

École polytechnique de Louvain

Prospective Life Cycle Analysis meets Energy Planning Models

and Application to the Belgian Energy System

Author: **Pauline LAURENT**

Supervisor: **Francesco CONTINO**

Readers: **Thomas PARDOEN, Patricia LUIS ALCONERO, Diederik COPPIT-TERS**

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Abstract

Growing concerns about climate change have prompted world leaders to establish and ratify international agreements such as the United Nations Framework Convention on Climate Change (UNFCCC) in 1992, the Kyoto Protocol in 1997, and the Paris Agreement in 2015. These agreements aim to mitigate greenhouse gas (GHG) emissions to combat climate change. In alignment with these agreements, the European Union has enacted the Climate Act, which legally enforces the targets set by the European Green Deal. These targets include a minimum 55% reduction in GHG emissions by 2030 compared to 1990 levels, and achieving climate neutrality by 2050. Achieving these goals requires active participation from all sectors of the economy and society [5].

To formulate effective decarbonisation strategies, comprehensive whole-energy models of the energy system are essential. These models analyse the energy system holistically, considering the complex interactions between the demand of different sectors (such as electricity, heating, and mobility), technologies, and energy carriers.

While many energy models exist, only a few meet the following characteristics: multi-sector integration, open-source accessibility, reasonable computation time, and fine temporal resolution, which is crucial for accounting for the fluctuating nature of renewable energies and storage operations. The EnergyScope TD model, developed by Limpens et al. [7, 4], satisfies these requirements.

This model optimizes the yearly cost and operation of the energy system while constraining GHG emissions. However, the model and its particular application to the Belgian energy system face three major issues: partial quantification of construction emissions, neglect of emissions from imported renewable fuels, and the use of traditional Life Cycle Assessment (LCA) in the Global Warming Potential (GWP) calculation, which is not well-suited for prospective analysis and large scale applications.

To address these issues, a prospective Life Cycle Assessment (pLCA) approach was adopted for quantifying the construction emissions of the different technologies. This was achieved by modifying the *ecoinvent* database using the *premise* Python library coupled with Integrated Assessment Model (IAM) scenarios, and the Activity Browser LCA tool alongside its 'scenario analysis' setup. Concerning the operation emissions of renewable synthetic fuels, data from the literature were taken and kept constant over the transition.

The impact of this re-quantification is studied over the 2020, 2035, and 2050 Belgian energy systems, using two different IAM scenarios. This analysis provides insights into the implications of employing pLCA over historical LCA methodology for assessing GHG emissions in future energy systems.

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Acronyms

EROI Energy Return on Investment

ESTD EnergyScope Typical Days

EU European Union

EUD End-Use Demand

EUTs End-Use Types

FEC Final Energy Consumption

GHG greenhouse gas

GMST Global Mean Surface Temperature

GWP Global Warming Potential

IAM Integrated Assessment Model

IPCC Intergovernmental Panel on Climate Change

LCA Life Cycle Assessment

LCI Life Cycle Inventory

LCIA Life Cycle Impact Assessment

MILP Mixed-Integer Linear Programming

pLCA prospective Life Cycle Assessment

pLCI prospective Life Cycle Inventory

RCP Representative Concentration Pathway

SSP Shared Socio-economic Pathway

TD Typical Days

UNFCCC United Nations Framework Convention on Climate Change

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Chapter 1

Introduction

Growing concerns about climate change have urged world leaders to establish and ratify international agreements over time, including the UNFCCC in 1992, the Kyoto Protocol in 1997 and the Paris Agreement in 2015. These agreements were designed to tackle climate change by seeking to mitigate GHG emissions. In line with these agreements, the European Union (EU) has adopted the Climate Act, which legally imposes the targets set out in the European Green Deal. These targets involve a minimum 55% reduction in GHG emissions by 2030 compared to 1990 levels, as well as achieving climate neutrality by 2050. To achieve these targets, all sectors of the economy and society need to be actively engaged in the transition [5].

In order to formulate decarbonisation strategies, it is essential to have comprehensive whole-energy models of the energy system. These models analyse the energy system as a whole, taking into account the complex interactions between the demand of different sectors (such as electricity, heating and mobility), technologies and energy carriers, as defined by Contino et al. (2020) [6].

1.1. Current state of energy system models

Energy system models are mathematical representations designed to describe the complex interconnections between the various processes and components associated with the production, distribution and use of energy. Designed to answer specific questions, these models are only suitable for their intended purpose, and their inappropriate use can lead to significant misinterpretation. For instance, using a cost minimisation model to predict overall environmental impact can lead to incomplete assessments and misinterpretations. It is therefore essential to understand the purpose and scope of the system model before applying it.

These models vary in terms of temporal and spatial resolution, technical subtleties and modelling choices. They can be used to anticipate the environmental and economic consequences of specific policy decisions or the integration of innovative energy production technologies.

It is important to recognise that each model simplifies reality, incorporating only those elements considered significant by its developers at the time. Furthermore, any model forecasting future scenarios is inherently based on projections and assumptions, which may or may not prove accurate in specific circumstances, inevitably introducing uncertainty at the time of implementation.

1.1.1. Classification of the energy system models

As noted earlier, the selection of the appropriate model for a given application holds significant importance. Therefore, categorizing the array of energy models available proves to be valu-

able, streamlining the decision-making process when identifying the most suitable model for a particular objective. With the multitude of models documented in the literature, Limpens et al. (2019) [7] conducted an extensive review encompassing 54 energy system models, various classifications methods can be proposed. Drawing from classifications previously outlined by Van Beeck (1999) [8] and Lopion et al. (2018) [9], the focus here will be on the classification that best aligns with the specific interests addressed in this study.

The first step in selecting an energy model is to define its objective. This objective can cover a wide spectrum, from carrying out scenario analyses to looking closely at specific aspects such as energy demand or supply, and assessing the implications of certain decisions on environmental or economic aspects. In the literature, many models adopt an integrated approach, enabling them to fulfil several objectives simultaneously. Such an approach becomes imperative when examining the complex interaction between energy, the environment and the economy, as is the case in this study. In addition, the emphasis here is on models of whole-energy systems, which facilitate a more comprehensive exploration of the interactions between all sectors.

In terms of the analytical approach, based on Van Beeck (1999) [8] and Herbst et al. (2012) [10], two primary categories of models are defined as follows.

- **Top-down**, or macroeconomic, models take an economic perspective and are particularly valued by policy makers for their ability to provide reliable information on economic growth, employment and foreign trade, while projecting future energy systems. However, they are highly dependent on fluctuations in market prices and often lack the granularity necessary to accurately represent the technological aspects of energy systems. Although they reflect existing technologies, they tend to underestimate the potential for improving energy efficiency, among other factors. An example of top-down model is the ENPEP-BALANCE.
- **Bottom-up**, process-oriented or techno-economic models, on the other hand, take an engineering perspective and are excellent at describing technologies and their potential in detail. However, they are less suited to address macro-economic considerations and are therefore unable to offer insight into areas such as economic welfare or employment. Examples of bottom-up models include MARKAL/TIMES, EnergyPLAN and OSEMoSYS.

Each approach has its own set of advantages and disadvantages, making it suitable for particular applications. Nevertheless, hybrid approaches that incorporate elements of both methods are increasingly being explored and used.

In addition, energy models can be characterised according to the methodology they use. These models generally fall into one of two categories: simulation or optimisation. Simulation-based models simulate the operation and/or investment of a given energy system, while optimisation-based models aim to optimise these aspects.

- **Simulation model**: this type of model is a descriptive mathematical representation that replicates as closely as possible the behaviour of a system over time and under various conditions. Unlike optimisation models, simulation models do not aim to find the optimal solution, but rather to provide information about the operation and behaviour of the system as a function of input variables. They are generally used for short-term analyses. Examples of energy system simulation models include CIMS, EnergyPLAN and ENPEP-BALANCE.
- **Optimization model**: an optimisation model is a mathematical approach used to identify the best solution to a problem within a defined set of variables, taking into account specific

constraints and objectives. The main purpose of optimisation models is to achieve the optimum solution. Models such as MARKAL/TIMES and OSEMoSYS fall into this category.

Both simulation and optimization models are valuable tools with diverse applications. For complex systems requiring long-term planning, optimization models may be preferable due to their ability to handle numerous unknowns effectively. Additionally, multi-criteria models play a role in energy system optimization, considering factors beyond economic efficiency and GHG emissions, such as the land use or the Energy Return on Investment (EROI) as depicted by Muyldermans et al. (2021) [11].

Furthermore, several crucial factors should be considered when selecting an appropriate model:

- **Multi-sector approach:** Does the model take into account all energy sectors (electricity, mobility and heating) and their interactions, or does it focus on just one sector? Given the need to ensure the transition of all energy sectors to a fossil-free future, a multi-sector model is essential for a comprehensive analysis of the future energy system and its inter-sector interactions.
- **Open-source availability:** Public availability of the model is essential for transparency and reproducibility.
- **Resolution:** For systems heavily reliant on intermittent renewable energy sources and storage, an hourly resolution seems to be necessary to optimize investment and operational strategies effectively.
- **Computational time:** Optimization processes can be computationally intensive, especially when considering a model over the 8760 hours of the year. Therefore, choosing a model with reasonable computational time (e.g., a few minutes rather than hours) ensures that applications involving uncertainties remain affordable.

1.2. Contribution of this thesis

1.2.1. EnergyScope TD

In the literature, numerous energy system models have been developed to address specific questions, as summarized in the review conducted by Limpens et al. (2019) [7]. However, traditionally, these models have predominantly focused on individual energy sectors, with electricity receiving the most attention. Examples of such models include EMMA and SciGRID. Only a handful of models have taken into account the complex interactions between different sectors like electricity, heating, and mobility, and even then, certain aspects of the system, as seen in the Disp-SET model, are often simplified or disregarded. Additionally, many cross-sectoral energy system models do not offer full open access, such as the NEMS or MARKAL/TIMES models.

The EnergyScope Typical Days (ESTD) model is an open-source model designed to optimize the design and operation of a regional energy system, such as the Belgian system, with equal representation across all sectors and an hourly resolution for a targeted future year (in the *snapshot* version). Another version, called *EnergyScope Pathway*, is also available and allows optimization of the future energy system from an existing future year (usually 2015) to a targeted future year. The *snapshot* model optimizes the total yearly cost of the system while constraining GHG emissions, represented by the total GWP of the system, which corresponds to the sum of emissions from the different technologies and resources, as discussed next.

1.2.1.1. Accounting of the emissions

As previously introduced, the ESTD model imposes constraints on the emissions of the energy system by considering the GWP of various technologies and resources. Specifically, in the current version of the code, users can opt to limit either the total operational emissions ($\mathbf{GWP}_{\text{op}}$), associated with resources and encompassing their overall emissions, or the emissions linked to the construction of different technologies ($\mathbf{GWP}_{\text{constr}}$), which are annualized, alongside operational emissions. Further elaboration on this will be provided in Chapter 3; this only serves as an introduction to the objectives of the study.

Obtaining these GWP parameter values involved employing traditional LCA methods. It's worth noting that this quantification is inherently tied to the specific energy system under study. For instance, the Belgian energy system differs in characteristics (resources used, technologies, political framework, etc.) from the Swedish counterpart, and will does require different quantification.

It is important to note that resource emissions encompass all emissions from extraction to combustion, while technology emissions pertain to construction. Notably, the operational phase of technologies is not strictly considered; only resource combustion contributes to operational emissions. However, the use phase of energy conversion technologies may entail environmental impacts beyond fuel combustion. Though, an examination of these aspects is beyond the scope of this study.

Three significant issues emerged from the previous code version and its particular application to the Belgian energy system, as implemented in Limpens (2021) [4]:

- As highlighted by Limpens (2021), its thesis predominantly addresses resource-related emissions, by applying constraints only on the $\mathbf{GWP}_{\text{op}}$, overlooking a crucial aspect: construction-related emissions. This oversight results in significant gaps in the understanding of construction-related emissions across various sectors within the energy system. Notably, in the context of the Belgian energy system, emissions stemming from the construction of freight and passenger vehicles, synthetic fuels production units, and storage facilities — excluding electric car batteries and pumped-hydro storage — are neglected. Consequently, only the electricity and heat production construction emissions were accounted, limiting the ability to provide a comprehensive analysis of construction emissions across the entire energy landscape.
- Moreover, concerning the operational emissions, an assumption was made to neglect the emissions of imported renewable fuels such as bioethanol or renewable hydrogen. However, as described by Dumas et al. (2022) [12], this assumption leads to an other that stipulates the fact that these fuels emit fewer GHG emissions than other renewable resources, including solar or wind. Although, currently, the data available regarding the GWP of renewable fuels is insufficient to support this assumption.
- Finally, as highlighted by Sacchi et al. (2022) [3], the environmental footprint of a product is heavily influenced by the characteristics of the global supply chain and energy supply. Traditional LCA methodologies, reliant on historical databases and more suited to small-scale applications, prove inadequate for analyzing prospective energy systems. An innovative solution to this challenge can be found in the use of pLCA, which integrates temporal projections into the data collection phase. While the literature provides some insights into pLCA, its application to prospective energy systems is still in its early stages. Some models have been developed to study the environmental impacts of single future technologies or simplified systems, focusing mainly on individual sectors. Although useful,

their limited scope makes them less suitable for the prospective analysis of complex energy systems.

1.3. Research questions

Building on previous research on ESTD and identified gaps in pLCA application, this Master's thesis addresses the following questions

- What are the implications of employing pLCA instead of historical Life Cycle Inventory (LCI) databases and traditional LCA for assessing GWP in future energy systems?
- How do results from ESTD optimization change when quantifying construction-related emissions using pLCA compared to traditional LCA, specifically in the Belgian case study?
- What is the impact of re-quantifying emissions of neglected imported renewable fuels in the Belgian case study?
- How can uncertainties associated with the pLCA methodology be analysed and interpreted?

1.3.1. Outlines of the thesis

These research questions delineate the structure of this thesis:

- **Methodology to quantify emissions (Chapter 2):** This chapter begins with a review of traditional Life Cycle Assessment (LCA). It identifies the limitations of this methodology within the context of analysing prospective energy systems and proposes an alternative approach: prospective Life Cycle Assessment (pLCA). The challenges and issues associated with this method are discussed, followed by a detailed explanation of the *premise* Python library selected for this Master's thesis, along with other methodological choices and tools.
- **Energy system model (Chapter 3):** Here, the chosen application model, EnergyScope TD, is introduced. The focus is on the development choices made by Limpens et al., the structure, main equations, and parameters of the model. Additionally, the parameters undergoing modifications are described and placed within a mathematical framework, and the use of pLCA in the context of this model is motivated.
- **Case study - The Belgian energy system (Chapter 4):** This chapter outlines the criteria for selecting the case study, emphasizing the need for challenges in the model and homogeneous meteorological conditions within the territory. A brief presentation of the demand, resources, and technologies from 2020 to 2050 is provided, along with the applied modifications. Finally, an initial comparison of different scenarios for the year 2020 is presented to offer an overview of the general impacts of the modifications.
- **Belgian energy system in 2035 - scenario analysis (Chapter 5):** This chapter addresses the second, third, and fourth research questions. It is divided into two main sections. The first section examines the impacts of using pLCA instead of historical databases for quantifying the $gwp_{constr}(tech)$ parameter values, specifically applied to the Belgian energy system in 2035, by comparing the different systems studied. To address the fourth research question, this section also investigates the variations associated with different IAM scenarios used to modify the *ecoinvent* database. The second section focuses on the impacts of quantifying the operational emissions of imported renewable fuels. A similar comparative approach is employed, but using only one system, as the differences between systems have already been analysed in the first section.

- **Belgian energy system in 2050 - scenario analysis (Chapter 6):** This final chapter analyses the 2050 Belgian energy system, aiming to provide insights into the evolution of the re-quantified $gwp_{constr}(tech)$ parameter values over time and their implications on the outputs of the EnergyScope TD model.

Lastly, concluding remarks will summarise the main findings, offer suggestions and look to the future.

To complement Chapters 4, 5, and 6, two appendices (A and B) provide additional details. Appendix A outlines the *ecoinvent* processes and assumptions used to quantify the GWP parameter values of the Belgian energy system. Appendix B summarizes the different parameter values used in the three systems analysed in this Master's thesis for the years 2020, 2035 and 2050, with a special focus on the differences in the GWP quantification results.

Chapter 2

Methodology to quantify the emissions

As introduced in the previous chapter, Limpens et al. developed the EnergyScope TD model, which minimizes the total cost of the energy system while imposing a limit on global annual GHG emissions. To accurately assess these emissions, they adopted a life cycle approach, offering a comprehensive representation of the system's environmental impacts. Nevertheless, several gaps in the model have been identified concerning the quantification of these emissions. This chapter aims to succinctly outline the primary methodological framework used to quantify the environmental impacts of products or services. It also discusses the challenges and issues encountered in the prospective analysis of future energy systems, proposing the use of prospective life cycle assessment as a solution. The methodology is contextualized and explained, followed by a description of the main tools available and the methodological choices applied in the context of this research.

2.1. Principles of Life Cycle Assessment

The objective of a life cycle assessment (LCA) is to quantify the environmental implications associated with products or services across their entire life cycle, encompassing raw material extraction, manufacturing, usage, and end-of-life disposal. This approach aims to prevent any potential shifts in environmental impacts between different life cycle phases, such as those observed in the case of passenger mobility with the transition between combustion-powered and electric vehicles, where impacts may shift from fossil fuel usage to electricity generation or from the usage phase to the battery production.

Understanding the environmental impacts of a product or service throughout its entire life cycle is crucial for a comprehensive assessment of its sustainability. For instance, when comparing the impact of a photovoltaic panel and a gas turbine, focusing solely on the use phase might suggest that the photovoltaic panel emits minimal greenhouse gases (GHGs) while the gas turbine emits significantly more. However, this comparison overlooks factors such as materials extraction, manufacturing, and end-of-life management, which also contribute to the overall environmental impact. Thus, it is imperative to consider the complete life cycle in environmental evaluations.

The LCA approach provides a quantitative and standardised methodological framework for comparing the environmental impacts of different products or services. It is supported by internationally recognized standards provided by the International Organization for Standardization, the ISO 14040 series of standards, which facilitates the development of reliable LCAs. ISO 14040 [13] sets out the principles and frameworks, while ISO 14044 [14] specifies the requirements and guidelines, including the four steps illustrated in Figure 2.1, which will be developed in the next sections [15][16][17].

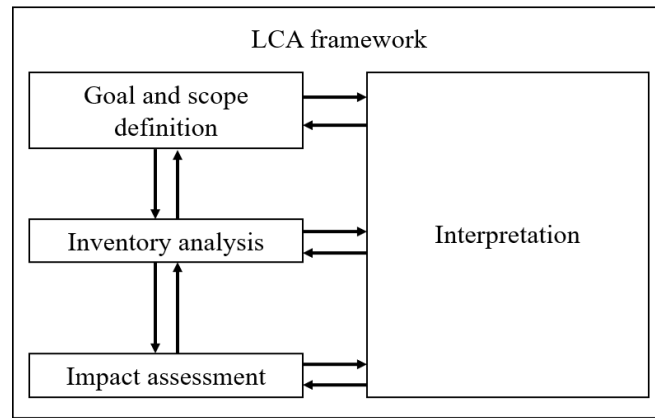


Figure 2.1: LCA framework defined by ISO 14040 standard

2.1.1. Goal and scope definition

An LCA approach first defines the goal and scope of the study, establishing its context. According to the ISO 14044, the objective should include elements such as the intended application of the study, the target audience and the reason for carrying it out. Defining the scope then consist of aligning the evaluation with the established objective, which requires key methodological decisions to be made. The most common are defined below but other choices can be made such as data quality requirements or identification of the allocation procedure, when working with co-products.

- The **functional unit** corresponds to the reference parameter that captures the LCA results and serves as the basis for comparisons. Its selection must be consistent with the objectives of the study and correspond to the purpose for which the product system was developed. For example, in a comparative LCA of different types of wind turbine, it could be defined as "1 kWh of electricity supplied to the grid".
- The **system boundaries** identify the unit of process that should be included in the life cycle. The 5 main life cycle steps are represented in Figure 2.2. Three main approaches exist and are detailed below.

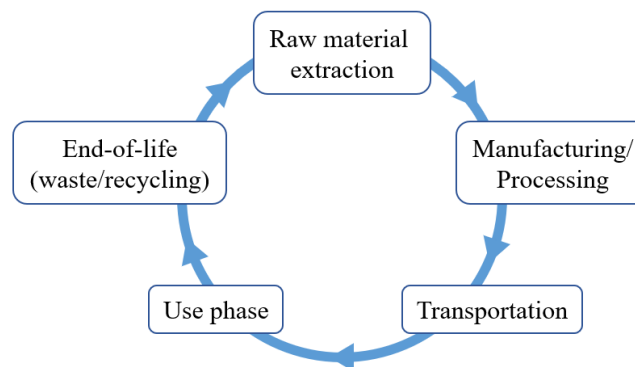


Figure 2.2: 5 stages of a product LCA

- **Cradle-to-gate:** Assesses the environmental impacts from the raw material extraction to the product's departure from the manufacturing facility (*'factory gate'*), excluding considerations of the product's usage phase and end-of-life management.

- **Cradle-to-grave:** Encompasses the entire life cycle, covering raw material extraction, processing, transportation, the utilization phase, and end-of-life product management.
- **Cradle-to-cradle:** An extension of cradle-to-grave assessment, including all five life cycle stages, with a focus on end-of-life management, incorporating recycling processes to facilitate material reuse from the initial product.

- **Impact categories and LCIA method:**

- The impact categories combine elements that have similar effects on the environment. For instance, the *climate change* category, expressed in $[kgCO_2 - eq.]$, offers a common metric to evaluate the climate effects of different gases such as methane, carbon dioxide or nitrous oxide.
- A multiple of **LCIA methods**, including the IPCC 2021, EPS 2020, and ReCiPe 2016, exist. They aim to translate emissions and resource extractions into environmental impacts using characterisation factors at midpoint or endpoint levels. As an example, Figure 2.3 illustrates the relationship between the midpoint impact categories and the endpoints (referred to as *area of protection*) in the ReCiPe 2016 method.

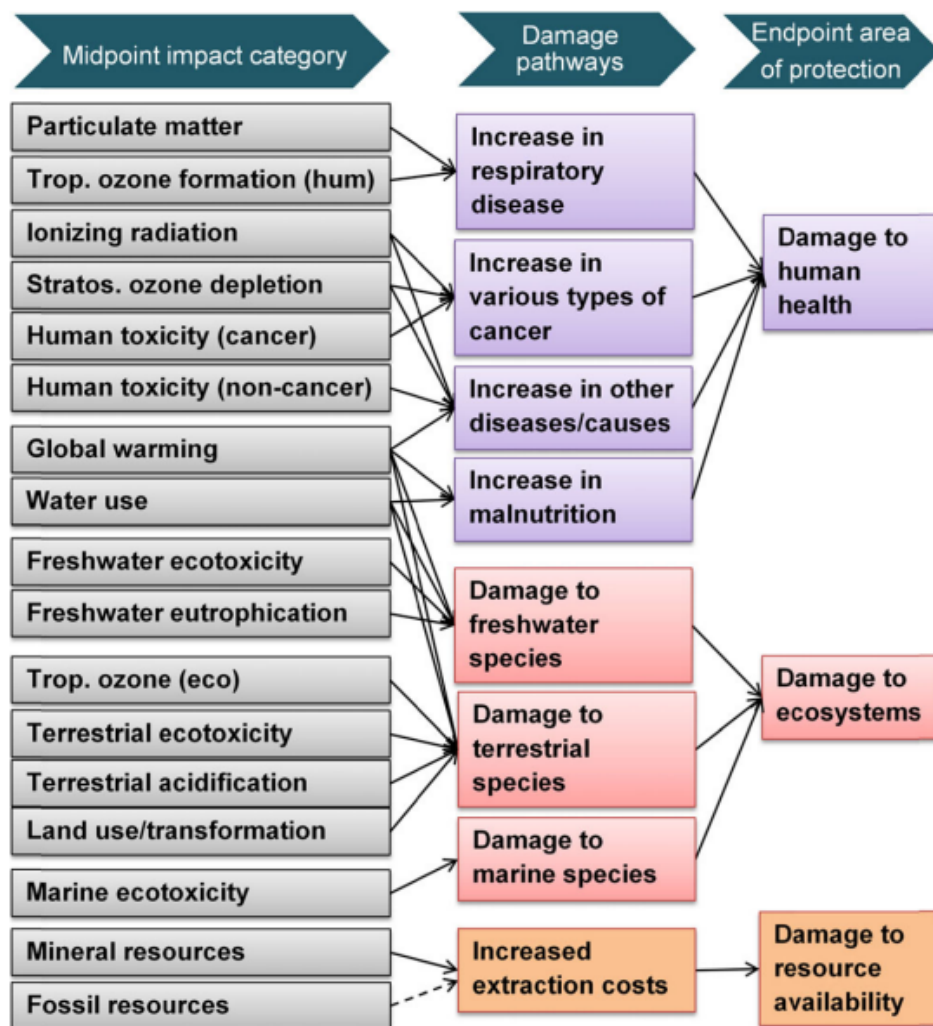


Figure 2.3: Overview of the impact categories and the relation linking midpoint and endpoint levels as describe in ReCiPe 2016, taken from Huijbregts et al. [1].

2.1.2. Inventory analysis

The LCI phase serves as the data collection stage in the LCA process. Its primary aim is to quantify the physical inputs and outputs, essentially measuring all the constituents entering and leaving the system defined in the previous step. These inputs and outputs encompass various aspects like energy, raw materials or emissions to the environment (air, soil, water). Given the complex nature of the systems under examination, this step typically starts with the development of a flow model, an example of which can be seen in Figure 2.4.

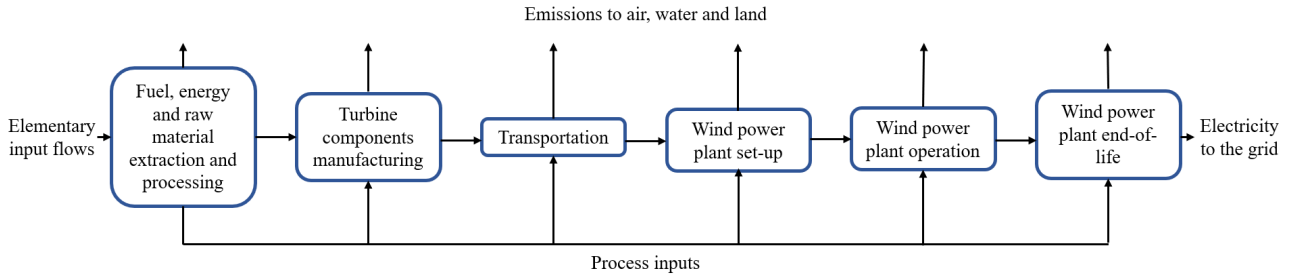


Figure 2.4: Flow model for a wind power plant, inspired by [2]

The system is methodically broken down into unit operations, as depicted in Figure 2.5, representing the smallest units for which data are available. This segmentation makes it possible to collect data for each sub-system, which facilitates the modelling of input-output flows. Inventory analysis is often based on databases presenting the input-output flows of unit processes, such as the *ecoinvent*, *NEEDS* and *GaBi* databases. The result of the LCI corresponds to a list of quantified elementary flows for the product or service system, expressed in terms of the functional unit.

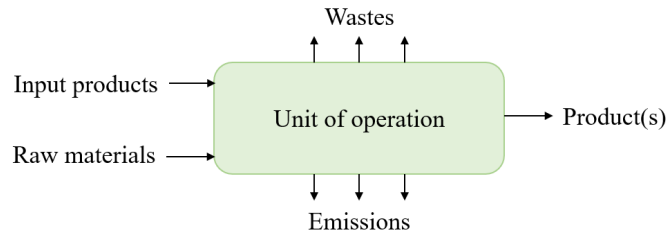


Figure 2.5: Structure of a unit of operation with the in and out flows

2.1.3. Impact assessment

In the Life Cycle Impact Assessment (LCIA) phase, the results obtained from the LCI are linked to specific impact categories selected using the LCIA method, as previously mentioned. This phase consists of four main stages, with the first two being mandatory according to the ISO 14040 standard.

- **Classification:** In this stage, each elementary flow identified in the inventory is allocated to particular impact categories based on its capacity to influence the selected indicator. For example, inputs or outputs leading to GHG emissions (CO_2 , CH_4 , N_2O , etc.) can be categorized under the climate change impact category.
- **Characterisation:** This step involves assessing the influence of each categorised input and output on the designated impact categories. The individual contributions are calculated and added together for each category. This calculation involves multiplying the categorised

values by the characterisation factor corresponding to each impact category considered. The characterisation factors indicate the degree of impact of a substance on a specific category. For example, when assessing the impacts of climate change, all GHG emissions are normalised to $[kgCO_2 - eq]$, which indicates the intensity of their impact in relation to carbon dioxide.

- **Normalisation:** Since impact scores are often expressed in units that are difficult to understand and compare, such as $kgCO_2 - eq$ for climate change and $kgSO_2 - eq$ for terrestrial acidification, the various impact scores characterised are standardised according to a common reference. This process involves dividing them by the score of a reference situation, making them dimensionless. This normalisation facilitates meaningful comparisons between impact scores.
- **Weighting:** Ranking is achieved by assigning weighting factors to the different normalized impact categories, thereby reflecting their relative importance. This allows for a quantitative expression of the severity of impacts in comparison to other categories.

2.1.4. Interpretation

In this stage, the results from the two previous steps are combined and analysed to answer the questions provided in the objective and scope definitions. Following ISO 14040 requirements, this stage comprises an extensive evaluation of completeness, sensitivity, and consistency, which provides essential data on the results' uncertainty and precision. The findings are then presented in a set of conclusions, limitations, and recommendations.

2.1.5. Issues and limitations

As indicated by Sacchi et al. (2022) [3] and Van Der Giesen et al. (2020) [18], the present LCA modelling framework, outlined by ISO standards 14040-14044, is primarily concerned with retrospective modelling and assessment of environmental impacts (*pre-ante*). This implies that data is derived from empirical experience after products or services have been in use for a long period of time. In the context of climate change and energy transition, significant changes are occurring, affecting the LCA of both existing and emerging technologies due to the rapid transformation of energy systems and industrial supply chains. This presents challenges to conducting thorough LCAs.

It is evident that traditional LCA, relying on static databases, lacks the capability to conduct *ex-ante* assessments of the environmental impact associated with future technologies, especially when pertinent information is unavailable prior to their large-scale deployment. Additionally, traditional LCA is typically tailored for small-scale applications and may not be well-suited for quantifying emissions related to the construction of technologies across entire energy systems, as discussed previously. Despite these challenges, *ex-ante* LCA holds promise in predicting potential environmental impacts and preventing environmental bottlenecks. However, this approach is hindered by data scarcity and a lack of coherent foresight into technological and societal trajectories. In response, pLCA has emerged as a viable alternative, integrating temporal projections into the LCI phase by adapting the underlying database utilized in the analysis.

2.2. Prospective Life Cycle Assessment

The pLCA literature is extensive, but has only recently been focusing on advanced methods that combine LCA with prospective energy systems or IAM scenarios. Early studies, in that field of research, linked IAM scenarios with LCA, primarily examining power generation, residential heating, and passenger mobility. Their aim was to assess the environmental impacts of future

technologies or system-wide effects with various transition pathways up to mid-century. One notable framework, primarily developed by Gibon et al. (2015) [19] and subsequently modified and improved on several occasions, 'THEMIS', integrated energy scenarios with prospective industry inventories to create a comprehensive hybrid LCA model that covers multiple world regions up to 2050.

These early studies were of considerable value, as they concentrated on modifying the background LCI database in order to create prospective Life Cycle Inventory (pLCI) databases that aligned with anticipated changes in the sector of interest. These efforts have introduced the concept of improving pLCA through IAM prospective scenarios and demonstrated its feasibility. However, these studies tended to focus on specific systems without considering broader industrial activities beyond the primary sector of interest. For instance, while focusing on the power generating sector, steel production or utilisation of cement were disregarded. In addition, previous technical integrations of IAM scenarios into LCI databases lacked adaptability across different databases.

To address these challenges, Sacchi et al. (2022) [3] developed an enhanced method for integrating IAM scenarios into the *ecoinvent* LCI database, based upon the work of Beltran and Cox [20][21]. The tool, designated *premise*, offers a more streamlined approach, facilitating comprehensive pLCA across diverse sectors and scenarios while enhancing the overall quality and consistency of pLCA. Moreover, it enables the development of consistent and reproducible databases, ensuring that results remain comparable regardless of the LCA software employed.

2.2.1. *premise*

The *premise* library¹, an open-source Python tool, facilitates the alignment of LCI data within the *ecoinvent* database to synchronise with the output results of IAM scenarios. Further details regarding the IAM scenarios and the *ecoinvent* database will be provided in Sections 2.2.1.2 and 2.2.1.3, respectively. This functionality enables the development of ad hoc LCI databases tailored to prospective policy scenarios extending from 2005 to 2100. The library is currently compatible with *ecoinvent* versions 3.6-3.9.1, supporting both "cut-off" and "consequential" system models. Support for the "consequential" model is however exclusively available for versions 3.8 and 3.9/3.9.1 of *ecoinvent*. The library is capable of accommodating a variety of IAM scenarios, including REMIND and IMAGE, and allows users to apply alternative scenarios as well.

In *premise*, scenarios are defined by their Shared Socio-economic Pathway (SSP), a climate trajectory, often by a Representative Concentration Pathway (RCP) and by a year. For instance, "SSP1-RCP2.6-2035" corresponds to the "SSP1-PkBudg1150-2035" in REMIND and has no attribute in IMAGE. This scenario follows '*optimistic trends for human development and economy, driven by sustainable practices*' and objectives of the Paris Agreement. It foresees a Global Mean Surface Temperature (GMST) increase of approximately 1.7°C by 2100. A table summarising the different scenarios implemented in *premise* is available in its online documentation.

2.2.1.1. Method

Figure 2.6 illustrates the fundamental workflow utilized by *premise* to generate pLCI within the framework of IAM-LCA. This process adheres to an extract-transform-load methodology.

Step 1 involves integrating the chosen IAM scenario into the process alongside the *ecoinvent* LCI database. Step 2 encompasses various transformations of the LCI database facilitated by *premise* using the *wurst* Python library. These alterations often necessitate additional external

¹online documentation is available at <https://premise.readthedocs.io/en/latest/index.html>

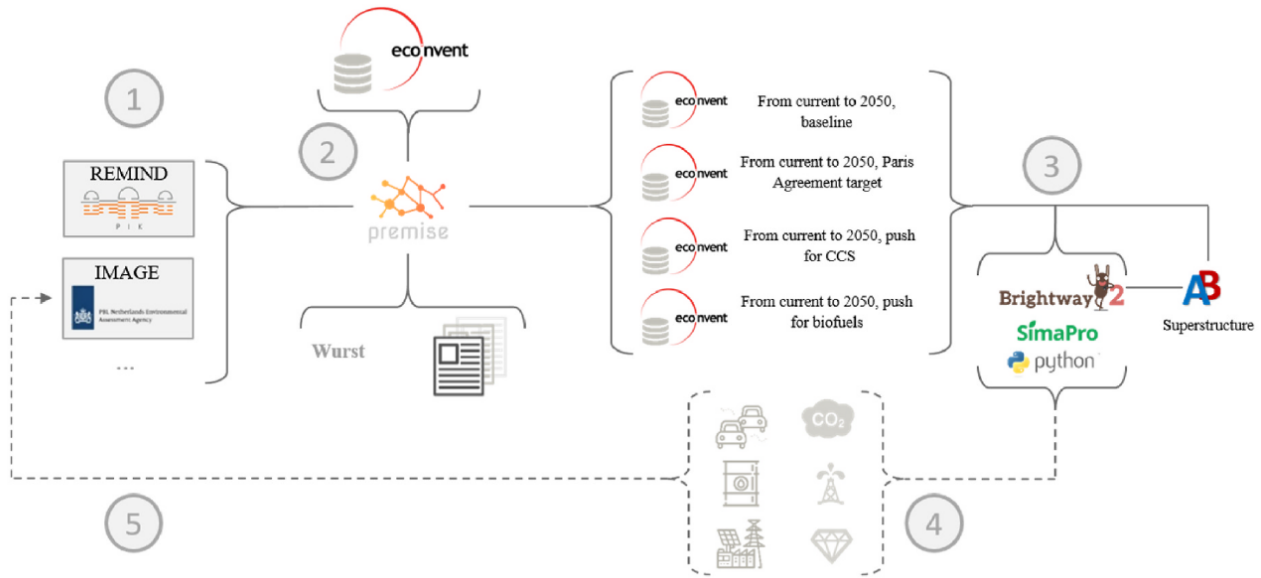


Figure 2.6: General IAM-LCA coupling workflow, taken from Sacchi et al. (2022) [3]

data, from existing literature, for the inclusion of emerging or future technologies. By the conclusion of this step, the LCI database is tailored to the specified year and scenario. The third step involves extracting the modified database into formats that are compatible with the different LCA software platforms such as Simapro or Brightway2. Alternatively, it can be reformatted into a set of sparse matrices that are suitable for numerical library processing. Another option, pertinent to this research, involves generating a "scenario difference file" to support a "superstructure" database compatible with Activity-Browser. This option enables the creation of a single database capable of exploring multiple scenarios. For instance, a global database corresponding to the "SSP1-RCP1.9" scenario spanning from 2005 to 2050 can be created with this last option. The subsequent steps, Step 4 and 5, involve generating LCA resource and environmental indicators, that subsequently feed back to the IAM scenario.

A more detailed explanation of each step is available [here](#) after.

1. The initial phase, referred to as the **EXTRACT** phase encompassing steps 1 and 2 in Figure 2.6, entails several key processes. This involves extracting and cleaning the *ecoinvent* database, alongside any supplementary inventories, and optionally incorporating user-provided data. Additionally, this phase includes caching, when the database or inventories are imported for the first time, and loading the IAM data.

Initially, *premise* can retrieve the database either from an existing Brightway2 project containing the database or from *ecospold2* files available on the *ecoinvent* website. In the context of this study, the first approach was adopted. Upon the initial extraction, a cache of the database is created and stored in the library folder.

The import of additional inventories follows the database extraction, irrespective of the scenario's designated year. This step aims to supplement the unaltered database to accommodate emerging technologies or update existing inventories. For instance, this could involve incorporating hydrogen production via various methods like coal gasification or revising inventories related to natural gas extraction. Detailed modifications are outlined in *premise*'s online documentation. It's important to note that the imported inventories may contain exchanges intended to link with an *ecoinvent* version different from the one

specified by the user during database creation in *premise*. Therefore, *premise* includes a migration map to translate certain exchanges, ensuring compatibility with the designated *ecoinvent* version.

Following the extraction of the database and additional inventories, *premise* proceeds to gather IAM data. An '*IAMDataCollection*' class is introduced to accomplish this, which is specifically designed to retrieve data from the IAM output file and organize it into multi-dimensional arrays. The collected data encompass various aspects, including production volumes crucial for establishing regional markets, dynamic efficiencies that evolve annually, land use and land use changes, as well as capture rates pertinent to carbon capture and storage technologies. Moreover, external data are used to complete the data collected from the IAM scenario. This is the case for instance for non-CO₂ pollutants emissions from different sectors like electricity, steel, and cement or anticipated efficiency enhancements for photovoltaic panels. To gather data relative to air emissions, *premise* utilizes specialized air emissions models like GAINS-EU or GAINS-IAM.

2. In the **TRANSFORM** phase, corresponding to step 2 in Figure 2.6, various adjustments, based on the data extracted in the previous phase, are made to the LCI database to align it with the performance of processes and technology market shares derived from the IAM scenario. These transformations encompass all sectors considered by *premise*, including biomass, power generation, steel and cement production, transport, direct air capture, and fuels. Initially, regional markets for specific products are established based on the IAM regions, receiving inputs from production activities situated within their respective geographical scopes. Subsequently, production activities are established, again defined by the regional geographies outlined in the scenario. These production activities incorporate region-specific efficiencies and non-CO₂ emissions. Furthermore, activities representing emerging technologies, obtained during the initial extraction step, are integrated to align with the selected scenario. Finally, input-consuming activities are linked to the newly created market activities situated within their geographic areas. Detailed descriptions of all modifications can be found in the online documentation.

The regional mapping of the various IAM models may differ slightly between each other and with the database. As an example, the geographical designation "Europe without Switzerland" within *ecoinvent* corresponds to the "EUR" region in REMIND and the "WEUR" region in IMAGE. Consequently, the *wurst* library performs a mapping to translate IAM regions into those used in *ecoinvent*. Upon completion of this phase, *premise* generates a *log* file documenting all changes made to the database, ensuring full transparency of the process.

3. The final steps of the process comprise the **LOAD** phase, as previously introduced. This phase involves extracting the modified database into formats compatible with various LCA software. *premise* offers multiple options to accommodate different needs. The first option involves reintegrating the database into a Brightway2 project. It can be formatted as either a standard Brightway2 database or a superstructure database, with the latter preferred for analysing multiple scenarios. The superstructure consolidates all scenarios into one database, accompanied by a "scenario difference file" readable by Activity Browser. Another option is to convert the database into sparse matrices, particularly useful when direct LCA software usage is impractical or when avoiding connections to SQL databases. This process generates a set of CSV files containing all information from the modified database. The third option is to translate the database into Simapro CSV files, compatible with Simapro or a modified version compatible with OpenLCA.

At the end of this three phases process, the *ecoinvent* LCI database is modified. The modifications applied are specific to a year and the specific IAM scenario chosen. This database can then be used in a large variety of LCA tools in order to obtain values evolving with time. In the context of this study, as will be elaborated after, the objective was to introduce time variations in the GWP parameter values of the EnergyScope TD. This is why this methodology was used.

2.2.1.2. IAM prospective scenarios

As previously discussed, *premise* utilizes IAM scenarios to adjust the LCI database. These scenarios outline potential pathways for transforming interconnected energy-economy-land-climate systems. Their aim is to offer valuable insights into global environmental change and sustainable development by quantitatively describing crucial processes within human and earth systems and their interactions.

IAM scenarios are broadly categorized into two types: cost-benefit IAMs and process-detailed IAMs. Cost-benefit IAMs, like DICE or Fund, assess the potential reduction in greenhouse gas emissions by considering carbon prices, without explicitly modelling underlying system changes. In contrast, process-detailed IAMs offer intricate representations of energy systems, GHG emission sources, and mitigation technologies, including detailed information on energy stocks, flows, and conversion technologies. Examples of process-based IAMs integrated within *premise* include IMAGE and REMIND.

- **IMAGE** (Integrated Model to Assess the Global Environment) is an integrated assessment model designed to simulate how human activities impact the global environment. IMAGE aims to provide a deeper understanding of the dynamics and long-term (up to 2100) implications of global transformations triggered by a variety of socio-economic and environmental factors.

Projection on the implications of energy, land, water and other natural resources, taking into account resource availability and quality are made through a socio-economic approach. In addition, the model calculates and accounts for unanticipated secondary effects such as emissions to air, water and soil, or the depletion and degradation of remaining stocks, such as fossil fuels and forest resources, in future projections [22].

To learn more about the model, readers are invited to visit the model's website at https://models.pbl.nl/image/Welcome_to_IMAGE_3.3_Documentation.

- Another compatible IAM with *premise* is **REMIND** (REgional Model of Investment and Development). This model, aimed at projecting the future trajectories of global economies, particularly focuses on the energy sector's evolution and its environmental implications. Its primary goal is to optimize investment allocation across both economy and energy sectors within each simulated region, considering factors like population dynamics, technological advancements, policy frameworks, and climate-related limitations. REMIND also incorporates regional trade patterns for goods, energy resources, and emissions permits, while comprehensively addressing all greenhouse gas emissions resulting from human activities within its modelling framework [23].

Readers can access the online documentation for this model here: <https://rse.pik-potsdam.de/doc/remind/2.1.0/index.htm>.

Characterisation of IAM scenarios in *premise*

As introduced earlier, in *premise*, scenarios are designed based on their SSP, a climate trajectory (RCP), and a target year.

To elaborate, an international team of climate scientists, economists, and energy systems modellers has recently developed a series of new "pathways" called the "Shared Socio-economic Pathways" (SSPs). These SSPs explore potential changes in global society, demographics, and economics over the next century. They present five distinct pathways, offering a broader perspective than what was previously done. They indicate that some futures will make climate change mitigation and adaptation easier than others. For instance, they argue that a future characterized by '*resurgent nationalism*' and '*a fragmentation of the international order*' could make it impossible to achieve the Paris climate objective of "global warming in 2100 well below 2 °C" [24].

In contrast, the "Representative Concentration Pathways" (RCPs) outline different potential levels of greenhouse gases and other radiative forcings by 2100, without incorporating socio-economic narratives, since these are provided by the SSPs. Both SSPs and RCPs were designed to be complementary.

Together, the RCPs and SSPs provide a comprehensive framework. The RCPs project greenhouse gas concentrations and potential warming, while the SSPs depict possible socio-economic conditions under which emissions reductions may—or may not—be achieved. These scenarios demonstrate that varying underlying factors, such as population and economic growth, can lead to different future emissions and warming outcomes, even in the absence of climate policy.

The five scenarios include

- **SSP1:** a global landscape characterised by sustainable development and equitable progress,
- **SSP2:** a scenario in line with historical trends with moderate progress,
- **SSP3:** a fragmented scenario, marked by the resurgence of nationalist ideologies,
- **SSP4:** a scenario characterised by an escalation of inequality,
- **SSP5:** a scenario characterised by rapid and unrestrained economic and energy expansion.

In *premise*, only the SSP1, SSP2 and SSP5 are represented.

Employed IAM scenarios in the context of this Master's thesis

One objective of this study is to assess the impacts of using pLCA rather than traditional LCA and static-historical LCI databases for quantifying emissions in future energy systems. Emissions are inherently linked to specific systems, so a particular application will be selected and described in Chapter 4. This pLCA approach will be applied to the construction-related emissions of the EnergyScope TD model using multiple IAM scenarios to facilitate meaningful discussions on the results. Two scenarios have been chosen for their distinct approaches to the future and transition pathways. The first scenario envisions a reduction in carbon emissions while maintaining a capitalist and predominantly fossil-based society. In contrast, the second scenario depicts a world where no major societal shifts occur, continuing along current trajectories. Their characteristics are compared in Table 2.1.

Both selected scenarios have been taken from the REMIND model. Their names combine the SSP pathway they represent with a peak budget that corresponds to the limitation of

SSP-RCP scenario	SSP2-RCP2.6	SSP5-RCP1.9
REMIND	SSP2-PkBudg1150	SSP5-PkBudg500/no equivalent
GMST increase by 2100	1.6-1.8°C	≈ 1.0°C
Society/economy trend	extrapolation from historical developments	optimistic trends for human development and economy, driven by fossil fuels
Climate policy	Paris Agreement objective	Paris Agreement objective
Peak carbon budget	1,500 GtCO ₂	500 GtCO ₂

Table 2.1: Comparison of the IAM scenarios selected for this Master’s thesis. The information are coming from the *premise* online documentation.

cumulative carbon dioxide emissions (not CO₂-equivalent emissions).

These two scenarios are noteworthy as they illustrate different pathways for transitions and encompass a broad range of possibilities. As previously stated and developed in the online *premise* scenarios explorer², the SSP2 scenarios occupy a middle ground between SSP1 and SSP5, depicting a future where social, economic, and technological trends continue without significant deviations from historical patterns. This reflects moderate progress toward development goals, a gradual decrease in resource and energy intensity, and a slow reduction in fossil fuel reliance. Conversely, in the SSP5 scenario set, economic growth is prioritised as the means to achieve societal goals, emphasising competitive markets, innovation, and consumerism. This approach results in considerable technological development and human capital advancement, but is strongly dependent on fossil fuels, with the energy system dominated by carbon-intensive resources.

Exploring one of the SSP1 scenarios would have offer valuable insights, showcasing a world transitioning towards sustainability. This set of scenarios is characterised by a reduction in resource and energy usage, a decline in dependence on fossil fuels, and a prioritisation of well-being over consumption. In these SSP1 scenarios, extensive international collaboration facilitates sustainable and equitable economic progress, technological breakthroughs, and the mitigation of income and social disparities, adhering to a "green road" trajectory.

It is important to note that the characteristics of the same SSP-RCP scenario can differ depending on whether the REMIND or IMAGE model is used, as shown by the CO₂ emissions for the SSP2-RCP2.6 scenario in Figure 2.7.

2.2.1.3. *ecoinvent* database

As introduced before, in this research, the *ecoinvent* database³ will be used due to its compatibility with the *premise* library. Although other databases like NEEDS or ELCD exist, *ecoinvent* stands out as a comprehensive global resource, born from collaboration among Swiss Federal Offices and research institutes. It furnishes detailed LCI data covering inputs, outputs, and environmental impacts across diverse industries. Widely embraced by researchers, businesses, and policymakers, *ecoinvent* facilitates thorough assessments of product and system environmental performance. It also ensures consistency and relevance, delivering transparent data on energy/material flows, emissions, and resource usage in sectors spanning agriculture to waste management. Transparency is ensured through meticulous documentation of process datasets, employing consistent methodological standards [25]. Different versions are available

²<https://premisedash-6f5a0259c487.herokuapp.com/>

³online documentation is available at <https://ecoinvent.org/>

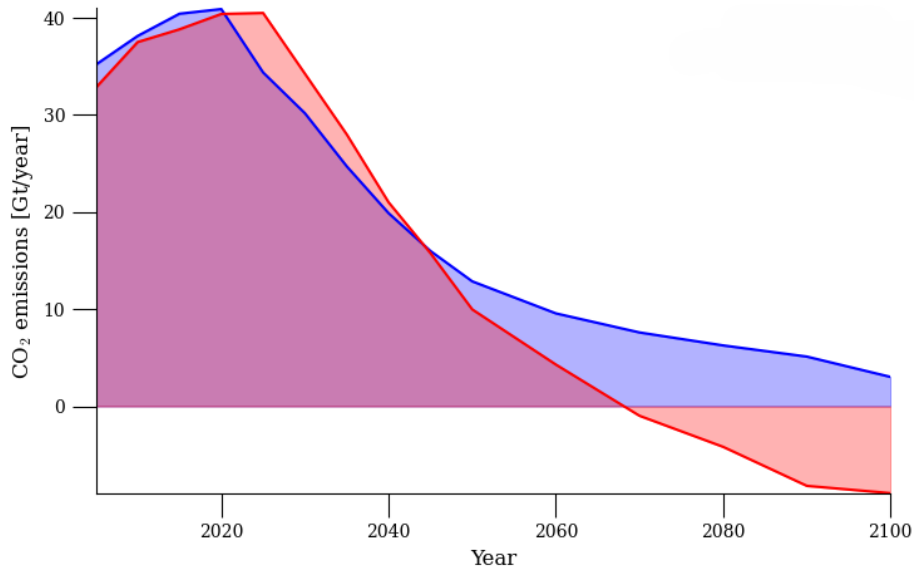


Figure 2.7: Comparison of the CO₂ emissions, at world scale, as modelled by the REMIND SSP2-PkBudg1150 (blue) and the IMAGE SSP2-RCP26 (red) scenarios.

though a license and various system models are also offered as explained in the online support documentation⁴. Those system models define where the allocation of impacts (or burdens) takes place through a set of modelling choices.

This study will employ the *ecoinvent* v3.8 database with the "allocation, cut-off by classification" method. The "cut-off" approach, in short, distinguishes between waste and recyclable materials, assigning waste management responsibility to producers ("polluter pays") and promoting the adoption of recyclable products.

Additionally, *premise* is also compatible with the "consequential" system model, which evaluates system changes by considering different assumptions. This model is valuable for forecasting future developments and conducting perspective analyses. However, it is limited to small scale applications.

Lastly, Limpens et al. applied *ecoinvent* version 3.2, employing the "allocation at the point of substitution" system model, which is not suitable for *premise*. This approach adopts an attribution-based method where waste responsibility is distributed between producers and subsequent users. These users benefit from treatment processes by utilizing the valuable products generated.

2.2.1.4. Activity Browser

Accessing the *ecoinvent* database and other LCI databases requires the utilization of specialized LCA software tools. These tools serve a crucial role in connecting processes, generating LCIs, and computing impacts, all of which involve handling intricate datasets and making numerous assumptions regarding impact attribution. Various LCA software options exist, such as GaBi, openLCA, and SimaPro. In the context of this research, the selection of software is based on several criteria, including the availability of an open-source solution, compatibility with *ecoinvent* database and *premise* library, and the capability for scenario modelling.

⁴<https://support.ecoinvent.org/system-models>

Given these considerations, Activity Browser⁵ has been selected. As described by Steuding et al. (2020) [26], it is an open-source tool designed for advanced LCA. Activity Browser offers a user-friendly interface to the Brightway2 LCA framework, streamlining tasks such as project and database management, inventory modelling, and result analysis. It also includes sophisticated features for LCA modelling and data analysis, enhancing contemporary LCA research. Activity Browser enables parametrization, scenario modelling, graph exploration, and the creation of pLCI databases using *premise*, among other advanced functionalities.

Another key feature of Activity Browser, outlined by Steubing and de Koning (2021) [27], involves utilizing a superstructure in scenario analysis. As previously discussed, integrating IAM scenarios into LCI databases often results in multiple scenario-specific databases, which presents challenges for LCA modelling. One suggested approach is to amalgamate these scenario-specific databases into a single comprehensive "superstructure" database, accompanied by a corresponding scenario difference file. This superstructure database encompasses all unique flows and processes found across all scenario databases, while the scenario difference file documents differences between scenarios, facilitating the transformation of the superstructure into specific scenario databases.

Once the database is modified using *premise* and a specific IAM scenario, obtaining the time varying results of the pLCA is made really easy using the combination of the superstructure and 'scenario LCA setup' of Activity Browser. This is the approach taken in this Master's thesis.

⁵<https://github.com/LCA-ActivityBrowser/activity-browser>

Chapter 3

Energy system model

As mentioned in the introduction, the EnergyScope TD model has been chosen for the analysis in this Master’s thesis. Chapter 1, outlined emerging concerns regarding the existing code version, particularly regarding emissions quantification. Subsequently, Chapter 2 detailed the primary methodology for quantifying environmental impacts, addressing its limitations and challenges within the framework of prospective energy system analysis, and suggested an alternative approach (pLCA).

This chapter examines the ESTD model in depth, elucidating the developers’ decisions, core equations, and parameters. Furthermore, it examines parameters that are scheduled for re-quantification using the pLCA approach, providing detailed discussions on the necessary modifications.

3.1. Selected model - EnergyScope TD

This study will use the EnergyScope TD model (ESTD), as outlined by Limpens et al. [4][7], which builds upon prior research made by Moret et al. (2016) [28] and Gironès et al. (2015) [29]. Developed through collaboration between UCLouvain and EPFL, this open-source whole-energy system - meaning that the model represents the electricity, heating and mobility sectors with the same level of details - optimization model aims to minimize the overall annual cost while meeting the demand of the system. It has been designed for regional energy systems like those of entire countries and the version chosen operates as a *snapshot* model, projecting the energy system into a targeted future year without considering the existing infrastructure. Validation for the Belgian whole-energy system of 2035 is documented in Limpens (2021) [4], which will constitute one of the application case in the context of this study. Additionally, the model has been applied to other energy systems including the Italian one for instance [30]. Extensions to the model, such as the multi-regional EnergyScope Multi-Cell by Thiran et al. [31], and pathway optimization methods, as discussed by Limpens (2021) [4] and Li et al. (2022) [32], have been developed. Further details on the model and its extensions are available in the online documentation (<https://energyscope.readthedocs.io/en/master/index.html>).

The model framework is illustrated in Figure 3.1, Limpens et al. have adopted a methodology consisting of two main steps. Initially, the model preprocess the time series data and solve a Mixed-Integer Linear Programming (MILP) problem to determine a set of typical days, as detailed in Section 3.1.1. Subsequently, the model optimizes the design and operation of the energy system based on these typical days, determining technology selection, quantities, and operational strategies for the target year. This process will be elaborated upon in Section 3.1.2.

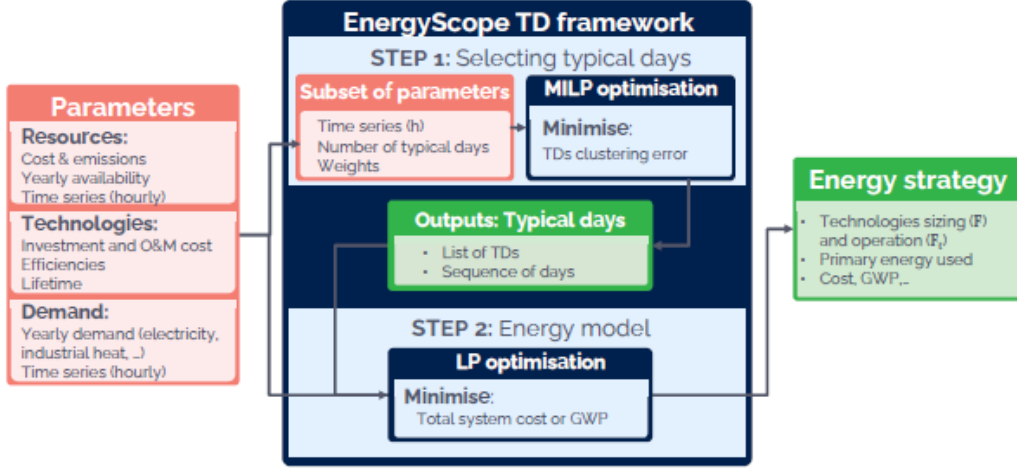


Figure 3.1: Overview of the EnergyScope TD framework, taken from Limpens (2021) [4].

3.1.1. Step 1 - Typical days

Due to computational constraints, the model's design, as outlined by Limpens (2021) [4], necessitated a number of decisions. Specifically, to ensure that the model could be used to analyse the integration of intermittent renewable energy resources and storage, an hourly resolution was required. However, optimizing such a complex energy model over 8760 hours would be very time-consuming. For instance, running the ESTD over the entire 8760-hour time series would consume more than 19 hours, compared to less than a minute with the chosen approach. These decisions revolve around the use of representative Typical Days (TD), striking a balance between computational efficiency and the introduction of approximation errors in the representation the energy system.

In ESTD, five time series are considered to classify the days of the year into TD. These time series represent end-use demand (electricity and space heating) and weather conditions (solar irradiance, onshore wind speed, and offshore wind speed), each weighted according to its relative importance. To cluster the days, the k-methods variant developed by Domínguez-Muñoz et al. (2011) [33] was adopted for its manageable computational requirements and efficiency. This method involves a MILP problem that groups days by minimizing the disparity between their time series and optimal cluster time series. The typical days for each group, used in the following steps, correspond to the centroid of the group, which represents its most characteristic day.

Another decision concerns the limitations of using TDs regarding inter-day or seasonal storage, due to the discontinuity between selected TDs. Inspired by Gabrielli et al. (2018) work [34], Limpens introduced "Method 1" or "Coupling typical days," where each day of the year is assigned to a TD via a sequence (TD_OF_DAY). This method connects the energy stored at the last hour of day x to the energy stored at the first hour of day $x+1$.

Employing a limited number of TD in system optimization may introduce biases in yearly demand and capacity factors. To mitigate this, time series normalization is employed in the model. For instance, if the historical data indicates a wind offshore capacity factor of 42%, while the calculated capacity factor is 40.6%, the wind offshore time series is adjusted accordingly, increasing it by 3.4%.

To find the optimal number of TD, various TD configurations need to be explored and their impact on thermal storage capacities, strategies to improve flexibility in the power sector and

computation time evaluated. After performing these evaluations, it was concluded that the use of 12 TD achieves a favourable balance between computational efficiency and accuracy of results. Consequently, this study also adopts the use of 12 TD.

3.1.2. Step 2 - Energy model

3.1.2.1. Linear programming formulation

The optimization model described is based on linear programming formulation. A simplified representation of this model can be found in Figure 3.2. The inputs, or parameters, of the model are known values representing various aspects such as system demand, variable bounds, resource availability, or construction emissions of different technologies. Concerning the core of the model, variables or unknown values, such as the capacity of wind onshore or the amount of coal used, need to be derivated to correspond to the objective function and constraints. These variables are constrained within specified bounds, typically between a minimum and maximum value defined in the parameters. Constraints, in the form of linear equality and inequality, must be satisfied for the model to be valid. The optimization process is guided by an objective function, typically aiming to minimize or maximize a particular aspect of the system. In this study, the objective function aims to minimize the total system cost, while constraints, such as those related to annualized construction and operation emissions, play a crucial role in shaping the optimization process.

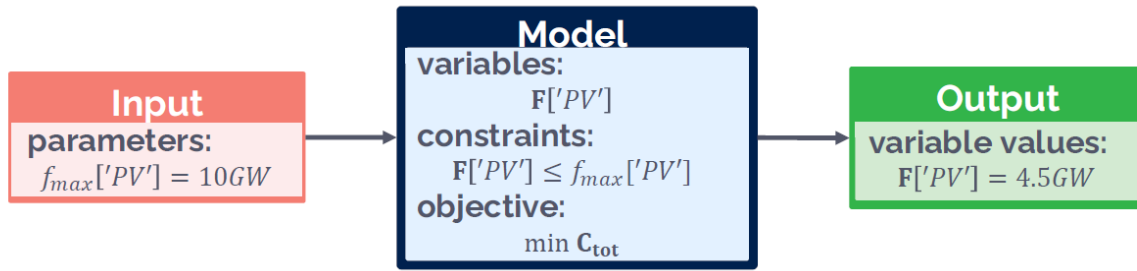


Figure 3.2: Conceptual illustration of the Linear Programming formulation and the nomenclature used, taken from [4]. In italic are the *parameters*, in bold uppercase the **Variables** and in italic capitals the *SETS*, which represent collection such as the resources or technologies. Symbols description: f_{max} maximum installed capacity, F installed capacity. Here PV has been taken from the set of technologies.

3.1.2.2. Conceptual modelling framework

The modelling framework proposed by Limpens et al. for EnergyScope TD offers a simplified representation of the energy system, encompassing electricity, heating, mobility and non-energy sectors with the same degree of detail. Its main objective is to align energy supply with known demand in these sectors. One of the notable features of this model is that it differs from conventional approaches that focus on Final Energy Consumption (FEC). Instead, it articulates demand around End-Use Demand (EUD), which identifies the energy required to meet specific needs. For example, in the context of high-temperature heat production using industrial gas boilers, FEC represents the amount of gas needed to run the boiler, while EUD reflects the heat generated by the boiler to meet the demand.

In the model, EUD represents the overall demand of the four sectors considered. This demand is then segmented into specific End-Use Types (EUTs) for each sector. For example, in the electricity sector, it is categorised into baseload and lighting. In the heating sector, a distinction

is made between high-temperature heat for industrial processes, low-temperature heat for space heating and for hot water, while the mobility sector is divided into passenger mobility and freight mobility. The non-energy sector includes fuels used primarily as raw materials in industry rather than for direct energy purposes. These include substances such as ammonia, methanol and HVC (high value chemicals).

The energy framework in EnergyScope TD consists of three elements, described below:

- The **resources** represent available primary energy, whether sourced locally or imported. Examples include natural gas, wet biomass or uranium.
- The **energy conversion technologies** act as the links between demand and resources, they can also be referred to as layers in this model. Within these layers the balance between demand and supply needs to be ensured at all time. For example, in the high-temperature heat layer, production and storage must constantly match consumption and losses. The technologies that link the layers of the model can be classified as follows: end-use (converting energy from one layer to the end-use layers), storage (transferring energy within the same layer) and infrastructure (connecting the non-use layers).
- The **demand** is expressed in terms of EUD, encompassing the four primary sectors.

Figure 3.3 illustrates the division of the energy system into three parts. In this representation, electricity imports, solar energy and natural gas are the resources used. Demand is divided between electricity, space heating and passenger mobility, taking losses into account. Specific technologies such as cogeneration or solar thermal are needed to convert solar energy and natural gas into their end-use layers, while electricity imports can either be used directly or transformed to meet heating or mobility needs.

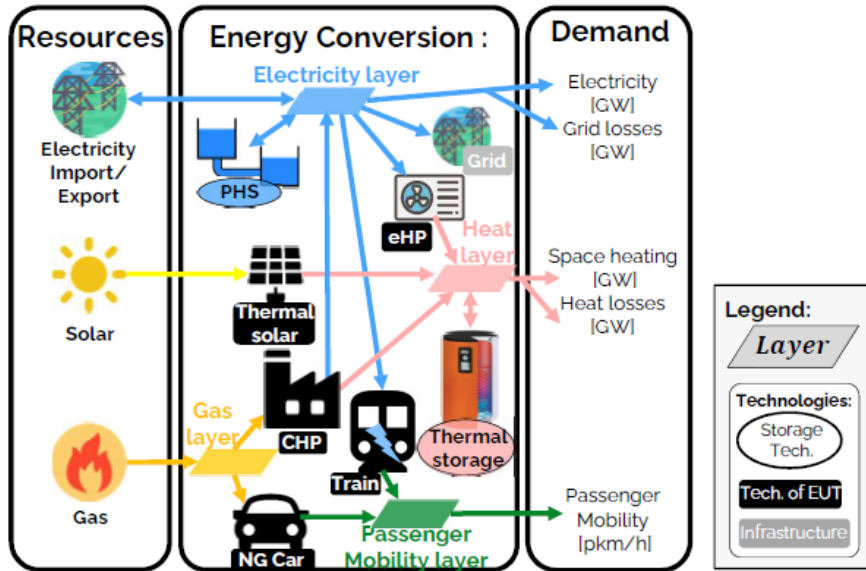


Figure 3.3: Conceptual representation example of a simplified energy system in EnergyScope TD using 3 resources, 8 technologies and meeting the demand of 3 EUTs. Figure taken from Limpens et al. [4].

3.1.2.3. Optimization model formulation

This section will focus on the development of some of the most useful elements of the model in the context of this study. For a comprehensive overview of the various sets, parameters,

variables and constraints of the model, readers are directed to Limpens (2021) [4].

Tables 3.1 and 3.2 provide a condensed summary of the key parameters and variables of this research and present in the equations presented here after. The parameter $gwp_{constr}(tech)$ is under particular consideration as it will be subject to adjustments using a pLCA approach, as discussed in Chapters 2 and 4. Additionally, the $gwp_{op}(res)$ parameter is significant, as it will undergo minor modifications to address the third research question.

Parameter	Units	Description
$c_{inv}(tech)$	$[M\text{€}_{2015}/\text{GW}]^{cde}$	Technology specific investment cost
$c_{maint}(tech)$	$[M\text{€}_{2015}/\text{GW}]^{cde}$	Technology specific maintenance cost
$c_{op}(res)$	$[M\text{€}_{2015}/\text{GWh}]$	Specific cost of resources
$\tau(tech)$	$[-]$	Investment cost annualization factor
i_{rate}	$[-]$	Real discount rate
$t_{op}(h, td)$	$[h]$	Time period duration (default 1h)
$lifetime(tech)$	$[year]$	Technology lifetime
$gwp_{constr}(tech)$	$[ktCO_2\text{-eq.}/\text{GW}]^{abc}$	Technology specific CO_2 -eq. construction emissions
$gwp_{op}(res)$	$[ktCO_2\text{-eq.}/\text{GWh}]$	Resource specific CO_2 -eq. emissions
gwp_{limit}	$[ktCO_2\text{-eq.}/y.]$	Higher yearly CO_2 -eq. emissions limit

Table 3.1: List of parameters of particular interest in the context of this study.

^a [Mpk] (millions of passenger-km) for passenger mobility technologies

^b [Mtk] (millions of ton-km) for freight mobility technologies

^c [GWh] for storage technologies

^d [Mpk/h] for passenger mobility technologies

^e [Mtk/h] for freight mobility technologies

Variable	Units	Description
$F(tech)$	$[GW]^{abc}$	Installed capacity
$F_t(tech \cup res, t, td)$	$[GW]^{abc}$	Operation in each period
C_{tot}	$[M\text{€}_{2015}/y.]$	Total annual cost of the energy system
$C_{inv}(tech)$	$[M\text{€}_{2015}/y.]$	Total annualized investment cost
$C_{maint}(tech)$	$[M\text{€}_{2015}/y.]$	Total maintenance cost
$C_{op}(res)$	$[M\text{€}_{2015}/y.]$	Total cost of resources
GWP_{tot}	$[ktCO_2\text{-eq.}/y.]$	Total yearly emissions of the system
$GWP_{constr}(tech)$	$[ktCO_2\text{-eq.}/y.]$	Total annualized construction emissions
$GWP_{op}(res)$	$[ktCO_2\text{-eq.}/y.]$	Total emissions of resources

Table 3.2: List of variables of particular interest in the context of this study.

^a [Mpk] (millions of passenger-km) for passenger mobility technologies

^b [Mtk] (millions of ton-km) for freight mobility technologies

^c [GWh] for storage technologies

Cost, emissions and objective function

The objective function, as expressed in Equation 3.1, in the EnergyScope TD model aims to minimize the total cost (represented by C_{tot}) of the energy system. This total cost comprises three components: the annualized investment cost (C_{inv}), the yearly maintenance cost (C_{maint}),

and the operational cost ($\mathbf{C}_{\text{op}}$), which covers the expenses related to the resources used for energy supply.

The first two costs are determined for each technology by multiplying the respective parameters for investment (c_{inv}) or maintenance (c_{maint}) costs by their installed capacity ($\mathbf{F}$), as shown in Equations 3.3 and 3.4. However, the calculation of operational cost is more intricate. It is computed as the sum of the resource-specific cost (c_{op}) multiplied by the quantity of resources used ($\mathbf{F}_t$) and the duration of the period (t_{op}), as indicated in Equation 3.5. Here, h denotes the hour of resource consumption, and td signifies the typical day within which that hour falls. Utilizing the set T_H_TD for this summation is equivalent to aggregating over the 8760 hours of the year.

It's worth noting that the annualization of $\mathbf{C}_{\text{inv}}$ accounts for the lifetime (*lifetime*) of the technology, considering an investment rate (i_{inv}), as described in Equation 3.2.

$$\min \mathbf{C}_{\text{tot}} = \sum_{j \in \text{TECH}} (\tau(j) \cdot \mathbf{C}_{\text{inv}}(j) + \mathbf{C}_{\text{maint}}(j)) + \sum_{i \in \text{RES}} \mathbf{C}_{\text{op}}(i) \quad (3.1)$$

$$\tau(j) = \frac{i_{\text{rate}} \cdot (i_{\text{rate}} + 1)^{\text{lifetime}(j)}}{(i_{\text{rate}} + 1)^{\text{lifetime}(j)} - 1} \quad \forall j \in \text{TECH} \quad (3.2)$$

$$\mathbf{C}_{\text{inv}}(j) = c_{\text{inv}}(j) \cdot \mathbf{F}(j) \quad \forall j \in \text{TECH} \quad (3.3)$$

$$\mathbf{C}_{\text{maint}}(j) = c_{\text{maint}}(j) \cdot \mathbf{F}(j) \quad \forall j \in \text{TECH} \quad (3.4)$$

$$\mathbf{C}_{\text{op}}(i) = \sum_{t \in T | [h, td] \in T_H_TD(t)} c_{\text{op}}(i) \cdot \mathbf{F}_t(i, h, td) \cdot t_{\text{op}}(h, td) \quad \forall i \in \text{RES} \quad (3.5)$$

As already introduced in the previous chapters, emissions are calculated using a traditional LCA within the framework of the existing model developed by Limpens et al. The model chooses the GWP as an indicator of GHG emissions, which is expressed in ktCO₂-eq./year. As a reminder, GHGs contribute to Earth's warming by trapping energy and slowing its escape to space, effectively acting as an insulating blanket. The impact of different GHGs on warming varies due to two key factors: their radiative efficiency, which is their capacity to absorb energy, and their atmospheric lifetime, or the duration they remain in the atmosphere. To compare the warming effects of different GHGs, the Global Warming Potential (GWP) was developed. Specifically, GWP quantifies the energy absorbed by the emission of 1 unit of gas over a given period relative to the emissions of 1 unit of CO₂. Thus, it is expressed in CO₂-equivalent, meaning that the higher the GWP, the more energy that unit of gas absorbs compared to one unit of CO₂ emissions [11][35].

The main equations and inequations of the model concerning on the emissions are listed below.

$$\mathbf{GWP}_{\text{tot}} = \sum_{j \in \text{TECH}} \frac{\mathbf{GWP}_{\text{constr}}(j)}{\text{lifetime}(j)} + \sum_{i \in \text{RES}} \mathbf{GWP}_{\text{op}}(i) \quad (3.6)$$

$$\left(\text{or, as done in Limpens (2021): } \mathbf{GWP}_{\text{tot}} = \sum_{i \in \text{RES}} \mathbf{GWP}_{\text{op}}(i) \right) \quad (3.7)$$

$$\mathbf{GWP}_{\text{constr}}(j) = gwp_{\text{const}}(j) \cdot \mathbf{F}(j) \quad \forall j \in \text{TECH} \quad (3.8)$$

$$\mathbf{GWP}_{\text{op}}(i) = \sum_{t \in T | [h, td] \in T_H_TD(t)} gwp_{\text{op}}(i) \cdot \mathbf{F}_t(i, h, td) \cdot t_{\text{op}}(h, td) \quad \forall i \in \text{RES} \quad (3.9)$$

$$\mathbf{GWP}_{\text{tot}} \leq gwp_{\text{limit}} \quad (3.10)$$

Equations 3.6 and 3.7 presents the computation of the annual total emissions ($\mathbf{GWP}_{\text{tot}}$) of the energy system. This can be represented either as the sum of the yearly construction emissions

($\mathbf{GWP}_{\text{const}}$) from the various installed technologies and the emissions from all resources used to operate the system ($\mathbf{GWP}_{\text{op}}$) (3.6), or solely as the operational emissions, as considered by Limpens (2021) (3.7). The approach selected for this Master's thesis is the first option, providing a more comprehensive perspective on the significant challenges associated with the European Union's goal of achieving carbon neutrality by 2050.

Equations 3.8 and 3.9 provide a more detailed description of the specific characteristics of these variables. The methodology matches that used for cost calculations, in which specific construction ($gwp_{\text{constr}}(\text{tech})$) and resource-related emissions ($gwp_{\text{op}}(\text{res})$) are employed.

As previously mentioned, the $gwp_{\text{constr}}(\text{tech})$ parameter represents the construction-related emissions associated with the different technologies in the model. It is quantified using a life cycle approach from 'cradle-to-gate'. In contrast, the resources-related emissions parameter ($gwp_{\text{op}}(\text{res})$), also referred to as the operation-related emissions parameter, represents the total emissions of the resources, from 'cradle-to-combustion'. This approach differs from traditional methods that only account for combustion emissions (direct emissions), thereby neglecting the indirect emissions related to extraction, transport, and other processes. The LCA boundaries of this specific model are illustrated in Figure 3.4. It is important to note that the use phase of different technologies is not strictly considered here. The combustion or use of the resource constitutes the operational part of the emissions, which can have significant impacts when considering other environmental indicators, some of which used in the Multi-criteria extension of the ESTD model for instance.

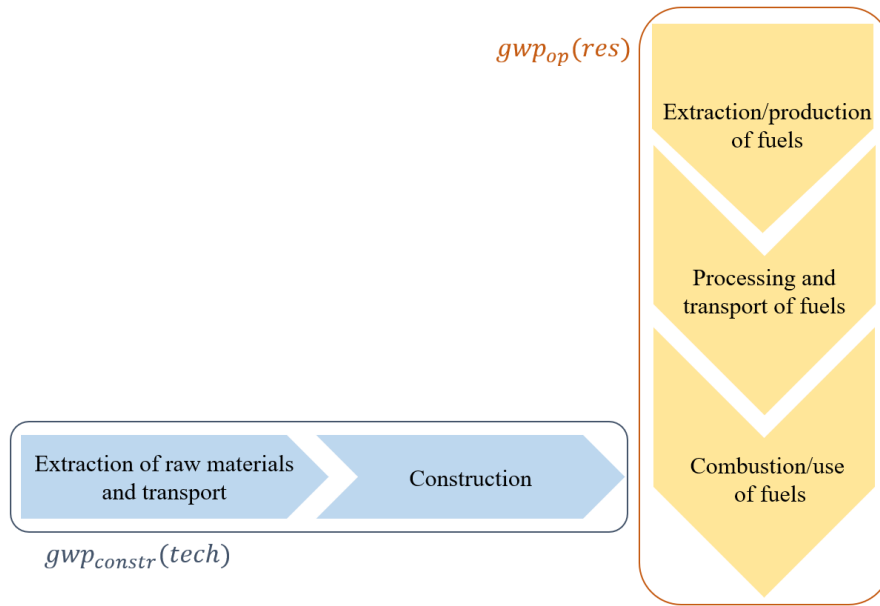


Figure 3.4: System boundaries of the EnergyScope TD LCA, in blue for the construction-related and in yellow for the operation-one.

In the context of this study, one final crucial constraint remains: the limitation on the annual emissions of the system, as depicted in Equation 3.10. This limit is defined within the model parameters and can be readily adjusted to examine the model's response to varying thresholds.

Modifications and justification for prospective life cycle analysis

Except for Equation 3.7, all equations from the existing model will remain unchanged in this study. Modifications will occur at the parameter level, tailored to the chosen case study. This includes re-quantifying $gwp_{\text{constr}}(\text{tech})$ for all technologies, many of which were previously ne-

glected, and $gwp_{op}(res)$ for some previously overlooked resources, as detailed in Chapter 4. Moreover, the values previously quantified are fixed in time, as a traditional LCA approach was used. However, since the model is designed to study the evolution of the energy system, this appears as an issue. The goal is to use a methodology which allows the variations of these GWP values over time, in order to represent the reality as closely as possible.

This section aims to justify the use of prospective life cycle assessment (pLCA) for quantifying the emissions of the system, rather than relying on traditional LCA and its static historical database in the context of this specific model. As explained in this chapter, the goal of the ESTD model is to optimize future regional energy system cost and operation. From this objective, two challenges arise for traditional LCA.

First, as detailed in Chapter 2, traditional LCA is more suited for small-scale applications due to factors such as the complexity of data collection. It may lack the capability to quantify the emissions of an entire regional energy system, which relies on hundreds of conversion technologies and many resources. The second challenge lies in the prospective nature of the study. Traditional LCA relies on static-historical databases derived from empirical experience, which limits its effectiveness when studying the environmental impacts of emerging technologies for which large-scale applications are not yet available to collect pertinent data. A solution is found in the use of pLCA, specifically through tools like *premise* and Activity Browser tool, as implemented in this study. Using pLCA rather than traditional LCA in the quantification of the $gwp_{constr}(tech)$ parameter values will introduce variations in time, as will be discussed in the next chapters.

Chapter 4

Case study - The Belgian energy system

The previous chapters outlined the methodologies for emissions quantification, including both pLCA and historical LCA, and highlighted their specific challenges and methodological choices made in this study. Subsequently, the chosen model, EnergyScope TD, for studying the implications of employing pLCA over historical LCA databases in assessing the Global Warming Potential (GWP) within future energy systems was presented.

This chapter shifts focus to the specific case study selected to examine the impacts of such re-quantification. It begins by discussing the criteria behind the case study selection and proceeds to describe the characteristics of the resources, demand, and technologies involved. Special attention is given to explaining the modifications made between the previously implemented system and the revised versions, along with the methodology employed for these adjustments. Additionally, an initial comparison of the different systems for the year 2020 is provided, offering an overview of the general impacts of the modifications.

4.1. Choice of the case study

To effectively demonstrate the relevance of the model and the modification of methodology adopted in the calculation of $gwp_{constr}(tech)$ and the re-quantification of neglected $gwp_{op}(res)$, it is essential to select a case study that is both consistent and challenging. The selection should prioritise an energy system characterised by robust development, ensuring minimal energy congestion, and located in a region with uniform meteorological conditions. In addition, the chosen system must present challenges related to the limited availability of resources, high demand in all sectors and a lack of clear pathways towards achieving carbon neutrality.

The Belgian energy system emerges as an excellent selection, aligning with the outlined criteria and having been previously investigated by Limpens (2021) [4]. Moreover, issues in quantifying certain resources and technologies have surfaced in this case study, as they were previously neglected. This study aims to examine the Belgian energy system for the years 2020, 2035, and 2050. Modifications will be necessary to adapt the existing model to address diverse research inquiries, particularly involving the re-quantification, using the pLCA methodology described in Chapter 2, of construction-related emissions ($gwp_{constr}(tech)$) associated with the various technologies of the energy system. Subsequently, neglected operational emissions ($gwp_{op}(tech)$) of certain resources will be quantified, using less advanced methodology.

Belgium, a rather small country with an area of 30,689 km² and a population of 11.7 million (in January 2023), has a remarkably high population density of 381 people per square kilometre. Geographically located in north-western Europe, Belgium's landscape is predominantly flat with a short coastline along the North Sea and some hilly areas near the German

border. The country benefits from stable weather patterns and has a well-developed energy infrastructure, particularly in gas and electricity distribution. However, despite these advantages, Belgium faces significant challenges in its energy sector as it aims to transition to a climate-neutral future. Limited access to renewable energy sources such as wind, solar, biomass, hydro and geothermal is a notable obstacle. In 2022, renewable energy and waste accounted for only 11.3% of total primary energy consumption, lagging behind many European peers. In addition, Belgium's significant final energy demand, amounting to 36.9 Mtep (429.15 TWh) in 2022, with the industrial sector accounting for around 26% of this demand, represents a significant barrier to achieving carbon neutrality. As a result, developing pathways to a carbon-neutral future in Belgium is proving more challenging than in countries such as Sweden or Norway, which have greater access to renewable resources. [36][37]

4.2. Belgian energy system modelling

The Belgian energy system described in EnergyScope TD is based on the foundations established by Limpens (2021) [4]. Covering the Belgian whole-energy system and projecting to 2050, the model incorporates the resources, intermediate networks and conversion technologies, and final demand, as explained in Section 3.1.2.2.

Depicted in Figure 4.1, the implemented system consists of 10 different end-use categories, 101 technologies, and 28 layers. Enhancements have been made to the 2015 energy system by incorporating promising future technologies and resources like carbon capture and storage facilities or the production of e-fuels. The figure also illustrates existing critical supply routes, such as meeting public road mobility demand with diesel buses.

As mentioned earlier, this current case study heavily relies on the foundational research outlined in Limpens (2021) [4]. Readers are encouraged to refer to this thesis for comprehensive details regarding the underlying assumptions and data sources. However, pertinent information will also be provided within this chapter. Additionally, other assumptions made will be thoroughly elaborated upon, and all data will be accessible in this chapter and in Appendix B. It should be noted that modifications have been applied to the technologies present in the system, with 112 technologies included in this study.

The following subsections will outline the figures and important aspects of the Belgian energy system, focusing on the process through which gwp_{op} and gwp_{constr} have been re-quantified, and the projections for the 2035 and 2050 system. This will be divided in three parts: resources, demand and technologies.

4.2.1. Resources

Resources are divided into 2 groups: endogenous and exogenous. In the context of this study, endogenous resources are locally produced. They are therefore limited in availability and mostly renewable. This category includes solar, wind, hydro, geothermal, biomass and waste, of which waste is the only non-renewable resource. These resources are defined by their maximum potential within the model. Energy can also be imported from abroad using exogenous resources, which include for instance imported electricity, uranium and other fuels. Their import price and maximum availability characterise these resources.

4.2.1.1. Endogenous - Local resources

At this point in time, there can be no doubt that the transition to a decarbonised economy is centred on three main areas: the movement towards sustainable energy sources, which must

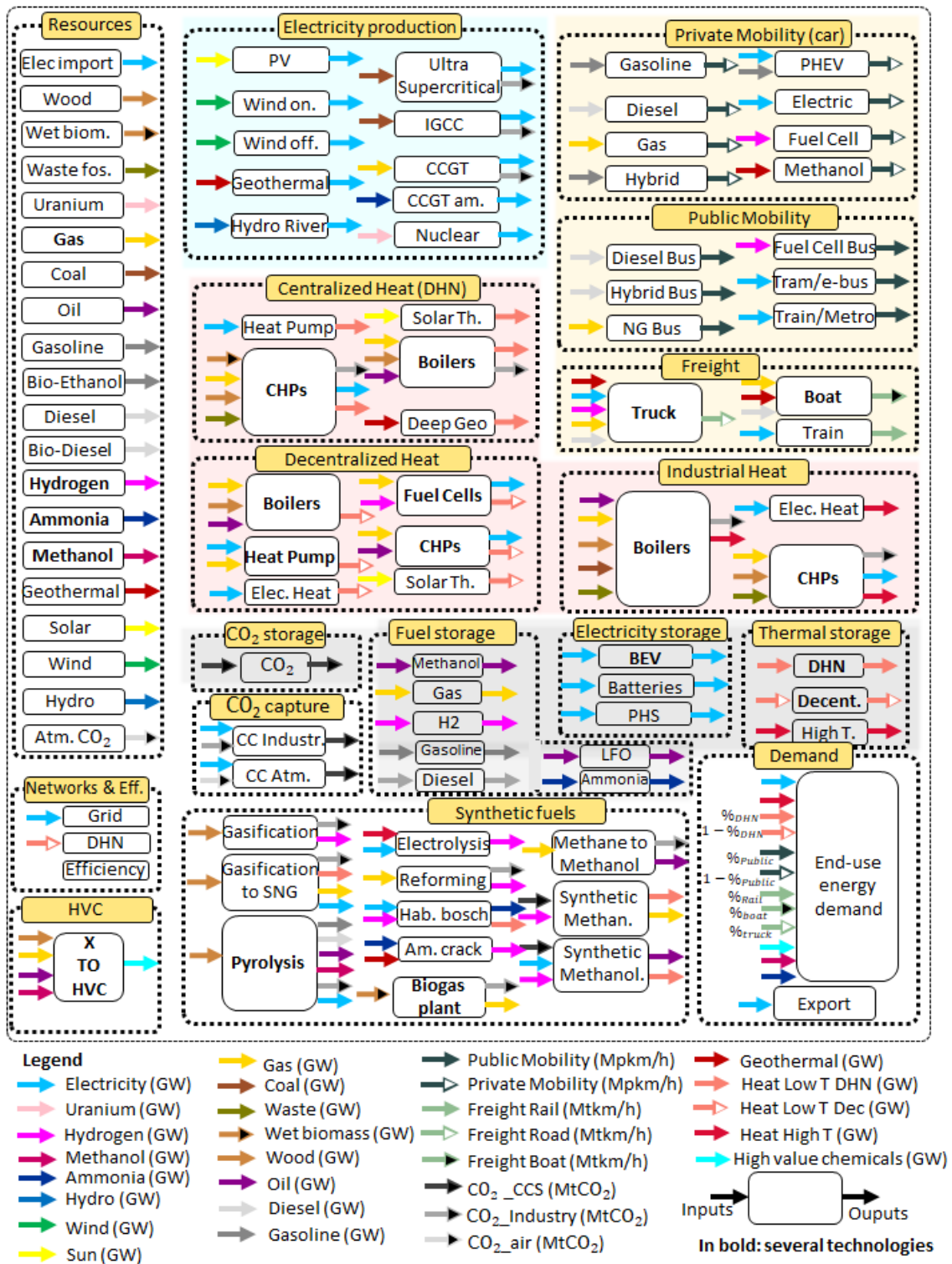


Figure 4.1: Application of the EnergyScope TD to the Belgian energy system, as modelled by Limpens (2021): overview of the resources, technologies and demands implemented. Technologies (in **bold**) represent groups of technologies with different energy inputs (e.g. Boilers include gas boilers, oil boilers ...). ‘Decent.’ represents the group of thermal storage for each decentralised heat production technology. Abbreviations: atmospheric (Atm.), battery electric vehicle (BEV), combined cycle gas turbine (CCGT), carbon capture (CC), carbon capture and storage (CCS) cogeneration of heat and power (CHP), district heating network (DHN), hydrogen (H₂), heat pump (HP), integrated gasification combined cycle (IGCC), methanation (methan.), natural gas (NG), onshore (on.), offshore (off.), plug-in hybrid electric vehicle (PHEV), pumped hydro storage (PHS), photovoltaic (PV) and synthetic liquid fuel (SLF). The figure has been taken from Limpens (2021) [4].

be renewable; a decrease in reliance on fossil fuels; and the electrification of the entire system, within feasible limits. However, the development of renewable energy faces considerable challenges in Belgium due to the limited resources at its disposal. As previously mentioned, renewable energy and waste accounted for only 11.3% of Belgium’s total primary energy use in 2022.

The potential of various resources is elaborated in Tables 4.1 (in terms of potential capacity) and 4.2 (in terms of available potential), juxtaposed with actual data from 2015.

	Technology	2015 [GW]	maximum potential [GW]
Electricity production	photovoltaic	3.85	≈ 60
	onshore wind	1.18	10
	offshore wind	0.69	6
	hydro river	0.11	0.12
	geothermal	0	≈ 0
Heat production	geothermal	≈ 0	≈ 0
	centralised solar thermal	0	≈ 70
	decentralised solar thermal	0	≈ 70

Table 4.1: Comparison between 2015 data and the maximum potential in the model for installed capacity of renewable energy-based technologies.

	Resource	2015 [TWh]	maximum potential [TWh]
Synthetic fuels	bioethanol	0.48	0
	biodiesel	2.89	0
	SNG	0	0
	Hydrogen	0	0
Biomass	woody	13.9	23.4
	wet biomass	11.6	38.9
Non-renewable	waste	7.87	17.8

Table 4.2: Comparison between 2015 data and the yearly maximum potential in the model of local resources.

Assumption 1. *Within this context, waste encompasses fossil waste such as plastics, while biomass denotes organic matter, considered renewable. Wet biomass refers to organic materials digestible by bacteria (such as crop residues or kitchen scraps like carrot peels), while woody biomass denotes those resistant to bacterial breakdown (from lignocellulosic biomass such as wood and sawdust). The organic waste collected by municipalities will then be classified as either wet or woody biomass.*

4.2.1.2. Exogenous - Imported resources

Different energy resources can be imported and categorized into two groups based on distinct criteria: renewable or non-renewable, depicted as columns in Table 4.3. In the model, imports are assumed to have infinite availability, except for coal and electricity imports, which will be treated separately.

Predicting future fuel prices is a challenging task, with many uncertainties, as articulated

by Limpens (2021) [4]: *'The only certainty for those who forecast future fuel prices is that they will be wrong.'* Indeed, recent events such as the COVID-19 crisis or the war in Ukraine have underscored the high dependency of fuel prices on various factors, actors, and unpredictable events.

The data presented in Table 4.3 are the outcomes of prior analyses and will remain unchanged in the context of this research.

Assumption 2. *Prices are assumed to increase or decrease linearly from 2015 to 2050, except for uranium that has a constant price.*

	Non-renewable				Renewable		
	2020	2035	2050		2020	2035	2050
gasoline	65.6	82.4	94	bioethanol	122.5	111.3	100.1
diesel	63.5	79.7	91.1	biodiesel	131.4	120.1	108.8
LFO	47.9	60.2	68.7	-	-	-	-
natural gas	33.6	44.3	53.3	SNG	132.3	118.3	104.3
uranium	3.9	3.9	3.9	-	-	-	-
coal	15.5	17.7	18.1	woody biomass	31.1	32.8	35.5
waste	21.2	23.1	25	wet biomass	5.3	5.8	6.2
H ₂	77.6	88	95.5	H ₂ RE	137.9	119.2	100.6
ammonia	72	94.7	114.1	ammonia RE	92.8	81.8	70.9
methanol	81.2	102	116.5	methanol RE	122.5	111.3	100.1

Table 4.3: Fuel prices [€₂₀₁₅/MWh] between 2020 and 2050 for the different resources of the case study. Except for biomass, all resources are imported. Abbreviations: LFO (light fuel oil), SNG (synthetic natural gas), RE (renewable). Fuel prices are increasing for non-renewable energy sources and decreasing for renewable ones, at the exception of biomass. Uranium is assumed to keep a constant price in the future.

The table provides a comparison of renewable alternatives to fossil fuels. These alternatives can be derived from biomass (*bio-fuels*) or electricity (*electro-fuels*). Various technologies are employed in the model to produce these renewable substitutes, as will be elaborated later. Renewable fuels can also be imported from other countries.

Assumption 3. *The price of electro-fuels is assumed to be equivalent to its production cost.*

Assumption 4. *The prices of imported bio-fuels are presumed to be the same as the one of their equivalent electro-fuels. No distinction is made between electro and bio fuels.*

Electricity imports The electricity import availability is limited by the country's maximum net transfer capacity ($elec_{import,max}$ in [GW]), and it is expected that prices will rise over time. These factors remained unaltered within the scope of this study and can be found in Table 4.4. The final parameter related to electricity imports (gwp_{op}) will be addressed next (Section 4.2.1.3).

Assumption 5. *A limit has been established with regard to the proportion of electricity originating from neighbouring countries in order to prevent a potential electrical dependency from abroad. It is been fixed to 30% of the EUD in electricity.*

	2020	2035	2050
availability [TWh]	25.2	27.6	32.4
c_{op} [€ ₂₀₁₅ /MWh]	63.7	84.3	104.9

Table 4.4: Availability and price (c_{op}) of the electricity imports between 2020 and 2050. The availability and cost are expected to increase with time.

Coal As detailed in Section 4.2.2.2, Belgium, as implemented by Limpens (2021), is in line with the goals of the European Green Deal, striving for a climate-neutral Europe by 2050. Over time, all fossil fuels except for waste, which is considered as fossil, will be gradually eliminated from the Belgian energy mix. Consequently, the quantity of coal available in the model from 2015 to 2050 is limited to the level consumed in 2015 (33.4 TWh/y).

4.2.1.3. Accounting of the emissions

As previously mentioned, there are various methods for assessing the GHG emissions of resources available in the literature. These methods include those that account for direct emissions, typically from the combustion of the resource, and those that account for indirect emissions. The latter takes a life cycle approach, considering all stages of the resource's life cycle, including extraction, transformation, and transportation.

In this study, similar to the methodology used by Limpens et al., both direct and indirect emissions are incorporated into the model and represented as gwp_{op} in [ktCO₂-eq/GWh].

Limpens derived these values using a traditional LCA approach from 'cradle-to-combustion', as explained in Section 3.1.2.3. The assessment utilized the *ecoinvent* v3.2 database and applied the "allocation at the point of substitution" method, using the "GWP100a-IPCC2013" indicator. However, it is crucial to recognize that indirect emissions may change in the future as the energy mix shifts towards decarbonization, although this aspect hasn't been factored into the model. Addressing this issue would necessitate re-quantifying the $gwp_{op}(res)$ parameter for all resources present in the case study using the pLCA methodology described earlier. This goes outside of the scope of this study. Only the re-quantification of the gwp_{op} for the "electricity imports" resource was done using this approach.

Assumption 6. *Indirect emissions are assumed to remain constant from 2015 to 2050, except for those related to electricity imports.*

It is important to note that the previous version of the case study also included evolving emissions related to imported electricity. The method employed by Limpens (2021) involved the calculation of the gwp_{op} for the year 2015, followed by the assumption of a linear decrease between 2015 and 2050, with the value reaching zero by that year.

Table 4.5 presents a summary of the emissions associated with the various resources included in the model. It can be observed that emissions resulting from the use of imported renewable fuels have not been accounted for in the previous analysis. As advanced by Dumas et al. (2022) [12], it is assumed that these fuels emit fewer GHG emissions than other renewable resources, including solar, wind, and geothermal energy. Currently, the data available regarding the GWP of renewable fuels is insufficient to support this assumption. To answer this issue, the neglected values will be re-quantified, based on data found in the literature.

		Resource	$gwp_{op}(res)$ [ktCO ₂ -eq/GWh]
Non-renewable	Fossil fuel	gasoline	0.3448
		diesel	0.3148
		LFO	0.3115
		natural gas	0.2666
		coal	0.4014
	Other non-renewable	uranium	0.0039
		waste	0.1501
		hydrogen	0.3638
		ammonia	0.285
		methanol	0.35
		electricity imports	0.413
Renewable	Biomass	woody biomass	0.0118
		wet biomass	0.0118
	Bio-fuel	bioethanol	0
		biodiesel	0
		SNG	0
		hydrogen RE	0
		ammonia RE	0
		methanol RE	0

Table 4.5: Emissions linked to the different resources implemented in the previous Belgian case study for the year 2020, as done by Limpens (2021) [4]. All $gwp_{op}(res)$ parameter values will remain unchanged, at the exception of electricity imports and imported renewable fuels.

Changes made

Electricity imports Belgium’s electricity landscape is intricately linked with its neighbouring countries through several interconnections, such as the Nemo link with the UK, ALEGrO with Germany, and the Avelgem-Avelin connection with France. These connections facilitate the exchange of electricity, with import and export flows fluctuating annually based on the circumstances in each nation. For instance, in 2022, Belgium’s electricity exports to France surged to 10,688 GWh, while imports stood at a mere 839 GWh, largely influenced by France’s nuclear energy challenges. While for the year 2021, the exports from Belgium were of 6,976 GWh and imports from France of 4,372 GWh [38][39].

Moreover, these interconnections are subject to continual development, with new projects constantly emerging. The commissioning of the UK link in early 2019 marked a significant milestone, while ongoing initiatives like the cross-border interconnection with Denmark underscore the evolving nature of Belgium’s energy infrastructure [40].

Navigating the future of electricity imports poses a considerable challenge given this dynamic landscape. In this study, the percentage of imports from each neighbouring country has been used to evaluate the $gwp_{op}(res)$ of future electricity imports. Using historical data and forecasts provided by ENTSO-E for 2040 [41], the distribution of imports as shown in Table 4.6 has been calculated using linear regression. Detailed information are available in Appendix A.1.1.

	2020	2035	2050
United Kingdom	4.83	10.88	12.59
the Netherlands	52.29	40.94	37.73
Germany	9.93	15.58	17.18
Luxembourg	0.44	0.05	-0.06
France	32.51	32.55	32.56

Table 4.6: Belgian electricity imports by origin [%].

Subsequently, employing these percentages, the Activity Browser tool and the *ecoinvent* database, previously modified using *premise* and the IAM scenarios presented before, the gwp_{op} parameter values outlined in Table B.4 were obtained.

	gwp_{op} [ktCO ₂ -eq/GWh]		
	2020	2035	2050
Limpens (2021) ^a	0.413	0.206	0
REMIND SSP2-PKBudg-1150 ^b	0.335	0.031	0.017
REMIND SSP5-PKBudg-500 ^b	0.317	0.016	0.012

Table 4.7: Comparison of overall emissions for electricity imports as previously and newly quantified in the EnergyScope TD model. Differences are observable, depending on the method used to quantified the GWP.

^a using *ecoinvent* v3.2 database and IPCC 2013 GWP100 indicator

^b using *ecoinvent* v3.8 database and IPCC 2021 GWP100 indicator

Imported renewable fuels As previously mentioned, the emissions associated with imported renewable fuels were neglected in the earlier version of the case study. To address the third research question, it is necessary to modify the $gwp_{op}(res)$ of these fuels. However, due to the complexity of data collection for these resources, an alternative and more expedient approach was employed. Here, since the objective is to assess the impact of including these emissions rather than neglecting them, fixed data from the literature were used, as shown in Table 4.8. The use of the pLCA methodology to quantify these emissions and those linked to other resources can constitute future improvements, as will be proposed in the conclusion of this work. The complete methodology and sources used are detailed in Appendix A.1.2. It is to be noted that these data are highly uncertain, due to the lack of information in this field of research. Nevertheless, considering uncertain data is preferable to omitting these emissions entirely, as it provides a more comprehensive and realistic assessment of the environmental impact. This will be elaborated upon in Section 5.2.

4.2.2. Energy demand and political framework

4.2.2.1. Energy demand

As computed and elaborated in greater detail within Limpens (2021) [4], the annual end-use demand (EUD) across all sectors relies on the projections conducted by the European Commission for Belgium. Table 4.9 illustrates the projected trend for future end-use demand between 2020 and 2050.

A review of the data reveals that both passenger and freight mobility are anticipated to experience growth in the near future. This is a consequence of the demographic evolution in

$gwp_{op}(res)$ [ktCO ₂ -eq/GWh]	
biodiesel	0.271
bioethanol	0.447
hydrogen renewable	0.269
ammonia renewable	0.377
methanol renewable	0.393
gas renewable	0.2445

Table 4.8: New values for the $gwp_{op}(res)$ of the previously neglected imported renewable fuels.

EUD	EUT	2020	2035	2050	units
Electricity	baseload	50.6	67.4	73.3	[TWh/y]
	lighting	24.2	29.9	31.9	[TWh/y]
Heat	high temperature	59.4	61.9	56.7	[TWh/y]
	space heating	103.1	96.1	92.1	[TWh/y]
	hot water	25.5	23.6	22.6	[TWh/y]
Mobility	passenger	109.7	151.2	159.3	[Gpkm/y]
	freight	69.2	84.7	92.8	[Gtkm/y]
Non energy	non energy	51.5	53.1	55	[TWh/y]

Table 4.9: Evolution of the energy demand by end-use demand (EUD) and end-use type (EUTs) between 2020 and 2050 in Belgium. Predictions made showcase an increase the demand in all EUDs, except for the heat sector.

Belgium that is predicted to be positive. Furthermore, the increase in the number of inhabitants will also impact the demand for electricity and low-temperature heat. Nevertheless, the implementation of efficiency measures, such as the insulation of habitations and the reduction of public lighting, will serve to mitigate the rising effect.

It is crucial to differentiate between the implementation of efficient technologies and the adoption of efficiency measures. Efficient technology is defined as technology that consumes less primary energy for a similar or improved service. For instance, heat pumps are capable of fulfilling similar demands as those met by electric heaters, yet they consume fewer resources. In contrast, efficiency measures are actions taken to reduce end-use demand for a similar service. In the context of the implemented Belgian energy system, the reduction in low and high-temperature end-use demand is attributed to the implementation of efficiency measures.

4.2.2.2. Political framework

The present case study is set within a Belgian policy framework aligned with the objectives outlined in the European Green Deal, which aims for a climate-neutral Europe by 2050. Accordingly, fossil fuels, with the exception of waste, will be phased out of the Belgian energy mix between 2015 and 2050.

Coal As previously stated, coal was still utilized in 2015 and continues to be a component of the resources employed for high-temperature generation. Consequently, in order to achieve the goal of reducing the use of coal progressively to reach a zero level by 2050, the availability limit of coal was set to the amount used in 2015, which was approximately 33.4 TWh.

Nuclear power In 2022, nuclear power plants generated 43.9 TWh of electricity, which represents 45.7% of the total gross electricity production. This production was ensured by seven reactors, two of which have been decommissioned since September 2022 and January 2023. The decision to decommission these reactors was preceded by a political announcement made in December 2021, which outlined the gradual phase-out of all seven reactors between 2022 and 2025. This phased shut-down led to a reduction in available electricity production from 5.9 GW to just 2 GW by 2025. The actual production (2024) is ensured by five reactors spread over two sites (Doel and Tihange), all of which are approaching the end of their planned operational lifespans. However, on 18 March 2022, it was declared that the operational life of two reactors (Doel 4 and Tihange 3) would be extended beyond 2025 for an additional ten years. Together, these two units contribute approximately 2 GW to the electricity grid. In order to reflect the new political decisions, modifications were made to the initial case study implemented by Limpens (2021) [42][43].

4.2.3. Technologies

In the forthcoming years, technological developments are anticipated to align with increasingly stringent environmental regulations, with a particular focus on enhancing efficiency and leading to variations in costs (primarily reductions, though occasionally increases). The EnergyScope TD model incorporates these variations into the case study.

As proposed by Limpens (2021), four characteristics of the various technologies are evolving over time to follow the transition: capital cost (c_{inv}), maintenance cost (c_{maint}), efficiency (f) and annual capacity factors. The existing values for these parameters will remain unchanged in this version of the case study. In addition, the lifetime of the technologies, which does not evolve over time for the sake of simplicity, can be added to the already mentioned parameters. Nevertheless, one technology-related parameter that was previously implemented as constant throughout the transition will be modified, namely construction-related emissions ($gwp_{contr}(tech)$). This change will be outlined in greater detail in Section 4.2.3.1.

Finally, all implemented data will be summarized in Appendix B. For further insight into the data sources and calculation methodologies employed for previously implemented data, readers are referred to Limpens (2021) [4].

4.2.3.1. Accounting for emissions

Previously, emissions related to the construction of various technologies were considered constant throughout the transition period. These emissions were calculated using the *ecoinvent* database v3.2 with the "allocation at the point of substitution" method, and the "GWP100a-IPCC2013" indicator was used to determine the Global Warming Potential (GWP). As shown in Appendix B.3.3, data for certain technologies, such as diesel buses and hydrogen storage, were unavailable and thus excluded from the analysis. In fact, only the emissions for the electricity and heat production sectors were quantified. The emissions from other sectors, such as synthetic fuel production, storage, and mobility, were neglected. Furthermore, as noted by Limpens, his thesis primarily focused on resource-related emissions, so the $gwp_{contr}(tech)$ parameter was not directly utilized.

One objective of this study consists of analysing the impact of changing the method used to calculate the $gwp_{contr}(tech)$ parameter. To do so and as previously explained in Section 2.2, the library *premise* has been used to modified the historical cut-off *ecoinvent* database v3.8 to align with the scenarios chosen. Then the different technologies were represented following an existing database developed by some researchers of the UCLouvain. This database has been

revised and modified when needed, as explained in Appendix A.2. Finally, the $gwp_{constr}(tech)$ values were obtained through the use of Activity Browser with the 'GWP100 - IPCC 2021' indicator and the scenario LCA setup.

Indicator selection A comprehensive test using all available climate change indicators within the Activity Browser LCA tool was conducted to select the most appropriate for quantifying the Global Warming Potential (GWP) of the various technologies.

For the GWP indicator, the duration a gas remains in the atmosphere is crucial as it determines the amount of energy this gas can absorb over time. To account for this, the Intergovernmental Panel on Climate Change (IPCC) has established three time horizons: 20, 100, and 500 years. The 100-year horizon is the most commonly used and recommended as it provides a balanced perspective between short-term and long-term impacts. These values are periodically updated, with changes made in 2001, 2007, 2013, and 2021.

During the tests made on some of the technologies implemented in the system, six indicators for GWP calculation were evaluated: IPCC 2013 GWP20-100-500, IPCC 2021 GWP20-100-500, and ReCiPe 2016 GWP1000. The results indicated that GWP100 is the most appropriate choice, as predicted. Given the update to the IPCC GWP100 in 2021, this indicator was selected.

Data acquisition Regarding data acquisition, it is important to note that no new 'proper' data collection was conducted for this study. Instead, the data acquisition for the technologies is based on prior work carried out by a research group at the IMMC institute of UCLouvain, as collecting new data was beyond the scope of this research. Consequently, this study relies on an existing database, which has been revised and utilized to perform the pLCA of various technologies within the energy system. A summary of the assumptions and methodologies used to create this database is provided in Appendix A. Special attention is given to transport technologies, as the database was adjusted to reflect the specifics of the Belgian fleets.

4.3. Reference case - Belgium in 2020

As the EnergyScope TD model and the Belgian case study have already been validated by several studies, this research will not compare reported values with the model's outputs but will directly compare the outputs of the model for different scenarios. Each scenario corresponds either to the Belgian energy system as implemented by Limpens (2021) or to the modified system using different IAM scenarios to alter the *ecoivent* database (SSP2-RCP2.6 or SSP5-RCP1.9 as modelled by REMIND).

In Table 4.10, the model outputs for the different systems tested are compared. The three scenarios have been constrained to emit **107** MtCO₂-eq., for both construction and operation, reflecting the emission levels of Belgium in 2020 [44]. In this context, the model outputs remain unchanged whether or not the re-quantification of imported renewable fuels is considered, as the model does not choose to utilize any imported renewable fuels. Therefore, the primary objective here is to understand the overall changes induced by the re-quantification of construction-related emissions using the pLCA approach.

From the tables comparing the different $gwp_{constr}(tech)$ parameter values for the year 2020 (presented in Appendix B), it can be observed that the differences between the re-quantified values, using the pLCA approach, are quite small, accounting for approximately 1% of average relative difference across all technologies. This small divergence can be explained by the fact

that both IAM scenarios used to modify the *ecoinvent* database with *premise* exhibit similar characteristics in 2020. These parameter values and their relative difference are expected to evolve over time, as will be discussed in the subsequent chapters. On the other hand, the differences between both re-quantified systems and the previously implemented one are important, as only the emissions of the power and heat production sectors were accounted.

		Limpens (2021)	SSP2-RCP2.6 (REMIND)	Δ_{rel}	SSP5-RCP1.9 (REMIND)	Δ_{rel}
GHG emissions [MtCO ₂ -eq./y.]	construction	0.77	23.69	2976.62	23.91	3005.19
	operation	106.28	83.36	-21.57	83.14	-21.77
Cost [b€ ₂₀₁₅ /y.]	investment	16.62	17.13	3.07%	17.13	3.07%
	maintenance	5.07	5.48	8.09%	5.48	8.09%
	operation	13.45	11.80	-12.27%	11.80	-12.27%
	TOTAL	35.14	34.41	-2.08%	34.41	-2.08%
Primary energy [TWh/y.]	fossil fuels	337.37	243.11	-27.94%	243.11	-27.94%
	other non-RE	67.24	168.67	150.85%	168.67	150.85%
	Total non-RE	404.61	411.79	1.77%	411.79	1.77%
	biomass	0	59.58	-	59.58	-
	RE-fuels	0	0	-	0	-
	solar-wind-hydro	21.27	21.67	1.88%	21.69	1.97%
	Total RE	21.27	81.25	281.99%	81.27	282.09%
	TOTAL	425.86	493.03	15.77%	493.06	15.78%

Table 4.10: Abbreviations and symbol: RE (renewable), Δ_{rel} (relative difference with Limpens (2021)).

Emissions As anticipated, there is a substantial difference in construction-related emissions between the case study implemented by Limpens and the modified scenarios with adjusted $gwp_{constr}(tech)$ values for different technologies. From Table 4.10, construction-related emissions increase from just 0.7% (Limpens) to 22.1% and 22.3% in the SSP2-RCP2.6 and SSP5-RCP1.9 scenarios, respectively.

The increase in construction-related emissions, particularly their growing share in the total allowed emissions, will constrain operational emissions, necessitating adjustments in resource utilization. Consequently, this will impact the selection and deployment of conversion technologies within the system.

This growing share can be explained by multiple factors. As can be seen in Table 4.11 and in Appendix B, the construction emissions of the power and heat production sectors were already accounted for in the system as developed by Limpens (2021). When re-quantifying the $gwp_{constr}(tech)$ of the technologies present in these sectors, differences can be observed between the previous and new parameter values. When comparing the Limpens and SSP2 parameter values, it can be observed that the new values for the electricity, high temperature heat, low temperature centralised heat, and decentralised heat sectors are respectively 11% lower, 45.5% higher, 168% higher, and 79% higher. This leads to a global increase of 74% over the different technologies that were already accounted for. For the other sectors, the increase is also significant as the emissions were not previously accounted for.

From Table 4.11, it can be observed that the main impact of the modifications made in these sectors is in the 'other storage' sector. This difference can be explained first by the fact that the construction emissions for this sector were not accounted for in the system modelled by Limpens and are relatively large for both of the REMIND scenarios (on average 652 and 642 ktCO₂-eq./GWh of installed capacity for the SSP2 and SSP5 scenarios, respectively). Secondly, this difference is due to variations in the installed capacities, which will be discussed next. Both re-quantified systems have similar outputs, but small variations are present. These can also be explained by the small variations in the parameter values related to the construction emissions (approximately 1% average relative difference across all technologies) and installed capacities.

		Limpens (2021)	SSP2-RCP2.6 (REMIND)	Δ_{rel}	SSP5-RCP1.9 (REMIND)	Δ_{rel}
Production	electricity	237.45	251.45	5.90%	248.91	4.83%
	heat high temperature	15.8	40.64	157.22%	40.52	156.46%
	heat low temperature	513.07	416.47	-18.83%	410.77	-19.94%
	synthetic fuels	0.0	683.52	-	671.41	-
Mobility	passenger mobility	0.0	0.66	-	0.65	-
	freight mobility	0.0	0.05	-	0.05	-
Infrastructure	infrastructure	0.0	27.93	-	27.56	-
Storage	electricity storages	0.83	0.24	-71.08%	0.23	-72.29%
	thermal storages	0.0	420.97	-	419.98	-
	other storages	0.0	21,844.43	-	22,089.81	-

Table 4.11: Comparison of the annualised construction-related emissions breakdown, in [ktCO₂-eq./y.] for the different scenarios.

Primary Energy As expected, the increased constraints imposed on the system by the reassessment of construction-related emissions ($gwp_{constr}(tech)$) calls for strategic adjustments in the allocation of resources. Examination of the data presented in Table 4.12 highlights a significant increase in the proportion of renewable resources in the results of the re-quantified systems (16.48%) compared to the Limpens one (4.99%). This significant increase is mainly due to the integration of biomass, which until now has been under-utilised. In addition, a pronounced impact on the diversification of resources and the electrification of the heat low temperature sector is marked in particular by the increased use of uranium and electricity imports, which are enhancing the electricity production and replacing carbon-intensive non-renewable resources, such as natural gas.

Nevertheless, fossil fuels remain the predominant driver of the energy landscape in all 2020 scenarios, with non-renewable resources accounting for 95% in the Limpens scenario and 83.52% in the REMIND scenarios. It is imperative to point out that total primary energy consumption increases in the re-quantified systems, resulting from the higher constraints on total operational emissions.

Cost From Table 4.10, the total cost variations across the evaluated scenarios are relatively minor, primarily impacting operation and maintenance expenses. This indicates that alterations will manifest in the distribution of primary energy consumption, as already discussed, and in the installed technologies, as the cost parameters remained unchanged across all scenarios in this study.

		Limpens (2021)	SSP2-RCP2.6 (REMIND)	Δ_{rel}	SSP5-RCP1.9 (REMIND)	Δ_{rel}
Non-RE [%]	electricity imports	1.68	2.47	47.02%	2.47	47.02%
	LFO	17.11	14.78	-13.62%	14.78	-13.62%
	natural gas	54.28	27.77	-48.84%	27.76	-48.86%
	coal	7.83	6.76	-13.67%	6.76	-13.67%
	uranium	7.61	26.13	243.36%	26.13	243.36%
	waste	4.18	3.61	-13.64%	3.61	-13.64%
	ammonia	2.32	2.0	-13.79%	2.0	-13.79%
RE [%]	woody biomass	0.0	4.19	-	4.19	-
	wet biomass	0.0	7.89	-	7.89	-
	wind	4.99	4.3	-13.83%	4.3	-13.83%
	hydro	0.0	0.1	-	0.1	-

Table 4.12: Comparison of the resource breakdown for the different scenarios.

Table 4.13 summarizes the differences in annualized investment costs across the different scenarios. Notably, the disparity between the two IAM scenarios is negligible, except for the investment in 'other storage'.

As anticipated from Table 4.10, significant differences in installed capacities can be observed, which are reflected in the differences in annualized investment costs for the different sectors, as the cost parameters were not altered between the Limpens (2021) scenario and the two others. The major distinction lies in the electricity production sector. A closer examination reveals that this difference is attributable to the larger installed capacities for nuclear power and hydro river, and the reduction in CCGT gas units in the IAM scenarios compared to the Limpens (2021) scenario. This electrical production is also enhanced to supply other sectors that are electrifying, such as the low-temperature heat sector. This production is assured by greater capacities in the power generation sector but also by the use of co-generation units in the industrial heat production sector. The conversion technologies are shifting from gas-dependent to electricity and biomass-dependent, which also impacts the storages. For instance, the high-temperature heat sector is shifting from the use of gas boilers to wood boilers and industrial gas-fired co-generation units. The synthetic fuel production sector is impacted by the installation of biomethanation units used to reduce the imports of natural gas and continue to use gas-fired units. The transport sector is not modified.

Regarding the cost differences in the 'other storage' sector between the two IAM scenarios, these variations stem from minor changes in installed capacities across various technologies within the sector, such as LFO, methanol, CO₂, and ammonia storage systems. The storage sector is experiencing an overall increase in storage capacities across all three sub-sectors (electricity, heat, and other), when comparing the Limpens and REMIND systems, resulting from higher constraints on operational emissions.

Regarding the operation costs associated with the resources, Table 4.10 indicates that the total quantity of primary energy is higher for systems with recalculated construction-related emissions compared to the previously implemented system. However, the operation costs for these resources are lower in the IAM scenarios. This suggests that the system utilizes a greater quantity of less expensive resources, such as uranium and biomass, and a lower quantity of more expensive resources like natural gas, as already developed.

		Limpens (2021)	SSP2-RCP2.6 (REMIND)		SSP5-RCP1.9 (REMIND)	
				Δ_{rel}		Δ_{rel}
Investment cost [M€ ₂₀₁₅ /y.]	electricity	725.3	1,2224.0	1,585.37%	1,2224.0	1,585.37%
	heat high temperature	67.9	78.5	15.61%	78.5	15.61%
	heat low temperature	788.6	681.7	-13.56%	681.7	-13.56%
	synthetic fuels	169.8	272.4	60.42%	272.4	60.42%
	passenger mobility	6,223.3	6,223.3	0.00%	6,223.3	0.00%
	freight mobility	1,092.9	1,092.9	0.00%	1,092.9	0.00%
	infrastructure	7,474.4	7,470.0	-0.06%	7,470.0	-0.06%
	electricity storages	8.4	10.9	29.76%	10.9	29.76%
	thermal storages	50.8	57.3	12.80%	57.3	12.80%
	other storages	15.5	17.4	12.26%	17.5	12.90%

Table 4.13: Comparison of the cost breakdown, annualised investments, for the different scenarios.

Conclusion

As observed in the subsequent analysis, the modification of the $gwp_{op}(res)$ for imported renewable fuels has no impact, as no imported renewable fuels are utilized by the system. It is also notable that the differences between the outputs of the system modified using pLCA are almost negligible. Overall, the re-quantification of $gwp_{constr}(tech)$ for the various resources constrains the operation-related emissions by elevating the importance of construction-related emissions. Consequently, the system is forced to utilize more environmentally benign resources such as uranium and biomass, thereby increasing the share of renewable resources and reducing the consumption of non-renewable resources, particularly natural gas. This shift also influences the conversion technologies employed in the model. Technologies dependent on natural gas are partially replaced, when possible, by either nuclear power and hydroelectric power for electricity production, or by biomass and electricity for the heat sector.

It is anticipated that the significance of the emissions modifications will intensify in a system with more stringent emission constraints. This will be a focal point of the following chapters.

Chapter 5

Belgian energy system in 2035 - scenario analysis

In the previous chapter, the global impacts of modifications made to the construction-related parameter values were studied for the 2020 energy system. The model was constrained to a relatively large total yearly emissions limit (107 MtCO₂-eq./year). Significant differences were observed between the previously implemented system and the modified ones, although there were almost no differences between the two re-quantified systems. Moreover, the quantification of the imported renewable fuels' emissions was not studied as the model did not choose to use these primary energy sources.

To address the research questions of this master's thesis, this chapter will examine the outputs of the 2035 energy system, comparing the results of the previously implemented system with the newly modified ones. The primary goal is to examine the impact of using prospective Life Cycle Assessment (pLCA) rather than traditional Life Cycle Assessment (LCA) in the quantification of the Global Warming Potential (GWP) of prospective energy systems. This is why the 2035 energy system has been chosen. The variations linked to the methodological choices made by this study will be studied by comparing the outputs of both systems with modified GWP values using pLCA. This will be done in Section 5.1.

Then, this chapter will also investigate the impacts of re-quantifying the operational emissions of imported renewable fuels on the model outputs, which will be explored in Section 5.2.

It is to be noted, that this chapter also studies the evolution of the outputs when more stringent constraints on emissions are imposed. To achieve this, the outputs depicted in the graphs have been derived for different emissions limits. Given that linear programming problems focus on a single objective — minimizing the total annualized cost of the system in the EnergyScope TD model — the systems have been constrained by an upper limit set parametrically. Specifically, this constraint adheres to Equation 3.10 (the equality part) for different values of gwp_{limit} , which are represented as the x-axis values in the subsequent graphs.

5.1. Neglecting emissions from imported renewable fuels

In this section, the objective is to analyse the impact of modifying the $gwp_{constr}(tech)$ parameter values for the different technologies within the system using a pLCA approach and various IAM scenarios. Initially, the new values for $gwp_{op}(res)$ of imported renewable fuels will not be incorporated into the model.

As discussed in the previous chapter, the overall increase in construction-related emissions

within the system's total emissions has necessitated a reallocation of resources and a change in the installed conversion technologies. However, the prior analysis focused on a relatively high emissions constraint (107 MtCO₂-eq./y.). In this analysis, the range will extend from **90** MtCO₂-eq./y., as it represents a middle ground between the cost-optimum scenarios analysed for 2020, to **10** MtCO₂-eq./y. At lower values, the system begins to decommission essential renewable technologies such as photovoltaic panels, indicating it has reached its operational limits.

5.1.1. Discussion

5.1.1.1. Global analysis

Emissions First, regarding the emissions released into the atmosphere, Figure 5.1 shows that the total construction-related emissions ($\mathbf{GWP}_{\text{constr}}$) throughout the transition are significantly higher for the systems with a re-quantification of $gwp_{\text{constr}}(\text{tech})$ using pLCA. Indeed, the

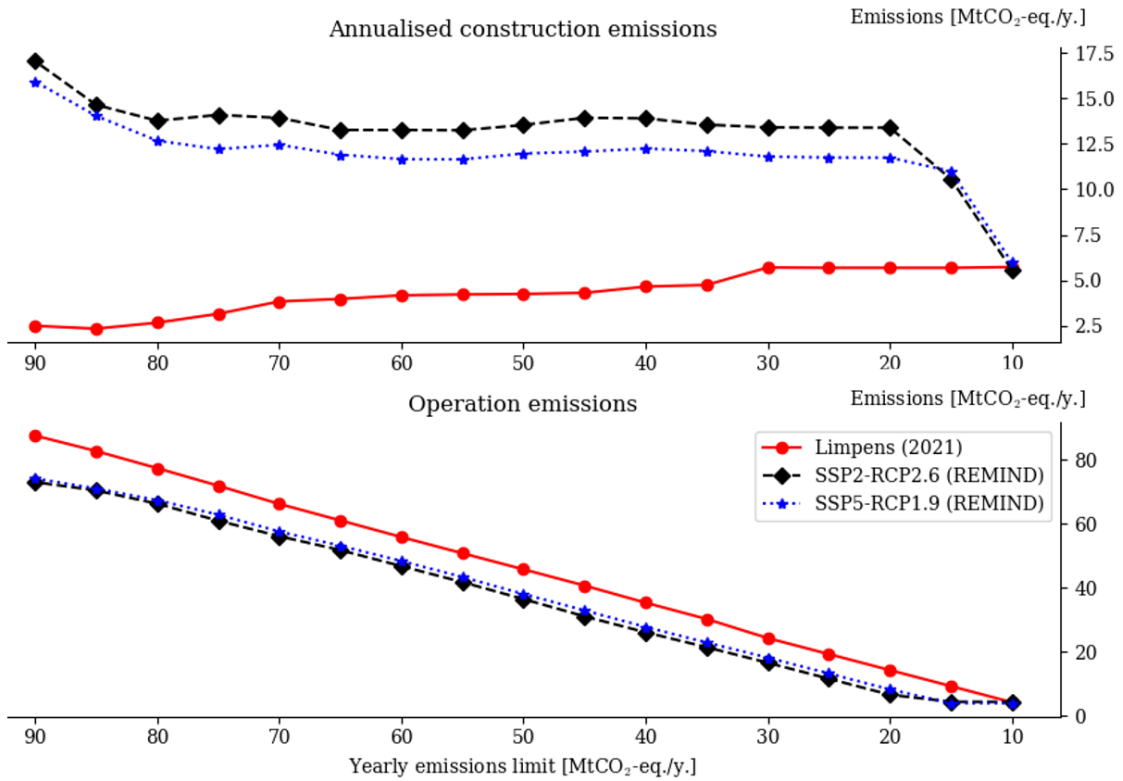


Figure 5.1: Construction and operation-related emissions evolution for the different systems and over the transition. The emissions of the y-axis represent the $\mathbf{GWP}_{\text{constr}}$ and the $\mathbf{GWP}_{\text{op}}$ for the upper and lower sub-plots respectively. It can be observed that the total construction emissions of the system as modelled by Limpens are, in average from 90 to 10 Mt of emissions limit, 241% and 209% when compared to the SSP2 and SSP5 outputs. This is leading to more stringent constraints on the operation emissions.

average relative difference over the emissions limits tested is of 241% between the Limpens and the SSP2 systems. This value decreases to 209% when comparing the outputs of the Limpens and SSP5 systems. This outcome is logical and expected, given that the previously implemented system only accounted the emissions of technologies from the power and heat production sectors. The differences between the two IAM scenarios (10.1% average relative difference over the different emissions limit values) stem from their inherent characteristics. Specifically, the SSP5-RCP1.9 scenario, as modelled by REMIND, imposes a total peak carbon budget three

times lower than that of the SSP2-RCP2.6 scenario, making it less carbon-intensive. The modifications applied to the *ecoinvent* database reflect this, resulting in a lower $gwp_{constr}(tech)$ for all technologies (by 12% on average) and, consequently, lower total construction emissions.

When looking in more details to the gwp_{constr} parameter values, as depicted in Appendix B, it can be observed that the quantification made by Limpens for the technologies of the power and heat production sectors was underestimating the reality. Indeed, the parameter values from the re-quantification done using the pLCA approach are, in average, 17.8% (SSP2) and 4.1% (SSP5) higher than the one calculated using the traditional LCA. Moreover, as already said, the case study developed by Limpens was neglecting the construction emissions of the technologies in the other sectors of the energy system. This is leading to higher GWP values for the construction of the technologies and thus an increase of the total construction emissions variable value.

As observed in the 2020 analysis, since the system is constrained to a given upper limit for the $\mathbf{GWP}_{tot}$ variable, and since this variable is expressed as the sum of the total annualized construction and operation emissions (Equation 3.6), with the share of construction emissions increasing in the modified systems, the operation emissions are more constrained, and so is the energy system optimisation. This will have some impacts in the choices made by the model, leading to differences in costs, primary energy sources and consequently conversion technologies.

Costs To illustrate these impacts, Figure 5.2 depicts the cost evolution of the different systems under various emissions limits for 2035. As shown, all scenarios exhibit a similar trend in total system cost, though some differences are evident. The outputs of the base system, modeled by Limpens (2021), indicate the lowest cost, followed by the system modified by the SSP5-RCP1.9 scenario, and finally, the SSP2-RCP2.6 scenario. On average, the relative differences between the Limpens' total cost and the cost of the re-quantified systems is of 1.4% (SSP2) and 0.8% (SSP5), over the different emissions limits.

However, a detailed examination of the cost breakdown reveals differences in operational and annualized investment costs. Both systems with modified GWP parameter values have relatively similar costs, with only 0.4% and 1.6% of average relative difference for annualised investment and operation costs respectively, but differ significantly from the base scenario. When comparing the total investment and operation costs for the Limpens and SSP2 systems, average relative differences of 1.7% and 4.4% can be noticed, respectively. These differences reflect changes in primary energy use and distribution, as well as variations in the conversion technologies implemented within the systems, since the different costs remain consistent with those used by the Limpens (2021) case study and have not been altered in this research.

This increase in total yearly cost, resulting from the modification of the $gwp_{constr}(tech)$ parameter for the different technologies, is due to the aforementioned higher constraint on the system's operation-related emissions. It is evident that the system altered by the SSP5-RCP1.9 scenario is less constrained (due to lower $\mathbf{GWP}_{constr}$) and is thus less expensive than the one modified by the SSP2-RCP2.6 scenario.

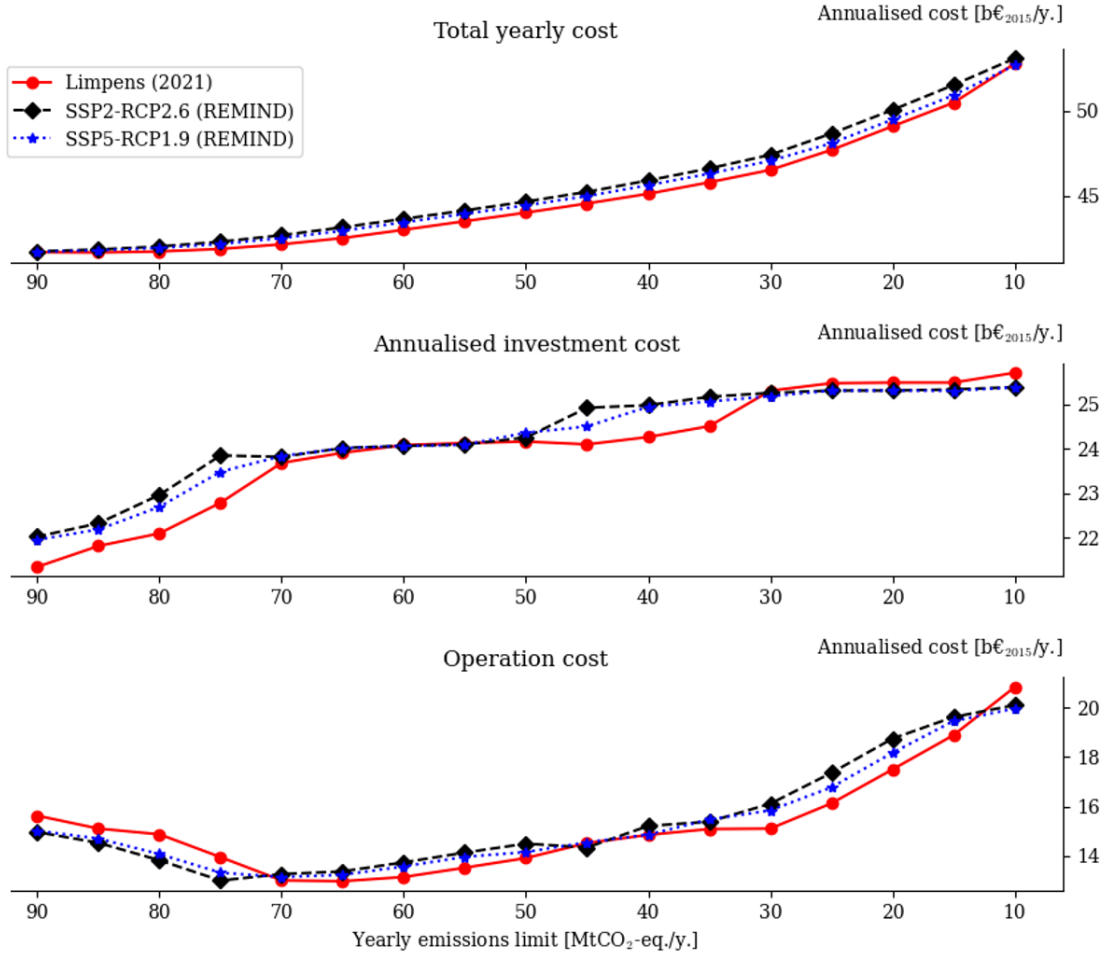


Figure 5.2: Total yearly, annualised investment and operation costs evolution over different emissions limits for the different systems. The total cost is globally the same for all systems of the transition. However, variations in the annualised investment and operation costs reflects changes in the primary energy sources distribution and installed capacities of conversion technologies.

5.1.1.2. Emissions

Figure 5.3 illustrates the distinct variations observed in annualized construction emissions across different sectors. Notably, emissions from storage and synthetic fuels production technologies were omitted in the case study as modelled by Limpens (2021). Similarly, the transport sector, not depicted in this figure, was also excluded in the emission quantification.

The disparities in other sectors when comparing the outputs of the Limpens and re-quantified systems can be attributed to two primary factors: modifications made to the gwp_{constr} parameter values and differences in installed capacities. This observation holds true when comparing both re-quantified systems. The first point has already been developed in the global analysis and the second will be treated after.

5.1.1.3. Primary energy

Limpens outputs Regarding the impact of modifications on the primary energy distribution among different energy sources, the analysis first focuses on the outputs of the system as implemented by Limpens (2021), shown in Figure 5.4. This figure compares the evolution of primary energy distribution for 2035 with the previously studied year 2020 ($gwp_{limit} = 107$ MtCO₂-eq./year). The graph clearly demonstrates that fossil resources are progressively replaced by renewable resources and electricity imports over the transition. As emission limits decrease,

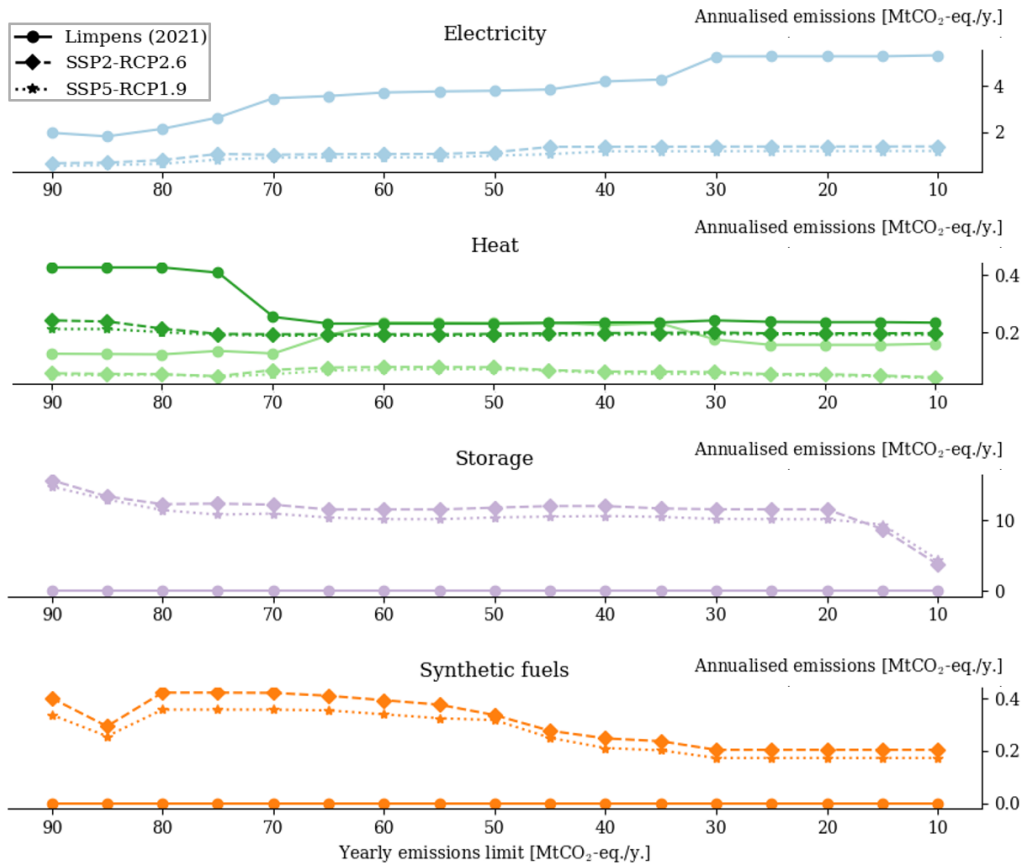


Figure 5.3: Comparison of the annualised construction emissions evolution over different emissions limits. For the heat sector, the light green represents the heat production at high temperature and the dark green represents the heat production at low temperature for (de)centralised consumption.

the relative share of coal and natural gas increases since they are the cheapest fuels. Coal imports are limited to approximately 33 TWh/y., and this limit is reached for emissions limits above 70 MtCO₂-eq./year.

To reduce emissions initially, more efficient technologies are employed, followed by an increased presence of renewable resources. For instance, in the low-temperature heat sectors, heat pumps are utilized, and in the industrial sector, gas CHPs are used, enabling heat production at a lower cost and with less primary energy consumption. This shift towards more efficient technologies happens at higher emissions limits than the one present on the graph. In the range of emissions limits studied in Figure 5.4, renewable-based technologies are deployed — first wind, then solar. Additionally, non-renewable waste, wet and woody biomass are used from the beginning at their full potential. Electricity imports increase at 80 MtCO₂-eq./year to also reach its maximum availability. LFO (light oil fuel), mainly used to produce HVC (high value chemicals), is progressively replaced by renewable methanol, which is two times more expensive than LFO. Once coal is phased out (at 40 MtCO₂-eq./year) and all renewable potentials are exploited — except for solar, which reaches its maximum use at 30 Mt of emissions limit — the system relies on imported renewable fuels and electricity, either imported or produced via renewable sources, to replace natural gas. This shift from fossil fuels to renewables is reflected in the technologies used by the different sectors, such as transitioning from coal boilers to wood boilers and from gas-powered buses to hybrid diesel buses and trains.

The deployment of solar energy occurs in two phases: the first phase, before 75 Mt of emissions limit, is purely cost-effective, and the second phase, between 75 and 30 Mt, is necessary to replace fossil resources. Nuclear power, still present in 2035 and used at its full potential (2 GW of installed capacity), provides a stable base for electricity production during the transition. This energy source is valued for its low cost and emissions.

Imported renewable fuels, including methanol, ammonia, hydrogen and gas renewable, appears as 'magical' solutions when the system becomes more constrained as their emissions are still neglected here. This appears clear with example such as the installation of co-generation units running on renewable ammonia to replace units running on natural gas for instance. However, it is to be noted that renewable ammonia is used from the higher emission limit (90 Mt) to produce hydrogen. It is preferred to its non-renewable counterpart for its lower cost. The modifications of the gwp_{op} for the imported renewable fuels will be discussed in Section 5.2.

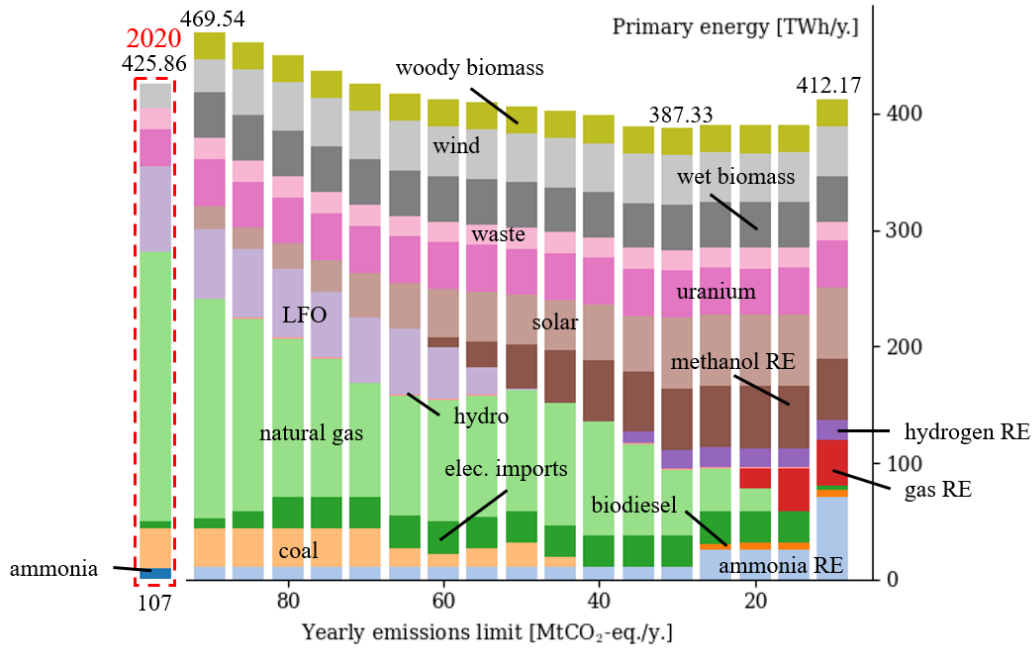


Figure 5.4: Primary energy sources distribution evolution over different emissions limits for the system as implemented by Limpens (2021) for the year 2035.

Now, concerning the differences introduced by the modification of the $gwp_{constr}(tech)$ parameter for all technologies, Figures 5.5 and 5.6 illustrate the evolution over the transition for grouped resources and individual resources, respectively.

From Figure 5.5, it can be observed that biomass use is not impacted by the modifications applied to the system, they are used to their full potential. This is not a surprise as woody and wet biomass are among the resources largely available, with low cost and low carbon intensity, making them good candidates for producing heat with minimal impacts for instance. Overall, the results for both modified systems are quite similar. The differences are linked to the varying constraints on the systems due to the re-quantification applied and their consequences on the share of the total construction-related emissions within the total emissions permitted, as explained before.

To recall, the $gwp_{constr}(tech)$ data calculated using the *ecoinvent* database modified by the REMIND SSP5 scenario are lower than those for the modification using the REMIND SSP2 scenario. This directly impacts the total construction emissions and their relative share, making

it less constrained than the SSP2 one. Given, these informations it appears clear that the SSP5 system is using more fossil and less renewable fuels than the SSP2.

However, the system as implemented by Limpens (2021) is even more dependent on fossil fuels throughout the transition and uses fewer renewable fuels, except at emissions limitations lower than 15 Mt. It should be recall that these fuels are not accounted for in terms of emissions, and do appear as 'magical' solutions in this context. This system is also less dependent on non-renewable fuels above 80 Mt and below 15 Mt, making it more carbon-intensive. Around the target emissions limit for 2035, 53.5 Mt, the three systems are quite similar, with differences becoming more pronounced at the extremes.

To give some data, the outputs of the Limpens system are in average using 7% and 5% less renewable primary energy sources than the SSP2 and SSP5 systems. However, it used, respectively 8 and 5% more non-renewable resources than the SSP2 and SSP5 systems. The variation occurring, in the re-calculation of the gwp_{constr} parameter values between both re-quantified systems, is leading to differences of 2% and 3% in the use of renewable and non-renewable resources over the different emissions limits.

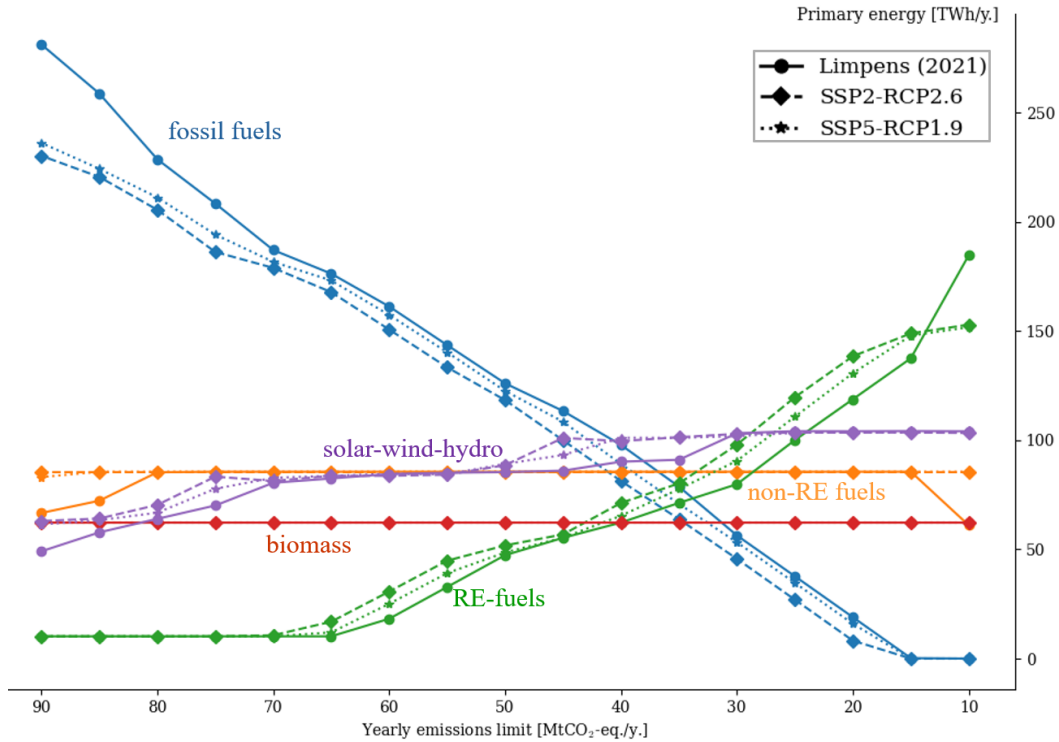


Figure 5.5: Primary energy distribution evolution over different emissions limits for the system as implemented by Limpens (2021) for the year 2035. Fossil fuels: coal, gas natural, LFO; Non-RE fuels: electricity imports, uranium, waste; RE-fuels: ammonia RE, biodiesel, gas RE, hydrogen RE, methanol RE; Biomass: wet and woody biomass.

When analyzing the results in more detail, as shown in Figure 5.6, it can be observed that two factors influence the choice of primary energy sources and inherently the choice of conversion technologies: the cost to be minimized and the constraints on the emissions.

Regarding fossil fuels, the maximum use of coal is reached at approximately 75 MtCO₂-eq./y. for both modified systems, which is 5 MtCO₂-eq./y. higher than the outputs of the system as implemented by Limpens. This can be explained by the higher constraint on operational

emissions, which forces the model to choose less carbon-intensive resources over the transition. The use of LFO also decreases sooner compared to the Limpens system, with LFO being replaced by renewable methanol earlier to produce HVC. The cost of LFO is almost two times less than that of renewable methanol, which explains why the model opts to use LFO until it is no longer possible, due to stringent constraints on the emissions. The use of natural gas is also affected

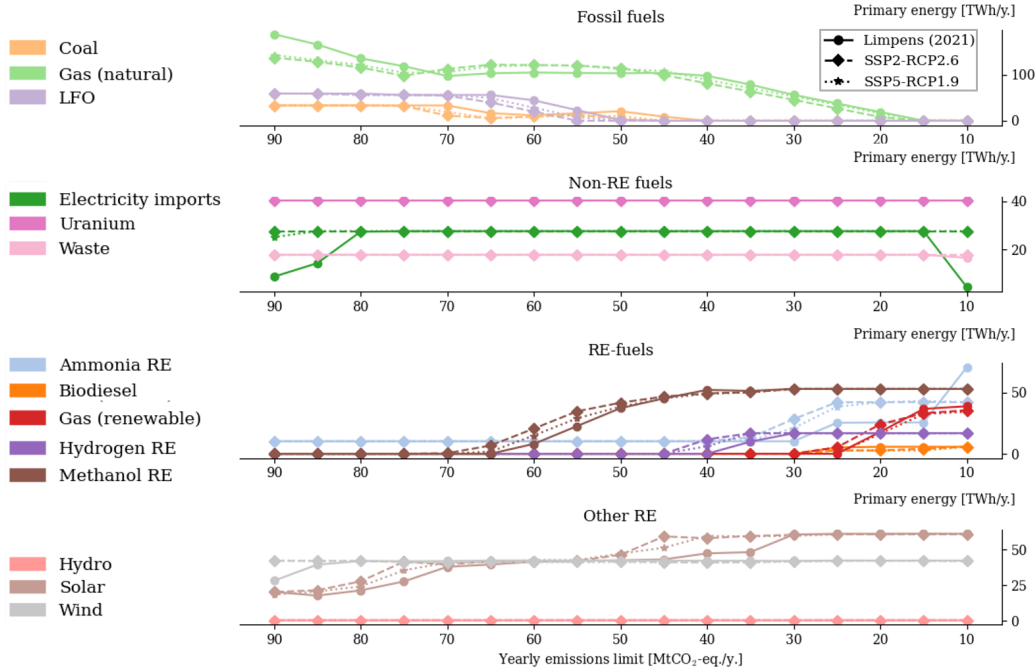


Figure 5.6: Comparison of the primary energy distribution evolution over different emissions limits for the different systems implemented for the year 2035.

by the same economical and environmental characteristics as above. At high emissions limits, electricity imports are replaced by natural gas and CCGT in the Limpens system, but not in the modified systems, explaining the significant difference. The model choice can be explained by the fact that the system modelled by Limpens is reaching its cost optimum at 84.3 MtCO₂-eq./y. As already outlined by Limpens (2021) [4], once the system reaches its cost optimum it has the tendency to use massively natural gas, thus replacing electrical imports by gas-fired CCGT units installation.

For non-renewable fuels, waste and uranium represent good primary energy sources among the least polluting and expensive resources available. They are used to produce a significant share of electricity and heat, as the model chooses to use their full potential. Differences between the systems regarding electricity imports are pronounced at the extremes of emissions limits. On the higher emissions side, this has already been explained, while on the lower side, the decrease in electricity imports is countered by an increase in renewable ammonia and CCGT running on ammonia to produce electricity. This fuel is part of the 'magic' resources as its emissions are not yet taken into account, which allows production with minimal impact.

Concerning renewable energy sources, a general observation is that they are utilized earlier by the modified systems compared to the Limpens one. This is due to the higher constraint on operational emissions. Their implementation is not driven by economic considerations but rather by the need to replace carbon-intensive resources. This is particularly true for imported renewable fuels, which have no impact on operational emissions yet. However, solar installation occurs in two phases, as already explained for the Limpens system, one economically driven and

one needed to replace natural gas, which appears clear when looking at both curves.

5.1.1.4. Costs and installed capacities

Now concerning the insights of the costs breakdown it appears clear from the previous discussions that the main impact of the modifications of the $gwp_{constr}(tech)$ is to higher the relative share of the total construction emissions variable in the total emissions allowed by the model. This leads to a system forced to use less carbon-intensive resources and technologies sooner in the transition. A system more constrained will lead to higher cost as already seen in Figure 5.2.

Concerning the repartition of total yearly cost for the system as modelled by Limpens (2021) for 2035, it is available in Figure 5.7. It is also compared to the results obtained for the year 2020 with an emission limit of 107 MtCO₂-eq./y.. The costs are grouped by technologies and resources.

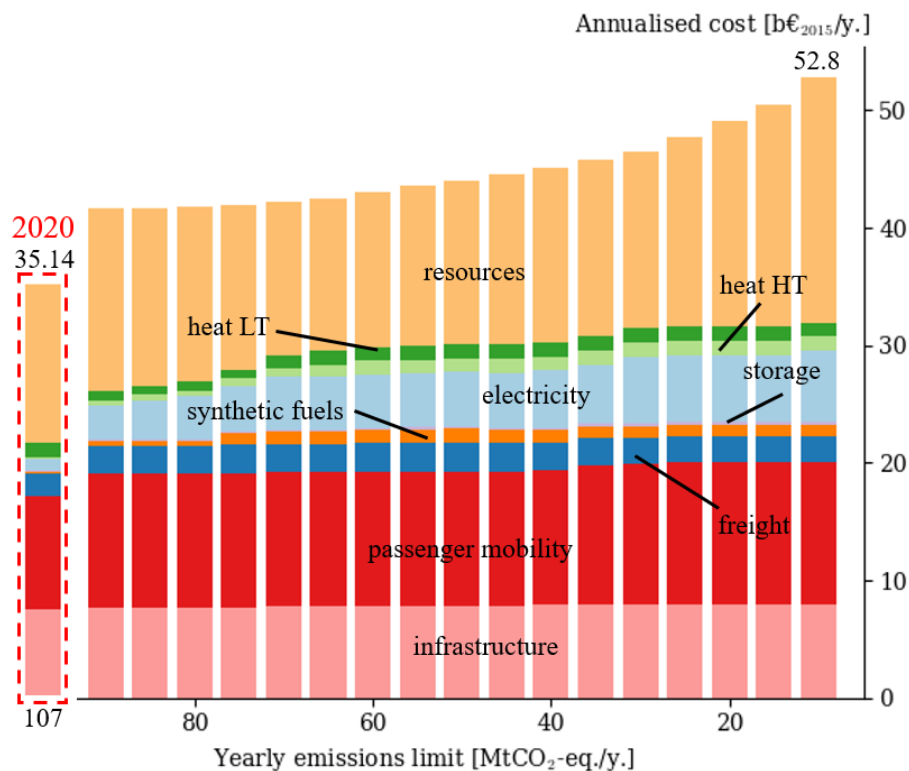


Figure 5.7: Cost distribution evolution over different emissions limits for the system as modelled by Limpens (2021).

In 2020, the cost was mainly determined by: resources purchase (38%), transport technologies (33%), infrastructure (21%), heat generation (4%) and power generation technologies (3%). The general trends for the evolution of the year 2035 a diminution of the relative share of transport and infrastructure technologies in favour of the augmentation of the electricity technologies and synthetic fuels production technologies, due to larger installed capacities to sustain the transition. Between, 2020 and 2035, the mobility strategy changes, public mobility is deployed at its maximum leading to higher expenditures for buses, trains and trams. The costs for infrastructures is accounting for DHN and electrical network, but also the efficiency measures taken. This sector is barely not evolving as both networks were already well developed in 2020, and no major efficiency measures were taken between 2020 and 2035.

The interest lies in understanding the differences induced by modifications in the $gwp_{constr}(tech)$ parameter values. Figure 5.8 illustrates the comparison of annualized investment and maintenance costs over the transition emission limits for the three scenarios. It is evident that both modified systems yield similar outputs that differ from the system as implemented by Limpens. A general observation reveals that, while all systems employ similar technologies, their phase-in or phase-out occurs at different emission limits. Systems with modifications transition from technologies utilizing emission-intensive resources to those harnessing renewable ones earlier than the Limpens system, due to stricter operational emission constraints. In the power

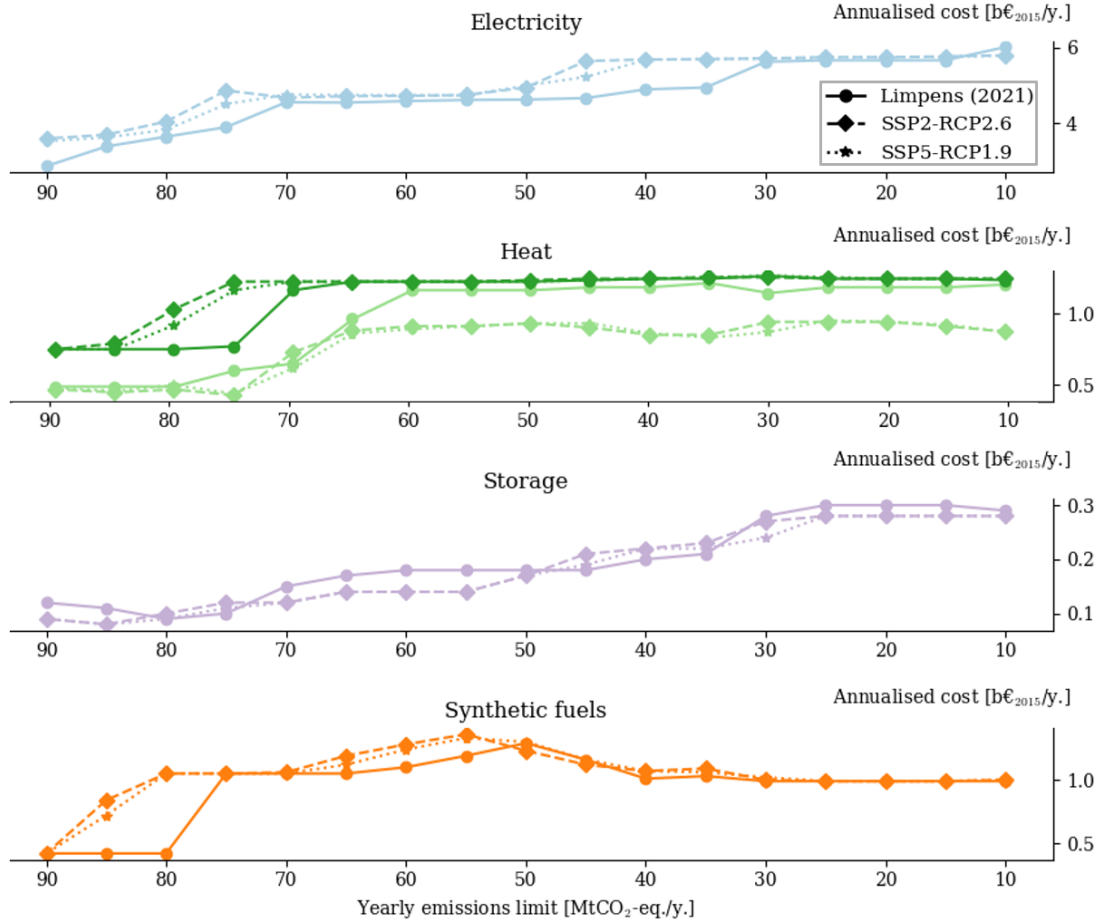


Figure 5.8: Comparison of the annualised investment and maintenance costs evolution over different emissions limits for the different systems. For the heat sector, the light green represents the heat production at high temperature and the dark green represents the heat production at low temperature for (de)centralised consumption.

generation sector, above 70 Mt of emissions, the differences emerge with the earlier installation of offshore wind and photovoltaic panels in the modified systems. These technologies reach their maximum capacities sooner than in the Limpens system. This is a direct consequence of stricter operational emission constraints, necessitating the earlier replacement of emission-intensive technologies. The modified systems continue to use CCGT running on gas for a longer period, maintaining installed capacities below 2 GW. This decision is driven by economic considerations, as these CCGT units are cheaper than other power generation technologies and the system has already reached its limit in electricity imports. The phase-out of CCGT running on gas is compensated by the installation of CCGT powered by renewable ammonia, as the emissions of this resource is not accounted for. Nuclear power is utilized at its maximum capacity across all three systems, a logical choice given its low emissions and cost-effectiveness in providing constant power. Hydro-power and onshore wind also exhibit similar characteristics in all systems, as they

are used to their full potential.

In the heat sector, there is a notable shift from technologies running on non-renewable energy sources to those utilizing renewable energy sources. For example, the transition from thermal heat pumps running on gas to electrical heat pumps occurs earlier in the modified systems (starting at 90 Mt of emissions instead of 80 Mt). However, the use of gas boilers instead of electric resistors, likely driven by economic considerations — since electric resistors are almost six times more expensive than gas boilers — explains the lower costs for high-temperature heat in the modified systems. This choice, while economically favourable, increases the emission constraints for other sectors due to the continued use of natural gas.

In the mobility sector, not represented in the figure, the modified systems experience a transition from electric cars to renewable gas-powered cars at low emission limits (below 20 MtCO₂-eq./y). This shift is driven by the growing constraints on emissions, as the construction and operational emissions of renewable gas-powered cars are lower than those of electric cars. This strategic choice underscores the necessity to reduce overall emissions in response to stricter environmental regulations, thereby favouring technologies with lower lifecycle emissions. Regarding synthetic fuels, differences occurring above 75 Mt, are observed due to the adoption of biomass hydrolysis and biomass-to-methanol technologies by the modified systems before the Limpens system. From 70 to 50 Mt, there is an installation of methane-to-methanol units, in the modified systems, to support the transition from LFO to renewable methanol in the production of HVC.

Concerning storage, the small differences observed are due to variations in the installed capacities of gas, high-temperature, and seasonal storage among the different systems.

Overall, the decisions made by the model for the different systems are driven by both economic and environmental constraints.

Conclusion

The analysis of emissions, primary energy distribution, and costs under different scenarios reveals significant differences induced by modifications in the $gwp_{constr}(tech)$ parameter values. The re-quantification of emissions using pLCA has led to a notable augmentation in the total construction-related emissions. While emissions were reduced for some technologies in the power and heat production sectors due to re-quantification, they are however more important in average over the different technologies of these sectors. Moreover, all other sectors that were previously not accounted for experienced considerable increases in their emissions. This augmentation shifts the burden of emissions to the operational phase, as the emission limits are applied to the sum of operation and construction-related emissions, thereby influencing the energy system optimization and driving the early adoption of renewable sources and less emission-intensive technologies.

Overall, the decisions made by the model for the different systems are driven by both economic considerations and environmental constraints. The modifications in the $gwp_{constr}(tech)$ parameter result in a more constrained system, leading to higher costs and a faster transition to renewable energy sources. Despite these differences, the global trajectory remains the same, with phase-in and phase-out of technologies and resources occurring at different emission levels. For example, CCGT running on gas are kept in use for a longer period in the modified systems purely for economic reasons, despite their emissions intensity. On the other hand, technologies such as wood-fired boilers and offshore wind are being installed more quickly because of their low carbon intensity.

These findings underscore the importance of accurate emissions quantification and the need for integrated strategies that balance economic viability and environmental sustainability in energy system planning. It is important to note that the choice of the scenario used to perform the modification on the *ecoinvent* database has a significant influence on the quantification results. In this study, the SSP5-RCP1.9 scenario yielded lower GWP outputs than the SSP2-RCP2.6 scenario, as SSP5-RCP1.9 is driven by less carbon-intensive technologies and resources, leading to a lower GMST increase. Consequently, the scenario results in lower GWP when quantifying emissions.

However, an issue arises with the neglect of emissions from imported renewable fuels. These fuels are used by the systems as "magical solutions" when the constraints on emissions become more stringent. The implications of their quantification will be the focus of the next section.

5.2. Accounting emissions for imported renewable fuels

This section examines the impacts of re-quantifying the operational emissions of imported renewable fuels that were previously overlooked. These fuels were often seen as 'magical' solutions when emission constraints were stringent. Notably, renewable ammonia used by all systems across the different emission limits in the previous section was favoured over non-renewable ammonia due to its lower cost and emissions, making it both economically and environmentally advantageous.

For other renewable fuels, their costs exceeded those of their non-renewable counterparts, with the model choosing these renewable options solely based on environmental considerations. As observed, the production of HVC transitioned from LFO to renewable methanol. This was followed by the adoption of technologies powered by renewable hydrogen, renewable gas, and eventually biodiesel in the transport sector, as tightening emission constraints forced the shift towards renewable solutions. These choices were driven by environmental motivations.

To address the third research question and understand how the model would react to increased emissions from these imported renewable fuels, the system with modified $gwp_{constr}(tech)$ parameter values using the SSP2 scenario was selected. This system was chosen because the differences with the others were already well understood, and the previous section outlined the importance of accurately accounting for emissions, making the selection of one of the modified systems logical.

The graphs present in the following discussion represent the outputs of the model optimization for both systems and with varying total emission limits. The goal was to see the evolution of the different variables over a growing emission constrain sets, the analysis ranges from 90 Mt to 45 MtCO₂-eq./y. as the model was not able to find a solution to the system with re-quantified operation emissions, with the optimisation options given to the model, due to the enhanced constraints on the system.

5.2.1. Discussion

5.2.1.1. Global analysis

Regarding emissions, both systems exhibit similar profiles for emission limits higher than 65 Mt, with only minor differences observed before reaching 80 Mt, as can be seen in Figure 5.9. Beyond this threshold, the systems' outputs begin to diverge significantly due to more stringent emission constraints. In the system without modifications to account for the emissions of imported

renewable fuels, renewable methanol is incorporated into the energy mix at 70 MtCO₂-eq./y. emission limit. The model is confronted to higher constraints on the emissions and a solution is found in the use of methanol renewable over LFO as the emissions of this resource are null. However, when modifications of the $gwp_{op}(res)$ are applied to the imported renewable fuels, this is no longer the case, and the system must identify alternatives that are both economically viable and produce limited emissions. Consequently, the importance of operational emissions increases within the total emission production, and the annualized construction emissions are significantly impacted, as illustrated in Figure 5.9.

The increase in operational emissions occurs in two phases: initially at 65 MtCO₂-eq./y. due to the switch from renewable ammonia to traditional ammonia, and subsequently at 55 Mt with the switch from LFO to methanol in the production of HVC. This switch was also observed in the previously implemented system using the SSP2 scenario but at lower emission limits (40 Mt). It is important to note that both renewable ammonia and methanol have higher global warming potential values (gwp_{op}) compared to their traditional counterparts, which justifies their use. These data are subject to considerable uncertainty, as the literature in this field is not yet well-developed.

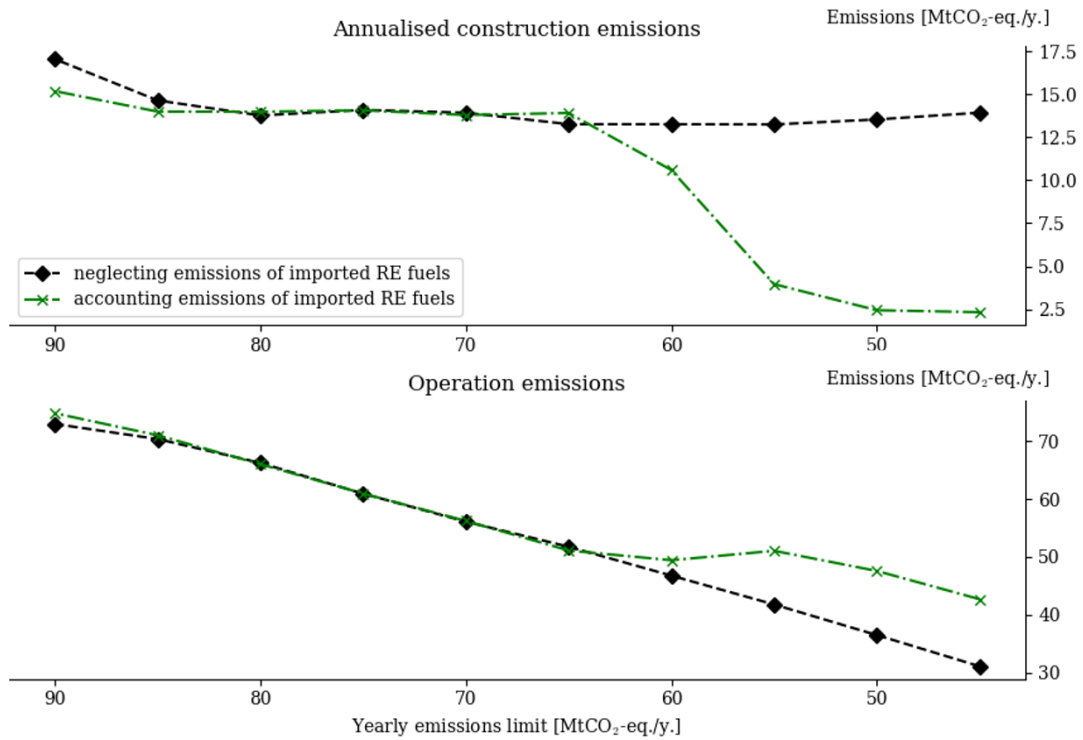


Figure 5.9: Comparison of the evolution of the total annualised construction and operation emissions over different emission limits for both systems, with and without accounting of the emissions of imported renewable fuels.

Regarding cost, as can be seen in Figure 5.10, the total annual cost follows similar trends for both systems up to 70-65 Mt of emission limits. Beyond this point, the differences become more pronounced. However, variations in the annualized investment and operational costs occur before 70 Mt, which can be attributed to the use of renewable ammonia in both systems prior to 65 Mt. Since the emissions of renewable ammonia are now accounted for, the model must find alternative solutions to mitigate these emissions by utilizing more renewable resources and associated conversion technologies. This solution is found in the implementation of PV panels earlier than what is done in the system neglecting imported renewable fuels emissions. This shift

leads to a reduction in the use of natural gas in the power production sector as the electricity is produced by the PV panels. Coal usage is also decreased sooner in the modified system to counter the higher operational emissions of renewable ammonia. This is resulting in increased investment costs but decreased operational costs, as solar energy incurs no operational expenses and the used quantity of natural gas and coal is reduced.

A similar pattern is observed beyond 70 Mt of emission limit, where the previously implemented system transitioned from LFO to renewable methanol, a change not adopted in the newly implemented system due to the accounting of renewable methanol emissions. Consequently, the model is forced to install more solar energy capacity to offset the continued use of LFO and to reduce the consumption of natural gas and coal, as will be discussed in more detail after.

After the 70-65 Mt emission limits, the modified system faces more stringent constraints, leading to an increase in costs. The model attempts to mitigate this increase by adopting technologies with higher investment costs but lower operational costs.

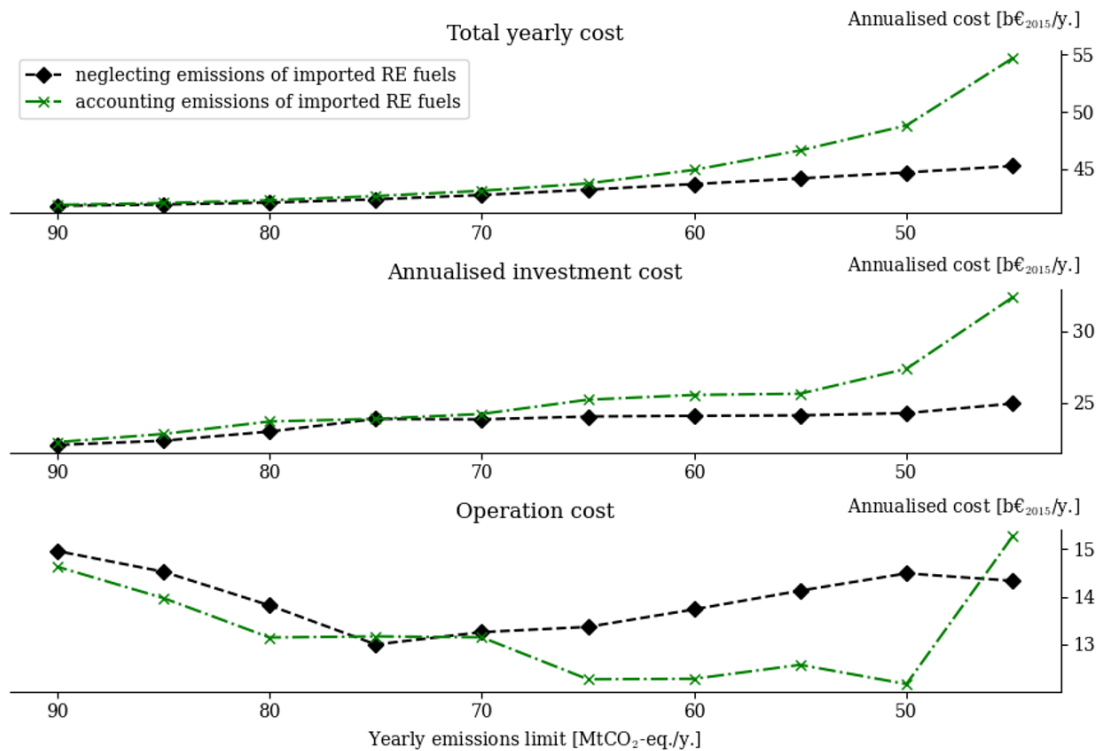


Figure 5.10: Comparison of the evolution of the total, annualised investment and operation costs over different emission limits for both systems, with and without accounting of the emissions of imported renewable fuels.

5.2.1.2. Primary energy

Regarding primary energy use, the system faces two main challenges: increased operational emissions from renewable ammonia and methanol. As illustrated in Figure 5.11, both systems utilize renewable ammonia to produce hydrogen before the 65 Mt emissions threshold, for cost concerns as this renewable resource is cheaper than its non-renewable alternative but its gwp_{op} is higher. When accounting for emissions from this resource, there is an increase of 3.8 MtCO₂-eq./y. in the total operation emissions, necessitating the use of less emission-intensive resources.

Initially, this is achieved by increasing solar energy use to reduce gas consumption in the power production sector. Subsequently, coal consumption for heat production is also decreased and replaced by wood and waste boilers, as well as industrial heating resistors. These alternatives are both economically and environmentally beneficial, as they are less polluting and cheaper than coal. Although the construction of electrical resistors is twice as costly compared to coal-fired units, the substantial reduction in emissions justifies the expense. The system also transitions more rapidly from gas thermal heat pumps to electric ones in the decentralized low-temperature heat sector. After the 70 Mt threshold, the newly modified system shifts towards traditional

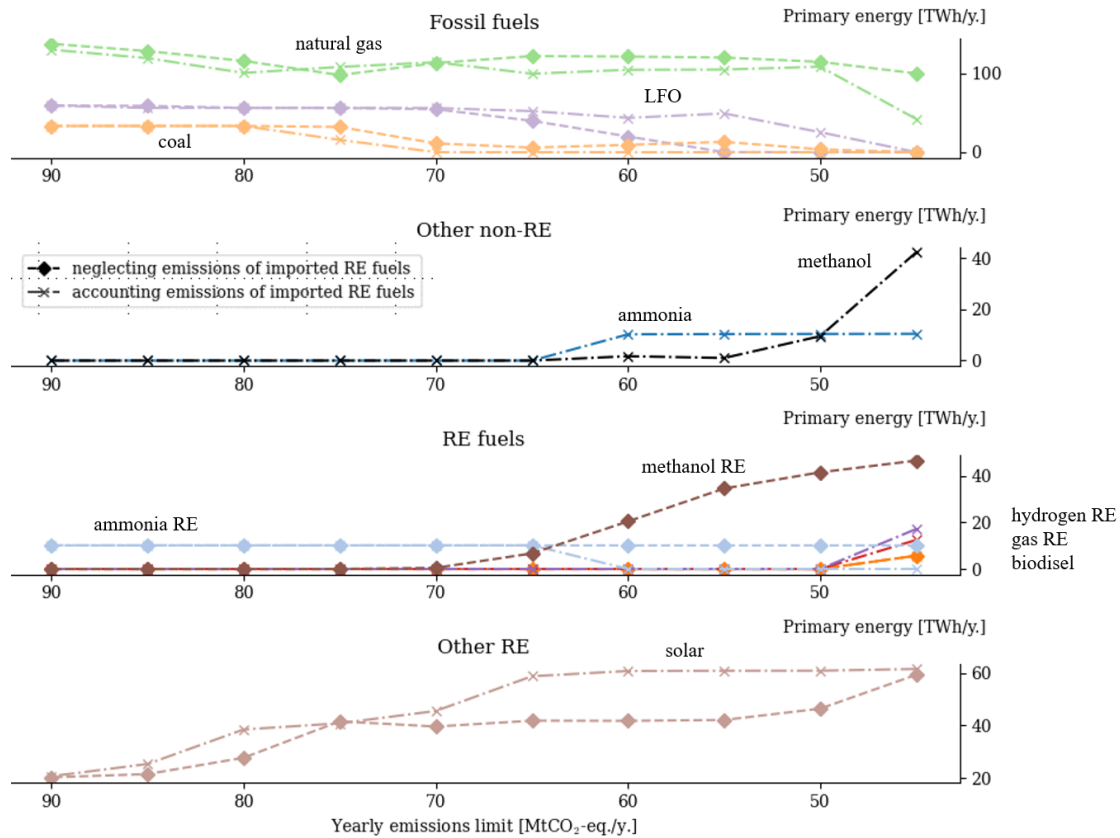


Figure 5.11: Comparison of the evolution of the primary energy sources over different emission limits for both systems, with and without accounting of the emissions of imported renewable fuels.

ammonia due to its lower emissions, even though renewable ammonia was previously used for economic reasons, being cheaper than traditional ammonia. This shift explains the differences in operational costs observed at lower emissions limits than 75 Mt, as shown in Figure 5.10.

For the second issue, concerning renewable methanol, the previously implemented system used this particular resource to replace LFO in HVC production. In the newly implemented model, this is not the case, as traditional methanol has lower emissions than both renewable methanol and LFO. Thus, the system continues to use LFO for HVC production for a longer period, until 45 Mt compared to 55 Mt. However, a transition still occurs between LFO and methanol-based HVC production after the 70 MtCO₂-eq./y. emission limit. This transition is phased, involving the introduction of gas-to-HVC, methanol-to-HVC, and methane-to-methanol conversion technologies between 70 and 45 Mt. These decisions are driven by a complex balance of economic and emission constraints on synthetic fuel production and storage technologies, operational costs and emissions, and the growing constraints on total emissions, not to forget the interaction with the other sectors.

Other resources are significantly influenced by these two main issues. For example, the maximum capacity of solar energy must be reached earlier (by 60 Mt instead of 45 Mt) to reduce operational emissions in the power production sector by replacing CCGT gas and to allow for more emission in other sectors. Regarding hydrogen production, previously assured by renewable and then traditional ammonia, after the 50 Mt emissions limit, its import becomes more favourable due to emission constraints, despite increased costs. The ammonia still imported is then used to produce electricity through CCGT. These changes, coupled with methanol imports, result in a substantial increase in both operational and investment costs, as seen in Figure 5.10.

It is important to note that resources that remain constant between both systems and are not shown in Figure 5.11 include uranium, electricity imports, waste, wind, hydro, wet, and woody biomass. These resources have all reached their maximum availability and are utilized for their favourable characteristics, such as low cost and low emissions.

5.2.1.3. Construction emissions and installed capacities

Since the construction emissions have not changed between both systems, Figure 5.12 effectively represents the differences in installed capacities of various technologies, regarding the evolution of annualized construction emissions across different emission limits.

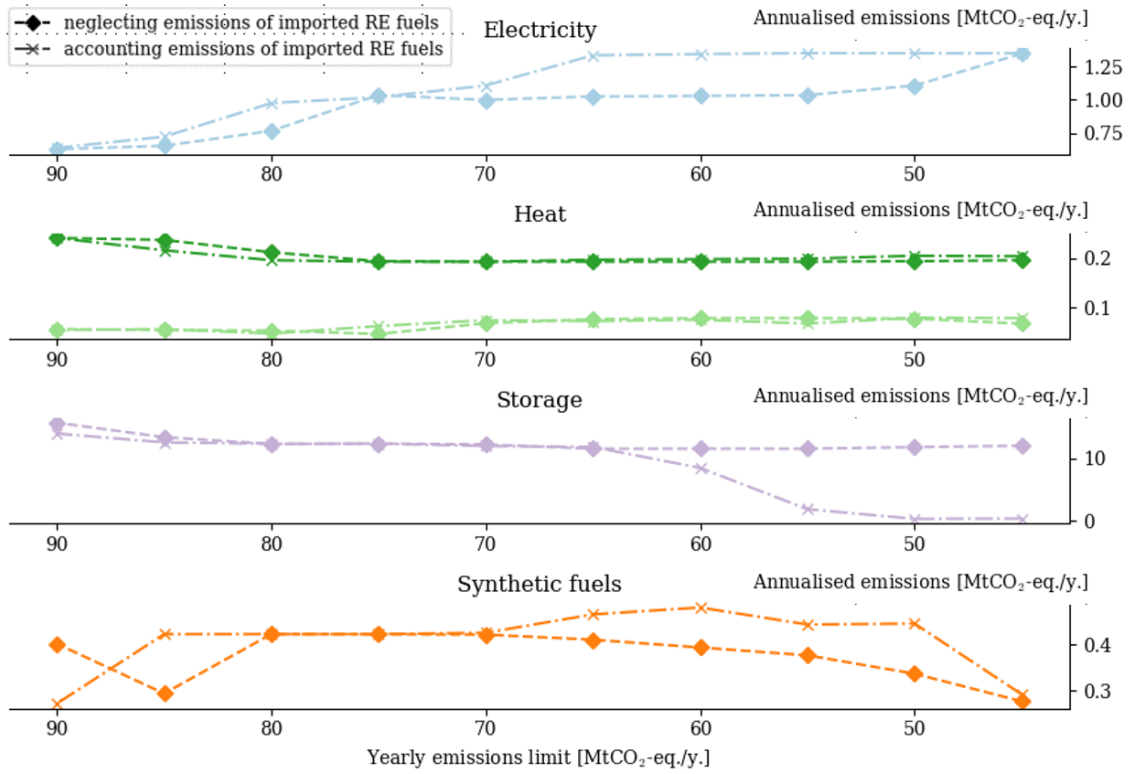


Figure 5.12: Comparison of the evolution of the total annualised construction emissions over different emission limits for both systems, with and without accounting of the emissions of imported renewable fuels. For the heat sector, the light green represents the heat production at high temperature and the dark green represents the heat production at low temperature for (de)centralised consumption. This figure is also representing the evolution in the installed capacities for the different technologies as the gwp_{constr} parameter values are the same in both systems.

For the power generation sector, the differences between the two systems primarily stem from the installation of PV panels at different emission limits, as explained before, and the

variations in installed capacity for CCGT units. The heat sector is minimally impacted, with the only notable differences arising from the earlier shift from gas thermal heat pumps to electric heat pumps in the newly modified system, occurring between 90 and 75 Mt. This shift was done between 85 and 75 Mt, in the system neglecting the imported renewable fuels emissions. In high-temperature production, the differences are due to the transition from coal to other renewable alternative boilers and the installation of electric resistors.

In terms of differences in the storage construction-related emissions, these must be linked to the transport sector. Indeed, the private passenger mobility sector experiences a shift from electric cars with traditional batteries to vehicles powered first by gas (at 65 Mt) and then by fuel cells (hydrogen) at 50 Mt, in the newly modified system. This progressive shift impacts the emissions from electrical storage construction, as car batteries gradually transition to lithium-ion batteries, which emit fewer emissions. This shift is driven by increasing emission constraints, which explains the significant decrease in annualized construction emissions for storage technologies. Additionally, other storage capacities are minimized to their essential levels to ensure the system's functionality, highlighting the growing constraints.

The newly modified system employs a more diverse fleet of vehicles across various emission limits, progressively adopting less emission-intensive technologies and resources. For instance, buses powered by compressed natural gas (CNG) are gradually replaced by public trains (at 70 Mt) and fuel cell hydrogen buses (at 50 Mt) due to their lower costs and emissions.

Regarding the synthetic fuel production sector, previously mentioned differences include the shift from LFO to methanol in HVC production. Above the 80 Mt emission limit, the differences arise from varying installed capacities of biomethanation, biomass-to-HVC, biomass-to-methanol, and biohydrolysis technologies.

5.2.1.4. Conclusion

In conclusion, the analysis identifies two major issues that impose significant constraints on both operational and construction emissions when the $gwp_{op}(res)$ for imported renewable fuels are accounted for. The model's decisions are influenced by a complex balance of economic and emission-related concerns, primarily to address the accounting of renewable ammonia and methanol resources, which were previously used as 'magical' solutions to growing emission constraints.

A primary solution involves the extensive and faster installation of photovoltaic panels, which effectively reduce operational emissions in the power sector, thereby allowing more flexibility for other sectors. While the heat sector remains relatively unaffected in terms of construction-related emissions, it shifts faster towards more renewable energy sources, allowing a reduction in operational emissions.

In contrast, the transport, storage, and synthetic fuel sectors experience substantial impacts. The transport sector, for instance, undergoes a progressive shift towards less emission-intensive technologies and energy sources, such as fuel cell hydrogen vehicles. Similarly, storage technologies are minimized to essential levels to accommodate stricter emission constraints. Across all sectors, a complex balance between environmental and economic considerations is evident, highlighting the intricate interplay between reducing emissions and maintaining economic optimality.

Chapter 6

Belgian energy system in 2050 - scenario analysis

The previous section examined the 2035 Belgian energy system with and without the re-quantification of the $gwp_{constr}(tech)$, for all technologies, and $gwp_{op}(res)$ parameter values, specifically for electricity imports and imported renewable fuels. These analyses highlighted the critical importance of accurately accounting for emissions in the model.

The goal of this chapter is to extend the study to the 2050 Belgian energy system. Compared to the 2035 analysis, there are four minor changes in the parameters used for 2050:

- Imported electricity is more expensive.
- Technologies are more efficient, and their costs generally decrease.
- Imports of renewable fuels are more affordable.
- Yearly end-use demand rises slightly, except for heat demand, which decreases.

These differences were outlined in the case study presented in Chapter 4 and are detailed in Appendix B.

In alignment with the 'Green Deal' ambition, the Belgian energy system must achieve carbon neutrality by 2050. To maintain consistency with previous results, the 2050 energy system will be analysed for different GHG emission targets, including near-zero emissions.

The analysis will begin with a global overview of yearly costs and total annualized construction and operation emissions. Following this, a detailed focus will be placed on primary energy sources, construction emissions, and investment costs across different sectors.

Specifically, the chapter will explore scenarios with GHG emissions below 70 Mt, considering that the cost optimum for the Limpens 2050 model is at 75.8 Mt. The objective is to understand how the system reacts to the loss of nuclear power and the changes in gwp_{constr} over a different year than 2035. Globally, the gwp_{constr} values are lower than in 2035, leading to lower constraints but potential changes in costs. No changes will be made to gwp_{op} due to the already uncertain data used and its increase over time.

Special attention will be given to the behaviour of the system under low emission limits, pushing the model to its limits to understand how the model would react to constraints achieving near-zero emissions.

6.1. Global analysis

As shown in Figure 6.1, the observations for 2050 are consistent with those made for 2035. By re-quantifying the gwp_{contr} parameter values of the different technologies within the Belgian energy system, it is evident that the total annualized construction emissions are higher compared to the system previously implemented by Limpens (2021). The total construction emissions of the SSP2 and SSP5 systems are in average 103 and 100% higher than the one of the Limpens system. The differences between the re-quantified systems are smaller in 2050 than in 2035, with only 2% of average difference in 2050. This is explained by the lower mean relative difference of 4% across the gwp_{constr} parameter value of the 112 technologies in 2050, compared to 12% in 2035, as discussed in Appendix B.

Similar to the scenario in 2035, this increase in total annualized construction emissions results in a higher proportion of these emissions within the total emissions allowed to the system. Consequently, there is a reduced share for operational emissions, leading to greater constraints on the latter variable. This forces the model to adopt more sustainable choices, which subsequently leads to variations in the primary energy sources mix and the installed capacities of corresponding conversion technologies.

One observation can already be made on the behaviour of the Limpens system. Beyond the 10 Mt annual emissions limit, the system diverges from its original trajectory. Given that the variation is apparent in the total annualized construction emissions, the changes must occur within either the power or heat production sectors, as they are the only sectors accounted for. This will be elaborated upon later.

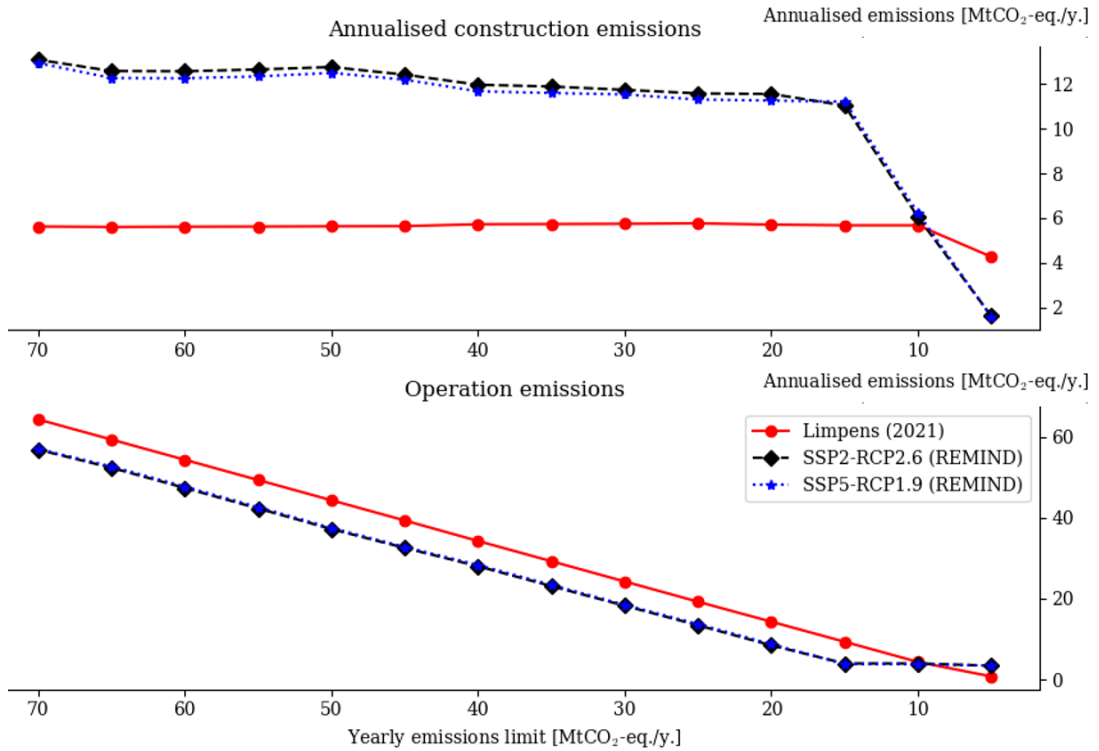


Figure 6.1: Comparison of the evolution of the total annualised construction and operation emissions over different emission limits for the three systems. It can be observed that the total annualised construction emissions are lower in the re-quantified systems, leading to greater constraints on the operation emissions.

Figure 6.2 represents the evolution of the total costs for the three systems studied. The observations made for 2035 are also applicable to the 2050 case, with the exception that the differences in total annualised investment and operation costs are less pronounced in 2050. When comparing the Limpens and SSP2 systems' outputs, it appears that the relative difference is on average of 2% in 2050, this value was of 4.4% in 2035. This is likely due to smaller differences in solar installation capacities, as this technology significantly impacts the total annual investment cost. Both re-quantified systems with more constraints exhibit higher total yearly costs due to increased operational costs. The model is compelled to choose more renewable or at least less emission-intensive resources, which come with higher costs.

Two major cost characteristics are noteworthy concerning the differences occurring between the two re-quantified systems and the one implemented by Limpens. First, the investment costs below the 15 Mt emissions limit occur in two steps, and second, the operational cost variations below the 10 Mt emissions limit. These differences are the result of the model's choices, which will be elaborated upon later.

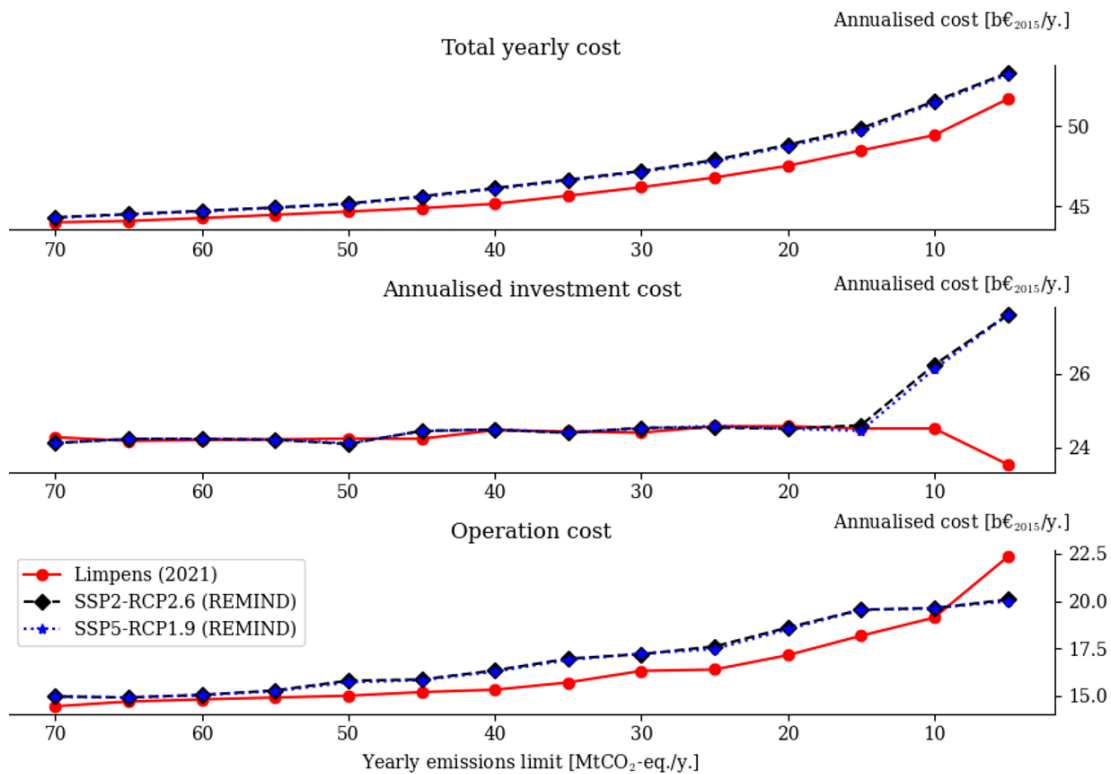


Figure 6.2: Comparison of the evolution of the total yearly, total annualised investment and operation costs over different emission limits for the three systems. It can be observed that the total yearly cost is higher for both re-quantified systems, due to increase in the operation cost.

6.2. Primary energy

To provide context for the following analysis, Figure 6.3 illustrates the evolution of the primary energy sources mix in 2050 for the system modelled by Limpens. The profile shows similar trends to the 2035 system, except that uranium and nuclear power are no longer available in Belgium, as explained in Section 4.2.2.2. This political decision necessitates finding alternatives to replace this low-cost, low-emission energy source.

As expected, the system maximizes its use of endogenous renewable resources: wet biomass (38.9 TWh/y), wind (42.5 TWh/y), woody biomass (23.4 TWh/y), and hydro (0.5 TWh/y). Solar also reaches its maximum capacity (61.5 TWh/y) when emissions limits are below 30 Mt. Additionally, the system utilizes the maximum potential of waste (17.8 TWh/y) across various limits and electricity imports (32.44 TWh/y) from 60 Mt of emissions. Collectively, these sources provide a significant percentage of the total primary energy needed, averaging 54% across the GHG limits studied. The remainder is supplied primarily by fossil fuels, with a transition towards renewable fuels as constraints on total yearly emissions increase. This transition is driven by economic reasons, such as reduced fuel imports, and environmental reasons, as the emissions from these fuels are not accounted for. This topic was discussed in the previous chapter.

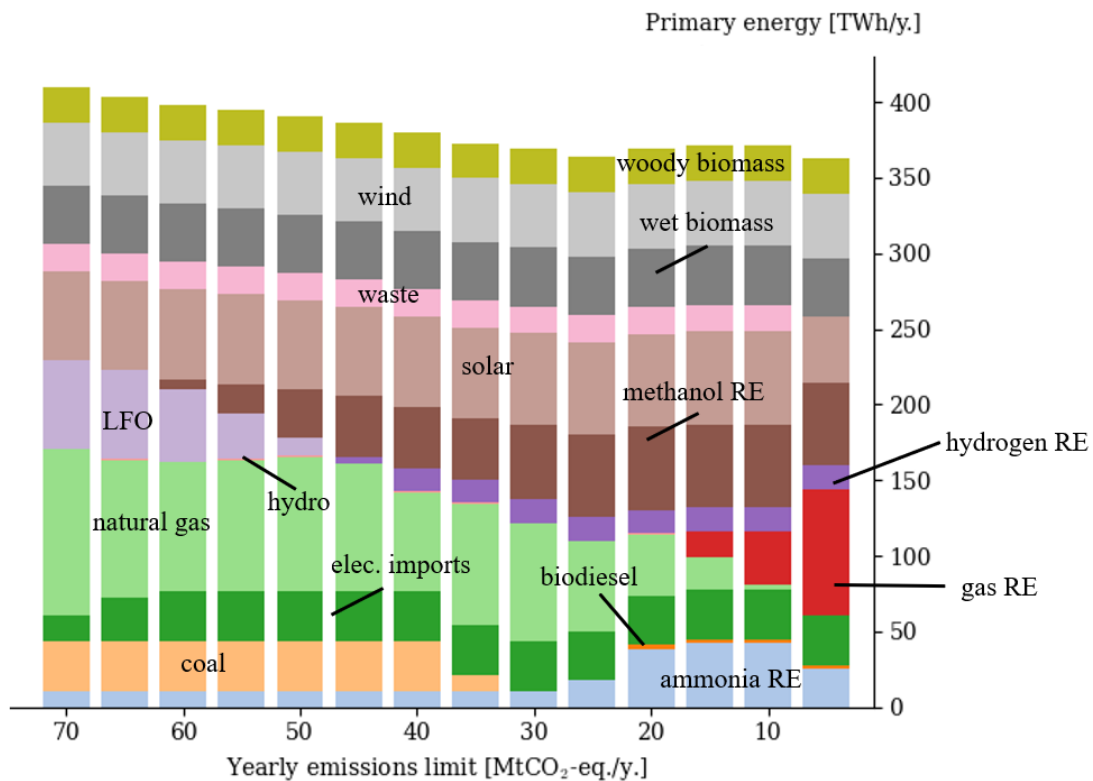


Figure 6.3: Comparison of the evolution of the primary energy sources quantities over different emission limits for the system as develop by Limpens.

Figure 6.4 depicts the evolution of primary energy source quantities used across different GHG limits for the various systems analysed. Wind, hydro, wet biomass, and woody biomass are not shown as they have reached their maximum potential levels and do not vary. Biodiesel is also not represented because its evolution is the same for all three systems studied.

The observations previously made for 2035 remain valid here. However, the use of natural gas extends longer in 2050 due to CCGT units replacing the electricity production previously supplied by nuclear power. Despite the increased demand, except for the heat sector, no significant rise in primary energy usage is observed. This is due to the improved efficiencies of various technologies compared to 2035. The shift from non-renewable to renewable technologies is dictated by a complex balance between economical considerations and constraints on emissions.

Regarding renewable methanol, its usage increases in two steps, linked to the shift from LFO to renewable methanol for HVC production. This transition happens progressively with

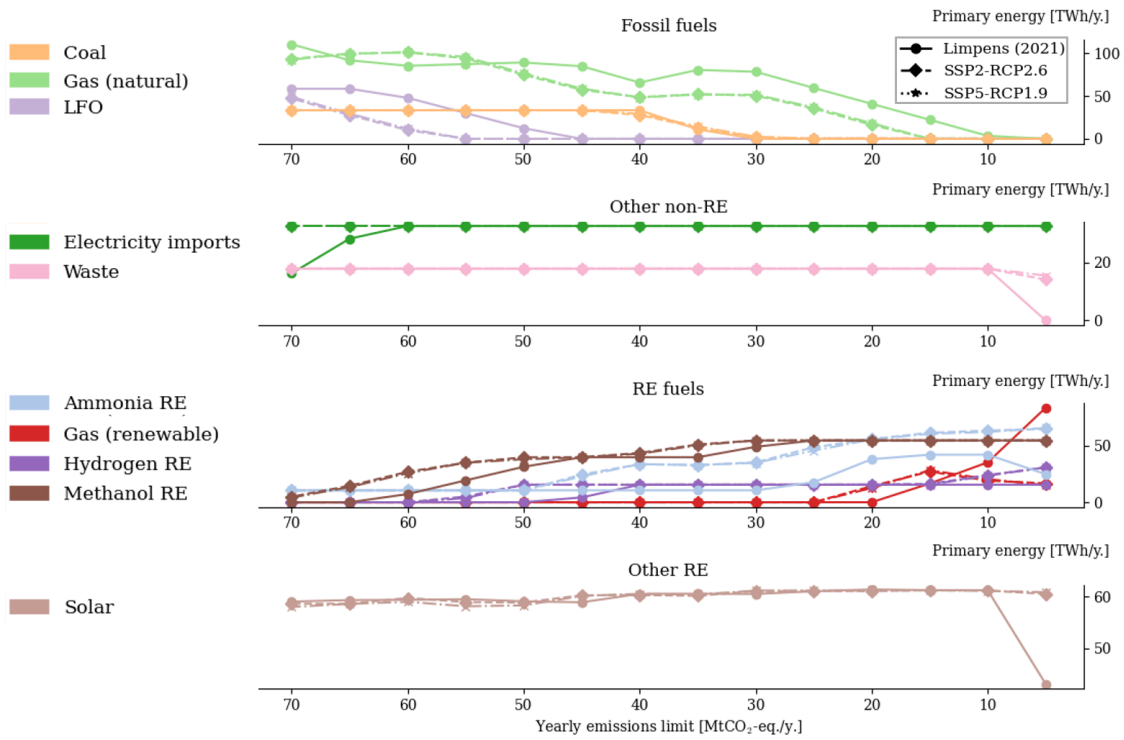


Figure 6.4: Comparison of the evolution of the primary energy sources quantities over different emission limits for the three systems.

the introduction of methane-to-methanol and biomass-to-methanol technologies above 30 Mt of emissions, eventually leading to the exclusive use of renewable methanol, in the re-quantified systems. In the Limpens system, this shift occurs later, as the emissions from constructing synthetic fuel production technologies, among others, are not accounted for and the constraints on operational emissions are lower. The shift is supported by biomass-to-methanol units, which reduces operational costs compared to other methanol production methods or direct imports of renewable methanol.

Another difference lies in the use and import of renewable ammonia. Initially, all three systems use renewable ammonia to produce hydrogen. Subsequently, it is imported in greater quantities to generate electricity through CCGT powered by ammonia, replacing gas-powered CCGT and resulting in decreased natural gas use. This shift begins at the 50 Mt emissions limit for the re-quantified systems, compared to the 30 Mt emissions limit for the Limpens system. This decision is driven solely by emission constraints, as the operational emissions of renewable ammonia are not accounted for, unlike those of natural gas. Moreover, while both technologies incur the same construction costs, renewable ammonia entails greater expenses for its purchase.

Above the 60 Mt emissions limit, the model for re-quantified systems opts to import the full potential of electricity, unlike the Limpens system. This decision limits the installed capacity of CCGT to 3.9 GW compared to the 7.5 GW achieved in the Limpens system.

Finally, below 10 MtCO₂-eq./y., the Limpens system starts to reach its limits, deinstalling crucial renewable conversion technologies such as PV panels and replacing its electricity production with renewable gas-fired units. This impacts the system's costs and emissions, as previously introduced. The re-quantified systems reach this limit at lower GHG constraints (3 Mt), but this might not be the case if the emissions from imported renewable fuels were accounted for.

6.3. Installed capacities and annualised investment cost

In this section, the annualized investment cost for each sector will be analysed using Figure 6.5. This figure shows the annualized investment costs across different sectors. Since the cost is consistent across the different systems studied, it serves as a basis for analysing the fluctuations in installed capacities of the various technologies used. Some information has already been discussed in the previous section and will be reintroduced here and contextualized with the given graph.

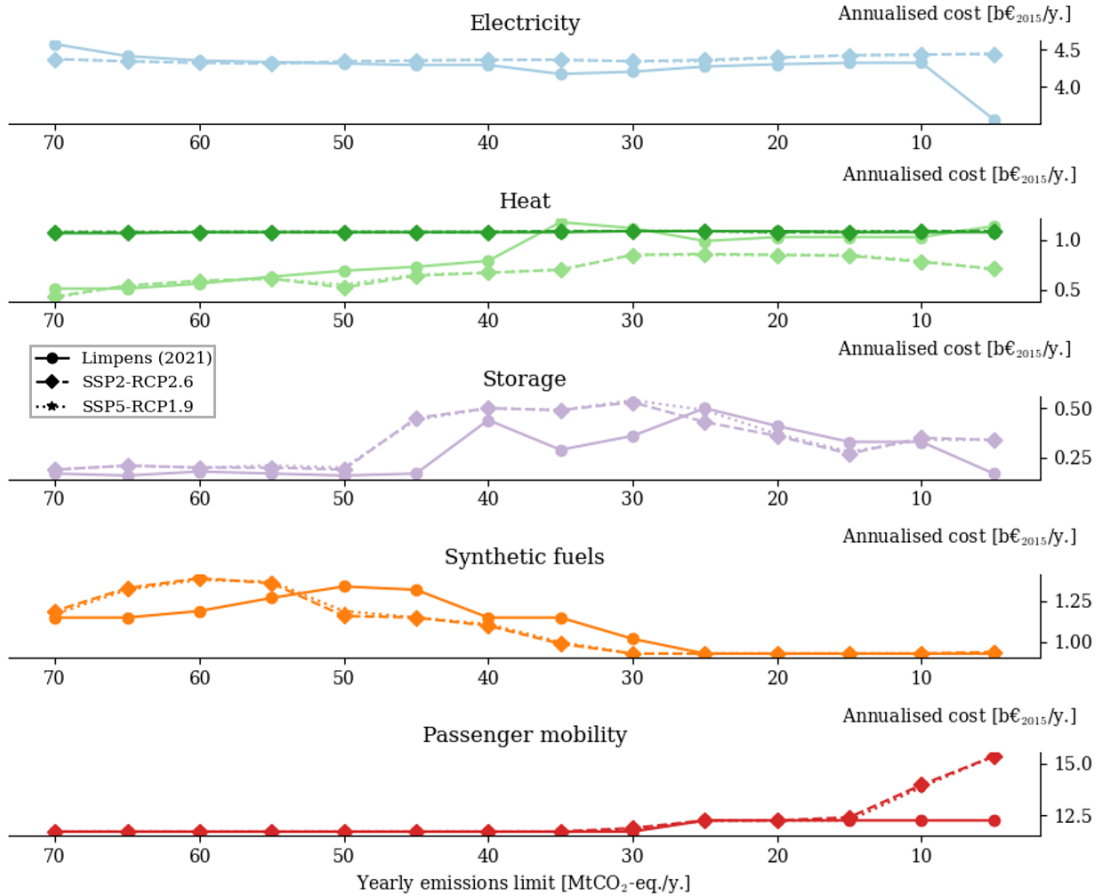


Figure 6.5: Comparison of the evolution of primary energy sources quantities over different emission limits for the three systems.

Regarding the power generation sector, since nuclear power is no longer available, the model had to find alternatives to meet the demand. This was achieved through the full capacity of PV panels, reached before the 2035 scenarios (before 70 Mt instead of between 45 and 30 Mt, depending on the system in 2035). The differences seen in Figure 6.5 are due to the installed capacities of gas or ammonia-powered CCGT units. The differences occurring before 60 Mt are due to the extensive use of CCGT to compensate for the non-imported electricity in the system modelled by Limpens (it installs 7.5 GW compared to 3.8 GW in the re-quantified systems). After 50 Mt, the differences are due to the use of ammonia-powered CCGT in the re-quantified systems, as previously explained. The removal of some PV panels in Limpens' system after 10 Mt is also visible.

In the heat sector, only minor differences are visible in the production of low-temperature heat. These are due to minimal differences in the installed capacities of electrical heat pumps for decentralized heat supply. In the production of high-temperature heat, larger differences are noticeable. These are due to the smaller installation of industrial co-generation units powered by

natural gas in the re-quantified systems (below 2.8 GW compared to 5.8 GW in the other case). These units are replaced by industrial gas boilers for their lower cost and emissions, followed by the earlier introduction of renewable alternatives such as wood boilers in the re-quantified systems.

The differences in the storage sector are due to the introduction and varying use of lithium batteries, as these technologies represent the major source of cost in this sector. Other variations occur in gas storage capacities for instance, but they have minimal impact on the total investment and maintenance costs. Lithium batteries account for 66% of the cost of the SSP2 system at 45 MtCO₂-eq/y., demonstrating their significant impact.

The analysis of the synthetic fuel sector can be divided into three parts. First, above 55 Mt of emissions limit, the differences are due to the earlier shift from LFO to methanol as a source to produce HVC, as seen before, using methane-to-methanol units. The construction of methanol-to-HVC units is twice as costly as oil-to-HVC technologies, but their operational emissions are reduced or null, depending on whether the methanol is derived from methane, biomass, or imported renewable sources. Between 55 and 40 Mt, the differences are due to the use of hydrogen electrolysis units by the Limpens system, which are not used by the re-quantified systems that prefer to import more renewable hydrogen from abroad. The Limpens system also has higher capacities of SMR units, leading to increased investment costs. Finally, below 40 Mt, the difference is due to the lower capacities of methane-to-methanol units in the re-quantified systems as they import more renewable methanol.

In passenger mobility transport, there are some differences between the re-quantified systems and the Limpens system. These differences are due to the shift from electric cars to fuel cell cars (hydrogen), which are more expensive but produce fewer emissions, especially during the operation phase, as they use renewable hydrogen, the emissions of which are not accounted for. This shift also explains the increase in the quantity of imported renewable hydrogen occurring after 15 Mt.

6.4. Conclusion

The analysis reveals that the results of the 2050 Belgian energy systems follow similar trends concerning total cost and construction emissions as observed in 2035. However, the differences in the $gwp_{constr}(tech)$ parameter values between the Limpens and re-quantified systems are smaller in 2050. This is attributed to the characteristics of the IAM scenarios used to modify the *ecoinvent* database. The re-quantified systems remain more constrained than the Limpens one, prompting a quicker shift towards renewable energy sources and associated conversion technologies. Additionally, the differences between both re-quantified systems are also lower in 2050.

The electrical production previously met by nuclear power is now generated using the full capacity of PV panels, even at 70 Mt, and gas-powered units, with natural gas being utilized longer in 2050 than in 2035. As the system transitions towards more stringent constraints on total emissions allowed, it is compelled to find solutions that minimize total cost while respecting emission constraints. This involves a shift to more sustainable resources, such as renewable ammonia and methanol, to produce electricity and HVC. This shift happens earlier in the re-quantified system compared to the Limpens one, as it was the case in 2035.

The system modelled by Limpens reaches its limits before the re-quantified system, evidenced

by the phase-out of key renewable technologies like PV panels and the replacement of their production with renewable gas-fired units.

Chapter 7

Conclusion

Growing concerns about climate change have urged world leaders to establish and ratify international agreements over time, including the UNFCCC in 1992, the Kyoto Protocol in 1997, and the Paris Agreement in 2015. These agreements aim to mitigate GHG emissions. In line with these agreements, the EU has adopted the Climate Act, legally enforcing the targets set out in the European Green Deal, which involve a minimum 55% reduction in GHG emissions by 2030 compared to 1990 levels, and achieving climate neutrality by 2050. To achieve these targets, all sectors of the economy and society need to be actively engaged in the transition .

To formulate decarbonization strategies, it is essential to have comprehensive whole-energy models of the energy system. These models analyse the energy system as a whole, considering the complex interactions between different sectors' demands (such as electricity, heating, and mobility), technologies, and energy carriers . However, traditional energy system models have predominantly focused on individual sectors, especially electricity. Only a few models have addressed the complex interactions between different sectors like electricity, heating, and mobility, often simplifying or disregarding certain aspects of the system. Additionally, many cross-sectoral energy system models do not offer full open access.

In response, the EnergyScope TD model was developed by Limpens et al. [4][7]. It is an open-source model designed to optimize the design and operation of a regional energy system, such as the Belgian system, with equal representation across all sectors and an hourly resolution for a targeted future year. The model optimizes the total yearly cost of the system while constraining GHG emissions, represented by the total Global Warming Potential (GWP) of the system, which corresponds to the sum of emissions from construction of the different technologies and overall emissions of resources.

The quantification of these GWP parameter values was achieved using traditional LCA methods. However, three significant issues emerged from the previous version of the code and its specific application to the Belgian energy system, as implemented in Limpens (2021) :

- **Neglect of construction-related emissions:** Limpens (2021) primarily addressed resource-related emissions by applying constraints only on $\mathbf{GWP}_{\text{op}}$, overlooking construction-related emissions. This oversight resulted in significant gaps in understanding construction-related emissions across various sectors within the energy system. Emissions from the construction of freight and passenger vehicles, synthetic fuels production units, and storage facilities were neglected. Consequently, only the construction emissions from electricity and heat production were accounted for, limiting the ability to provide a comprehensive analysis of construction emissions across the entire energy landscape.
- **Assumptions about imported renewable fuels:** An assumption was made to neglect

the emissions of imported renewable fuels such as bioethanol or renewable hydrogen. This assumption leads to the belief that these fuels emit fewer GHG emissions than other renewable resources, including solar or wind. However, the available data on the GWP of renewable fuels is currently insufficient to support this assumption.

- **Limitations of traditional LCA methodologies:** As highlighted by Sacchi et al. (2022) [3], the environmental footprint of a product is heavily influenced by the characteristics of the global supply chain and energy supply. Traditional LCA methodologies, reliant on historical databases and more suited to small-scale applications, prove inadequate for analyzing prospective energy systems. An innovative solution to this challenge is the use of prospective Life Cycle Assessment (pLCA), which integrates temporal projections into the data collection phase. While literature provides some insights into pLCA, its application to prospective energy systems is still in its early stages. Some models have been developed to study the environmental impacts of single future technologies or simplified systems, focusing mainly on individual sectors. Although useful, their limited scope makes them less suitable for the prospective analysis of complex energy systems.

Building on previous research on ESTD and identified gaps in pLCA application, this Master's thesis has addressed the following questions:

1. What are the implications of employing pLCA instead of historical LCI databases and traditional LCA for assessing GWP in future energy systems?
2. How do results from ESTD optimization change when quantifying construction-related emissions using pLCA compared to traditional LCA, specifically in the Belgian case study?
3. What is the impact of re-quantifying emissions of neglected imported renewable fuels in the Belgian case study?
4. How can uncertainties associated with the pLCA methodology be analysed and interpreted?

This conclusion will recap the primary contributions of this thesis by addressing the various research questions and compiling the key findings and necessary steps.

1. Employing pLCA instead of traditional LCI databases and LCA for assessing GWP in future energy systems has several significant implications. Traditional LCA, which relies on static LCI databases, is not well-suited for prospective quantification of environmental impacts, particularly for large-scale applications. This limitation is due to its inability to account for time-related changes and evolutions in the data. By introducing time evolution into the LCI database through pLCI, the database becomes time-variant. This dynamic approach, implemented using the *premise* Python library and specific Integrated Assessment Model (IAM) scenarios in this research, allows the database to reflect changes over time, aligning more closely with the prospective reality of future energy systems. As a result, the environmental impacts quantified using pLCA evolve with time, providing more accurate and relevant assessments of GWP for future energy systems.
2. When applying a pLCA approach to quantify construction-related emissions in the ESTD model, time-evolution of parameter values is observed. This study focused on the Belgian energy system for the years 2020, 2035, and 2050, leading to two main findings. First, for technologies already included in the emission quantification (power and heat production sectors), re-quantification using pLCA resulted in increased average values across all scenarios and years analysed, even if exceptions can be found. Second, for

previously neglected technologies, re-quantification led to varying degrees of increase in parameter values. This overall increase in construction-related emissions contributed to higher total construction emissions for the different systems and years tested. The results were depending on the year, the emissions limits studied and the scenario (either no modification, modification resulting from the use of the SSP2-RCP2.6 or SSP5-RCP1.9 scenarios in the alteration of the *ecoinvent* database).

Consequently, the increased share of construction-related emissions tightened the constraints on operational emissions, pushing the model to adopt renewable alternatives to meet various demands. This shift led to decreased reliance on fossil fuels and non-renewable energy sources, favouring greener alternatives like solar PV and heat sector electrification. These changes were happening at higher GHG limits compared to the system implemented by Limpens. The total costs of the re-quantified systems were also higher than the previously implemented system, showcasing the increased constraints on operation emissions.

Additionally, the study highlighted the use of imported renewable fuels as solutions when emission constraints became more stringent, due to their unaccounted operation emissions. This illustrates the model's response to stricter constraints by transitioning towards more low emissions energy sources.

3. Concerning the quantification of the renewable imported fuels, the analysis focused on the 2035 Belgian energy system model, using construction emissions parameter values re-quantified with the SSP2-RCP2.6 scenarios in the alteration of the *ecoinvent* database. It was observed that the main issues encountered by the model were related to the use of renewable ammonia and methanol, which were previously favoured for their attractive prices and negligible emissions. When the emissions for these fuels were accounted for, the model was forced to find alternatives that were both economically and environmentally viable.

This re-quantification led to higher pressure on the emissions and a faster shift towards renewable alternatives such as PV panels and the electrification of the heat sector to reduce operational emissions. The model struggled to find solutions for the system beyond the 45 Mt emissions limit. The altered system was also more expensive at emissions limits lower than 70 Mt, highlighting the increased pressure and constraints on the emissions. It is to be noted that the data used were highly uncertain but highlighted the importance of correctly assessing the operational emissions of all resources.

4. Concerning the last research question, an analysis of the variations implied by the use of different IAM scenarios in the alteration of the *ecoinvent* database was necessary. This analysis highlighted the importance of correctly choosing the scenario, as the $gwp_{constr}(tech)$ parameter values varied depending on the year and scenario selected. These variations were mainly dependent on intrinsic characteristics of the scenario, such as the emissions allowance trajectory and the maximal peak carbon budget in the case of the REMIND scenarios. The differences were most pronounced in 2035, almost non-existent in 2020, and reduced compared to 2035 in 2050.

To analyse and interpret uncertainties associated with the pLCA methodology, it is crucial to understand how different IAM scenarios impact the parameter values. This involves examining the range of potential outcomes based on variations in scenario characteristics and assessing their influence on the resulting environmental impacts. By comparing results across multiple scenarios and years, one can identify the extent and sources of uncertainties, thereby improving the robustness and reliability of the pLCA methodology.

Based on the outcomes of this study, several perspectives towards the future can be made. It has been observed that the correct evaluation of emissions is crucial for understanding the prospective

Belgian energy system. The pLCA approach used to re-quantify construction-related emissions can also be applied to operational emissions. In addition, a more comprehensive analysis of the uncertainties linked to the use of pLCA can be conducted by analysing other scenarios and energy systems. Sensitivity analysis can also be used to assess and quantify uncertainty in pLCA studies.

The application of pLCA can also be extended to other case studies and versions of the EnergyScope TD model, such as the pathway or multi-cell extensions. Moreover, as previously mentioned, only the use phase of the technologies is accounted for in terms of resource use, which omits part of the reality. It would be interesting to study the impact of incorporating the use phase of the technologies along with other aspects beyond just resource use.

Finally, the pLCA approach can also be used to quantify other environmental impacts besides GWP, such as land use. These additional impacts can then be incorporated into the multi-criteria extension of the EnergyScope model, providing a more holistic assessment of future energy systems.

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Appendix A

Data acquisition

This appendix details the reference products from the *ecoinvent* database used to represent various conversion technologies and resources. These are essential for quantifying either their $gwp_{constr}(tech)$ or $gwp_{op}(res)$ values, as utilized by the EnergyScope TD model in the context of the Belgian energy system. Additionally, it outlines the assumptions and conversions necessary to ensure consistent units for the parameter values.

The work is divided into two parts: resources and technologies. For resources, the focus is first on re-quantifying the electricity imports and then on quantifying the emissions from imported renewable fuels. For the latter, *ecoinvent*, its modification using *premise*, and the GWP calculation using Activity-Browser were not used. Instead, the employed method is described in more detail. For technologies, the work is categorized by sectors and end-use types. The results of the GWP calculations done by Activity Browser will be described in Appendix B.

To recall, the *ecoinvent* database was previously modified using the *premise* Python library according to different IAM scenarios. Once the database is updated and the resources or technologies are represented using *ecoinvent* processes to re-quantify their $gwp_{constr}(tech)$ or $gwp_{op}(res)$ values, the Activity-Browser tool, with its 'scenario setup' feature, can be used to calculate the desired values. This appendix presents the *ecoinvent* processes used.

A.1. Resources

A.1.1. Electricity imports

To calculate the gwp_{op} of electricity imports using pLCA, two approaches were considered, but only one was chosen. The first approach involves considering the European electricity mix as the source of electricity imports to Belgium, and thus quantifying the GWP of the evolving European electricity mix over time, as modelled by *premise*. The second approach involves directly quantifying the emissions from imports based on the specific exporting countries, using the *ecoinvent* database altered by *premise*, and then assigning a relative share to each exporter based on the actual proportion of imports from each country. The second approach was selected and will be described below.

In the *ecoinvent* database, activities representing high voltage electricity imports from one country to another are available, expressed in [kWh]. To accurately represent Belgian electricity imports, the share of electricity imported and its predicted evolution had to be calculated based on the country of origin. Historical data for the years 2017, 2018, 2021, and 2022 were found in the ENTSO-E documentation, as shown in Table A.1. Unfortunately, data for the years 2019 and 2020 and after 2022 were not available. Nonetheless, the available data were valuable as

they illustrated the variations in quantity of imports and their origins over different years. To represent the future evolution of this electricity import mix, predictions for 2040 provided by ENTSO-E were used.

countries of origin	Electricity imports [TWh]				Previsions 2040 [41]
	2017 [45]	2018 [46]	2021 [38]	2022 [39]	
United Kingdom	0	0	0.139	2.523	5
the Netherlands	10.252	10.783	5.292	6.221	17
Germany	0	0	2.572	3.229	7
Luxembourg	0.027	0.103	0.054	0.104	0
France	3.918	10.765	4.372	0.839	14
TOTAL	14.197	21.651	12.429	12.916	43

Table A.1: Belgian electricity imports, historical data and previsions used to estimate the share by origin for 2020, 2035 and 2050.

Once all the data were collected, a linear regression approach was used to estimate the import quantities country by country for the years 2020, 2035, and 2050, as depicted in Figure A.1. The line was forced to pass by the 2040 predicted data. With this estimates of the quantity

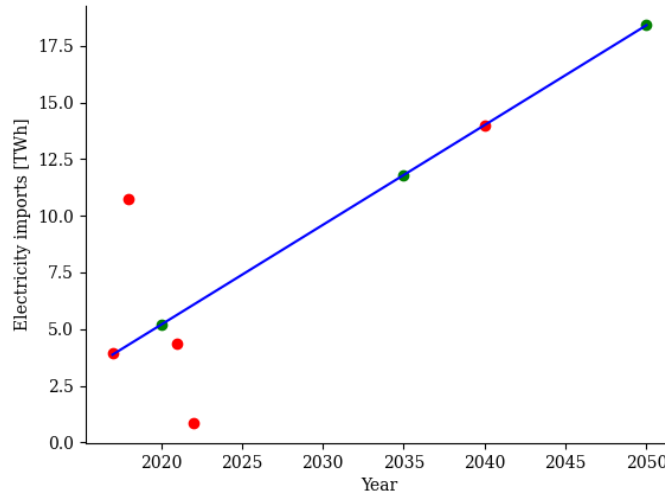


Figure A.1: Belgian electricity imports from France. In red are represented the data found in the ENTSO-E documentation, in green the obtained values and in blue the linear regression used. The same kind of line was obtained for the other exporter countries. Full results are available in Table A.2.

it was then possible to obtain the specific share as depicted in Table A.2.

These estimated shares were then used to weight the different activities from the *ecoinvent* database, presented in Table A.3, previously modified using *premise* and a specific scenario. The GWP values for the different years were obtained using the "GWP100-IPCC 2021" indicator and the scenario LCA setup of Activity Browser.

A.1.2. Imported renewable fuels

To quantify the emissions of imported renewable fuels that were neglected in the previous version of the case study, data from the literature were utilized. Often, the data were expressed in units

	Electricity imports (TWh)			Electricity imports (%)		
	2020	2035	2050	2020	2035	2050
United Kingdom	0.77	3.94	7.11	4.83	10.88	12.59
The Netherlands	8.35	14.84	21.32	52.29	40.94	37.73
Germany	1.59	5.65	9.71	9.93	15.58	17.18
Luxembourg	0.07	0.02	-0.04	0.44	0.05	-0.06
France	5.19	11.80	18.40	32.51	32.55	32.56

Table A.2: Projected electricity imports to Belgium from various countries in TWh and percentage shares for the years 2020, 2035, and 2050.

Resource	Reference product	Location
electricity imports	electricity, high voltage, import from GB	BE
	electricity, high voltage, import from NL	BE
	electricity, high voltage, import from DE	BE
	electricity, high voltage, import from LU	BE
	electricity, high voltage, import from FR	BE

Table A.3: *ecoinvent* processes used to represent the Belgian electricity imports.

other than [ktCO₂-eq./GWh], necessitating the use of conversion factors, including the lower heating value (LHV). Additionally, for some resources, the GWP value depends on either the technology used or the composition of the electricity imports. In such cases, average values were used for this analysis. Moreover, the data from the literature were relative to the production of the fuels. To maintain consistency with the original quantification assumptions, combustion data from Limpens (2021) were added to obtain the overall emissions. Table A.4 summarizes the production, combustion, and overall emissions, as well as the sources used to collect these data.

	gwp_{prod} [ktCO ₂ -eq/GWh]	gwp_{comb} [ktCO ₂ -eq/GWh]	$gwp_{op}(res)$ [ktCO ₂ -eq/GWh]
biodiesel	0.001 ^a	0.27	0.271
bioethanol	0.197 ^b	0.25	0.447
hydrogen renewable	0.269 ^c	0	0.269
ammonia renewable	0.377 ^d	0	0.377
methanol renewable	0.147 ^e	0.246	0.393
gas renewable	0.0445 ^f	0.2	0.2445

Table A.4: Production, combustion and overall emissions of the imported renewable fuels.

^a from González-García et al. (2013) [47], considering a LHV of 37.53 kg/MJ.

^b from Zhao et al. (2019) [48], considering the average GWP value for the different technologies proposed.

^c from Cho et al. [49] considering the average GWP value for the different technologies proposed and a LHV of 33.33 kg/MJ.

^d from Boero et al. (2021) [50] considering a LHV of 18.6 kg/MJ.

^e from Galusnyak et al. (2021) [51], considering the average GWP values for different technologies and energy sources proposed and a LHV value of 19.9 kg/MJ.

^f from [52], considering the average GWP value for wood-based bio-SNG production.

A.2. Technologies

This section is divided into several subsections, each corresponding to a sector of the energy system. The specific conversions needed from the *ecoinvent* database to the database used for the representation and quantification of the construction-related emissions for the different conversion technologies are explained for each sector. Specific details are provided for certain technologies as necessary, and assumptions made are also discussed.

A.2.1. Electricity Production

In this section, technologies are classified into two categories based on whether they utilize renewable or non-renewable resources. All products are located in Belgium and represent 1 GW of installed capacity.

Renewable electricity supply technologies

Conversion needed 1. *Since all products in the generated database must represent 1 GW of installed capacity, conversions are necessary for different technologies. For this sector, the conversion is straightforward as most technologies are already expressed in watts (W), with the exception of solar PV, which is expressed in peak watts (Wp). The same approach is valid for non-renewable supply technologies.*

Technology	Reference product
solar PV	photovoltaic slanted-roof installation, 93 kWp, multi-Si, panel, mounted, on roof
on. wind turbine	wind turbine, 2MW, onshore
off. wind turbine	· wind power plant, 2MW, offshore, fixed parts · wind power plant, 2MW, offshore, moving parts
hydro river	hydropower plant, run-of-river
geothermal	geothermal power plant, 5.5MWe

Table A.5: *ecoinvent* processes used to represent renewable electricity production technologies. Abbreviations: on. (onshore), off. (offshore).

Non-renewable electricity supply technologies

Assumption 7. *The reference product for the CCGT-ammonia is assumed to be the same as for CCGT-NG but has been resized due to lower efficiency.*

Technology	Reference product
nuclear	nuclear power plant, pressure water reactor, 1000MW
CCGT	NGCC power plant, 400MWe
CCGT ammonia	NGCC power plant, 400MWe
U-S coal	Hard coal PC power plant 500MW
IGCC coal	Hard coal IGCC power plant 450MW

Table A.6: *ecoinvent* processes used to represent non-renewable electricity production technologies. Abbreviations: CCGT (combined cycle gas turbine), U-S (ultra-supercritical), IGCC (integrated gasification combined cycle)

A.2.2. Heat

For this sector, the technologies will be classified into three categories, i.e. heat high temperature (industry), heat low temperature (centralised) and heat low temperature (decentralised). The products, located in Belgium, for these technologies represent 1 GW of installed thermal capacity.

Conversion needed 2. *For this sector, the conversions needed are a bit more complex, they often necessitates assumptions, from ecoinvent, premise or other external sources to transform the unit of the initial activity into the one of the desired product. For instance, the thermal and electrical efficiencies of the co-generation unit, expressed as an electrical installed capacity, has to be found in order to obtain the thermal installed capacity. Another example concerns the industrial boiler (coal) for which the average thermal output had to be found.*

Heat high temperature - industry

Assumption 8. *The industrial waste boiler is considered equivalent to the industrial wood boiler, although with different efficiencies.*

Assumption 9. *Gas and oil boilers are assumed to be similar, in line with the assumption made by premise.*

Technology	Reference product
cogen. gas	· heat and power co-generation unit, 200kW electrical, common components for heat+electricity · heat and power co-generation unit, 200kW electrical, components for electricity only
cogen. wood	· heat and power co-generation unit, 200kW electrical, components for heat only · dust collector, electrostatic precipitator, for domestic use · heat and power co-generation unit, organic Rankine cycle, 200kW electrical · furnace, wood chips, with silo, 1000kW
cogen. waste	municipal waste incineration facility
boiler gas	industrial furnace, 1MW, oil
boiler wood	furnace, wood chips, with silo, 1000kW
boiler oil	industrial furnace, 1MW, oil
boiler coal	industrial furnace, coal, 1-10MW
boiler waste	furnace, wood chips, with silo, 1000kW
electrical resistors	auxiliary heating unit, electric, 5kW

Table A.7: *ecoinvent* processes used to represent industrial heating technologies. Abbreviations: cogen. (co-generation).

Heat low temperature - centralised

Assumption 10. *Aligned with premise, the gas boiler and oil boiler are considered the same.*

Assumption 11. *The efficiencies of some of the technologies, such as the co-generation unit (gas), have been revised to match the ESTD documentation, leading to a change of thermal output.*

Assumption 12. *For the co-generation hydrolysis, the hydrolysis plant is assumed similar to a digestion plant (used by the co-generation wet biomass technology). The two technologies have similar characteristics, although encounters differences in efficiencies and thermal output.*

Heat low temperature - decentralised

Assumption 13. *Gas boiler and oil boiler are considered similar, following the premise assumption*

Technology	Reference product
heat pump	heat pump, brine-water, 10kW
cogen. gas	NGCC power plant, 400MWe
cogen. wood	· dust collector, electrostatic precipitator, for industrial use · furnace, wood chips, with silo, 1000kW · heat and power co-generation unit, organic Rankine cycle, 200kW electrical
cogen. waste	municipal waste incineration facility
cogen. wet biomass	· heat and power co-generation unit, 200kW electrical, common components for heat+electricity · heat and power co-generation unit, 200kW electrical, components for electricity only · heat and power co-generation unit, 200kW electrical, components for heat only
cogen. hydrolysis	· anaerobic digestion plant, for biowaste · heat and power co-generation unit, 200kW electrical, common components for heat+electricity · heat and power co-generation unit, 200kW electrical, components for electricity only · heat and power co-generation unit, 200kW electrical, components for heat only
boiler gas	industrial furnace, 1MW, oil
boiler wood	furnace, wood chips, with silo, 1000kW
boiler oil	industrial furnace, 1MW, oil
geothermal	geothermal heat plant
solar thermal	flat plate solar collector, Cu absorber

Table A.8: *ecoinvent* processes used to represent the centralised heat technologies. Abbreviations: cogen. (co-generation)

Technology	Reference product
electrical heat pump	heat pump, brine-water, 10kW
thermal heat pump gas	heat pump, diffusion absorption, 4kW, future
cogen. gas	· heat and power co-generation unit, 50kW electrical, common components for heat+electricity · heat and power co-generation unit, 50kW electrical, components for electricity only · heat and power co-generation unit, 50kW electrical, components for heat only
cogen. oil	· heat and power co-generation unit, 50kW electrical, common components for heat+electricity · heat and power co-generation unit, 50kW electrical, components for electricity only · heat and power co-generation unit, 50kW electrical, components for heat only
adv. cogen. gas	fuel cell, stack solid oxide, 125kW electrical, future
adv. cogen. H ₂	fuel cell, stack solid oxide, 125kW electrical, future
boiler gas	industrial furnace, 1MW, oil
boiler wood	furnace, wood chips, with silo, 1000kW
boiler oil	industrial furnace, 1MW, oil
solar thermal	flat plate solar collector, Cu absorber
direct electrical heaters	auxiliary heating unit, electric, 5kW

Table A.9: *ecoinvent* processes used to represent the decentralised heat production technologies. Abbreviations: cogen. (co-generation), adv. (advanced).

A.2.3. Transport

To accurately represent transport technologies and quantify their construction-related emissions, two primary challenges were encountered.

Firstly, the transport technologies were initially expressed in units, e.g. one passenger train, rather than in Mtonkm (Megatonne-kilometers) or Mpkm (Megapassenger-kilometers), as required by the EnergyScope TD model.

Conversion needed 3. *The conversion process for the transport technologies involved adhering to the assumptions of the EnergyScope TD model to derive load or occupancy, average annual distance, and vehicle lifetime. This process enabled the transition from unit measurements to Mtkm (for freight mobility) or Mpkm (for passenger mobility).*

The second challenge is related to the *premise* database. When modifying the database according to specific scenarios, *premise* generates new activities to track the evolution of various

transport technologies over time. As detailed in the *premise* documentation, updates can be made for two-wheelers, passenger cars, medium and heavy-duty trucks, and buses according to a given scenario. This process imports new inventories for these transport activities. The inventories cover construction years from 2000 to 2050, in 5-year intervals. However, *premise* only imports activities for vehicles with a construction year up to the scenario year. Table A.11 exemplifies activities for a medium-duty truck, EURO-VI running on compressed gas, using the REMIND SSP2-PKBudg-1150 scenarios from 2020 to 2050. Similar activities are available for other mobility technologies.

To accurately represent the fleet, the age distribution of the Belgian fleet of private cars, buses, and trucks was determined. Data on the age distribution of these fleets were obtained from Statbel [53]. This dataset spans from August 1, 2014, to August 1, 2023, detailing the percentage and number of vehicles for each age category, from the year of registration to 16 years and older.

Assumption 14. *The lifetime of cars was assumed to be 10 years, while the lifetime for trucks and buses was assumed to be 15 years, consistent with the ESTD assumptions.*

Assumption 15. *Vehicles are considered new in the year of their registration.*

Given the 5-year intervals between inventories generated by *premise*, vehicles were grouped into different age classes: the year of registration, 1-5 years old, 6-10 years old (with private cars considered as 6 years and older), and 11 years and older. For each age class, the average percentage of vehicles over the dataset period (2014-2023) was calculated to capture general trends and distributions within each class. These results are summarized in Table A.10.

Age class	Private cars [%]	Buses [%]	Trucks [%]
Same year as the AB activity	5.23	3.68	5.01
1 to 5 years older than the AB activity	37.81	27.76	36.34
6 to 10 years older than the AB activity	56.97	27.42	26.90
11 or more years older than the AB activity	-	41.15	31.75

Table A.10: Average percentage of vehicles in each age class over the period from 2014 to 2023.

These percentages enabled the allocation of the conversion factor for different technologies to the corresponding inventory age class accurately. An example of this allocation is provided in Table A.11.

Product	Activity	Amount
Medium duty truck, EURO-VI	Medium duty truck, compressed gas, 26t gross weight, 2015, EURO-VI, regional delivery	0
Medium duty truck, EURO-VI	Medium duty truck, compressed gas, 26t gross weight, 2020, EURO-VI, regional delivery	0
Medium duty truck, EURO-VI	Medium duty truck, compressed gas, 26t gross weight, 2025, EURO-VI, regional delivery	0
Medium duty truck, EURO-VI	Medium duty truck, compressed gas, 26t gross weight, 2030, EURO-VI, regional delivery	0
Medium duty truck, EURO-VI	Medium duty truck, compressed gas, 26t gross weight, 2035, EURO-VI, regional delivery	0.058
Medium duty truck, EURO-VI	Medium duty truck, compressed gas, 26t gross weight, 2040, EURO-VI, regional delivery	0.049
Medium duty truck, EURO-VI	Medium duty truck, compressed gas, 26t gross weight, 2045, EURO-VI, regional delivery	0.066
Medium duty truck, EURO-VI	Medium duty truck, compressed gas, 26t gross weight, 2050, EURO-VI, regional delivery	0.009

Table A.11: Representation of a truck (methanol) for the year 2050, using Activity-Browser, the *ecoinvent* v3.8 database altered with *premise* and the REMIND SSP2-PKBudg1150 scenario from 2020 to 2050. The amount are expressed in [unit].

Passenger mobility

Technology	Reference product
train passenger	· maintenance, train, passenger, regional · train production, passenger, regional
bus diesel	Passenger bus, diesel, 13m single deck coach bus, 20xx, EURO-VI
bus diesel hybrid	Passenger bus, diesel hybrid, 13m single deck coach bus, 20xx, EURO-VI
bus gas	Passenger bus, compressed gas, 13m single deck coach bus, 20xx, EURO-VI
bus fuel cell (hydrogen)	Passenger bus, fuel cell electric, 13m single deck coach bus, 20xx
tram or metro	market for tram
car gasoline	Passenger car, gasoline, Medium, 20xx, EURO-6d
car diesel	Passenger car, diesel, Medium, 20xx, EURO-6ab
car gas	Passenger car, compressed gas, Medium, 20xx, EURO-6d
car methanol	Passenger car, gasoline, Medium, 20xx, EURO-6d
car hybrid (gasoline)	Passenger car, gasoline hybrid, Medium, 20xx, EURO-6d
car plug-in hybrid	Passenger car, plugin gasoline hybrid, Medium, 20xx, EURO-6d
car electric	Passenger car, battery electric, NMC-622 battery, Medium, 20xx
car fuel cell (hydrogen)	Passenger car, fuel cell electric, Medium, 20xx

Table A.12: *ecoinvent* processes used to represent the passenger mobility technologies.

Freight mobility

Technology	Reference product
train (freight)	· market for goods wagon · market for locomotive · market for maintenance, goods wagon · market for maintenance, locomotive
boat diesel	· market for barge tanker · market for maintenance, barge
boat methanol	· market for barge tanker · market for maintenance, barge
truck diesel	Medium duty truck, diesel hybrid, 26t gross weight, 20xx, EURO-VI, regional delivery
truck methanol	Medium duty truck, compressed gas, 26t gross weight, 20xx, EURO-VI, regional delivery
truck fuel cell (hydrogen)	Medium duty truck, fuel cell electric, 26t gross weight, 20xx, regional delivery
truck electric	Medium duty truck, battery electric, NMC-622 battery, 26t gross weight, 20xx, regional delivery
truck gas	Medium duty truck, compressed gas, 26t gross weight, 20xx, EURO-VI, regional delivery

Table A.13: *ecoinvent* processes used to represent the freight mobility technologies.

A.2.4. Storage

Electric storage

Conversion needed 4. *The conversion process for electric storage involved using formulas and conversion factors to translate measurements from kg or unit to GWh or GW for batteries and PHS, respectively. Assumptions and data from the literature were also needed to determine the capacity of one battery in Wh/kg and the capacity (W) and corresponding production (Wh) of one reservoir.*

Assumption 16. *The three types of batteries present in the EnergyScope TD model are assumed to be the same when quantifying their GWP.*

Technology	Reference product
lithium batteries	battery, Li-ion, NMC111, rechargeable, prismatic
batteries of electric cars	battery, Li-ion, NMC111, rechargeable, prismatic
batteries of plug-in hybrid cars	battery, Li-ion, NMC111, rechargeable, prismatic
pumped hydro storage	reservoir, non-alpine regions

Table A.14: *ecoinvent* processes used to represent the electric storage technologies.

Thermal storage

Conversion needed 5. *Concerning thermal storage, formulas, conversion factors, and assumptions were also required to convert the 'unit' of heat storage (in litres) to the unit required by the model for storages, i.e., GWh.*

Assumption 17. *All thermal storage systems were considered the same.*

Technology	Reference product
dec. direct elec.	heat storage, 2000l
dec. electrical heat pump	heat storage, 2000l
dec. thermal heat pump (gas)	heat storage, 2000l
dec. cogen. gas	heat storage, 2000l
dec. cogen. oil	heat storage, 2000l
dec. adv. cogen. gas	heat storage, 2000l
dec. adv. cogen. H ₂	heat storage, 2000l
dec. boiler gas	heat storage, 2000l
dec. boiler wood	heat storage, 2000l
dec. boiler oil	heat storage, 2000l
DHN daily	heat storage, 2000l
DHN seasonal	heat storage, 2000l
high temperature	heat storage, 2000l

Table A.15: *ecoinvent* processes used to represent the thermal storage for low temperature (de)centralised and high temperature EUTs. Abbreviations: dec. (decentralised), cogen. (co-generation), adv. (advanced), DHN (district heating network, centralised).

Other storage

Conversion needed 6. *For other types of storage, the process becomes more complex. The technologies are expressed either in kg or in units depending on their targeted content, such as hydrogen or oil, respectively. For liquid storages, conversion factors and formulas were used to convert from units to GWh, using the LHV of the different fuels as a reference. For gaseous storage, a similar approach was followed.*

Assumption 18. *All storages intended for gaseous resources were considered the same, with different conversion factors. The same approach was applied to liquid resources, using another technology.*

Technology	Reference product
gas	high pressure hydrogen storage tank
hydrogen	high pressure hydrogen storage tank
diesel	oil storage, 3000l
gasoline	oil storage, 3000l
LFO	oil storage, 3000l
ammonia	high pressure hydrogen storage tank
methanol	high pressure hydrogen storage tank
CO ₂	high pressure hydrogen storage tank

Table A.16: *ecoinvent* processes used to represent the other storage technologies.

A.2.5. Others

This section only presents the processes used to represent the electric grid infrastructure. The district heating network and efficiency measures will not have their construction-emissions quantified.

Conversion needed 7. *The reference products used to represent the Belgian electrical grid are expressed in 'km'. The purpose of the conversion was to transform these distances into their installed capacity, measured in GW, using data from 2014.*

Assumption 19. *The distances and installed capacities for the Belgian electrical grid from 2014 were utilized, with the data assumed to remain constant in the future.*

Technology	Reference product
electrical grid	distribution network, electricity, low voltage
	transmission network, electricity, medium voltage
	transmission network, electricity, high voltage

Table A.17: *ecoinvent* processes used to represent the electrical grid infrastructure.

A.2.6. Synthetic fuels production

Conversion needed 8. *For the synthetic fuels production technologies, the goal of the conversion is to go from 'unit' to GW of installed capacity. To achieve this, data from the literature or assumptions from premise were used to determine the annual output of the different units. Then the conversion was completed using elements like LHV, capacity factor, or efficiency.*

Assumption 20. *The energy source to HVC technologies was considered the same in their construction-emissions quantification. The same applies to the carbon capture technologies. Other processes used the same technologies but with different conversion factors, such as the wood pyrolysis ones.*

Technology	Reference product
electrolyser	· electrolyzer, 1MWe, PEM, Balance of Plant
SMR	· electrolyzer, 1MWe, PEM, Stack
biomass to H ₂	chemical factory, organics
wood gasification	· industrial furnace, 1MW, oil
	· synthetic gas factory
H ₂ methanation	· industrial furnace, 1MW, oil
biomass methanation	· synthetic gas factory
biomass hydrolysis	synthetic gas factory
wood pyrolysis to LFO	anaerobic digestion plant, for biowaste
	· industrial furnace, 1MW, oil
	· synthetic gas factory
wood pyrolysis to gasoline and diesel	· chemical factory, organics
	· industrial furnace, natural gas
	· synthetic gas factory
CC atmosphere	· chemical factory, organics
CC industry	· industrial furnace, natural gas
H ₂ methanolation	· synthetic gas factory
	direct air capture system
methane to methanol	direct air capture system
biomass methanolation	· chemical factory, organics
	· synthetic gas factory
	methanol factory
Haber Bosch (H ₂ to ammonia)	· chemical factory, organics
ammonia to H ₂	· industrial furnace, natural gas
oil to HVC	· synthetic gas factory
gas to HVC	chemical factory, organics
biomass to HVC	chemical factory, organics
methanol to HVC	chemical factory, organics

Table A.18: *ecoinvent* processes used to represent the synthetic fuels production technologies. Abbreviations: SMR (steam methane reforming), LFO (light fuel oil), CC (carbone capture), HVC (high value chemicals).

Appendix B

Belgian energy system data

This appendix will represent the data used to represent the Belgian energy system in 2020, 2035, and 2050. The data will be divided in three parts: resources, demands and technologies.

B.1. Resources

This section, focusing on the data used to represent the resources of the Belgian energy system in 2020, 2035 and 2050. The different tables contains the parameter values for the system as modelled by Limpens (2021). The availability, operation cost and direct emissions were not modified. However, as already explained in the previous appendix, the $gwp_{op}(res)$ for the electricity imports have been re-quantified, these data will also be presented. Concerning the overall emissions of imported renewable fuels, readers are asked to refer to Table A.4.

			availability [GWh/y]	$gwp_{op}(res)$ [ktCO2-eq./GWh]	c_{op} [M€ ₂₀₁₅ /GWh]	gwp_{direct} [ktCO2-eq./GWh]
Non-renewable	Other non-renewable	electricity imports	25,206	0.4130	0.0637	0.0
		uranium	1.00E+15	0.0039	0.0039	0.0
		waste	17,800	0.1501	0.0212	0.26
		hydrogen	1.00E+15	0.4140	0.0776	0.0
		ammonia	1.00E+15	0.2850	0.0720	0.0
		methanol	1.00E+15	0.3500	0.0812	0.2457
	Fossil fuel	gasoline	1.00E+15	0.3448	0.0656	0.25
		diesel	1.00E+15	0.3148	0.0635	0.27
		LFO	1.00E+15	0.3115	0.0479	0.26
		natural gas	1.00E+15	0.2666	0.0336	0.2
	coal	33,355	0.4014	0.0155	0.36	
Renewable	Biofuel	bioethanol	1.00E+15	0.0	0.1225	0.25
		biodiesel	1.00E+15	0.0	0.1314	0.27
		gas RE	1.00E+15	0.0	0.1323	0.2
		hydrogen RE	1.00E+15	0.0	0.1379	0.0
		ammonia RE	1.00E+15	0.0	0.0928	0.0
		methanol RE	1.00E+15	0.0	0.1225	0.2457
	Biomass	woody biomass	23,400	0.0118	0.0301	0.39
		wet biomass	38,900	0.0118	0.0053	0.39
	Non-biomass	wind	1.00 E+15	0.0	0.0	0.0
		solar	1.00 E+15	0.0	0.0	0.0
		hydro	1.00 E+15	0.0	0.0	0.0
		geothermal	1.00 E+15	0.0	0.0	0.0
Export	electricity exports	1.00 E+15	0.0	0.0	0.0	
	CO ₂ emissions	1.00 E+15	0.0	0.0	0.0	
Others	CO ₂ atmosphere	1.00 E+15	0.0	0.0	0.0	
	CO ₂ industry	0.0	0.0	0.0	0.0	
	CO ₂ captured	0.0	0.0	0.0	0.0	

Table B.1: Price, GHG emissions and availability of resources, in 2020. Abbreviations: LFO (light fuel oil), RE (renewable).

			availability [GWh/y]	$gwp_{op}(res)$ [ktCO2-eq./GWh]	c_{op} [M€ ₂₀₁₅ /GWh]	gwp_{direct} [ktCO2-eq./GWh]
Non-renewable	Other non-renewable	electricity imports	27,567	0.2065	0.0843	0.0
		uranium	1.00E+15	0.0039	0.0039	0.0
		waste	17,800	0.1501	0.0231	0.26
		hydrogen	1.00E+15	0.3638	0.0880	0.0
		ammonia	1.00E+15	0.2850	0.0947	0.0
		methanol	1.00E+15	0.3500	0.1020	0.2457
	Fossil fuel	gasoline	1.00E+15	0.3448	0.0824	0.25
		diesel	1.00E+15	0.3148	0.0797	0.27
		LFO	1.00E+15	0.3115	0.0602	0.26
		natural gas	1.00E+15	0.2666	0.0443	0.2
coal		33,355	0.4014	0.0177	0.36	
Renewable	Biofuel	bioethanol	1.00E+15	0.0	0.1113	0.25
		biodiesel	1.00E+15	0.0	0.1201	0.27
		gas RE	1.00E+15	0.0	0.1183	0.2
		hydrogen RE	1.00E+15	0.0	0.1192	0.0
		ammonia RE	1.00E+15	0.0	0.0818	0.0
		methanol RE	1.00E+15	0.0	0.1113	0.2457
	Biomass	woody biomass	23,400	0.0118	0.0328	0.39
		wet biomass	38,900	0.0118	0.0058	0.39
	Non-biomass	wind	1.00 E+15	0.0	0.0	0.0
		solar	1.00 E+15	0.0	0.0	0.0
		hydro	1.00 E+15	0.0	0.0	0.0
		geothermal	1.00 E+15	0.0	0.0	0.0
Export		electricity exports	1.00 E+15	0.0	0.0	0.0
		CO ₂ emissions	1.00 E+15	0.0	0.0	0.0
Others		CO ₂ atmosphere	1.00 E+15	0.0	0.0	0.0
		CO ₂ industry	0.0	0.0	0.0	0.0
		CO ₂ captured	0.0	0.0	0.0	0.0

Table B.2: Price, GHG emissions and availability of resources, in 2035. Abbreviations: LFO (light fuel oil), RE (renewable).

			availability [GWh/y]	$gwp_{op}(res)$ [ktCO2-eq./GWh]	c_{op} [M€ ₂₀₁₅ /GWh]	gwp_{direct} [ktCO2-eq./GWh]
Non-renewable	Other non-renewable	electricity imports	27,567	0.0	0.1049	0.0
		uranium	1.00E+15	0.0039	0.0039	0.0
		waste	17,800	0.1501	0.0250	0.26
		hydrogen	1.00E+15	0.3366	0.0955	0.0
		ammonia	1.00E+15	0.2850	0.1141	0.0
		methanol	1.00E+15	0.3500	0.1165	0.2457
	Fossil fuel	gasoline	1.00E+15	0.3448	0.0940	0.25
		diesel	1.00E+15	0.3148	0.0911	0.27
		LFO	1.00E+15	0.3115	0.0687	0.26
		natural gas	1.00E+15	0.2666	0.0533	0.2
coal		33,355	0.4014	0.0181	0.36	
Renewable	Biofuel	bioethanol	1.00E+15	0.0	0.1001	0.25
		biodiesel	1.00E+15	0.0	0.1088	0.27
		gas RE	1.00E+15	0.0	0.1043	0.2
		hydrogen RE	1.00E+15	0.0	0.1006	0.0
		ammonia RE	1.00E+15	0.0	0.0709	0.0
		methanol RE	1.00E+15	0.0	0.1001	0.2457
	Biomass	woody biomass	23,400	0.0118	0.0355	0.39
		wet biomass	38,900	0.0118	0.0062	0.39
	Non-biomass	wind	1.00 E+15	0.0	0.0	0.0
		solar	1.00 E+15	0.0	0.0	0.0
		hydro	1.00 E+15	0.0	0.0	0.0
		geothermal	1.00 E+15	0.0	0.0	0.0
Export		electricity exports	1.00 E+15	0.0	0.0	0.0
		CO ₂ emissions	1.00 E+15	0.0	0.0	0.0
Others		CO ₂ atmosphere	1.00 E+15	0.0	0.0	0.0
		CO ₂ industry	0.0	0.0	0.0	0.0
		CO ₂ captured	0.0	0.0	0.0	0.0

Table B.3: Price, GHG emissions and availability of resources, in 2050. Abbreviations: LFO (light fuel oil), RE (renewable).

	gwp_{op} [ktCO ₂ -eq/GWh]		
	2020	2035	2050
Limpens (2021) ^a	0.413	0.206	0
REMIND SSP2-PKBudg-1150 ^b	0.335	0.031	0.017
REMIND SSP5-PKBudg-500 ^b	0.317	0.016	0.012

Table B.4: Overall emissions for electricity imports depending on the system quantified.

^a using *ecoivent* v3.2 database and IPCC 2013 GWP100 indicator

^b using *ecoivent* v3.8 database and IPCC 2021 GWP100 indicator

B.2. Demand

As modelled by Limpens (2021), which is also done in this study, the demand is evolving between 2020 and 2050, as can be seen in Table B.5.

EUD	EUT	2020	2035	2050	units
Electricity	baseload	50.6	67.4	73.3	[TWh/y]
	lighting	24.2	29.9	31.9	[TWh/y]
Heat	high temperature	59.4	61.9	56.7	[TWh/y]
	space heating	103.1	96.1	92.1	[TWh/y]
	hot water	25.5	23.6	22.6	[TWh/y]
Mobility	passenger	109.7	151.2	159.3	[Gpkm/y]
	freight	69.2	84.7	92.8	[Gtkm/y]
Non energy	non energy	51.5	53.1	55	[TWh/y]

Table B.5: Evolution of the energy demand by end-use demand (EUD) and end-use type (EUTs) between 2020 and 2050 in Belgium.

B.3. Technologies

In this section, the $gwp_{constr}(tech)$ parameter values used in the different systems are compared sector by sector and year by year. The parameter values concerning cost, lifetime, capacity factor, and maximal allowed capacity are also presented. These will remain consistent across the different systems, unlike the $gwp_{constr}(tech)$ values.

For the comparisons, relative differences are used to highlight the variations occurring between the different systems. The following abbreviations will be used: Δ_{L-SSP2} , Δ_{L-SSP5} , and $\Delta_{SSP2-SSP5}$, representing the differences between the Limpens and SSP2 systems, Limpens and SSP5 systems, and SSP2 and SSP5 systems, respectively.

B.3.1. Electricity production

2020

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]
nuclear	707.88	475.09	462.78
CCGT	183.79	156.23	155.31
ammonia CCGT	183.79	196.85	195.68
U-S coal	331.60	269.23	268.29
IGCC coal	331.60	365.64	362.73
solar PV	2,081.43	1,073.71	1,047.83
wind onshore	622.85	601.96	598.04
wind offshore	622.85	816.79	810.88
hydro river	1,262.82	1,351.48	1,344.25
geothermal	24,929.10	13,126.25	13,479.58

Table B.6: $gwp_{constr}(tech)$ parameter values used in the different systems, for electricity production technologies, in 2020. Abbreviations: CCGT (combined cycle gas turbine), U-S (ultra-supercritical), IGCC (integrated gasification combined cycle).

	c_{inv} [M€ ₂₀₁₅ /GW]	c_{maint} [M€ ₂₀₁₅ /GW/y]	$lifetime$ [years]	c_p [-]	f_{max} [GW]
nuclear	4,845.73	102.93	60	0.84	5.925
CCGT	825.96	20.92	25	0.96	1.00E+15
ammonia CCGT	825.96	20.92	25	0.59	1.00E+15
U-S coal	2,598.77	30.34	35	0.86	0
IGCC coal	3,351.65	50.00	35	0.85	0
solar PV	1,220.85	13.94	25	1	59.2
wind onshore	1,141.96	13.28	30	1	10
wind offshore	5,357.30	37.27	30	1	6
hydro river	5,044.92	50.44	40	1	0.115
geothermal	8,764.36	162.82	30	0.95	0

Table B.7: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for electricity production technologies, in 2020. Abbreviations: CCGT (combined cycle gas turbine), U-S (ultra-supercritical), IGCC (integrated gasification combined cycle).

2035

	Limpens (2021) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
nuclear	707.88	225.73	-68.11%	189.69	-73.20%	-15.97%
CCGT	183.79	124.50	-32.26%	114.95	-37.46%	-7.67%
ammonia CCGT	183.79	156.87	-14.65%	144.83	-21.20%	-7.67%
U-S coal	331.60	194.44	-41.36%	167.40	-49.52%	-13.90%
IGCC coal	331.60	279.52	-15.71%	243.43	-26.59%	-12.91%
solar PV	2,081.43	455.58	-78.11%	385.35	-81.49%	-15.42%
wind onshore	622.85	392.95	-36.91%	348.42	-44.06%	-11.33%
wind offshore	622.85	586.67	-5.81%	523.85	-15.89%	-10.71%
hydro river	1,262.82	990.47	-21.57%	874.64	-30.74%	-11.69%
geothermal	24,929.09	4,470.90	-82.07%	3,813.80	-84.70%	-14.70%

Table B.8: $gwp_{constr}^{(tech)}$ parameter values used in the different systems, for electricity production technologies, in 2035. Abbreviations: CCGT (combined cycle gas turbine), U-S (ultra-supercritical), IGCC (integrated gasification combined cycle).

	c_{inv} [M€ ₂₀₁₅ /GW]	c_{maint} [M€ ₂₀₁₅ /GW/y]	$lifetime$ [years]	c_p [-]	f_{max} [GW]
nuclear	4,845.73	102.93	60	0.85	2
CCGT	771.99	19.55	25	0.96	1.00E+15
ammonia CCGT	771.99	19.55	25	0.96	1.00E+15
U-S coal	2,516.71	29.38	35	0.87	0
IGCC coal	3,245.81	48.42	35	0.86	0
solar PV	870.00	9.94	25	1	59.2
wind onshore	1,040.00	12.10	30	1	10
wind offshore	4,974.63	34.61	30	1	6
hydro river	5,044.92	50.44	40	1	0.115
geothermal	7,488.00	139.11	30	0.95	0

Table B.9: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for electricity production technologies, in 2035. Abbreviations: CCGT (combined cycle gas turbine), U-S (ultra-supercritical), IGCC (integrated gasification combined cycle).

2050

	Limpens (2021) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
nuclear	707.88	180.35	-74.52%	161.02	-77.25%	-10.71%
CCGT	183.79	110.76	-39.74%	105.56	-42.56%	-4.69%
ammonia CCGT	183.79	139.55	-24.07%	133.01	-27.63%	-4.69%
U-S coal	331.60	154.47	-53.42%	144.00	-56.57%	-6.78%
IGCC coal	331.60	240.02	-27.62%	213.74	-35.54%	-10.95%
solar PV	2,081.43	326.92	-84.29%	320.66	-84.59%	-1.91%
wind onshore	622.85	316.75	-49.15%	311.51	-49.99%	-1.65%
wind offshore	622.85	497.07	-20.19%	465.25	-25.30%	-6.40%
hydro river	1,262.82	736.78	-41.66%	660.48	-47.70%	-10.36%
geothermal	24,929.10	3,456.30	-86.14%	3,018.71	-87.89%	-12.66%

Table B.10: $gwp_{constr}^{(tech)}$ parameter values used in the different systems, for electricity production technologies, in 2050. Abbreviations: CCGT (combined cycle gas turbine), U-S (ultra-supercritical), IGCC (integrated gasification combined cycle).

	c_{inv} [M€ ₂₀₁₅ /GW]	c_{maint} [M€ ₂₀₁₅ /GW/y]	$lifetime$ [years]	c_p [-]	f_{max} [GW]
nuclear	4,845.73	102.93	60	0.85	0
CCGT	750.87	19.02	25	0.96	1.00E+15
ammonia CCGT	750.87	19.02	25	0.63	1.00E+15
U-S coal	2,434.64	28.43	35	0.87	0
IGCC coal	3,139.97	46.84	35	0.86	0
solar PV	638.95	7.30	25	1	59.2
wind onshore	978.82	11.38	30	1	10
wind offshore	4,653.20	32.37	30	1	6
hydro river	5,044.92	50.44	40	1	0.115
geothermal	6,977.45	129.63	30	0.95	0

Table B.11: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for electricity production technologies, in 2050. Abbreviations: CCGT (combined cycle gas turbine), U-S (ultra-supercritical), IGCC (integrated gasification combined cycle).

B.3.2. Heating and co-generation**2020**

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]
cogen. gas	1,024.32	485.98	479.83
cogen. wood	165.33	253.32	252.44
cogen. waste	647.82	452.50	451.76
boiler gas	12.32	10.75	10.69
boiler wood	28.87	80.34	80.28
boiler oil	12.32	10.75	10.69
boiler coal	48.18	91.28	90.88
boiler waste	28.87	84.68	84.61
electrical resistors	1.47	1.52	1.51
heat pump	174.79	160.03	159.82
cogen. gas	490.88	195.28	194.13
cogen. wood	165.33	264.75	263.71
cogen. waste	647.82	452.50	451.76
cogen. wet biomass	1,024.00	4,971.29	4,936.65
cogen. hydrolysis	647.80	3,450.35	3,425.38
boiler gas	12.32	10.75	10.69
boiler wood	28.87	80.34	80.28
boiler oil	12.32	10.75	10.69
geothermal	808.76	856.08	850.81
solar thermal	221.22	2,242.76	2,207.38
elec. heat pump	164.89	160.03	159.82
thermal heat pump gas	381.93	339.90	334.66
cogen. gas	1,024.32	753.70	744.05
cogen. oil	1,024.32	753.70	744.05
adv. cogen. gas	2,193.45	311.78	306.30
adv. cogen. H ₂	2,193.45	311.78	306.30
boiler gas	21.09	10.75	10.69
boiler wood	21.09	80.34	80.28
boiler oil	21.09	10.75	10.69
solar thermal	221.22	2,242.76	2,207.38
direct electrical heaters	1.47	1.63	1.60

Table B.12: $gwp_{constr}(tech)$ parameter values used in the different systems, for heat production technologies, in 2020. The upper part is focused on the high temperature technologies, and the lower part on the low temperature centralised and decentralised ones. Abbreviations: cogen. (co-generation), elec. (electrical), adv. (advanced).

	c_{inv} [M€ ₂₀₁₅ /GW]	c_{op} [M€ ₂₀₁₅ /GW/y]	$lifetime$ [years]	c_p [-]	f_{max} [GW]
cogen. gas	1,528.10	98.22	25	0.8449	1.00E+15
cogen. wood	1,172.95	42.94	25	0.8449	1.00E+15
cogen. waste	3,182.91	117.34	25	0.8449	1.00E+15
boiler gas	70.67	1.42	17	0.9443	1.00E+15
boiler wood	138.22	2.76	17	0.8946	1.00E+15
boiler oil	65.83	1.42	17	0.9443	1.00E+15
boiler coal	138.22	2.76	17	0.8946	1.00E+15
boiler waste	138.22	2.76	17	0.8946	1.00E+15
electrical resistors	387.73	1.76	15	0.9443	1.00E+15
heat pump	395.73	13.42	25	0.9443	1.00E+15
cogen. gas	1 361.46	39.81	25	0.8449	1.00E+15
cogen. wood	1 172.95	42.94	25	0.8449	1.00E+15
cogen. waste	3 182.91	117.34	25	0.8449	1.00E+15
cogen. wet biomass	1 491.64	121.40	25	0.7455	1.00E+15
cogen. hydrolysis	4 923.77	240.59	15	0.8449	1.00E+15
boiler gas	70.67	1.42	17	0.9443	1.00E+15
boiler wood	138.22	2.76	17	0.8946	1.00E+15
boiler oil	65.83	1.42	17	0.9443	1.00E+15
geothermal	1 611.94	60.40	30	0.8449	0
solar thermal	381.37	0.45	30	1	1.00E+15
elec. heat pump	564.78	23.55	18	1	1.00E+15
thermal heat pump gas	362.35	10.59	20	1	1.00E+15
cogen. gas	1,528.10	98.22	20	1	1.00E+15
cogen. oil	1,416.89	86.93	20	1	1.00E+15
adv. cogen. gas	9,185.33	171.18	20	1	1.00E+15
adv. cogen. H ₂	9,185.33	171.18	20	1	1.00E+15
boiler gas	190.24	5.71	17	1	1.00E+15
boiler wood	554.93	19.42	17	1	1.00E+15
boiler oil	170.86	10.25	17	1	1.00E+15
solar thermal	757.56	8.41	20	1	1.00E+15
direct electrical heaters	43.61	0.19	15	1	1.00E+15

Table B.13: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for heat production technologies, in 2020. The upper part is focused on the high temperature technologies, and the lower part on the low temperature centralised and decentralised ones. Abbreviations: cogen. (co-generation), elec. (electrical), adv. (advanced).

2035

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
cogen. gas	1,024.32	338.67	-66.94%	308.86	-69.85%	-8.80%
cogen. wood	165.33	166.41	0.65%	148.80	-10.00%	-10.58%
cogen. waste	647.82	354.56	-45.27%	301.92	-53.39%	-14.85%
boiler gas	12.32	7.44	-39.59%	6.19	-49.80%	-16.89%
boiler wood	28.87	53.32	84.68%	47.65	65.06%	-10.62%
boiler oil	12.32	7.44	-39.59%	6.19	-49.80%	-16.89%
boiler coal	48.18	71.12	47.61%	63.00	30.76%	-11.41%
boiler waste	28.87	56.20	94.65%	50.23	73.97%	-10.62%
electrical resistors	1.47	0.99	-32.45%	0.89	-39.53%	-10.48%
heat pump	174.79	139.88	-19.97%	136.12	-22.12%	-2.69%
cogen. gas	490.88	155.63	-68.30%	143.68	-70.73%	-7.67%
cogen. wood	165.33	173.41	4.89%	154.94	-6.29%	-10.65%
cogen. waste	647.82	354.56	-45.27%	301.92	-53.39%	-14.85%
cogen. wet biomass	1,024	3,751.82	266.39%	3,176.61	210.22%	-15.33%
cogen. hydrolysis	647.8	2,594.45	300.50%	2,204.18	240.26%	-15.04%
boiler gas	12.32	7.44	-39.59%	6.19	-49.80%	-16.89%
boiler wood	28.87	53.32	84.68%	47.65	65.06%	-10.62%
boiler oil	12.32	7.44	-39.59%	6.19	-49.80%	-16.89%
geothermal	808.76	598.72	-25.97%	502.94	-37.81%	-16.00%
solar thermal	221.22	1,388.20	527.52%	1,244.77	462.68%	-10.33%
elec. heat pump	164.89	139.88	-15.17%	136.12	-17.45%	-2.69%
thermal heat pump gas	381.93	203.96	-46.60%	174.07	-54.42%	-14.65%
cogen. gas	1,024.32	523.67	-48.88%	478.10	-53.33%	-8.70%
cogen. oil	1,024.32	523.67	-48.88%	478.10	-53.33%	-8.70%
adv. cogen. gas	2,193.45	199.55	-90.90%	183.27	-91.64%	-8.16%
adv. cogen. H ₂	2,193.45	199.55	-90.90%	183.27	-91.64%	-8.16%
boiler gas	21.09	7.44	-64.71%	6.19	-70.67%	-16.89%
boiler wood	21.09	53.32	152.80%	47.65	125.95%	-10.62%
boiler oil	21.09	7.44	-64.71%	6.19	-70.67%	-16.89%
solar thermal	221.22	1,388.20	527.52%	1,244.77	462.68%	-10.33%
direct electrical heaters	1.47	1.02	-30.46%	0.89	-39.18%	-12.55%

Table B.14: $gwp_{constr}(tech)$ parameter values used in the different systems, for heat production technologies, in 2035. The upper part is focused on the high temperature technologies, and the lower part on the low temperature centralised and decentralised ones. Abbreviations: cogen. (co-generation), elec. (electrical), adv. (advanced).

	c_{inv} [M€ ₂₀₁₅ /GW]	c_{op} [M€ ₂₀₁₅ /GW/y]	$lifetime$ [years]	c_p [-]	f_{max} [GW]
cogen. gas	1,408.03	90.51	25	0.85	1.00E+15
cogen. wood	1,080.79	39.57	25	0.85	1.00E+15
cogen. waste	2,927.87	107.94	25	0.85	1.00E+15
boiler gas	58.89	1.18	17	0.95	1.00E+15
boiler wood	115.18	2.30	17	0.9	1.00E+15
boiler oil	54.86	1.18	17	0.95	1.00E+15
boiler coal	115.18	2.30	17	0.9	1.00E+15
boiler waste	115.18	2.30	17	0.9	1.00E+15
electrical resistors	332.34	1.51	15	0.95	1.00E+15
heat pump	344.76	11.69	25	0.95	1.00E+15
cogen. gas	1,254.49	36.68	25	0.85	1.00E+15
cogen. wood	1,080.79	39.57	25	0.85	1.00E+15
cogen. waste	2,927.87	107.94	25	0.85	1.00E+15
cogen. wet biomass	1,374.44	111.86	25	0.75	1.00E+15
cogen. hydrolysis	4,536.90	221.69	15	0.85	1.00E+15
boiler gas	58.89	1.18	17	0.95	1.00E+15
boiler wood	115.18	2.30	17	0.9	1.00E+15
boiler oil	54.86	1.18	17	0.95	1.00E+15
geothermal	1,500.00	56.20	30	0.85	0
solar thermal	362.00	0.43	30	1	1.00E+15
elec. heat pump	492.04	20.52	18	1	1.00E+15
thermal heat pump gas	315.68	9.23	20	1	1.00E+15
cogen. gas	1,408.03	90.51	20	1	1.00E+15
cogen. oil	1,305.56	80.10	20	1	1.00E+15
adv. cogen. gas	7,242.28	134.97	20	1	1.00E+15
adv. cogen. H ₂	7,242.28	134.97	20	1	1.00E+15
boiler gas	158.54	4.76	17	1	1.00E+15
boiler wood	462.44	16.18	17	1	1.00E+15
boiler oil	142.38	8.54	17	1	1.00E+15
solar thermal	719.07	7.98	20	1	1.00E+15
direct electrical heaters	39.98	0.17	15	1	1.00E+15

Table B.15: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for heat production technologies, in 2035. The upper part is focused on the high temperature technologies, and the lower part on the low temperature centralised and decentralised ones. Abbreviations: cogen. (co-generation), elec. (electrical), adv. (advanced).

2050

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
cogen. gas	1,024.32	300.65	-70.65%	291.37	-71.55%	-3.09%
cogen. wood	165.33	132.27	-19.99%	132.90	-19.61%	0.48%
cogen. waste	647.82	286.69	-55.75%	245.52	-62.10%	-14.36%
boiler gas	12.32	6.39	-48.17%	5.69	-53.81%	-10.88%
boiler wood	28.87	42.11	45.85%	42.04	45.61%	-0.16%
boiler oil	12.32	6.39	-48.17%	5.69	-53.81%	-10.88%
boiler coal	48.18	59.21	22.88%	54.80	13.74%	-7.45%
boiler waste	28.87	44.38	53.72%	44.31	53.47%	-0.16%
electrical resistors	1.47	0.87	-40.99%	0.84	-42.92%	-3.27%
heat pump	174.79	134.33	-23.15%	133.69	-23.51%	-0.47%
cogen. gas	490.88	138.45	-71.80%	131.95	-73.12%	-4.69%
cogen. wood	165.33	138.00	-16.53%	138.62	-16.16%	0.44%
cogen. waste	647.82	286.69	-55.75%	245.52	-62.10%	-14.36%
cogen. wet biomass	1,024.00	3,080.94	200.87%	2,519.53	146.05%	-18.22%
cogen. hydrolysis	647.80	2,138.16	230.07%	1,763.98	172.30%	-17.50%
boiler gas	12.32	6.39	-48.17%	5.69	-53.81%	-10.88%
boiler wood	28.87	42.11	45.85%	42.04	45.61%	-0.16%
boiler oil	12.32	6.39	-48.17%	5.69	-53.81%	-10.88%
geothermal	808.76	472.21	-41.61%	417.07	-48.43%	-11.68%
solar thermal	221.22	1,201.53	443.14%	1,177.47	432.26%	-2.00%
elec. heat pump	164.89	134.33	-18.54%	133.69	-18.92%	-0.47%
thermal heat pump gas	381.93	164.94	-56.81%	158.75	-58.43%	-3.75%
cogen. gas	1,024.32	464.90	-54.61%	451.01	-55.97%	-2.99%
cogen. oil	1,024.32	464.90	-54.61%	451.01	-55.97%	-2.99%
adv. cogen. gas	2,193.45	178.30	-91.87%	175.61	-91.99%	-1.51%
adv. cogen. H ₂	2,193.45	178.30	-91.87%	175.61	-91.99%	-1.51%
boiler gas	21.09	6.39	-69.72%	5.69	-73.02%	-10.88%
boiler wood	21.09	42.11	99.65%	42.04	99.32%	-0.16%
boiler oil	21.09	6.39	-69.72%	5.69	-73.02%	-10.88%
solar thermal	221.22	1,201.53	443.14%	1,177.47	432.26%	-2.00%
direct electrical heaters	1.47	0.87	-40.82%	0.84	-42.79%	-3.33%

Table B.16: $gwp_{constr}(tech)$ parameter values used in the different systems, for heat production technologies, in 2050. The upper part is focused on the high temperature technologies, and the lower part on the low temperature centralised and decentralised ones. Abbreviations: cogen. (co-generation), elec. (electrical), adv. (advanced).

	c_{inv} [M€ ₂₀₁₅ /GW]	c_{op} [M€ ₂₀₁₅ /GW/y]	$lifetime$ [years]	c_p [-]	f_{max} [GW]
cogen. gas	1,309.80	84.19	25	0.85	1.00E+15
cogen. wood	1,005.39	36.81	25	0.85	1.00E+15
cogen. waste	2,652.42	97.78	25	0.85	1.00E+15
boiler gas	58.89	1.18	17	0.95	1.00E+15
boiler wood	115.18	2.30	17	0.9	1.00E+15
boiler oil	54.86	1.18	17	0.95	1.00E+15
boiler coal	115.18	2.30	17	0.9	1.00E+15
boiler waste	115.18	2.30	17	0.9	1.00E+15
electrical resistors	332.34	1.51	15	0.95	1.00E+15
heat pump	317.78	10.78	25	0.95	1.00E+15
cogen. gas	1,166.97	34.12	25	0.85	1.00E+15
cogen. wood	1,005.39	36.81	25	0.85	1.00E+15
cogen. waste	2,652.42	97.78	25	0.85	1.00E+15
cogen. wet biomass	1,278.55	104.05	25	0.75	1.00E+15
cogen. hydrolysis	4,220.37	206.22	15	0.85	1.00E+15
boiler gas	58.89	1.18	17	0.95	1.00E+15
boiler wood	115.18	2.30	17	0.9	1.00E+15
boiler oil	54.86	1.18	17	0.95	1.00E+15
geothermal	1,432.84	53.68	30	0.85	0
solar thermal	346.70	0.41	30	1	1.00E+15
elec. heat pump	453.53	18.91	18	1	1.00E+15
thermal heat pump gas	290.98	8.50	20	1	1.00E+15
cogen. gas	1,309.80	84.19	20	1	1.00E+15
cogen. oil	1,214.48	74.51	20	1	1.00E+15
adv. cogen. gas	5,652.51	105.34	20	1	1.00E+15
adv. cogen. H ₂	5,652.51	105.34	20	1	1.00E+15
boiler gas	158.54	4.76	17	1	1.00E+15
boiler wood	462.44	16.18	17	1	1.00E+15
boiler oil	142.38	8.54	17	1	1.00E+15
solar thermal	688.69	7.64	20	1	1.00E+15
direct electrical heaters	37.80	0.17	15	1	1.00E+15

Table B.17: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for heat production technologies, in 2050. The upper part is focused on the high temperature technologies, and the lower part on the low temperature centralised and decentralised ones. Abbreviations: cogen. (co-generation), elec. (electrical), adv. (advanced).

B.3.3. Transport

2020

	Limpens (2021) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./Mtkm]	SSP2-RCP2.6 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./Mtkm]	SSP5-RCP1.9 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./Mtkm]
tram or metro	0	0.00231	0.00228
bus diesel	0	0.00927	0.00918
bus diesel hybrid	0	0.00935	0.00926
bus gas	0	0.00941	0.00933
bus fuel cell (H ₂)	0	0.01325	0.01301
train passenger	0	0.00082	0.00082
car gasoline	0	0.05226	0.05147
car diesel	0	0.05561	0.05476
car gas	0	0.0536	0.05278
car methanol	0	0.05226	0.05147
car hydrib (gasoline)	0	0.05906	0.05812
car plug-in hybrid	0	0.06834	0.06721
car electric	0	0.08561	0.08406
car fuel cell (H ₂)	0	0.18048	0.17452
train freight	0	0.00182	0.00181
boat diesel	0	0.00103	0.00103
boat gas	0	0.00103	0.00103
boat methanol	0	0.00103	0.00103
truck diesel	0	0.01928	0.01886
truck methanol	0	0.0194	0.01899
truck fuel cell (H ₂)	0	0.03226	0.03132
truck electric	0	0.04835	0.04740
truck gas	0	0.0194	0.01899

Table B.18: $gwp_{constr}^{(tech)}$ parameter values used in the different systems, for transport technologies, in 2020. The upper part is focused on the passenger mobility technologies, and the lower part on the freight mobility ones. The units for passenger mobility are [ktCO₂-eq./Mpk].

	c_{inv} [M€ ₂₀₁₅ /Mtkm]	c_{op} [M€ ₂₀₁₅ /Mtkm/y]	$lifetime$ [years]	c_p [-]	f_{max} [Mtkm]
tram or metro	625.00	12.50	30	0.3425	1.00E+15
bus diesel	577.94	30.56	15	0.2968	1.00E+15
bus diesel hybrid	822.56	33.33	15	0.2968	1.00E+15
bus gas	585.04	30.56	15	0.2968	1.00E+15
bus fuel cell (H ₂)	1,114.04	31.25	15	0.2968	1.00E+15
train passenger	1,506.02	54.35	40	0.2751	1.00E+15
car gasoline	397.47	24.00	10	0.0514	1.00E+15
car diesel	410.87	24.00	10	0.0514	1.00E+15
car gas	411.06	24.00	10	0.0514	1.00E+15
car methanol	397.47	24.00	10	0.0514	1.00E+15
car hydrib (gasoline)	423.86	34.00	10	0.0514	1.00E+15
car plug-in hybrid	473.46	34.00	10	0.0514	1.00E+15
car electric	613.66	10.00	10	0.0514	1.00E+15
car fuel cell (H ₂)	1,062.10	10.00	10	0.0514	1.00E+15
train freight	104.42	2.09	40	0.3425	1.00E+15
boat diesel	72.24	3.82	40	0.1142	1.00E+15
boat gas	73.13	3.82	40	0.1142	1.00E+15
boat methanol	72.24	3.82	40	0.1142	1.00E+15
truck diesel	350.97	18.56	15	0.0926	1.00E+15
truck methanol	350.97	18.56	15	0.0926	1.00E+15
truck fuel cell (H ₂)	430.17	12.07	15	0.0926	1.00E+15
truck electric	878.38	23.13	15	0.0926	1.00E+15
truck gas	355.28	18.56	15	0.0926	1.00E+15

Table B.19: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for transport technologies, in 2020. The upper part is focused on the passenger mobility technologies, and the lower part on the freight mobility ones. The units for passenger mobility are [ktCO₂-eq./Mpk].

2035

	Limpens (2021) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./Mtkm]	SSP2-RCP2.6 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./Mtkm]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./Mtkm]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
tram or metro	0	1.47E-03	-	1.28E-03	-	-13.13%
bus diesel	0	4.30E-03	-	3.71E-03	-	-13.69%
bus diesel hybrid	0	4.33E-03	-	3.72E-03	-	-13.96%
bus gas	0	4.39E-03	-	3.80E-03	-	-13.51%
bus fuel cell (H ₂)	0	6.49E-03	-	5.55E-03	-	-14.54%
train passenger	0	5.13E-04	-	4.46E-04	-	-12.93%
car gasoline	0	3.19E-02	-	2.75E-02	-	-13.80%
car diesel	0	3.24E-02	-	2.80E-02	-	-13.79%
car gas	0	3.31E-02	-	2.85E-02	-	-13.71%
car methanol	0	3.19E-02	-	2.75E-02	-	-13.80%
car hydrib (gasoline)	0	3.42E-02	-	2.94E-02	-	-14.13%
car plug-in hybrid	0	3.92E-02	-	3.37E-02	-	-14.16%
car electric	0	4.84E-02	-	4.15E-02	-	-14.21%
car fuel cell (H ₂)	0	9.86E-02	-	8.52E-02	-	-13.52%
train freight	0	1.27E-03	-	1.17E-03	-	-7.76%
boat diesel	0	7.81E-04	-	7.05E-04	-	-9.64%
boat gas	0	7.81E-04	-	7.05E-04	-	-9.64%
boat methanol	0	7.81E-04	-	7.05E-04	-	-9.64%
truck diesel	0	1.08E-02	-	9.31E-03	-	-13.98%
truck methanol	0	1.09E-02	-	9.43E-03	-	-13.78%
truck fuel cell (H ₂)	0	1.82E-02	-	1.55E-02	-	-14.67%
truck electric	0	2.15E-02	-	1.85E-02	-	-14.03%
truck gas	0	1.09E-02	-	9.43E-03	-	-13.78%

Table B.20: $gwp_{constr}^{(tech)}$ parameter values used in the different systems, for transport technologies, in 2035. The upper part is focused on the passenger mobility technologies, and the lower part on the freight mobility ones. The units for passenger mobility are [ktCO₂-eq./Mpk].

	c_{inv} [M€ ₂₀₁₅ /Mtkm]	c_{op} [M€ ₂₀₁₅ /Mtkm/y]	$lifetime$ [years]	c_p [-]	f_{max} [Mtkm]
tram or metro	625.00	12.50	30	0.3425	1.00E+15
bus diesel	611.11	30.56	15	0.2968	1.00E+15
bus diesel hybrid	833.33	33.33	15	0.2968	1.00E+15
bus gas	611.11	30.56	15	0.2968	1.00E+15
bus fuel cell (H ₂)	1,041.67	31.25	15	0.2968	1.00E+15
train passenger	1,506.02	54.35	40	0.2751	1.00E+15
car gasoline	420.29	24.00	10	0.0514	1.00E+15
car diesel	434.45	24.00	10	0.0514	1.00E+15
car gas	429.38	24.00	10	0.0514	1.00E+15
car methanol	420.29	24.00	10	0.0514	1.00E+15
car hydrib (gasoline)	429.41	34.00	10	0.0514	1.00E+15
car plug-in hybrid	456.37	34.00	10	0.0514	1.00E+15
car electric	433.83	10.00	10	0.0514	1.00E+15
car fuel cell (H ₂)	672.41	10.00	10	0.0514	1.00E+15
train freight	104.42	2.09	40	0.3425	1.00E+15
boat diesel	76.39	3.82	40	0.1142	1.00E+15
boat gas	76.39	3.82	40	0.1142	1.00E+15
boat methanol	76.39	3.82	40	0.1142	1.00E+15
truck diesel	371.11	18.56	15	0.0926	1.00E+15
truck methanol	371.11	18.56	15	0.0926	1.00E+15
truck fuel cell (H ₂)	402.22	12.07	15	0.0926	1.00E+15
truck electric	771.11	23.13	15	0.0926	1.00E+15
truck gas	371.11	18.56	15	0.0926	1.00E+15

Table B.21: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for transport technologies, in 2035. The upper part is focused on the passenger mobility technologies, and the lower part on the freight mobility ones. The units for passenger mobility are [ktCO₂-eq./Mpk].

2050

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./Mtkm]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./Mtkm]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./Mtkm]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
tram or metro	0	1.21E-03	-	1.17E-03	-	-3.24%
bus diesel	0	3.57E-03	-	3.43E-03	-	-3.88%
bus diesel hybrid	0	3.60E-03	-	3.46E-03	-	-3.88%
bus gas	0	3.66E-03	-	3.52E-03	-	-3.84%
bus fuel cell (H ₂)	0	4.99E-03	-	4.82E-03	-	-3.30%
train passenger	0	4.19E-04	-	4.04E-04	-	-3.58%
car gasoline	0	2.64E-02	-	2.56E-02	-	-2.81%
car diesel	0	2.67E-02	-	2.60E-02	-	-2.79%
car gas	0	2.71E-02	-	2.63E-02	-	-2.81%
car methanol	0	2.64E-02	-	2.56E-02	-	-2.81%
car hydrib (gasoline)	0	2.72E-02	-	2.64E-02	-	-2.82%
car plug-in hybrid	0	3.08E-02	-	2.99E-02	-	-2.81%
car electric	0	3.97E-02	-	3.85E-02	-	-2.88%
car fuel cell (H ₂)	0	7.39E-02	-	7.24E-02	-	-2.12%
train freight	0	1.11E-03	-	1.12E-03	-	1.02%
boat diesel	0	6.77E-04	-	6.57E-04	-	-3.00%
boat gas	0	6.77E-04	-	6.57E-04	-	-3.00%
boat methanol	0	6.77E-04	-	6.57E-04	-	-3.00%
truck diesel	0	9.27E-03	-	8.86E-03	-	-4.36%
truck methanol	0	9.21E-03	-	8.81E-03	-	-4.37%
truck fuel cell (H ₂)	0	1.39E-02	-	1.34E-02	-	-3.44%
truck electric	0	1.25E-02	-	1.20E-02	-	-3.87%
truck gas	0	9.21E-03	-	8.81E-03	-	-4.37%

Table B.22: $gwp_{constr}(tech)$ parameter values used in the different systems, for transport technologies, in 2050. The upper part is focused on the passenger mobility technologies, and the lower part on the freight mobility ones. The units for passenger mobility are [ktCO₂-eq./Mpm].

	c_{inv} [M€ ₂₀₁₅ /Mtkm]	c_{op} [M€ ₂₀₁₅ /Mtkm/y]	$lifetime$ [years]	c_p [-]	f_{max} [Mtkm]
tram or metro	625.00	12.50	30	0.34247	1.00E+15
bus diesel	631.97	30.56	15	0.2968	1.00E+15
bus diesel hybrid	861.10	33.33	15	0.2968	1.00E+15
bus gas	627.96	30.56	15	0.2968	1.00E+15
bus fuel cell (H ₂)	1,048.43	31.25	15	0.2968	1.00E+15
train passenger	1,506.02	54.35	40	0.27507	1.00E+15
car gasoline	434.63	24.00	10	0.05137	1.00E+15
car diesel	449.28	24.00	10	0.05137	1.00E+15
car gas	441.22	24.00	10	0.05137	1.00E+15
car methanol	434.63	24.00	10	0.05137	1.00E+15
car hydrib (gasoline)	443.72	34.00	10	0.05137	1.00E+15
car plug-in hybrid	461.55	34.00	10	0.05137	1.00E+15
car electric	414.67	10.00	10	0.05137	1.00E+15
car fuel cell (H ₂)	576.21	10.00	10	0.05137	1.00E+15
train freight	104.42	2.09	40	0.34247	1.00E+15
boat diesel	79.00	3.82	40	0.11416	1.00E+15
boat gas	78.50	3.82	40	0.11416	1.00E+15
boat methanol	79.00	3.82	40	0.11416	1.00E+15
truck diesel	383.78	18.56	15	0.09259	1.00E+15
truck methanol	383.78	18.56	15	0.09259	1.00E+15
truck fuel cell (H ₂)	404.83	12.07	15	0.09259	1.00E+15
truck electric	744.16	23.13	15	0.09259	1.00E+15
truck gas	381.34	18.56	15	0.09259	1.00E+15

Table B.23: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for transport technologies, in 2050. The upper part is focused on the passenger mobility technologies, and the lower part on the freight mobility ones. The units for passenger mobility are [ktCO₂-eq./Mpm].

B.3.4. Storage

2020

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GWh]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GWh]	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GWh]
lithium batteries	61.3	118.92	116.63
batteries of electric cars	0	118.92	116.63
batteries of plug-in hybrid cars	0	118.92	116.63
pumped hydro storage	8.33	1.50	1.49
dec. direct elec.	0	10.30	10.28
dec. electrical heat pump	0	10.30	10.28
dec. thermal heat pump (gas)	0	10.30	10.28
dec. cogen. gas	0	10.30	10.28
dec. cogen. oil	0	10.30	10.28
dec. adv. cogen. gas	0	10.30	10.28
dec. adv. cogen. H ₂	0	10.30	10.28
dec. boiler gas	0	10.30	10.28
dec. boiler wood	0	10.30	10.28
dec. boiler oil	0	10.30	10.28
DHN daily	0	10.30	10.28
DHN seasonal	0	10.30	10.28
high temperature	0	10.30	10.28
gas	0	40.90	40.24
hydrogen	0	16.07	15.82
diesel	0	0.04	0.04
gasoline	0	0.04	0.04
LFO	0	0.03	0.03
ammonia	0	102.63	100.99
methanol	0	96.88	95.32
CO ₂	0	4,960.61	4,880.97

Table B.24: $gwp_{constr}(tech)$ parameter values used in the different systems, for storage technologies, in 2020. The upper part is focused on the electrical storages, the middle part on the thermal storages and the lower part on the other ones. Abbreviations: dec. (decentralised), cogen. (co-generation), adv. (advanced), DHN (district heating network, centralised), LFO (light oil fuel).

	c_{inv} [M€ ₂₀₁₅ /GWh]	c_{op} [M€ ₂₀₁₅ /GWh/y]	$lifetime$ [years]	c_p [-]	f_{max} [GWh]
lithium batteries	501.30	0.7750	15	1	1.00E+15
batteries of electric cars	0.00	0.0000	1	1	1.00E+15
batteries of plug-in hybrid cars	0.00	0.0000	1	1	1.00E+15
pumped hydro storage	58.80	0.0000	50	1	6.5
dec. direct elec.	18.97	0.1328	20	1	1.00E+15
dec. electrical heat pump	18.97	0.1328	20	1	1.00E+15
dec. thermal heat pump (gas)	18.97	0.1328	20	1	1.00E+15
dec. cogen. gas	18.97	0.1328	20	1	1.00E+15
dec. cogen. oil	18.97	0.1328	20	1	1.00E+15
dec. adv. cogen. gas	18.97	0.1328	20	1	1.00E+15
dec. adv. cogen. H ₂	18.97	0.1328	20	1	1.00E+15
dec. boiler gas	18.97	0.1328	20	1	1.00E+15
dec. boiler wood	18.97	0.1328	20	1	1.00E+15
dec. boiler oil	18.97	0.1328	20	1	1.00E+15
DHN daily	3.00	0.0086	40	1	1.00E+15
DHN seasonal	0.59	0.0032	25	1	1.00E+15
high temperature	28.03	0.3000	25	1	1.00E+15
gas	0.05	0.0013	50	1	1.00E+15
hydrogen	6.19	0.3900	20	1	1.00E+15
diesel	0.01	0.0004	20	1	1.00E+15
gasoline	0.01	0.0004	20	1	1.00E+15
LFO	0.01	0.0004	20	1	1.00E+15
ammonia	0.01	0.0004	20	1	1.00E+15
methanol	0.01	0.0004	20	1	1.00E+15
CO ₂	49.50	0.4950	30	1	1.00E+15

Table B.25: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for storage technologies, in 2020. The upper part is focused on the electrical storages, the middle part on the thermal storages and the lower part on the other ones.

2035

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GWh]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GWh]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GWh]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
lithium batteries	61.3	67.54	10.18%	59.32	-3.23%	-12.18%
batteries of electric cars	0	67.54	-	59.32	-	-12.18%
batteries of plug-in hybrid cars	0	67.54	-	59.32	-	-12.18%
pumped hydro storage	8.33	1.10	-86.80%	0.97	-88.35%	-11.74%
dec. direct elec.	0	6.16	-	5.46	-	-11.37%
dec. electrical heat pump	0	6.16	-	5.46	-	-11.37%
dec. thermal heat pump (gas)	0	6.16	-	5.46	-	-11.37%
dec. cogen. gas	0	6.16	-	5.46	-	-11.37%
dec. cogen. oil	0	6.16	-	5.46	-	-11.37%
dec. adv. cogen. gas	0	6.16	-	5.46	-	-11.37%
dec. adv. cogen. H ₂	0	6.16	-	5.46	-	-11.37%
dec. boiler gas	0	6.16	-	5.46	-	-11.37%
dec. boiler wood	0	6.16	-	5.46	-	-11.37%
dec. boiler oil	0	6.16	-	5.46	-	-11.37%
DHN daily	0	6.16	-	5.46	-	-11.37%
DHN seasonal	0	6.16	-	5.46	-	-11.37%
high temperature	0	6.16	-	5.46	-	-11.37%
gas	0	29.37	-	28.48	-	-3.04%
hydrogen	0	11.54	-	11.19	-	-3.04%
diesel	0	0.02	-	0.02	-	-12.19%
gasoline	0	0.03	-	0.02	-	-12.19%
LFO	0	0.02	-	0.02	-	-12.19%
ammonia	0	73.71	-	71.47	-	-3.04%
methanol	0	69.57	-	67.46	-	-3.04%
CO ₂	0	3562.50	-	3454.21	-	-3.04%

Table B.26: $gwp_{constr}(tech)$ parameter values used in the different systems, for storage technologies, in 2035. The upper part is focused on the electrical storages, the middle part on the thermal storages and the lower part on the other ones. Abbreviations: dec. (decentralised), cogen. (co-generation), adv. (advanced), DHN (district heating network, centralised), LFO (light oil fuel).

	c_{inv} [M€ ₂₀₁₅ /GWh]	c_{op} [M€ ₂₀₁₅ /GWh/y]	$lifetime$ [years]	c_p [-]	f_{max} [GWh]
lithium batteries	302	0.4669	15	1	1.00E+15
batteries of electric cars	0	0	1	1	1.00E+15
batteries of plug-in hybrid cars	0	0	1	1	1.00E+15
pumped hydro storage	58.8	0	50	1	6.5
dec. direct elec.	18.97	0.1328027	20	1	1.00E+15
dec. electrical heat pump	18.97	0.1328	20	1	1.00E+15
dec. thermal heat pump (gas)	18.97	0.1328	20	1	1.00E+15
dec. cogen. gas	18.97	0.1328	20	1	1.00E+15
dec. cogen. oil	18.97	0.1328	20	1	1.00E+15
dec. adv. cogen. gas	18.97	0.1328	20	1	1.00E+15
dec. adv. cogen. H ₂	18.97	0.1328	20	1	1.00E+15
dec. boiler gas	18.97	0.1328	20	1	1.00E+15
dec. boiler wood	18.97	0.1328	20	1	1.00E+15
dec. boiler oil	18.97	0.1328	20	1	1.00E+15
DHN daily	3	0.0086	40	1	1.00E+15
DHN seasonal	0.54	0.0030	25	1	1.00E+15
high temperature	28.03	0.3	25	1	1.00E+15
gas	0.05	0.0013	50	1	1.00E+15
hydrogen	6.19	0.3900	20	1	1.00E+15
diesel	0.01	0.0004	20	1	1.00E+15
gasoline	0.01	0.0004	20	1	1.00E+15
LFO	0.01	0.0004	20	1	1.00E+15
ammonia	0.01	0.0004	20	1	1.00E+15
methanol	0.01	0.0004	20	1	1.00E+15
CO ₂	49.5	0.4950	30	1	1.00E+15

Table B.27: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for storage technologies, in 2035. The upper part is focused on the electrical storages, the middle part on the thermal storages and the lower part on the other ones.

2050

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GWh]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GWh]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GWh]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
lithium batteries	61.3	56.46	-7.90%	54.93	-10.40%	-2.71%
batteries of electric cars	0	56.46	-	54.93	-	-2.71%
batteries of plug-in hybrid cars	0	56.46	-	54.93	-	-2.71%
pumped hydro storage	8.33	0.81	-90.30%	0.69	-91.73%	-14.76%
dec. direct elec.	0	4.75	-	4.98	-	4.75%
dec. electrical heat pump	0	4.75	-	4.98	-	4.75%
dec. thermal heat pump (gas)	0	4.75	-	4.98	-	4.75%
dec. cogen. gas	0	4.75	-	4.98	-	4.75%
dec. cogen. oil	0	4.75	-	4.98	-	4.75%
dec. adv. cogen. gas	0	4.75	-	4.98	-	4.75%
dec. adv. cogen. H ₂	0	4.75	-	4.98	-	4.75%
dec. boiler gas	0	4.75	-	4.98	-	4.75%
dec. boiler wood	0	4.75	-	4.98	-	4.75%
dec. boiler oil	0	4.75	-	4.98	-	4.75%
DHN daily	0	4.75	-	4.98	-	4.75%
DHN seasonal	0	4.75	-	4.98	-	4.75%
high temperature	0	4.75	-	4.98	-	4.75%
gas	0	28.37	-	28.10	-	-0.95%
hydrogen	0	11.15	-	11.04	-	-0.95%
diesel	0	0.02	-	0.02	-	3.57%
gasoline	0	0.02	-	0.02	-	3.57%
LFO	0	0.02	-	0.02	-	3.57%
ammonia	0	71.19	-	70.52	-	-0.95%
methanol	0	67.20	-	66.56	-	-0.95%
CO ₂	0	3,441.07	-	3,408.24	-	-0.95%

Table B.28: $gwp_{constr}(tech)$ parameter values used in the different systems, for storage technologies, in 2050. The upper part is focused on the electrical storages, the middle part on the thermal storages and the lower part on the other ones. Abbreviations: dec. (decentralised), cogen. (co-generation), adv. (advanced), DHN (district heating network, centralised), LFO (light oil fuel).

	c_{inv} [M€ ₂₀₁₅ /GWh]	c_{op} [M€ ₂₀₁₅ /GWh/y]	$lifetime$ [years]	c_p [-]	f_{max} [GWh]
lithium batteries	156.66	0.2422	15	1	1.00E+15
batteries of electric cars	0	0	1	1	1.00E+15
batteries of plug-in hybrid cars	0	0	1	1	1.00E+15
pumped hydro storage	58.8	0	50	1	6.5
dec. direct elec.	18.97	0.1328	20	1	1.00E+15
dec. electrical heat pump	18.97	0.1328	20	1	1.00E+15
dec. thermal heat pump (gas)	18.97	0.1328	20	1	1.00E+15
dec. cogen. gas	18.97	0.1328	20	1	1.00E+15
dec. cogen. oil	18.97	0.1328	20	1	1.00E+15
dec. adv. cogen. gas	18.97	0.1328	20	1	1.00E+15
dec. adv. cogen. H ₂	18.97	0.1328	20	1	1.00E+15
dec. boiler gas	18.97	0.1328	20	1	1.00E+15
dec. boiler wood	18.97	0.1328	20	1	1.00E+15
dec. boiler oil	18.97	0.1328	20	1	1.00E+15
DHN daily	3	0.0086	40	1	1.00E+15
DHN seasonal	0.52	0.00283	25	1	1.00E+15
high temperature	28.03	0.3	25	1	1.00E+15
gas	0.05	0.00131	50	1	1.00E+15
hydrogen	6.19	0.39	20	1	1.00E+15
diesel	0.01	0.0004	20	1	1.00E+15
gasoline	0.01	0.0004	20	1	1.00E+15
LFO	0.01	0.0004	20	1	1.00E+15
ammonia	0.01	0.0004	20	1	1.00E+15
methanol	0.01	0.0004	20	1	1.00E+15
CO ₂	49.5	0.495	30	1	1.00E+15

Table B.29: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for storage technologies, in 2050. The upper part is focused on the electrical storages, the middle part on the thermal storages and the lower part on the other ones.

B.3.5. Synthetic fuels production

2020

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]
electrolyser	0.00	1,398.53	1,390.38
SMR	0.00	774.23	757.93
biomass to H ₂	0.00	115.34	114.60
wood gasification	0.00	115.34	114.60
H ₂ methanation	0.00	109.95	109.30
biomass methanation	0.00	2,399.60	2,384.36
biomass hydrolysis	0.00	114.25	113.58
wood pyrolysis to LFO	0.00	2,073.25	2,030.96
wood pyrolysis to gasoline and diesel	0.00	1,988.44	1,948.02
CC atmosphere	0.00	164.93	163.57
CC industry	0.00	164.93	163.57
H ₂ methanolation	0.00	4,014.24	3,929.01
methane to methanol	0.00	71.68	71.12
biomass methanolation	0.00	4,024.02	3,938.65
Haber Bosch (H ₂ to ammonia)	0.00	4,031.58	3,942.55
ammonia to H ₂	0.00	774.23	757.93
oil to HVC	0.00	1,611.50	1,575.92
gas to HVC	0.00	1,611.50	1,575.92
biomass to HVC	0.00	1,611.50	1,575.92
methanol to HVC	0.00	1,611.50	1,575.92

Table B.30: $gwp_{constr}(tech)$ parameter values used in the different systems, for synthetic fuels production technologies, in 2020. Abbreviations: SMR, (steam methane reforming), LFO (light oil fuel), CC (carbon capture), HVC (high value chemicals).

	c_{inv} [M€ ₂₀₁₅ /GW]	c_{op} [M€ ₂₀₁₅ /GW/y]	$lifetime$ [years]	c_p [-]	f_{max} [GW]
electrolyser	2,784.81	76.5823	15	0.8946	1.00E+15
SMR	775.33	71.5478	25	0.8548	1.00E+15
biomass to H ₂	4,798.23	338.0305	25	0.8548	1.00E+15
wood gasification	4,007.94	282.5397	25	0.8449	1.00E+15
H ₂ methanation	349.60	89.3237	40	1	1.00E+15
biomass methanation	1,122.22	15.5455	20	0.8449	1.00E+15
biomass hydrolysis	1,811.76	123.5268	15	0.8449	1.00E+15
wood pyrolysis to LFO	2,554.01	116.0842	25	0.8449	1.00E+15
wood pyrolysis to gasoline and diesel	2,593.50	72.2000	25	0.8449	1.00E+15
CC atmosphere	5,342.73	132.6240	40	1	1.00E+15
CC industry	2,671.37	66.3120	40	1	1.00E+15
H ₂ methanolation	2,647.88	75.1412	20	0.9443	1.00E+15
methane to methanol	1,511.16	66.0771	25	0.8449	1.00E+15
biomass methanolation	4,788.00	73.1500	20	0.9940	1.00E+15
Haber Bosch (H ₂ to ammonia)	963.97	18.8470	20	0.9940	1.00E+15
ammonia to H ₂	775.33	71.5478	25	0.8548	1.00E+15
oil to HVC	449.55	2.3900	15	0.9940	1.00E+15
gas to HVC	907.75	22.6938	25	0.9940	1.00E+15
biomass to HVC	3,311.70	98.8000	20	0.9940	1.00E+15
methanol to HVC	793.49	71.4137	20	0.9940	1.00E+15

Table B.31: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for synthetic fuels production technologies, in 2020. Abbreviations: SMR, (steam methane reforming), LFO (light oil fuel), CC (carbon capture), HVC (high value chemicals).

2035

	Limpens (2021) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
electrolyser	0.00	1,055.26	-	857.68	-	-18.72%
SMR	0.00	404.25	-	350.36	-	-13.33%
biomass to H ₂	0.00	88.79	-	80.06	-	-9.83%
wood gasification	0.00	88.79	-	80.06	-	-9.83%
H ₂ methanation	0.00	85.06	-	76.94	-	-9.54%
biomass methanation	0.00	1,826.01	-	1,534.23	-	-15.98%
biomass hydrolysis	0.00	88.04	-	79.42	-	-9.79%
wood pyrolysis to LFO	0.00	1,098.21	-	936.44	-	-14.73%
wood pyrolysis to gasoline and diesel	0.00	1,055.72	-	900.59	-	-14.69%
CC atmosphere	0.00	122.78	-	105.09	-	-14.41%
CC industry	0.00	122.78	-	105.09	-	-14.41%
H ₂ methanolation	0.00	2,068.87	-	1,755.50	-	-15.15%
methane to methanol	0.00	43.66	-	38.61	-	-11.56%
biomass methanolation	0.00	2,075.57	-	1,761.05	-	-15.15%
Haber Bosch (H ₂ to ammonia)	0.00	2,019.86	-	1,704.19	-	-15.63%
ammonia to H ₂	0.00	404.25	-	350.36	-	-13.33%
oil to HVC	0.00	807.38	-	681.20	-	-15.63%
gas to HVC	0.00	807.38	-	681.20	-	-15.63%
biomass to HVC	0.00	807.38	-	681.20	-	-15.63%
methanol to HVC	0.00	807.38	-	681.20	-	-15.63%

Table B.32: $gwp_{constr}^{(tech)}$ parameter values used in the different systems, for synthetic fuels production technologies, in 2035. Abbreviations: SMR, (steam methane reforming), LFO (light oil fuel), CC (carbon capture), HVC (high value chemicals).

	c_{inv} [M€ ₂₀₁₅ /GW]	c_{op} [M€ ₂₀₁₅ /GW/y]	$lifetime$ [years]	c_p [-]	f_{max} [GW]
electrolyser	696.20	19.15	15	0.9	1.00E+15
SMR	681.24	62.87	25	0.86	1.00E+15
biomass to H ₂	2,525.39	177.91	25	0.86	1.00E+15
wood gasification	2,525.00	178.00	25	0.85	1.00E+15
H ₂ methanation	262.20	66.99	40	1	1.00E+15
biomass methanation	986.05	13.66	20	0.85	1.00E+15
biomass hydrolysis	1,591.91	108.54	15	0.85	1.00E+15
wood pyrolysis to LFO	1,344.22	61.10	25	0.85	1.00E+15
wood pyrolysis to gasoline and diesel	1,365.00	38.00	25	0.85	1.00E+15
CC atmosphere	5,160.00	128.09	40	1	1.00E+15
CC industry	2,580.00	64.04	40	1	1.00E+15
H ₂ methanolation	1,679.65	47.66	20	0.95	1.00E+15
methane to methanol	958.58	41.92	25	0.85	1.00E+15
biomass methanolation	2,520.00	38.50	20	1	1.00E+15
Haber Bosch (H ₂ to ammonia)	847.00	16.56	20	1	1.00E+15
ammonia to H ₂	681.24	62.87	25	0.86	1.00E+15
oil to HVC	395.00	2.10	15	1	1.00E+15
gas to HVC	797.60	19.94	25	1	1.00E+15
biomass to HVC	1,743.00	52.00	20	1	1.00E+15
methanol to HVC	697.20	62.75	20	1	1.00E+15

Table B.33: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for synthetic fuels production technologies, in 2035. Abbreviations: SMR, (steam methane reforming), LFO (light oil fuel), CC (carbon capture), HVC (high value chemicals).

2050

	Limpens (2021) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}^{(tech)}$ [ktCO ₂ -eq./GW]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
electrolyser	0.00	842.70	-	568.68	-	-32.52%
SMR	0.00	329.00	-	313.69	-	-4.65%
biomass to H ₂	0.00	76.41	-	69.34	-	-9.25%
wood gasification	0.00	76.41	-	69.34	-	-9.25%
H ₂ methanation	0.00	73.21	-	66.42	-	-9.27%
biomass methanation	0.00	1,487.43	-	1,192.05	-	-19.86%
biomass hydrolysis	0.00	75.77	-	68.70	-	-9.33%
wood pyrolysis to LFO	0.00	875.92	-	828.10	-	-5.46%
wood pyrolysis to gasoline and diesel	0.00	842.51	-	796.27	-	-5.49%
CCS atmosphere	0.00	101.81	-	79.19	-	-22.22%
CCS industry	0.00	101.81	-	79.19	-	-22.22%
H ₂ methanolation	0.00	1,638.50	-	1,555.21	-	-5.08%
methane to methanol	0.00	34.76	-	35.26	-	1.42%
biomass methanolation	0.00	1,644.18	-	1,560.35	-	-5.10%
Haber Bosch (H ₂ to ammonia)	0.00	1,587.75	-	1,513.30	-	-4.69%
ammonia to H ₂	0.00	329.00	-	313.69	-	-4.65%
oil to HVC	0.00	634.66	-	604.90	-	-4.69%
gas to HVC	0.00	634.66	-	604.90	-	-4.69%
biomass to HVC	0.00	634.66	-	604.90	-	-4.69%
methanol to HVC	0.00	634.66	-	604.90	-	-4.69%

Table B.34: $gwp_{constr}^{(tech)}$ parameter values used in the different systems, for synthetic fuels production technologies, in 2050. Abbreviations: SMR, (steam methane reforming), LFO (light oil fuel), CC (carbon capture), HVC (high value chemicals).

	c_{inv} [M€ ₂₀₁₅ /GW]	c_{op} [M€ ₂₀₁₅ /GW/y]	$lifetime$ [years]	c_p [-]	f_{max} [GW]
electrolyser	506.33	13.9241	15	0.9	1.00E+15
SMR	630.24	58.1587	25	0.86	1.00E+15
biomass to H ₂	1767.77	124.538	25	0.86	1.00E+15
wood gasification	2404.76	169.524	25	0.85	1.00E+15
H ₂ methanation	172.88	44.1711	40	1	1.00E+15
biomass methanation	912.22	12.6364	20	0.85	1.00E+15
biomass hydrolysis	1472.71	100.411	15	0.85	1.00E+15
wood pyrolysis to LFO	940.95	42.7679	25	0.85	1.00E+15
wood pyrolysis to gasoline and diesel	955.5	26.6	25	0.85	1.00E+15
CC atmosphere	4977.27	123.552	40	1	1.00E+15
CC industry	2488.63	61.776	40	1	1.00E+15
H ₂ methanolation	957.07	27.1595	20	0.95	1.00E+15
methane to methanol	546.2	23.8833	25	0.85	1.00E+15
biomass methanolation	1764	26.95	20	1	1.00E+15
Haber Bosch (H ₂ to ammonia)	783.58	15.3201	20	1	1.00E+15
ammonia to H ₂	630.24	58.1587	25	0.86	1.00E+15
oil to HVC	365.42	1.94276	15	1	1.00E+15
gas to HVC	737.88	18.447	25	1	1.00E+15
biomass to HVC	1220.1	36.4	20	1	1.00E+15
methanol to HVC	645	58.0497	20	1	1.00E+15

Table B.35: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for synthetic fuels production technologies, in 2050. Abbreviations: SMR, (steam methane reforming), LFO (light oil fuel), CC (carbon capture), HVC (high value chemicals).

B.3.6. Others

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]
efficiency measures	0.00	0.00	0.00
DHN	0.00	0.00	0.00
electrical grid	0.00	2,129.83	2,101.27

Table B.36: $gwp_{constr}(tech)$ parameter values used in the different systems, for infrastructure technologies, in 2020. Abbreviations: DHN (district heating network).

2020

	c_{inv} [M€ ₂₀₁₅ /GW]	c_{op} [M€ ₂₀₁₅ /GW/y]	$lifetime$ [years]	c_p [-]	f_{max} [GW]
efficiency measures	5,600.00	0	1	1	1.00E+15
DHN	825.88	0	60	1	1.00E+15
electrical grid	74,919.06	0	80	1	1.00E+15

Table B.37: Cost, lifetime, capacity factor and maximal allowed capacity parameter values used in the different systems, for infrastructure technologies, in 2020, 2035 and 2050. Abbreviations: DHN (district heating network).

2035

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
efficiency measures	0.00	0.00	-	0.00	-	-
DHN	0.00	0.00	-	0.00	-	-
electrical grid	0.00	1,344.45	-	1,148.02	-	-14.61%

Table B.38: $gwp_{constr}(tech)$ parameter values used in the different systems, for infrastructure technologies, in 2035. Abbreviations: DHN (district heating network).

2050

	Limpens (2021) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	SSP2-RCP2.6 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	Δ_{L-SSP2}	SSP5-RCP1.9 (REMIND) $gwp_{constr}(tech)$ [ktCO ₂ -eq./GW]	Δ_{L-SSP5}	$\Delta_{SSP2-SSP5}$
efficiency measures	0.00	0.00	-	0.00	-	-
DHN	0.00	0.00	-	0.00	-	-
electrical grid	0.00	1,109.32	-	1,032.43	-	-6.93%

Table B.39: $gwp_{constr}(tech)$ parameter values used in the different systems, for infrastructure technologies, in 2050. Abbreviations: DHN (district heating network).

UNIVERSITÉ CATHOLIQUE DE LOUVAIN

École polytechnique de Louvain

Rue Archimède, 1 bte L6.11.01, 1348 Louvain-la-Neuve, Belgique | www.uclouvain.be/epl