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# Interlinking the Renewable Electricity and Gas Sectors: A Techno-Economic Case Study for Austria

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**Abstract:** Achieving climate neutrality requires a massive transformation of current energy systems. Fossil energy sources must be replaced with renewable ones. Renewable energy sources with reasonable potential such as photovoltaics or wind power provide electricity. However, since chemical energy carriers are essential for various sectors and applications, the need for renewable gases comes more and more into focus. This paper determines the Austrian green hydrogen potential, produced exclusively from electricity surpluses. In combination with assumed sustainable methane production, the resulting renewable gas import demand is identified, based on two fully decarbonised scenarios for the investigated years 2030, 2040 and 2050. While in one scenario energy efficiency is maximised, in the other scenario significant behavioural changes are considered to reduce the total energy consumption. A techno-economic analysis is used to identify the economically reasonable national green hydrogen potential and to calculate the averaged levelised cost of hydrogen ($LCOH_2$) for each scenario and considered year. Furthermore, roll-out curves for the necessary expansion of national electrolysis plants are presented. The results show that in 2050 about 43% of the national gas demand can be produced nationally and economically (34 TWh green hydrogen, 16 TWh sustainable methane). The resulting national hydrogen production costs are comparable to the expected import costs (including transport costs). The most important actions are the quick and extensive expansion of renewables and electrolysis plants both nationally and internationally.

**Keywords:** power to gas; electrolysis; green hydrogen; national potential; decarbonisation; scenario analysis; national energy system; techno-economic analysis; levelised cost of hydrogen

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## 1. Introduction

The EU Green Deal [1] aims for climate-neutrality of the European continent by 2050. This goal requires a fundamental transformation of the energy system since fossil sources like natural gas and oil must be replaced by renewable ones. One central point of the Green Deal is the massive expansion of renewable energy plants [2,3]. The massive expansion in renewable electricity generation is intended to be used for the direct electrification (e.g., heat pumps, electric vehicles) and the indirect electrification (e.g., renewable hydrogen in industrial processes and long-range freight transport) of the European energy system [3].

However, for several sectors (e.g., long-range freight transport or iron and steel making), currently there does not exist an economically viable option for decarbonisation [4]. In total, all sectors that have currently no economic decarbonisation option account for about one-third of the total energy-related $CO_2$ emissions. However, hydrogen could enable the decarbonisation of these sectors in the future [5]. In their review, Hanley et al. [6] identified several drivers for hydrogen, such as large renewable generation capacities, decarbonisation in general, cost-efficient decarbonisation of sectors that are otherwise difficult to decarbonise (e.g., freight) and lack of development for carbon capture and storage (CCS). In the publications they investigated, a variety of possible applications for hydrogen were found. For example, the use of hydrogen in the field of transport (e.g., [7,8]), in the field of industry (e.g., [9]) or in the field of energy supply (e.g., [10]) has been recently examined.

In addition to broad applicability, hydrogen enables decoupling between volatile generation and controllable energy supply [5]. Furthermore, it is suitable for seasonal energy storage. For long storage periods such as summer to winter, it is more cost-effective to store hydrogen instead of electricity in batteries [11]. The importance of hydrogen for the energy transition has been highlighted in various publications based on its advantages and versatility (e.g., [12–14]). Furthermore, according to the comprehensive review by Kovač et al. [15] energy transition strategies without hydrogen do not have the potential for achieving full $CO_2$ neutrality.

BloombergNEF and the Hydrogen Council are expecting hydrogen to account for up to 24% and 18% of global final energy consumption in 2050, respectively [16,17]. The production of such large quantities of hydrogen can be achieved by different production routes. A nomenclature based on different colours is now widely used to distinguish between them [18,19]:

- Grey hydrogen: Production of hydrogen via steam methane reforming of methane or gasification of coal. Thereby, $CO_2$ emissions are emitted into the atmosphere. Thus, grey hydrogen is not an option for a decarbonised energy supply.
- Blue hydrogen: It uses the same production process as grey hydrogen but includes carbon capture and storage (CCS). This technology raises additional costs for the transport and storage of $CO_2$. However, CCS can only reduce $CO_2$ emissions up to 95% but not eliminates them.
- Turquoise hydrogen: Pyrolysis of methane is used to produce hydrogen and solid carbon black. Storage of solid carbon black is easier than storage of gaseous $CO_2$ (blue hydrogen). Alternatively, carbon could also be used in industry and agriculture as raw materials.
- Pink hydrogen: Use of water electrolysis to produce hydrogen. The required electrical energy is provided by nuclear power plants.
- Green hydrogen: Renewable energy is used to produce hydrogen. Several processes are available. However, the most important process for the production of green hydrogen is the electrolysis of water, supplied by renewable electricity. The electrolysis of water can be implemented as a zero-emissions route. In this work, green hydrogen always refers to this process.

Decarbonised energy systems can in principle be based on blue, turquoise, pink or green hydrogen. However, pink hydrogen should be viewed critically, as the final disposal of nuclear waste is still unclear. Blue and turquoise hydrogen rely on natural gas with the associated problem of leakage. For example, the total US-wide methane losses are estimated to be about 1.3% of the overall transported methane [20]. Methane has an 84–86 or 28–34 times higher global warming potential compared to $CO_2$ within the first 20 or 100 years after release, respectively [21]. In addition, in Europe, acceptance problems of blue hydrogen exist, but it can be seen as a bridging technology until green hydrogen becomes widely available [18]. Currently, the production costs of green hydrogen are about 2 to 3 times higher than of grey hydrogen [12]. In the long term, green hydrogen is the hydrogen type of choice for a fully decarbonised energy system.

For reaching the 1.5 °C global warming target, the EU will have an annual hydrogen demand between 1536 and 1953 TWh in 2050 [22], according to the EU's long-term strategy [23]. Due to the enormous renewable electricity demand required to produce this amount of hydrogen, imports of green hydrogen will probably be necessary in addition to European production of green hydrogen [24]. Eventually, various European countries such as Germany [24] or Austria [25] do not have accessible renewable potentials to cover their current national primary energy demand.

Many different studies address hydrogen production costs on a national or regional level. Such studies can include a lot of detail, such as regional characteristics. The study by Agora Verkehrswende, Agora Energiewende and Frontier Economics [26] and their associated calculation tool [27] analyses the production costs of power to hydrogen, power to methane and power to liquid for different regions. For example, according to their calculation tool [27], in 2050, the cost of hydrogen production from offshore wind turbines at North and Baltic Seas would range from 6.0 to 11.8 €ct/kWh$_{H2}$, depending on the scenario (pessimistic to optimistic). In contrast, the costs of hydrogen from geothermal energy in Iceland were calculated between 3.5 and 4.3 €ct/kWh$_{H2}$. Both examples include operating and investment costs of electrolysis, electricity costs, lifetime as well as expected full-load hours. The considered full-load hours are equal to the full-load hours of the respective renewable source. Thus, the entire electrical generation is used for hydrogen production.

However, an integrated consideration of the entire energy system (all sectors, all energy carriers, from resource to energy service) is important to obtain meaningful results. Such a holistic consideration is necessary for the calculation of the actual residual loads. The residual load is the not controllable electricity demand minus the not controllable electricity generation. Not controllable generations are fluctuating generations such as photovoltaics as well as heat-driven CHPs. If the not controllable electricity generation is higher or lower than the not controllable electricity demand, it is known as negative or positive residual load, respectively. The positive residual load must be compensated by controllable electricity generation (e.g., gas-fired power plants) or discharging of electricity storages. The negative residual load can be handled by renewable generation reduction or can be used for different applications, such as the production of hydrogen. To maximise the overall efficiency of the energy system, mainly negative residual load should be used for hydrogen production. For example, this approach was used to analyse the annual hydrogen production in Italy [28]. Otherwise, avoidable conversion losses will occur (production of hydrogen and controllable electricity generation at the same time).

The amount of negative residual load strongly depends on the renewable generation. A low amount of electricity available for electrolysis (e.g., due to a low amount of negative residual loads) might lead to a low number of full-load hours. This increases hydrogen costs [12]. Therefore, a hydrogen production cost analysis should include the negative residual loads and their temporal characteristics.

The current Austrian government programme [29] aims for complete decarbonisation by 2040. However, there is currently no comprehensive decarbonisation strategy of Austria available. Although no such strategy is yet in place, hydrogen is expected to play a central role according to the current political discussion. In this context, many essential aspects (e.g., national demand of hydrogen, national hydrogen production potential or the hydrogen import demand) have not yet been clarified. Nevertheless, these aspects are mandatory for such a strategy. As a step towards a comprehensive decarbonisation strategy of Austria, this study provides such insights regarding the national hydrogen situation. Since these insights have not been published in any study we found, the following research questions are investigated for Austria:

1. How will the Austrian green hydrogen potential for negative residual loads develop between 2030 and 2050?
2. Which part of this potential can be economically realised? What are the resulting levelised costs of hydrogen (LCOH$_2$)?
3. Which share of the national renewable gas demand can be covered by national green hydrogen production? How much renewable gas imports are necessary?

To answer the research questions, the entire Austrian energy system, including all sectors and all energy carriers, is analysed. Based on two scenarios, possible trends until 2050 are depicted. Both scenarios aim for full decarbonisation and consider the same renewable expansion till 2050. However, there are major differences in consumption and technologies used: The scenario *Energy Efficiency* relies on the optimal mix of novel technologies to maximise energy efficiency. In contrast, the scenario *Sufficiency* is based on conventional technologies in combination with massive behavioural changes (sufficiency measures). Based on negative residual loads of both scenarios, the potential of hydrogen production by water electrolysis was assessed and related $LCOH_2$ was quantified for cost structures expected for 2030, 2040 and 2050.

Answering the research questions using the mentioned approach provides a valuable contribution to scientific knowledge. The contribution consists of two aspects: methodology and results. In this work, entire national energy system models (including all sectors and all energy carriers) are used. Entire national energy system models such as EnergyPLAN [30] are common in the scientific literature and include both technical and economic aspects. The analysis of such models is often used for feasibility studies of national decarbonisation strategies (e.g., [31–34]). Furthermore, different pathways can be compared to determine the minimum cost of decarbonisation. These studies do include hydrogen, but it is not the focus of the research questions. In addition to this, there are also studies that investigate hydrogen and its production in detail but do not take all sectors into account (e.g., [28,35]). Thereby, negative residual loads are used to determine the hydrogen production. Since not all sectors are considered, the residual load does not include the electrification of the other sectors that may be necessary to enable complete decarbonisation (e.g., heat pumps or battery electric vehicles). Furthermore, no statements can be made about the total gas demand in the future system. This work combines both types of studies: The focus is on hydrogen potential and costs, but in the background the complete energy system and the complete decarbonisation strategy is considered. Such a combination has not been seen before and represents a further development and improvement of existing approaches.

In addition to the methodological novelty, the results of this study are interesting for the scientific community. On the one hand, answering these questions for Austria can act as a blueprint for countries with similar structures. On the other hand, such national studies can be an important basis for supra-regional research analyses (e.g., EU-wide or worldwide).

This work is structured as follows: First, within the methodology (Section 2), the determination approach of the potential of nationally produced green hydrogen as well as its techno-economic assessment is shown. Next, the results are presented (Section 3) and discussed (Section 4). Within the discussion, the feasibility of the results is analysed. Furthermore, the resulting $LCOH_2$ is compared with the production costs of other publications (considering green hydrogen, grey hydrogen, blue hydrogen and import of green hydrogen). Finally, Section 5 concludes the entire work.

## 2. Methodology

The methodology of this work is structured as follows (Figure 1): Firstly, the trend in the expansion of the national renewable energy generation is discussed (I). Secondly, two different consumption scenarios are presented (II-A and II-B). These two scenarios differ fundamentally in how the national full decarbonisation goal can be achieved. While scenario *Energy Efficiency* focuses on the optimal mix of novel technologies, scenario *Sufficiency* focuses on sufficiency measures. Thirdly, the time-resolved energy consumption per energy carrier of both scenarios is combined with the national renewable energy generation/production (III). Thereby the determination of the Austrian green hydrogen production potential via electrolysis per scenario is performed. Fourthly, these national green hydrogen potentials are techno-economically assessed to calculate the economic green hydrogen potential per scenario (IV). The technical and economic potentials are calculated for the considered years 2030, 2040 and 2050. Finally, performance indicators are identified, such as the primary energy consumption, the economic green hydrogen potential and the required renewable gas imports, and their temporal development is analysed for both scenarios (V).

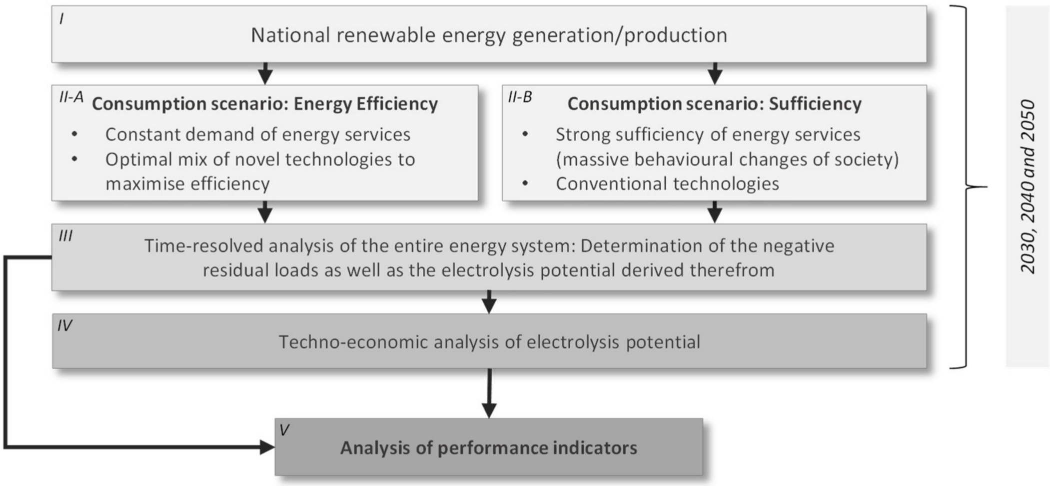


**Figure 1.** Flow chart of the methodology.

## 2.1. National Potential of Green Hydrogen Production

In this subsection, the approach for the determination of the national technical potential of green hydrogen is presented, which addresses steps I to III of Figure 1. First of all, the system boundaries of the applied energy system model are defined. It can be divided into three blocks (Figure 2):

1. The national renewable generation/production of various energy carriers.
2. The national energy conversion, transportation and distribution system, which connects the first and the third block.
3. Different final energy applications for covering all national energy services from all economic sectors. Such energy services might be space heating, process heat, lighting or mobility.

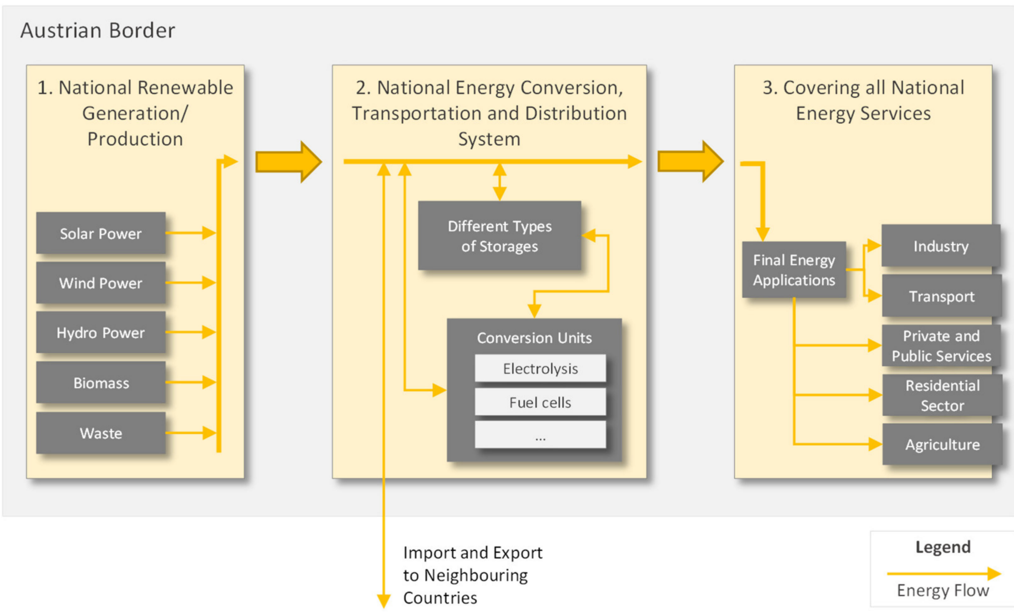


**Figure 2.** System boundaries of the Austrian energy system model.

In this model (Figure 2), the renewable generation/production and the required energy services are defined by boundaries conditions. Thus, the renewable generation/production can never exceed the predefined amounts and temporal behaviour, and all predefined energy services must always be covered. The national energy conversion, transportation and distribution system must compensate all temporal differences between renewable generation/production and final energy applications. Furthermore, the required type (e.g., electricity, heat or fuel) of final energy has to be provided. To achieve this, different controllable conversion units, storages as well as import/export to neighbouring countries can be used.

Various controllable applications are possible for utilising the negative residual loads such as charging of electricity storages, operation of electrolysis and supply of district heating grids via operation of central heat pumps or transport to neighbouring countries. In this work, only negative residual loads are used to determine the green hydrogen potential, but not all of them. Other energy carriers such as biomass are used for other purposes (e.g., heat supply) as well as for controllable renewable electricity generation to compensate the positive residual loads. The specific use of the negative residual loads are discussed in detail for each scenario individually.

For meaningful modelling, various aspects such as modelling scope, time horizon or spatial coverage must be considered [36]. A bottom-up approach is used to consider technological details. An operational model was chosen to ensure the consideration dynamics of supply and demand. Accordingly, time horizon and temporal resolution must correspond. In energy systems with a large share of renewable generation, annual, weekly and short-time fluctuations occur [37]. To consider all these fluctuations, a time-resolved analysis for a period of one year with a temporal resolution of hourly values is selected. The research questions are focused on Austria but do not include any spatially resolved aspects, such as grids. Thus, the spatial coverage is Austria without taking any spatial resolution into account. In the scenario *Energy Efficiency*, model formulation is based on a linear optimisation problem with the assessment criteria of maximum exergy efficiency. In contrast, the other scenario is arranged as a simulation task with linear formulation with specifications of the final energy consumption. Both scenarios ensure full decarbonisation for each considered year.

In the following, first, the renewable generation/production (1. block) is discussed in Section 2.1.1. Next, the two scenarios are presented in detail in Sections 2.1.2 and 2.1.3. These two scenarios include both, the national energy conversion, transportation and distribution system (2. block) as well as the final energy applications to cover the energy services (3. block).

#### 2.1.1. Renewable Generation/Production

In this subsection, the boundary conditions of the renewable generation/production are discussed. Renewable generation/production (Table 1) is the same for both scenarios. The expansion of fluctuating renewable generation (photovoltaics, wind power and hydro power) as well as for sustainable methane production (e.g., from biogas plants) is based on the 2030 targets from the current Austrian government programme [29] and continues linearly until 2050. The renewable generation of the year 2018 according to Statistics Austria is used as starting point for the expansion [38]. The current government programme [29] does not specify any expansion plans for woody biomass, ethanol fuel or biodiesel (from energy crop cultivation). Accordingly, the production of 2018 [38] is assumed to remain constant until 2050, as no significant increase is expected based on the current land use. However, additional expansion potential is theoretically available [25,39]. The trend of renewable generation of solar thermal energy and the availability of waste is defined by the Environmental Agency Austria (EAA) [40]. According to the EAA, the available waste for energy use will decrease until 2050. Normalized load profiles are multiplied by the annual generation/production sum to create supply time series.

**Table 1.** Renewable generation/production.

| Type | Value 2030 in TWh/a | Value 2040 in TWh/a | Value 2050 in TWh/a | Extrapolated Generation/Production Profile |
|---|---|---|---|---|
| Photovoltaic Systems | 12.4 | 21.6 | 30.7 | Generation from photovoltaic in Austria 2018 [41] |
| Wind Power Stations | 16.0 | 24.3 | 32.7 | Generation from wind in Austria 2018 [41] |
| Hydropower Plants | 42.6 | 46.8 | 50.9 | Generation from hydro in Austria 2018 [41] |
| Solar Thermal System | 5.7 | 5.7 | 7.3 | Generation from photovoltaic in Austria 2018 [41] |
| Woody Biomass Production | 41.9 | 41.9 | 41.9 | Assumed as constant based on current situation |
| Sustainable Methane Production | 7.7 | 12.9 | 16.1 | Assumed as constant based on current situation |
| Ethanol Fuel/Biodiesel Production | 2.3 | 2.3 | 2.3 | Assumed as constant based on current situation |
| Waste | 9.0 | 8.2 | 7.0 | Assumed as constant based on current situation |

#### 2.1.2. Scenario Energy Efficiency

In this scenario, no behavioural changes are taken into account. Instead, the reduction in primary energy consumption is only achieved by increasing national energy efficiency by means of an optimal mix of novel technologies. For this purpose, an exergy-based optimisation model with a linear formulation is used. In contrast to energy-based analysis, exergy as assessment criteria for maximising energy efficiency also includes the quality of energy. The quality of the energy describes the technical working capacity [42]. Since exergy is not a conservation variable, the cause of exergy reduction between input and output of a process can enable deeper insights. A distinction is made between exergy losses (exergy in unused waste flows such as exhaust gas) and exergy destruction (reduction of working capacity due to thermodynamic imperfections) [43]. In addition to the additional understanding of the location and cause of the exergy reduction, an exergy-based approach is necessary for energy systems including primary energy sources with different exergy levels. In this case, exergetic optimisation provides exergetically better results than an exclusively energetic optimisation. For this reason, the optimisation performed in this scenario is based on exergy.

The approach used takes into account the entire energy system and minimises the total of exergy losses and exergy destruction, whether they occur in the energy conversion, transformation and distribution systems or in the final energy applications (Figure 2). The holistic approach is crucial to also include the interaction between final energy applications and the energy conversion, transportation and distribution systems. For example, an electrified final application (e.g., battery electric vehicle) may have a worse overall efficiency than the conventional final application (e.g., internal combustion engine vehicle) when including the electricity provision (e.g., old and inefficient coal powered power plant).

For modelling this problem, a greenfield approach is chosen to find the best energy system without considering existing structures. The optimisation model used is based on the Open Energy Modelling Framework (*oemof*) [44,45]. The mathematical formulation of the optimisation model and further information of *oemof* can be found in the official documentation [46]. However, one important adaptation of *oemof* was made for this work. An additional constraint was introduced—that the ratio of the different final energy applications to each other must be constant for the entire optimisation period. This prevents redundant final energy applications. An example of redundant final energy applications would be that each vehicle owner has two or more vehicles, such as a battery electric car that is only driven when enough electricity is available (in summer) and a hydrogen vehicle that is otherwise used (in winter). Since this is unrealistic, it is prevented by an additional constraint. In contrast, for the energy conversion, transportation and distribution system the various technologies are redundantly available and can be used flexibly in order to maximise exergy efficiency.

In this scenario, the Austrian demand for energy services is determined by the useful exergy demand. It describes the actually required thermodynamic working demand of the useful energy. The optimization model must cover all specified useful exergy demands, while not exceeding the specified renewable resources. Between the generation- and demand-related boundary conditions, the mix, capacities and operation of various conversion units, storage and final energy applications are optimized to maximise overall energy efficiency (Figure 2). In addition, import/export of various energy carriers is possible.

Exergy efficiencies of all technologies describe the conversion of the input exergy to the output exergy. If a technology has several outputs (e.g., CHP), the total exergy efficiency can be determined from the sum of the individual efficiencies (e.g., power output in relation to the input as well as heat output in relation to the input). A complete list of all efficiencies can be found in Appendix A.1. The overall efficiency depends on the (time-resolved) operation and combination of the technologies used and the associated conversion chains. Maximising energy efficiency means minimising the total of exergy losses and exergy destruction $Ex_{LossDest,tot}$. It be calculated based on the total useful exergy demand of all national energy services $Ex_{UED,tot}$ and the total exergy used for supplying the national energy system $Ex_{Sup,tot}$ (Equation (1)). $Ex_{Sup,tot}$ is defined as the sum of all national renewable generation/production $Ex_{NatGP,i}$ and the balance of all exergy imports $Ex_{Imp,j}$ and exports $Ex_{Exp,k}$.

$$\min Ex_{LossDest,tot} = Ex_{Sup,tot} - Ex_{UED,tot} = \sum_i Ex_{NatGP,i} + \left( \sum_j Ex_{Imp,j} - \sum_k Ex_{Exp,k} \right) - Ex_{UED,tot} \quad (1)$$

The final objective function minimises the total of exergy losses and exergy destruction (Equation (1)). However, the national renewable production/generation and the total useful exergy demand are given as constraints (boundary conditions) of the optimisation task. Therefore, they can be neglected as optimisation variable. Accordingly, the objective function simplifies (Equation (2)). Thus, the exergy efficiency of an energy system can be maximised by minimising exergy imports and maximising exergy exports for a given national demand and national renewable generation/production. In order to increase national self-sufficiency, export is only possible if all national potential/production is used in the entire optimisation period.

$$\min f = \sum_j Ex_{Imp,j} - \sum_k Ex_{Exp,k} \quad (2)$$

The exergy-based optimisation model described here for the analysis of a national energy system in currently under review by the authors of this work [47]. Further information can be found there when it is published.

**Approach for the utilisation of negative residual loads:** The national green hydrogen potential is a direct result of the previously explained optimisation task. By minimising the exergy losses and exergy destruction, it is also determined when negative residual loads are mathematically optimally used for hydrogen production and when they are better used for other purposes. However, this multiple use of negative residual loads reduces the national green hydrogen potential as well as the full-load hours of the electrolysis.

In this scenario, only photovoltaic systems, wind power plants and hydro power plants are not controllable electricity sources (block 1 in Figure 2). All storages and conversion units of the energy conversion, transportation and distribution system (block 2 in Figure 2) are controllable (these are hydro pumped storages, battery storages, electrolyses plants, supply of district heating grids via central heat pumps), while all final electricity applications (e.g., battery electric vehicles, single decentral heat pumps per building, industrial stationary engines) are considered not controllable (block 3 in Figure 2).

**Used data:** As mentioned before, in this scenario the useful exergy demand is used to define the need for energy services. The useful exergy demand for 2030, 2040 and 2050 is based on the Austrian current useful exergy demand, which has already been published by the authors [25]. These data include all economic sectors (industry, residential, transport, private and public services as well as agriculture) as well as all statistically considered energy service classes of Austria (heat demand at different temperature levels between 25 and 1500 °C, transport demand of cars, light-duty trucks, heavy-duty trucks, railways, navigation, aviation, stationary work engines, lighting, information and communication technology as well as process demands). However, these demands are adjusted for economic growth (until 2030: +1.5% p.a., after 2030 +1.3% p.a. [40]) as well as the decrease in energy intensity (current value of −1.4% p.a. assumed [48]). The only change compared to the useful exergy demand published in [25], efficiencies adopted and to achieve full decarbonisation, the blast furnace route for crude steel production is replaced by a direct reduction process including an electric arc furnace. All used data and additional information about this scenario can be found in Appendix A.1.

### 2.1.3. Scenario *Sufficiency*

The scenario *Sufficiency* is based on renewable generation/production according to Table 1 as well as on the work of the Environment Agency Austria (EAA). The EAA published different possible future development energy scenarios for the Austrian energy system until 2050 [49] to satisfy the report requirements according to EU regulation No. 525/2013 [50]. All these EAA scenarios consider the entire energy system, from resource to energy service for all subordinated economic sectors (e.g., industry, residential sector, transport) and energy carriers. Furthermore, import and export are included. The EAA scenarios differ mainly in their assumptions regarding the implementation of energy efficiency and novel technologies as well as behavioural changes of society. Overall, the EAA scenarios cover a wide range from business as usual to very radical changes. The scenario *Sufficiency* in this work is based on the EAA scenario WAMplus (With Additional Measures Plus), which is the most ambitious scenario and strongly relies on sufficiency measures.

The storyline of the EAA scenario WAMplus describes a turning away from the current consumer society and includes resource-efficient concepts such as green economy and sharing economy. Accordingly, in the industry sector, the highly efficient use of resources and energy are assumed. Furthermore, the number of products produced will be reduced, which leads to a further decrease in energy use. However, due to the shift to high-value, durable and long used products, the value of production remains nearly constant. In the transport sector, the modal split is changing strongly towards environmentally-friendly transport modes (e.g., freight traffic by railway, increased usage of public transport). A strong reduction of motorised individual transport is assumed. The shift away from the consumer society is reducing the transport volume. The thermal renovation of buildings is another key measure. In the energy sector, the extension of renewable electricity production and district heating plays are relevant. Further details about the EAA scenario WAMplus can be found in [40].

The EAA scenario WAMplus is not decarbonised. It includes the use of fossil energy carriers such as oil, coal and natural gas. To reach the aim of full decarbonisation, in this paper the following approach is applied to the energy consumption specified in the EAA scenario WAMplus: Firstly, we calculated all actual energy service demand required by society for all economic sectors (e.g., total annual driving distance, total annual production of crude steel, heat demand for space heating) based on the assumptions and results of the WAMplus scenario. Subsequently, the final energy applications to be used for decarbonisation were determined. In the next step, by combining both, the actual energy service demand and the efficiency of the decarbonised final energy applications, the final energy consumption of the decarbonised energy system could be calculated. Finally, adaptions and decarbonisation of the energy conversion, transportation and distribution system were required to balance generation and supply (e.g., electricity generation, district heating supply).

In contrast to scenario *Energy Efficiency*, the decarbonisation strategy of this scenario is based mainly on conventional technologies. Consequently, only small technological changes are required, and large parts of the existing infrastructure can be further used. The most important measures are explained in the following:

Fossil fuels (e.g., coal, fuel oil, natural gas) for space and process heating as well as stationary engines in the residential, public and private services sectors as well as agriculture are fully replaced by renewable gases. Furthermore, also in the district heating supply, renewable gases replace natural gas entirely.

In this scenario, transport is based on both internal combustion engines (ICEs) and electric drives. To decarbonise ICE drives, renewable fuels are used. Renewable fuels are hydrocarbon-based fuels from sustainable sources, e.g., produced from atmospheric carbon dioxide and hydrogen from water electrolysis, supplied with renewable electricity. They are also known as electrofuels [51]. The share of battery electric vehicles (BEVs) over the years [40] is multiplied by the maximum possible amount of BEV, in accordance with the required range and transport capacity [47]. In general, these assumptions can be considered as rather conservative. For railways, electrification is assumed following the EAA scenario WAMplus. The rest of transport (including aviation and navigation) is entirely covered by renewable fuel powered ICE drives.

For the decarbonisation of the industrial sector, the *current infrastructure usage* scenario according to a recent study by Baumann et al. [52] is used. This study is based on a combination of top-down and bottom-up approaches to properly describe the decarbonisation of all industrial subsectors. For the application in this paper, the energy consumptions are adjusted according to the scenario assumptions of the EAA scenario WAMplus (e.g., annual production volume).

**Approach for the utilisation of negative residual loads:** In addition, in this scenario, the national potential of green hydrogen is calculated based on negative residual loads. For determining them, the not controllable generation in this scenario consists of photovoltaics, wind power plants, hydro power plants, electricity generation of industrial CHPs (8400 full-load hours a year assumed), utilization of waste in CHPs (8400 full-load hours a year assumed) and woody biomass CHPs (8000 full-load hours a year assumed). In this scenario, the total electricity consumption is not controllable, except for the operation of electrolysis as well as charging of pumped storage power plants and battery storage systems. Accordingly, this scenario has the same controllable consumption as the scenario *Energy Efficiency*, except for the central heat pumps.

The pumped storage power plants and battery storages are operated according to a greedy algorithm. This algorithm charges the storage whenever negative residual load occurs and discharges at positive residual loads. The only limitations are the storage capacities as well as the charging and discharging powers. The rest of the negative residual load can be used to determine the green hydrogen potential. All used data and additional information about this scenario can be found in Appendix **??**.

### 2.2. Techno-Economic Assessment of National Green Hydrogen Production

This analysis is used to determine the national economic potential for green hydrogen (Section 2.1), as well as their approximate energy production costs as levelized costs of hydrogen ($LCOH_2$). The analysis is based on the annuity method [53] and applied as described by Böhm et al., 2020 [54].

To determine the levelised costs of an energy product, all costs and proceeds are related to the energy output to be produced. The annuity of total annual payments $A$ is calculated as the difference between the annuity of proceeds from by-product sales $A_P$ and the sum of the annuities of capital-related $A_C$, demand-related $A_D$, operation-related $A_O$ and other costs $A_M$ (Equation (3)):

$$A = A_P - (A_C + A_D + A_O + A_M) \tag{3}$$

With the annuity and demand related variable costs $C_{var}$, one can calculate the $LCOH_2$ as described in Equation (4), with $P_{H2,y}$ as the annual hydrogen production [55].

$$LCOH_2 = \frac{-A + \sum_{y=1}^{n} C_{var,y}}{\sum_{y=1}^{n} P_{H2,y}} \quad (4)$$

In Table 2, all input parameters including the cost structures for the electrolysis reference plants for the techno-economic assessment are listed. For the economic evaluation, the electricity procurement costs for the electrolysis operation are derived from a mix of wind and PV generation costs and electricity grid tariffs/charges, based on optimal conditions and cross-checked with other prognoses on electricity prices [56]. In the medium and long term, decreasing electricity production costs from renewables is to be expected (Table 2) [54,57].

**Table 2.** Cost structures of the electrolysis reference plants.

| Type | Unit | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|
| General | | | | | |
| Interest | % | 4.0 | 4.0 | 4.0 | 4.0 |
| Life time | Years | 20 | 20 | 20 | 20 |
| Electricity cost [1] | €/$MWh_{el}$ | 50 | 40 | 35 | 30 |
| Electrolysis | | | | | |
| CAPEX | €/$kW_{el}$ | 944 [2]–1527 [3] | 510 [2]–983 [3] | 572 [2]–250 [3] | 477 [2]–200 [3] |
| El. efficiency (LHV) | % | 60 | 64 | 67 | 68 |
| OPEX | % of CAPEX | 4 | 3 | 2 | 2 |
| Power requirement for auxiliary units | % of nominal power | 1 | 1 | 1 | 1 |
| Cost water | €/$m^3 H_2O$ | 1.15 | 1.15 | 1.15 | 1.15 |
| Lifetime stack | Hours | 40,000 | 60,000 | 100,000 | 140,000 |
| Lifetime BoP | Years | 30 | 30 | 30 | 30 |
| Usable heat | % of nominal power | 16 | 16 | 16 | 16 |
| Additional costs | | | | | |
| Insurance | % of CAPEX | 0.5 | 0.5 | 0.5 | 0.5 |
| Management | % of CAPEX | 2 | 2 | 2 | 2 |
| Proceeds | | | | | |
| Heat | €/$MWh_{th}$ | 55 | 55 | 55 | 55 |
| Oxygen | €/$t_{O2}$ | 50 | 50 | 50 | 50 |

[1] Constant electricity purchase prices assumed (mix of wind and PV levelised cost of electricity (LCOE)); electricity grid tariffs and charges based on Austrian framework 2020; [2] reference plant scaling 1 $MW_{el}$; [3] reference plant scaling 100 $MW_{el}$.

The electrolyser plant accounts for significant investment cost (CAPEX) with plant-specific variability in electrolyser stack, potential $H_2$ compressor, storage, dispenser needs and supplement factors for the balance of a plant. Accordingly, learning curve and scale effects are also taken into account for these components in the calculations for the economic evaluation. The former considers the future reduction in production costs for these plant components through increasing experience in the manufacturing process (see electrolyser CAPEX development Table 2). This technological learning thus describes those cost reductions that can be expected from the increase in cumulative production and thus from the optimization of manufacturing processes and material use. In addition, spillover effects from concurrent technology uses such as electrical installation and control systems may also be relevant. A disaggregated learning curve model for analysing technological learning at the component level allows these aspects to be taken into account accordingly [58]. In addition to learning curves, scale effects are relevant. In addition to cost reductions by increasing the number of units produced (“economies of manufacturing scale”), the scaling of the respective electrolysis also has a significant influence on the specific investment costs ("economies of unit scale") [54].

For taking into account economies of scale, we use a mix of representative reference plant scalings. The scalings correspond to the economic data reference on component cost structures and corresponding scale factors [54] resulting in large scale industrial facilities. The reference plants are differentiated into small plants with a power range between 1 and 10 $MW_{el}$, medium plants between 10 and 50 $MW_{el}$ and large plants between 50 and 100 $MW_{el}$. Cost transformations through innovation (efficiency, durability, design), plant size (targeting up to 100 $MW_{el}$), component assembly lines and gigafactories will be needed to reach the anticipated roll-out curve of electrolyser plants, although there are hardly any plants of this size on the market, and there is little operating experience at the moment. For each year, a plant mix based on these reference plants was generated that can optimally process the previously calculated negative residual loads that are available for electrolysis. The ramp-up of the theoretical electrolysis potential is based on a CAGR (Compound Annual Growth Rate) of 25% [59] in the years 2020–2050 for all reference plants in line with corresponding press releases in this area, whereby the required ramp-up is massive and the forecast horizon is clearly a very long one and therefore highly uncertain.

**Techno-economic analysis procedure:** First of all, the $LCOH_2$ for each specific possible number of full-load hours of hydrogen, the considered years 2030, 2040 and 2050 as well as three different plant sizes are calculated, based on Equation (4) and Table 2. By using this comprehensive table, the threshold of economic full-load hours for each considered year and plant size, based on maximal $LCOH_2$, was defined. In this work, the maximum $LCOH_2$ economic limit is 15 €ct/$kWh_{HHV}$, based on hydrogen's cost competitiveness evaluation in recent literature [60–63]. In addition, the influence of this value is analysed within the discussion of this work (Section 4.1).

In the next step, the maximum number of economic full-load hours are analysed in combination with the negative residual loads available for green hydrogen production. For each considered year, the number of full-load hours is determined for each possible power of the residual load (between 0 and its maximum power in 0.01 $MW_{el}$ steps). If the number of full-load hours of a certain power is equal to the economic full-load hours determined in the first step, the maximum economic power limit is found. This power limit represents the maximum economic electrolysis power (in $GW_{el}$). This analysis is performed for both scenarios and all the considered years. The maximum electrolysis power determined in this way ensure that the previously defined maximal $LCOH_2$ economic limit for hydrogen is not exceeded.

Then, the theoretical expansion plan is developed based on the defined electrolytic reference plant mix. On this basis, the required yearly installations were quantified in the timeframe of 2020 to 2050.

Finally, the electrolysis power and the corresponding green hydrogen production forecasts are used to determine the final averaged $LCOH_2$ per scenario and considered year (Equation (4) with the parameters from Table 2). For this purpose, the $LCOH_2$ for different full-load hours must be evaluated, which are then averaged according to the actual production volume per full-load hour range.

### *2.3. Performance Indicators*

The following performance indicators (Table 3) were identified to enable a comparison of the two scenarios and their temporal development until 2050. All indicators consider annual totals and refer to Austria as a whole.

**Table 3.** List of performance indicators.

| Performance Indicator | Unit | Description |
|---|---|---|
| Primary energy consumption | TWh/a | Sum of national renewable generation/production and all energy imports |
| Final energy consumption | TWh/a | Sum of all energy flows for finale energy applications |
| Renewable energy generation and production | TWh/a | Sum of all renewable energy generation and production (including all renewable sources of Table 1) |
| Total negative residual loads | $TWh_{el}/a$ | Total amount of fluctuating renewable electricity generation not required for any other electrical application or any storage facility |
| Lower limit for full-load hours of electrolyser plants | h/a | Minimum full-load hours required in order not to exceed the maximum $LCOH_2$ economic limit |
| Installed electrolysis capacity | $GW_{el}$ | Total size of the economic electrolysis plants |
| Negative residual loads used for electrolysis | $TWh_{el}/a$ | Amount of negative residual loads used for green hydrogen production |
| Share of negative residual loads used for electrolysis | % | Share of all technical negative residual loads used for national economic green hydrogen production, based on the techno-economic analysis |
| Technical green hydrogen production | $TWh_{H2}/a$ | Technical green hydrogen output from electrolysis, produced exclusively by utilization of negative residual loads |
| Economic green hydrogen production | $TWh_{H2}/a$ | Economic green hydrogen output from electrolysis, produced exclusively by utilization of negative residual loads |
| Total consumption of renewable gases | TWh/a | Sum of national produced and imported hydrogen as well as sustainable methane |
| Required import of renewable gases (based on technical potentials) | TWh/a | Sum of imported hydrogen and sustainable methane (considers the national technical potentials) |
| Required import of renewable gases (based on economic potentials) | TWh/a | Sum of imported hydrogen and sustainable methane (considers the national economic potentials) |
| Share of technical national renewable gas production | % | Ratio of the national green hydrogen and sustainable methane production to the total consumption of renewable gases |
| Averaged levelised cost of national produced green hydrogen | $€ct/kWh_{HHV}$ | Levelised cost for hydrogen production averaged over the entire annual hydrogen production volume |
| Minimal levelised cost of national produced green hydrogen | $€ct/kWh_{HHV}$ | Minimal levelised cost for hydrogen production per year (large plant with high number of full-load hours) |
| Maximal levelised cost of national produced green hydrogen | $€ct/kWh_{HHV}$ | Maximal levelised cost for hydrogen production per year (small plant with low number of full-load hours) |

## 3. Results

The results of this work are presented in four sections. Firstly, the two scenarios are discussed from the energy point of view (Section 3.1). This includes the comparison of primary and final energy consumption, the resulting residual load as well as the negative residual loads usable for electrolysis. Then the results of the techno-economic analysis are shown (Section 3.2). The latter consists of different aspects such as the economic green hydrogen potential, the resulting averaged $LCOH_2$ as well as the number of electrolyser plants in Austria. In the next step, the import demand for renewable gases is examined (Section 3.3). Finally, performance indicators are used to summarise all results of both scenarios and their temporal development (Section 3.4).

### 3.1. Energy-Based Results

**Comparison of the primary energy consumption:** The primary energy consumption of the two scenarios for all years is shown in Figure 3. The comparison shows that the scenario *Energy Efficiency* has a lower consumption than the other scenario for each considered year. The difference is mainly caused by the utilisation of renewable gases. Both scenarios have a decreasing renewable gas consumption over the years, but scenario *Sufficiency* starts at a significantly higher level. The utilisation of electricity, solar thermal energy as well as biomass and waste are comparable for both scenarios. The electricity consumption increases over the years in both scenarios.

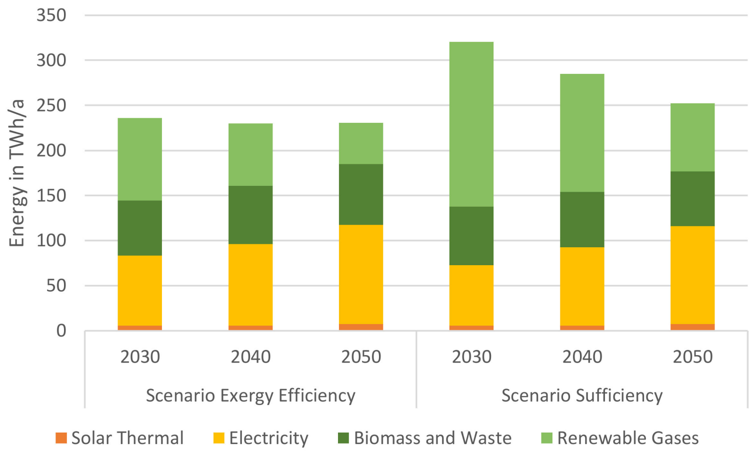


**Figure 3.** Comparison of the primary energy consumption for both scenarios and all considered years.

**Explanations of the difference in primary energy consumption:** For both scenarios, the decreasing primary energy consumption can be explained by the scenario assumptions. The assumed technological development leads to a reduction of the primary energy consumption due to better energy efficiencies independent of the scenario. In scenario *Energy Efficiency*, energy intensity (energy consumption in relation to GDP) decreases and over-compensates economic growth. As a result, primary energy consumption decreases over time (Figure 3). In the other scenario, increased behavioural changes lead to a massive decrease in the demand for energy services over the years. Thus, primary energy consumption is reducing. The significantly higher consumption of renewable gases in scenario *Sufficiency* is caused by exergetically inefficient technologies such as renewable gases for space heating instead of highly exergy efficient technologies such as heat pumps. Furthermore, renewable gases are also used for providing renewable fuels to supply internal combustion engine (ICE) drives for road transport. In addition to inefficient ICE drives, this conversion causes further losses. The comparable temporal development of electricity, biomass and waste, as well as for solar thermal energy can be explained by the same assumed renewable generation/production for both scenarios (Section 2.1.1). Increasing renewable generation over the years leads to a higher primary energy consumption of the associated energy carrier (e.g., electricity). In both scenarios, solar thermal energy as a primary energy source plays a minor role.

**Comparison of the final energy consumption:** The final energy consumption (Figure 4) shows clear differences in the consumption structures between the two scenarios: Compared to the scenario *Sufficiency*, scenario *Energy Efficiency* has significantly higher final energy consumption of solar thermal and district heating, electricity as well as renewable gases. In contrast, the scenario *Sufficiency* has a higher consumption of biomass and waste, as well as renewable fuels.

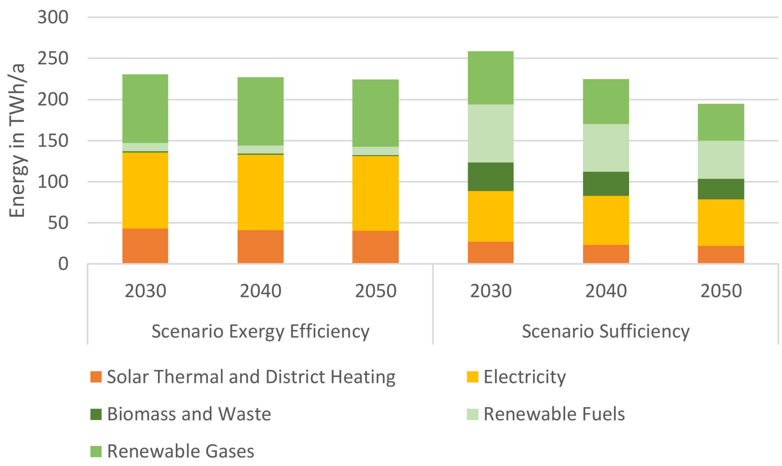


**Figure 4.** Comparison of the final energy consumption for both scenarios and all considered years.

**Explanations of the difference in final energy consumption:** These different consumption structures can be explained by the different scenario narratives. The scenario *Energy Efficiency* relies exclusively on the most energy-efficient technologies, which leads to strong structural changes compared to the current energy system: Transport consists mainly of electric and fuel cell drives (fuel cell drives are only used if electric drives are not feasible, e.g., due to the required range). Aviation is supplied with renewable fuels, due to the lack of other available technologies. In heat supply, all heat up to 150 °C is provided exclusively by excess heat and heat pumps. Incineration of woody biomass is only used for covering the demand at 250 °C. Heat demands at higher temperatures are covered by the incineration of renewable gases. A detailed discussion of the optimal technology mix to maximise Austria's exergy efficiency can be found here in [47].

In contrast, the scenario *Sufficiency* does not include major changes in the consumption structure compared to the current situation in Austria (Section 2.1.3). Only electric mobility is slowly reducing the share of internal combustion engines over the years, and fossil energy sources are mainly replaced by renewable alternatives (renewable gases and fuels). Thus, the differences to the scenario *Energy Efficiency* in final exergy consumption can be explained by the lower electrification, lower excess heat utilisation, still a significant share of combustion engines in transport, as well as the utilisation of biomass for space heating.

**Comparison of the residual loads:** In a time-resolved analysis of the residual loads, differences between not controllable generation and not controllable consumption can be shown. Residual loads are particularly relevant for the electrical energy system, as electricity storing is only possible to a limited extent (e.g., limited capacity of pumped storage power plants). Accordingly, only the electrical residual loads are discussed in the following.

The residual loads of the scenario *Energy Efficiency* show more positive values in both winter and summer than the scenario *Sufficiency* (Figure 5). This is also indicated by the maximum annual positive residual load (2030: 13.0 compared to 5.4 $GW_{el}$; 2040: 12.4 compared to 4.9 $GW_{el}$, 2050: 11.8 compared to 4.4 $GW_{el}$). In total, positive residual loads for the scenario *Energy Efficiency* sum up to 27, 17 and 11 $TWh_{el}/a$ for the considered years 2030, 2040 and 2050, respectively. In contrast, in the scenario *Sufficiency*, the accumulated positive residual load is much lower (2030: 6 $TWh_{el}/a$, 2040: 3 $TWh_{el}/a$, 2050: 1 $TWh_{el}/a$). Positive residual loads must always be compensated by controllable plants. When analysing negative residual loads, both scenarios show comparable maximum negative values for each year. However, scenario *Energy Efficiency* has significantly negative residual loads for each considered year (2030: −6 compared to −13 $TWh_{el}/a$; 2040: −18 compared to −33 $TWh_{el}/a$, 2050: −35 compared to −54 $TWh_{el}/a$).

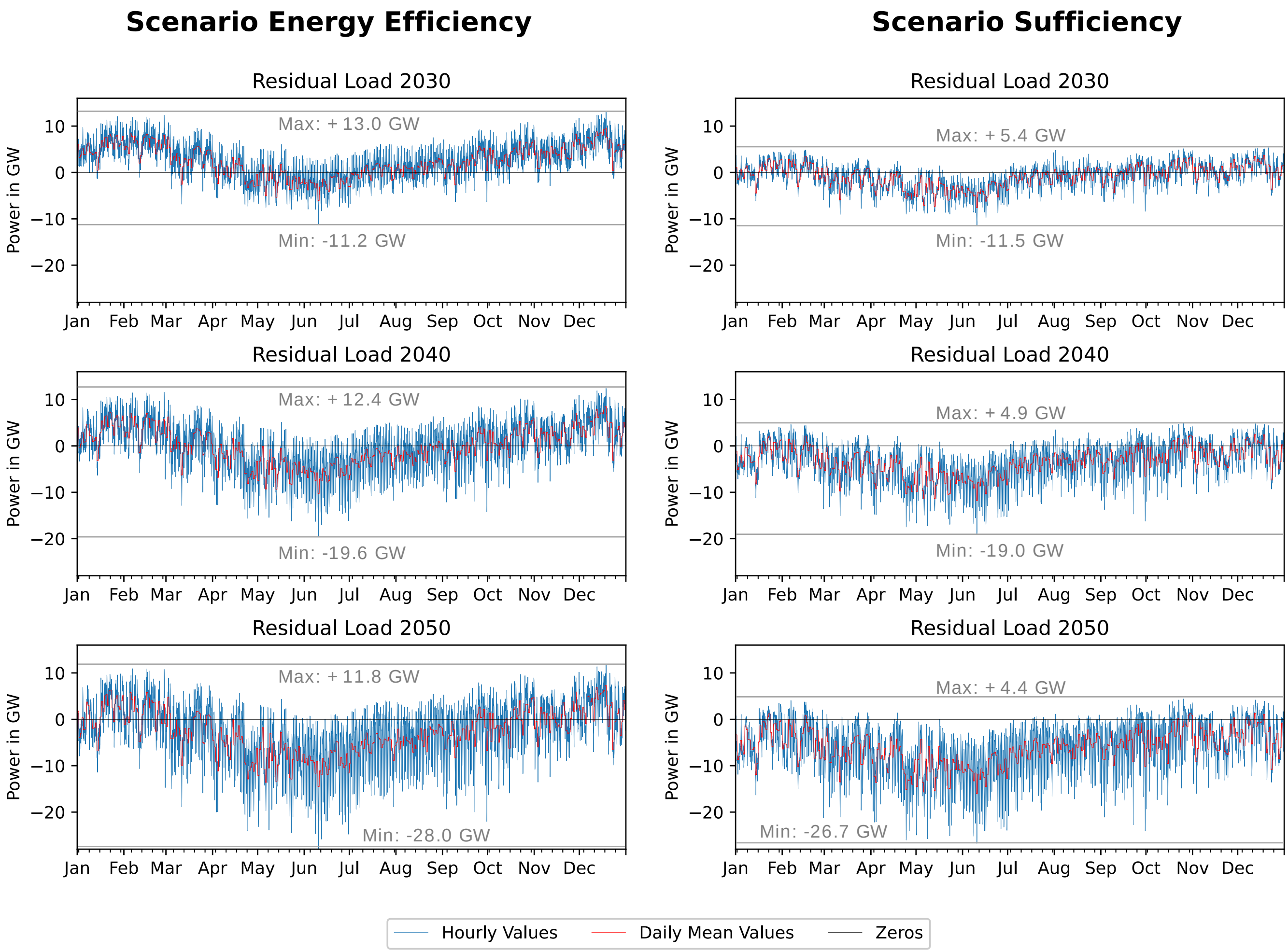


**Figure 5.** Residual load of both scenarios for all considered years.

**Explanations of the difference in residual loads:** This pattern has two causes. Firstly, there are differences between the two scenarios in the operation of electricity generation. While in the scenario *Energy Efficiency* only the fluctuating generation is not controllable, in the scenario *Sufficiency*, it is additionally the operation of industrial CHPs as well as waste and woody biomass fired CHPs (Section 2.1.3). In contrast, to maximize efficiency, all power plants can be operated flexibly in the scenario *Energy Efficiency* (2.1.2). Thus, the sufficiency scenario has a higher not controllable generation, especially in winter. Secondly, the scenario *Energy Efficiency* shows a significantly higher degree of electrification than the scenario *Sufficiency*, as well as more controllable electricity consumers. In the scenario *Sufficiency*, the storages, as well as the electrolysis are the only controllable electricity consumers (Section 2.1.3). In comparison, the scenario *Energy Efficiency* has additionally the central district heating grid supplying heat pumps, which can be operated flexible (Section 2.1.2). The combination of these two causes explains the differences in the resistive loads of the two scenarios.

**Difference in residual loads available for electrolysis:** As mentioned in the methodology, to determine the economically viable share of the negative residual loads that can be consumed by electrolysis, the complete ones as shown in Figure 5 are used as the basis. Beforehand, the residual loads are smoothed by controllable power generators and consumers such as pumped storage power plants. In addition to storages and flexible power plants (which are considered in both scenarios), flexible central heat pumps are also used exclusively in the scenario *Energy Efficiency* to supply the district heating system to maximise overall exergy efficiency. The accumulated negative residual loads available for electrolysis in the scenario *Energy Efficiency* for the years 2030, 2040 and 2050 amount to 1, 7 and 20 $TWh_{el}$/a, respectively. In the other scenario, they are significantly higher. For the scenario *Sufficiency*, the negative residual loads usable for electrolysis amount to 11, 30 and 53 $TWh_{el}$/a for the years 2030, 2040 and 2050, respectively.

**Explanation of the difference in residual loads available for electrolysis:** The difference can be explained by the larger negative residual load (mentioned before) and the fact that in the scenario *Sufficiency* there are no additional controllable central heat pumps as in the scenario *Energy Efficiency*. In the following subsection, the technical, as well as the economic national green hydrogen potential, is determined based on these negative residual loads.

### *3.2. Results of the Techno-Economic Analysis*

**Correlation of $LCOH_2$, full-load hours and plant size:** In accordance with the methodology of the techno-economic analysis (Section 2.2), first, the $LCOH_2$ (depending on the full-load hours, the size of the plant and the considered year) were calculated. Small plants have a power range between 1 to 10 $MW_{el}$, medium plants between 10 to 50 $MW_{el}$ and large plants between 50 and 100 $MW_{el}$. The results show the major influence of the full-load hours on the $LCOH_2$ (Table 4). Furthermore, it can be determined that larger plants have lower $LCOH_2$ than small ones and that the plants (independent of the size and full-load hours) will get cheaper over time based on the anticipated learning rates.

**Table 4.** $LCOH_2$ as a function of electrolysis size and number of full-load hours for the years 2030, 2040 and 2050. $LCOH_2$ is derived from cost structures represented in Table 2.

| | LCOH$_2$ in €ct/kWh$_{HHV}$ | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Full-Load Hours in h/a** | **Small Plants [A] 2030** | **Medium Plants [B] 2030** | **Large Plants [C] 2030** | **Small Plants [A] 2040** | **Medium Plants [B] 2040** | **Large Plants [C] 2040** | **Small Plants [A] 2050** | **Medium Plants [B] 2050** | **Large Plants [C] 2050** |
| 8000 | 7.1 | 6.8 | 6.7 | 5.0 | 4.8 | 4.7 | 3.9 | 3.8 | 3.7 |
| 7500 | 7.4 | 7.0 | 6.9 | 5.1 | 4.9 | 4.9 | 4.1 | 3.9 | 3.8 |
| 7000 | 7.6 | 7.3 | 7.1 | 5.3 | 5.1 | 5.0 | 4.2 | 4.1 | 4.0 |
| 6500 | 7.9 | 7.5 | 7.4 | 5.6 | 5.3 | 5.2 | 4.5 | 4.3 | 4.2 |
| 6000 | 8.2 | 7.8 | 7.7 | 5.8 | 5.6 | 5.5 | 4.7 | 4.5 | 4.4 |
| 5500 | 8.7 | 8.2 | 8.0 | 6.1 | 5.8 | 5.7 | 5.0 | 4.7 | 4.7 |
| 5000 | 9.1 | 8.6 | 8.4 | 6.5 | 6.2 | 6.1 | 5.3 | 5.1 | 5.0 |
| 4500 | 9.7 | 9.2 | 9.0 | 7.0 | 6.6 | 6.5 | 5.7 | 5.4 | 5.3 |
| 4000 | 10.5 | 9.8 | 9.6 | 7.5 | 7.1 | 7.0 | 6.2 | 5.9 | 5.8 |
| 3500 | 11.4 | 10.7 | 10.4 | 8.3 | 7.8 | 7.6 | 6.9 | 6.6 | 6.4 |
| 3000 | 12.6 | 11.8 | 11.5 | 9.3 | 8.7 | 8.5 | 7.8 | 7.4 | 7.2 |
| *2500* | 14.5 | 13.5 | 13.1 | 10.7 | 10.0 | 9.8 | 9.0 | 8.5 | 8.4 |
| *2000* | 17.4 | 16.1 | 15.6 | 12.7 | 11.9 | 11.6 | 10.9 | 10.3 | 10.0 |
| *1500* | 22.1 | 20.4 | 19.8 | 16.2 | 15.1 | 14.7 | 14.0 | 13.1 | 12.8 |
| *1000* | 31.6 | 29.0 | 28.1 | 23.1 | 21.5 | 20.9 | 20.2 | 18.9 | 18.4 |
| 500 | 60.0 | 54.8 | 52.9 | 43.8 | 40.6 | 39.4 | 38.7 | 36.1 | 35.2 |

[A] Small plants from 1 to 10 $MW_{el}$, Ø 5 $MW_{el}$; [B] medium plants between 10 and 50 $MW_{el}$, Ø 30 $MW_{el}$; [C] large plants between 50 and 100 $MW_{el}$, Ø 75 $MW_{el}$.

In Table 4, the text colour (green/red) indicates the maximum $LCOH_2$ as economic limits at 15 €ct/$kWh_{HHV}$ (used in this work for hydrogen cost competitiveness). It can be seen that the required number of full-load hours to meet this economic limit decreases over time, as well as for larger plant sizes. Higher full-load hours reduce the proportional capital-related costs per produced unit of hydrogen most significantly. The cost advantage of large plants over smaller ones, as well as of later considered years over earlier ones, can be linked to the techno-economic assumptions (Table 2).

**Economic minimum of full-load hours:** With the help of the previous analysis, the minimum full-load hours required to meet the maximum $LCOH_2$ of 15 €ct/$kWh_{HHV}$ could be determined. As a result, the minimum full-load hours required are 2200 h/a (in 2030), 2000 h/a (in 2040) and 1500 h/a (in 2050). These minimum full-load hours are the same for both scenarios. By combining these minimum full-load hours with the negative residual loads available for electrolysis, the total maximum electrolysis size (in $GW_{el}$) could be determined for each scenario and year.

**Comparison of the economic electrolyser sizes:** The scenario *Energy Efficiency* has an economic green hydrogen potential only in 2050, due to the required full-load hours. The associated total electrolysis size is 5.9 $GW_{el}$. In the other scenario, all considered years fulfil the anticipated threshold for the minimum full-load hours. The electrolysis size was determined with 2.1, 5.9 and 11.0 $GW_{el}$ for the years 2030, 2040 and 2050, respectively. In Figure 6, the total negative residual loads available for electrolysis are shown in grey. The economically feasible share due to the limited electrolysis size is indicated in blue. For both scenarios and each considered year, the figure contains a time-resolved representation (in each case on the left) as well as an ordered duration curve of the negative residual load hours (in each case on the right). The minimum required full-load hours can be easily identified from the ordered duration curve.

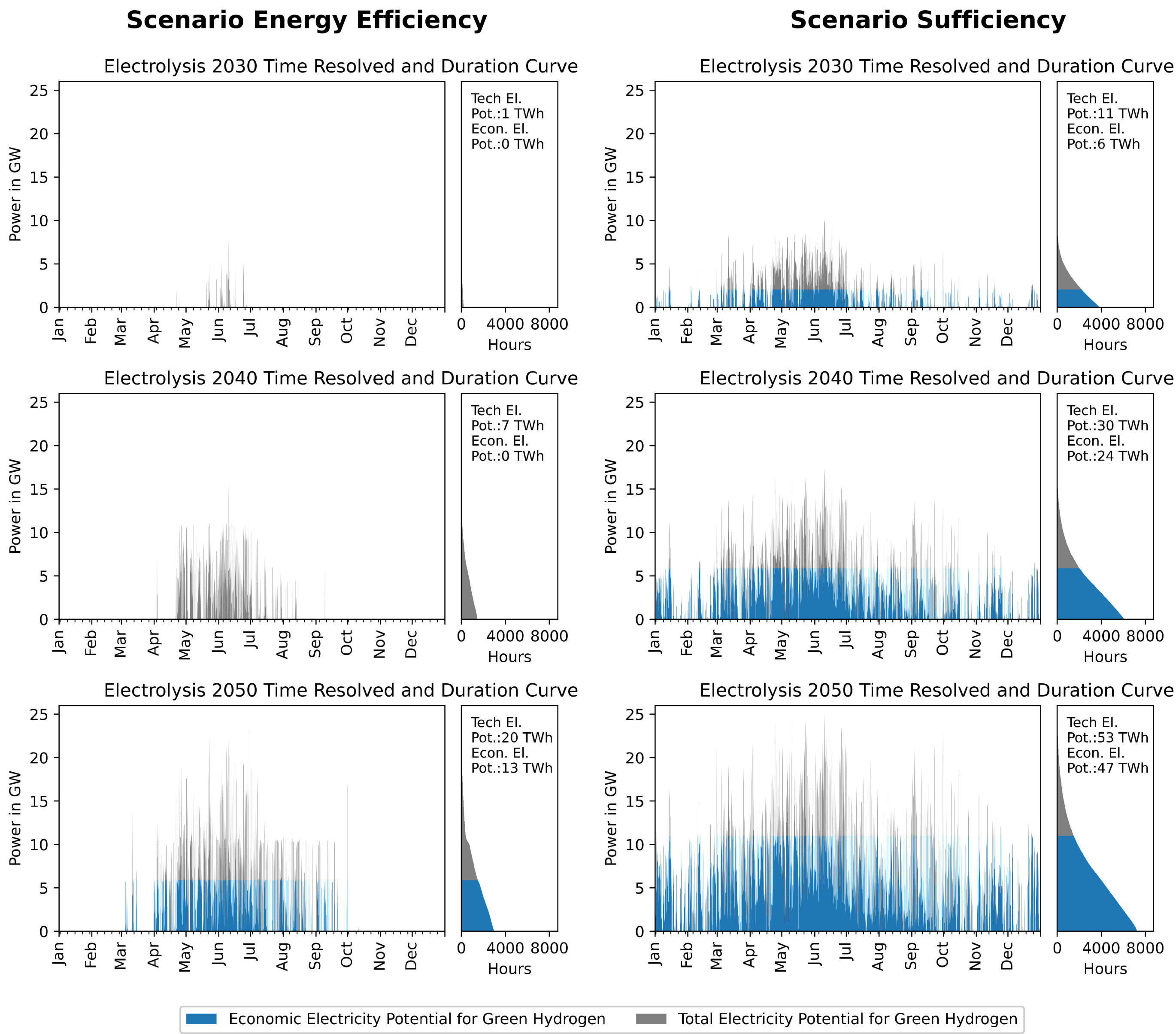


**Figure 6.** Technical potential of negative residual load usable by electrolysis (grey) as well as the economically realisable potential (blue). For each scenario and each considered year, the temporally resolved diagram (always left) and the ordered duration curve (always right) is shown.

**Comparison and explanation of the technical and economic electricity potential for green hydrogen:** The figure shows that the scenario *Energy Efficiency* has always a significantly lower total and economic potential for national green hydrogen, than the scenario *Sufficiency*. In the scenario *Energy Efficiency*, there is no economic potential until 2050. On the one hand, this is caused by the high degree of electrification and, on the other hand, it is the consequence of the availability of other controllable consumers such as heat pumps. Flexible operation during negative residual loads of central heat pumps can help increase overall efficiency [47].

**Roll-out of electrolyser plants:** Since the economic hydrogen production potential in the scenario *Energy Efficiency* is very low and only available in 2050, a more detailed roll-out and cost analysis will only be carried out for the scenario *Sufficiency* in the following. As mentioned in the methodology, the theoretical Austrian roll-out for electrolyser plants for the scenario *Sufficiency* was estimated based on a compound annual growth rate (CAGR) of 25% (Figure 7). Until 2030, mainly smaller plants in a capacity range between 0.5 and 1 $MW_{el}$ will be installed. Subsequently, the expansion of medium-sized plants between 1 and 5 $MW_{el}$ will also be accelerated. From 2030 onwards, it can also be assumed that more plants will be installed in a capacity range between 5 and 10 $MW_{el}$. Medium (10–50 $MW_{el}$) and large scale plants (50–100 $MW_{el}$) significantly contribute to the increase in capacity in the ramp-up curve in the second half of the considered period. In total, an installed capacity of more than 10 $GW_{el}$, represented in more than 500 plants till 2050, is anticipated in the developed roll-out scenario to reach a national green hydrogen production capacity. According to this roll-out scenario, a continuous capacity expansion would have to begin in 2021, and especially in the period 2040–2050; a doubling of already anticipated capacities and the number of plants is required to fully valorise the potential.

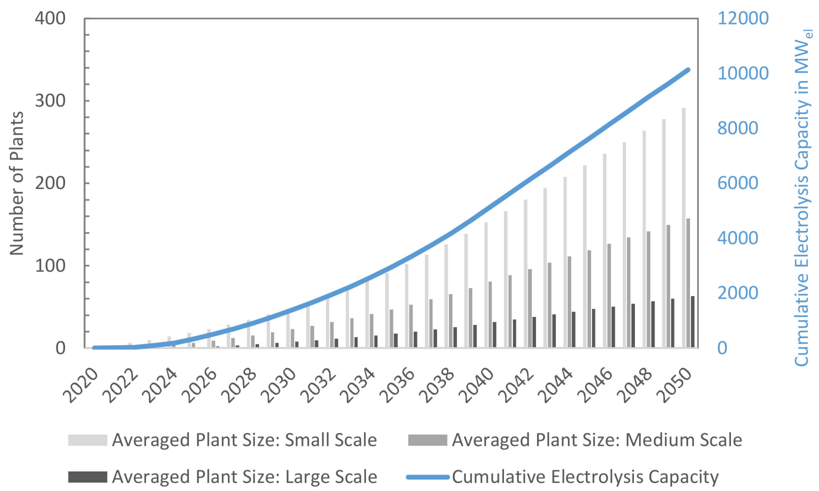


**Figure 7.** Roll-out curve of electrolyser plants in the scenario *Sufficiency*, considering economic boundary conditions 2021–2050.

**The final cost structure of the LCOH$_2$:** It is shown for the scenario *Sufficiency* in Figure 8. The figure represents the proportion of CAPEX and OPEX (orange and yellow shades) as well as revenues from the sale of by-products such as oxygen and excess heat (grey). The final costs resulting from all costs and proceeds are marked with a black line. All costs are averaged according to the actual hydrogen production. The final average levelised cost of hydrogen ranges between 12.1 (in 2030) and 6.3 €ct/$kWh_{HHV}$ (in 2050). Electricity costs, as well as electricity grid tariffs and charges, account for the largest share of the costs. The figure shows a significant decrease in the resulting costs over time. This is mainly related to the electricity costs and the capital-related costs. According to the scenario assumption, the costs for electricity are decreasing (Section 2.2 and Table 2) based on the excess from a strong expansion of fluctuating renewables. The decrease of the capital-related costs is caused by learning curves (Table 2) as well as the significant increase in full-load hours over time, since only negative residual loads can be used.

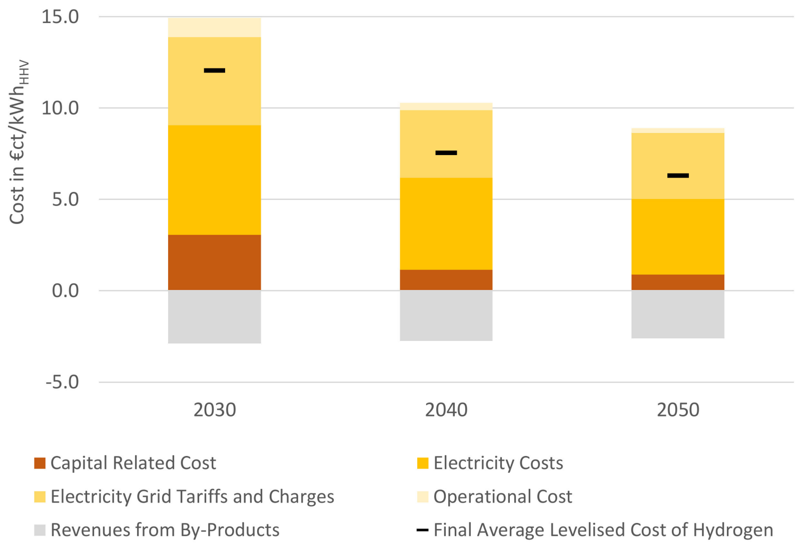


**Figure 8.** Averaged hydrogen production cost structure for scenario *Sufficiency.*

### *3.3. Import Demand of Renewable Gases*

This subsection combines the results of Sections 3.1 and 3.2 to determine the import demand of renewable gases. Based on the total renewable gas consumption and the national renewable gas production, the import demand can be determined. In both scenarios, the national sustainable methane potential (from anaerobic digestion) is considered in addition to the technical and economic national green hydrogen potential. Furthermore, exclusively in the scenario *Energy Efficiency*, the technical potential of wood gas via the gasification of woody biomass is also included. Wood gasification and wood gas utilisation enable a better exergetic utilisation of woody biomass than the typical thermal biomass utilisation for the provision of low-temperature heat such as space heating [47]. In this section, first the technical import demand (use of all technical potentials) and then the economic import demand (use of exclusively economic production) are discussed.

**Total consumption of renewable gases:** The results show the total consumption is between 99 and 195 TWh/a, depending on the scenario and the considered year (Figure 9). About 8, 12 and 16 TWh$_{SM}$/a are provided by national sustainable methane production (both scenarios), depending on the considered year. Furthermore, a technical wood gas potential of about 28 TWh$_{WG}$/a is supplied by the gasification of woody biomass (only the scenario *Energy Efficiency*), independent of the considered year. When considering the technical potential, between 0.3 and 37.2 TWh$_{H2}$/a of green hydrogen can be produced by national electrolysis plants. The rest, between 41 (scenario *Energy Efficiency* 2050) and 180 TWh/a (scenario *Sufficiency* 2030) of renewable gases must be imported.

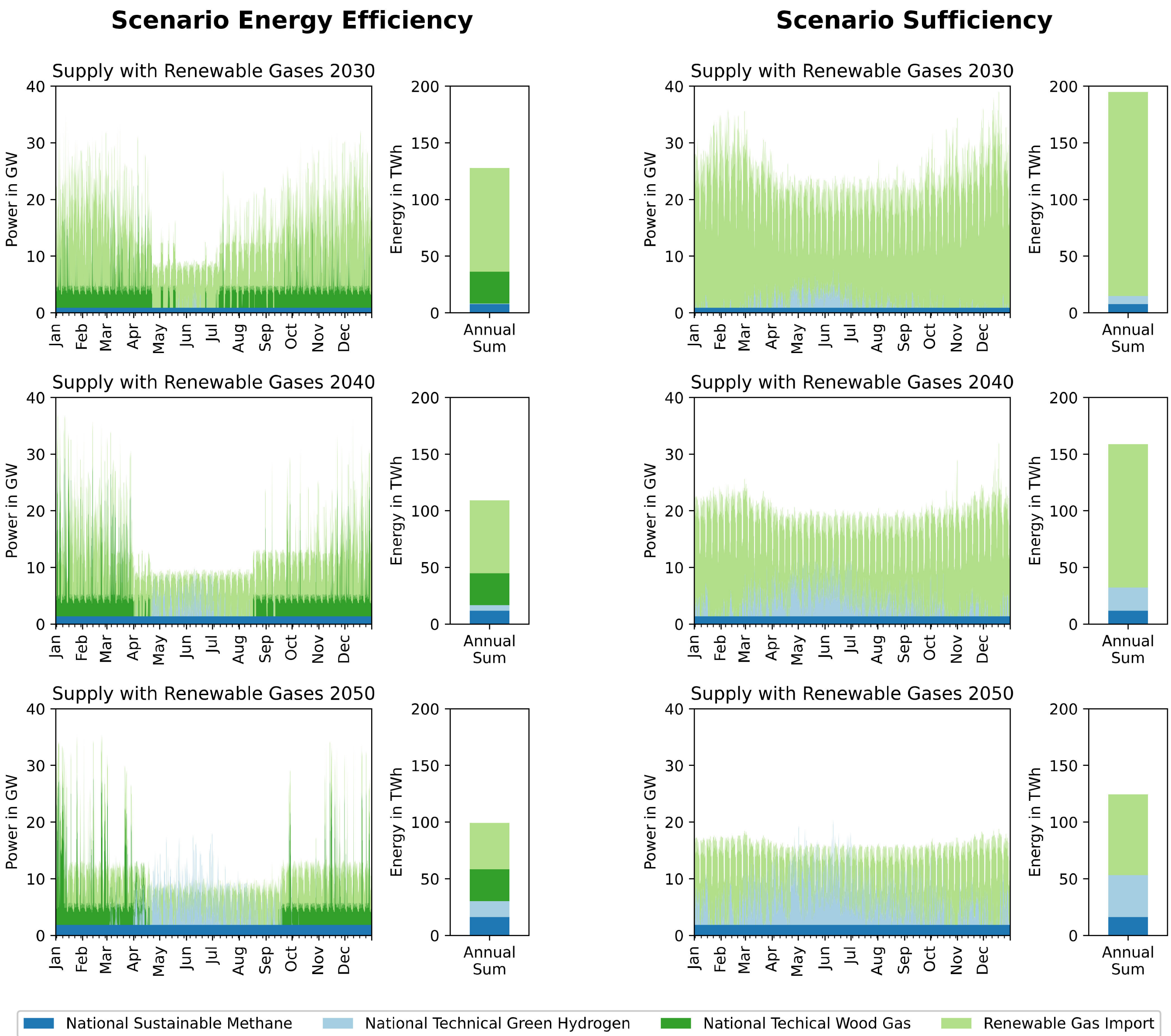


**Figure 9.** Sources of the required renewable gases. For each scenario and each considered year, the temporally resolved diagram and the annual sum of the technical potentials and import demand are shown.

**Comparison of the technical supply with renewable gases:** The time resolved and annual sum of the technical potentials and import demand is shown in Figure 9. The technical green hydrogen potential of the scenario *Energy Efficiency* is between 0.3 in 2030 and 14.1 $TWh_{H2}/a$ in 2050. For comparison, in the scenario *Sufficiency*, it ranges between 7.1 $TWh_{H2}/a$ in 2030 and 37.2 $TWh_{H2}/a$ in 2050. Despite the higher technical green hydrogen production in the scenario *Sufficiency*, the gasification of woody biomass in the scenario *Energy Efficiency* leads in total to a larger share of renewable gas self-supply for each considered year, compared to the scenario *Sufficiency* (2030: 28 compared to 8%, 2040: 41 compared to 20%, 2050: 59 compared to 43%). A seasonal component can be identified in both scenarios, especially in 2030. However, this seasonal component significantly reduces over time. National green hydrogen is mainly produced in summer, while sustainable methane production does not show seasonal fluctuations. In the scenario *Exergy Efficiency*, wood gas production is volatile but primarily in winter.

**Explanation of the difference in the technical gas supply:** The lower hydrogen production in the scenario *Energy Efficiency* can be explained by the lower amount of negative residual loads available for electrolysis plants (Sections 3.1 and 3.2). The seasonality of gas consumption is caused by two effects: On the one hand, renewable gases are needed to generate electricity to compensate for the positive residual load in the winter half-year. On the other hand, there is a significantly higher demand for space heat in the winter half-year. In the scenario *Energy Efficiency*, the demand for space heating is almost exclusively covered by heat pumps. For this reason, significantly more electricity must be provided by CHPs in winter in this scenario. In contrast, in the scenario *Sufficiency*, part of the space heating is covered by the incineration of renewable gases. The expansion of renewables in 2040 and 2050 reduces the need for controllable generations to cover the positive residual load. In addition, the final energy consumption decreases over time in both scenarios. Accordingly, the demand for space heating and its seasonal component also decreases. This effect on reduction is significant in the scenario *Sufficiency* due to the strong assumptions of behavioural changes. Due to the easy storability of woody biomass as well as of wood gas, the gasification plant can be operated very flexibly when excess heat (at about 90 °C) is needed. Accordingly, wood gasification only operates if the excess heat can be used. Since these are technical analyses, this also explains the large power peaks of gasification in Figure 9. As a consequence, operations take place primarily in winter due to the greater heat demand. In contrast, the operation of electrolysis is primarily in summer, due to the negative residual loads. According to the assumptions, sustainable methane is produced constantly.

**Comparison of technical and economic supply with renewable gases:** The small amount of negative residual loads for hydrogen production results in economic green hydrogen potentials in the scenario *Energy Efficiency* only in the year 2050. Accordingly, as mentioned above, national economic green hydrogen potential is only analysed for the scenario *Sufficiency*. The direct comparison of the technical and economic potential of national green hydrogen shows that a reduction in national production must be compensated for by an increase in renewable imports (Figure 10). However, the difference between technical and economic green hydrogen potentials has little impact on total renewable gas imports (2030: +1.7%; 2040: +3.2%; 2050: +4.0%). The absolute difference is between 3 and 4 TWh/a for all considered years. The small difference shows that an evaluation of renewable gas imports based on technical potential provides a good estimate in comparison to a more detailed economic analysis.

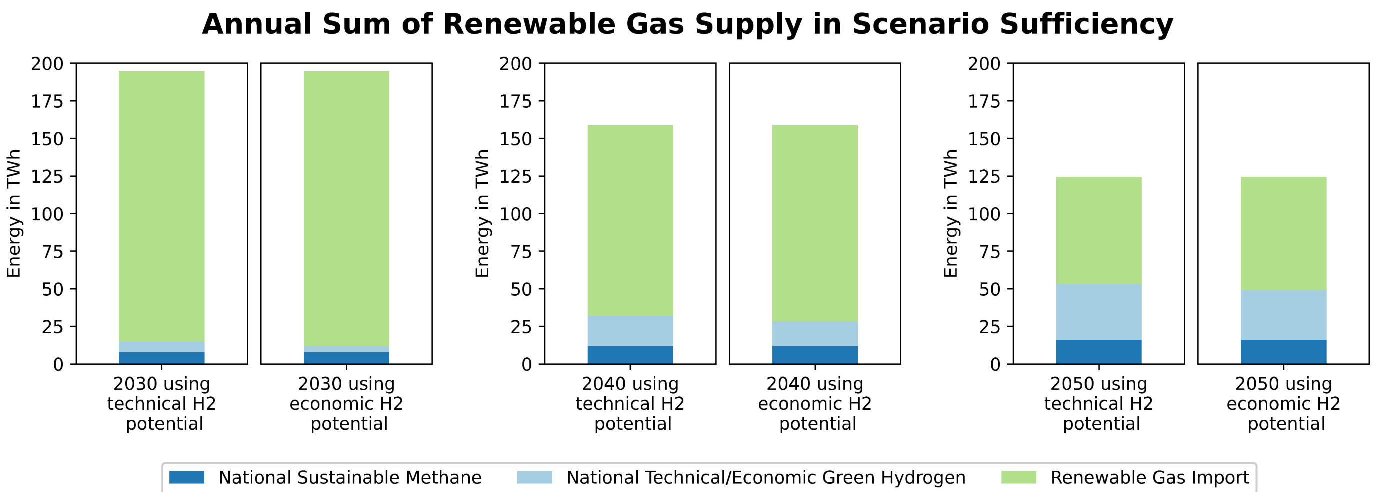


**Figure 10.** Comparison of renewable gas sources for the two cases: technical and economic green hydrogen potentials (only for the scenario *Sufficiency*).

### 3.4. Performance Indicators

Finally, this subsection presents performance indicators for both scenarios and the years 2030, 2040 and 2050 in Table 5. It represents a total overview of the results from Sections 3.1–3.3.

**Table 5.** Overview of the performance indicators for both scenarios and all considered years.

| Performance Indicator | Scenario *Energy Efficiency* | | | Scenario *Sufficiency* | | |
|---|---|---|---|---|---|---|
| | **2030** | **2040** | **2050** | **2030** | **2040** | **2050** |
| Primary energy consumption in TWh/a | 236 | 232 | 233 | 320 | 285 | 252 |
| Final energy consumption in TWh/a | 231 | 227 | 206 | 259 | 225 | 194 |
| Renewable energy generation and production in TWh/a | 138 | 163 | 189 | 138 | 163 | 189 |
| Total negative residual loads in TWhel/a | 1 | 7 | 20 | 11 | 30 | 53 |
| Lower limit for full-load hours of electrolyser plants in h/a [1] | 2200 | 2000 | 1500 | 2200 | 2000 | 1500 |
| Installed electrolysis capacity in GWel | 0.0 | 0.0 | 5.9 | 2.1 | 5.9 | 11.0 |
| Negative residual loads used for electrolysis in TWhel/a | 0 | 0 | 13 | 6 | 24 | 47 |
| Share of negative residual loads used for electrolysis in % | 0 | 0 | 67 | 57 | 80 | 89 |
| Technical green hydrogen production in TWhH2/a | 0 | 5 | 14 | 7 | 20 | 37 |
| Economic green hydrogen production in TWhH2/a | 0 | 0 | 9 | 4 | 17 | 34 |
| Total consumption of renewable gases in TWh/a | 128 | 109 | 99 | 195 | 159 | 125 |
| Required import of renewable gases (based on technical potentials) in TWh/a | 91 | 64 | 41 | 180 | 127 | 71 |
| Required import of renewable gases (based on economic potentials) in TWh/a | - [3] | - [3] | - [3] | 183 | 131 | 76 |
| Share of technical national renewable gas production in % | 28 [2] | 41 [2] | 59 [2] | 8 | 20 | 43 |
| Averaged levelised cost of national produced green hydrogen in €ct/kWhHHV | - [3] | - [3] | - [3] | 12.1 | 7.5 | 6.3 |
| Minimal levelised cost of national produced green hydrogen in €ct/kWhHHV | - [3] | - [3] | - [3] | 9.6 | 5.0 | 3.7 |
| Maximal levelised cost of national produced green hydrogen in €ct/kWhHHV | - [3] | - [3] | - [3] | 14.5 | 12.7 | 13.9 |

[1] Maximal $LCOH_2$ economic limit of 15 €ct/$kWh_{HHV}$; [2] including national wood gas production; [3] not calculated due to the small potential of the scenario, as mentioned in Section 3.2.

## 4. Discussion

This section first analyses the relations between economic green hydrogen potential, the averaged $LCOH_2$ and the maximum $LCOH_2$ economic limit (Section 4.1). Then, in Section 4.2, the resulting averaged $LCOH_2$ of national green hydrogen production determined in this study are compared with the costs documented in other publications.

### 4.1. Techno-Economic Relations

For the analysis, the negative residual load that can be used for green hydrogen production and their cost structures are investigated. This analysis was performed for the scenario *Sufficiency* only. To compare the economic green hydrogen potential and the resulting average $LCOH_2$, no minimum full-load hours or maximum $LCOH_2$ economic limits were taken into account. Instead, these two values were calculated in increments of 500 full-load hours over the entire available time range of the ordered duration curve for all considered years. The time range of the ordered duration curve starts for all considered years with 0 full-load hours (i.e., the maximum negative residual load peak power) and ends as soon as the negative residual load power drops to 0 (see duration curve in Figure 6).

The average $LCOH_2$ for a certain hydrogen potential is calculated by the actual potential weighted mean of all $LCOH_2$ of the individual 500 full-load hour increments, which are necessary to reach the potential. The comparison of the averaged $LCOH_2$ and the corresponding economic green hydrogen potentials for all three considered years is shown in Figure 11. In addition, this figure also shows different maximum $LCOH_2$ economic limits and their effect on averaged $LCOH_2$ as well as on the reachable green hydrogen potential. The maximal $LCOH_2$ economic limit of 15 €ct/kWh$_{HHV}$ (applied in this work) is indicated in red.

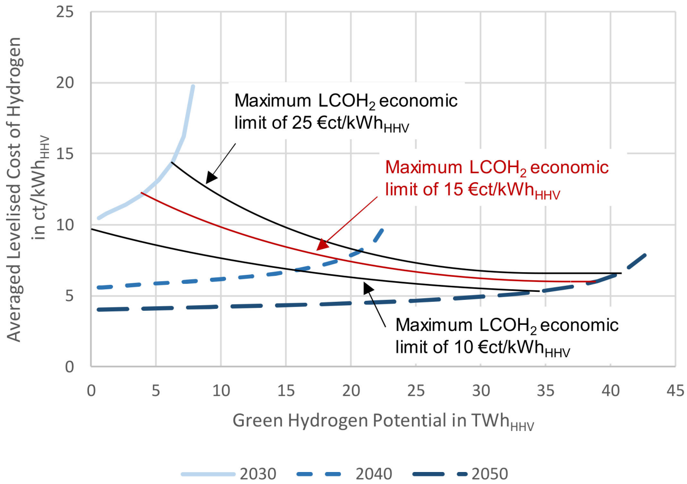


**Figure 11.** Relation between averaged levelised cost of hydrogen and economic green hydrogen potential. In addition, the maximum $LCOH_2$ economic limits (corresponding to the full-load hours) are visualised for 10, 15 and 25 €ct/kWh$_{HHV}$.

Figure 11 shows that greater potential utilisation leads to higher average $LCOH_2$. The slope of the curves is small at low potential utilisation and becomes increasingly larger towards maximum potential utilisation. Thereby, the slope increases by a factor between 10 (2030) and 32 (2050). Thus, the utilisation of the last few per cent of the potential leads to a significant increase in average $LCOH_2$. The curve for the year 2050 shows a significantly lower slope at the maximum potential than the other curves. This is primarily caused by the averaging of the $LCOH_2$. The higher the potentials with low $LCOH_2$ (high number of full-load hours), the smaller the effect of small potentials with high $LCOH_2$ (low number of full-load hours). The maximum available full-load hours based on the negative residual load available for electrolysis in 2030, 2040 and 2050 are 3855, 6097 and 7267 h/a, respectively.

A comparison of the curves shows that the averaged $LCOH_2$ in 2050 are significantly lower than in 2040 or 2030. This can be explained by two aspects: On the one hand, CAPEX and electricity costs will decrease according to the anticipated learning effects (Table 2). On the other hand, according to the scenario assumptions, there will be significantly higher full-load hours in 2050 (due to the higher renewable generation and decreasing demand), which will lead to significantly lower specific costs and higher economic green hydrogen potential.

In 2030, increasing the maximum $LCOH_2$ economic limit from 15 €ct/kWh$_{HHV}$ to 25 €ct/kWh$_{HHV}$ has a significant impact on the average $LCOH_2$ as well as the potential (Figure 11): +2.3 TWh$_{HHV}$ (+57%) of potential but averaged $LCOH_2$ would increase by 2.2 €ct/kWh$_{HHV}$ (+18%). For comparison, in 2050 the same change in maximum $LCOH_2$ economic limit only leads to a change of +0.6 €ct/kWh$_{HHV}$ (+9%) on the average $LCOH_2$ as well as a change in the potential increase of 1.9 TWh$_{HHV}$ (+5%). Therefore, the relative impact in 2030 is significantly higher than in 2050. This can be explained by the large difference in the total potential with a maximum $LCOH_2$ economic limit of 15 €ct/kWh$_{HHV}$ for these two considered years (2030: 4.0 TWh$_{HHV}$; 2050: 39.0 TWh$_{HHV}$), while the increase in potential due to a higher maximum $LCOH_2$ economic limit is comparable (2.3 $TWh_{HHV}$ for 2030, 1.9 $TWh_{HHV}$ for 2030) as well as by the averaging of the $LCOH_2$; a high share of the potential with low costs can nearly compensate a small share of the potential with higher costs, due to the method of actual potential weighted averaging.

### *4.2. Overview of Hydrogen Production Cost Trend in the Literature*

In this subsection, the hydrogen production costs available in the literature are compared with the costs determined in this work. A distinction is made between the resulting costs of green, blue and grey hydrogen.

The Energy Transition Commission [64] clearly states that blue hydrogen will always be more expensive than grey hydrogen, as long as there is no carbon price. They also point out that in the medium term, green hydrogen may be cheaper than grey hydrogen in many regions because of a fall in prices for renewable energy and electrolysers. However, $CO_2$ emission prices are important to make clean hydrogen types competitive with fossil fuels. The Hydrogen Council [65] states that green hydrogen will become cost-competitive in the future because of three aspects: the levelised costs of energy are declining, a significant decrease in electrolyser CAPEX can be expected and the full-load hours continue to increase. With the introduction of carbon costs, green hydrogen could be cost-competitive around 2030 [65]. According to the International Energy Agency's (IEA) [66] prognosis, a cost reduction of up to 30% by 2030 is possible for the production of green hydrogen because of declining costs of renewables. IRENA says that in the best locations, renewable hydrogen will be competitive with hydrogen derived from fossil fuels within 3–5 years, and they also point out that $CO_2$ prices are beneficial for green hydrogen to become competitive [67].

Table 6 compares the costs of different types of hydrogen production over time, published in the literature. The costs of grey, blue and green hydrogen (including $CO_2$ emission costs) are visualized in Figure 12. It can be seen how the costs for green hydrogen are decreasing. The costs for grey hydrogen are rising due to the $CO_2$ emission costs. The costs determined in this study for the production of green hydrogen from negative residual loads in Austria amount to 12.1, 7.5 and 6.3 €ct/$kWh_{HHV}$ in 2030, 2040 and 2050, respectively (all values for the scenario *Sufficiency*). The comparison shows that the costs are in a comparable order of magnitude, but due to the low full-load hours (especially in 2030), they are not competitive with other concepts/regions with higher full-load hours (e.g., offshore wind generation or photovoltaics in desert regions exclusively for hydrogen production). However, if the national costs are compared with the import costs of green hydrogen (including transport costs), it becomes clear that the national costs are competitive (Table 6). In this context, it is important to note that the actual import costs in the future are still very uncertain. It is currently unclear whether hydrogen will be imported directly (compressed or liquefied) or chemically bound (e.g., as ammonia or methane). The costs for direct import in the 2030–2035 range from about 2.1 €ct/$kWh_{HHV}$ (pipeline from Iberia) to 5.9 €ct/$kWh_{HHV}$ (ship from Australia) [68]. The transport costs depend significantly on the transport distance. Hydrogen imported liquefied via ship from Morocco to Belgium is estimated at 3.3 €ct/$kWh_{HHV}$ (in 2030–2035) [68]. For comparison, the Hydrogen Council expects 3.1 €ct/$kWh_{HHV}$ for the ship transport of liquid hydrogen from Saudi Arabia to Germany in 2030 [60]. The high direct hydrogen transportation costs result from the required effort for liquefaction and refrigerated transport, as well as from the low volumetric energy density and thus higher costs per transported unit [68]. In the case of indirect hydrogen imports, the transport costs are significantly reduced, but additional costs arise for the conversion. According to the Hydrogen Roadmap Europe [69], various modes of transport for hydrogen are possible, as all of them are cheaper than a transmission grid for electricity.

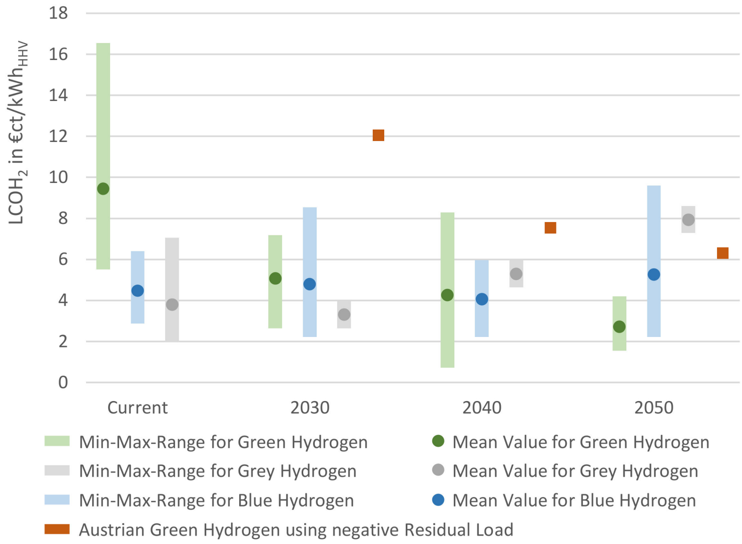


**Figure 12.** Literature overview of the development of hydrogen production costs over time. Green, blue and grey bars represent green, blue and grey hydrogen, respectively. All bars show the range in the literature between the minimum and maximum values. The dots represent the arithmetic mean. Blue and grey hydrogen include $CO_2$ emission costs. All values and corresponding sources can be found in Table 6. For comparison, the Austrian averaged $LCOH_2$ (determined in this study) are indicated by red squares.

In the future, the import of renewable gases will be important, since Austria cannot completely self-supply its demand for renewable gases (Section 3.3). For other European countries like Germany or Belgium, the situation is quite similar [24,68]. A problem in central European countries like Germany or Austria is the competition between renewable energy generation and other land use forms, which is not the case in unsettled areas in, for example, Northern Africa [24]. Therefore, renewable gas imports, mostly originating from solar energy in desert areas or wind energy from offshore wind plants seem to be the key strategy to satisfy the demand. However, this requires the implementation of new infrastructure. The Hydrogen Import Coalition [68] identifies regions like Morocco, Spain, Chile, Oman and Australia as promising.

As the import of green hydrogen will be a key aspect in the future, it is important to mention that the conditions in the export countries must also be taken into account, so that no disadvantages arise regionally for people and the environment. Accordingly, support for the global south is necessary, as the energy demand in urban environments in these regions is rising. In addition to the advantages of importing, it is nevertheless important to consider the dependence of the energy supply on exporting countries [24].

**Table 6.** Production price comparison for different hydrogen types until 2050.

| Type | Hydrogen Price (€ct/kWh$_{HHV}$) | | | |
|---|---|---|---|---|
| | Current | 2030 | 2040 | 2050 |
| Production of Grey | *Including $CO_2$ emission costs* | | | |
| | 2.4–3.8 [3]<br>2.0–7.1 [4] | 2.6–4.0 [3] | 4.6–6.0 [3] | 7.3–8.6 [3] |
| | *Excluding $CO_2$ emission costs* | | | |
| | 4.0 [1]<br>1.8–3.1 [3]<br>1.5–4.9 [7]<br>3.8 [8] | 1.8–3.1 [3] | 1.8–3.1 [3] | 1.8–3.1 [3] |
| Production of Blue | *Including $CO_2$ emission costs* | | | |
| | 3.3–6.4 [4]<br>2.9–5.5 [6] | 5.0 [1]<br>2.2–3.5 [3]<br>2.9–5.7 [6]<br>5.5–8.5 [10] | 4.8 [1]<br>2.2–3.5 [3]<br>3.1–6.0 [6] | 2.2–3.5 [3]<br>3.3–6.4 [6]<br>6.6–9.6 [10] |
| | *Excluding $CO_2$ emission costs* | | | |
| | 4.9 [1]<br>3.1–7.5 [5]<br>2.9–6.4 [7]<br>5.1 [8] | 3.0–7.5 [5] | | 3.0–6.6 [5] |
| Production of Green | 8.0 [1]<br>8.8–12.1 [3]<br>6.6–16.6 [4]<br>5.5–10.2 [5]<br>5.7–14.8 [6]<br>5.7–9.9 [7]<br>6.3–14.0 [8] | 6.0 [1]<br>2.9–5.1 [3]<br>2.6–6.0 [5]<br>3.5–7.1 [6]<br>4.4–7.2 [10] | 5.2 [1]<br>2.2–4.2 [3]<br>2.6–5.5 [6]<br>0.7–8.3 [10] | 1.8–3.3 [3]<br>1.6–3.5 [5]<br>2.0–4.2 [6] |
| Production and Import of Green (incl. transport cost) | 25.0–27.5 [2] | 16.0–22.0 [2]<br>6.5–9.0 [9]<br>7.5 [11] | 14.0–17.5 [2] | 12.0–13.0 [2]<br>5.5–7.5 [9] |

Assumptions for conversion: 1 € = 1.15 USD; HHV of $H_2$: 39.4 kWh/kg. [1] [70], $CO_2$ price: unknown but included. [2] [34], considers import to Germany. [3] [65], $CO_2$ prices: 26.09 €/$t_{CO2}$ (2020), 43.48 €/$t_{CO2}$ (2030), 130.43 €/$t_{CO2}$ (2040), 260.87 €/$t_{CO2}$ (2050). [4] [66], $CO_2$ prices [71]: 0–18.4 €/$t_{CO2}$ (2020), 86.3–115.0 €/$t_{CO2}$ (2030), 166.8–184.0 €/$t_{CO2}$ (2050). [5] [72], no carbon tax applied. [6] [67], $CO_2$ prices: 43.48 €/$t_{CO2}$ (2030), 86.96 €/$t_{CO2}$ (2040), 173.91 €/$t_{CO2}$ (2050), depicted max. values are avg. values (actual max. values not available for public purposes). [7] [64], no carbon tax applied. [8] [73], no carbon tax applied. [9] [68], considers import to Belgium. [10] [74], $CO_2$ prices: 100 €/$t_{CO2}$ (2030), 150 €/$t_{CO2}$ (2040). [11] [60], export from Saudi Arabia to Germany.

## 5. Conclusions

By combining the results with the discussion, the following main conclusions can be drawn:

**Renewable gases will be crucial in the future to reach our climate targets:** Depending on the scenario and the considered year, renewable gas consumption between 99 and 195 TWh/a was identified. For comparison, Austria had a total natural gas consumption of about 89 TWh/a in 2019 [38].

Massive expansion of renewables is mandatory for national green hydrogen production. Nevertheless, the share is small compared to the import demand. In this paper, only negative residual loads from renewable sources are used for the production of green hydrogen. To reach significant negative residual loads, massive expansion of renewables is required. In the scenarios, the already ambitious renewable expansion plan until 2030 [29] was extrapolated linearly until 2050. Despite this massive expansion, the maximum technical green hydrogen potential can only cover about 14 and 30% of the total renewable gas consumption for the scenarios *Energy Efficiency* and *Sufficiency* in 2050, respectively. Based on the maximum potential of sustainable methane from biogenic sources in Austria [52], at least 54% of the renewable gas consumption must be imported. Considering the assumptions used in this study, the minimum import share is even higher (57%).

**Higher $LCOH_2$ can be accepted at the beginning if the expansion of renewables is continued:** An increasing number of full-load hours of the electrolysis (due to expansion of renewables) leads to decreasing averaged $LCOH_2$. Lower full-load hours are expected at the beginning of the electrolysis plant roll-out. Accordingly, the maximum $LCOH_2$ economic limit can be set higher at the beginning. When a high number of full-load hours is reached, the higher maximum $LCOH_2$ economic limit does not lead to a significantly higher average $LCOH_2$. The cost analysis has also shown that the use of all available negative residual loads increases the average costs due to the low number of full-load hours for the last few per cent of additional hydrogen production. Accordingly, a maximum $LCOH_2$ economic limit is suggested if no further significant increase in negative residual loads is to be expected. It ensures that no excessive increase in the average $LCOH_2$ is to be anticipated. To reduce costs, in the beginning, a non-exclusive supply with negative residual loads can be applied. Supply from the grid can increase full-load hours but will also lead to higher electricity costs.

**The costs of nationally produced green hydrogen are comparable to the costs of importing green hydrogen:** The comparison of the resulting averaged levelised cost of hydrogen with other studies shows that the national green hydrogen production is more expensive, especially in 2030. This is mainly caused by the low number of full-load hours reachable based on the scenarios to exclusive utilise negative residual loads. In 2040 and 2050, the available negative residual loads, as well as the full-load hours, are significantly higher than in 2030. Consequently, the average cost decreases. National green hydrogen is becoming competitive, especially in comparison with imported green hydrogen (including transport costs).

In this paper, two fully decarbonised scenarios are considered. Accordingly, there are no energy-related $CO_2$ emissions in Austria. However, the actual reduction of $CO_2$ emissions through the measures discussed in this study is not quantifiable. It depends on the actual sources of the imported gases. As mentioned in the introduction, hydrogen can be produced using different processes (grey, blue, turquoise, pink or green hydrogen). Each of these processes can be attributed to different amounts of $CO_2$ emissions per quantity of hydrogen produced (carbon footprint). Accordingly, it is a global task to ensure the use of exclusively renewable sources for the provision of renewable gas. Only this can ensure the full decarbonisation of countries with energy import demands.

The results clearly indicate the strong demand for cheap renewable electricity production as a prerequisite for the upscale and broad roll-out of electrolysis technologies. Accordingly, very rapid expansion of renewables but also of electrolysis plants are required, nationally and internationally to reach the goal of climate neutrality.

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**Nomenclature of abbreviations**

| | |
|---|---|
| $A$ | Annuity of total annual payments |
| $A_C$ | Annuities of capital-related costs |
| $A_D$ | Annuities of demand-related costs |
| $A_O$ | Annuities of operation-related costs |
| $A_P$ | Annuity of proceeds from by-product sales |
| $A_M$ | Annuities of other costs |
| $C_{var}$ | Demand related variable costs |
| CAGR | Compound annual growth rate |
| CAPEX | Capital expenditures, investment cost |
| CCS | Carbon capture and storage |
| CHP | Combined heat and power plant |
| $CO_2$ | Carbon dioxide |
| EAA | Environmental Agency Austria |
| EU | European Union |
| $Ex_{LossDest,tot}$ | Total of exergy losses and exergy destruction, caused by both energy conversion, transportation and distribution systems as well as final energy applications |
| $Ex_{Sup,tot}$ | Total exergy used for supplying the national energy system |
| $Ex_{UED,tot}$ | Total useful exergy demand of all national energy services |
| $Ex_{NatGP,i}$ | National renewable generation or production of resource i |
| $Ex_{Imp,j}$ | Exergy import of energy carrier j |
| $Ex_{Exp,k}$ | Exergy export of energy carrier k |
| f | Objective function |
| $GW_{el}$ | Gigawatt of electrical power |
| h | Hours |
| $H_2$ | Hydrogen |
| HHV | Higher heating value |
| ICE | Internal combustion engines |
| $kW_{el}$ | Kilowatt of electrical power |
| $kWh_{H2}$ | Kilowatt hour of hydrogen based on LHV |
| $kWh_{HHV}$ | Kilowatt hour of hydrogen based on HHV |
| LCOE | Levelised cost of electricity |
| $LCOH_2$ | Levelised cost of hydrogen |
| LHV | Lower Heating Value |
| $m^3H_2O$ | Cubic meter water |
| $MW_{el}$ | Megawatt of electrical power |
| $MWh_{el}$ | Megawatt hour of electrical energy |
| $MWh_{th}$ | Megawatt hour of thermal energy |
| OPEX | Operational expenditures |
| p.a. | Per anno |
| $P_{H2,y}$ | Annual hydrogen production |
| PV | Photovoltaic |
| $t_{O2}$ | Tons of oxygen |
| $t_{CO2}$ | Tons of carbon dioxide |
| TWh | Terawatt hour (independent of the type of energy) |
| $TWh_{el}$ | Terawatt hour of electrical energy |
| $TWh_{H2}$ | Terawatt hour of hydrogen based on LHV |
| $TWh_{HHV}$ | Terawatt hour of hydrogen based on HHV |
| $TWh_{SM}$ | Terawatt hour of sustainable methane |
| $TWh_{WG}$ | Terawatt hour of wood gas |
| USD | United States Dollar |
| WAMplus | With Additional Measures Plus |
| € | Euro |
| €ct | Eurocent |
| /a | Per annum |

## Appendix A

### *Appendix A.1 Additional Information of Scenario Energy Efficiency*

Table A1 summarises the exergy demands taken into account in the scenario *Energy Efficiency* to cover all Austrian energy services. Table A2 to Table A8 provide a complete list of available conversion technologies, including the exergy efficiencies used. Maximum power is not limited. Available storage units can be found in Table A9. The exergy efficiencies considered here take into account both exergy destruction and exergy losses. Further details about all efficiencies can be found in [47].

**Table A1.** Useful exergy demand for the scenario *Energy Efficiency* (calculation based on [25]).

| Type | Exergy Demand 2030 in TWh/a | Exergy Demand 2040 in TWh/a | Exergy Demand 2050 in TWh/a | Used Profile |
|---|---|---|---|---|
| Transport Demand Cars and Trucks | 29.9 | 29.6 | 29.3 | Cars [75,76] [2]; Trucks [77–79] [2] |
| Transport Demand Others | 5.1 | 5.1 | 5.0 | Aviation: Austrian Transport Report 2017 [80]; navigation: assumed as constant between 5 and 22 o'clock on working days and constant between 5 and 15 o'clock on Saturdays; railways: measured values of Austrian Railways [81]; pipelines: assumed as constant |
| Heat Demand (up to 100 °C) | 19.0 | 18.9 | 18.7 | FfE SigLinDe [82], combined industrial load profile [83] [1], synthetic load profiles [84] [1] |
| Heat Demand (100 to 400 °C) | 11.7 | 11.6 | 11.5 | Combined industrial load profile [83] [1], synthetic load profiles [84] [1] |
| Heat Demand (above 400 °C) | 15.3 | 15.2 | 15.1 | Combined industrial load profile [83] |
| Industrial Processes (Iron- and Steelmaking, Electrochemical Demand, Non-Energy Use) | 29.1 | 28.8 | 28.5 | Iron- and steelmaking assumed as constant; rest: combined industrial load profile [83] [1] |
| Stationary Engine Demand | 16.3 | 16.1 | 15.9 | Combined industrial load profile [83] [1], synthetic load profiles [84] [1] |
| Lighting and ICT Demand | 4.3 | 4.3 | 4.2 | Combined industrial load profile [83], synthetic load profiles [84] |

[1] Without seasonal component; [2] outside temperature additionally taken into account for heating/cooling demand.

**Table A2.** Available CHPs of the scenario *Energy Efficiency* [47].

| Type | Exergy Efficiency of Electricity | Exergy Efficiency of Usable Excess Heat | Exergy Destruction | Exergy Losses |
|---|---|---|---|---|
| Woody biomass fired CHP (Clausius–Rankine-cycle) | 0.270 | 0.130 | 0.566 | 0.034 |
| Wood gas fired CHP (ICE) | 0.300 | 0.124 | 0.543 | 0.034 |
| Fuel cell CHP (PEM) | 0.639–0.659 [85] | 0.064–0.065 | 0.310 | 0.045 |
| Sustainable methane fired CHP (combined cycle) | 0.590–0.630 [85] | 0.049–0.058 | 0.310 | 0.034 |

**Table A3.** Available conversion units of the scenario *Energy Efficiency* [47].

| Type | Exergy Efficiency of Conversion | Exergy Efficiency of Usable Excess Heat | Exergy Destruction | Exergy Losses |
|---|---|---|---|---|
| Water Electrolysis (PEM) | 0.651–0.702 [85] | 0.033–0.045 | 0.233 | 0.034 |
| Methanation of Hydrogen to Sustainable Methane | 0.800 | 0.011 | 0.155 | 0.034 |
| Gasification of Woody Biomass to Wood Gas plus Methanation to Sustainable Methane | 0.560 | 0.065 | 0.341 | 0.034 |
| Gasification of Woody Biomass to Wood Gas | 0.700 | 0.034 | 0.233 | 0.034 |
| Production of Kerosene or Diesel from Hydrogen via Fischer–Tropsch-Synthesis | 0.769 | - | 0.185 | 0.046 |
| Production of Kerosene or Diesel from Sustainable Methane via Reforming and Fischer–Tropsch-Synthesis | 0.650 | - | 0.281 | 0.069 |

**Table A4.** Available grids of scenario *Energy Efficiency* [47].

| Type | Exergy Efficiency of Transport | Exergy Destruction | Exergy Losses |
|---|---|---|---|
| Electricity Grid | 0.953 | 0.038 | 0.009 |
| District Heating Grid (92 to 90 °C; return at 30 °C) | 0.949 | 0.050 | 0.000 |
| District Heating Grid (85 to 80 °C; return at 31 °C) | 0.859 | 0.140 | 0.001 |
| District Heating Grid (34 to 32.5 °C; return at 15 °C) | 0.868 | 0.132 | 0.001 |
| District Heating Grid (31 to 27.5 °C; return at 15 °C) | 0.659 | 0.340 | 0.002 |

**Table A5.** Available conversion units for covering heat demand of the scenario *Energy Efficiency* [47].

| Type | Overall Exergy Efficiency | Overall Exergy Destruction | Overall Exergy Losses |
|---|---|---|---|
| District Heating Application at 25 °C | 0.254 | 0.746 | 0.000 |
| District Heating Application at 65 °C | 0.821 | 0.179 | 0.000 |
| District Heating Application at 25 °C | 0.864 | 0.136 | 0.000 |
| Heat Pump (31 to 90 °C) | 0.593 | 0.407 | 0.000 |
| Heat Pump (80 to 100 °C) | 0.849 | 0.151 | 0.000 |
| Heat Pump (80 to 150 °C) | 0.714 | 0.286 | 0.000 |
| Heat Pump (between ambient and from 25 up to 150 °C) | 0.500 | 0.500 | 0.000 |
| Heat Supply at 25 °C by Incineration of Chemical Energy (Hydrogen, Sustainable Methane, Wood Gas, Woody Biomass) or Electric Direct Heating | 0.0428 | 0.9076 | 0.0496 |
| Heat Supply at 65 °C by Incineration of Chemical Energy (Hydrogen, Sustainable Methane, Wood Gas, Woody Biomass) or Electric Direct Heating | 0.1383 | 0.8120 | 0.0496 |
| Heat Supply at 100 °C by Incineration of Chemical Energy (Hydrogen, Sustainable Methane, Wood Gas, Woody Biomass) or Electric Direct Heating | 0.2051 | 0.7453 | 0.0496 |
| Heat Supply at 150 °C by Incineration of Chemical Energy (Hydrogen, Sustainable Methane, Wood Gas, Woody Biomass) or Electric Direct Heating | 0.2813 | 0.6690 | 0.0496 |
| Heat Supply at 250 °C by Incineration of Chemical Energy (Hydrogen, Sustainable Methane, Wood Gas, Woody Biomass) or Electric Direct Heating | 0.3901 | 0.5497 | 0.0603 |
| Heat Supply at 400 °C by Incineration of Chemical Energy (Hydrogen, Sustainable Methane, Wood Gas) or Electric Direct Heating | 0.4926 | 0.4472 | 0.0603 |

**Table A5.** *Cont.*

| Type | Overall Exergy Efficiency | Overall Exergy Destruction | Overall Exergy Losses |
|---|---|---|---|
| Heat Supply at 750 °C by Incineration of Chemical Energy (Hydrogen, Sustainable Methane, Wood Gas) or Electric Direct Heating | 0.6149 | 0.3249 | 0.0603 |
| Heat Supply at 1500 °C by Incineration of Chemical Energy (Hydrogen, Sustainable Methane, Wood Gas) or Electric Direct Heating | 0.7143 | 0.2098 | 0.0759 |

**Table A6.** Available conversion units for covering transport demand of the scenario *Energy Efficiency* [47].

| Type | Overall Exergy Efficiency for Movement | Overall Exergy Destruction | Overall Exergy Losses |
|---|---|---|---|
| BEV—Cars and Light Duty Trucks | 0.741 | 0.229 | 0.030 |
| BEV—Heavy Duty Trucks | 0.734 | 0.236 | 0.030 |
| Electric Locomotives | 0.871 | 0.111 | 0.018 |
| FC—Locomotives | 0.491 | 0.406 | 0.103 |
| FC—Cars and Light Duty Trucks | 0.434 | 0.451 | 0.115 |
| FC—Heavy Duty Truck (long-distances) | 0.484 | 0.413 | 0.103 |
| FC—Ship | 0.276 | 0.621 | 0.103 |
| Airplanes | 0.276 | 0.225 | 0.499 |
| ICE—Cars and Light Duty Trucks | 0.268 | 0.459 | 0.274 |
| ICE—Heavy Duty Truck | 0.291 | 0.446 | 0.263 |
| ICE—Ship | 0.168 | 0.569 | 0.263 |
| ICE—Locomotive | 0.299 | 0.438 | 0.263 |

**Table A7.** Available conversion units for covering other demands of the scenario *Energy Efficiency* [47].

| Type | Overall Exergy Efficiency | Overall Exergy Destruction | Overall Exergy Losses |
|---|---|---|---|
| LED Light | 0.131 [86] | 0.76 | 0.11 |
| Electric Compressor for Gas Pipelines | 0.840 | 0.16 | 0.00 |
| Variable-Frequency Drive (Electric Engine) | 0.880 | 0.08 | 0.04 |

**Table A8.** Available conversion units for covering both, heat and shaft work demand of the scenario *Energy Efficiency* [47].

| Type | Exergy Efficiency of Provision of Shaft Work | Exergy Efficiency of Usable Excess Heat | Overall Exergy Destruction | Overall Exergy Losses |
|---|---|---|---|---|
| Methane fired Stationary Engine (ICE) with direct Excess Heat Usage at 25 °C | 0.500 | 0.018 | 0.422 | 0.060 |
| Methane fired Stationary Engine (ICE) with direct Excess Heat Usage at 65 °C | 0.500 | 0.057 | 0.383 | 0.060 |
| Methane fired Stationary Engine (ICE) with direct Excess Heat Usage at 100 °C | 0.500 | 0.084 | 0.355 | 0.060 |
| Methane fired Stationary Engine (ICE) with direct Excess Heat Usage at 150 °C | 0.500 | 0.116 | 0.324 | 0.060 |
| Methane fired Stationary Engine (ICE) with direct Excess Heat Usage at 250 °C | 0.500 | 0.161 | 0.279 | 0.060 |

**Table A8.** *Cont.*

| Type | Exergy Efficiency of Provision of Shaft Work | Exergy Efficiency of Usable Excess Heat | Overall Exergy Destruction | Overall Exergy Losses |
|---|---|---|---|---|
| Wood Gas fired Stationary Engine (ICE) with direct Excess Heat Usage at 25 °C | 0.300 | 0.028 | 0.612 | 0.060 |
| Wood Gas fired Stationary Engine (ICE) with direct Excess Heat Usage at 65 °C | 0.300 | 0.089 | 0.550 | 0.060 |
| Wood Gas fired Stationary Engine (ICE) with direct Excess Heat Usage at 80 °C | 0.300 | 0.109 | 0.531 | 0.060 |
| Wood Gas fired Stationary Engine (ICE) with direct Excess Heat Usage at 100 °C | 0.300 | 0.133 | 0.507 | 0.060 |
| Wood Gas fired Stationary Engine (ICE) with direct Excess Heat Usage at 150 °C | 0.300 | 0.182 | 0.458 | 0.060 |
| Wood Gas fired Stationary Engine (ICE) with direct Excess Heat Usage at 250 °C | 0.300 | 0.252 | 0.387 | 0.060 |

**Table A9.** Parameter of the used storages in the scenario *Energy Efficiency*.

| Type | Capacity in $GWh_{el}$ | Max. Charging Power in $GW_{el}$ | Max. Discharging Power in $GW_{el}$ | Cycle Exergy Efficiency | Exergy Losses and Destruction over Time |
|---|---|---|---|---|---|
| Thermal Storage (low temperature) | unlimited [1] | unlimited [1] | unlimited [1] | 0.951 | 3%/day |
| Thermal Storage (low medium) | unlimited [1] | unlimited [1] | unlimited [1] | 0.938 | 5%/day |
| Waste Storage, Woody Biomass Storage | unlimited [1] | unlimited [1] | unlimited [1] | 1 | 0 [2] |
| Wood Gas Storage, Sustainable Methane Storage, Kerosene Storage, Gasoline/Diesel Stroage | unlimited [1] | unlimited [1] | unlimited [1] | 0.98 | 0 [2] |
| Hydrogen Storage | unlimited [1] | unlimited [1] | unlimited [1] | 0.95 | 0 [2] |
| Battery Storages | 2.1–11.8 [3,4] | 1.1–5.9 [4,5] | 1.1–5.9 [4,5] | 0.9 | 0 [6] |
| Pumped Storages | 160 [37] | 1.2–3.6 [4,7] | 1.4–4.3 [4,7] | 0.8 | 0 [6] |

[1] Storage for the district heating system and for chemical energy are not restricted in design for the purpose of maximum exergy efficiency [47]. [2] Losses over time for chemical storages are neglected. [3] Capacity calculated based on [87] corresponding to the photovoltaic rooftop expansion. Photovoltaic rooftop is about 40% of total photovoltaic potential (Table 1) [25]. [4] Range covers the different considered years between 2030 (min value) and 2050 (max value). [5] Typical ratio between capacity and power for commercial and industrial photovoltaic storages is chosen [88]. [6] Due to the short storage period, the losses over time are neglected. [7] Power is increased over time until maximum expansion [37] is reached.

### *Appendix A.2 Additional Information of Scenario Sufficiency*

Tables A10 and A11 show the used data for final energy consumption and the energy consumption of the energy supply system, including the load profiles. The data are based on the WAMplus scenario of the Environment Agency Austria [40] but has been modified to ensure full decarbonisation. The parameter of storages, the efficiencies of the conversion units as well as the specific consumption of land transport are shown in Tables A12–A14.

**Table A10.** Final energy consumption for the scenario *Sufficiency* final energy (calculation based on [40]).

| Type | Energy Consumption 2030 in TWh/a | Energy Consumption 2040 in TWh/a | Energy Consumption 2050 in TWh/a | Used Profile |
|---|---|---|---|---|
| Transport Cars and Trucks | 58.7 | 48.1 | 36.7 | Cars [75,76] [2]; Trucks [77–79] [2] |
| Transport Others | 14.8 | 15.6 | 15.8 | Aviation: Austrian Transport Report 2017 [80]; navigation: assumed as constant between 5 and 22 o'clock on working days and constant between 5 and 15 o'clock on Saturdays; railways: measured values of Austrian Railways [81]; pipelines: assumed as constant |
| Residential Sector | 56.2 | 46.4 | 39.3 | FfE SigLinDe [82], synthetic load profiles [84] [1] |
| Private and Public Services | 28.3 | 22.3 | 18.3 | FfE SigLinDe [82], synthetic load profiles [84] [1] |
| Agriculture | 3.2 | 3.2 | 3.2 | FfE SigLinDe [82], synthetic load profiles [84] [1] |
| Industry | 102.0 | 94.5 | 86.4 | FfE SigLinDe [82], combined industrial load profile [83] [1] |

[1] in some cases without seasonal component. [2] Outside temperature additionally taken into account for heating/cooling demand.

**Table A11.** Consumption of the energy supply system for the scenario *Sufficiency* final energy (based on [40]).

| Type | Energy Consumption 2030 in TWh/a | Energy Consumption 2040 in TWh/a | Energy Consumption 2050 in TWh/a | Used Profile |
|---|---|---|---|---|
| Transformation Losses | 17.1 | 18.5 | 21.5 | According to consumption |
| Transport Losses | 6.7 | 6.9 | 6.9 | Assumed as proportional according to generation and consumption |
| Consumption of Sector Energy | 17.2 | 16.1 | 13.3 | Assumed as constant |
| Non Energy Use | 21.5 | 20.0 | 18.6 | Combined industrial load profile [83] [1] |

[1] Without seasonal component.

**Table A12.** Parameter of the used storages in the scenario *Sufficiency*.

| Type | Capacity in $GWh_{el}$ | Max. Charging Power in $GW_{el}$ | Max. Discharging Power in $GW_{el}$ | Cycle Efficiency | Losses over Time |
|---|---|---|---|---|---|
| Battery Storage | 2.1–11.8 [1,2] | 1.1–5.9 [2,3] | 1.1–5.9 [2,3] | 0.9 | 0 [4] |
| Pumped Storage | 160 [37] | 1.2–3.6 [2,5] | 1.4–4.3 [2,5] | 0.8 | 0 [4] |

[1] Capacity calculated based on [87] corresponding to the photovoltaic rooftop expansion. Photovoltaic rooftop is about 40% of total photovoltaic potential (Table 1) [25]. [2] Range covers the difference considering the years between 2030 (min value) and 2050 (max value). [3] Typical ratio between capacity and power for commercial and industrial photovoltaic storages is chosen [88]. [4] Due to the short storage period, the losses over time are neglected. [5] Power is increased over time until maximum expansion ([37]) is reached.

**Table A13.** Conversion efficiencies of the scenario *Sufficiency.*

| Conversion Unit. | Energy Efficiency |
|---|---|
| Fuels from hydrogen | $\eta = 0.77$ [89–92] |
| Gas fired power plant | $\eta = 0.60$ [93,94] |
| Biomass fired CHP | $\eta_{el} = 0.28$, $\eta_{th} = 0.57$ [37] |
| Electrolysis | $\eta = 0.65–0.70$ [1] [85] |

[1] Range covers the difference considering the years between 2030 (min value) and 2050 (max value).

**Table A14.** Energy consumption of cars and trucks in the scenario *Sufficiency* (calculated values based on [25,47]).

| Type | Internal Combustion Engine Drive in kWh/100 km | Battery Electric Drive in kWh/100 km | Fuel Cell Drive in kWh/100 km |
|---|---|---|---|
| Cars | 68.8 | 21.7 | 36.5 |
| Light-Duty Trucks | 85.5 | 24.1 | 40.6 |
| Medium-Duty Trucks | 192.5 | 85.3 | 125.3 |
| Heavy-Duty Trucks | 337.9 | 169.4 | 248.9 |

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