Abstract: To mitigate global warming, the European Union aims at climate neutrality by 2050. In order to reach this, the transportation sector has to contribute especially, which accounts for about a quarter of the European greenhouse gas emissions. Herein, electricity-based fuels are a promising approach for reducing emissions. However, a large-scale deployment of electricity-based fuels has a significant impact on the power system due to high electricity demand and the requirement to use renewable energy sources in order to be sustainable. At the same time, this fuel production could offer additional flexibility for the power system. This article investigates the opportunities and challenges of electricity-based fuels and flexible electricity-based fuel production for the European power system. In a literature analysis, the pivotal role of electricity-based fuels for climate neutrality is confirmed. To analyze the impact of flexible fuel production, European power market simulations for the year 2035 are conducted. Results indicate that flexibilization leads to an increased integration of electricity based on renewable energy sources as well as reductions in both carbon dioxide emissions and total operational costs of the power system. However, very high flexibility levels also benefit high-emission power plants and may even lead to increased emissions.

Keywords: demand-side management; fuels; minimization methods; power system economics; power system simulation; transportation industry
from renewable energy sources (RES) [6]. In particular, e-fuels are discussed for areas where direct electrification is challenging, e.g., aviation and waterborne transportation [7]. However, there is a controversial debate about whether e-fuels are actually needed for reaching European GHG emission reduction targets [8]. Furthermore, a large-scale utilization of e-fuels consumes large amounts of electricity. This requires an extensive expansion of power plants based on RES, which confronts the power system with major challenges due to increasing volatile feed-in. High penetration of RES and the lack of large-scale flexibility options increasingly lead to situations in which the electricity generation from RES exceeds electricity demand and, therefore, needs to be curtailed. In the course of reducing GHG emissions, curtailment of RES is not desired and should be avoided whenever possible. To avoid curtailment, flexible generators, storages, or consumers are required [9,10]. E-fuel production processes represent one such flexibility option [11]. However, the implementation of flexible e-fuel production processes is tied to technical challenges and costs. Thus, it is important to determine a reasonable level of flexibility from the power system perspective. Therefore, the benefits of flexible e-fuel production for the power system should be analyzed in economic (e.g., costs) and ecological (e.g., GHG emission savings, additional RES integration) terms in order to determine a reasonable amount of flexibility.

Against this background, this article investigates the impact of increasing electricity demand for e-fuel production on the European power system. First, we conduct a meta-analysis regarding the future e-fuel demand with a focus on the German transportation sector. Our meta-analysis confirms the need for the utilization of e-fuels considering GHG emission reduction targets for the transportation sector. Therein, the demand for sustainable e-fuels implies the additional electricity demand, which is of European importance. On this basis, we estimate the additional required expansion of RES for Europe. Second, we apply a mixed-integer nonlinear optimization model for the European power market (ENTSO-E region) to quantify the economic and ecological impacts of an increase in electricity demand due to e-fuel production on the European power system. We model flexible e-fuel plants as Demand Side Management processes. Our model has a high temporal and spatial resolution to adequately capture the dynamics of the European power market. To cope with the resulting model complexity, we apply a multi-stage decomposition approach. Third, we analyze the economic and ecological impacts that result for the European power system from different levels of flexibility of e-fuel production processes in a case study. In particular, we evaluate the impact of the total temporal shiftable demand and the maximum temporal shift of demand.

The organization of this paper is as follows. In Section 2, we provide a brief overview of e-fuel production pathways in terms of flexibility. We then analyze the predicted amounts of e-fuels for the German transportation sector in Section 3. Section 4 presents our methodical approach to analyze the impact of flexible e-fuel production on the European power system. We apply this framework to a European case study in Section 5. Finally, Section 6 concludes this article and derives implications for policy makers.

2. Flexibility of E-Fuel Production Pathways

E-fuels comprise gaseous and liquid fuels that are produced from electricity as main feedstock [12]. E-fuels include hydrogen, synthetic methane, methanol, diesel, gasoline, kerosene, polyoxymethylene dimethyl ethers (OME), dimethyl ether (DME), as well as ammonia. A major advantage of e-fuels results from the fact that there is no technological or chemical difference between these fuels and their fossil counterparts. Thus, e-fuels can be distributed via existing infrastructures (gas network, fuel trucks, and fuel stations) and used in conventional vehicle engines. Figure 1 gives an overview of the major production pathways for e-fuels.
Every production pathway initially requires the generation of electricity. In order to achieve GHG emission reductions through the utilization of e-fuels, the electricity has to be generated by power plants based on RES (electricity used for e-fuel production is assumed to be generated solely from RES). The next production step of e-fuels is water electrolysis to produce hydrogen, as shown by the following equation:

$$2 \text{H}_2\text{O} \rightarrow 2 \text{H}_2 + \text{O}_2$$ (1)

For the process of water electrolysis either alkaline electrolyzers, proton-exchange-membrane electrolyzers (PEM), or solid oxide electrolyzers are used. The technologies differ in terms of input materials and process conditions (pressure, temperature), resulting in diverse operating ranges and efficiency curves. Alkaline electrolyzers are a mature technology and widely used in the industrial sector [12]. However, intermittent operation of conventional alkaline electrolyzers is restricted to a minimum part load of 20% to 40% of the nominal load [12,13]. PEM electrolyzers represent a promising option for flexible operation. Currently, industrial PEM electrolyzers with a nominal load of 100 MW are in the development stage and are expected to achieve a minimum part-load capability of around 5% to 10% (including all peripheral devices). PEM electrolyzers with a nominal load of 4 MW are already operated, and recent tests demonstrate that PEM electrolysis plants can follow realistic wind profiles [14]. Solid oxide electrolyzers are a recent technological development with a low level of technology readiness. Furthermore, the high required operating pressure and temperature result in low flexibility [12].

It is possible to directly use the hydrogen produced by water electrolysis in the transportation sector or in industrial applications. However, the integration of hydrogen in the existing gas infrastructure and storage is limited due to its low volumetric energy density [12]. Therefore, the further processing of hydrogen to high energy density fuels provides enhanced compatibility with existing infrastructure.

Different chemical or biological synthesis processes are known to convert hydrogen to gaseous or liquid fuels such as synthetic methane, methanol, diesel, gasoline or kerosene, OME, DME, as well as ammonia. The hydrocarbons commonly used in the transport sector today are produced with carbon dioxide as additional feedstock, so that these are in focus in the following. The required carbon dioxide can be captured from atmospheric air or exhaust and product gas streams of industrial processes and power plants. Technological pathways that are already commercially used or that are in an advanced development stage include the Sabatier process, Fischer-Tropsch synthesis, methanol synthesis, and synthesis of DME.

Figure 1. E-fuel production pathways.
The Sabatier process is the most technologically advanced hydrogen conversion process using carbon dioxide to produce gaseous synthetic methane [15,16], as shown by the following equation:

\[ 4 \text{H}_2 + \text{CO}_2 \rightarrow \text{CH}_4 + 2 \text{H}_2\text{O} \quad (2) \]

Production plants for synthetic methane are capable of partial load operation of 40% of nominal load [12].

Fischer-Tropsch synthesis is a common process for the production of liquid e-fuels. The Fischer-Tropsch process converts hydrogen and carbon monoxide (syngas) to hydrocarbons of various chain lengths. Different shares of synthetic diesel, gasoline, or kerosene can be produced depending on relevant conditions, i.e., the ratio of hydrogen to carbon monoxide in syngas, temperature, pressure, and catalyst. However, the flexible operation of the Fischer-Tropsch process poses challenges due to complex fluid and thermodynamic reaction behavior [12].

3. Future E-Fuel Demand—A Meta-Analysis for the German Transportation Sector

In this section, a range of studies is analyzed with regard to the predicted e-fuel demand for 2050 and the resulting GHG emission reduction potential in comparison to the year 1990. The future e-fuel demand depends on a variety of factors (e.g., availability of alternative energy carriers, mobility demand). As the future development of these factors is uncertain, the future of e-fuel demand is uncertain.

For our analysis, we refer to studies that model and analyze the German energy system until at least 2050. Furthermore, only studies that quantify the future e-fuel demand and analyze at least one scenario with high GHG emission reductions are considered. The scope is limited to recent studies published since the years 2014. In addition, studies with a methodically sound elaboration and high transparency concerning methodology, input data, and results are preferred. An overview of the considered studies is given in Table 1. The rightmost column lists the scenarios analyzed within the respective studies. Scenario identifiers specify the study as well as the GHG emission reductions realized in the respective scenario, separated by an underscore. A more detailed overview of the studies is provided in Tables A1 and A2 in Appendix A [17].

| Abbreviation | Name of Study | Scenario(s) |
|--------------|--------------|-------------|
| BCG [18]     | Klimapfade für Deutschland | BCG_61, BCG_80, BCG_95 |
| ENV [19]     | Erneuerbare Gase–ein Systemupdate der Energiewende | ENV_100_elec, ENV_100_opt |
| FRO [20]     | Der Wert der Gasinfrastruktur für die Energiewende in Deutschland | FRO_95_elec, FRO_95_elecStorage, FRO_95_elecEFuel |
| ISE [21]     | Was kostet die Energiewende? Wege zur Transformation des deutschen Energiesystems bis 2050 | ISE_85 |
| ISI [22]     | Langfrist- und Klimaszenarien | ISI_54, ISI_80_base, ISI_80_grid, ISI_80_RES, ISI_80_lessRest |
Within most of these studies, road transportation is modeled with a high level of detail, e.g., applying cost minimization approaches. In contrast, the other transportation modes (rail, aviation, waterborne transportation) are mostly modeled based on simplified projections, e.g., of today’s fuel demand into the future.

Figure 2 shows the predicted e-fuel demand for the German transportation sector of the analyzed studies in 2050 sorted by GHG emission reductions. In particular, the demand is differentiated by the type of e-fuel (hydrogen, methane, gaseous (if no separate values for hydrogen and methane are given), and liquid e-fuel). As can be seen in Figure 2, nearly no e-fuel demand is predicted by scenarios that aim at GHG emission reductions below 85%, as e-fuels are too expensive compared to other options (e.g., direct electrification by battery electric vehicles or trolleytrucks (see studies of ISI [22] and ÖKO [24])). However, e-fuels are essential in all scenarios that aim at a reduction of GHG emissions by 85% or more. The predicted e-fuel demand varies between the studies, and e-fuel demand does not strictly increase with increasing GHG emission reductions. These variations are analyzed in the following.

![Predicted e-fuel demand for the German transportation sector, 2050](image)

**Figure 2.** Predicted e-fuel demand for the German transportation sector, 2050 [18–24].

Figure 3 displays the relative share of the energy carriers e-fuel, fossil fuel, biofuel, and electricity (i.e., direct electrification; e.g., battery electric vehicles, trains, trolleytrucks) in the scenarios associated with GHG emission reductions of at least 95%. The share of each energy carrier varies widely. E-fuels have a share of 30% to 95% and electricity has a share of 5% to 37%. In particular, the scenario FRO_95_elecEFuel has the highest share of e-fuels (95%) and the lowest share of electricity (5%). For scenario FRO_95_elecEFuel, it is assumed that 90% of road transportation and 100% of aviation and
waterborne transportation are supplied by e-fuels. In contrast, the share of e-fuels (31%) is the lowest for scenario ÖKO_95, where the share of electricity (37%) is highest. In scenario ÖKO_95, battery electric vehicles and trolleytrucks are used on a large scale, and the full potential of direct electrification (60% of final energy demand in transportation) is achieved.

It should be noted that the scenarios of FRO [20] are associated with a particularly high demand for mobility and thus final energy demand. Contrary to this, the studies of BCG [18], ENV [19], NIT [23], and ÖKO [24] assume engine efficiency improvements as well as other developments, e.g., modal shift and traffic reduction, leading to lower final energy demand. Notably, scenario ÖKO_95 considers substantial changes in the travel behavior of young people. Biofuels are used only in the studies of BCG [18], NIT [23], and ÖKO [24]. In the studies of ENV [19] and FRO [20], it is assumed that biofuels are not available for transportation.

![Figure 3. Share of final energy demand in the German transportation sector, 2050 [18–24].](image)

In all studies, direct electrification of the transportation sector is limited to a threshold, which is caused by the technical challenge to electrify aviation or waterborne transportation. Large GHG emission reductions cannot be achieved without extensive e-fuel usage. This is even more important if biofuels are not available for transportation and if measures for the reduction of the final energy demand (e.g., efficiency improvements, modal shift, traffic reduction) are realized to a lesser extent.

The predicted large-scale utilization of e-fuels will require large amounts of electricity and thus, will significantly affect the power system. At the same time, e-fuel production presents opportunities to deal with challenges in the power system arising from an increasing share of RES. As discussed in Section 2, e-fuel production processes may be operated flexibly by temporarily deviating from the nominal load and in this way, provide flexibility to the power system.

In the scenarios BCG_95, NIT_94.5, and ÖKO_95, flexible e-fuel production is regarded as one option to provide flexibility to the power system besides electric vehicles, Power-to-Heat, and pumped storage power plants. Table 2 gives an overview of the modeling of flexible e-fuel production in the respective scenarios. Herein, data on the size of production capacities which can be operated flexibly by temporarily deviating from the nominal load is given. The studies do not provide data on the maximum deviation from the nominal load. In the scenario BCG_95, flexible e-fuel production is limited to hydrogen production for the industrial sector and gaseous e-fuel production for the energy/transformation sector. The flexibility data given for scenario ÖKO_95 relates to liquid e-fuel production.
production for the transportation sector and hydrogen and methane production for re-energization. The flexible e-fuel production capacities are of the same magnitude for scenarios NIT_94.5 and ÖKO_95; the capacities for the scenario BCG_95 are about ten times smaller. It is also interesting to note that flexible e-fuel production is only modeled in scenarios with GHG emission reductions of at least 94%. This can be explained by the fact that these high emission reductions imply a high integration of RES in the power system and thus, flexibility options gain an important role. For the scenario BCG_95, it is stated that flexible e-fuel production and other flexibility options (namely Power-to-Heat, battery electric vehicles, pumped storage power plants) are sufficient to avoid large non-network related curtailment of RES generation even for the case of more than 90% volatile power generation. The benefit of specific flexibility options is not analyzed.

| Scenario | Flexible E-Fuel Production Capacities [GW el] |
|----------|-----------------------------------------------|
| BCG_95   | 2050: 11 (hydrogen and methane) (Installed capacities relate to the capacities of hydrogen production for the industrial sector and gaseous e-fuel production for the energy/transformation sector) |
| NIT_94.5 | 2050: 140 (hydrogen) |
| ÖKO_95   | 2040: 10 (hydrogen) + 10 (methane) + 23.7 (liquid e-fuel) 2050: 30 (hydrogen) + 50 (methane) + 30.2 (liquid e-fuel) (Installed capacities relate to capacities of liquid e-fuel production for the transportation sector as well as hydrogen and methane production for power generation (re-energization)) |

As can be seen, the discussed studies regard flexible e-fuel production to some extent. However, a detailed analysis of the potential of this flexibility and its benefits is missing. Analyses of possible economic and ecological benefits of flexible e-fuel production have especially not received much attention within the considered studies. Thus, an analysis of the impact of additional electricity demand for e-fuel production on the power system based on a power market simulation is presented in the following, specifically aiming to determine the economic and ecological benefits of specific levels of flexibility for e-fuel production.

### 4. Methodical Approach

In the following section, the methodical approach for analyzing the impact and benefits of flexible e-fuel production on for the power system is outlined. The approach is applied to a case study presented in Section 5. The case study focuses on a future scenario that assumes a large-scale production and utilization of e-fuels. Due to the European wide interdependencies of the power network and the power markets, an analysis of the impact and the economic and ecological benefits of e-fuel production on for the power system requires a European scope. Thus, the European-wide electricity and RES demand due to e-fuels have to be determined first. The methodical approach is divided into five steps, which are also depicted in Figure 4:

1. A reasonable assumption is made on the electricity demand resulting from a European-wide e-fuel production rollout in addition to the forecasted electricity demand in the future without the consideration of e-fuels. Section 4.1 gives a more detailed explanation.
2. E-fuels can only reduce the GHG emissions of the transportation sector if the electricity required for e-fuel production is generated from RES. Therefore, the additional electricity demand for e-fuel production has to be met by an expansion of RES capacities. Thus, the additional expansion of RES due to e-fuels results in the expansion that is needed in addition to the forecasted expansion of RES capacities without the consideration of e-fuels. Section 4.2 gives a more detailed explanation.
3. The analysis is based on a European power market simulation. The details of the analysis are described in Section 4.3.

4. In order to analyze the economic and ecological benefits of future flexible e-fuel production, the flexibility of e-fuel production has to be considered within the power market simulation. The modeling of flexibility is explained in detail in Section 4.4.

5. Finally, the set of simulations for analyzing the sensitivity of the results with regard to different flexibility levels is described in Section 4.5.

Figure 4. Methodical approach for deriving benefits of flexible e-fuel production. (a) Deriving additional electricity demand for producing e-fuels; (b) Deriving additional RES expansion for generating additional electricity demand; (c) Deriving benefits of flexible e-fuel production by applying multiple European power market simulations.

4.1. Additional Electricity Demand for E-Fuel Production

The additional electricity demand for e-fuel production in a future scenario is determined in a three-step procedure, which is depicted in Figure 4a. The future European e-fuel demand is calculated on the basis of the aggregated transportation sector model SULTAN [25,26]. This model allows estimating the impact of a variety of input parameters such as transportation demand, vehicle stock,
and used types of vehicle powertrains on a range of outputs such as overall fuel and sustainable fuel (e.g., e-fuel) demand for the European transportation sector until the year 2050. To derive country-specific e-fuel demands, the future e-fuel demand is distributed among the ENTSO-E member states considering today’s country-specific final energy demands in the transportation sector.

Finally, the additional electricity demand for e-fuel production in a future scenario is determined for each country considering efficiency losses during the production and distribution of e-fuels.

4.2. Additional RES Expansion

To ensure sustainable fuel production, it is important to cover the additional electricity demand exclusively by RES generation. Thus, an additional expansion of RES generation units is necessary. The approach for estimating the additional RES expansion—in addition to the already forecasted expansion of RES capacities until a future point in time without e-fuels—is illustrated in Figure 4b. This expansion is based on annual generation volumes of the most relevant RES technologies, i.e., photovoltaics, wind onshore, and wind offshore. Herein, the generation volumes are proportionally expanded concerning the already forecasted share for each country until coverage of the additional electricity demand for e-fuel production is reached. Thus, we assume that the composition of RES generation remains the same. RES expansion is modeled individually for each country as European countries pursue their own national expansion policies. The resulting generation volumes are translated to capacities using country- and technology-specific full load hours. As a result, the capacity expansion of power plants based on RES is obtained for each country and technology.

4.3. Power Market Simulation

To derive implications of flexible e-fuel production on the power system, appropriate simulations on the power system are necessary to conduct. There are many types of power system simulations existing, e.g., long term system planning [27] and agent based market simulations [28]. Possible investigations are economic evaluations of power plants or power storages, but also macroeconomic and overall economic investigations regarding welfare or even carbon dioxide emissions. In addition, power market simulations can estimate the medium to the long-term development of electricity prices [27,28]. However, under the premise of deriving e-fuel production and RES expansion in advance and taking a macroeconomic perspective, we use an existing European power market simulation, which has been applied for research multiple times and whose methodical approach is published in [29–31].

Power market simulations in principle simulate the accepted bids in the markets for buying and selling scheduled energy and control reserve power. Scheduled energy is the supplied energy, sold by power plant operators to e.g., power sales companies with households as customers. The energy provided by those power plants is reported to the Transmission System Operator (TSO). Control reserve power is bought by TSOs in order to be able to balance short-term imbalances between scheduled supply and demand. As is usual in power market simulations [32], the applied power market simulation takes the provision of control reserve energy into account so that the provided control reserve power per bidding zone is exogenously predefined.

In general, the estimated accepted bids reflect power plant commitments, more precisely thermal and hydraulic power plant commitments. Thus, it is necessary to simulate those commitments, which are subject to the power plant operators’ aim to maximize their contribution margin. Assuming perfect information and efficient markets, the economic total surplus or economic welfare, i.e., consumer surplus and producer surplus, is maximized. Since the simulation considers a limited time frame, the consumer surplus is constant and thus can be externalized. As a result, the producer surplus can be maximized by minimizing production costs while producing the right quantity to meet the demand (cf. Figure 5) [33]. Hence, the maximization of the power plant operators’ contribution margin can be achieved by minimizing the power generation costs.
Therefore, the optimization goal of the market simulation is the minimization of the economic costs of power generation for a specified geographical, temporal, and systemic scope. Important constraints include the balance of supply and demand at any point in time as well as the provision of control reserve power. Furthermore, the generation units are subject to technical restrictions.

The system area (Figure 6) is defined by the geographical scope and is subdivided into individual subsystems, so-called bidding zones. Within those bidding zones, it is assumed that power transmission is possible without restraints from the underlying transmission network. Each bidding zone is furthermore characterized by its own consumer and generation structure. The power generation units can be subdivided into three different groups: thermal, hydraulic, and RES based power. Additional components comprise demand-side management (DSM) processes, which are able to shift demand to other points in time. Thereby, DSM represents flexibility on the demand side. Furthermore, a sufficient amount of control reserve power has to be provided to compensate uncertainties for every bidding zone at any point in time. The bidding zones are interconnected, i.e., a cross border power exchange is possible with limited transfer capacities, which are derived from physical line capacities across bidding zones.

![Figure 6. System area, cf. [29].](image-url)

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All technical restrictions of the thermal and hydro-electric power plants and the DSM, as well as the system boundary conditions regarding demand and reserve coverage, are taken into account for the minimization of the production costs. An in-depth discussion of the mathematical formulation of the power market simulation model can be found in [31].

There are various technical restrictions, e.g., concerning the minimum uptime and downtime of power plants. This implies that a shutdown of an operating power plant is only possible after a minimum uptime. Analogously, a start-up is only possible after a minimum downtime has passed. The start-up decision of a power plant is an important variable that leads to increased complexity since there is a quadratic dependence between the operating costs and heat consumption. The temporal scope can be chosen between a period of one day and one year, while the temporal resolution is one hour.

Due to the technical restrictions of thermal and hydro-electric power plants, the long-term temporal scope, detailed temporal resolution, and large geographical scope, the problem results in a complex non-linear mixed-integer program. To efficiently solve the problem, a decomposition approach is inevitable. Benders’ decomposition [34], Dantzig-Wolfe reformulation [35], and Lagrangian decomposition [36] are mainly used in literature, but many others exist [37,38]. Due to the large scale optimization problem for the complete European system, the simulation used within this article applies a multi-stage decomposition procedure is applied (Figure 7) [11,31].

An initial solution is obtained by solving a linear variant of the problem, where start-up decisions of the thermal power plants are neglected. In a second stage, a Lagrangian relaxation approach is applied to decompose the problem by bidding zone. Within each bidding zone, the problem is further decomposed into subproblems for the thermal and hydraulic power plants as well as the DSM, which are solved via dynamic programming, linear programming, and network flow problems respectively. The final stage is similar to the first one, but start-up decisions are taken into account in order to guarantee compliance with the technical restrictions. The solution determines the final dispatch, control reserve power provision, final cross-border power exchanges, and overall costs of the considered system consisting of power generation in every bidding zone, power exchange between bidding zones, and use of DSM [29]. A more detailed mathematical view with the objective function, most important constraints, and a description of the sets, variables, and parameters can be found in Appendix B.
4.4. Modeling Flexible E-Fuel Production Plants

The flexibility of e-fuel production has to be modeled to assess its economic and ecological benefits for the power system. For this purpose, the e-fuel production plants are not modeled explicitly, but the common approach of modeling DSM within the electricity system is used (cf. Figure 4c and Section 4.3). Herein, flexibility is characterized by two dimensions: total shiftable demand and maximum temporal demand shift. The total shiftable demand is considered as the degree of flexibilization of the additional electricity demand, i.e., flexible share of the additional electricity demand for assumed e-fuel production. The maximum temporal demand shift specifies the maximum possible duration of shifting an e-fuel production process—and thus the electricity demand—at a specific time to a previous or later point in time. Furthermore, costs for the use of DSM (i.e., costs for using flexibility) are set to zero. Thus, the determined economic benefit for the power system can serve as maximum costs for flexibilization of e-fuel production.

4.5. Application within the Power Market Simulation

The European power market simulation required to assess the economic and ecological benefits of flexibility is described in Section 4.3. The additional electricity demand for e-fuel production (Section 4.1) and the corresponding expansion of power plants based on RES (Section 4.2) serve as input data for the power market simulation.

To derive the benefits of flexible e-fuel production for the power system, many different levels of flexibility are evaluated using the power market simulation. Each level of flexibility considers a different value for the total shiftable demand and maximum temporal demand shift. The resulting set of simulations consists of different degrees of flexibilization for e-fuel production, ranging from 0 to 100% (Sampling points: 0%, 25%, 50%, 75%, 100%) of the additional electricity demand for e-fuel production, while each degree considers a range of maximum temporal shifts from one to 48 h (Sampling points: 1 h, 2 h, 4 h, 6 h, 12 h, 24 h, 48 h) (cf. Figure 4c). As a result, a set of 35 different levels of flexibilization are investigated within the simulation representing different combinations for the ranges of total shiftable demand and maximum temporal demand shift.

5. Results

In the future, high penetration of RES and the lack of large-scale flexibility options can frequently lead to situations in which the electricity generation of RES exceeds electricity demand and, therefore, needs to be curtailed. However, in the course of reducing GHG emissions, curtailment of emission-free electricity generation from RES is not desired and should be avoided whenever possible. Thus, the flexibility of e-fuel production can be utilized to provide needed flexibility for the power system. This section analyzes the benefits of flexible e-fuel production for the European power system to answer the research questions (cf. Section 1) for a future scenario in the year 2035.

Section 5.1 describes the data basis for the power market simulation focusing on the year 2035, i.e., additional electricity demand for e-fuel production and resulting additional expansion of RES. Section 5.2 analyzes the results of this study and discusses the economic and ecological benefits of flexible e-fuel production by examining the above-presented set of 35 power market simulations (cf. Section 4.5). Herein, the benefits are assessed in terms of the additional integration of RES generation into the power system, the reduction of carbon dioxide emissions of the power system, and annual total power system costs.

5.1. Input Data and Scope

The geographical scope of the study covers the entire ENTSO-E region without Cyprus and Iceland (cf. Figure 8a). The year 2035 is chosen for temporal scope since it provides the long-term perspective that is necessary for an integration of e-fuels into the transportation sector.
The European e-fuel demand is calculated on the basis of the aggregated transportation sector model SULTAN, as explained in Section 4.1 [25,26]. The future European e-fuel demand is derived for road transportation as well as waterborne transportation, as these account for the largest share of final energy demand in the transportation sector. Input parameters for SULTAN are defined according to the scenario defined in [39]. This scenario represents a cost-effective pathway to reach GHG emission reductions of 60% in the transportation sector by 2050, which corresponds to the overall cross-sectoral target of GHG emission reductions of 80% to 95% by 2050 due to the high challenges and costs of reducing GHG emissions in the transportation sector in comparison to the other sectors. It is assumed that the sustainable fuel demand for road and waterborne transportation (except hydrogen) calculated by SULTAN is supplied in equal parts by e-fuels and biofuels. The share of hydrogen supplied by electrolysis is defined according to [40]. Data for the final energy demand for road and inland waterborne transportation per ENTSO-E member state are primarily adopted from [41]. Country-specific e-fuel demands for maritime waterborne transportation are derived considering transshipment volumes at ports, which are mainly based on [42,43].

Using this data, an e-fuel demand of 423 TWhth/a is determined for the entire ENTSO–E region in 2035. This resembles a share of e-fuels of around 11% of the final energy demand for road and waterborne transportation. Providing a more detailed breakdown, e-fuels are mainly used for road transportation (share of 84% total e-fuel demand) despite the market penetration of electric vehicles. The share of e-fuels used within inland and maritime waterborne transportation is considerably less (2% and 14% respectively).

The regional distribution results in an assignment of 58% of the e-fuel demand to France, Germany, Italy, Spain, and the United Kingdom due to their high overall transportation demand. For example, an e-fuel demand of 54 TWhth/a is predicted for Germany.

![Geographical scope](image)

**Figure 8.** (a) Geographical scope; (b) share of energy carriers and share of transportation sectors for 2035.

Based on the e-fuel demand, the electricity demand for the production of e-fuels is determined considering the efficiency values for the production processes of hydrogen and further processes, e.g., synthesis (66% and 56% [44]).

Basic input data for the European power system in 2035, i.e., basic electricity demand, the basic installed capacity of RES, and power plant characteristics are extracted from [45] (mean values of Vision 2 and Vision 3) and [46], as shown in Figure 9 (lower diagram). These reflect the characteristics...
of the power system without the production of e-fuels, i.e., officially assumed electricity demand for 2035 for all sectors.

As explained in Section 4, additional electricity demand and additional expansion of RES need to be calculated to account for a European-wide e-fuel production rollout. Figure 9 shows the basic electricity demand and basic expansion of RES without the rollout (Figure 9 lower diagram) as well as the additional electricity demand and additional expansion of RES for the assumed e-fuel production per country (Figure 9 upper diagram). This additional electricity demand only results from producing e-fuels in the derived amount and considering the mentioned efficiency factors.

![Figure 9. Basic and additional electricity demand and expansion of RES (exemplary countries, 2035).](image)

As can be seen, Austria has a low additional electricity demand of 15 TWh/a due to low transportation demand. In particular, there is no demand for maritime waterborne transportation as Austria is landlocked. Germany and France are each characterized by an additional electricity demand of nearly 100 TWh/a. As stated before, the resulting RES expansion is based on the additional electricity demand. Thus, high RES expansions are determined for France and Germany to cover the additional annual electricity demand. An overall expansion by 50 GW is needed for Germany, while additional capacities in France amount to 43 GW. The difference results mainly from the lower full load hours of photovoltaics in Germany so that higher capacities are needed.

Additional annual electricity demand of 750 TWh/a across the ENTSO-E region leads to a total RES expansion of 1200 GW, which represents an additional 69% in comparison to the basic RES expansion until 2035 without the rollout of e-fuels.
In summary, the derived input data reflects the forecasted electricity demand and RES generation based on [45,46] for 2035, plus additional electricity demand and additional RES expansion due to e-fuel production. Due to the high expansion of RES, the electricity system under investigation is dominated by RES.

5.2. Simulation Results

The power market simulation (Section 4.3) is applied for different degrees of flexibilization and temporal shifts based on the input data described in the previous section. Herein, costs for the use of DSM (i.e., costs for using flexibility) are set to zero to determine a maximum price for flexibilization in the process design of e-fuel production.

As stated before, the curtailment of RES generation is used in situations in which electricity generation exceeds the electricity demand. Without any flexibility from e-fuel production, annual curtailment volumes of RES generation amount to 16.5 TWh\(_{\text{el}}\). This also means that the required electricity demand for e-fuel production cannot be supplied completely from the RES capacities that are specifically expanded for that purpose.

Furthermore, Figure 10 shows the impact of different flexibility levels for e-fuel production on the additional integration of RES generation volumes, i.e., the reduction of RES generation curtailment.

![Figure 10. Additional integration of RES generation.](image)

The additional RES integration generally increases with higher values for both the degree of flexibilization, i.e., the flexible share of the electricity demand for e-fuel production, as well as for the maximum temporal shift. However, the marginal additional RES integration decreases with higher flexibility levels. Focusing on the degree of flexibilization at a constant maximum temporal shift of one hour, a flexibility degree of 5% allows integrating additional RES of 0.7 TWh\(_{\text{el}}\)/a. A complete flexibilization of the electricity demand for e-fuel production results in an additional RES integration of 7.7 TWh\(_{\text{el}}\)/a. This is a significant share compared to the curtailment of 16.5 TWh\(_{\text{el}}\)/a without any flexibility. The marginal RES integration strongly decreases if the maximum temporal shift exceeds two hours. Overall, the flexibility of e-fuel production leads to a noticeable integration of RES generation, but it is characterized by a diminishing marginal additional RES integration regarding both flexibility dimensions.

Furthermore, interesting insights are obtained when the impact of e-fuel production on carbon dioxide emissions of the European power system is analyzed (cf. Figure 11).
On the one hand, emissions decrease for maximum temporal shifts of up to two hours as expected, resulting in emission reductions in the range of 0.1 to 1.2% (for 5 and 100% degrees of flexibilization respectively) compared to a totally inflexible e-fuel production system. On the other hand, longer durations of maximum shifts result in higher emissions, which even exceed the emissions of a totally inflexible e-fuel production system. This is due to the fact that flexibility has several impacts depending on the level of flexibility and the different types of power plants that benefit from the flexibility:

- As long as the generation of RES needs to be curtailed, higher flexibility leads to higher integration of RES into the power system as explained and seen in Figure 10.
- Once the majority of RES generation is integrated, other power plants than RES will benefit from the increased demand side flexibility due to an increased level of flexibility of e-fuel production plants. This is reached at a maximum temporal shift of two hours at which inert thermal power plants that are characterized by low costs but high emissions (e.g., coal power plants) reach higher operating levels.
- Within a power system that aims at minimizing operational costs of power plants and under the premise of being able to fully integrate RES generation, increasing flexibility leads to higher emissions compared to the case of inflexible e-fuel production.

Finally, the evaluation of the total operational power system costs combines all relevant effects, (cf. Figure 12a). Marginal annual operational system costs also decrease with an increasing degree of flexibilization, particularly regarding maximum temporal shifts. Here, annual costs decrease by up to 8% to 52 billion € in case of 100% flexible e-fuel production and a maximum shift of one hour. Considering that most of today’s fuel production plants are completely inflexible, Figure 12b depicts the average savings of annual operational power system costs per shifted energy unit for maximum shifts of one hour. Noticeable is the decreasing average savings with higher degrees of flexibilization as well as the highest savings of 150 €/MWh\text{el}.
The results of this section suggest that flexibility of e-fuel production has a substantial impact and provides potential benefits for the European power system. Almost complete integration of RES generation can be achieved even with low flexibility levels. In terms of the impact on carbon dioxide emissions, it can even be observed that “too high” flexibility levels lead to increased total emissions. This is mainly due to higher operating levels of high-emission baseload power plants as soon as most of RES generation is integrated. These findings lead to the conclusion that a certain flexibility level of e-fuel production is desirable. This is substantiated by high average cost savings in the electricity system of 150 €/MWh$_{el}$ at low flexibility levels. These savings can serve as an input parameter for the future process design of flexible e-fuel production when comparing these savings with the costs of flexibilization of e-fuel production processes.

6. Conclusions

A meta-analysis of studies analyzing the German transportation sector showed that e-fuels are essential if ambitious GHG emission reduction targets of 85% and above are aimed at compared to 1990 levels. For scenarios assuming GHG emission reductions of at least 95%, e-fuels have a share of 30% to 95% on final energy demand in the transportation sector (while direct electrification achieves a share of 5% to 37%). For GHG emission reductions of less than 85%, e-fuels are too expensive compared to other mitigation options. The analyzed studies assume certain benefits of a flexible e-fuel production on the power system. However, a detailed, quantitative analysis based on a power system simulation is missing so far.

To provide such a quantitative assessment of the impact on the power system, a European wide study was conducted. Herein, power market simulations for the year 2035 were conducted, assuming the large scale deployment of e-fuels in order to reach GHG emission reductions of 80% to 95% by 2050. Additional electricity demand for e-fuel production of 750 TWh$_{el}$/a and expansion of RES generation capacities by 69% to 1200 GW for Europe were derived. Different levels of flexible e-fuel production were evaluated, which show that higher flexibility levels lead to increased integration of RES generation, i.e., less curtailment. A complete flexibilization of the electricity demand for e-fuel production and a maximum temporal shift of one hour would result in an additional integration of 7.7 TWh$_{el}$/a. Further, higher flexibility levels lead to reduced carbon dioxide emissions up to a temporal shift of two hours, where a maximum reduction of 1.2% is obtained. Above this threshold, emissions increase again due to better conditions for high-emission power plants. The investigation of operational power system costs combines all effects and show decreasing costs with increasing flexibility levels while being characterized by a diminishing marginal benefit of flexibility. The maximum average cost reduction...
per shifted unit of energy is 150 €/MWh\textsubscript{el} and may serve as an input parameter for the future process design of flexible e-fuel production.

In conclusion, our policy recommendations are as follows. First, our meta-analysis shows that the future role of e-fuels is uncertain but promising. Therefore, by creating a stable policy framework with respect to the future technology mix in transportation, policy makers could incentivize investments into e-fuel production. In designing this framework, policy makers should take into account the merit of flexible e-fuel production that enables the maximum average cost reduction of 150 €/MWh\textsubscript{el}. Second, we note that beyond a certain level of flexibility, emissions increase due to better conditions for high-emission power plants, despite high RES integration. Therefore, the availability of high flexibility e-fuel production technology does not guarantee a reduction of carbon dioxide emissions. To ensure a sustainable rollout of e-fuels, careful guidance from policy makers is needed, e.g., through incentives for low-emission power plants. Third, to accommodate the increased demand for renewable energy associated with a European wide e-fuel rollout, we recommend further fixed feed-in payments or subsidies for investments into RES power plants. Finally, we recommend promoting the identified opportunities by fostering research on the corresponding technology, e.g., PEM electrolysis, such that technological maturity is achieved.

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### Appendix A

| Abbreviation | Name of Study | Author(s) | Contracting Authority | Publication Year | Reference |
|--------------|--------------|-----------|-----------------------|------------------|-----------|
| BCG          | Klimapfade für Deutschland | The Boston Consulting Group (BCG), Prognos AG | Bundesverband der Deutschen Industrie (BDI) | 2018 | [18] |
| ENV          | Erneuerbare Gase–ein Systemupdate der Energiewende | enervis energy advisors GmbH (enervis) | Initiative Erdgasspeicher (INES), Bundesverband Windenergie (BWE) | 2017 | [19] |
| FRO          | Der Wert der Gasinfrastruktur für die Energiewende in Deutschland | Frontier Economics, Institut für Elektrische Anlagen und Energiewirtschaft (IAEW) der RWTH Aachen University, 4Management, EMCEL | Vereinigung der Fernleitungsnetzbetreiber (FNBGas e.V.) | 2017 | [20] |
| ISE          | Was kostet die Energiewende? Wege zur Transformation des deutschen Energiesystems bis 2050 | Fraunhofer-Institut für Solare Energiesysteme (Fraunhofer ISE) | – | 2015 | [21] |
| ISI          | Langfrist- und Klimaszenarien (ongoing project) | Fraunhofer-Institut für System- und Innovationsforschung (Fraunhofer ISI), Consentec GmbH, Institut für Energie- und Umweltforschung Heidelberg GmbH (ifeu) | Bundesministerium für Wirtschaft und Energie (BMWi) | 2018 | [22] |
| NIT          | Die Energiewende nach COP 21–Aktuelle Szenarien der deutschen Energieversorgung | Joachim Nitsch | Bundesverband Erneuerbare Energien | 2016 | [23] |
| ÖKO          | Klimaschutzszenario 2050. 2. Endbericht | Öko-Institut, Fraunhofer ISI | Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit (BMU) | 2015 | [24] |
Table A2. Detailed overview of analyzed studies.

| Abbreviation | Objective | Applied Model(s) | Scenario Description |
|--------------|-----------|------------------|----------------------|
| BCG          | Analysis of economically efficient ways to achieve German greenhouse gas (GHG) emission reduction targets until the year 2050. | Hybrid model consisting of: (1) macro-economic top-down model VIEW of Prognos AG which displays 42 countries and (2) bottom up models for each sector (private households, industrial sector, trade and services, transportation, business, power market, non-energetic consumption) to determine the sectoral final energy demand. VIEW model and sectoral models are linked by input/output models. | BCG_61: reference scenario; projection of current measures and conditions. BCG_80: GHG emission reduction target of 80% until 2050; assumes that only single countries pursue climate targets. BCG_95: GHG emission reduction target of 95% until 2050; assumes global climate protection, international coordination and increased willingness to pay for GHG emission reductions. |
| ENV          | Analysis of an economically efficient transformation to a GHG-neutral German energy system in the year 2050; identification of areas, in which renewable gases (biogas and gaseous e-fuels) are technically required or economically advantageous. | Enervis models for heating sector, transportation, and power market. | ENV_100_elec: assumes far-reaching electrification of all end user segments until the year 2050. ENV_100_opt: decision for energy carriers and technologies is a model result. |
| FRO          | Analysis of the cost effects of a further usage of the existing gas infrastructure for the transportation of gaseous e-fuels. | Models for the power market as well as the power and gas grid. | FRO_95_elec: assumes predominantly electrification of end user segments, no deployment of gaseous e-fuels and energy transportation mainly by the power grid. FRO_95_elecStorage: similar to FRO_95_elec, but gaseous e-fuels are used for electricity storage and re-energization. FRO_95_elecEFuel: assumes that end use segments are partly based on gaseous e-fuels; energy transportation by both the power and the gas grid. |
| ISE          | Analysis of a cost-efficient transformation of the German energy system until the year 2050, while considering all energy carriers and consumption sectors for achieving the climate targets. | Simulation and optimization model REMod-D-Trans (evolution of the model REMod-D). | ISE_85: assumes an ambitious rate of building renovation, an accelerated phase-out of coal energy until the year 2040 and a mix of powertrain technologies for transportation (direct electric, fuel cell, internal combustion engine). |
| Abbreviation | Objective | Applied Model(s) | Scenario Description |
|--------------|-----------|-----------------|---------------------|
| ISI          | Analysis of a cost-optimal German energy system until the year 2050. | Several models (which are iteratively applied): (1) bottom up models for determining hourly demands in the sectors power, heat, and transportation, (2) modeling of load profiles and load management, (3) models for the estimation of potentials of RES, (4) optimization of the extension of conventional power plants, RES plants, power stores, and capacities for the transmission grid, (5) power plant operation, and (6) load flow and network security models for transmission and distribution grid. | ISI_54: reference scenario, assumes phase-out of the energy revolution. ISI_80_base: base scenario; other scenarios are varied based on this scenario. ISI_80_grid: assumes less expansion of the transmission grid compared to the base scenario. ISI_80_RES: assumes geographically more uniform distribution of RES power plants (according to the regional RES potential). ISI_80_lessRest: less restrictions compared to the base scenario (e.g., regarding the expansion of RES power plants). Note: Data of further scenarios not published until December 2019. |
| NIT          | Analysis of possible pathways of the German energy system until the year 2050 considering the climate targets. | Not specified. | NIT_58: no GHG emission reduction targets; projection until the year 2050 considering current energy political measures and plans. NIT_94.5: assumes GHG emission reduction targets until the year 2050. NIT_95.3: assumes the achievement of the 2 °C target, which requires almost complete decarbonization until the year 2040. |
| ÖKO          | Analysis of a projection of the current climate policy on the German energy system and its emissions; analysis of required measures to achieve GHG emission reductions of 80 and 95% respectively until the year 2050. | Combination of several models to cover all sectors, e.g.: building sector: ERNSTL/EE-Lab/INVERT, demand modeling: FORECAST, power system: PowerAce/ELIAS/PowerFlex. | ÖKO_54: projection of measures, which have been implemented until October 2012. ÖKO_80: assumes that the targets of the „Energiekonzept“ regarding GHG emission reductions (80%), deployment of RES and energy efficiency are achieved. ÖKO_95: assumes an ambitious GHG emission reduction target of 95% until the year 2050. |
Appendix B. Mathematical Formulation of the Optimization Problem Described in Section 4.3

### Table A3. Sets.

| Symbol       | Description                                                                 |
|--------------|-----------------------------------------------------------------------------|
| $I_{\ell}$   | Set of bidding zones with approach $g \in G$ (zonal or nodal)               |
| $B_{i}^{hy}$ | Hydro-electric power plants in bidding zone $i \in I_{\ell}$               |
| $B_{i}^{th}$ | Thermal power plants in bidding zone $i \in I_{\ell}$                      |
| $B_{i} = B_{i}^{hy} \cup B_{i}^{th}$ | Power plants in bidding zone $i \in I_{\ell}$ |
| $B_{\ell}^{hy} \cup B_{\ell}^{th}$ | Hydro-electric power plants |
| $B_{\ell}^{th}$ | Thermal power plants |
| $B\ell = B_{I}^{hy}$ | All power plants |
| $T$          | Time intervals                                                             |

### Table A4. Technical Parameters.

| Symbol       | Description                                                                 |
|--------------|-----------------------------------------------------------------------------|
| $A_{b}$      | Production costs at minimum power of power plant $b \in B$                  |
| $L_{b}$      | Specific costs of power plant $b \in B$                                     |
| $k_{b}^{alert,\text{const}}$ | Constant startup costs of power plant $b \in B |
| $k_{b}^{n}(t)$ | Additional startup costs dependent on downtime intervals $n \in N$ in time |
| $k_{b}^{exchange}_{i \to j}(t)$ | Specific costs for power exchange between bidding zone $i \in I_{\ell}$ and $j \in I_{\ell}$ in time interval $t \in T$ |
| $NA_{b}$     | Amount of intervals in linear startup cost curve of power plant $b \in B$   |
| $p_{b}^{\text{max}}(t)$ | Maximum technical possible power of power plant $b \in B$ |
| $p_{b}^{\text{min}}(t)$ | Minimum technical possible power of power plant $b \in B$ |
| $p_{l}^{\text{RL, x}}(t)$ | Exogenous preset necessary positive (+) respectively negative (-) reserve of control power in bidding zone $i \in I_{\ell}$ in time interval $t \in T$ |
| $p_{l}^{\text{exchange, NTC}}(t)$ | Maximum power exchange from bidding zone $i \in I_{\ell}$ to bidding zone $j \in I_{\ell}$ in time interval $t \in T$ according to NTC procedure |
| $\text{ResLoad}_{i}(t)$ | Residual load to be covered (Load minus feed-in from RES) in bidding zone $i \in I_{\ell}$ in time interval $t \in T$ |
| $T_{b}^{\text{run,min}}$ | Minimum runtime of power plant $b \in B$ |
| $T_{b}^{\text{down,max}}$ | Minimum downtime of power plant $b \in B$ |
| $A_{b}$      | Production costs at minimum power of power plant $b \in B$                  |
| $L_{b}$      | Specific costs of power plant $b \in B$                                     |
| $k_{b}^{alert,\text{const}}$ | Constant startup costs of power plant $b \in B |
| $k_{b}^{n}(t)$ | Additional startup costs dependent on downtime intervals $n \in N$ in time |
| $k_{b}^{exchange}_{i \to j}(t)$ | Specific costs for power exchange between bidding zone $i \in I_{\ell}$ and $j \in I_{\ell}$ in time interval $t \in T$ |
| $NA_{b}$     | Amount of intervals in linear startup cost curve of power plant $b \in B$   |
| $p_{b}^{\text{max}}(t)$ | Maximum technical possible power of power plant $b \in B$ |
| $p_{b}^{\text{min}}(t)$ | Minimum technical possible power of power plant $b \in B$ |
| $p_{l}^{\text{RL, x}}(t)$ | Exogenous preset necessary positive (+) respectively negative (-) reserve of control power in bidding zone $i \in I_{\ell}$ in time interval $t \in T$ |
| $p_{l}^{\text{exchange, NTC}}(t)$ | Maximum power exchange from bidding zone $i \in I_{\ell}$ to bidding zone $j \in I_{\ell}$ in time interval $t \in T$ according to NTC procedure |
| $\text{ResLoad}_{i}(t)$ | Residual load to be covered (Load minus feed-in from RES) in bidding zone $i \in I_{\ell}$ in time interval $t \in T$ |
| $T_{b}^{\text{run,min}}$ | Minimum runtime of power plant $b \in B$ |
| $T_{b}^{\text{down,max}}$ | Minimum downtime of power plant $b \in B$ |
Table A5. Variables.

| Variable                  | Description                                                                 |
|---------------------------|-----------------------------------------------------------------------------|
| $e_b(t) \in \{0, 1\}$    | Switch-on decision of power plant $b$ in time interval $t$                  |
| $P_b(t) \in \mathbb{R}$  | Power of power plant $b$ in time interval $t$ ($\geq 0$ for $b \in B^h$)  |
| $P_{RL, \pm}^b(t) \in \mathbb{R}$ | Reserved negative/positive control power of power plant $b$ in time interval $t$ |
| $P_{exchange}^{i \rightarrow j}(t) \in \mathbb{R}$ | Power exchange from bidding zone $i$ to bidding zone $j$ in time interval $t$ |
| $E_{X_i}(t) \in \mathbb{R}$ | Net export from bidding zone $j$ in time interval $t$                     |
| $K_{startup}^b(t) \in \mathbb{R}_+$ | Startup costs of power plant $b$ in time interval $t$               |
| $K_{stat}^b(t) \in \mathbb{R}_+$ | Stationary costs of power generation of power plant $b$ in time interval $t$ |

Objective Function

$$\min \sum_{t \in T} \left( \sum_{i \in I_g} \left( \sum_{b \in B_i} K_{stat}^b(t) + K_{startup}^b(t) + \sum_{j \in I_g \setminus \{i\}} K_{exchange}^{i \rightarrow j}(t) P_{exchange}^{i \rightarrow j}(t) \right) \right)$$

Objective Function: Thermal production costs

$$K_{stat}^b(t) = A_b e_b(t) + L_b P_b(t)$$

With $L_b$ fixed for every power plant.

Objective Function: Thermal startup costs

$$-K_{startup}^b(t) + K^b_{startup}(t) \left( e_b(t) - \sum_{\tau=1}^n e_b(t-\tau) \right) \leq -K^b_{startup, const}(t)$$

$\forall t \in T, b \in B_i^h, i \in I_g; n = 1, \ldots, NA_b$

Objective Function: Hydro-electric production and startup costs

$$K_{stat}^b(t) = 0 \quad \forall b \in B_i^{hy}$$

$$K_{startup}^b(t) = 0 \quad \forall b \in B_i^{hy}$$

System Constraints

System Constraints: Load Coverage

$$\sum_{b \in B_i^h \cup B_i^{hy}} P_b(t) + \sum_{j \in I_g \setminus \{i\}} \left( P_{exchange}^{i \rightarrow j}(t) - P_{exchange}^{j \rightarrow i}(t) \right) = ResLoad_i(t) \quad \forall t \in T, i \in I_g$$

System Constraints: Reserve of control power

$$\sum_{b \in B_i} P_{RL, +}^b(t) \geq P_{RL, +}^i(t) \quad \forall t \in T, i \in I_g$$

$$\sum_{b \in B_i} P_{RL, -}^b(t) \geq P_{RL, -}^i(t) \quad \forall t \in T, i \in I_g$$

System Constraints: Exchange between bidding zones

$$P_{exchange}^{i \rightarrow j}(t) \leq P_{exchange, NTC}^{i \rightarrow j} \quad \forall t \in T, i \in I_g, j \in I_g \setminus \{i\}$$
System Constraints: Net export

\[ EX_i(t) = \sum_{j \in I^+ \setminus \{0\}} \left( p_{\text{exchange}}^{\text{ex}}(t) - p_{\text{exchange}}^{\text{in}}(t) \right) \quad \forall t \in T, i \in I_g \]

Technical Constraints for Individual Units

Technical Constraints for Individual Units: Minimum and maximum power of thermal power plants

\[ p_{\min}^b(t) \cdot e_b(t) - P_b(t) + P_{RL-}^b(t) \leq 0 \quad \forall t \in T, b \in B^h_t, i \in I_g \]
\[ -p_{\max}^b(t) \cdot e_b(t) + P_b(t) + P_{RL+}^b(t) \leq 0 \quad \forall t \in T, b \in B^h_t, i \in I_g \]

Technical Constraints for Individual Units: Minimum up- and down-times

\[ \sum_{t=1}^{T_{\text{run,}min}-1} e_b(t) - T_{\text{run,}min}^b \cdot (e_b(t) - e_b(t - 1)) \geq 0 \quad \forall t \in T, b \in B^h_t, i \in I_g \]
\[ \sum_{t=1}^{T_{\text{down,}min}} (1 - e_b(t)) - T_{\text{down,}min}^b \cdot (e_b(t - 1) - e_b(t)) \geq 0 \quad \forall t \in T, b \in B^h_t, i \in I_g \]

Technical Constraints for Individual Units: Reserve control power of each thermal power plant

\[ P_b(t) + p_{RL+}^b(t) \leq p_{\max}^b(t) \quad \forall t \in T, b \in B^h_t, i \in I_g \]
\[ P_b(t) - p_{RL-}^b(t) \geq p_{\min}^b(t) \quad \forall t \in T, b \in B^h_t, i \in I_g \]

Comparable impact of hydro-electric power plants and demand side management processes. Please find more details in [29].

Lagrange relaxation approach is applied to the optimization problem to decompose per bidding zone. More details can be found in [29].

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