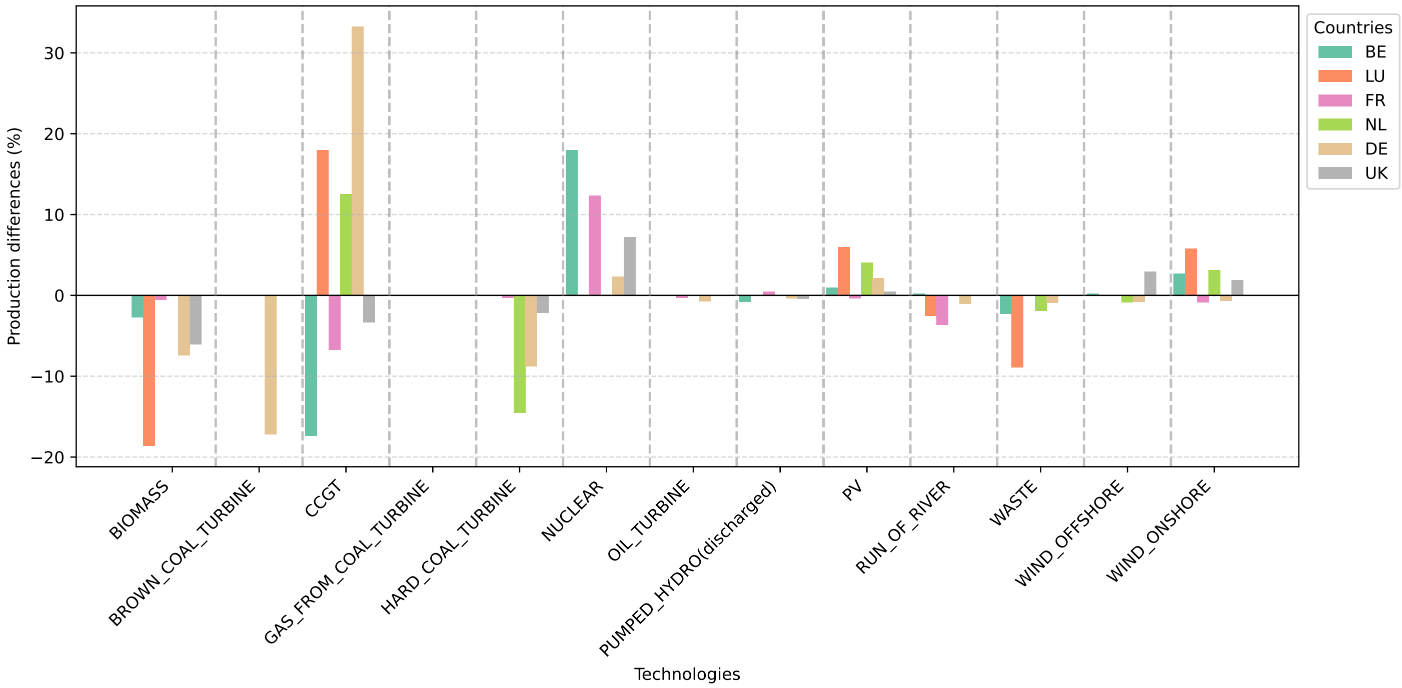


Figure 6.6: Differences in the shares of each electricity generation technology for all countries between the results obtained by the theoretical model using dynamic carbon taxes and gas prices and the actual data communicated by ENTSO-E.

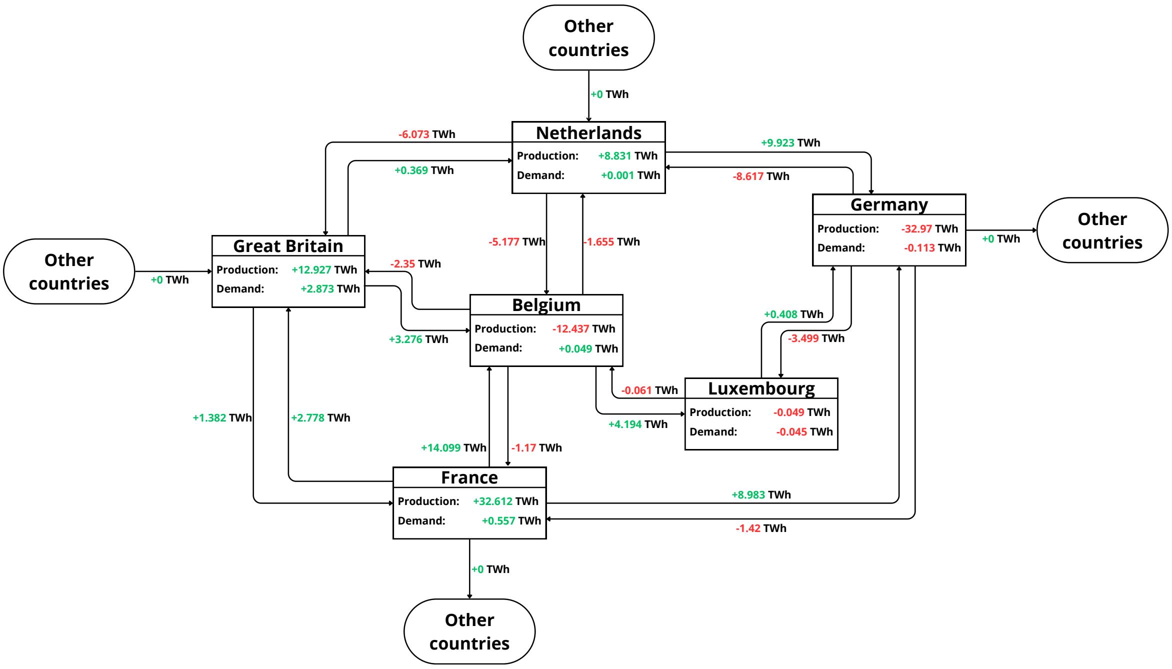


Figure 6.7: Scheme of the differences between the model using dynamic carbon taxes and gas prices and the reality of the electrical production (with hydro-pumped storage production), electrical demand (without the hydro-pumped storage consumption) and cross-border electricity exchanges (without considering losses in lines) in TWh over the year 2019.

6.3 Discussion

After evaluating two hypotheses in order to observe whether they had a significant impact on the results obtained and whether they could be the cause of the relatively large discrepancies observed between the model and reality, the conclusion is that these hypotheses do not have a major impact on the results. So why do energy mixes behave differently in reality, using power generation technologies that are valued more highly in the model ? Several hypotheses can be put forward to criticise the model:

- The more abundant use of nuclear energy may be due to the choice of "ramp up" and "ramp down" parameters limiting the variation in electricity production between 2 time steps, which may not be high enough to constrain these variations sufficiently. In the case of France, nuclear power generation fluctuates widely over the year, allowing an approximate load-following.
- The abundant use of natural gas as a primary energy source in combustion plants replacing other sources may be due to the assumption of an infinite supply of natural gas, which does not take into account the monitoring of stocks in producing countries or the reserves of each country. Unfortunately, these data are not available to model a supply that would depend on pipeline capacity, the frequency of supply by ship and the capacity of each country's reserves.

- Another hypothesis that could explain the use of primary energy sources other than gas is that the cost of this source is actually lower than the cost considered in the model based on indices or studies, which makes it more advantageous than gas-fired power plants in reality.
- As for biomass and waste combustion plants, their use in reality can be explained by a contribution of subsidies to make these plants more profitable or by a lower taxation following carbon emissions justified by the fact that biomass combustion plants have a theoretically neutral cycle and that waste combustion plants allow the recovery of non-recyclable waste.
- The assumption of perfect and known forecasts of meteorological data allowing to know exactly what renewable power sources will produce leads to a variation of the backup power technologies. Indeed, in reality, there are large uncertainties in the renewable production leading to overestimations of the renewable production requiring the use of available backup power sources in order to replace these assets which are ultimately not available. Conversely, the underestimation of this production means that certain sources of backup have been programmed and are therefore used in place of this cheap energy thus not following the logic of the model minimising the production costs.

This list of assumptions is not exhaustive and other explanations can be provided. The conclusion of this chapter is that the model obtained allows to logically represent the use of various technologies in order to ensure a secure electricity supply in order to meet the electricity demand by correctly interconnecting with bordering countries. However, some more or less significant gaps between the annual production of certain technologies compared to reality are observable showing the limits of the model showing the difficulty in representing the complex energy markets at stake. Added to this is the difficulty in obtaining open-source information to model these markets, the search for the improvement of this model in order to perfectly model the energy markets cannot be resolved in one chapter of this thesis. This would require a thesis on this subject and this is not the objective of this thesis. This justifies stopping research on improving the model to fit with real data having evoked avenues of exploration that can be used in a future project to improve this model. These limitations will be taken into account when analysing the results from the 2050 model, so that these results can be criticised.

CHAPTER 7

WEST EUROPEAN MODEL FOR 2050

With Europe aiming for carbon neutrality by 2050, the role of gas in electricity generation is the subject of strategic debate. Although gas is mainly sourced from natural gas which is a fossil fuel, it is a highly adaptable molecule, making it a valuable ally in offsetting the intermittency of renewable sources. This chapter examines various energy transition scenarios in Western Europe, with the aim of assessing the extent to which it is possible to meet the neutrality in carbon emissions without this flexible energy source.

To do this, the study takes several key factors into account: the degree of integration of renewables, connection capacities for electricity and gas between countries, the use or non-use of nuclear power stations, and the magnitude of natural gas prices. These analyses are carried out using an hourly model over a full year, which makes it possible to understand seasonal dynamics and daily variations in supply and demand.

This chapter therefore seeks to provide concrete answers to the following question: is it possible to have a zero-carbon electricity system without depending on gas-fired power stations, or is their flexibility still essential for maintaining the balance of the European electricity network?

To begin this chapter, the sources of the data used in the model as well as the processing carried out on them will be provided. Then, the various scenarios allowing to the study of several configurations of the model will be studied.

7.1 Data

7.1.1 Limits on capacities

Limits on renewable capacities

The limits set on renewable electricity production technologies (onshore and offshore wind, PV and batteries) are taken from the *Global Ambition* scenario studied in the TYNDP report published in 2024 [3]. In this report, the capacities to be installed in 2050 in order to ensure the

electricity demand of all sectors, whether industries, transport, or others, in order to achieve the net carbon neutrality objective was studied and reported. The study is conducted on all 27 member countries of the European Union and therefore provides the total capacity to be installed by technology across all these territories to supply the electricity necessary to meet the demand of these 27 member countries. The first part of the study of this thesis focuses on 2019 when the European Union still had 28 member countries due to the presence of Great Britain and does not have the details by country of the capacities to be installed, a calculation using assumptions must be made in order to virtually add Great Britain into the TYNDP study.
This virtual integration of Great Britain into their result is done by starting with computing the share of Great Britain's electricity demand in 2019 relative to the overall electricity demand of the 28 member countries of the European Union given in the ENTSO-E report [2], giving a share of 11.62% of electricity demand. This share is assumed to remain the same in 2050, thus increasing the electricity demand of the entire European Union by the same amount. This share will also be added to the capacity to install renewable power technologies according to the model developed in the TYNDP, thus considering that an increase of 11.62% in demand simply leads to an increase of the same value in the capacity to install. This strong and simplifying hypothesis makes it possible to artificially reintegrate Great Britain into the European Union and thus extend the results by taking Great Britain into account.

Now that the capacity to be installed for renewable energy production technologies has been scaled not to the 27 but to the 28 countries of the European Union, a calculation must be made to detail this capacity to be installed by country. For land-based technologies such as PV, onshore wind turbines and batteries, the share of the surface area of each country compared to the surface area of the EU28[1] is calculated for the 6 countries studied in this thesis. This ratio is then applied to the capacity to be installed by technology in order to obtain the capacity to be installed not for the entire EU28 but for each country studied. A similar method, but taking into account the length of the maritime coasts of each country, was applied to calculate the capacity to be installed for offshore wind turbines for each of the countries studied. This method fairly distributes the resources to be installed by country, taking into account the available surfaces. However, it does not take into account the electrical demands of each country and therefore a country with an equivalent surface area like Spain or Sweden will be distributed the same capacity limits while their respective electrical demands are 2 to 3 times less important, thus relocating production. Another negative point is that this distributes the technologies to be installed without taking into account the available resources such as strong exposure to the sun. It is for these reasons that a scenario, appearing in SUBSECTION 7.2.2, aimed at varying these limits is created in order to study the impacts of these hypotheses.
The renewable capacities to be installed according to the TYNDP on the EU27, the renewable capacities to be installed recalculated on the EU28 to include Great Britain, the shares of land surface area and maritime coast length of each country, and the renewable capacities to be installed detailed by country are reported in TABLE 7.1.

[1] the 28 countries of the European Union

Geographical area	Share of land surface [%]	Share of maritime coasts length [%]	Capacities [GW] WOFF	WON	PV	BAT
EU27	94.427	79.711	407.457	804.044	1 670.132	956
EU28	100	100	454.796	897.459	1 864.171	1 067.07
BE	0.695	0.084	0.383	6.236	12.954	7.415
LU	0.059	0	0	0.528	1.097	0.628
FR	12.558	5.953	27.073	112.7	234.096	133.999
NL	0.945	0.575	2.616	8.483	17.62	10.086
DE	8.126	3.046	13.855	72.928	151.483	86.71
UK	5.573	20.289	92.272	50.012	103.882	59.463

Table 7.1: Shares of land surface area and maritime coast length for the considered geographical area used to compute the capacity of renewable technologies that have to be installed by 2050 to reach carbon neutral net zero emissions according to the TYNDP report.

Regarding hydrology, the IHA (International Hydropower Association)[2] [40] indicated that according to its 2020 figures, 254 GW of hydropower generation capacity was installed in Europe and that according to their estimate, the maximum capacity is 350 GW. This gives an increase potential of 137.795% for hydropower in Europe. This increase factor is then added to the hydropower capacities, represented by pumped hydropower storage and run-of-river & water reservoirs. These figures are shown in Table 7.2.

Year	Maximal capacity of HPS [GW]						Maximal capacity of ROR [GW]					
	BE	LU	FR	NL	DE	UK	BE	LU	FR	NL	DE	UK
2019	1.308	0	5.023	0	9.422	2.744	0.172	0.036	19.234	0.038	5.281	1.885
2050	1.802	0	6.921	0	12.983	3.781	0.237	0.05	26.504	0.052	7.277	2.597

Table 7.2: Installed hydropower capacities for hydro pumped storage as for run-of-river & water reservoirs in 2019 and maximal hydropower capacities in 2050.

High voltage line capacities

In the model, different configurations of power transmission line installations are tested. In all cases, these limits are based on a list of capacity that should be installed by 2040 listed by Ember [38], which is based on current installations and adds to this the lines that will be built in the future based on the list of projects that have been validated in [34]. These project proposals are submitted by the electricity system operators (TSOs[3]) of ENTSO-E member countries to ENTSO-E, which compiles them in their TYNDP report. These project proposals contain the details of the project like what will be built, what will be upgraded, the length of the lines, the increase in transmission capacity brought and the cost. Ember has done the work of listing these projects that have been validated and adds to that the capacities that will be installed in addition according to the TYNDP scenarios.

[2] the IHA is an international non-profit organisation representing the global hydropower sector. Their goal is to promote the sustainable development of hydropower. The developers, operators, manufacturers, consultants, and financial institutions that comprise it offer training, certification, and protocols to follow.

[3] Transmission System Operators

7.1.2 Technical and economical parameters

The technical and economic data for the nodes presented in the tables in Section 5.6 are, as in 2019, based on the Danish Energy Agency's catalogues [19] and a report from the European Commission [6]. These two sources present the values of these parameters in future years, taking into account inflation and technological developments. Priority is given to the Danish catalogues due to their more recent publication date.

The prices for fossil fuels and the price of pure water are those for 2019, to which inflation has been added, which can be translated by Eq. 7.1:

$$C_{2050} = C_{2019} \cdot (1 + r)^N \tag{7.1}$$

where C_{2019} and C_{2050} are, respectively, the prices considered for the years 2019 and 2050, r is the inflation rate which is equivalent to 2.2412% on average over the period 1991 to 2024 [18] and N is the number of years of difference, here $N = 31$. In this model, the price of natural gas is calculated from the annual average calculated for the year 2019, thus considering a uniform price of 36.173 €/MWh across the entire system, which corresponds well with the hypothesis of centralised economic management and it is also considered time-invariant, which does not strongly impact the results in view of the results of Exp. 3 of the previous chapter.

The cost of the electrical transmission lines being evaluated on the basis of future projects listed in [34], will be considered the same as those presented in Section 6.1, i.e. 3.732 M€/GW/km for submarine HVDC cables, 5.631 M€/GW/km for terrestrial HVDC lines, and 2.364 M€/GW/km for terrestrial HVAC lines. In the same way as in Section 6.1, the price of terrestrial HVDC being more expensive than HVAC, the model will not use them and therefore they will not be modelled. The average length of future HVAC line projects connecting two border countries was calculated based on the projects presented by [34] and is 92.857 km, thus allowing the calculation of the CAPEX of HVAC lines in M€/GW, or 219.543 M€/GW. As for the length considered in the model to connect 2 countries sharing a maritime border and to be connected by HVDC maritime cables, in particular the connections between Great Britain and its neighbours, the length used in the model is based on the length of HVDC cables already installed in 2019 as well as the length of other HVDC line projects installed between 2019 and 2024 and listed in [33]. These average lengths are reported in Table A.3b.

7.1.3 National time-series

Electrical demand

The electricity demand profile for the year 2050 cannot be known precisely. Therefore, the 2019 profile will be used, to which a coefficient is applied at each time step to account for the increase in electricity demand expected following the electrification of certain energy sectors. This coefficient is calculated by Eq. 7.2:

$$f = \frac{D_{2050}}{D_{2019}} = \frac{3616}{2660} = 1.359 \ , \tag{7.2}$$

where D_{2050} is the total annual demand expected in 2050 according to the model produced by ENTSO-E in partnership with ENTSO-G in their TYNDP 2024 Scenarios Report [3], D_{2019}

is the total annual electricity demand in Europe in 2019. In this report, they indicate the European annual consumption in 2019, which is 2 660 TWh, and the expected consumption in 2050, which is 3 616 TWh, according to the *Global Ambition* scenario which, unlike the *Distributed Energy* scenario, takes into account a transition initiated at the European level, a key assumption of this thesis.
This method makes it possible to obtain time-series hourly electricity demands for each country while taking into account the increase in electricity demand and maintaining the electricity demand profile of each country.

Renewable capacity factor

Since meteorological data from such a distant year are impossible to predict, the capacity factors used for the PV, WON and WOFF nodes are the same as those of 2019 and similarly to 2019, the hourly time-series capacity factor associated with the ROR node is always modelled by a constant factor throughout the year.

7.2 Scenarios

Firstly, a scenario 0 is created in order to observe how the model reacts if no limit is set on the maximum capacities that the model can install, assuming an unlimited budget, resources and construction space. Then, limits will be placed on the models and particularly on renewable energy sources. These limits will be criticised by varying them in order to criticise the model that generated these values. Next, a limit on nuclear power generation will be added in order to model the major debate surrounding this energy source. Finally, the purchase cost of natural gas will be studied through a sensitivity study, which will make it possible to determine at what price hydrogen becomes interesting or even to determine at what price natural gas power stations are no longer competitive in the model. In these scenarios, all pre-installed capacity will be considered to be zero, on the assumption that all electricity generation technologies will have to be replaced.

7.2.1 Scenario 0 - No limit

As already stated, Scenario 0 is intentionally an unfeasible scenario assuming an unlimited budget and resources. The first sub-scenario studies the case where all pre-installed capacities are zero, thus starting from scratch, assuming that the entire energy fleet must be rebuilt and limiting all maximum capacities to 500 GW or kt/h[4], which represents a disproportionately large value supposedly representing infinity. 500 GW represents half of the European Union's production capacity in 2019, thus ensuring its excessiveness.
In the second sub-scenario, a study on the importance of cross-border connections is conducted, no longer assuming an infinite maximum capacity but imposing a limit. This limit is based on the values of Ember [38], which provides the electricity exchange capacities between neighbouring countries in 2040 according to the projects included in the TYNDP [34]. Therefore, the hypothesis is that there will be no new construction between 2040 and 2050.

[4]The nodes whose capacities are expressed in kt/h are: the DAC, the PCCC nodes and the CO2_STORAGE node.

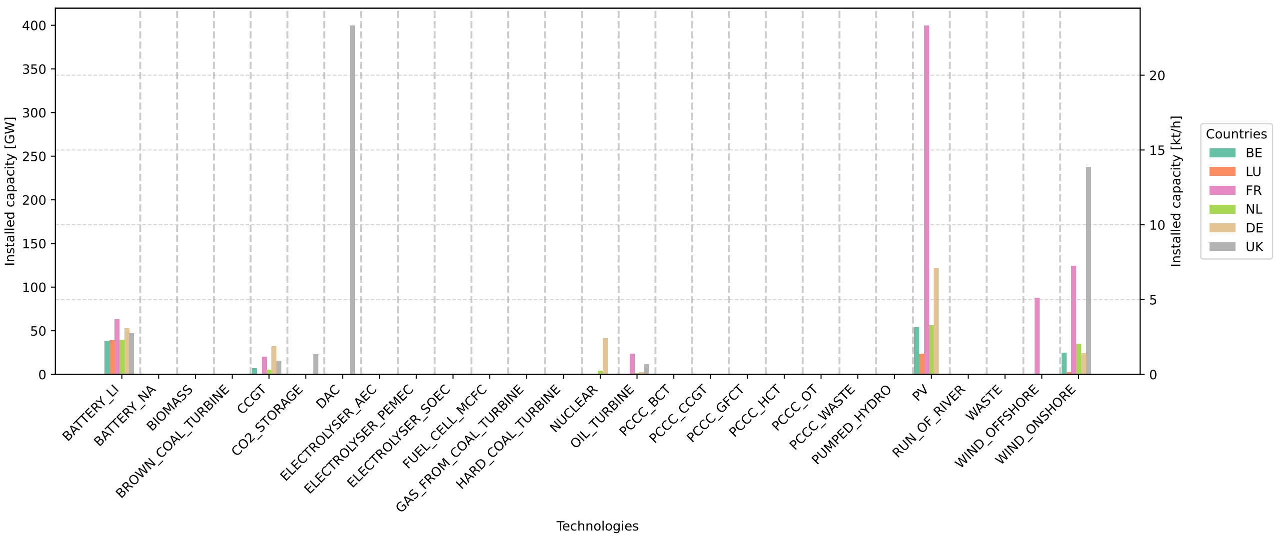
Scenario 0.1

To represent the total renewal of the energy park assuming that everything must be rebuilt, the parameter representing the pre-installed capacity, $\underline{\kappa}^n$, is set to 0 GW or kt/h for all technologies. To represent infinity in terms of maximum installation limit, the parameter representing the maximum capacity that the model can install, $\overline{\kappa}^n$, is set to 500 GW or kt/h for each of the technologies in the model.

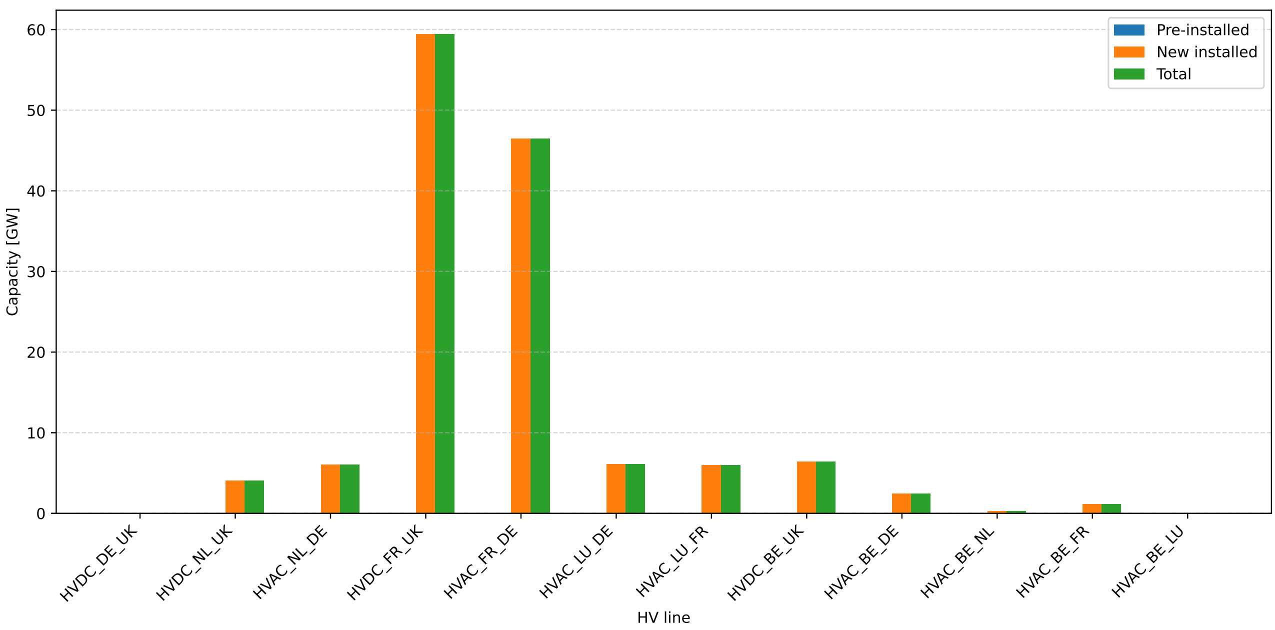
This assumption means that the lifespan of the facilities is exceeded, which will be true for some of the energy parks that were built years ago, but which is not true for the most recent facilities. By imposing no limits on the model, this assumes that no budget, resource, or space limitations for construction are considered.

Although it may not seem very realistic, this scenario above all provides a better understanding of how the model works by showing which technologies are favoured when there are no external constraints on their development. In the subsequent scenarios, additional constraints will be introduced to reduce the gap between the theoretical and realistic insights that can be derived from the model.

Figure 7.1a shows the installed capacity, expressed in GW or in kt/h, of all technologies in each of the countries studied. The installed production technologies are: gas-fired power plants, nuclear power plants, oil-fired power plants, solar panels, and wind turbines (onshore and offshore). To provide storage, lithium-ion batteries are installed in each country which seems to be the cheapest storage technology. The least expensive solution for capturing carbon emitted by gas-fired and oil-fired power plants appears to be the installation of a huge CO_2 capture plant directly from the air, located in Great Britain. The installed capacity of French solar panels forms a peak that is significantly higher than other installed capacities, as does the installation of onshore wind turbines in Great Britain. Overall, it would appear that large production capacities are installed in France. Figure 7.1b, showing the installed capacity of cross-border electricity transmission lines, shows a large interconnection between Great Britain, France and Germany, with France in the middle of this interconnection. The other countries have interconnections of the order of 1 to 6.5 GW, which is well above the installed capacity in 2019 shown in Table 6.2. These observations suggest a logic of centralisation of renewable production in the most advantageous countries followed by a redistribution of electricity to neighbouring countries with poorer weather conditions.



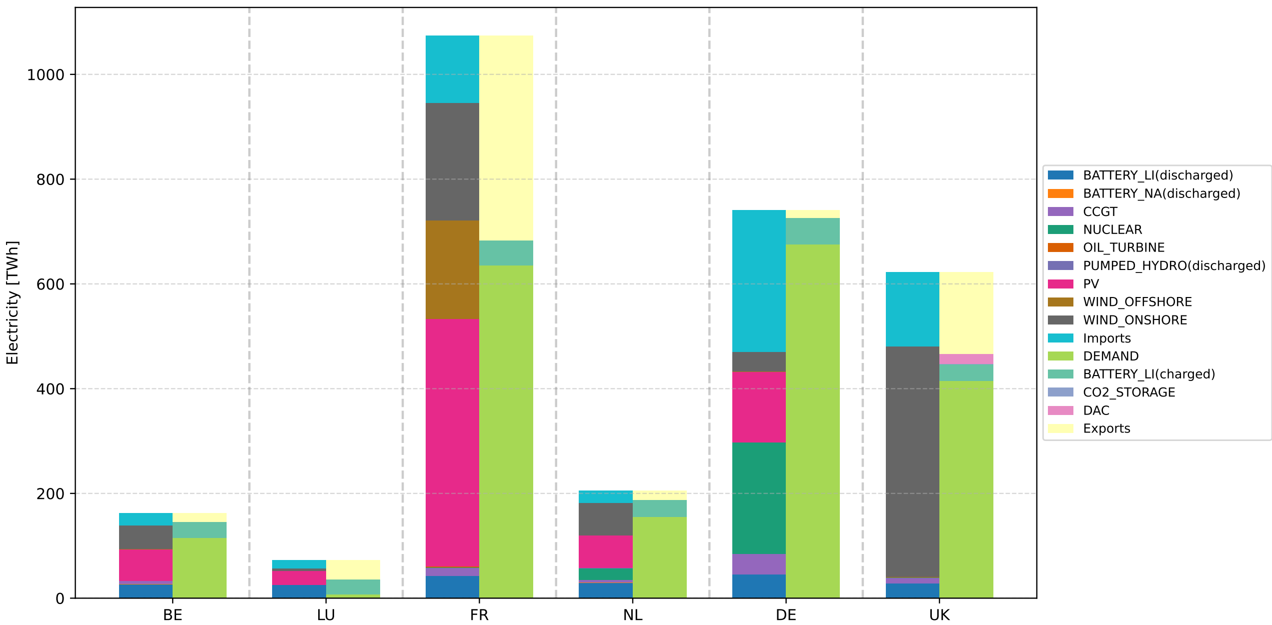
(a) Installed capacity for each technology.



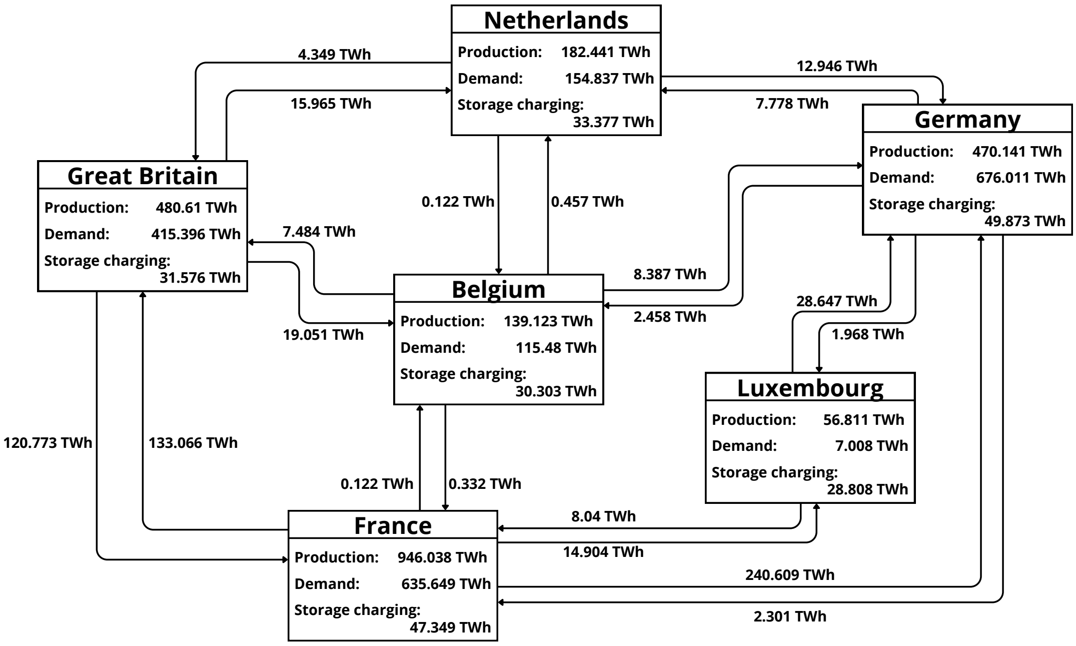
(b) Installed capacity for each HV lines.

Figure 7.1: Installed capacities of each technology in the different countries and for all high-voltage transmission connections between countries for scenario 0.1 for the year 2050.

Figure 7.2 shows the distribution of production according to each production technology as well as the distribution of consumption induced by the electricity demand specific to each country but also the electricity consumption of certain installations. This figure shows in fact the hypothesis of a centralised production in France producing much more electricity than necessary to meet its demand, notably via renewables (PV, WON and WOFF). Table 7.3 presents the annual averages of the capacity factors considered in order to represent the meteorological dependence classified in order of the most advantaged to the most deprived of good conditions. France is at the top of the ranking with the best annual average for PV and WOFF and has the second place for onshore wind, beaten by Great Britain. This position in the ranking of countries enjoying the best meteorological conditions can explain the choice of the model to choose this country rather than another in order to place a large renewable production capacity there.



(a) Production and consumption shares in TWh.



(b) HV exchanges in TWh.

Figure 7.2: Electrical production and consumption for each technology in the different countries studied in TWh and the amount of electrical exchanges in TWh for scenario 0.1 for the year 2050.

<table>
<tr><th rowspan="2">Ranking position</th><th colspan="2">PV</th><th colspan="2">WON</th><th colspan="2">WOFF</th></tr>
<tr><th>Country</th><th>Value [-]</th><th>Country</th><th>Value [-]</th><th>Country</th><th>Value [-]</th></tr>
<tr><td>1</td><td>FR</td><td>0.142</td><td>UK</td><td>0.283</td><td>FR</td><td>0.461</td></tr>
<tr><td>2</td><td>LU</td><td>0.132</td><td rowspan="2">LU - FR</td><td rowspan="2">0.256</td><td>UK</td><td>0.362</td></tr>
<tr><td>3</td><td>DE</td><td>0.127</td><td>DE</td><td>0.337</td></tr>
<tr><td>4</td><td>NL</td><td>0.126</td><td>BE</td><td>0.252</td><td>NL</td><td>0.324</td></tr>
<tr><td>5</td><td>BE</td><td>0.123</td><td>NL</td><td>0.241</td><td>BE</td><td>0.31</td></tr>
<tr><td>6</td><td>UK</td><td>0.11</td><td>DE</td><td>0.195</td><td>LU</td><td>0</td></tr>
</table>

Table 7.3: Ranking of countries with the most favourable annual average capacity factor for weather-dependent technologies such as photovoltaic panels, onshore wind turbines and offshore wind turbines.

FIGURE 7.2b shows the quantities of electricity exchanged between countries[5]. France is indeed an electricity exporter with a large part of its export going to Germany. Germany, not being at the top of the ranking in terms of weather conditions and having a high electricity demand, meets its electricity demand largely through imports from its neighbouring countries. The

[5]the production shown in the figure takes into account the quantity of electricity reinjected by the batteries into the network when it is discharged

remainder of its production is provided by nuclear energy, PV, gas-fired power plants and onshore wind turbines in order of importance.

The choice of DAC unit installation also seems linked to weather conditions but also to interconnections. Great Britain, listed first in TABLE 7.3 in the WON column, enjoys the best weather conditions for onshore wind turbine installation. Therefore, it meets its electricity demand largely through this technology, which seems to be the most economically advantageous compared to all production technologies. This installation allows it to have excess electricity production that can cover the demand of a DAC unit. Another point that could justify the choice of implementing DAC in Great Britain rather than in France, which has a large excess of electricity production, or even Luxembourg, which also has excess electricity production but on a much smaller scale, is that it is not a neighbouring country of Germany. As a reminder, Germany relies heavily on its neighbours to meet its electricity demand, and therefore the excess electricity production of its neighbours goes largely to Germany.

These observations allow us to understand the production technologies that are the least expensive to install and use, which are renewable power sources, in particular solar followed by onshore wind and finally offshore wind. When renewable production is not optimal, the choice of nuclear energy seems to be the most economical in order to ensure constant electricity production given the model's assumptions. The high penetration of renewables in the energy mix implies strong fluctuations in production involving a significant installation of electrical storage capacity provided by lithium-ion batteries but also by a large electrical transmission network with significant capacity allowing the export of renewable surplus production to other countries to maximise the production of renewables. These important exchanges between countries with high concentrations of renewable production are perfectly observed with the link between France and Great Britain. When the production of these technologies is not sufficient to quickly keep up with the variation in electricity demand or to provide electricity during large peaks in demand, gas and oil power plants seem to be the most economical solution. Conversely, when production is too high, the batteries are full and no neighbouring country needs electricity, it is always possible to curtail renewable energy. Indeed, Eq. 5.2 allows the model to curtail part of the electrical production of the PV, WON and WOFF nodes in case of overproduction which is not necessary for the network. Thus, in this scenario, a total of 424.656 TWh of electricity that was not injected into the grid represents a large quantity of "lost" energy capable of meeting Great Britain's demand.

FIGURE 7.3 shows the profile of daily averages of gas-fired power plants production across all countries in the system. The profile includes many peaks and not a constant profile, demonstrating their properties as backup production technologies ensuring electricity production in the event of high electricity demand on the network or during low electricity production from renewable power technologies. These low production moments occur particularly in winter when solar panels produce little, characterising a seasonal production profile that is reflected in the production profile of gas-fired power plants, which are much more often used during these winter months. The peaks observed in summer require a closer look. To this end, FIGURE 7.4 shows the profile of electricity production and consumption in Germany between July 6 and 11. It clearly shows the profile of classic daily demand with a decrease in consumption during the night as well as a solar production profile with a peak around the middle of the day, which is partly stored in batteries to be released in the evening. The peak use of the gas plant occurs in the night of July 11th when solar production is non-existent coupled with the batteries being discharged following their discharge the previous evening and not being able to count on imports from neighbouring countries thus forcing Germany to use its gas plants to ensure its demand. This figure perfectly shows the hypothesis of perfect foresight in view of the nuclear production profile which, 3 days in advance begins to increase its production in order to meet the electricity demand of the night of July 11th and thus reduce the use of the gas plant as much as possible.

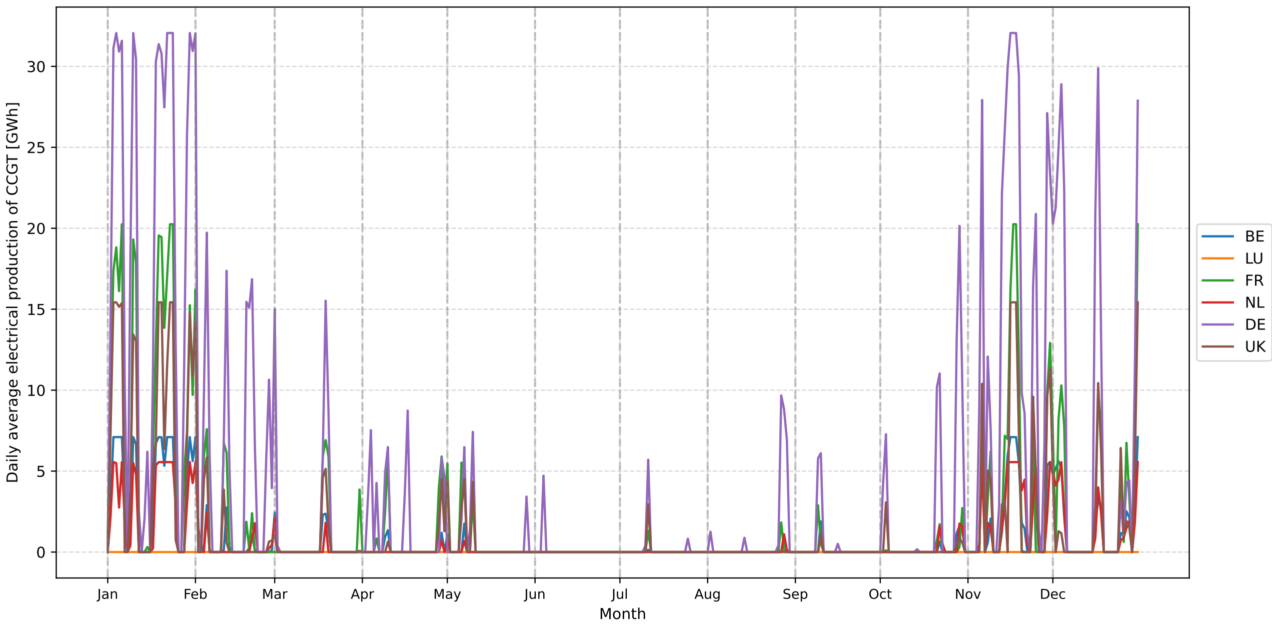


Figure 7.3: Daily average production of gas-fired power plants in each country of the system expressed in GWh obtained from scenario 0.1 over the year 2050.

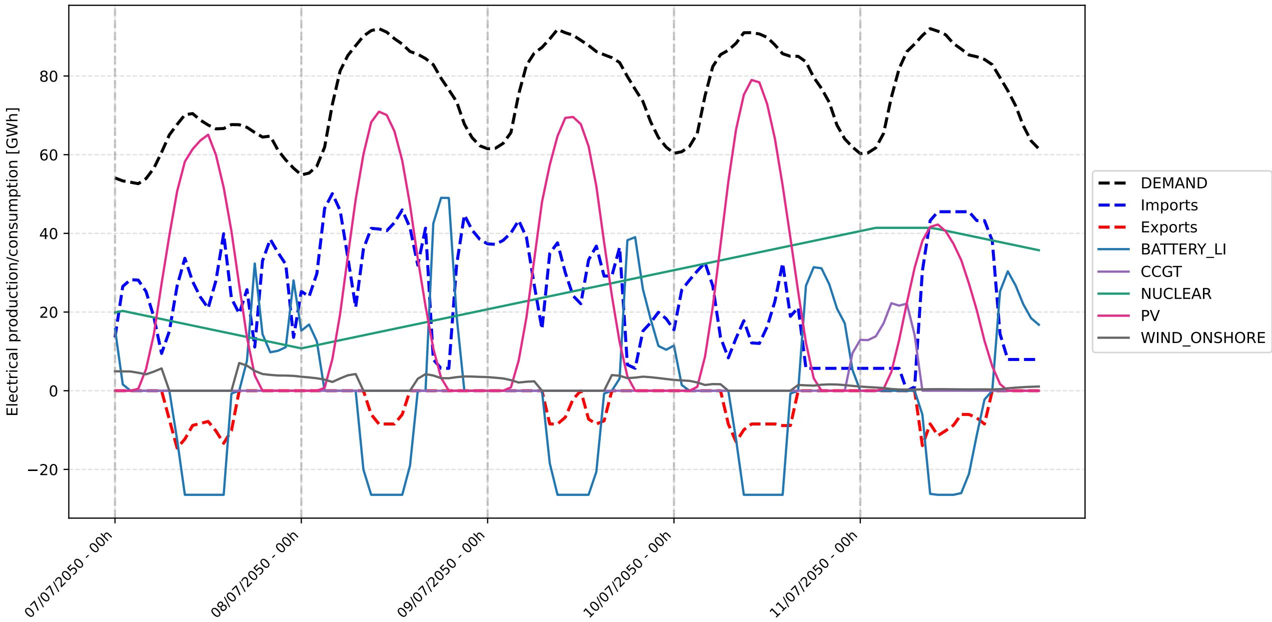


Figure 7.4: Electrical production and consumption of Germany between the 6th and the 11th of July obtained from scenario 0.1 over the year 2050.

The total cost of this system is 150.55 billion euros per year (G€/yr). This cost does not take into account the renewal of the internal electricity distribution system of a country and considering the limits of the model observed with the analysis of the year 2019, a certain uncertainty must be taken into account given the limits of the model to represent the economic markets and the assumptions made. The purchase cost of electricity obtained via this scenario is 66.17 $€_{2050}/MWh_{el}$. By bringing this price back to a 2019 equivalent, that is to say by reversing inflation, this price is equivalent to 33.29 $€_{2019}/MWh_{el}$. Compared to the cost of electricity in 2019 which is worth 35.88 $€_{2019}/MWh_{el}$, obtained by calculating the weighted average of the price of electricity in the 6 countries studied given by [37], this optimal cost of an unlimited system is slightly lower whereas one could expect a much lower cost because the electricity mix in 2019 is far from ideal. This is due to the ageing of the electricity production fleet in these countries allowing the managers of these fleets to sell electricity at a lower cost because the investment cost of these plants has already been amortised over the years.

15.039 Mt of CO_2 were emitted, captured and stored in the soil of Great Britain. Its storage capacity estimated by [14] being 14 610 Mt, this would allow this system to operate for 971 years at this rate before the British soils are full, assuming constant carbon emissions over this period.

During this analysis, the importance of cross-border electrical interconnections between countries allowing for greater integration of renewable power sources could be observed. Overproduction in one country can then be used by a neighbouring country, reducing system costs and the use of fossil energy, which would replace these exchanges, allowing the system to balance production with consumption. In order to analyse the influence of cross-border transmission capacity limits on the electrical mix of the system, sub-scenario 0.2 is introduced.

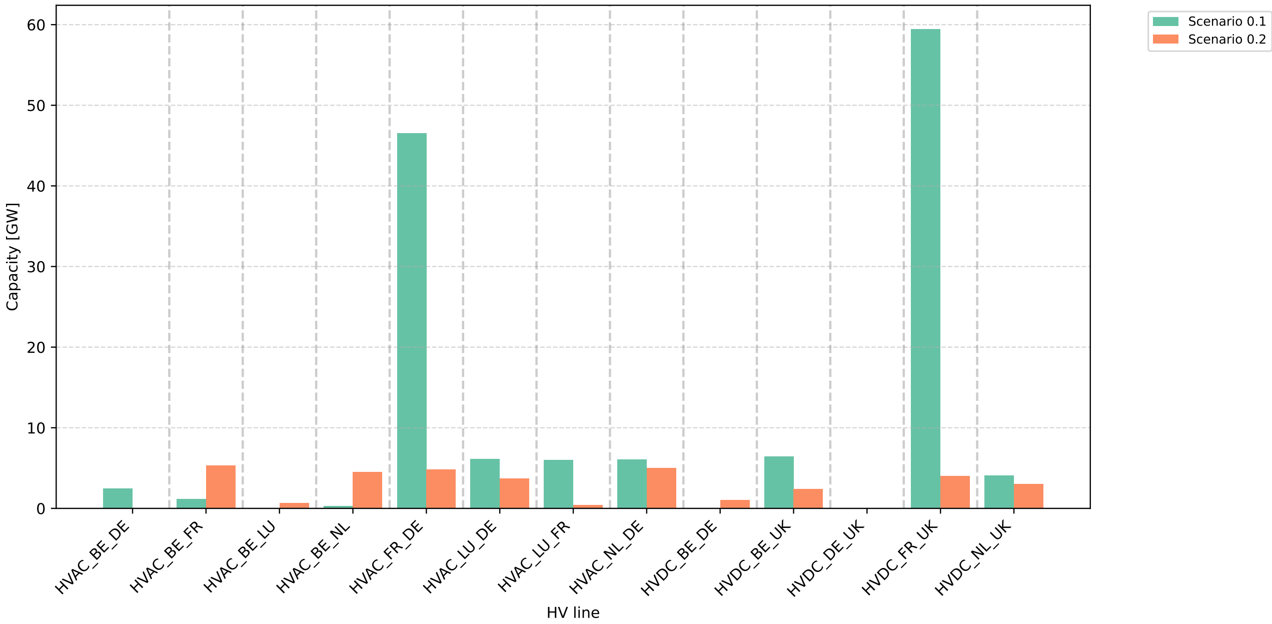
Scenario 0.2

This scenario allows to observe the importance of electrical interconnections between countries in order to obtain an optimal model with a lower cost. In the previous scenario, no capacity limit was set on these transmission lines. In this scenario, the capacities that will be installed by 2040, listed by [38] which is based on the construction projects of these lines presented on the TYNDP website [34], will be used to set the pre-installed capacities of these lines, $\underline{\kappa}^n$, but also the maximum capacities that the model can install, $\overline{\kappa}^n$, as defined in Eq. 5.3. This therefore prevents the additional installation of transmission capacities than what is planned by 2040, thus assuming that no other projects to increase the transmission networks are planned between 2040 and 2050. TABLE 7.4 reports these capacities.

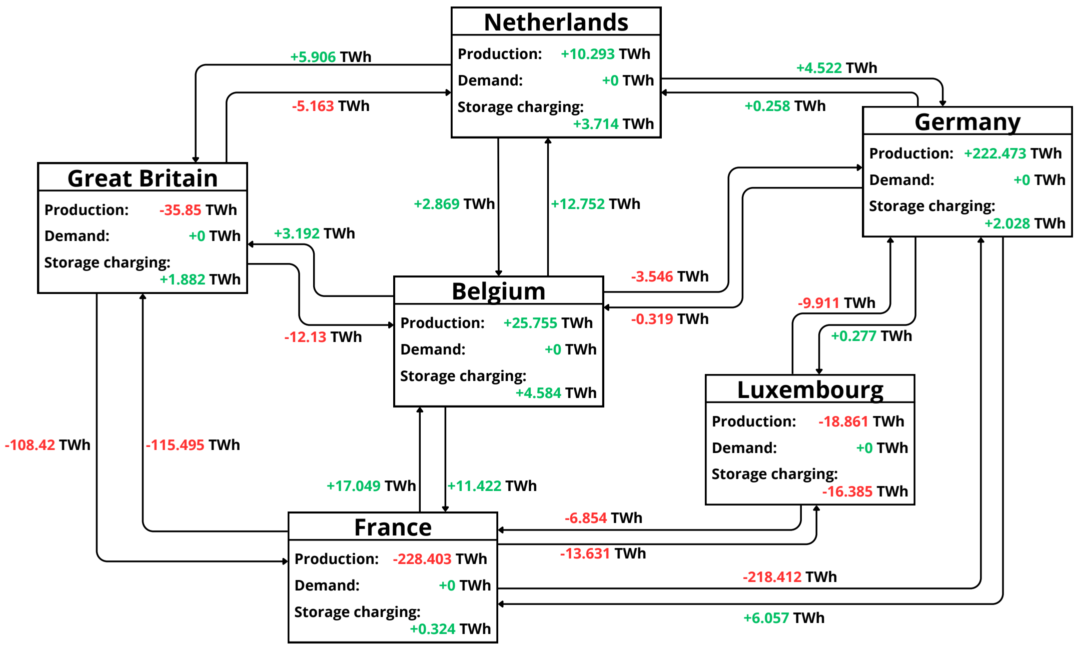
Transmission line	$\underline{\kappa}^n = \overline{\kappa}^n$ [GW]
HVAC_BE_LU	0.68
HVAC_BE_FR	5.3
HVAC_BE_NL	5.4
HVAC_BE_DE	0.0
HVDC_BE_DE	1.0
HVDC_BE_UK	2.4
HVAC_LU_FR	0.38
HVAC_LU_DE	3.7
HVAC_FR_DE	4.8
HVDC_FR_UK	4.0
HVAC_NL_DE	5.0
HVDC_NL_UK	3.0
HVDC_DE_UK	0.0

Table 7.4: Pre-installed and maximal capacities of electrical cross-border transmission interconnections assumed for scenario 0.2 for the year 2050.

FIGURE 7.5a shows the capacities of cross-border interconnections allowing the transfer of electricity between countries by showing the values of scenario 0.1 as well as scenario 0.2. The limitation imposed by scenario 0.2 has the overall effect of reducing the capacities of electrical exchanges between countries with a very strong decrease for the lines linking France to Germany and that linking France to Great Britain. FIGURE 7.5b is a diagram representing the electrical connections between countries. The written values represent the differences in TWh between scenario 0.2 and scenario 0.1 whether for production (production takes into account the electricity discharged by the storage units on the network), for the quantity of electricity loaded by the storage units as well as the exchanges on these electrical transmission lines. This diagram clearly shows that limiting trade has the effect of preventing the model from installing huge renewable generation capacities in countries with the best weather conditions, as was previously the case, which explains the enormous decrease in French production, as well as the decrease in the United Kingdom and Luxembourg. Countries that were dependent on this French renewable production, particularly Germany, must therefore increase their production.



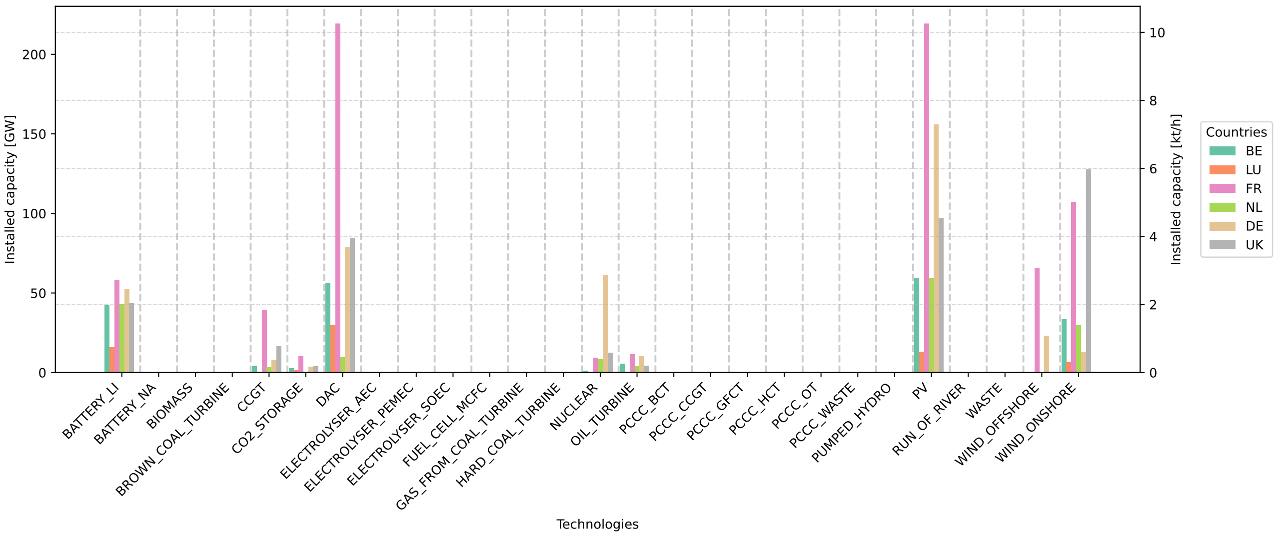
(a) Installed capacity for each HV lines.



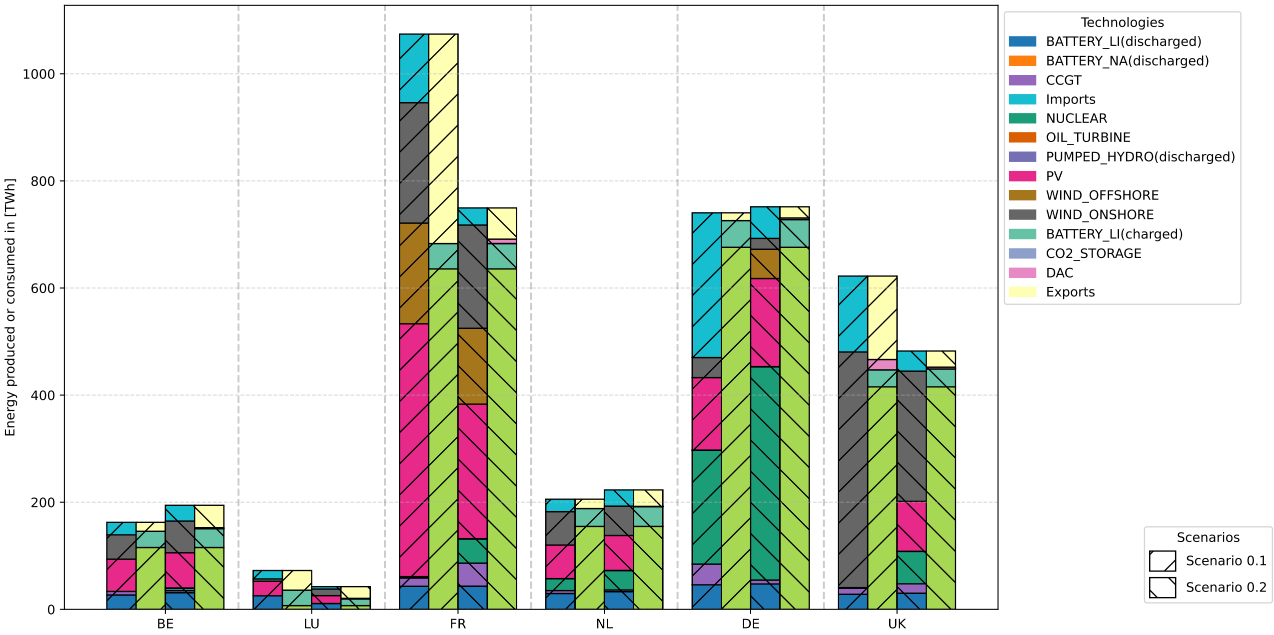
(b) Differences in exchanges on HV in TWh.

Figure 7.5: Installed capacities comparison between scenario 0.1 and scenario 0.2 of each high-voltage cross-border interconnection and the difference of the annual amount of electrical exchanges on those lines between those two scenarios in TWh for the year 2050.

To observe this in more detail, FIGURE 7.6a, showing the installed capacities of the technologies used by the model for the two scenarios 0.1 and 0.2, and FIGURE 7.6b, showing the comparison between scenarios 0.1 and 0.2 in the distribution of production by technology type as well as the distribution of consumption in TWh, are used. The effect of limiting these electricity exchanges between countries has the effect of isolating them, forcing them to no longer depend on neighbouring countries to export their surplus production and to import the electricity needed to meet their demand. The production technologies favoured by the model are always the same: renewable productions, firstly solar and then onshore or offshore wind depending on the capacity factor coupled with lithium-ion batteries. When renewable productions are not sufficient, nuclear energy is favoured and, to ensure load-following, small gas and oil power plants are used. The decrease in electricity exchanges is clearly observable. This need for countries to produce their own electricity by depending less on their neighbours leads to an increase in nuclear production, which ensures more constant production than renewable power technologies. Another interesting observation is that countries like France or Great Britain, which depended heavily on their connection with neighbouring countries to balance their electricity balance, which was highly fluctuating due to a high penetration rate of renewables, must therefore resort more extensively to gas-fired power plants to replace part of the renewable production. Since there are no countries with large amounts of excess electricity production, the optimal solution is no longer to install a large DAC unit in a country with large electricity overproduction but to install smaller units in all countries. The total CO_2 emitted is 14.059 Mt, which is slightly lower than the previous scenario due to an overall decrease in the use of gas and oil-fired power plants.



(a) Installed capacity for each technology.



(b) Production and consumption shares in TWh.

Figure 7.6: Installed capacities of each technology in the different countries and the distribution of electricity production according to each of these technologies, as well as the distribution of electricity demand in each country compared between scenario 0.1 and scenario 0.2 for the year 2050.

On the other hand, the cost of the overall system increased by 8 billion euros per year, reaching a total of 158.513 billion euros per year. This increase is therefore reflected in the cost of electricity for the overall system, which now costs 70.43 $€_{2050}/\text{MWh}_{\text{el}}$.

Scenario 0 - Conclusion

To conclude, these two scenarios, although impossible to achieve in practice due to no realistic constraints on the maximum capacities that can be deployed for each technology, made it possible to understand which technologies were the least expensive for the model and therefore the one it will use first to meet demand. The impact of weather conditions, expressed through capacity factors, was demonstrated. The importance of large electrical exchange capacities allowing a large integration of inexpensive renewable power sources, which reduces the overall cost of the system, was observed. Despite ideal scenarios in which the model was not limited in terms of electrical storage and exchanges, combustion plants offering a rapid response to fluctuations in demand and not dependent on weather conditions showed their necessity in an electricity mix in order to safely balance the production and electrical demand of the model, despite the constraint of net neutral carbon emissions requiring the installation of units to capture this emitted carbon and its storage, thus having an economic impact.

7.2.2 Scenario 1 - Limits on renewables

In view of the previous results, it is necessary to limit the model in its capacity to install renewable power technologies otherwise they will install huge installations that are economically unfeasible in terms of resources needed to build these technologies or even in terms of space available for their installation on the soil of each country. Therefore, a limit on the maximum installable capacities on PV, on wind turbines (onshore and offshore) as well as on hydroelectricity (run-of-river & water reservoir and on pumped-hydro storage). These limits (PV, WON, WOFF and BAT) come from the *Ten-Year Network Development Plans* (TYNDP) 2024 report [3] which is a study carried out jointly by the managers of the European electricity and gas networks, ENTSO-E and ENTSO-G, respectively. The source of these limits is discussed in more depth in SECTION 3.2 and the calculation to obtain the limits by country is explained in more detail in SECTION 7.1. This report does not specify what type of battery is used and seeing that the cheapest solution according to the results of the previous scenarios is the lithium-ion battery, it is on this storage node that the limit will be imposed. From then on, sodium-ion batteries will no longer be used by setting their maximum capacity, $\overline{\kappa}^n$, to 0, thus preventing their installation by the model.
Concerning hydroelectricity, the limits are based on a report [40] having studied the theoretical maximum capacity of hydroelectricity in Europe. Assuming that the possibility of increase is equivalent across the entire European territory, and therefore for each country in the study, and assuming that this increase factor is identical for both types of technologies, it is then possible to obtain the limits of maximum installable capacity in each country. Regarding other technologies, no limit is imposed (in fact, $\overline{\kappa}^n$ is set at 200 GW or kt/h which is large enough seing the results of the previous scenarios). The pre-installed capacity parameter, $\underline{\kappa}^n$, of all nodes, excepted for the high-voltage cross-borders transmission lines, is fixed to 0 assuming that everything have to be built.

Scenario 1.1 will aim to study the model's behaviour in the face of these limits, reported in TABLE A.14 in the appendix, with particular attention to gas-fired power plants.
Since this report itself is the result of a model that does not represent an absolute truth, and given that certain assumptions had to be made in order to discretise the results reported at the European level in order to translate them to the national level of the countries studied in this thesis, it is important to observe the model's behaviour in the face of variations in these limits. This is what will be done in scenario 1.2, in which deviations from these limits will be tested in order to observe the degree of model variation and the uncertainty thus introduced by these limits. The limits set on renewable technologies are also reported in TABLE A.14.

In addition to the limits imposed on renewable energy, the limit imposed on cross-border electricity interconnections is retained, thus setting the parameter representing pre-installed capacity, $\underline{\kappa}^n$, at the previously imposed values. These values, based on a study for 2040, allow for the possibility of installing an additional 5 GW on each of these lines, which represents nearly twice the largest capacity increase planned between 2019 and 2040, which was an additional 3 GW on the Belgium - Netherlands line. These limits are reported in TABLE A.15, included in the appendix.

Scenario 1.1

By adding these limitations to the model, the result of what the model installed to produce the electricity needed to meet the overall system demand is shown in FIGURE 7.7. An additional technology is used by the model compared to previous scenarios: the pumped-storage hydroelectric unit serving as additional storage. However, run-of-river & water reservoir units are still not used by the model to produce electricity due to their high CAPEX. In previous scenarios, the priority installation of renewable power technologies, being the least expensive, could be observed. The choice of which renewable energy was installed first depended on the country's weather conditions, which is expressed through the capacity factor, which is ranked and represented in TABLE 7.3.
The installation of one technology rather than another is therefore different for each country, depending on its electricity demand (high demand requires the country to combine several renewable energy sources), its average capacity factors, and its connections with its neighbouring countries. The optimal solution for each country is: the maximum installation of Belgian onshore wind turbines and the use of no other renewable power sources, the same for Luxembourg with in addition an almost total (87%) installation of PV, France, enjoying very good weather conditions appearing at the top of the capacity factor ranking, instals the maximum renewable energy allowed to it with the exception of the run-of-river & water reservoir as already stated, the Netherlands having similar weather characteristics to Belgium opts for the same strategy, Germany having bad conditions for onshore wind does not install its entire limit unlike other countries and instals 80% of this limit and, in order to meet its high demand, its entire limit of offshore wind is installed with an additional 35% of its limit of solar installed also, Great Britain instals its entire limit of onshore wind having very good weather conditions by adding respectively 5 and 10% of solar and offshore wind. In all model countries, approximately 15% of the maximum capacity limiting lithium-ion batteries are installed. Based on observations made in previous scenarios, when weather conditions are unsuitable, the model instals nuclear power plants. These units, having a more stable production, do not require the installation of large storage capacities, which justifies the batteries not being installed at the maximum capacity allowed in the model.

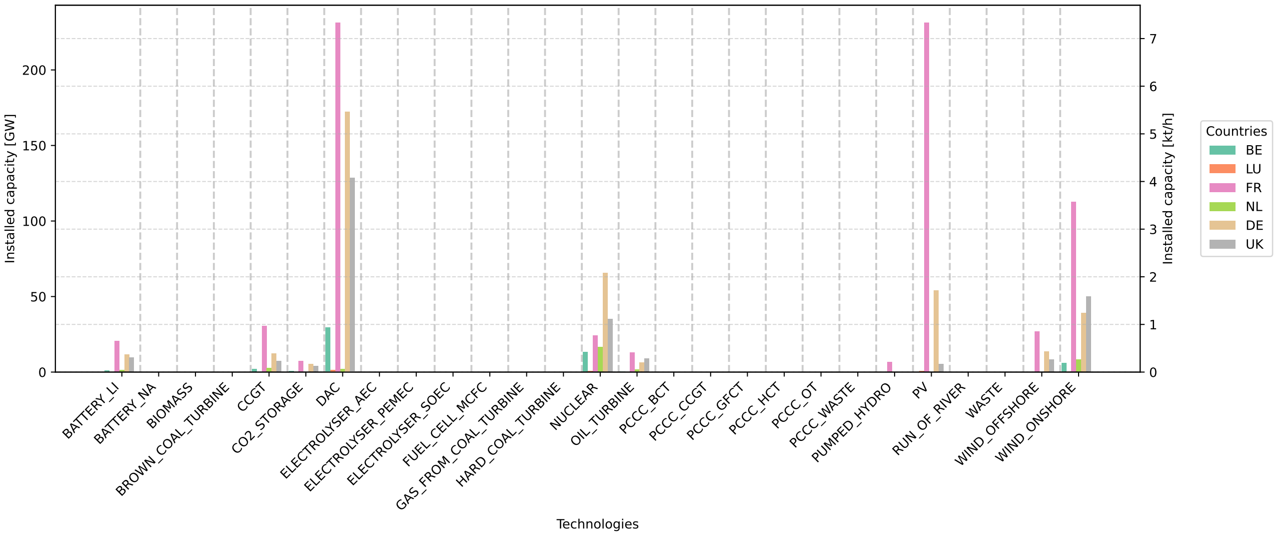


Figure 7.7: Installed capacity for each technology in the different countries for scenario 1.1 for the year 2050.

FIGURE 7.8 shows the installed capacity of electrical interconnections between countries compared to scenario 0.2. Since France has good weather conditions, the optimal solution is to install as much renewable energy as possible there and use these electrical connections to export this inexpensive and carbon-neutral electricity production. This explains the need to strengthen the lines connecting France to other countries, particularly the line with Germany and Great Britain. Connections between Great Britain and its neighbours, with the exception of the Netherlands, are also being strengthened to allow the exchange of each country's excess renewable energy production.

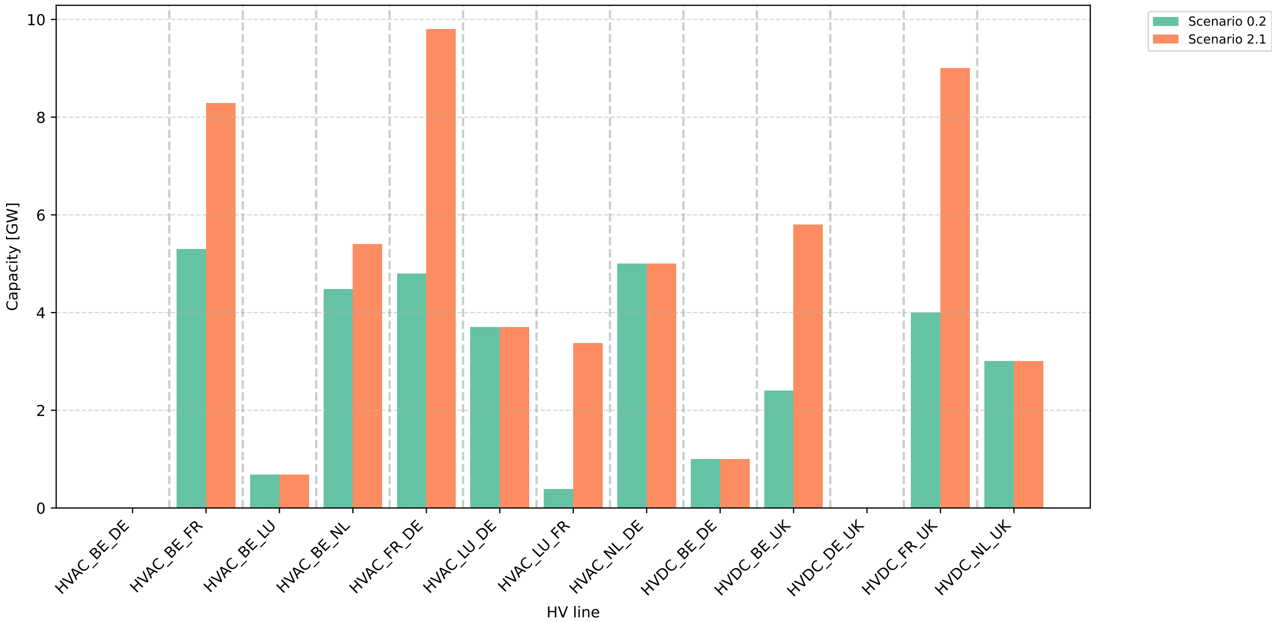


Figure 7.8: Installed capacity for each HV line compared between scenario 0.2 and scenario 1.1 for the year 2050.

FIGURE 7.9 compares the distribution of electricity production and electricity consumption according to the different sources between scenario 0.2 and scenario 1.1. The increase in electricity produced by nuclear power plants is clearly observable, becoming for most countries, except France, the primary source of production. As expected by observing the installed capacities, France exports part of its electricity production to neighbouring countries. These electricity exchanges can be observed in FIGURE 7.10. The role of France as a renewable producer for its neighbours and the export of this energy is clearly visible. Its imports have also increased, demonstrating once again the dependence of electricity exchanges during a high penetration rate of renewables in an electricity mix.

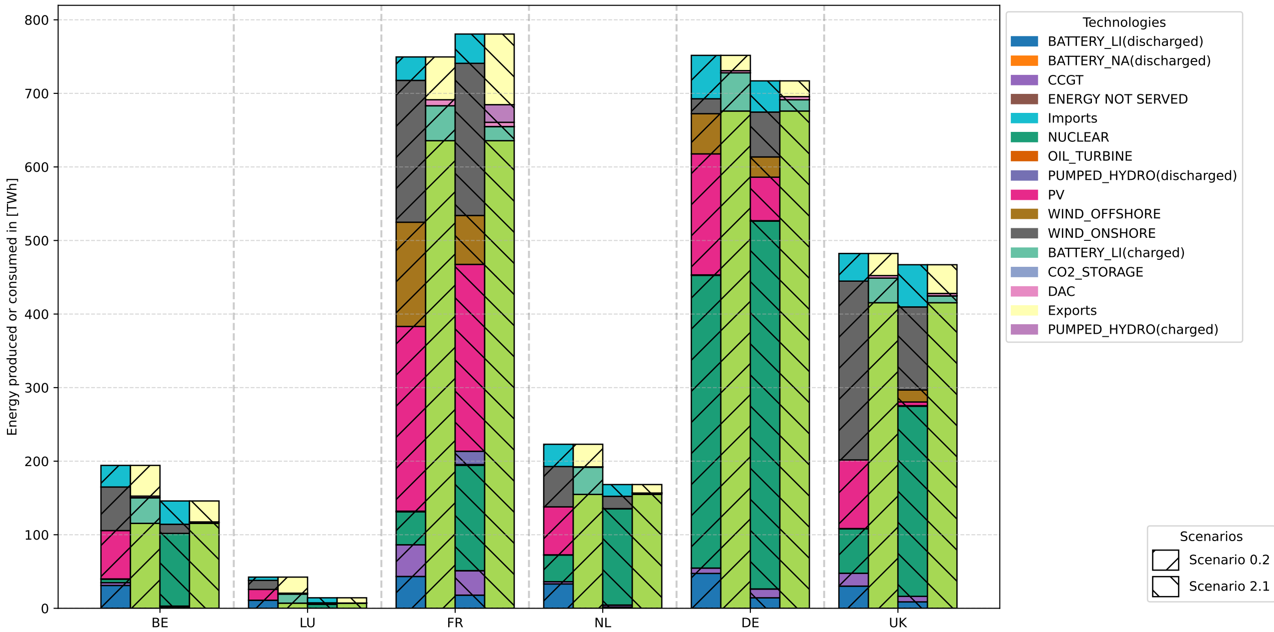


Figure 7.9: Distribution of electricity production according to each technology, as well as the distribution of electricity consumption in each country compared between scenario 0.2 and scenario 1.1 for the year 2050.

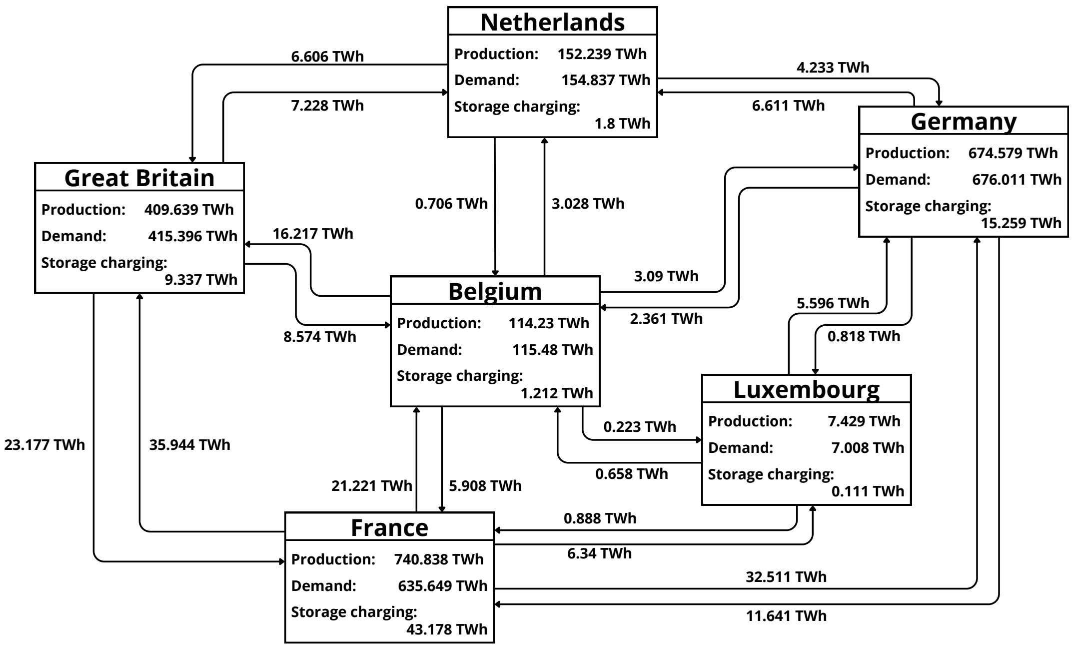


Figure 7.10: Scheme of the amount of annual electricity exchanges in the HV lines according to scenario 1.1 for the year 2050.

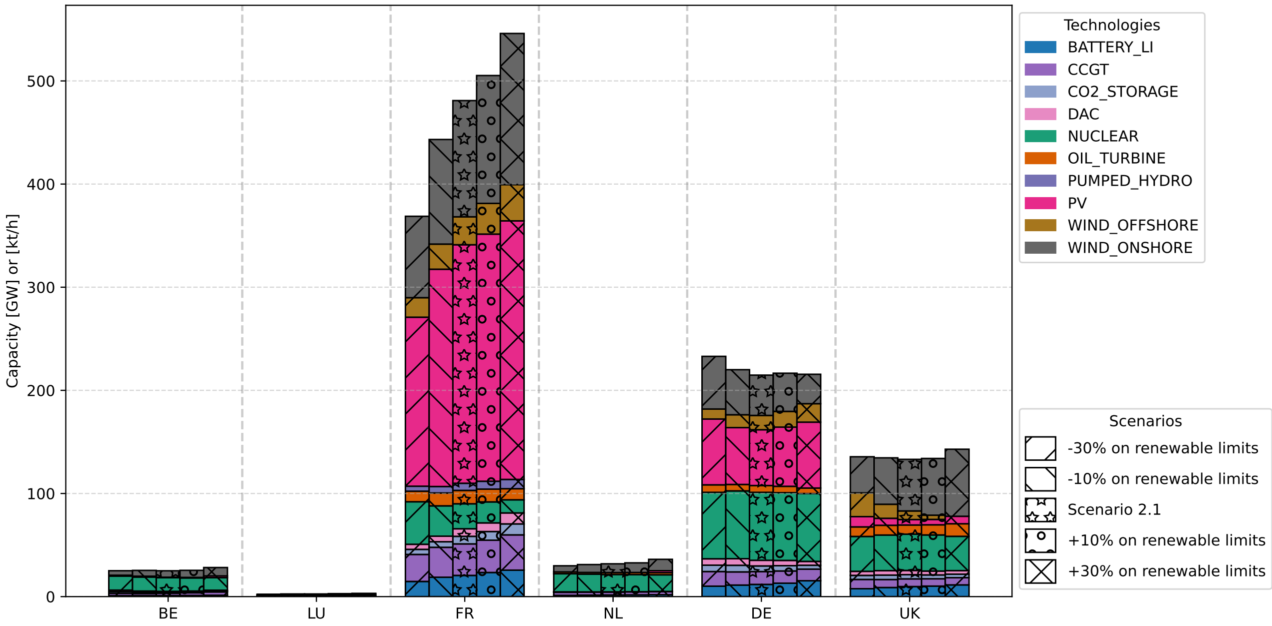
The model's electricity mix, which relies less on intermittent renewable energy and more on stable production from wind power (not affected by the intermittency of production linked to the night) and nuclear power, reduces the need for backup energy such as gas-fired power plants but remains necessary. In this scenario, 77.187 TWh of natural gas were consumed, which is nearly 1.6 times less than in scenario 0.2. This decrease can be partly explained by an increase in electricity exchange capacity, allowing a country with an electricity need to meet this demand by overproduction in a neighbouring country rather than by using gas-fired power plants. The amount of CO_2 emitted by gas and oil-fired power plants is 10.981 Mt. These emissions are captured by DAC units, particularly installed in countries with the largest share of renewable production, in order to supply it with inexpensive electricity.

The cost of this system has increased more than that observed between scenario 0.1 and scenario 0.2, with a total cost of 168 billion euros per year, which is an increase of almost 6% compared to scenario 0.2. The cost of electricity then increases from 70.43 $€_{2050}/MWh_{el}$ to 80.04 $€_{2050}/MWh_{el}$. This increase in the cost of the model is largely due to the increase in the share of nuclear energy, which is more expensive than renewable power technologies.

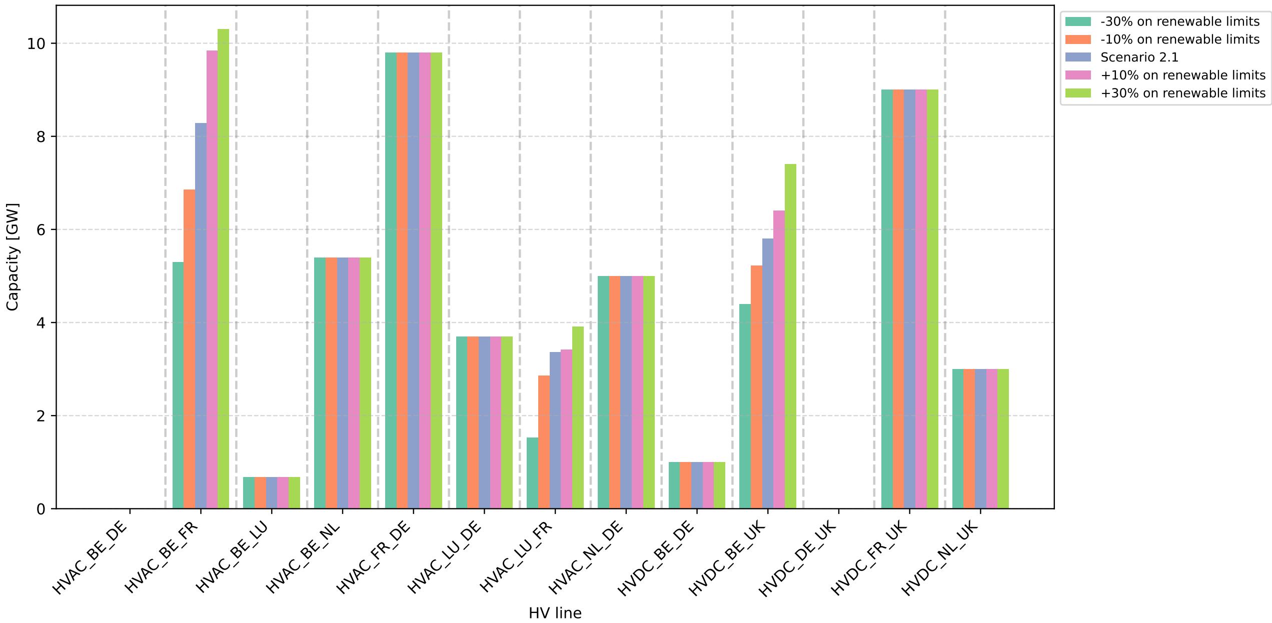
Scenario 1.2

The limits imposed on renewable power assets are derived from theoretical models which are open to criticism and, moreover, assumptions had to be made because the given limits encompassed all the territories of the European Union and therefore it was necessary to process these data and make assumptions in order to discretise these limits for each country in the model considered here. These values are therefore subject to certain uncertainties which are worth studying. This sub-scenario aims to analyse the variations of the model when these limits are deviated from their basic values in order to study this uncertainty.
To do this, scenario 1.1 will be used as a reference base and a variation of $\pm 10\%$ as well as a variation of $\pm 30\%$ on the limits imposed on renewable power assets are studied giving 4 results diverging from the reference scenario.

Figure 7.11 shows 2 sub-figures: the first represents a graph comparing the installed capacities of cross-border electricity connections between the reference scenario and its variations, the second is a graph representing the distribution of installed capacities according to the technologies used by the model. Observations already explained in the analysis of the previous scenarios are even more visible. The increase in installable capacity by the renewable energy model has the main effect of increasing the renewable capacities installed in France, which is strengthening its electrical transmission lines in order to share this inexpensive and decarbonised electricity, which has the effect of reducing the renewable capacity of technologies with a poor capacity factor, such as German onshore wind power.



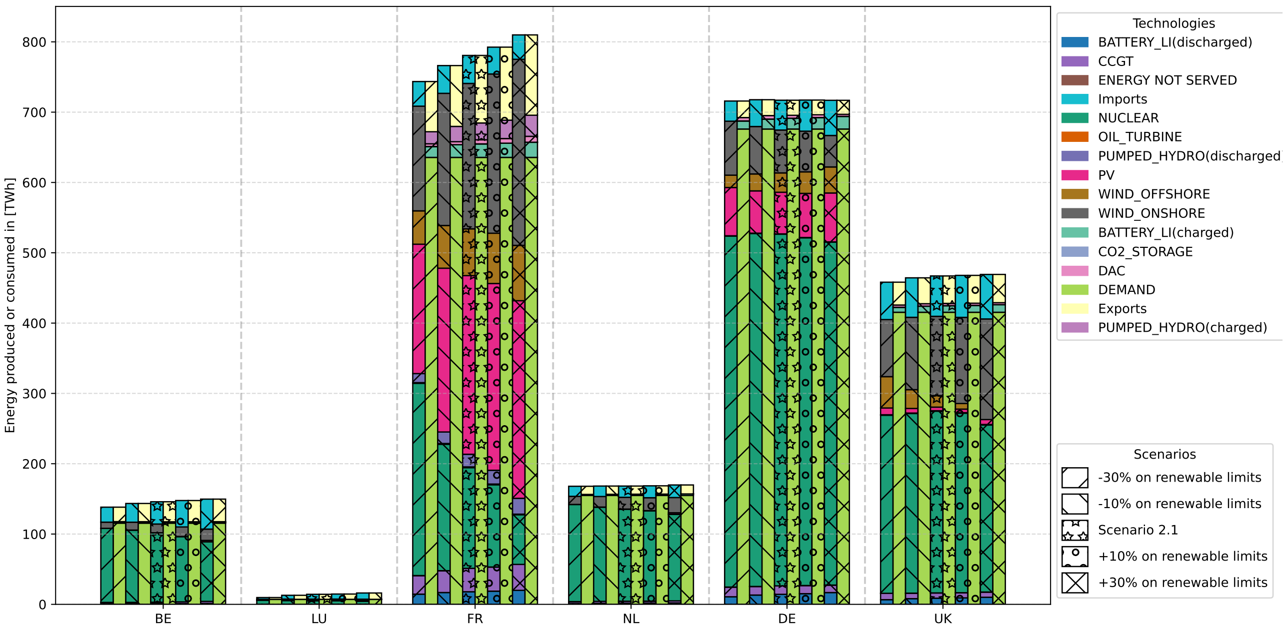
(a) Installed capacity for each technology.



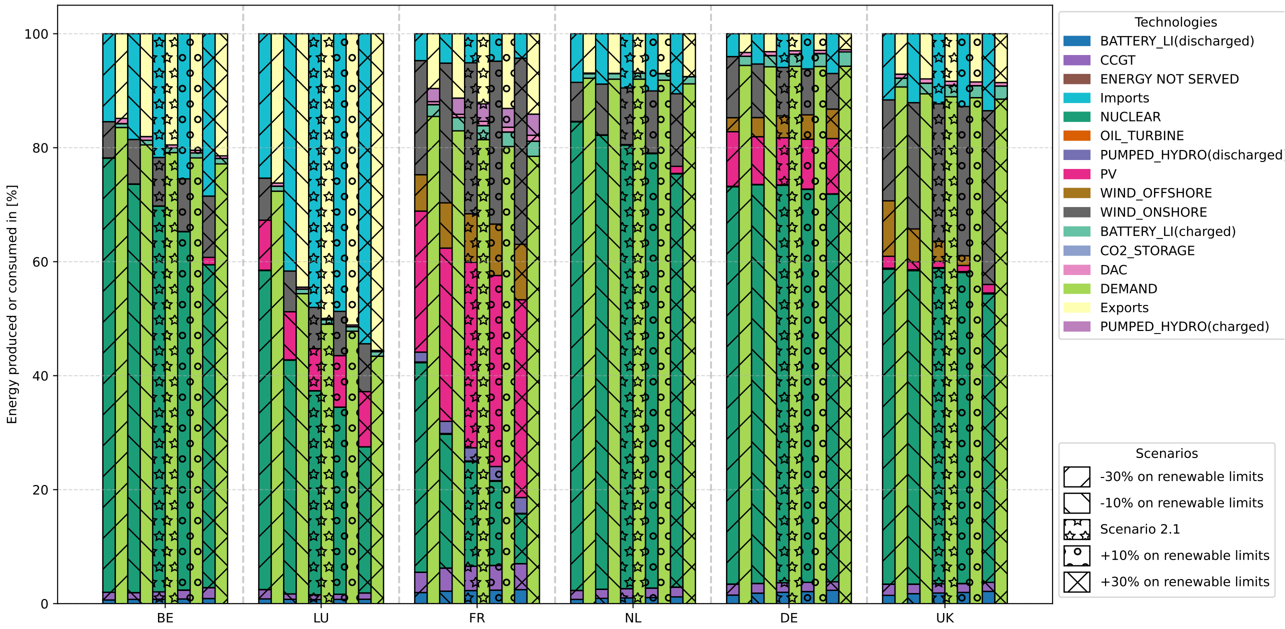
(b) Installed capacity for each HV lines.

Figure 7.11: Installed capacities of each technology in the different countries and for all high-voltage transmission connections between countries obtained for variations of $\pm 10\%$ and $\pm 30\%$ on the limits imposed on renewable power technologies compared to the reference scenario 1.1 for the year 2050.

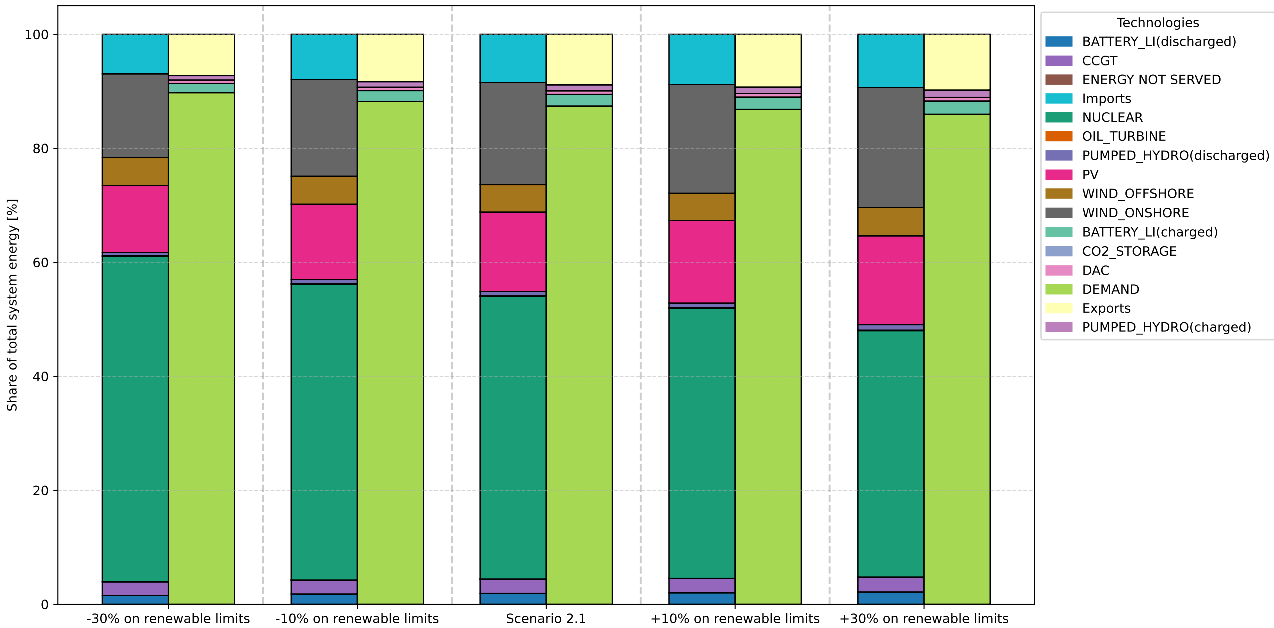
Figure 7.12 represents the graph of the distribution of production and consumption in each country by comparing these values between the reference scenario and its variations. This figure is divided into 3 sub-figures, the first representing this production and consumption in TWh and detailed for each country, the second representing the same data but expressed in % and the third expressed in % and showing the electrical mix of the overall system. The increase in the limits of admissible renewable capacities has had the effect of increasing renewable generation, mainly in France, where climatic conditions are optimal, particularly despite nuclear generation. This increase in production allows for increased exports. Belgium benefits from these exports, which, coupled with an increase in onshore wind turbine production, allow for a reduction in nuclear generation. Luxembourg clearly benefits from these exports, which also reduces its nuclear generation. In the Netherlands and Great Britain, the decrease in the share of nuclear power is mainly due to the increase in onshore wind generation. Germany's electricity mix does not vary much, with the exception of a slight increase in the share of photovoltaic and offshore wind in favour of onshore wind and nuclear power. These observations confirm what was previously determined in terms of model behaviour. Looking at Figure 7.12c, the most notable variations concern the shares of onshore wind, solar, and imports, all three of which increase as the permissible limits increase, despite the share of nuclear power, confirming previous observations. Other technologies are not significantly impacted by these variations. It is interesting to note a slight increase in the share of gas-fired power plants with the increase in the penetration rate of renewables, demonstrating their role as a backup unit, compensating for the lack of production and the intermittency of renewable power sources.



(a) Productions and consumptions in TWh.



(b) Productions and consumptions in percent.



(c) Productions and consumptions in percent.

Figure 7.12: Distribution of production and consumption detailed for each country and expressed in TWh or in % as well as a distribution across the entire system expressed in % obtained for variations of ±10% and ±30% on the limits imposed on renewable power technologies compared to the reference scenario 1.1 for the year 2050.

To further observe the impact of these variations on the system, Table 7.5 is provided. It contains the amount of natural gas consumed by the entire system, the amount of carbon emit-

ted, and therefore captured and stored, by the entire system, as well as the overall cost of this system and the cost of electricity obtained by dividing this system cost by the total amount of electricity produced. In addition to the numerical observation of findings already observed and discussed, such as the increase in natural gas consumption in gas-fired power plants linked to the increase in the penetration rate of renewables in the model or the decrease in the cost of the system and therefore the price of electricity linked to the decrease in nuclear production, also linked to the increase in the penetration rate of renewables, these figures show an asymmetry of the results. Indeed, between -30% and -10%, natural gas consumption increases by nearly 2.8 TWh while it increases by 4.1 TWh between +10% and +30%. This asymmetry is also observable in the system costs. This phenomenon reflects the threshold effects in the optimal solution, that is to say, certain levels of renewable capacity make it possible to achieve more optimal solutions (for example, by avoiding the use of expensive technologies). This property demonstrates that the optimisation of an energy model cannot rely on simple proportional approaches. This nonlinearity highlights another important point: changes to the initial constraints impact the overall system result. While seeking to optimise the total system cost, this can lead to non-linear changes in energy flows or technology choices. Therefore, uncertainty about the maximum limits of renewable installations not only creates a quantitative margin of error but also a risk of qualitative changes in the optimal system configuration.
A variation of ±30% in the renewable energy installation limits results in a variation of approximately ±6 TWh in natural gas consumption, representing a relative variation of ±6% in the system's natural gas consumption. The cost of the overall system, meanwhile, varies by up to ±3.5 billion euros per year, representing a relative variation of ±2%. These figures demonstrate a low sensitivity of the results to uncertainties related to the installation capacity of renewable technologies. However, it should be kept in mind that this stability of the entire model masks relatively significant internal adjustments, as shown by the results from France.

	-30%	-10%	Scenario 1.1	+10%	+30%
NG consumed [TWh_{CH_4}]	91.38	94.176	97.514	99.126	103.254
CO_2 emitted [Mt_{CO_2}]	10.318	10.637	10.981	11.168	11.543
Global cost [$G€_{2050}$/yr]	171.561	169.057	168.002	167.063	165.476
Cost of electricity [$€_{2050}/MWh_{el}$]	82.55	80.8	80.04	79.38	78.27

Table 7.5: Variations of the total natural gas consumption, total carbon emission, global cost and the electricity cost over scenario 1.1 and its variations on the limits imposed on renewable power sources for the year 2050.

Scenario 1 - Conclusion

The limits imposed on renewable power sources in this scenario are derived, for solar, wind and batteries, from a distribution proportional to the surface area of the territory and the length of the maritime coasts of each country from the results obtained by a detailed model integrating all energy sectors and studying the entire European Union developed by the European electricity and gas managers. This distribution is not optimal because it does not take into account capacity factors representing meteorological data. The limits obtained by this distribution are therefore questionable. Other distributions could have been considered, such as a distribution based on the electricity consumption of each country, for example. This demonstrates the

difficulty in estimating the maximum installable capacities in each country. Starting from a spatial basis is complex because it is necessary to know the surface area of the spaces that can be developed for the construction of these installations, while knowing that the space required for a 1 GW wind or solar installation also depends on the efficiency, which depends on technological advances.
These imposed limits represent a 500% global increase compared to the renewable capacities installed in 2019. It is difficult to quantify whether this increase is achievable by 2050 in terms of budget and resources. The TYNDP report proposes a 1200% global increase compared to the renewable capacities installed in 2019. In this TYNDP report, the authors acknowledge that this increase will require addressing numerous challenges in terms of logistics, budget, policy, and land management but are unable to quantify these last points.
Scenario 1.2, analysing the variations in these limits, demonstrated that the system as a whole was fairly stable in the face of these variations, but this overall stability concealed more or less strong variations within countries, which had the effect of modifying the choice of technologies to be installed more or less strongly depending on the thresholds crossed by these variations, as in the Netherlands which uses solar energy when the capacity limit exceeds 30%. This demonstrates the non-linearity of the model's behaviour in the face of these variations, making it very complex to predict its evolution based on the refinement of these predictions regarding the renewable capacities that will be available in 2050.

7.2.3 Scenario 2 - Limit on nuclear

Until now, no limits were imposed on the installation of nuclear power generation units. Nuclear power in Europe is a controversial subject, sometimes swinging towards a shutdown with the argument of nuclear waste management and safety and sometimes towards continuity and reinvestment in this technology with the arguments of the constant supply of decarbonised energy, therefore not dependent on weather conditions, being less expensive than other production units and occupying less space benefiting from excellent specific energy with a perfect example of recent Belgian news on this subject [10]. Therefore, the study of 2 sub-scenarios with the aim of studying the impact of limitations on the maximum installable capacities in nuclear technologies on the model is conducted.

Scenario 2.1

The first scenario aims to set the maximum installable capacity limit to the capacity installed in 2019, meaning that the model can at most renew the 2019 nuclear fleet, which is already a technical complexity that is not easy to achieve [41]. Concretely, $\overline{\kappa}^n$ of the nuclear node is set to the value given in Tables 6.1, A.4, A.5, A.6, A.7 and A.8 reporting the nuclear capacity installed in 2019 in each country of the study. The limits on renewable capacities and cross-border electricity connections are the same as those set in scenario 1.1. In addition, in order to best reflect reality in terms of carbon storage capacity, especially for the Netherlands which does not have any, the maximum capacity of this storage is set to 0. The storage capacity of other countries is not limited in order to ensure that the model always has a solution and subsequently the result will be analysed. Setting this limit from this scenario in this thesis does not have a big impact given that in the previous scenario the Netherlands only stored a small amount of carbon and prohibiting the model from storing CO_2 in the Netherlands would simply have amounted to moving the installed capacity of the DAC unit present in this country to other countries.

The limitation of the installable nuclear energy capacity per country has the effect of reducing the installed nuclear energy capacity in the countries compared to scenario 1.1 which installed capacities higher than that present in 2019 as shown in Figure 7.13, except for France which compensates for the loss of other countries by increasing its nuclear installation to its maximum limit. These countries, limited in the installation of nuclear power pants, replaced this loss of production with a more substantial installation of solar panels and gas power plants for the most part, as well as an increase in the installation of offshore wind turbines in Great Britain. The use of run-of-river & water reservoir technology modelled by constant production allows in certain countries to replace a part of this nuclear energy. Some countries are no longer able to ensure large production, the CO_2 emission capture units DAC are installed mainly in France which benefits from a large nuclear fleet and good weather conditions to maximise renewable production but also in Great Britain which benefits from the relatively stable production of offshore wind turbines. The reduction of nuclear power and therefore a stable source of production requires the system to use PCCC units to ensure part of the carbon capture emitted by the CCGTs. These units, although more expensive, require nearly half as much electricity as the DACs to operate. The loss of large, inexpensive and carbon-free electricity production units therefore forces the model to resort to a more expensive and less efficient carbon capture system because it is cheaper than running more expensive electricity production units to power the DACs.

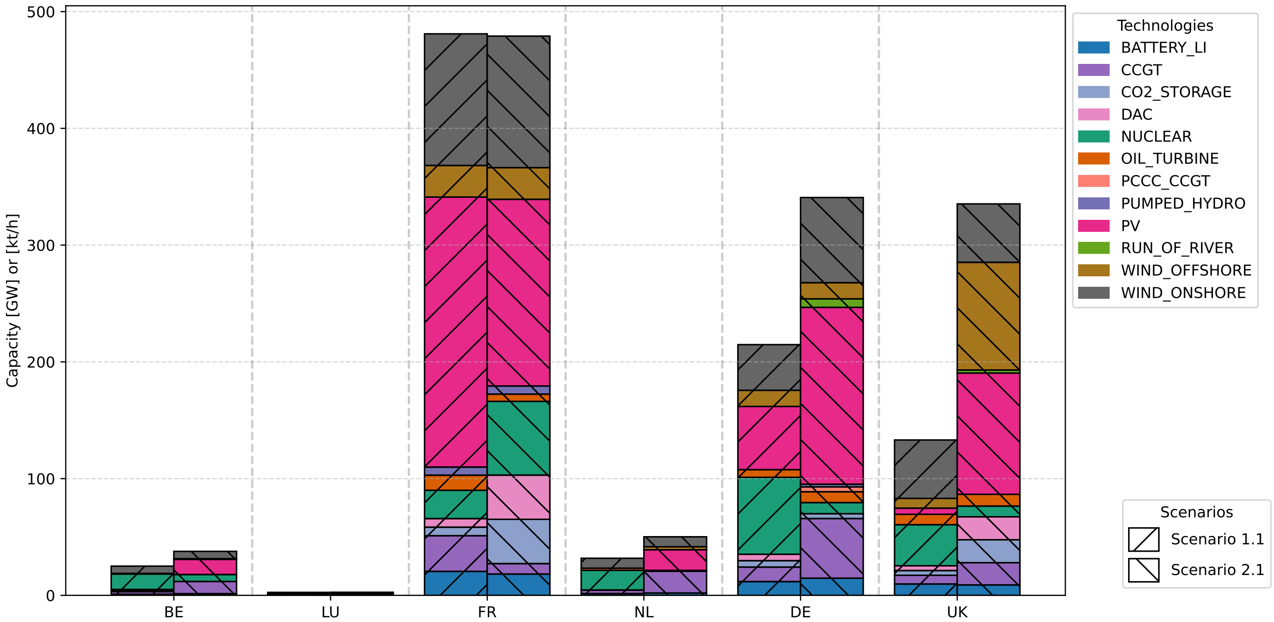


Figure 7.13: Installed capacities of each technology in the different countries expressed in GW compared across scenario 1.1 and scenario 2.1 for the year 2050.

Figure 7.14 shows the comparison between scenario 1.1 and the current scenario of the distribution of production as well as the electricity consumption according to the technologies used by the model. The decrease in nuclear production in favour of solar, gas plants and offshore wind in Great Britain. Electricity exchanges increase overall in the system. Indeed, FIGURE 7.15a showing a comparison of the installed capacities of cross-border electricity transmission lines between scenario 1.1 and the current scenario, shows an increase in the capacity of electricity exchanges on all connections in general with even the installation of additional lines such as the HVAC line linking Belgium to Germany in addition to the increase in the capacity of this same line in DC as well as the installation of an exceptionally long cable joining Germany to Great Britain. These exchanges can be observed in more detail via FIGURE 7.15b showing a diagram reporting the annual electricity exchanges between the countries. France and Great Britain appear to be major electricity exporters due to their cheaper electricity production through their significant renewable capacity and France's large nuclear production. These exports benefit all other countries, but particularly Germany and, secondarily, the Netherlands, which, without these imports, would have to rely more heavily on their gas-fired power plants.

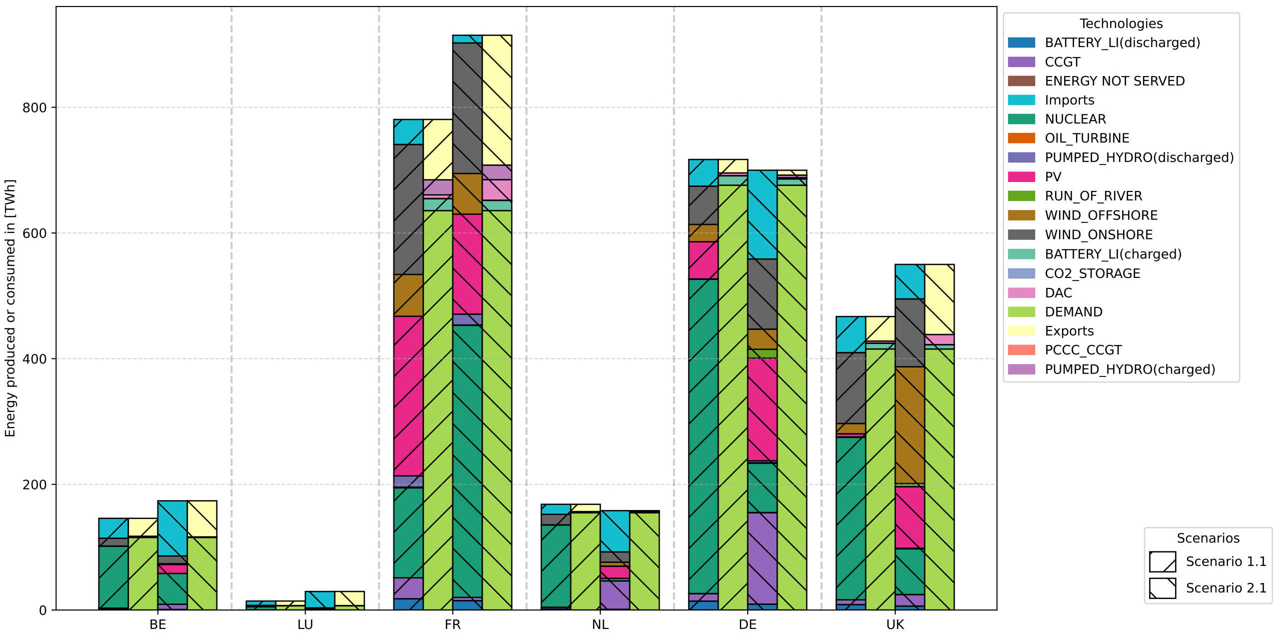
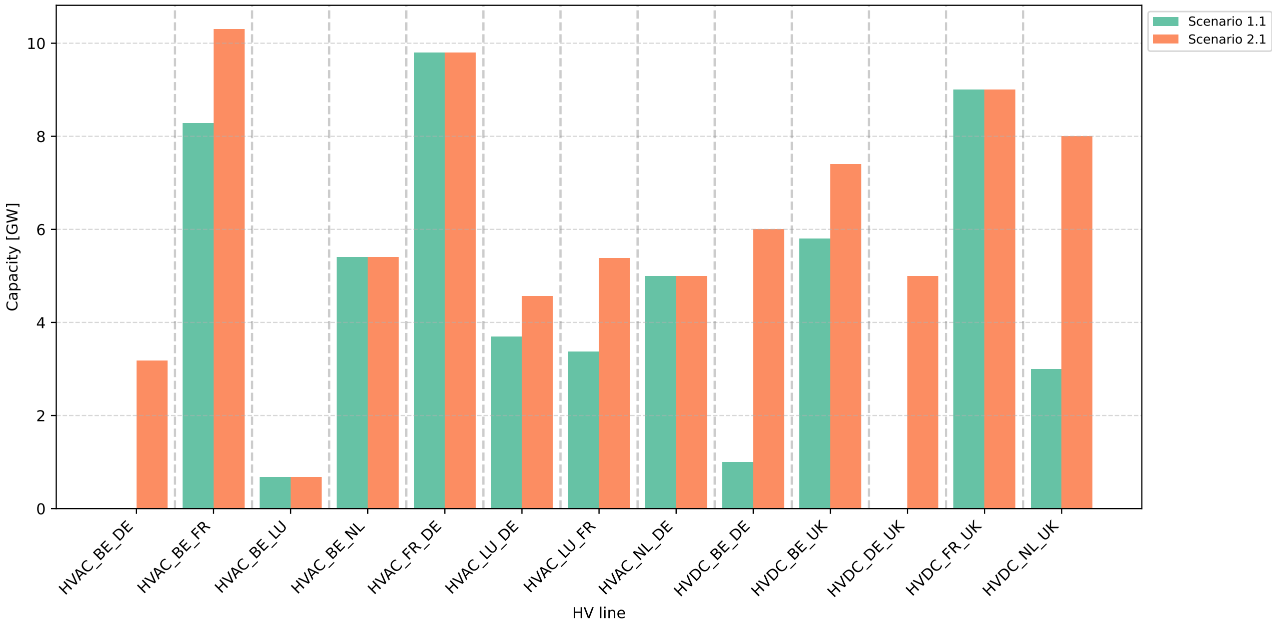
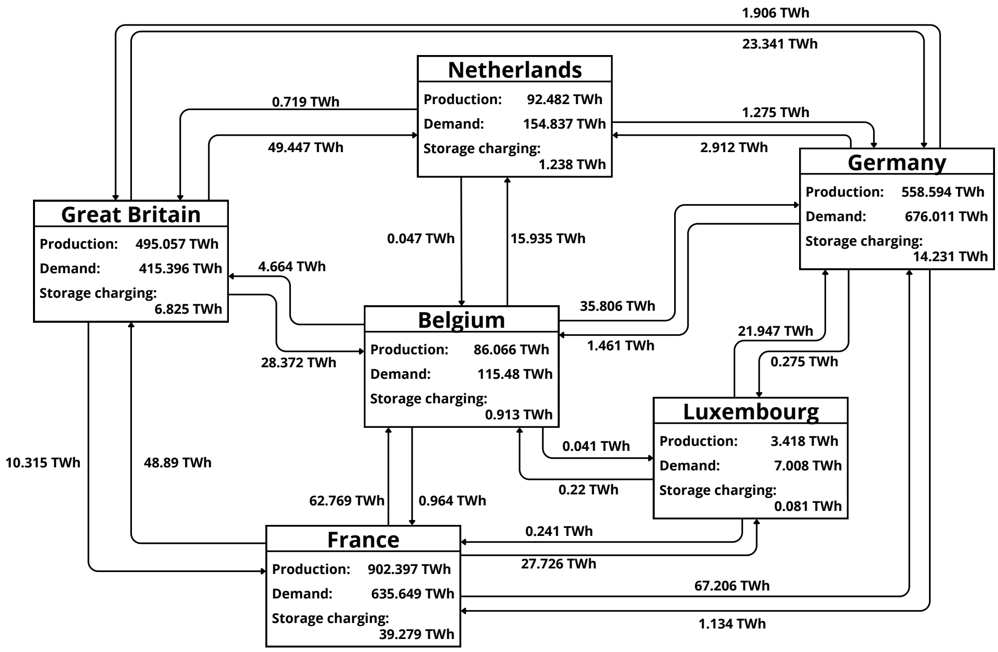


Figure 7.14: Distribution of production and consumption detailed for each country and expressed in TWh compared between scenario 1.1 and scenario 2.1 for the year 2050.



(a) Installed capacities.



(b) HV exchanges in TWh.

Figure 7.15: Comparison of the HV line installed capacities between scenario 1.1 and scenario 2.1 as well as the annual amount of electricity exchanges on these lines for scenario 2.1 over the year 2050.

In this system configuration, 40.8 Mt of CO_2, representing four times the emissions of scenario

1.1, were emitted, of which 6.72% were captured via the PCCC unit installed in Germany. The share of electricity production from nuclear power decreased by 24.34%, from 49.56% in scenario 1.1 to 25.22% in the current scenario, which led to a 6.34% increase in the share of electricity production from gas-fired power plants, thus leading to an increase of nearly 30 Mt of CO_2 that must be captured and stored. A little over 62.5% of this carbon is captured and stored in France, 30.7% is captured and stored in Great Britain and the remainder in Germany. Considering a constant rate of emission and capture, given the storage capacity of each country given by [14], each country can maintain this rate for 340 years for France, 1166 years for Great Britain and 6229 years for Germany.

The cost of this system has been significantly impacted by this limit on nuclear power, increasing from 168 billion euros per year for scenario 1.1 to nearly 189.5 billion euros per year for this scenario. Despite the decrease in cost related to nuclear power plants, which in scenario 1.1 was the largest share of the total system cost as shown in FIGURE 7.16, the increase in expenses related to the cost of gas-fired power plants and the purchase of natural gas, capture and storage systems as well as an increase in expenses related to the installation of offshore wind turbines leads to an overall increase in the system cost. It is noted that the CCGT, natural gas purchase and CO_2 capture and storage system together represent 28% of the overall system cost while the production of gas-fired power plants represents only 10.5% of the overall system electricity mix, demonstrating its heavy economic impact on the model.

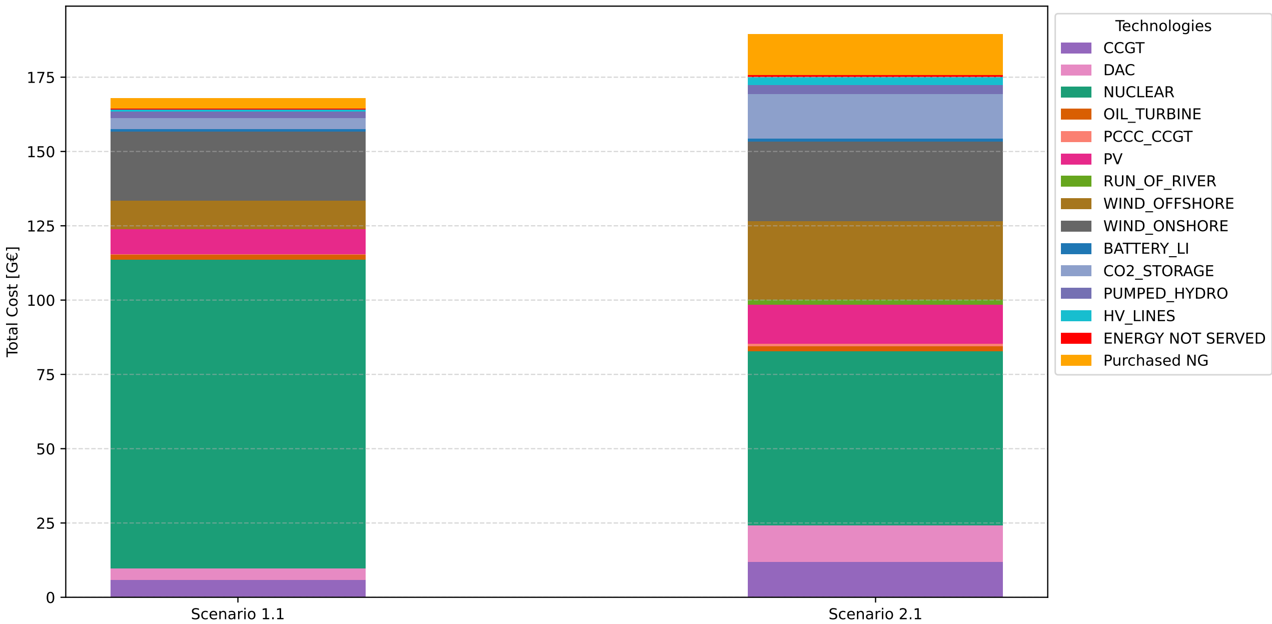


Figure 7.16: Distribution of the total cost of the system according to the different technologies used across the entire system expressed in billions of euros per year and compared between scenario 1.1 and scenario 2.1 for the year 2050.

Scenario 2.2

The second scenario considers the more radical case in which the European Union decides to completely phase out nuclear power. Specifically, the $\overline{\kappa}^n$ parameter, which sets the maximum limit that the model can install is set to zero, preventing the installation and use of nuclear energy while maintaining the limits on renewable energy and cross-border electricity connections set in scenario 1.1.

The nuclear phase-out has a significant impact on the model. FIGURE 7.17, comparing the capacity installed by the model across all countries in the system between scenario 1.1, which has no nuclear limits, scenario 2.1, which allows the model to renew the nuclear fleet in these countries in 2019, and the current scenario, which does not allow nuclear installations, shows a sharp increase in the installed capacity of gas-fired power plants and the associated capture and storage systems. Once again, the system is forced to install capture units that are more expensive and less efficient than DACs by installing PCCC units that consume less electricity, demonstrating the fragility of electricity production. The model instals the maximum number of renewable generation technologies allowed (PV, WON, WOFF, and ROR), implying a slight increase in storage capacity. The remaining lost nuclear generation capacity is replaced by gas-fired power plants.

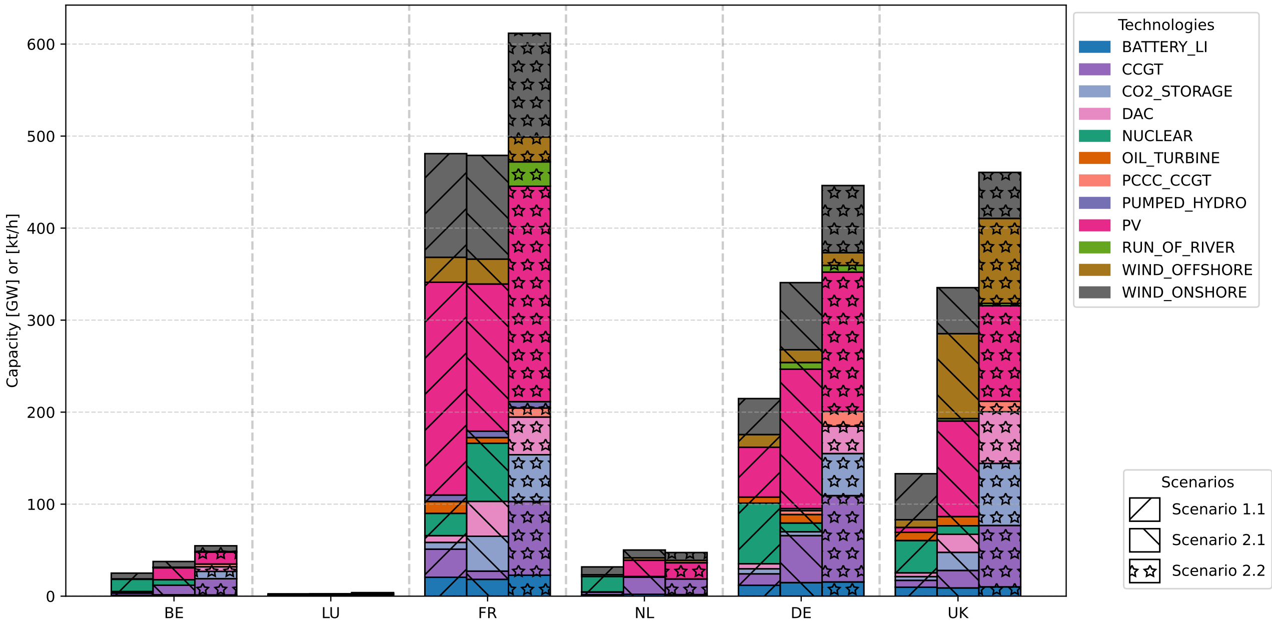


Figure 7.17: Installed capacities of each technology in the different countries expressed in GW compared across scenario 1.1, scenario 2.1 and scenario 2.2 for the year 2050.

FIGURE 7.18 represents the distribution of electricity production and consumption in each of the countries in scenarios 1.1, 2.1 and the current scenario, allowing for comparison. As observed in FIGURE 7.17, electricity production from nuclear power is first replaced by renewable power sources up to their maximum limit and the remaining share is replaced by electricity production from gas-fired power plants. This increase in the use of fossil fuels leads to an increase in carbon emissions and therefore in the consumption of capture and storage systems. In this scenario, this represents a total electricity consumption of around 145 TWh, which represents a relative increase in demand of 7%. In the current configuration for which the limits of renewable production capacity installation are reached, an increase in demand or a decrease

in renewable production following adverse weather factors would lead to an increase in the electricity production of gas-fired power plants and therefore an increase in the consumption of the carbon capture and storage systems emitted which will have to be ensured by renewable electricity production which is limited by the imposed capacity limits.
Electricity trade between countries has declined significantly due to the reduction in overproduction that some countries, such as France, had from their nuclear production, which they exported to their neighbouring countries. However, trade is still higher than in scenario 1.1 due to the high penetration rate of renewable energy.

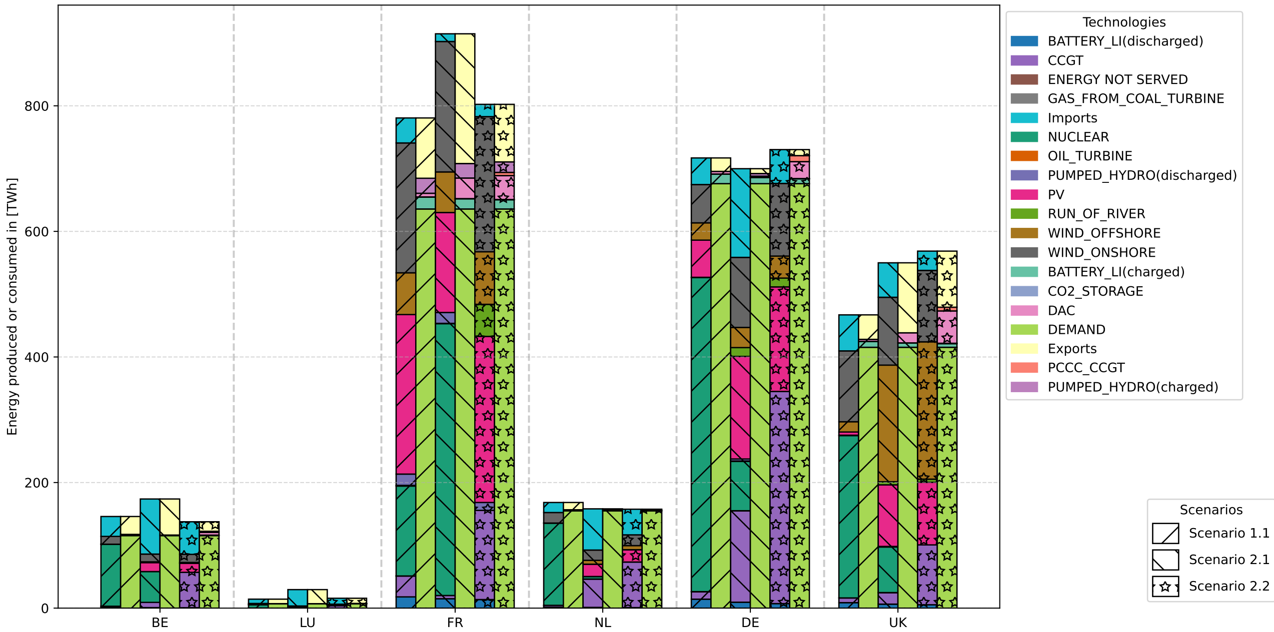


Figure 7.18: Distribution of production and consumption detailed for each country and expressed in TWh compared between scenario 1.1, scenario 2.1 and scenario 2.2 for the year 2050.

In order to better observe the role of the gas-fired power plant in this context, Table 7.6, which provides a comparison of the operational results of CCGTs across the various scenarios studied, shows that this technology no longer serves solely as a backup generation source from scenario 2.1 onwards for countries such as the Netherlands and Germany that do not have large nuclear facilities. Consequently, gas-fired power plants no longer play the role of a backup source but as a basis for the electricity mix, ensuring a significant and regular share of the electricity mix. This behaviour is all the more visible in this last scenario, which does not benefit from stable nuclear production.

Scenario	Country	Peak power [GW]	Operating time [h]	Load factor [%]
Scenario 0.2	BE	3.883	1031	11.202
	LU	0	0	0
	FR	39.26	1436	12.514
	NL	3.197	993	10.963
	DE	7.598	1021	10.932
	UK	16.426	1228	12.142
Scenario 1.1	BE	2.203	1000	9.723
	LU	0.135	1121	10.145
	FR	30.561	1549	12.438
	NL	2.941	1143	10.699
	DE	12.439	1239	11.006
	UK	7.431	1178	11.506
Scenario 2.1	BE	10.452	1083	9.06
	LU	0.862	1268	12.197
	FR	8.937	1567	6.603
	NL	18.567	4658	27.772
	DE	51.071	5323	35.549
	UK	19.027	1548	11.023
Scenario 2.2	BE	17.693	5582	36.335
	LU	1.091	5519	36.335
	FR	80.127	4029	20.23
	NL	16.948	6414	48.88
	DE	93.839	6606	41.099
	UK	66.738	3338	16.303

Table 7.6: Comparison of gas power plant results in each country of the system across scenario 0.2, scenario 1.1, scenario 2.1 and scenario 2.2 over the year 2050.

Assuming a constant rate of use of gas-fired power plants and therefore constant carbon emissions, the underground storage systems of the global system will be full in 318 years. This leaves a sufficiently large time margin to find solutions for using this CO_2, such as methanation to produce synthetic natural gas by combining carbon dioxide and hydrogen, allowing these stocks to be emptied.

The optimal cost determined by the solver is 246.5 G€/yr, which illustrates the enormous impact on the system cost of the nuclear shutdown, which no longer allows for the supply of a large quantity of cheap, carbon-free electricity. The cost price of electricity is therefore 111.76 $€_{2050}/MWh_{el}$, which is a relative increase of just over 26% compared to the price in the previous scenario. Capturing and storing these 127.403 Mt of CO_2 emissions, which represents 22% of the carbon emissions of these same countries in 2019, costs 91.4 billion euros per year, which represents 37% of the system cost. 12.5% of the system cost is used by gas-fired power plants and 17.6% for the purchase of natural gas. In total, 67.1% of the total system cost allows for the production of 32% of the total electricity produced in the system, which has a significant impact on the price of electricity.

Scenario 2 - Conclusion

During the study of these two sub-scenarios, the impact of the political decision regarding the future of nuclear power on the model could be observed. The most radical decision to do without nuclear energy illustrated by scenario 2.2 demonstrates the system's dependence on natural gas based on the production of renewable resources. The higher the system's penetration rate of renewables in its electricity production fleet, the less the use of natural gas will be necessary. This dependence on gas-fired power plants leads to high volatility in electricity cost prices and, in order to meet the objective of net-carbon neutral emissions, requires the installation of very expensive capture and storage systems. Beyond the aspect of safety and nuclear waste management, stopping the use of nuclear energy has a very significant social and economic impact leading to a significant electricity price. To overcome this, the solution would be to increase the installed capacity of renewable generation technologies, while not knowing whether the limits set are achievable by 2050 and whether it is possible to increase these limits as discussed in SUBSECTION 7.2.2.

The choice to maintain nuclear power in Europe is a matter of debate beyond the scope of this thesis. The aim here is to observe the economic impact of this choice and how the model responds to it. The TYNDP report, for its part, has decided and opted for the renewal of the nuclear fleet. Indeed, the authors consider the installation of 105 TW of nuclear capacity in all 27 member states of the European Union, which represents 10 TW more than the installed capacity in 2024, thus taking into account a slight increase. The question of primary energy reserves is important to address in order to determine the operating life of such a system. According to a 2022 article in Science&Vie [42], uranium reserves are sufficient for 165 years. However, according to [43], breeder reactors using alternative fuels like thorium could extend resource lifetimes from 1650 years to 4.3 billion years by taking into account all planetary reserves. This type of nuclear power plant already exists, such as the French Superphénix reactor [44], but its deployment is still limited due to persistent technical, economic, and societal challenges.

7.2.4 Scenario 3 - Natural gas price study

Until now, the price of natural gas was fixed at that of 2019 simply increased by inflation which gave a purchase price of natural gas of 36.17 $€_{2050}/\mathrm{MWh_{NG}}$. However, the price of gas is very volatile as demonstrated in recent years where the price of natural gas went from 3.89 $€/\mathrm{MWh_{NG}}$ according to the TTF index dated 18 May 2020 to 339.2 $€/\mathrm{MWh_{NG}}$ on 22 August 2022 and fluctuated between 30 and 60 $€/\mathrm{MWh_{NG}}$ between July 2024 and May 2025 being very unstable according to the curves of the TTF index serving as a reference basis for the price of European natural gas [27]. Given these strong fluctuations caused by many reasons, the future price of natural gas is a great source of uncertainty in the model and this is why this scenario 3 is created in order to study the impact of the variation of this price on the model.

Increasing natural gas prices would simply result in it being replaced by another type of combustion plant that does not see its fuel price increase. Therefore, all other fuel plant installations are prevented by setting its maximum capacity $\overline{\kappa}^n$ to 0 as well as its pre-installed capacity $\underline{\kappa}^n$. By Eq. 5.3, the only possible solution by the model is to not install any additional capacity, thus preventing the use of these technologies by the model. This choice can be justified by the fact that all these plants use fossil fuels that are not replaceable and which, according to the Science&Vie article [42], have a lifespan, given the available reserves, of 135 years for coal, 52 years for oil and 200 years for gas (conventional and unconventional), considering a constant consumption of these resources. It is therefore imperative to replace technologies using these resources that are not sustainable over time. But for gas-fired power plants, it is still possible to power them with hydrogen or even e-methane produced by combining hydrogen ideally produced by electrolysis powered by green electricity and CO_2, which makes it possible to recover the CO_2 stocks captured and stored in the soil. Regarding biomass power plants and waste combustion plants, their shutdown can be justified by various arguments, but the most convincing is that the replacement of gas-fired power plants, which would have become more expensive following the variation in the cost of gas, would require the combustion of enormous quantities of biomass and waste. This significant quantity of biomass would no longer be solely fuelled by waste from the forestry sector, agricultural waste and organic waste from the agri-food sector but would have much greater needs, which would lead to the obligation of cultivation specifically dedicated to fuelling these power plants, leading to conflicts in land and resource management. For waste combustion plants, the objective is to reduce waste by limiting it at the source and maximising recycling, which is contradictory with a large plant requiring large quantities of waste to fuel it.

Another result that will be studied is the price of natural gas from which hydrogen becomes more interesting with hydrogen produced from electrolysis. To operate the electrolysers, this requires energy which leads to an overall balance of electricity consumption. Indeed, the formula to produce 1 GWh of electricity by combining an electrolyser and a gas plant running on hydrogen is given by Eq. 7.3. Taking the example of an AEC-type electrolyser, the total balance to produce 1 GWh of electricity is a total consumption of 2.425 GWh of electricity leading to a net consumption of 1.425 GWh. The scenarios in which hydrogen has a future are the scenarios which have the possibility of increasing their electricity production in order to meet this additional consumption. From then on, 2 sub-scenarios will be studied: the first starts from the limits set by scenario 2.1 limiting renewable capacities and authorising the renewal of the nuclear fleet based on that installed in 2019, the second considers the shutdown of nuclear power but, given the non-possibility of increasing production in view of the results obtained for scenario 2.2 showing that the model already used the maximum of the limits imposed on renewables and in view of the questionability of these limits, authorised double the limits imposed on solar, wind and batteries than what had been set in scenario 1.1. The limits imposed on hydroelectric technologies (HPS and ROR) based on a serious study of capacities not yet exploited according to the continent will not be modified.

$$\text{Electrical consumption of an electrolyser to supply the CCGT with } H_2 = \frac{1}{\text{efficiency of the CCGT}} \cdot \frac{1}{\text{Efficiency of the EC}} \ [\text{GWh}_{\text{el}}/\text{GWh}_{H_2}] \ . \tag{7.3}$$

Scenario 3.1

In this scenario 3.1, the model is limited in its capacity to install technologies by limiting the maximum capacities, $\overline{\kappa}^n$, of renewable technologies which are given in Table A.14 with as a reminder a choice of the type of battery which are lithium-ion because cheaper than sodium-ion batteries whose maximum capacity $\overline{\kappa}^n$ is fixed at zero thus preventing its installation, nuclear is limited by authorising at most to renew the nuclear fleet of 2019, that is to say by fixing $\overline{\kappa}^n$ at the value of the installed capacities given by TABLE 6.1 and TABLES A.4 to A.8. The installed and maximum electrical transmission capacities are the same as scenario 1.1 and are given in TABLE A.15. For all technologies except the electrical transmission lines, the pre-installed capacity $\underline{\kappa}^n$ is always fixed at 0 assuming that the entire electrical fleet is to be rebuilt.

FIGURE 7.19 shows the evolution of hydrogen and natural gas consumption within the gas-fired power plant according to the cost of natural gas, which varies from 5 $€_{2050}/\text{MWh}_{\text{NG}}$ to 505 $€_{2050}/\text{MWh}_{\text{NG}}$. This graph shows that hydrogen produced from an electrolyser becomes economically attractive from a natural gas cost of 145 $€_{2050}/\text{MWh}_{\text{NG}}$. Its use increases linearly up to 215 $€_{2050}/\text{MWh}_{\text{NG}}$ before decreasing its growth and reaching a plateau around 65 TWh of hydrogen consumed annually across the entire system, which makes it possible to supply 38.35 TWh of electricity, representing 1.8% of the total net production (without taking into account the electricity discharged by storage means). On this same graph, between 5 and 145 $€_{2050}/\text{MWh}_{\text{NG}}$ of natural gas, despite the non-use of hydrogen, the consumption of natural gas in the gas-fired power plant decreases. This behaviour is explained by the decrease in the installation of gas-fired power plants as shown in FIGURE 7.20, accompanied by a decrease in their production, which becomes less economically profitable than other technologies with the increase in the price of its primary energy. In this configuration, when the price of natural gas increases, the electricity production of gas-fired power plants is replaced by a larger share of nuclear production as well as PV and hydroelectric production from ROR units, coupled with a small increase in hydroelectric storage capacities to compensate for the loss of flexibility of gas-fired power plants as shown in FIGURE 7.21.

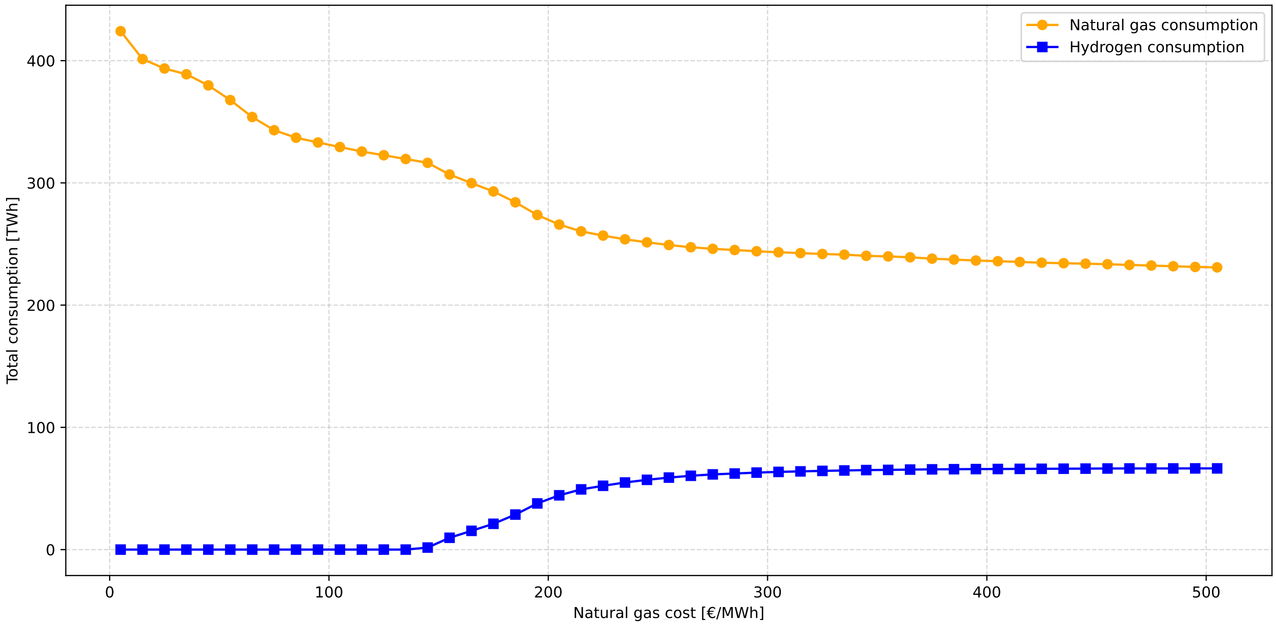


Figure 7.19: Evolution of annual consumption, expressed in TWh, of natural gas and hydrogen by the entire CCGT system as a function of the purchase price of natural gas obtained for scenario 3.1 for the year 2050.

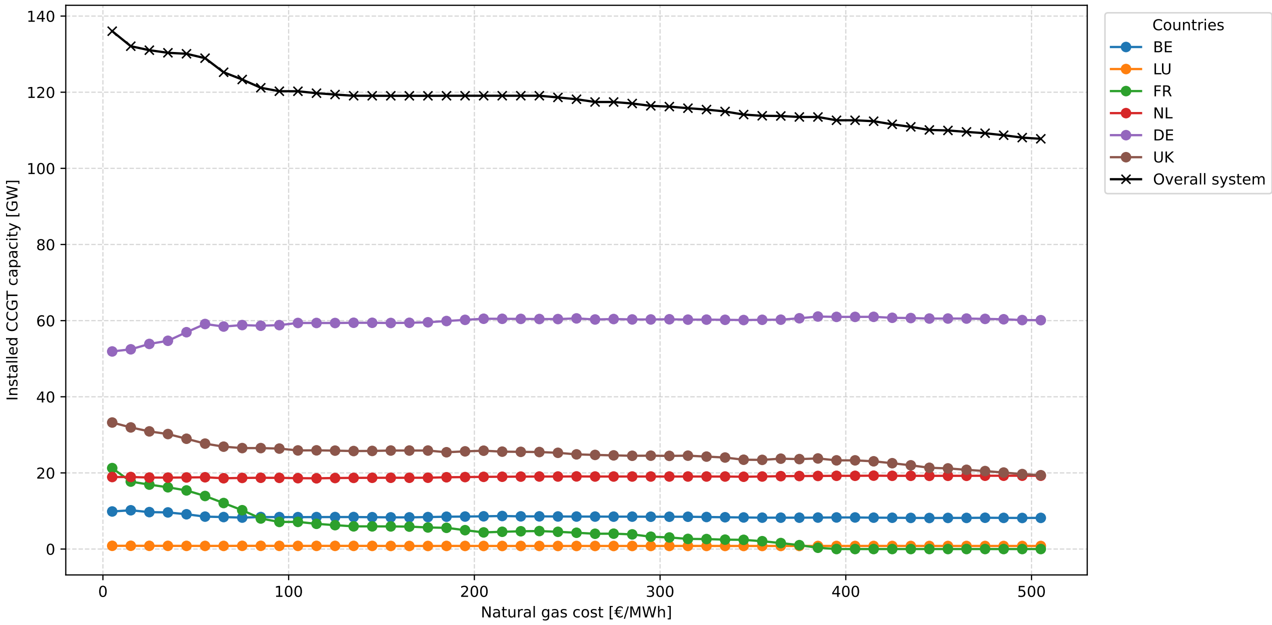


Figure 7.20: Evolution of installed capacity of CCGTs in each country as well as the sum of these capacities installed across the entire system, expressed in GW, as a function of the purchase price of natural gas obtained for scenario 3.1 for the year 2050.

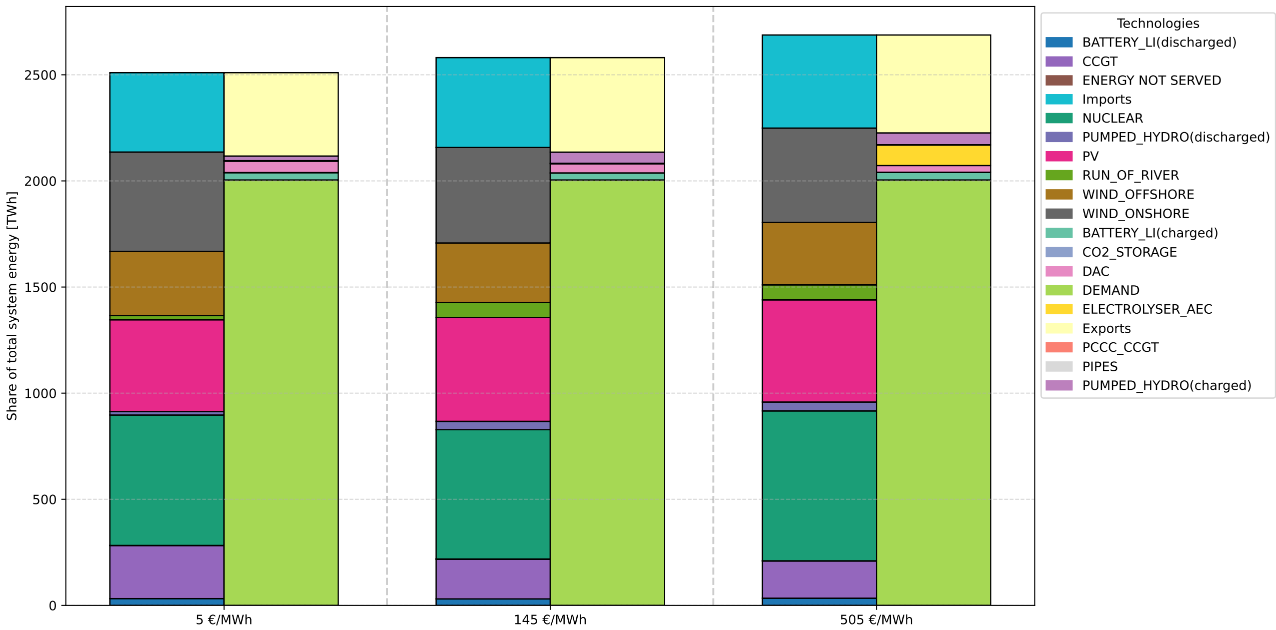


Figure 7.21: Comparison of the distribution of production and annual electricity consumption of each asset across the entire system, expressed in TWh based on the purchase price of natural gas obtained for scenario 3.1 for the year 2050.

The plateau reached by the use of hydrogen in gas-fired power plants shown in FIGURE 7.19 can be justified by FIGURE 7.22, which shows the evolution of the installed capacities of electricity production technologies (PV, WON, WOFF and ROR) on the entire system as a function of the purchase price of natural gas compared to the maximum limit imposed on each of these technologies. In this figure, the model reaches the maximum installation of electricity production technology for a gas price equivalent to 215 €$_{2050}$/MWh$_{NG}$, which corresponds to the beginning of the decrease in the increase in consumption, and therefore in production, of hydrogen. This explains the plateau obtained in hydrogen consumption, which is due to reaching the limit of electricity production. Since the system cannot produce more electricity, it cannot supply more power to the electrolysers producing this hydrogen, thus limiting its production. Between 215 €$_{2050}$/MWh$_{NG}$ and 295 €$_{2050}$/MWh$_{NG}$ of natural gas purchases, hydrogen production increases again very slightly, which can be explained by the addition of storage capacity allowing a larger part of the production of gas-fired power stations to be replaced, which reduces natural gas consumption and allows a little more hydrogen to be produced by electrolysis.

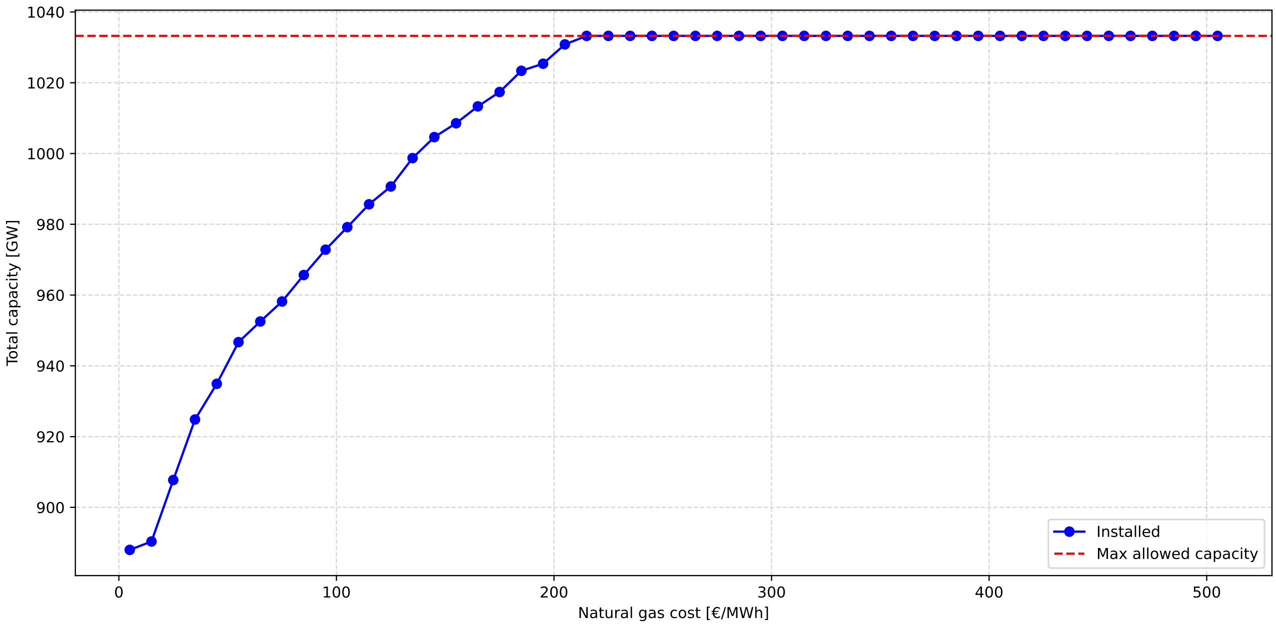


Figure 7.22: Evolution of the installed capacities of electricity production technologies (PV, WON, WOFF, NK and ROR) as a function of the purchase price of natural gas compared to the maximum limit imposed on each of these technologies obtained for scenario 3.1 for the year 2050.

To understand how hydrogen fits into this electricity mix, the results obtained associated with a natural gas price of 505 €$_{2050}$/MWh$_{NG}$ will be analysed. First, FIGURE 7.23 shows the average daily hydrogen production in each country over the entire year, as well as the average daily consumption of this hydrogen by gas-fired power plants in each of these countries. The first notable fact is that two countries, France and Great Britain, produce the hydrogen of all other countries. The choice of these countries for the model is explained by their large nuclear production capacity which can ensure the electricity production necessary for their own demand coupled with good weather conditions allowing the use of this excess electricity production from renewable power technologies to power the electrolysers to produce hydrogen which will then be entirely exported. Germany is the leading consumer of French hydrogen, and the Netherlands is the leading consumer of British hydrogen due to the coincidence of production and consumption profiles. This is confirmed in FIGURE 7.24, which shows the annual hydrogen exchanges in the pipelines. Hydrogen fuels 27% of all gas-fired power plants, with the remainder supplied by natural gas. This share is becoming dominant, particularly in the Netherlands, reaching 63.69% and even 41.16% in Belgium. Luxembourg and Germany have a hydrogen supply share of 20.15% and 25.76%, respectively.

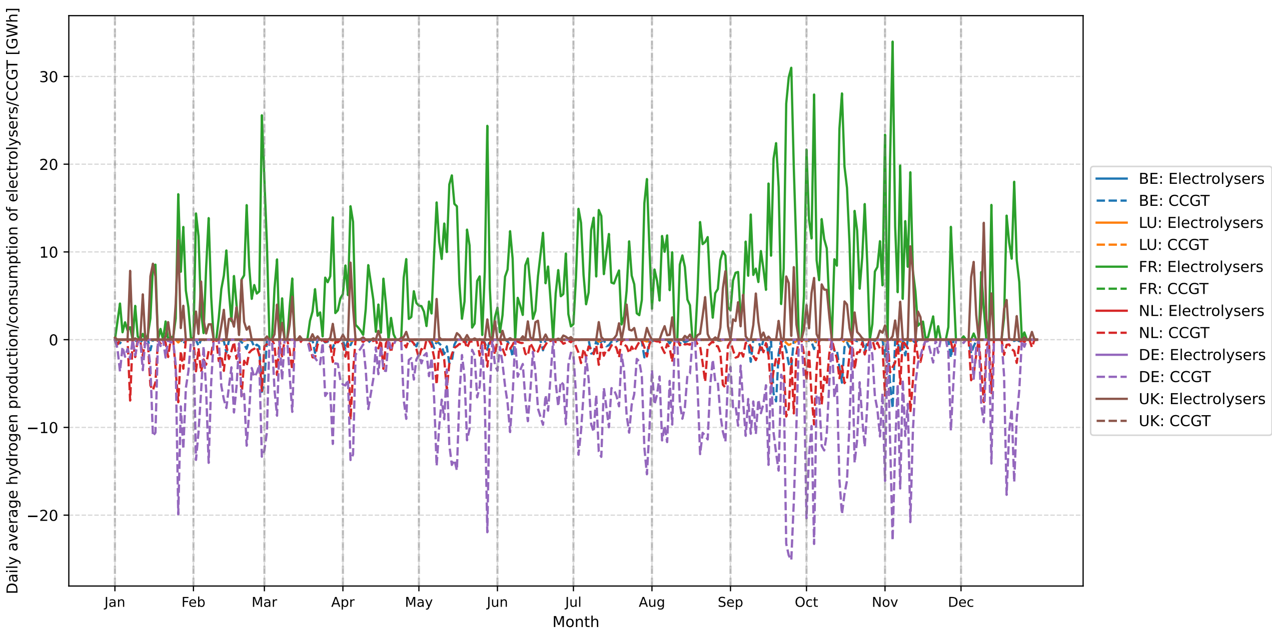


Figure 7.23: Average daily production and consumption of hydrogen in electrolysers and CCGTs for each country in the system obtained by scenario 3.1 for a natural gas purchase price of 505 €$_{2050}$/MWh$_{NG}$ for the year 2050.

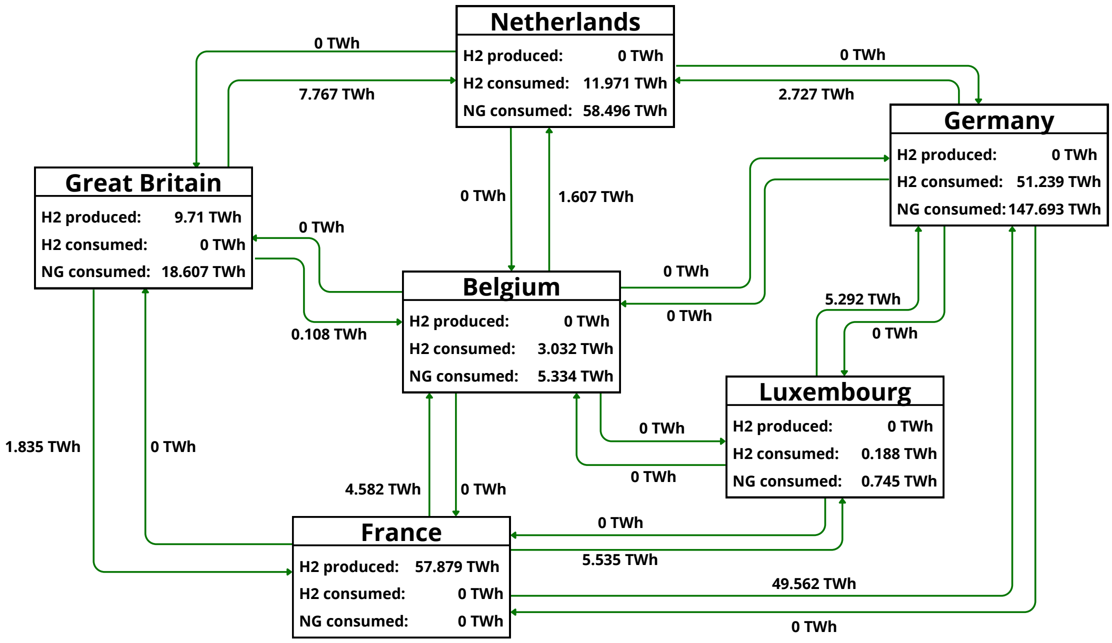
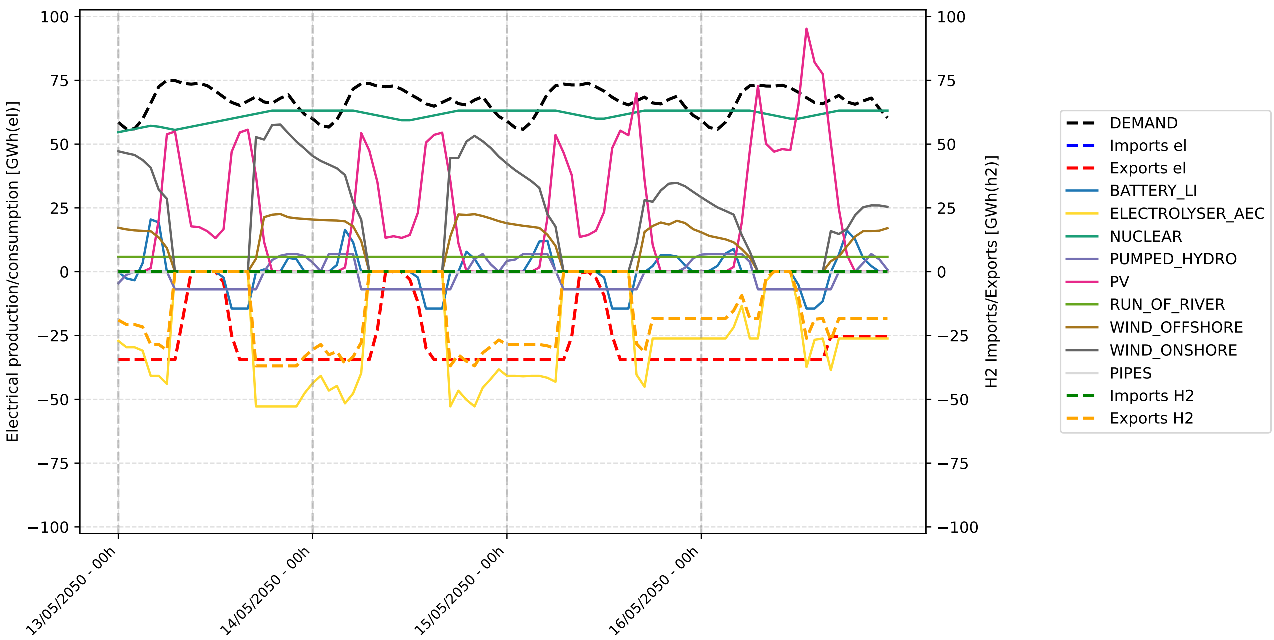
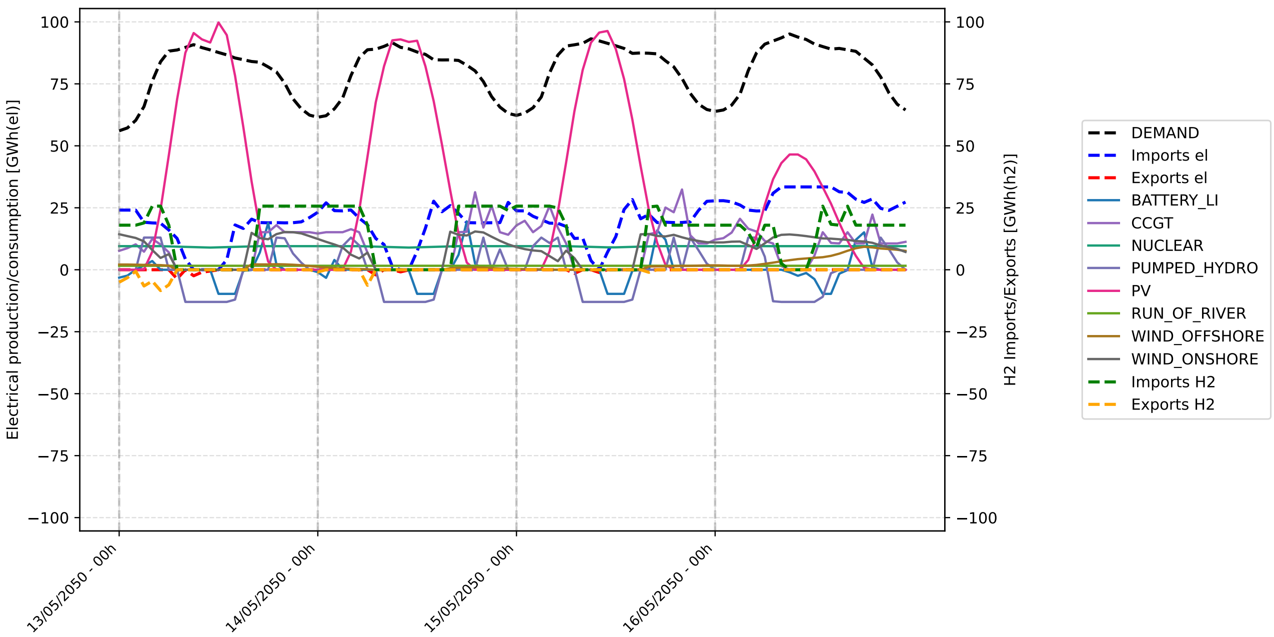


Figure 7.24: Quantity of hydrogen exchanged annually in the pipes connecting the countries as well as the annual production and consumption of hydrogen and natural gas of each country in the system obtained by scenario 3.1 for a natural gas purchase price of 505 $€_{2050}/\mathrm{MWh}_{\mathrm{NG}}$ for the year 2050.

To take a closer look at the interactions between hydrogen and other production technologies, Figure 7.25 is provided. This figure represents the electricity production and consumption of each technology as well as the total electricity and hydrogen imports and exports for France and Germany, zoomed in on the period from May 13 to 17, which was chosen arbitrarily. Figure 7.25a shows that France produces hydrogen from an alkaline electrolyser, which is therefore the most advantageous type of electrolyser in this configuration of the electrical system, during the night when onshore and offshore wind turbines produce electricity that is not necessary for the country's own consumption, which is ensured by maintaining stable nuclear production. The unusual appearance of the solar panel production profile shows the curtailment carried out to avoid overproduction in the middle of the day. Germany receives almost all of this hydrogen produced as shown in Figure 7.25b, allowing it to meet its nighttime electricity demand, which cannot be produced solely by wind turbines, which are not sufficient on their own.



(a) France.



(b) Germany.

Figure 7.25: Hourly electricity production and consumption in France and Germany between 13 and 17 May 2050, as well as their electricity and hydrogen import and export, obtained by scenario 3.1, considering a natural gas purchase price of 505 $€_{2050}/\mathrm{MWh_{NG}}$.

The cost of such a system increases in a quasi-linear manner, leading to an electricity price ranging from 83.12 $€_{2050}/\mathrm{MWh_{el}}$ when the purchase price of natural gas is at 5 $€_{2050}/\mathrm{MWh_{NG}}$

to 140.97 €$_{2050}$/MWh$_{el}$ when the purchase price of natural gas is at its maximum, i.e. 505 €$_{2050}$/MWh$_{NG}$. To compare this with the cost of electricity in 2019, inflation must be reversed to compare on the same basis. Thus the cost of natural gas from which hydrogen begins to be used in the model is 145 €$_{2050}$/MWh$_{NG}$ which, brought back to 2019 euros, gives 72.94 €$_{2019}$/MWh$_{NG}$ leading to an electricity cost of 105.29 €$_{2050}$/MWh$_{el}$, or 52.96 €$_{2019}$/MWh$_{el}$ in 2019 euros. Hydrogen begins to be economically interesting in this configuration of the system when natural gas quadruples its purchase price compared to the European average of 2019 which has the effect of multiplying by a factor of 1.5 the average electricity cost of this system compared to the considered average of the electricity cost of these 6 countries reported by [37].

Scenario 3.2

In this sub-scenario 3.2, the same study on the price of natural gas is studied but using a very different model in terms of installed technology portfolio. No nuclear resources can be used by the model, so $\overline{\kappa}^n$ of the nuclear nodes of each country is set to 0. Taking into account the remarks made in Subsection 7.2.2 concerning the limits imposed on renewable power assets and in particular the distribution by country which was carried out for the PV, WON, WOFF and LI-BAT nodes, these limits will be doubled. This will allow the model not to behave as in sub-scenario 2.2 in which the model maximised the installation of renewable energy but which was not sufficient, which led to a high use of CCGTs. By increasing these limits, the model will be able to have excess electricity production allowing it to run the electrolysers and provide the system with an alternative to natural gas by producing hydrogen via the electrolysers powered by this excess electricity.

Again, Figure 7.26 shows the point at which hydrogen starts to be used and thus becomes more economically advantageous. In this configuration, this point occurs when the purchase price of natural gas exceeds 155 €$_{2050}$/MWh$_{NG}$. Then the resulting curve has the same shape as that shown in Figure 7.19 of scenario 3.1 and therefore the explanations justifying this shape are the same as before. This configuration makes it possible to achieve a near equivalent in terms of hydrogen consumption compared to the configuration of scenario 3.1, however, natural gas consumption in this case reaches a level significantly lower than the previous scenario, which is explained by a high penetration rate of renewables coupled with large storage systems making it possible to partially replace the flexibility of gas-fired power stations.

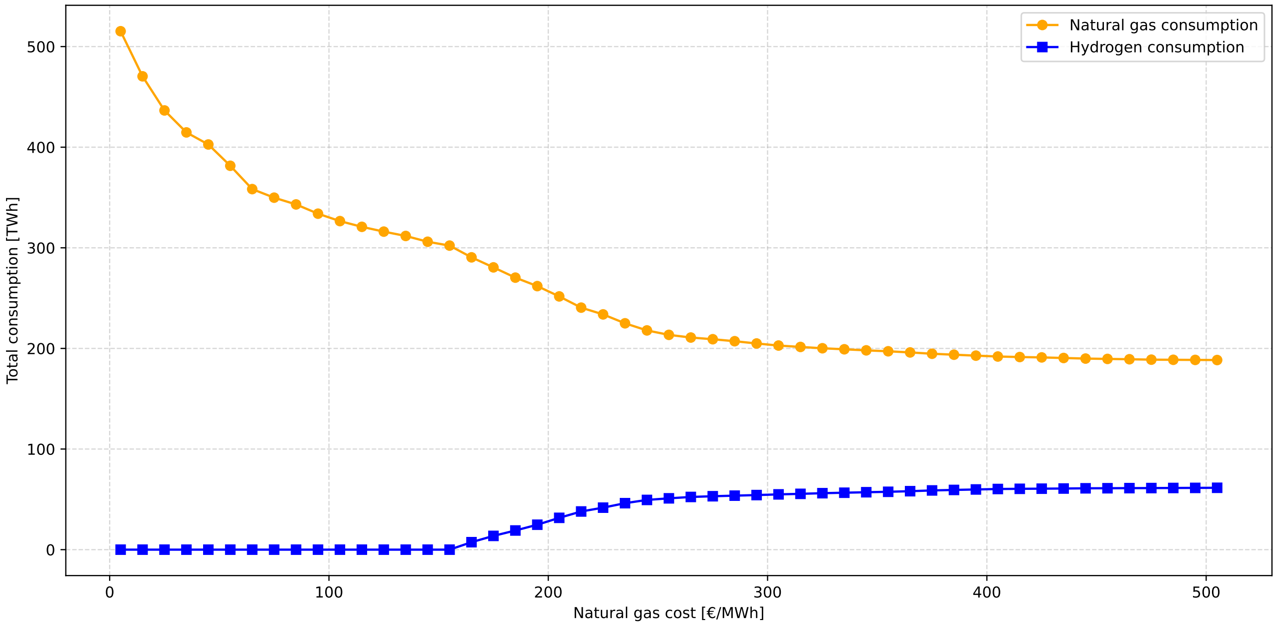


Figure 7.26: Evolution of annual consumption, expressed in TWh, of natural gas and hydrogen by the entire CCGT system as a function of the purchase price of natural gas obtained for scenario 3.2 for the year 2050.

FIGURE 7.27, showing the average daily production of hydrogen by electrolysers in each country and the average daily consumption of this hydrogen in gas-fired power plants in each country obtained for a purchased natural gas price of 505 $€_{2050}/MWh_{NG}$, shows that, again, France and Great Britain produce hydrogen for all countries in the system. This is justified by their limited capacity of electricity production technologies which are higher than their demand as well as their more advantageous weather conditions than other countries allowing them to use their renewable surplus production to supply electricity to the electrolysers in order to synthesise hydrogen and share it with other countries in the system. The consumption profile has a seasonal pattern meaning that the gas-fired power plant is more often used in winter when the electricity production of solar panels is not ideal.

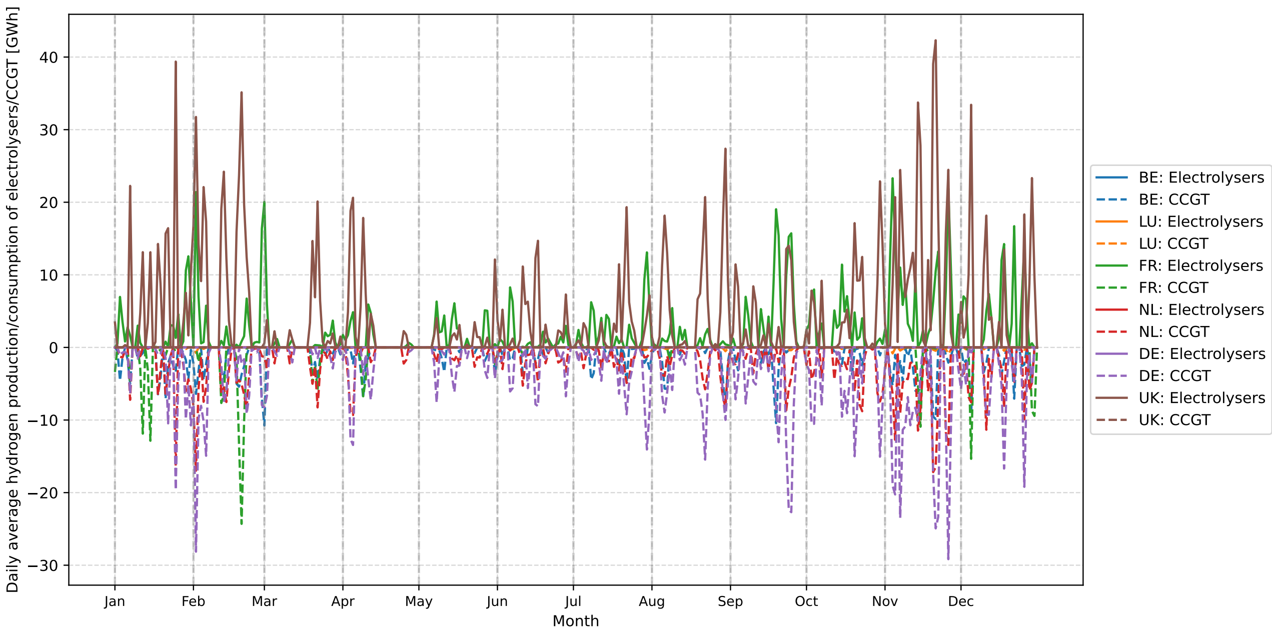


Figure 7.27: Average daily production and consumption of hydrogen in electrolysers and CCGTs for each country in the system obtained by scenario 3.2 for a natural gas purchase price of 505 $€_{2050}$/MWh_{NG} for the year 2050.

Figure 7.28 shows the annual hydrogen exchanges between countries through pipelines in a system configuration in which the purchase price of natural gas is 505 $€_{2050}$/MWh_{NG}. In this system configuration in which the model no longer uses nuclear power, Great Britain now becomes the largest hydrogen producer in the system followed by France, which is the reverse of the previous result shown in Figure 7.24. This inversion is explained by the fact that France uses its excess electricity production to supply its neighbouring countries, thus leaving it with less excess electricity to power its electrolysers. This observation was made during the analysis of scenario 2.2. The average share of hydrogen supplying gas-fired power plants across the entire system is 24.6%, thus decreasing by 2.4% compared to the configuration of scenario 3.1.

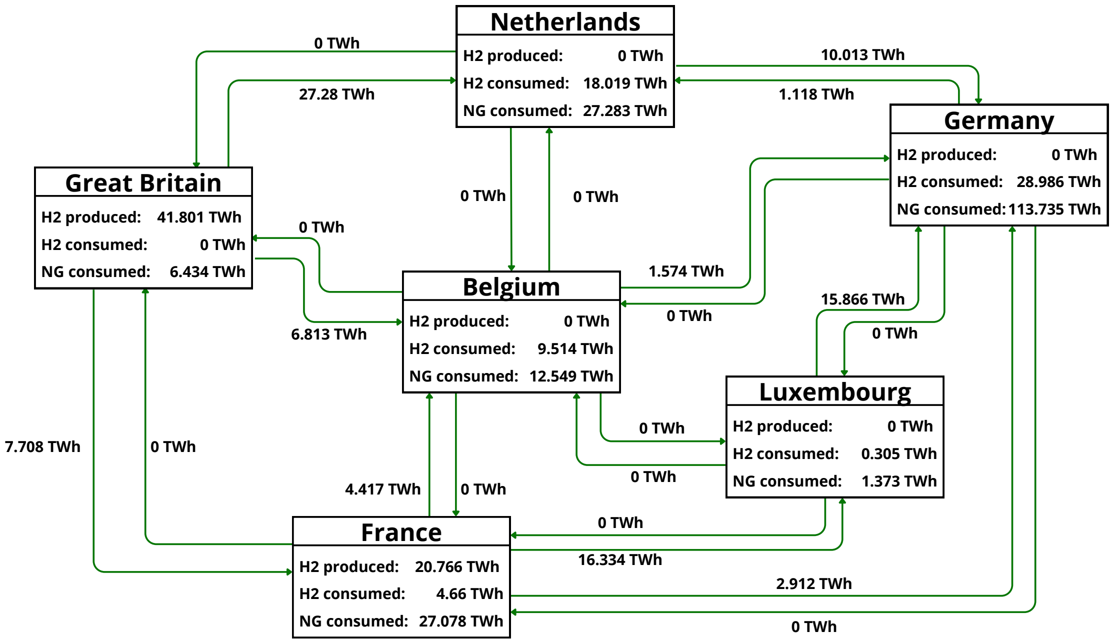
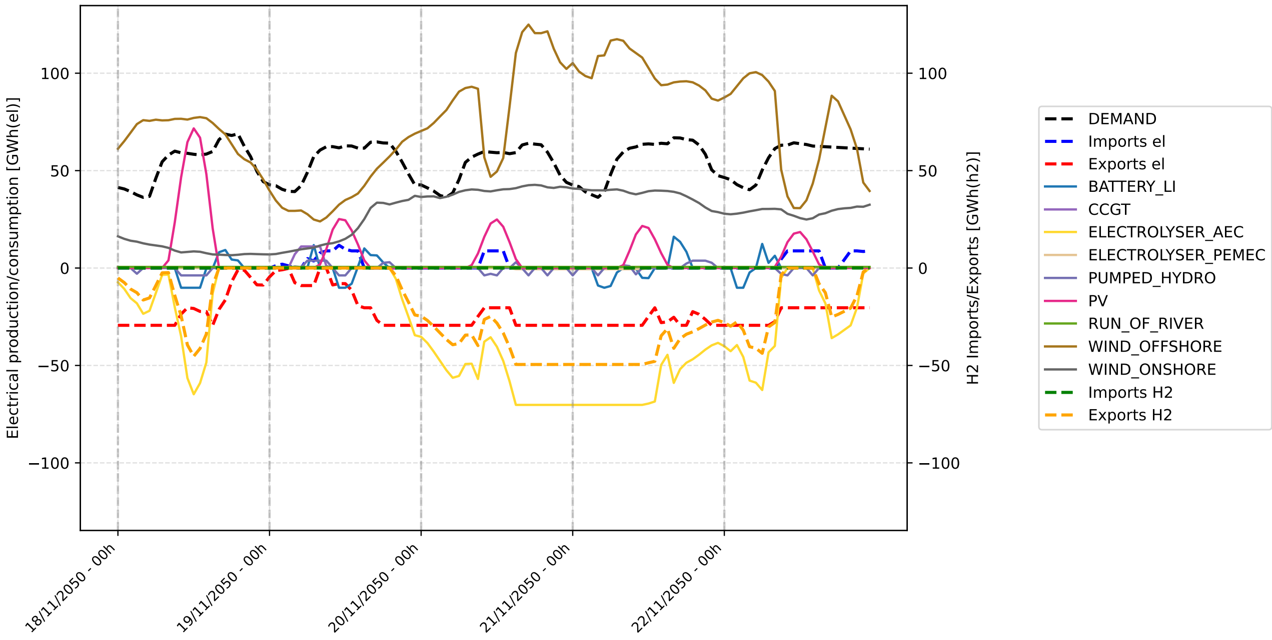
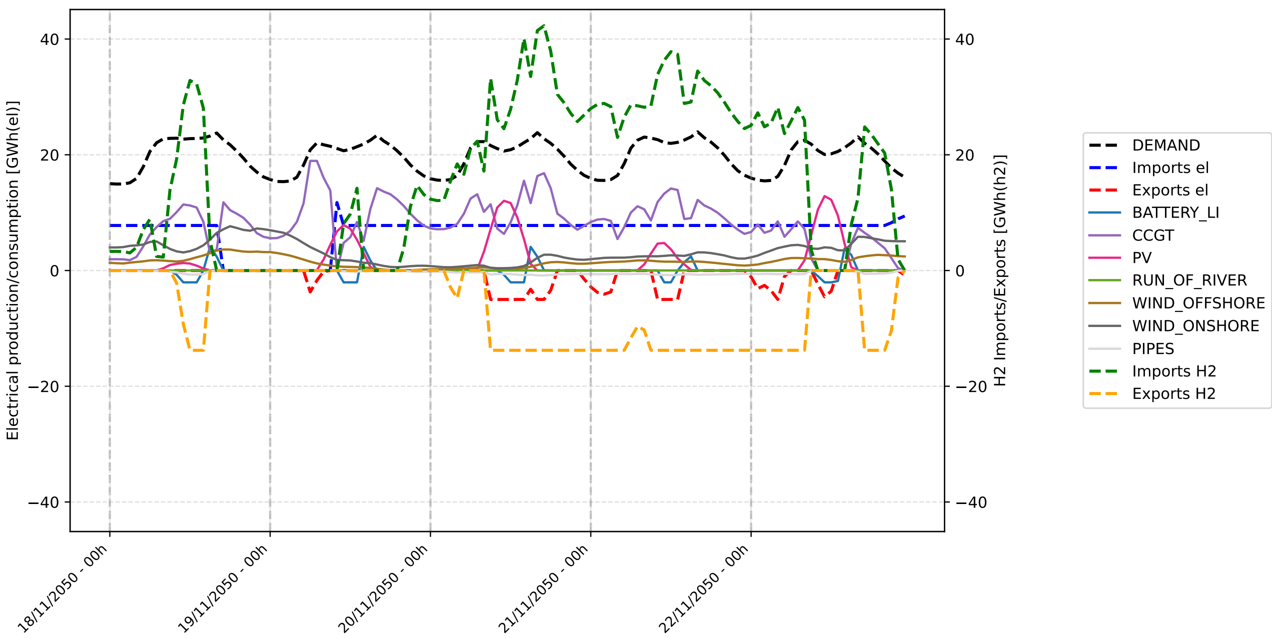


Figure 7.28: Quantity of hydrogen exchanged annually in the pipes connecting the countries as well as the annual production and consumption of hydrogen and natural gas of each country in the system obtained by scenario 3.2 for a natural gas purchase price of 505 €$_{2050}$/MWh$_{NG}$ for the year 2050.

Figure 7.29 provides 2 graphs, each of which is a profile of electricity production and consumption for each asset, as well as electricity and hydrogen imports and exports, zoomed in on the period from 18 to 22 November 2050. The first relates to Great Britain and the second relates to the Netherlands. This period was chosen arbitrarily, taking a period in which hydrogen use was high in order to observe its integration into the electricity mix as best as possible. In Figure 7.29a, Great Britain uses the overproduction of its renewable technologies such as PV during the day of 18 November or its wind turbines during the days and nights of 20 to 22 November. The use of renewable productions is maximised by minimising curtailment, unlike scenario 3.1. The excess production is then used to produce hydrogen. In Figure 7.29b, the Netherlands receives a major portion of this hydrogen produced by Great Britain. This hydrogen is then either re-exported to Germany (given that none to other countries are used as seen in Figure 7.24) or directly used by Dutch gas-fired power plants to produce the electricity needed to meet its demand, which cannot be met by its renewable electricity generation assets.



(a) Great Britain.



(b) The Netherlands.

Figure 7.29: Hourly electricity production and consumption in Great Britain and the Netherlands between 18 and 22 November 2050, as well as their electricity and hydrogen import and export, obtained by scenario 3.3, considering a natural gas purchase price of 505 $€_{2050}/\text{MWh}_{\text{NG}}$.

As in scenario 3.1, the overall cost of this system increases relatively steadily with the increase in the purchase price of natural gas. It follows that the cost price of electricity for this system also increases with the increase in the purchase price of natural gas, demonstrating the dependence of this system on this resource. When the purchase price of natural gas is 5 $€_{2050}/MWh_{NG}$, the price of electricity is 78.72 $€_{2050}/MWh_{el}$, rising to 132.23 $€_{2050}/MWh_{el}$ when the purchase price is at the maximum of this study, i.e. 505 $€_{2050}/MWh_{NG}$. It is noted that these prices are lower by 4.4 and 8.74 $€_{2050}/MWh_{el}$ respectively than the results obtained for scenario 3.1. In the current configuration, hydrogen begins to be economically viable for the model when the purchase price of natural gas is 155 $€_{2050}/MWh_{NG}$ which, by reversing inflation to compare in 2019 euros, is equivalent to 77.97 $€_{2019}/MWh_{NG}$ which is 4.3 times more expensive than the purchase price of natural gas in 2019. The cost price of electricity associated with this amount of the purchase price of natural gas is 103.64 $€_{2050}/MWh_{el}$, which is equivalent to 52.13 $€_{2019}/MWh_{el}$ which is 1.45 times more expensive than the annual average electricity price of these 6 countries (obtained by weighted average of the annual average price of each country) in 2019 according to [27]. These prices are not exorbitant given the recent price of the TTF index which shows an average of 54,545 $€_{2050}/MWh_{NG}$, without counting the additional taxes to know the real purchase price of a power plant over the last 5 years[6]. It should not be forgotten that this price is a lower bound because hydrogen pipes were assumed to have the same cost as standard natural gas pipes.

Scenario 3 - Conclusion

During these two scenarios, various configurations of the European energy future were tested by varying a highly volatile and therefore difficult to predict parameter, the future purchase price of natural gas. The first scenario studied the configuration of a penetration rate of renewables in the electricity mix considered as "low" even though it multiplies by a factor of 5 the renewable assets deployed in 2019 while considering the maintenance of the use of nuclear energy at the same level as the nuclear fleet present in 2019. In this configuration, the use of hydrogen starts from a purchase price of natural gas of 145 $€_{2050}/MWh_{NG}$. This system makes it possible to produce electricity with a cost price of 105.29 $€_{2050}/MWh_{el}$. The second scenario envisages a high penetration rate of renewables in the electricity mix but assumes the total phase out of nuclear energy in Europe. This inability to use this stable, carbon-free, and inexpensive electricity generation pushes the purchase price of natural gas, at which hydrogen becomes economically viable in this system, to 155 $€_{2050}/MWh_{NG}$, thus producing electricity with a cost price of 103.64 $€_{2050}/MWh_{el}$. The average index for the last 5 years (from 8 June 2020 to 2 June 2025) of the EU TTF is 55.416 $€_{2025}/MWh_{NG}$, or 96.45 $€_{2050}/MWh_{NG}$ [27]. The natural gas purchase price at which hydrogen is competitive in this model is 50 to 60 $€_{2050}/MWh_{NG}$ more expensive than the average gas market price marked by exceptional circumstances leading to high natural gas purchase prices. The conditions leading to the use of hydrogen are therefore exceptional.

In each of these scenarios, hydrogen is produced by France and Great Britain alone, which partially or entirely export this production to neighbouring countries, notably the Netherlands and Germany. Hydrogen, produced from alkaline electrolysers, is produced during overproduction of renewable assets, notably solar panels and wind power (onshore and offshore), coupled with the use of gas-fired power plants in neighbouring countries following low production of

[6] Average calculated over the period between 8 June 2020 and 2 June 2025

their renewable assets or peak electricity consumption. When neighbouring countries do not need hydrogen, this excess electricity production is stored in lithium-ion batteries or pumped-hydro storage. Conversely, when a country needs hydrogen to run its gas-fired power plants but the renewable assets of hydrogen-producing countries do not overproduce enough electricity to power the electrolysers, the use of natural gas becomes mandatory.

This last point demonstrates the electricity system's dependence on natural gas, the only way to break away from it is to oversize the renewable electricity production facilities needed to synthesise the hydrogen, which can then be used in gas-fired power plants.

CHAPTER 8

CONCLUSION, LIMITATIONS AND PERSPECTIVES

The objective of this thesis was to determine the role of natural gas in the European electricity mix, which aims to achieve carbon neutrality by 2050. To address this challenge, a linear model formulated using the GBOML language with a techno-economic approach was developed, modelling six Western European countries (Belgium, Luxembourg, France, the Netherlands, Germany, and Great Britain) as unique nodes interconnected by power lines and gas pipelines. This model simulates, over a full year with an hourly resolution, the energy mix of these countries by modelling the assets necessary to ensure the balance between electricity consumption and electricity production using conversion, storage, and transmission technologies, taking into account three energy vectors: electricity, natural gas, and hydrogen.

First, this model was validated by comparing its results with the reference year 2019. This part of the thesis demonstrated the difficulties in perfectly representing the interconnectedness of energy markets in order to obtain results as close as possible to reality. This simplified representation of the electricity market used in this model leads to divergences in the shares of each technology in each country's electricity mix obtained by the model compared to those presented by ENTSO-E, ranging from -18.6% to +33.23%. In particular, these variations mainly concern combustion power plants, for which the model strongly favours gas-fired power plants. Renewable technologies, on the other hand, are well modelled, obtaining divergences of up to 5%.

Next, various scenarios were evaluated to test various configurations of the European electricity mix:

- **Scenario 0 - base case:** This reference scenario, with no constraints on the maximum installable capacity of assets, shows that the optimal electricity mix is based on the massive use of renewable power technologies, particularly solar and wind power, coupled with lithium-ion batteries and large electricity interconnection capacities between countries, enabling renewable technologies to be installed in countries with favourable weather conditions. Gas-fired power stations play an important role as a source of back-up generation in the event of underproduction of electricity from renewable assets or peaks in electricity

demand. The carbon capture system used is a large DAC unit installed in 1 country allowing the capture of 15.039 Mt_{CO_2}/yr offering a longevity of 971 years to the storage of this country before being full. This system gives an electricity cost price of 66.17 $€_{2050}/MWh_{el}$ (or 33.29 $€_{2019}/MWh_{el}$) compared to the real average annual price of these six countries in 2019 of 35.88 $€_{2019}/MWh_{el}$.
More realistic limits have been added to the system's electricity transmission capacity, making it possible to observe the importance of this capacity in the integration of renewable technologies, leading to an increase in the energy independence of countries replacing these electricity imports with greater nuclear electricity production capacity. These limits lead to a more expensive system, with an electricity cost of 4.26 $€_{2050}/MWh_{el}$.

- **Scenario 1 - limits on renewables:** Adding realistic limits on renewable power capacities replaces these productions with nuclear electricity, leading to an electricity cost price 13.87 $€_{2050}/MWh_{el}$ more expensive than the base case. The less intermittent production of the system leads to a reduction in the use of gas-fired power plants, thus emitting 4 Mt_{CO_2}/yr less than the base case.
The variation of $\pm 10\%$ and $\pm 30\%$ of the limits imposed on renewable power technologies, allowing to represent the uncertainty of the massive development capacities of these technologies, demonstrated that the global system was stable in the face of these variations. However, this apparent stability in reality has more or less strong impacts at the national scale in terms of the configuration of the electricity system and the optimal electricity mix obtained. These non-linear impacts linked to the variations of the limits imposed on renewable technologies demonstrate the difficulty of predicting the behaviour of the system.

- **Scenario 2 - limits on nuclear:** Previous scenarios have demonstrated a replacement of renewable electricity production in favour of nuclear power. However, nuclear power in Europe is the source of heated political and societal debates and its future is therefore uncertain in Europe.An energy system that allows for the maximum renewal of the nuclear fleet leads to an electricity cost price of 88.6 $€_{2050}/MWh_{el}$ (or 44.57 $€_{2019}/MWh_{el}$). A system that does without nuclear power entirely has an electricity cost price of 111.76 $€_{2050}/MWh_{el}$ (or 56.22 $€_{2019}/MWh_{el}$), thus demonstrating the impact on citizens' wallets of the nuclear phase-out in Europe. In both cases, this nuclear production is mainly replaced by gas-fired power plants, therefore requiring larger systems for capturing and storing the carbon emitted, which increases by 25.76 Mt_{CO_2}/yr and 112.364 Mt_{CO_2}/yr respectively.

- **Scenario 3 - Natural gas purchased price study:** The sensitivity study of the purchase price of natural gas according to two very distinct system configurations, one authorizing the use of nuclear power plants and the other without them but using a very high penetration rate of renewables, leads to the use of hydrogen synthesized by hydrolysis when the purchase price of natural gas exceeds 145 $€_{2050}/MWh_{NG}$ (i.e. 72.94 $€_{2019}/MWh_{NG}$) in the first case and 155 $€_{2050}/MWh_{NG}$ (i.e. 77.97 $€_{2019}/MWh_{NG}$) in the second case. The system cannot do without natural gas in both cases due to a lack of excess electricity production to power the electrolysers, leading to a level of approximately 65 TWh_{H_2} produced annually. Thus, the system remains heavily dependent on natural gas and its market price. The only way for Europe to become independent of fossil fuels is to significantly increase renewable technologies and use nuclear power.

These more or less realistic scenarios have all demonstrated the economic viability of gas-fired power plants in a fully carbon-neutral electricity mix, serving as backup production sources needed during high electricity demand or low production from renewable technologies. Thus, the economic dependence of the electricity market remains strongly linked to the use of gas-fired power plants and the volatility of natural gas purchase prices. This flexible source of electricity production is therefore an essential component in ensuring the balance between demand and future electricity production in Europe and remaining economically competitive despite the coupling with a system for capturing and storing the CO_2 emitted in order to comply with the carbon neutrality constraint imposed by the EU.

8.1 Limitations

The results of this thesis presented above are based on a set of assumptions that should be recalled. The model studies a full year with an hourly time step that does not allow for intra-hourly fluctuations to be taken into account, which has the effect of smoothing the load profile and underestimating the system's rapid flexibility needs, which allows for a lower electricity cost price. The meteorological data taken into account are based on the year 2019, therefore impacting solar and wind electricity production. A year with poorer weather conditions leads to an increase in the electricity cost price, as has been observed through the various scenarios, but also in the presentation of the price of natural gas, from which hydrogen is competitive in the model, which depends on the overproduction of these assets. The model is based on the assumption of centralised planning with perfect knowledge, which neglects the reality of multiple actors taking part in energy markets and neglects the uncertainty related to demand, weather conditions and operations. Congestion in the electrical transmission network is also not taken into account, allowing the model to utilise the maximum capacity of the transmission line. The results shown for hydrogen are a lower bound, given that the costs associated with hydrogen pipelines are assumed to be the same as those of standard natural gas pipelines, while a higher price can be expected, thus increasing the price of natural gas from which hydrogen is competitive.

8.2 Perspectives

The model that was developed in this thesis was designed to easily integrate future improvements, including an expansion of the field of study by adding other European countries, which could not be achieved within the framework of this thesis due to lack of time. It is also relatively simple to add new technologies as scientific advances progress. Another way of expanding the model would be to add the gas demand of each country and the addition of nodes representing this energy sector, which would allow us to observe the interactions between the electricity sector and the gas sector.

APPENDIX A

APPENDIX

A.1 Node parameters

n	Commodity r	α^n -	μ^n -	Δ_+^n/Δ_-^n -	Source
PV	Electricity	0	0	-	[4]
WON	Electricity	0	0	-	[4]
WOFF	Electricity	0	0	-	[4]
ROR	Electricity	0	0	-	[4]
BIO	Electricity	3/52	0.45	0.25/0.3	[4]
BCT	Electricity	2.3/52	0.45	1.0/1.0	[4, 19]
CCGT	Electricity	2/52	0.4	1.0/1.0	[4, 19]
GFCT	Electricity	2/52	0.4	1.0/1.0	[4, 19]
HCT	Electricity	2/52	0.23	1.0/1.0	[4, 22]
OT	Electricity	2/52	0.2	1.0/1.0	[4, 19]
WA	Electricity	1.8/52	0.2	0.25/0.3	[4]
NK	Electricity	3/52	0.0	0.01/0.01	[4]
AEC	H_2	11/365	0.1	1.0/1.0	[4, 19]
PEMEC	H_2	11/365	0.1	1.0/1.0	[4, 19]
SOEC	H_2	11/365	0.1	1.0/1.0	[4, 19]
MCFC	Electricity	0.1/52	0.1	1.0/1.0	[4, 19]
DAC	CO_2	0	0	-	[19]
PCCCC	CO_2	0	0	-	[19]

(a) Technical parameters.

n	Unit of r $\star$	ϕ_{el} $\star/GWh_{el}$	ϕ_{H_2} $\star/GWh_{H_2}$	ϕ_{CH_4} $\star/GWh_{CH_4}$	ϕ_{CO_2} $\star/kt_{CO_2}$	ϕ_{H_2O} $\star/kt_{H_2O}$	ϕ_{fuel} $\star/GWh_{fuel}$ or $\star/kt_{fuel}$	Source
BIO	GWh_{el}	-	-	-	0.4/0.41	-	0.4	[6, 7]
BCT	GWh_{el}	-	-	-	1/0.28	-	0.37	[6, 7]
CCGT	GWh_{el}	-	[0, 1]	[0, 1]	1/0.18	-	0.59	[7, 19]
GFCT	GWh_{el}	-	-	-	1/0.168	-	0.41	[6, 23]
HCT	GWh_{el}	-	-	-	1/0.37	-	0.43	[6, 7]
OT	GWh_{el}	-	-	-	1/0.26	-	0.42	[7, 19]
WA	GWh_{el}	-	-	-	0.34/1	-	0.34	[6, 24]
NK	GWh_{el}	-	-	-	0	-	0.38	[6]
MCFC	GWh_{el}	-	0.69	-	0	2.553	-	[6]
AEC	GWh_{H_2}	0.699	-	-	-	3.7	-	[19]
PEMEC	GWh_{H_2}	0.664	-	-	-	3.7	-	[19]
SOEC	GWh_{H_2}	0.725	-	-	-	3.7	-	[19]
DAC	kt_{CO_2}	1/1.284	-	-	1.0	-	-	[19]
PCCCC	kt_{CO_2}	1/0.068	-	-	0.95	-	-	[19]

(b) Conversion factors.

n	$CAPEX^n$ M€/GW or M€/kt/h	θ_f^n M€/Gw-yr or M€/(kt/h)-yr	θ_v^n M€/GWh or M€/kt	χ_i^n M€/MWh or M€/kt	L^n years	Source
PV	290	7.4	0	0	40	[19]
WON	1 090.288	15.602	$1.85 \cdot 10^{-3}$	0	30	[19]
WOFF	1 985.693	28	$2.78 \cdot 10^{-3}$	0	30	[19]
ROR	2 300	8.1	0	0	50	[6]
BIO	1 700	38.4	$3.56 \cdot 10^{-3}$	$87.07 \cdot 10^{-3}$	40	[6, 25]
BCT	1 800	32.5	$3 \cdot 10^{-3}$	$45.5 \cdot 10^{-3}$	40	[6, 26]
CCGT	850.698	27.6477	$4.25 \cdot 10^{-3}$	$66.34 \cdot 10^{-3}$	25	[6, 27, 28]
GFCT	3 150	61.9	$6.91 \cdot 10^{-3}$	$41.87 \cdot 10^{-3}$	30	[6, 29]
HCT	1 600	25.6	$2.4 \cdot 10^{-3}$	$57.19 \cdot 10^{-3}$	40	[6, 26]
OT	361.547	0	0	$148.6 \cdot 10^{-3}$	25	[6, 26]
WA	1 997	39.2	$0.82 \cdot 10^{-3}$	0	20	[6]
NK	4 700	105	$7.8 \cdot 10^{-3}$	$8.83 \cdot 10^{-3}$	60	[6, 30]
AEC	275	11	0.11	0.378	25	[19, 31]
PEMEC	325	6.5	0.11	0.378	25	[19, 31]
SOEC	500	50	0.11	0.378	25	[19, 31]
MCFC	2 668	40	$1.04 \cdot 10^{-3}$	-	20	[6]
DAC	1 800	70	0	-	30	[19]
PCCCC	1 900	60	$2.5 \cdot 10^{-3}$	-	25	[19]

(c) Economical parameters.

Table A.1: Technical and economical parameters of conversion nodes associated with the year 2019.

n	η_S^n	η_+^n	η_-^n	σ^n	ρ^n	ξ^n	ϕ_{el}^n $\text{GWh}_{\text{el}}/\text{GWh}_{\text{CO}_2}$	α^n	Source
LI-BAT	0.0042	0.985	0.975	0	0.5	4	-	0.1/52	[4, 19]
NA-BAT	0	0.922	0.922	0	50/300	50/300	-	0	[4, 19]
HPS	0	0.866	0.866	0	1	-	-	0	[4, 19]
CS	0	1	1	0	1	$1/T$	50/3600	0	[4, 19]

(a) Technical parameters.

	BE	LU	FR	NL	DE	UK	Source
ξ^{HPS}	1/5	0	1/21	0	1/6	1/5	[32]

(b) Conversion factors.

n	$\text{CAPEX}^n_{\text{stock}}$ M€/GWh or M€/kt	$\text{CAPEX}^n_{\text{flow}}$ M€/GW or M€/kt/h	ϑ_f^n M€/GWh or M€/kt	θ_f^n M€/GW or M€/kt/h	ϑ_v^n M€/GWh or M€/kt/h	θ_v^n M€/GW or M€/kt	L^n years	Source
LI-BAT	79.755	63.804	0	0.574	0	$1.7 \cdot 10^{-3}$	30	[19]
NA-BAT	148.876	350.922	0	5.2638	0	$1.91 \cdot 10^{-3}$	24	[19]
HPS	0	4 253.6	0	8.5072	0	0	50	[19]
CS	$1.93 \cdot 10^{-3}$	0	$0.71 \cdot 10^{-3}$	0	$1.02 \cdot 10^{-3}$	0	30	[19]

(c) Economical parameters.

Table A.2: Technical and economical parameters of storage nodes associated with the year 2050.

n	η^n	$\overline{\phi_{\text{H}_2}}$	ϕ_{el}^n $\text{GWh}_{\text{el}}/\text{GWh}_{\text{gas}}$	Source
HVAC	0.93	-	-	[4]
HVDC	$0.9801 - 2.940\,3 \cdot 10^{-5} \cdot$ length	-	-	[4]
Gas pipe	$1 - 2.2 \cdot 10^{-5} \cdot$ length	0.015	1.0*	[4]

* Only hydrogen pipes but can be used to represent a mix of hydrogen and natural gas in the pipe.

(a) Technical parameters.

	BE	LU	FR	NL	DE	UK
BE	-	-	-	-	100	140
LU	-	-	-	-	-	-
FR	-	-	-	-	-	72
NL	-	-	-	-	-	245
DE	100	-	-	-	-	713.333
UK	140	-	72	245	713.333	-

(b) Length matrix in km for HVDC.

	BE	LU	FR	NL	DE	UK
BE	-	138.28	478.1	179.26	406.9	633.2
LU	138.28	-	452.9	-	338.9	-
FR	478.1	452.9	-	-	778	890.4
NL	179.26	-	-	-	356.1	597.7
DE	406.9	338.9	778	356.1	-	713.333
UK	633.2	-	890.4	597.7	-	-

(c) Length matrix in km for pipes.

n	CAPEX^n M€/GW	θ_f^n M€/GW	θ_v^n M€/GWh	L^n years	Source
HVAC	422.48	0.015·CAPEX^n	10^{-6}	70	[4, 34]
HVDC	5.226·length	0.015·CAPEX^n	10^{-6}	40	[4, 34]
Gas pipe	0.201·length	0.015·length	10^{-6}	40	[4]

(d) Economical parameters.

Table A.3: Technical and economical parameters of transport nodes associated with the year 2050.

A.2 ENTSO-E Report 2019

Technologies	Installed capacity [GW]	Electricity produced [TWh]	Share [%]
Nuclear	0	0	0
Fossil brown coal	0	0	0
Fossil coal derived gas	0	0	0
Fossil gas	0.081	0.2	18.6
Fossil hard coal	0	0	0
Fossil oil	0	0	0
Hydro pumped storage	0	0*	0
Waste	0.021	0.1	9.3
Wind offshore	0	0	0
Wind onshore	0.154	0.3	27.91
Solar	0.136	0.1	9.3
Biomass	0.03	0.2	18.6
Run-of-river	0.036	0.1	9.3
Others	\	0.075	6.98
Total		1.075	

* Net production (production - consumption) = 0 - 0 = 0 TWh.

Table A.4: Installed capacities, electrical production and share in the electrical mix for each technology used to produce electricity in Luxembourg in 2019 according to ENTSO-E.

Technologies	Installed capacity [GW]	Electricity produced [TWh]	Share [%]
Nuclear	63.13	377.9	71.29
Fossil brown coal	0	0	0
Fossil coal derived gas	0	0	0
Fossil gas	11.952	37.9	7.15
Fossil hard coal	3.966	1.6	0.3
Fossil oil	3.271	1.6	0.3
Hydro pumped storage	5.023	5.0*	0.94
Waste	0	0**	0
Wind offshore	0	0	0
Wind onshore	13.61	32.7	6.17
Solar	8.188	11.4	2.15
Biomass	1.931	3.1	0.58
Run-of-river	19.234	54.2	10.22
Others	\	4.669	0.88
Total		530.069	

* Net production (production - consumption) = 5.0 - 5.4 = -0.4 TWh.
** Equal to 1.7 TWh in the report but as no installed capacity is given, this production will be reported in "others".

Table A.5: Installed capacities, electrical production and share in the electrical mix for each technology used to produce electricity in France in 2019 according to ENTSO-E.

Technologies	Installed capacity [GW]	Electricity produced [TWh]	Share [%]
Nuclear	0.486	3.7	3.26
Fossil brown coal	0	0	0
Fossil coal derived gas	0	0	0
Fossil gas	15.57	45	39.6
Fossil hard coal	4.631	16.5	14.52
Fossil oil	0	0	0
Hydro pumped storage	0	0*	0
Waste	0.758	2.2	1.94
Wind offshore	0.957	3.5	3.08
Wind onshore	3.436	3.2	2.82
Solar	4.608	0.1	0.09
Biomass	0.485	0	0
Run-of-river	0.038	0	0
Others	\	39.441	34.71
Total		113.641	

* Net production (production - consumption) = 0 - 0 = 0 TWh.

Table A.6: Installed capacities, electrical production and share in the electrical mix for each technology used to produce electricity in the Netherlands in 2019 according to ENTSO-E.

Technologies	Installed capacity [GW]	Electricity produced [TWh]	Share [%]
Nuclear	9.516	71	13.09
Fossil brown coal	21.205	102.7	18.93
Fossil coal derived gas	0	0*	0
Fossil gas	31.664	54.6	10.06
Fossil hard coal	25.293	47.8	8.81
Fossil oil	4.356	4	0.74
Hydro pumped storage	9.422	8.6**	1.58
Waste	1.686	5.9	1.09
Wind offshore	6.393	24.4	4.5
Wind onshore	52.792	99.9	18.41
Solar	45.299	41.8	7.7
Biomass	7.752	40.4	7.45
Run-of-river	5.281	16.5	3.04
Others	\	24.952	4.6
Total		542.552	

* Equal to 2 TWh in the report but as no installed capacity is given, this production will be reported in "others".
** Net production (production - consumption) = 8.6 - 11 = -2.4 TWh.

Table A.7: Installed capacities, electrical production and share in the electrical mix for each technology used to produce electricity in Germany in 2019 according to ENTSO-E.

Technologies	Installed capacity [GW]	Electricity produced [TWh]	Share [%]
Nuclear	9.229	52.5	18.63
Fossil brown coal	0	0	0
Fossil coal derived gas	0	0	0
Fossil gas	37.698	114.8	40.74
Fossil hard coal	8.794	6.1	2.16
Fossil oil	0.316	0	0
Hydro pumped storage	2.744	1.8*	0.64
Waste	0	0	0
Wind offshore	9.379	20	7.1
Wind onshore	13.633	27.1	9.62
Solar	13.438	11	3.9
Biomass	4.061	17.1	6.07
Run-of-river	1.885	3.6	1.28
Others	\	27.783	9.86
Total		281.783	

* Net production (production - consumption) = 1.8 - 1.8 = 0 TWh (No data given for the consumption of the hydro pumped storage so assume it is a perfect installation consuming any energy).

Table A.8: Installed capacities, electrical production and share in the electrical mix for each technology used to produce electricity in Great Britain in 2019 according to ENTSO-E.

A.3 Model results for the year 2019

Technologies	Electricity produced [TWh]	Share [%]	Difference* [%]
Nuclear	0	0	+0.0
Fossil brown coal	0	0	+0.0
Fossil coal derived gas	0	0	+0.0
Fossil gas	0.511	44.07	+25.46
Fossil hard coal	0	0	+0.0
Fossil oil	0	0	+0.0
Hydro pumped storage	0**	0	+0.0
Waste	0.001	0.12	-9.19
Wind offshore	0	0	+0.0
Wind onshore	0.346	29.84	+1.93
Solar	0.157	13.52	+4.22
Biomass	0	0	-18.6
Run-of-river	0.069	5.99	-3.32
Others	0.075	6.47	-0.5
Total	1.159		

* Compute as the difference in the share obtained by the model and the share given in the ENTSO-E report.
** Net production (production - consumption) = 0 - 0 = 0 TWh.

Table A.9: Electrical production and share in the electrical mix for each technology used to produce electricity in Luxembourg in 2019 according to the model as well as the variation in the production shares of technologies between the model and reality.

Technologies	Electricity produced [TWh]	Share [%]	Difference* [%]
Nuclear	470.778	82.97	+11.68
Fossil brown coal	0	0	+0.0
Fossil coal derived gas	0	0	+0.0
Fossil gas	7.386	1.3	-5.85
Fossil hard coal	0	0	-0.3
Fossil oil	0	0	-0.3
Hydro pumped storage	7.318**	1.29	+0.35
Waste	0	0	+0.0
Wind offshore	0	0	+0.0
Wind onshore	29.987	5.28	-0.88
Solar	10.2	1.8	-0.35
Biomass	0	0	-0.58
Run-of-river	37.068	6.53	-3.69
Others	4.669	0.82	-0.06
Total	567.406		

* Compute as the difference in the share obtained by the model and the share given in the ENTSO-E report.
** Net production (production - consumption) = 7.318 - 9.757 = -2.439 TWh.

Table A.10: Electrical production and share in the electrical mix for each technology used to produce electricity in France in 2019 according to the model as well as the variation in the production shares of technologies between the model and reality.

Technologies	Electricity produced [TWh]	Share [%]	Difference* [%]
Nuclear	4.012	3.27	+0.02
Fossil brown coal	0	0	+0.0
Fossil coal derived gas	0	0	+0.0
Fossil gas	63.96	52.18	+12.58
Fossil hard coal	0	0	-14.52
Fossil oil	0	0	+0.0
Hydro pumped storage	0**	0	+0.0
Waste	0	0	-1.94
Wind offshore	2.717	2.22	-0.86
Wind onshore	7.259	5.92	+3.11
Solar	5.107	4.17	+4.08
Biomass	0	0	+1.54
Run-of-river	0.073	0.06	+0.06
Others	39.441	32.18	-2.53
Total	122.569		

* Compute as the difference in the share obtained by the model and the share given in the ENTSO-E report.
** Net production (production - consumption) = 0 - 0 = 0 TWh.

Table A.11: Electrical production and share in the electrical mix for each technology used to produce electricity in the Netherlands in 2019 according to the model as well as the variation in the production shares of technologies between the model and reality.

Technologies	Electricity produced [TWh]	Share [%]	Difference* [%]
Nuclear	78.551	15.47	+2.38
Fossil brown coal	8.698	1.71	-17.22
Fossil coal derived gas	0	0	+0.0
Fossil gas	219.834	43.29	+33.23
Fossil hard coal	0	0	+8.81
Fossil oil	0	0	-0.74
Hydro pumped storage	6.053**	1.19	-0.39
Waste	0	0	-1.09
Wind offshore	18.853	3.71	-0.78
Wind onshore	90.391	17.8	-0.61
Solar	50.257	9.9	+2.19
Biomass	0	0	-7.45
Run-of-river	10.177	2.0	-1.04
Others	24.952	4.91	+0.32
Total	507.767		

* Compute as the difference in the share obtained by the model and the share given in the ENTSO-E report.
** Net production (production - consumption) = 6.053 - 8.07 = -2.017 TWh.

Table A.12: Electrical production and share in the electrical mix for each technology used to produce electricity in Germany in 2019 according to the model as well as the variation in the production shares of technologies between the model and reality.

Technologies	Electricity produced [TWh]	Share [%]	Difference* [%]
Nuclear	76.182	26.33	+7.7
Fossil brown coal	0	0	+0.0
Fossil coal derived gas	0	0	+0.0
Fossil gas	104.907	36.25	-4.49
Fossil hard coal	0	0	+2.16
Fossil oil	0	0	+0.18
Hydro pumped storage	0.448**	0.15	-0.48
Waste	0	0	+0.0
Wind offshore	29.656	10.25	+3.15
Wind onshore	33.8	11.68	+2.06
Solar	12.959	4.48	+0.57
Biomass	0	0	-6.07
Run-of-river	3.633	1.26	-0.02
Others	27.783	9.6	-0.26
Total	289.368		

* Compute as the difference in the share obtained by the model and the share given in the ENTSO-E report.
** Net production (production - consumption) = 0.448 - 0.597 = -0.149 TWh.

Table A.13: Electrical production and share in the electrical mix for each technology used to produce electricity in the Great Britain in 2019 according to the model as well as the variation in the production shares of technologies between the model and reality.

A.4 Model Parameters for the year 2050

Country	Node	$\overline{\kappa}^n$ [GW] -30%	-10%	Scenario 1.1	+10%	+30%
BE	PV	9.068	11.659	12.954	14.249	16.84
	WON	4.365	5.612	6.236	6.86	8.107
	WOFF	0.268	0.345	0.383	0.421	0.498
	LI-BAT	5.19	6.673	7.415	8.156	9.639
	ROR	0.166	0.213	0.237	0.261	0.308
	HPS	1.261	1.622	1.802	1.982	2.343
LU	PV	0.768	0.987	1.097	1.207	1.426
	WON	0.37	0.475	0.528	0.581	0.686
	WOFF	0	0	0	0	0
	LI-BAT	0.44	0.565	0.628	0.691	0.816
	ROR	0.035	0.045	0.05	0.055	0.065
	HPS	0	0	0	0	0
FR	PV	163.867	210.686	234.096	257.506	304.325
	WON	78.89	101.43	112.7	123.97	146.51
	WOFF	18.951	24.366	27.073	29.78	35.195
	LI-BAT	93.793	120.591	133.999	147.389	174.187
	ROR	18.553	23.854	26.504	29.154	34.455
	HPS	4.845	6.229	6.921	7.613	8.997
NL	PV	12.334	15.858	17.62	19.382	22.906
	WON	5.938	7.635	8.483	9.331	11.028
	WOFF	1.831	2.354	2.616	2.878	3.401
	LI-BAT	7.06	9.077	10.086	11.095	13.112
	ROR	0.036	0.047	0.052	0.057	0.068
	HPS	0	0	0	0	0
DE	PV	106.038	136.335	151.483	166.631	196.928
	WON	51.05	65.635	72.928	80.221	94.806
	WOFF	9.698	12.469	13.855	15.24	18.011
	LI-BAT	60.697	78.039	86.71	95.381	112.723
	ROR	5.094	6.549	7.277	8.005	9.46
	HPS	9.088	11.685	12.983	14.281	16.878
UK	PV	72.717	93.494	103.882	114.27	135.047
	WON	35.008	45.011	50.012	55.013	65.016
	WOFF	64.59	83.045	92.272	101.499	119.954
	LI-BAT	41.624	53.517	59.463	65.409	77.302
	ROR	1.818	2.337	2.597	2.857	3.376
	HPS	2.647	3.403	3.781	4.159	4.915

Table A.14: Maximal capacity imposed on renewable technologies for each country for scenario 1 and the variations of those limits which will be studied for the year 2050.

Transmission line	$\underline{\kappa}^n$	$\overline{\kappa}^n$ [GW]
HVAC_BE_LU	0.68	5.68
HVAC_BE_FR	5.3	10.3
HVAC_BE_NL	5.4	10.4
HVAC_BE_DE	0.0	5.0
HVDC_BE_DE	1.0	6.0
HVDC_BE_UK	2.4	7.4
HVAC_LU_FR	0.38	5.38
HVAC_LU_DE	3.7	8.7
HVAC_FR_DE	4.8	9.8
HVDC_FR_UK	4.0	9.0
HVAC_NL_DE	5.0	10.0
HVDC_NL_UK	3.0	8.0
HVDC_DE_UK	0.0	5.0

Table A.15: Pre-installed and maximal capacities of electrical cross-border transmission interconnections assumed for scenario 1 for the year 2050.

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