Cost-optimal reliable power generation in a deep decarbonisation future

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HIGHLIGHTS

• A detailed model of the 2050 Western Europe power system is developed.
• Variable system costs differ up to 25% with interannual weather variability.
• In most scenarios firm low-carbon capacity is above 75% of the peak demand.
• The role of green hydrogen as electricity storage is limited.

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ABSTRACT

Considering the targets of the Paris agreement, rapid decarbonisation of the power system is needed. In order to study cost-optimal and reliable zero and negative carbon power systems, a power system model of Western Europe for 2050 is developed. Realistic future technology costs, demand levels and generator flexibility constraints are considered. The optimised portfolios are tested for both favourable and unfavourable future weather conditions using results from a global climate model, accounting for the potential impacts of climate change on Europe’s weather. The cost optimal mix for zero or negative carbon power systems consists of firm low-carbon capacity, intermittent renewable energy sources and flexibility capacity. In most scenarios, the amount of low-carbon firm capacity is around 75% of peak load, providing roughly 65% of the electricity demand. Furthermore, it is found that with a high penetration of intermittent renewable energy sources, a high dependence on cross border transmission, batteries and a shift to new types of ancillary services is required to maintain a reliable power system. Despite relatively small changes in the total generation from intermittent renewable energy sources between favourable and unfavourable weather years of 6%, emissions differ up to 70 MtCO₂ yr⁻¹ and variable systems costs up to 25%. In a highly interconnected power system with significant flexible capacity in the portfolio and minimal curtailment of intermittent renewables, the potential role of green hydrogen as a means of electricity storage appears to be limited.

1. Introduction

The Paris Agreement on Climate Change states the objective to keep global mean surface temperature increase due to anthropogenic greenhouse gas (GHG) emissions well below 2 °C and strive to limit the increase to 1.5 °C [1]. With this in mind, the global carbon budget between 2017 and 2100 is estimated at 1000 GtCO₂ for a 66% chance of staying below 2 °C temperature increase. The budget to stay below 1.5 °C temperature increase is estimated at 850 GtCO₂ and 420 GtCO₂ for a 33% chance [2] and 66% chance [1] respectively. To reach the target set by the Paris Agreement, the power sector should decarbonise its emissions completely and most likely also contribute to negative emissions by 2050 [3].

There is a growing body of literature studying the transition to a 100% renewable or low or zero carbon power system. In general, these studies show that these power systems are feasible [4–6], under the condition that there is sufficient transmission [7], backup and storage capacity [8]. The power system will most probably increasingly rely on intermittent renewable energy sources (IREs) [1,9–14], complemented by large-scale low-, zero- or negative-carbon power sources and technologies such as fossil plants without and with CO₂ capture and storage (CCS), nuclear power, electricity storage systems and transmission capacity [9], to achieve a reliable supply of electricity. Still, the power system will face several challenges.
The increasing reliance on IRES will have consequences for the power system. Moments of high and low generation from IRES technologies can both present difficulties keeping supply and demand in balance. For example, IRES high production periods can lead to a lack of system inertia [15,16], while low production can lead to electricity supply shortages [17]. Moreover, with an increasing penetration of weather-dependent IRES, the power system as a whole is likely to become more dependent on weather conditions [13], spurring research into the impact of the weather on power system design and operation [18]. Events with very low generation from IRES and high demand will likely happen in the future and should be considered when designing a power system [17].

At the same time, the power sector needs to support decarbonisation in other sectors. Sector coupling with (district) heating system [19,20], mobility (e.g. electric vehicles) [21] and power-to-gas applications [22] influences the development of the power system. A large growth of demand can be expected with the increased electrification of other sectors [11].

Previous studies usually relied on single typical weather years in the modelling process [13] (see e.g. [9,16]), or a limited amount of less than 40 past years [13,15,18]. However, when the power system becomes more dependent on IRES, it also becomes more vulnerable to extreme conditions which are observed less frequently, with potential consequences for power sector emissions, security of supply and costs [13]. Additionally, with the climate changing towards 2050, weather impacts on the power system in the climate in 2050 are not necessarily well represented by past weather. Studies considering future weather and a multitude of weather years, indicate that climate change has a modest effect on the power supply and demand [17,23,24]. Even more than climate change, interannual variability of the weather affects the power system [23,24], stressing the need to include a large ensemble of weather years to capture extremes.

Studies of a heavily decarbonised European power system sometimes still allowed emissions up to 50–100 MtCO₂ yr⁻¹ [9,25,26], while even these levels exceed the carbon budget consistent with the Paris Agreement ambitions [2]. Going from a net-positive to net-zero or negative emission power system can significantly change the cost-optimal set-up of the power system [14,27]. Thus, long-term planning towards a zero- or net-negative carbon power system may prevent a lock-in of a sub-optimal generation portfolio and stranded assets [14].

The option of bioenergy in combination with CCS (BECCS) and Direct Air Capture of CO₂ (DAC) were often not included in studies (see [9–12,28]). However, when aiming for net-zero or negative emissions in the power sector, the role of these technologies might be crucial and influence the feasibility of other technologies in the system. Finally, technology-specific policy preferences might considerably influence the future generation mix.

In studies of future power systems, the focus is usually on an individual country (e.g. [16]) or a larger and interconnected region (e.g. [7]). It is also required to understand the operation of the system within one country while at the same time considering the highly detailed interactions with and in between the surrounding countries.

This study addresses increased IRES penetration, weather extremes and sector coupling while including a large set of future weather years, net-zero and negative emission targets and negative emission technologies. The study focuses on the following research question: What are major components of a reliable and cost-optimal electricity system that is both consistent with the Paris Agreement on climate change, and robust enough to deal with variable weather patterns?

2. Method

An overview of the method is presented in Fig. 1. The power system model is built in PLEXOS.¹ Within the PLEXOS framework, highly detailed power system models can be developed. An overview of modelling tools for electricity systems with large share of variable renewables shows that PLEXOS can model at multi-year and (sub) hourly timescales, while performing both portfolio optimisation and simulation [29]. Additionally, PLEXOS is one of the most comprehensive models which can include a wide variety of techno-economic parameters and thermal generator flexibility constraints [29].

In the PLEXOS model, the Long Term (LT) plan module expands the electricity generation portfolio and transmission network while minimizing total system costs. The LT optimisation is performed with a yearly resolution and is driven by aggregated electricity demand profiles, IRES generation profiles, and the techno-economic parameters of all electricity generation technologies. In this study, due to a lack of data on individual plants and computational time limitations, we take a greenfield approach and model only the year 2050. Consequently, legacy generation capacity and its decommissioning or retrofitting is not included.

After the LT plan is run, the PLEXOS Short Term (ST) schedule determines the unit commitment and economic dispatch (UCED) of the electricity generation portfolio under specific weather years by minimizing the operational costs. The ST simulation is hourly resolved and driven, among others, by the electricity demand profiles, IRES generation profiles, variable costs, and flexibility parameters of the different power plants. As the ST considers the full chronology, it accounts for intertemporal constraints and provides more detailed results on power system operation.

The reliability of operation of the power generation portfolios is assessed for different weather years. First, the LT plan is used to optimise and build the generation portfolios. The portfolio is optimised using an average weather year, selected from a dataset of nearly 500 potential future weather years. In the second step, the ST schedule is used to assess the reliable operation of the power system by simulating this portfolio for both a very favourable and unfavourable weather year, selected from the same large weather dataset (explained in Section 2.2).

The focus of this study is the Western European power system, see Fig. 2 for an overview of the countries considered in the study. The CO₂ emissions from public heat and power generation in this geographical region were 684 MtCO₂ in 2016 [30].

Next to the developments in the Western European power system, the reliable operation of a single bidding zone is studied as well because power system balance is to be maintained within bidding zones. The case of the Dutch power system is used for this analysis. With limited space onshore, a significant offshore wind potential which the government plans to develop [31], while surrounded by countries which have significant wind capacities offshore too, the future operation of the Dutch power system might be a challenging case. As we consider the operation of the Dutch power system with more detail, the Netherlands is modelled as an individual region. Smaller countries and countries further away from the Netherlands are clustered into regions (see Fig. 2) to reduce model complexity and computational costs.

2.1. Model runs

Five core scenarios are modelled to study the reliability of a low-carbon power system as shown in Table 1. In the Reference scenario, generator investment decisions are driven purely by cost minimisation, with transmission between countries limited to the level expected in 2027 based on current plans. In the other core scenarios, additional constraints are placed on the generation portfolio to reflect different policy choices. In the 70% IRES scenario, at least 70% of the Western European electricity generation comes from IRES, which is distributed across countries based on the ‘Global climate action’ scenario of the ten year network development plan (TYNDP) of ENTSO-E [26]. This scenario is in line with current policies such as the German feed-in tariff and the EU renewable energy targets in which the deployment of IRES

¹ PLEXOS is a detailed power system simulation modelling framework developed by Energy Exemplar (https://energyexemplar.com/).
is stimulated. The No CCS scenario is similar to the Reference scenario, but the application of CCS technologies is not allowed. Since the application of CCS in the power sector has received strong criticism from environmental non-governmental organisations and local inhabitants being faced with local underground carbon storage. Finally, the Low nuclear scenario is in line with the current phase out of nuclear energy in Germany and the planned decrease of nuclear capacity in France. The amount and distribution of nuclear capacity is exogenously fixed according to the TYNDP. The nuclear capacity is placed in France (38 GW), Britain (6 GW), Scandinavia (3 GW), Iberia (3 GW) and Italia (1.5 GW). There is no nuclear capacity in the Netherlands, Germany, Belgium and Luxembourg. In most core scenarios, power sector CO2 emissions in 2050 are constrained to zero. However, in the −1.1 Gt scenario, a more ambitious emission cap of −1.1 GtCO2 is enforced. This is the estimated contribution the Western European power system would need to make in 2050 for global emissions to be consistent with the ambitions of the Paris Agreement, based on a the global available budget [32] (see Appendix D).

Four additional sensitivity runs are also performed. In the Optimised transmission scenario, the configuration is the same as the Reference scenario except that transmission capacity can be completely optimised. The results of this sensitivity run can be used to find additional benefits from increased (or decreased) transmission capacity from the reference level. The 55% IRES run is based on the exogenously defined lower IRES capacity from the 'large scale RES' scenario from the e-Highway project [33] and gives insight in a different IRES penetration and distribution compared to the 70% IRES scenario. In the Fixed H2 storage scenario, 22 TWh of hydrogen storage capacity is exogenously forced into the portfolio, in line with the potential indicated in the Hyundai project [34]. With this sensitivity run, the potential contribution of seasonal hydrogen storage for IRES integration can be studied. In the Higher

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2 As the emission target is 0.0 GtCO2 yr−1 and in this study negative emissions could only be achieved with CCS technologies (BECCS and DAC), only zero emission power sources can be used.
demand sensitivity run, an additional constant load of 220 GW is added to study the impact of higher electrification of other sectors, such as industry or the production hydrogen (see Appendix B).

### 2.2. Weather and climate data

Input weather and climate data are taken from the EC-Earth climate model developed by the EC-Earth consortium [35,36]. EC-Earth generates high temporally (6 h) resolved simulations of future weather in climate projections and the output is bias-corrected and downscaled to a matching high spatial resolution (±25 km × 25 km) [24]. These simulations are forced by a prescribed future increase in GHG concentration in line with a 1 °C to 2 °C temperature increase by 2050 up to a 1.5 °C to 4 °C temperature increase at the end of the century. An ensemble of 16 members of this simulation is made starting from 16 different initial conditions, which results in different day-to-day variability and consequently different inter-annual variability between the 16 members. This approach ensures that natural variability, including weather extremes, is thoroughly sampled. The ensemble members are in a statistical sense equally likely. From each member, 30 years are considered to describe the weather and climate in 2050. Due to computational cost limitations, not all 480 weather years are used in the final power system modelling. Instead, the weather data for the average weather year are used for the portfolio optimisation with the PLEXOS LT plan, while the most favourable and unfavourable weather years are used to test the vulnerability for climate variability of the different generation portfolios and their reliability in the ST schedule. The favourable and unfavourable weather years are selected based on the average annual wind speed at 100 m and the average daily

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**Fig. 2.** Regions and countries modelled in this study. The cross-border transmission lines are indicated by the black lines.
3. Input data

3.1. Demand

The demand patterns for the year 2050 are based on the demand patterns of 2015 from ENTSO-E [38] with an added demand for electric vehicles (EVs) (579 TWh yr⁻¹) and heat pumps (262 TWh yr⁻¹). The heat pump demand profile is based on the outside air temperature derived from the climate model, thereby ensuring a realistic correlation between (electricity based) heat demand and IRES generation profiles. The total electricity demand is assumed to increase by 33% compared to current levels, to 3400 TWh yr⁻¹ with a system wide peak demand of 636 GW. A value of lost load (VOLL) of 100,000 € MWh⁻¹ is assumed. For more details on demand development in the individual regions see Appendix B.

3.2. Techno-economic parameters of generation technologies

An important part of the model parameters are the techno-economic parameters, which describe both the technical performance and costs of all technologies considered. In this study, we consider investment costs, fixed operation and maintenance (FOM) costs, variable operation (VOM) costs, and fuel costs. Additionally, the lifetime for each technology and a uniform discount rate of 8% are used to annualize the investment costs and include interest during construction.

As technological learning continues, it is expected that the costs of (most) electricity generating technologies fall while the performance improves. As the modelled year in this study is 2050, projected future costs for all electricity generating technologies are used. As all installed capacity in 2050 will have been installed in the years leading up to 2050, cost projections for 2040 are used.

In 2014, the European Commission Joint Research Centre (JRC) [39] published a detailed set of projections for cost and technical parameters for multiple electricity generating technologies for each decade up to 2050. The cost data from the JRC is based on several sources and is used mainly in this study to ensure consistency for most technologies. However, for the cost of wind turbines and PV, an updated report by the JRC with new projections is used [40].

For some technologies, no techno-economic parameters could be found in literature for the year 2040. The parameters for these technologies are inferred based on similar technologies for which the parameters are known. See the notes below Table 2 for more details.

As both hydro and geothermal power potential are limited by geological features, the distribution and capacity of these technologies are exogenously defined. Hydropower plants and plants using run of river (ROR), pumped hydro storage (PHS) and pure hydro dam storage (STO) are fixed at current levels (i.e. 162 GW in Western Europe) as the current deployment is already close to the maximum potential in Europe [41]. The geothermal capacity is assumed to grow to 50 GW in 2050 in the EU, in line with other high RES studies [10–12]. The capacity is distributed over the regions based on the estimated economical geothermal capacity [42].

Sepulveda, Jenkins, de Sisternes and Lester. [43] categorise power generating capacity according to three types: (1) fast-burst balancing resources such as storage and transmission capacity; (2) fuel saving options such as solar PV, on- and offshore wind and; (3) firm low-carbon capacity such as gas (with CCS), nuclear, storage, hydropower, and bioenergy. The same categorisation is applied in this study, and their roles in the power system specifically considered.

3.3. Techno-economic parameters of storage technologies

Two storage technologies are considered in the model: short-term storage in batteries (in EVs), and longer-term hydrogen storage. Battery storage equivalent to 10% of the EV fleet available for load shifting is fixed as an input in all scenarios, with a total of 125 GW over the whole Western European study region. All batteries are assumed to have eight hours of storage available, giving a total of 1 TWh battery storage. When applying EV storage, it can be interpreted as both smart charging (i.e. delaying or advancing the charging of the EV battery) and an option to provide flexibility (actual charging and discharging of the battery). Given the fact that a large number of EVs can provide this battery capacity, no additional investments are assumed.

Electrolysers and hydrogen turbines can be built by the model if this leads to lower system costs. In the core scenarios hydrogen can only be generated and stored for later use in the electricity sector. Storage of hydrogen is assumed to be in salt caverns due to their favourable storage characteristics [46]. For each salt cavern, a typical storage size of 500,000 m³ is assumed, allowing for 133 GWh of storage based on the lower heating value (LHV) of hydrogen storage [34]. The costs to develop a cavern for hydrogen storage are assumed to be 60 € m⁻³ [34]. The hydrogen withdrawal rates are limited at 3 kg s⁻¹ (360 MW LHV) to prevent sudden pressure drops or increases which could damage the integrity of the salt cavern. Three archetypical hydrogen storage sites are assumed with the same storage size (again 133 GWh) but varying discharge capacities, to represent different power-to-energy ratios. The combined costs (i.e. costs for cavern development, electrolyser and hydrogen turbine) of the archetypical hydrogen storages are presented in Table 3. Additionally, a round trip efficiency of 41%, VOM costs of 1.6 € MWh⁻¹ H₂ and FOM costs of 39 € kWh⁻¹ yr⁻¹ are assumed for all hydrogen storages.

3.4. Transmission capacity

In most scenarios, the transmission capacity is fixed at levels of what is expected by ENTSO-E in 2027 [47] (Table 4). As, several countries are aggregated into bigger regions, copper-plate transmission is assumed within individual countries and regions. For this reason, transmission capacity is deliberately kept at a limited level to account for the overestimation of transmission capacity within the regions.

3.5. Fuel

The assumed fuel prices, emission factors and maximum use (for bioenergy) are presented in Table 5. As the amount of biomass and biogas is restricted to their reported technical sustainable potentials, these fuels are assumed to be sustainable and to have no CO₂ emissions.

3.6. Demand shedding

Demand shedding in the industrial sector is included based on [9] and [51]. Costs for demand shedding range from 100 € MWh⁻¹ to 2100 € MWh⁻¹ with a total potential of 12.6 GW. The distribution of demand shedding potential and its costs are presented in Fig. 3.

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2 Note that when costs are discussed in this article, euros refer to 2016-euros (€2016).

4 Additional demand for hydrogen (e.g. for industrial end-use) is considered in the sensitivity analysis with a higher electricity demand.
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4. Results

4.1. Power generation portfolio performance

The Western European power generation portfolios for the different scenarios are shown in Fig. 4 while the annual generation with these portfolios is shown in Fig. 5 for both the favourable and the unfavourable weather year. Average capacity factors for the different technologies can be found in Appendix F.

The total installed capacity varies between 1231 GW to 2032 GW, exceeding the system peak demand of 636 GW considerably. The variation in total installed capacity is mainly explained by the different deployment of IRES capacity which, while representing around half the installed generation capacity in most scenarios, does not generate significantly during peak demand periods, and must be backed up by dispatchable capacity. Electricity generation by nuclear power delivers 30% of total demand in the Reference scenario up to 45% in the No CCS scenario. Natural gas is the only fossil fuel that is used both for mid-merit (CCGT) and peak (OCGT) generation. As the system needs to achieve net zero emissions, BECCS generation is used to offset the fossil emissions. Very little H2 storage is built across the scenarios (see Section 4.5).

In the 70% IRES scenario, when a large fixed share of IRES is forced into the system, nuclear disappears from the optimal generation portfolio as the capacity factors of thermal generation technologies are too low. With the higher shares of IRES capacity, the impact of the weather years becomes more pronounced. Compared with the favourable weather year, in the unfavourable weather year there is considerably more generation from OCGT (+100 TWh yr\(^{-1}\)) and CCGT (+70 TWh yr\(^{-1}\)) to make up for the decrease in IRES generation.

When CCS is excluded as an option, fossil-based generation disappears completely from the portfolio as the emissions from the fossil plants fuel usage also cannot be offset using BECCS or DAC\(^6\). Therefore, the portfolio in the No CCS scenario consists only of renewable and nuclear technologies.

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Table 4
Assumed transmission capacities between regions. Transmission capacity is based on projections for 2027 by ENTSO-E [47]. Note that for the totals the two-way transmission is counted double.

| MW     | The Netherlands | Belgium | Germany | Scandinavia | France | Iberia | Italia | British Isles | Total |
|--------|-----------------|---------|---------|-------------|--------|--------|--------|---------------|-------|
| The Netherlands | 3400 | 5000 | 1400 | 3550 | 1000 | 1000 | 1400 | 9380 | 13,600 |
| Belgium | 3400 | 1430 | 6700 | 4690 | 11,950 | 1400 | 9500 | 25,970 | 126,900 |
| Germany | 5000 | 1430 | 6700 | 4690 | 11,950 | 1400 | 9500 | 25,970 | 126,900 |
| Scandinavia | 1400 | 3550 | 4690 | 5000 | 5930 | 6800 | 25,970 | 126,900 | |
| France | | | | | | | | | |
| Iberia | | | | | | | | | |
| Italia | | | | | | | | | |
| British Isles | 3800 | 1000 | 1400 | 1400 | 6800 | 14,400 | |
| Total | 13,600 | 9380 | 31,170 | 9500 | 25,970 | 5000 | 17,880 | 14,400 | 126,900 |

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Table 5
Fuel input parameters for 2050 used in the PLEXOS model.

| Fuel      | Price (€GJ\(^{-1}\)) | Maximum fuel usage (EJ yr\(^{-1}\)) | Emission factors (kgCO\(_2\) GJ\(^{-1}\)) |
|-----------|----------------------|------------------------------------|-------------------------------------|
| Natural Gas | 7.0                  | –                                  | 56                                  |
| Coal      | 2.1                  | –                                  | 101                                 |
| Uranium   | 1.0                  | –                                  | 0                                   |
| Solid woody biomass | 6.9 | 4.9 | 0 |
| Biogas    | 16.9                 | 1.0                                | 0                                   |

\(a\) The natural gas and coal fuel costs are the European import prices taken from IEA [48] 2DS scenario, the uranium price is taken from [9] and the solid biomass and biogas price are taken as the average weighted costs for biomass from the medium availability biomass scenario of JRC [49].

\(b\) Based on the medium availability biomass scenario of JRC [49]. These biomass potentials only consist of biomass that can be produced in the countries within the scope of this study. Furthermore, sugar, starch and oil crops are excluded as these are reserved for biofuel production. Black liquor and wet silage are excluded due to a lack of data availability and stem wood is reserved for heating purposes.

\(c\) Biogas substrates are assumed to cost 6.4 €GJ\(^{-1}\) [49]. Additionally, the production of biogas from these substrates through a digester costs 10.4 €GJ\(^{-1}\) [50].

Table 6
Alternative techno-economic parameters for sensitivity analysis based on [39,40,52].

| Technology | TCR (€kW\(^{-1}\)) | FOM costs (€kW\(^{-1}\) yr\(^{-1}\)) | VOM costs (€MWh\(^{-1}\)) | Efficiency (–) | Lifetime (yr) | Build time (yr) |
|------------|-------------------|------------------------------------|--------------------------|----------------|---------------|----------------|
| Nuclear    | 7900              | 86                                 | 2.5                      | 38.0%          | 40            | 10             |
| Onshore Wind | 1000              | 29                                 | 0.0                      | –              | 25            | 1              |
| Offshore Wind | 1500              | 27                                 | 0.0                      | –              | 30            | 1              |
| Utility PV  | 300               | 5                                  | 0.0                      | –              | 30            | 1              |
| Root PV     | 400               | 8                                  | 0.0                      | –              | 30            | 1              |
| ACGT-CCS    | 1200              | 25                                 | 2.5                      | 59.0%          | 30            | 3              |

Abbreviations: TCR: total capital requirement, FOM: fixed operation and maintenance costs, VOM: variable operation and maintenance costs, ACGT-CCS: Allam cycle gas turbine with carbon capture and storage.

\(a\) The investment costs are based on the costs of a test plant at €3 million for a 300 MW plant. FOM and VOM costs, the lifetime and the build time are based on the CCGT data [39] and the data for the ACGT-CCS are taken from [52]. Additionally, a 100% capture rate of CO\(_2\) is assumed.

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\(6\) Negative emissions could be achieved without CCS through afforestation, carbon capture and utilisation (CCU) or other options [3], however, these options are outside the scope of this study.
which must be offset by DAC. As DAC is very energy intensive, it is only effective when running on (near) carbon neutral power generation [3], provided in this instance by a mix of nuclear power, BECCS, CCGT-CCS and IRES.

The scenario with the least constraints, the Reference scenario leads to a power system with the lowest costs of 285–291 billion € yr$^{-1}$, with an IRES penetration of 37%. The highest total power system costs for a carbon neutral system are found in the 70% IRES scenario. These costs are, however, only 10% higher than in the Reference scenario. Consequently, the Reference scenario results are expected to be highly sensitive to the input figures presented in Table 2. Total system costs increase with 36% with a negative emission cap.

Only in the No CCS scenario, with solely carbon neutral generation capacity, are there exactly zero emissions in both weather years. In the three other scenarios optimised for zero emissions in the LT plan, emissions are actually slightly above or below zero in the unfavourable and favourable weather year respectively. As both weather years are opposing positive and negative extremes, these deviations can be expected to even out over several weather years. When additional emissions still need to be avoided, other generation capacity can be replaced by BECCS. The additional costs will likely not lead to radical changes in the portfolio. Therefore, with minor changes to the portfolio, the emission target could still be met. In the −1.1 Gt scenario emissions are slightly above the target in both weather years. In this scenario available bioenergy is already a limiting factor and all gas-fired capacity is deployed with CCS. Thus, a small increase in DAC capacity for negative emissions and nuclear power to generate the needed electricity could be added to meet the target.

4.2. Weather variability

In Fig. 6 the annual generation is plotted against the installed capacity per IRES technology, showing that the difference in IRES generation between favourable and unfavourable weather years is limited at the European scale. Although there is a difference between the favourable and unfavourable weather year for the PV technologies (2.3%), this difference is much smaller than the difference for both onshore and offshore wind energy (6.1%). The higher capacity factors for wind energy only explain part of this result, rather it the higher
variability of wind generation between the favourable and unfavourable weather year which explains the difference. Thus, with an increasing share of installed wind capacity, the power generation portfolio becomes more vulnerable to the weather on an annual basis.

Although the difference in generation is small between the two extreme weather years, the difference in key indicators (see Table 7) are observable in all scenarios. The difference in emissions between the two weather years becomes larger with increasing rates of IRES penetration. In the 70% IRES scenario this difference increases to nearly 70 MtCO₂ yr⁻¹, while the difference in the Reference scenario is 26 MtCO₂ yr⁻¹. Also, power system costs differ with up to 12 billion euros in the No CCS scenario annually, representing 4% of the total system costs or 25% of the variable system costs.

4.3. Firm low-carbon capacity in the generation mix

In all scenarios, the cost-optimal portfolio consists of all three types of technologies (fast burst, fuel saving and firm low-carbon capacity) as introduced in Section 3.2. Since the fast-burst resources (available batteries and transmission) are fixed as inputs, this is not a result of the model. The fuel saving options are also found in all scenarios, but at different capacities and mixes and depending on the limitations placed on nuclear power and CCS.

The share of firm low-carbon capacity is stable (between 440 and 480 GW, or 69–77% of peak load) across the different scenarios, showing that firm low-carbon capacity is prerequisite for achieving a cost-optimal power generation portfolio targeting deep decarbonisation. The exact mix of firm low-carbon technologies, however, will depend on several factors such as (i) the penetration of IRES, which results in more peaking units, (ii) the level of climate ambition, with more CCGT-CCS and BECCS built in the −1.1 Gt scenario than in the Reference scenario, and (iii) policy choices forcing in or precluding certain technologies as, with only a limited number of low-carbon technologies available, the model has few alternative options to choose from.
Table 7
Key performance indicators of the Western European power system for the five core scenarios in 2050 based on PLEXOS ST runs.

| Scenario       | Weather year | Net emissions (MtCO₂ yr⁻¹) | Curtailed IRES generation (TWh yr⁻¹) | Total system costs (billion € yr⁻¹) | Variable system costs (billion € yr⁻¹) |
|----------------|--------------|----------------------------|-------------------------------------|-----------------------------------|--------------------------------------|
| Reference      | Unfavourable | 22                         | 48                                  | 291                               | 54                                   |
|                | Favourable   | −4                         | 55                                  | 285                               | 48                                   |
| 70% IRES       | Unfavourable | 32                         | 103                                 | 322                               | 45                                   |
|                | Favourable   | −35                        | 109                                 | 312                               | 35                                   |
| No CCS         | Unfavourable | 0                          | 1                                   | 310                               | 51                                   |
|                | Favourable   | 0                          | 2                                   | 298                               | 38                                   |
| Low nuclear    | Unfavourable | 6                          | 54                                  | 295                               | 63                                   |
|                | Favourable   | −43                        | 66                                  | 289                               | 56                                   |
| −1.1 Gt        | Unfavourable | −103                       | 31                                  | 393                               | 133                                  |
|                | Favourable   | −1075                      | 36                                  | 388                               | 128                                  |

Table 8
Utilisation of CCS technologies in 2050 in the five core scenarios.

| Scenario       | Weather year | CCS capacity (GW) | Emissions stored with CCS (MtCO₂ yr⁻¹) | Total negative emissions (MtCO₂ yr⁻¹) |
|----------------|--------------|-------------------|---------------------------------------|--------------------------------------|
| Reference      | Unfavourable | 20                | 150                                   | 150                                  |
|                | Favourable   | 19                | 159                                   | 159                                  |
| 70% IRES       | Unfavourable | 19                | 159                                   | 159                                  |
|                | Favourable   | 19                | 157                                   | 157                                  |
| No CCS         | Unfavourable | 0                 | 0                                     | 0                                    |
|                | Favourable   | 0                 | 0                                     | 0                                    |
| Low nuclear    | Unfavourable | 25                | 232                                   | 232                                  |
|                | Favourable   | 25                | 233                                   | 233                                  |
| −1.1 Gt        | Unfavourable | 179               | 1155                                  | 1043                                 |
|                | Favourable   | 179               | 1179                                  | 1086                                 |

* System costs do include fixed and operational costs, but do not include cost of unserved energy.

* Variable system costs consist of generator VOM costs, fuel costs, CO₂ transport and storage costs, generator start and shutdown costs and demand curtailment costs.

4.4. CCS deployment

With the exception of the No CCS scenario, CCS-based technologies are deployed (see Table 8). In all the net zero emission scenarios, BECCS is the only technology deployed with CCS, while in the negative emission scenario, other CCS technologies as CCST-CCS and DAC are also used. If the amount of nuclear capacity is constrained, more CCS capacity is needed.

4.5. Electricity storage

Hardly any hydrogen based electricity storage is deployed across the scenarios. A total of 10.4 GW of hydrogen storage is installed in Western Europe in the No CCS scenario as less other backup options are available. In the 70% IRES scenario a total of 1.7 GW of hydrogen storage is available in Western Europe.

Next to storage in hydrogen, storage in batteries is also possible in the model. The amount of electricity supplied from batteries in Western Europe is presented in Table 9. Even though the installed battery

capacity is the same in all scenarios, the amount of stored electricity varies considerably between the scenarios. With more IRES generation, the amount of electricity stored also increases.

4.6. Viability and reliable operation of high shares of IRES in a single country: A closer look at the Netherlands

While the aggregated results for the Western European power system can highlight the large-scale consequences of different portfolios and the impact of weather variability, considering only the total aggregated results across all regions can mask the impacts on individual countries, especially in a power system with a higher dependency on cross-border transmission. In this section, we take a closer look at the consequences of the different portfolios on the Netherlands.

All scenarios show considerable differences in the operation of the Dutch power system compared to the current situation (Table 10). Curtailment of IRES remains modest (less than 1% of generation) in scenarios where the IRES share of the portfolio is optimised. Further deployment of IRES, such as in the 70% IRES scenario, leads to more IRES generation but also large quantities and many more hours of curtailed energy.

Dispatchable generation provides at least 10% of the generation in most hours of the year across most scenarios. Only in the 70% IRES scenario, the amount of dispatchable generation below 10% of the total load most of the hours in the year.

Additionally, more flexibility is required from the transmission capacity. In the operation of the power system, ramps in transmission flows between two hours, larger than half the total transmission capacity, are observed several hundred times a year, while these do not occur in the current power system. Furthermore, the capacity factor of the transmission lines in the future power system almost doubles compared to the current situation.

The IRES penetration in the 70% IRES scenario is higher in the Netherlands than on average in Europe, extreme findings could be expected here. Still, the growth of IRES generation in the Netherlands is lower in the Reference scenario compared to the average growth in Western Europe, large growth of IRES capacity abroad also has its effects on the Dutch power system through transmission and storage. In the modelled power systems, a lot of flexibility is provided by battery storage and transmission capacity, both in absolute capacity as well as in ramping capabilities. Table 10 shows that the operation of the resulting power systems will differ considerably from the current situation. The total contributions to flexibility by the different sources in different scenarios are depicted in Fig. 7. The distribution of flexibility contributions for the 70% IRES unfavourable and Reference unfavourable run are also shown in a residual load duration curve in Fig. 8 and Fig. 9 respectively. These graphs show that in the 70% IRES scenario, most generation is provided by IRES, while dispatchable capacity provides more than 50% of total generation less than 5% of the time. As IRES do
Table 10
Operational indicators for the Dutch power system for the 5 core scenarios in 2050 based on PLEXOS ST runs.

| Scenario     | Weather year | Curtailed IRES (GWh yr⁻¹) | Hours with IRES curtailment (h yr⁻¹) | Hours in which dispatchable generation provides < 10% of load (h yr⁻¹) | Net import/export ramps > 50% of capacity per hour (h yr⁻¹) | Weighted average transmission capacity factor (%) |
|--------------|--------------|---------------------------|--------------------------------------|-----------------------------------------------------------------|-----------------------------------------------------------|-----------------------------------------------|
| Reference    | Unfavourable | 8                         | 193                                  | 0                                                               | 125                                                        | 78.2%                                         |
|              | Favourable   | 8                         | 183                                  | 8                                                                | 140                                                        | 77.0%                                         |
| 70% IRES     | Unfavourable | 30,058                    | 2500                                 | 7907                                                             | 633                                                        | 88.9%                                         |
|              | Favourable   | 32,249                    | 2804                                 | 8364                                                             | 595                                                        | 89.2%                                         |
| No CCS       | Unfavourable | 9                         | 193                                  | 88                                                               | 306                                                        | 77.3%                                         |
|              | Favourable   | 9                         | 206                                  | 50                                                               | 303                                                        | 77.6%                                         |
| Low nuclear  | Unfavourable | 8                         | 174                                  | 112                                                              | 329                                                        | 77.8%                                         |
|              | Favourable   | 8                         | 185                                  | 153                                                              | 366                                                        | 77.2%                                         |
| −1.1Gt       | Unfavourable | 9                         | 192                                  | 0                                                                | 974                                                        | 77.5%                                         |
|              | Favourable   | 8                         | 186                                  | 8                                                                | 990                                                        | 76.8%                                         |
| 2017a        | n/a          | 0                         | 0                                    | 0                                                                | 0                                                          | 42.6%                                         |

Based on [38,57].

Fig. 7. Total flexibility contributions and IRES generation in the 2017 Dutch power system and in the Reference unfavourable and 70% IRES unfavourable scenarios.

Fig. 8. Residual load duration curve with demand at days and flexibility contributions in the 70% IRES unfavourable run.
not typically deliver ancillary services, such as frequency and voltage control and balancing reserves at present [16,58], maintaining grid stability in the Netherlands could become more challenging at such high levels of IRES deployment. In response, technologies such as synchronous compensators or electronic controllers could be installed throughout the electricity grid to provide these ancillary services in the future, to compensate for the lack of conventional dispatchable capacity [16,58].

5. Sensitivity analysis

5.1. Alternative scenarios

Fig. 10 shows the power generation portfolios in the sensitivity runs. In the Western European power system transmission capacity only increases with 3% in comparison to the Reference scenario. Additionally, the optimisation of transmission capacity diminishes the need for gas turbines (OCGT) to provide peaking capacity and allows for slightly more IRES capacity. Changes in transmission capacity are the increased capacity to and from Scandinavia and the increase in transmission capacity between France and the Iberian region. Other connections are similar or smaller compared to the transmission in the Reference scenario.

In the Fixed H₂ storage sensitivity run, gas turbine (OCGT) peaking
capacity is required less than in the Reference scenario, but still more than in the Optimised transmission sensitivity run. The remainder of the installed capacity remains very similar to the Reference scenario.

As in the 70% IRES scenario, in the 55% IRES sensitivity run, OCGT power plants make up most of the backup capacity, but now there is also room for capacity other than OCGT. Additionally, with less generation from gas fired power plants the need for BECCS also decreases.

In the Higher demand run, the generation mix consists of similar capacities of IRES as in the Reference scenario. Thermal generation capacity is higher, especially nuclear capacity, which almost triples from 132GW in 2017 to 378GW in 2050. As the demand profile in the Higher demand sensitivity run is relatively flatter, there is more space for baseload capacity to run.

5.2. Availability of battery capacity

The exogenously fixed battery capacity of 125GW is used daily to shift the peak of PV supply to match demand. A sensitivity run is performed without this battery capacity available. In this run, the PV capacity decreases from 502GW in Western Europe to 281GW (see Fig. 11). Although the economics of hydrogen electricity storage improves without the batteries, it still is not part of the cost-optimal portfolio. The viability of PV beyond 280GW in the power generation mix depends on the availability of low-cost electricity storage. The PV capacity is replaced by nuclear capacity of 37 GW (+29%) and OCGT capacity of 103 GW (+190%).

5.3. Alternative techno-economic parameters

In most of the scenarios, nuclear power generation delivers between 30% and 45% of total demand despite the current trend in Western Europe where countries are generally turning away from nuclear power. The estimates for future investment costs for nuclear power generation in the future range considerably. However, if the total capital requirement is higher than assumed in the core scenarios (7900 instead of 5300 €kW−1), the economic lifetime of the plant only 40 instead of 60 years and the construction period 10 instead of 7 years, there is no longer a role for nuclear power generation. The remaining electricity demand is covered by an increase in gas fired capacity and IRES capacity.

Additionally, following current trends, further cost reductions for IRES technologies than assumed in this study may be achieved. Assuming the lowest cost estimates from the JRC projections [40], see Table 6, the portfolio changes considerably. The share of IRES almost doubles with the lower cost parameters. With less baseload capacity required, nuclear capacity disappears from the portfolio and CCGT capacity falls as well. Therefore, very flexible OCGT capacity with low investment costs, alongside some CCGT capacity, is used to complement the IRES dominated portfolio. The same mix of technologies can also fulfil the electricity supply with high demand. Only when the power system is also expected to supply negative emissions some changes are found in the cost-optimal portfolio. The OCGT capacity switches from natural gas to biogas, CCGT is converted to CCGT-CCS, nuclear capacity is reintroduced and some DAC capacity is needed to achieve the required amount of negative emissions.

When the ACGT-CCS technology (see Table 6) is introduced, it is almost the only thermal generation technology needed to complement the decreased IRES capacity. With relatively low costs and zero emissions, this technology might change the future power portfolio considerably.

With a lower discount rate of 3% nuclear capacity increases by 44% from 128GW to 184GW while PV capacity decreases by 61% from 502GW to only 195GW. The installed capacity of other technologies remains similar or decrease slightly compared to the capacities in the Reference scenario.

While other studies highlight the importance of CCGT-CCS capacity [9,16,43], the results of this study suggest that per MWh, CCGT in combination with BECCS is more economical than CCGT-CCS in combination with BECCS, but only when aiming for net zero emissions. The required share of rather expensive BECCS to offset fossil emissions from the CCGT plant is larger (21% BECCS, 79% CCGT) than the required share to offset the fossil emissions from the CCGT-CCS capacity (3% BECCS, 97% CCGT-CCS). Nonetheless, lower investment and operational costs and higher efficiencies of the CCGT plant compared to the CCGT-CCS plant lead to overall lower costs. The advantage, when including all relevant costs in the levelised cost of electricity (LCOE), is 12.3 €MWh−1. However, when aiming for net negative emissions in a biomass constrained world, the emissions from CCGTs are too costly to compensate with DAC, and CCGT-CCS plants become the most economic choice.

The graph in Fig. 12 shows the effect of a change in the techno-economic parameters on the LCOE of the two technologies in Western European power generation portfolio in 2050 assuming alternative techno-economic parameters (see Table 6). The portfolios in the sensitivity runs are not tested with an hourly simulation.
6. Discussion

6.1. Limitations of the study

In the modelling approach, several limitations can be identified. Here the most prominent limitations and their implications for the interpretation of the results are discussed.

6.1.1. Model exclusions

As countries are treated as copper-plates and sub-national transmission limitations are excluded, certain transit flows may exceed the internal capacity of national grid. For example, the results show that certain countries (e.g. the Netherlands) become major electricity transit hubs to transport electricity across Europe (e.g. from the British Isles to Italia). Further sub-national grid modelling would be necessary to identify how national transmission networks would need to be reinforced to deal with such large cross-border flows, this is beyond the scope of this study.

Additionally, the development path towards the 2050 power system is not considered. In particular, including the possibility of retrofitting existing power plants might lead to other cost-optimal solutions.

Although our results show a very limited role for hydrogen, hydrogen as an energy carrier in the future energy system should not be written off based on these results. Hydrogen usage in industry or hydrogen as an energy carrier in the future energy system should not be excluded to deal with such large cross-border flows, this is beyond the scope of this study.

Changes in the assumed investment costs and the efficiencies of the CCGT and CCGT-CCS plants influence the outcome the most. However, it should be noted that when CCGT investment costs would be higher than the previously assumed costs, it is very likely that that costs for CCGT-CCS plants would also be higher and hence their advantage would decrease. A similar argument holds for the efficiency.

combination with BECCS. Despite large changes in the techno-economic parameters, the option with CCGT and BECCS seems to be rather robust. Changes in the assumed investment costs and the efficiencies of the CCGT and CCGT-CCS plants influence the outcome the most. However, it should be noted that when CCGT investment costs would be higher than the previously assumed costs, it is very likely that that costs for CCGT-CCS plants would also be higher and hence their advantage would decrease. A similar argument holds for the efficiency.

production for different applications. Nonetheless, even in the 70% IRES scenario 75% of the curtailed energy is centred in about 1300 h annually. This would result in either a small electrolyser capacity or a low capacity factor for most of the electrolysers. These are unfavourable conditions for the electrolyser business case.

Outages of power plants are modelled; however, outages of transmission lines are not modelled. Historic average outages are around 9% but can be as large as 40% for individual links [59]. Transmission lines are used twice as much across all scenarios compared to the current situation. Thus outages of transmission lines could prove to pose large problems for a power system that relies so heavily on continental-scale transmission.

Concentrated solar power (CSP) might be a feasible technology in the southern parts of Spain, Portugal and Italy [5]. However, its costs remain high compared with other low-carbon technologies [40], and the solar power potential is still captured by utility PV in these regions. Nonetheless, if equipped with sufficient thermal storage in molten salts, CSP would classify as another firm low-carbon technology and could ultimately become a cost-effective option in low-carbon portfolios in regions with favourable solar resources.

Finally, linkage to energy systems outside of Western Europe could change the Western European power system. For example, low cost solar power from PV, CSP or even green hydrogen from the Sahara region could change the generation portfolio considerably. However, while such transcontinental projects were considered several years ago, development appears to have stalled at present. The import of sustainable biomass from other regions might change the power generation portfolios when aiming for net negative emissions. In the −1.1 Gt scenario, the availability of biomass is a limiting factor. With more biomass available, the need for DAC (and thus low-cost baseload capacity from nuclear power) would decrease. Additionally, since BECCS would also generate electricity, even the need for other generation (IRES, gas-fired etc.) would decrease, but could make the portfolio highly reliant on biomass.

6.1.2. Model detail

The IRES hourly capacity factors are fixed for each region in the model based on the IRES penetration rates in the 55% IRES run. This means that possibly more optimal IRES generation profiles could possibly be achieved through a different distribution. On the other hand, basing the IRES generation profiles on the 55% IRES distribution would
mean that additional capacity beyond 55% penetration would have to be built in less optimal locations leading to less favourable generation profiles. It can be expected that the average capacity factor of IRES would go down with further deployment. Nonetheless, major changes to the generation profile are not expected as weather patterns are often highly correlated between neighbouring regions [60].

Related to this, it is remarkable that there is no offshore wind in the Reference scenario, although offshore wind capacity is already installed in Western Europe. Near shore offshore wind energy is less expensive to install; however, no distinction between investment costs is made in this study based on the distance to shore. Additionally, a higher hub height for onshore wind turbines is assumed, which results in capacity factors for onshore wind which are approaching the offshore capacity factors. Consequently, the premium for offshore wind energy might not be justified if the capacity factor increases only slightly compared to onshore wind. On the other hand public acceptance of wind turbines seems higher for wind turbines offshore than of onshore.

With considerable amounts of electricity generation with CCS, the availability of enough storage sites for the captured CO2 also becomes relevant. Estimates of CO2 storage capacity in saline aquifers, hydrocarbon fields and coal fields add up to 95 GtCO2 within the Western European countries [61]. Another estimate [62] does not cover storage capacity in the whole Western European regions, but is more conservative where it overlaps with the previous estimate. Based on linear interpolations between the amounts of CO2 stored in the −1.1 Gt scenario and the Reference scenario, it is estimated that in a zero emission power system, roughly 8 GtCO2 needs to be stored in total until 2100, whereas in the −1.1 Gt scenario a total of 66 GtCO2 needs to be stored, equivalent to about two thirds of the total storage capacity.

Perfect foresight of IRES generation is assumed in the model. IRES generation forecast errors could be increasingly large with increased IRES penetration. This could lead to an increased need for dispatchable reserve capacity in real-time balancing markets and higher costs, which we do not consider.

6.1.3. Input parameters

No indirect emissions are assumed for biomass, or any of the fuels. It is assumed that sustainable biomass is used. Using unsustainable biomass can cause indirect emissions [63] and, even with CCS, may lead to net positive emissions. Indirect emissions from biomass depend on how it is produced, and the distance and means by which it is transported from the field to the power plant. In this study, biomass usage is limited at 5 EJ yr−1 which could be produced within the Western European region to limit transport emissions and costs [49]. As sustainable managed biomass production in Western Europe is deemed possible, the assumed carbon neutrality of biomass as a fuel is reasonable.

No extra costs are assumed for the availability of battery capacity. Additional costs are likely to occur due to extra investments in batteries, distribution grid infrastructure and, if EV batteries are used, bidirectional charging stations. There is likely a trade-off between the advantages of extra load shifting capacity and the additional costs. Since the capacity factor of batteries in the Reference scenario is only around 12% (see Appendix F), it is likely that the cost optimal capacity is lower than assumed in the current study. However, in the 70% IRES scenario, the capacity factors are around 19%. With higher IRES capacity, the cost optimal capacity of batteries will also increase.

6.1.4. Weather selection

In the selection of weather years, deciding which weather year is the most favourable or unfavourable for the power system is non-trivial. The length of a low production (i.e. low wind speed, low solar irradiation) event, the deviation from the average and the spatial distribution of an event influence how favourable or unfavourable certain weather is for the power system. In this study, the approach to select the weather years is based on an equal weighting of annual average wind speed and solar irradiation for the whole of Western Europe. As the selected unfavourable weather year matches the winter with the lowest production as identified in another study working with the same dataset [24], we are confident that the weather year is highly unfavourable for the Western European power system. Moreover, this year is selected from a dataset with 480 weather years and should thus be an extreme case.

6.2. Comparison with existing literature

Comparing the results to other studies, a common conclusion is the importance of interannual variability [17]. This variability has an effect on power system costs, emissions and curtailment and increases with the penetration of IRES [13].

As also found by other studies, the costs of the power system increase somewhat with increased penetration of IRES [5,9]. In this study, the 70% IRES scenario resulted in 10% higher system costs compared to the Reference scenario. Also [9] find about a 10% cost difference between the scenario with the lowest IRES penetration and the scenario with the higher IRES penetration, comparable to the Reference and 70% IRES scenarios respectively. Of course, this difference might decrease when the costs of solar-PV and wind turbines would decrease more than assumed in our study.

There is less consensus regarding the technology options used in the portfolio. The importance of firm low-carbon capacity is also stressed in other studies [5,8,43] but which technology should fulfill this role is less clear. However, some studies suggest much higher penetration rates of IRES (e.g. [4,6,7]). However, these studies focus on a 100% renewable power system and thus allow a limited capacity firm low-carbon capacity as firm renewable capacity is limited (e.g. CSP by suitable area, hydropower by geographic potential, biomass by sustainable availability).

Since nuclear power faces political opposition in Western Europe, nuclear capacity is often limited exogenously in other studies (e.g. [9,16]). However, when nuclear capacity is unconstrained, literature suggests that at near zero or zero carbon targets nuclear capacity could indeed play an important role [5,28]. This outcome is supported by our study, where under the assumptions in the Reference scenario, nuclear power provides 30% of the total load.

While some studies highlight the importance of CCGT-CCS capacity in low-carbon power systems [9,16,43], in this study no role for CCGT-CCS capacity is found in the Reference scenario with zero carbon emissions. CCGT-CCS only plays a role when deep negative emissions are required from the power system. One possible reason is the large role played by nuclear power. Another is that BECCS is included as a technology option, which was not included in the aforementioned studies. In our net zero portfolio, the availability of BECCS allows for the offset of emissions caused by the CCGT capacity. Daggush, Heuberger & Dowell also find that with allowing BECCS capacity, the CCGT capacity increases as well [64].

7. Conclusion

In this study, several scenarios of a future Western Europe power system in 2050 are modelled to identify the major components of a reliable and cost-optimal portfolio that are both consistent with the Paris Agreement on climate change and robust enough to deal with variable weather patterns. From the results, it is found that:

- Interannual weather variability leads to a difference in IRES generation between the most favourable and least favourable weather years of up to 6%, emissions differ up to 70 MtCO2 yr−1, total system costs up to 4% and variable system costs up to 25%.
- Although there is some curtailment of IRES in all scenarios, hydrogen as a means of storing excess electricity is hardly deployed due to the high investment costs, a low roundtrip efficiency and the low potential capacity factors of the storage. Even when IRES
provide up to 70% of the generation, curtailment reaches 100 TWh yr$^{-1}$, there is no significant hydrogen storage capacity deployed.

- Alongside IRES, firm low-carbon capacity is a vital part of the cost-optimal power generation portfolios and can be provided by a number of technologies including natural gas with CCS, nuclear, bioenergy with CCS and hydro. In most scenarios, low-carbon capacity of at least 75% of peak demand is required for a cost-optimal portfolio.
- In a power sector targeting net-zero emissions, CCS is most cost-effective when applied with bioenergy. Only when targeting significant net-negative emissions and the availability of sustainable biomass is limited, is CCS applied to gas-fired generation and direct air capture of CO$_2$ becomes necessary. This might change if 100% carbon capture from natural gas generation with CCS can be achieved cost-effectively in the future (e.g. with Allam cycle gas turbine technology).
- Based on the techno-economic parameters assumed in this study, nuclear power is one of the cost-optimal options to deliver firm zero-carbon capacity. However, given cost uncertainties, or if the contribution of nuclear power is constrained, the same amount of firm low-carbon capacity can be achieved with a combination of natural gas and bioenergy fired power plants with CCS at only 1% higher total system costs. Also, nuclear power is no longer economically attractive at a penetration level of 70% IRES or higher.

When considering the reliable operation of high IRES power systems within countries it should be noted that:

- System adequacy can be maintained by a combination of firm low-carbon technologies, a high dependence on cross border transmission, shifting electricity generation using batteries to match the demand and curtailment of up to 15% of total IRES generation.
- A shift to new types of ancillary power system service technologies such as synchronous compensators or electronic controllers is a prerequisite for high IRES systems as the role of traditional dispatchable thermal generation will decrease.

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Appendix A. Future weather years

We select weather years from the KNMI’14 scenarios [65] with the lowest and highest IRES generation to find the maximum influence of weather on the electricity system. The resulting unfavourable weather year is sample NR 80 from the scenario with a negative North Atlantic oscillation (NAO) index [66] and high temperature change. The NAO is the most dominant mode of atmospheric variability over the North Atlantic basin in winter. A negative NAO index generally results in low IRES energy production and vice versa [24,67]. The same sample is also identified by Ravestein, van der Schrier, Haarsma, Scheele & van den Broek et al. [24] as one of the years with a winter with the lowest IRES generation. The favourable weather year is sample NR 2 from the scenario with a positive NAO index and a high temperature change Fig. 13 shows all weather years available for selection with their averaged wind speed and solar irradiation. For the unfavourable weather year there are years with lower average wind speed and years with lower irradiation.

![Fig. 13. Average daily solar irradiation and average wind speed for All 480 Weather years. The unfavourable (red), average (yellow) and favourable (green) weather years are also indicated.](image)

Appendix B. Electricity demand

Future electricity demand in all regions is based on current electricity load patterns. ETNSO-E [68] load data for the year 2015 is available for all countries in the considered regions. It is generally expected that increasing energy efficiency will decrease the electricity demand. However, with increased electrification of other end use sectors, the total electricity demand is assumed to experience a net increase towards 2050. Especially in decarbonisation scenarios, the share of electricity in the final energy demand is expected to increase [10].

In this study we consider a demand increase towards 2050 based on increased usage of heat pumps (HPs) and electric vehicles (EVs). The increased demand adds up to an annual demand increase of 0.8% between 2015 and 2050. Additionally, in our study a case with a higher demand is also investigated. The annual increase in this Higher demand case is 2.1%, building up to more than a doubling in 2050. The electricity growth rate
in the low demand case is in line with ambitious European energy scenarios such as the advanced ‘energy [r]evolution’ scenario (0.6%) [11] the ‘Global Union’ scenario (0.8%) [69] and the ‘Roadmap 2050’ scenario (0.8%) [10]. In their mid-term adequacy forecast, ENTSO-E [70] predict annual demand changes for the countries considered in this study ranging between −0.3% (Germany) and 1.8% (Ireland).

With the increased electrification of other end use sectors, the demand profile is also expected to change. The demand pattern for EVs is based on projected data from Verzijlbergh [71] while accounting for different demands per weekday based on a JRC [72] report. The projections from JRC are based on survey data for current (mostly conventional) car usage patterns. We follow the assumption of the ECF [10] where roughly 60% of all vehicles, 100% of personal vehicles, equivalent to 4200 billion km driven, are fully electric or plug-in hybrid vehicles. The resulting annual electricity demand for EVs is assumed to be 710TWh for the whole of the European Union. According to the International Energy Agency more than 40% of global passenger cars will need to be electric vehicles in order to reach the below 2 degree scenario [73]. Therefore, we assume a share of 100% in Europe is considered ambitious but reasonable for a below 1.5-degree scenario. The electricity demand across the considered countries is distributed based on the most recent available data on the size of the passenger car fleet [74], see Table 11.

Within the Roadmap 2050 report [10] it is assumed that 90% of building heating and will be delivered by heat pumps. Given the current electric demand for heating and the current total heating demand [75] the new electricity demand per country is determined, see Table 11. Note that for countries which already have a high share of electric heating, the net increase due to HP demand can be small, or even below zero, meaning a decrease in electricity demand for electric heating. For the temperature, the bias-corrected data consists of the daily minimum, maximum and average temperature. The hourly temperature is approximated based on the historic relation of hourly temperature values to the daily minimum, maximum and average temperature. Additionally, for each grid cell the population density is determined, based on the European population density on a NUTS-3 level [76]. Using both the hourly temperature and the population density per grid cell, the hourly heating demand is approximated by calculating the population density weighted heating degree hours (E1)–(E3):

For each country \( c \) and every hour \( h \):

\[
HDH_{\text{weighted}_c,h} = \frac{\sum_g (HDH_{g,h} \cdot pop_{c,g})}{\sum_g pop_{c,g}}
\]  

(E1)

where \( pop_{c,g} \) is the population of country \( c \) in grid cell \( g \). The heating degree hours are calculated using Eq. (E2):

For every hour \( (h) \) in the year and every grid cell \( (g) \):

| Table 11 | Contributions to the total load in all study regions. |
|----------|---------------------------------------------------|
| Country  | Region    | Load 2015 (TWh) | Load EVs (TWh) | Load HPs (TWh) | High electrification (TWh) |
| Austria  | Italia    | 70              | 13             | 10             | 133                        |
| Belgium  | Belgium   | 85              | 16             | 13             | 120                        |
| Switzerland | Italia    | 62              | 13             | 7              | 37                         |
| Germany  | Germany   | 505             | 126            | 97             | 320                        |
| Denmark  | Scandinavia | 34           | 7              | 9              | 26                         |
| Spain    | Iberia    | 248             | 63             | 1              | 406                        |
| France   | France    | 471             | 91             | 29             | 382                        |
| Ireland  | British Isles | 27          | 6              | 4              | 61                         |
| Italy    | Italia    | 314             | 104            | 46             | 299                        |
| Luxembourg | Germany   | 6               | 1              | 1              | 22                         |
| Netherlands | The Netherlands | 113       | 22             | 16             | 175                        |
| Norway   | Scandinavia | 129           | 7              | −12            | 35                         |
| Portugal | Iberia    | 49              | 13             | 0              | 87                         |
| Sweden   | Scandinavia | 136           | 13             | −3             | 45                         |
| United Kingdom | British Isles | 291       | 85             | 44             | 226                        |
| Total in study | 2541      | 579            | 262            | 2285           |

| Table 12 | Summary of load profile per region. |
|----------|------------------------------------|
| Region   | Total load (TWh) | Peak load (GW) | Minimum load (GW) | Average load (GW) |
| Belgium  | 113.7               | 23.5           | 8.2               | 13.0              |
| British Isles | 456.0          | 92.6           | 29.7              | 52.1              |
| France   | 591.0               | 121.5          | 36.6              | 67.5              |
| Germany  | 736.9               | 163.8          | 48.4              | 84.1              |
| The Netherlands | 151.9         | 30.6           | 10.9              | 17.3              |
| Iberia   | 374.8               | 58.1           | 27.0              | 42.8              |
| Italia   | 638.1               | 130.6          | 40.1              | 72.8              |
| Scandinavia | 320.3          | 54.9           | 25.8              | 36.6              |
| Total    | 3382.7              | 665.9          | 259.8             | 386.2             |
Where the reference temperature is lower at night-time to reflect that most people are asleep and commercial buildings are generally unoccupied:

$$T_{ref} = \begin{cases} 
18 & \text{for } (h \mod 24) > 6 \text{ AND } (h \mod 24) < 10 \\
12 & \text{for } (h \mod 24) \leq 6 \text{ OR } (h \mod 24) \geq 10 
\end{cases}$$

(E3)

Finally, the electric heating demand is distributed over the hours in the year based on the In the Higher demand case, an even higher electrification is assumed. This demand is based on a projected average annual economic growth in line with the average annual growth for that country over the past 30 years [77] and an annual decrease of energy intensity for each country based on the last 20 years [78]. It is assumed that an additional effort can lead to an additional decrease of energy intensity of 1%-point. The current final energy demand [79,80] for each country is projected towards 2050 based on these values. In the Higher demand case, we assume that the electricity demand constitutes 67% of final energy demand. All the demand on top of the base, EV and HP profiles is added as a constant electricity demand throughout the year. For comparison, full electrification of the heavy industry in Europe in 2050 would add 1713 TWh [81]. The total, peak, minimum and average load per model region are shown in Table 12.

Appendix C. IRES generation profiles

Wind data is available at a six-hourly scale and linearly interpolated to hourly data. For onshore wind turbines we assume a hub height of 150 m, while for offshore turbines we assume a hub height of 100 m. The weather data contains wind speeds at these heights. Hence, no further weather data manipulation is needed.

Based on the yearly average wind speed, different onshore wind turbines classes are assigned to the different grid cells. If the yearly average wind speed is below 6.5 m/s, a grid cell is assigned class III turbines, if the wind speed is above 6.5 m/s but below 7.5 m/s, a grid cell is assigned class II turbines and with annual average wind speeds above 7.5 m/s, a grid cell is assigned class I turbines. Only one type of wind turbines is used for offshore wind locations. A power curve per different type of turbine is used to translate the wind speed to electric power generation. Since the wind speeds throughout a grid cell (or a wind farm) are not constant, the power curves are smoothed to approximate a multi-turbine wind curve, see Fig. 14.

Solar irradiation is available at as the total irradiation over a whole day. The hourly irradiation is determined based on the theoretical maximum irradiation received at the specific latitude and longitude at every hour of the year based on the Erbs model [82]. The hourly theoretical maximum irradiation is then scaled to the total daily irradiation.

All PV panels are assumed to be tilted 35° towards the south. Based on the ratio between the maximum theoretical hourly irradiation and the estimated hourly irradiation, the ratio between diffuse and direct radiation is calculated based on the Reindl model [83]. Consequently, the irradiation on the solar panels can be determined.

The electricity generation \( P_{pv,t} \) is calculated using equations E4-E6 where:

\[
P_{pv,t} = P_{STC} \left( \frac{G_{panel,t}}{G_{STC}} \right) (1 - \delta(T_{NOCT} - T_{cell,t}))PR
\]

(E4)

\[
T_{cell,t} = T_{mod,t} \left( \frac{G_{panel,t}}{G_{STC}} \right) \Delta T_{cond}
\]

(E5)

\[
T_{mod,t} = G_{panel,t} \times a^{4 \text{ loc} + T_{t}}
\]

(E6)
Appendix D. Emission target

The remaining global energy carbon budget\(^{11}\) (post 2017) for an unlikely chance (33%) of staying below 1.5 °C global temperature increase is 490 GtCO\(_2\) [2]. In highly ambitious mitigation scenarios, non-OECD countries will still emit between 502 GtCO\(_2\) and 620 GtCO\(_2\) in this century [2]. Although we are aware of the uncertainties surrounding negative emissions (see e.g., [84]), we assume that future negative emissions can offset current emissions. If non-OECD countries emit the average amount of CO\(_2\) (561 GtCO\(_2\)), the remaining OECD carbon budget for this century therefore is −71 GtCO\(_2\).

The final distribution of emission rights per country is in the end a political decision. Here we assume a distribution on the ground of the current population of the OECD member states [85,86]. Based on this distribution, the remaining carbon budget for energy related activities\(^1\) in the countries in the scope of this research is −22 GtCO\(_2\).

Additionally, we assume that emission decrease linearly towards 2050 and stay constant from 2050 to the end of the century. Current energy related emissions of these countries are 3 GtCO\(_2\)-eq annually. The resulting annual emission target in 2050 is −1.1 GtCO\(_2\). The assumed emissions pathway is shown in Fig. 15 below. In this study, we assume that all negative emissions should be achieved by the power sector, while other sectors combined must achieve net zero emissions in 2050.

![Fig. 15. Assumed emission pathway to achieve a 33% chance of staying below 1.5 °C global temperature increase for the countries in the scope of this research.](image)

Appendix E. IRES capacity

The location of installed IRES capacity (wind and solar PV) is based on the outcomes of the EC-Earth model\(^{12}\) and geographic land use data. The EC-Earth model has climatic results for each cell in a grid covering Europe. For each of these grid cells, the maximum installed renewable capacity is determined for the technologies (1) onshore wind, (2) offshore wind, (3) roof photovoltaics and (4) utility photovoltaics.

The maximum potential per grid cell is based on several geographical factors and assumptions on how the technologies can be located on varying land types. First, a dataset from Eurostat [87] of countries is used to determine the country where the grid cells are located. Additionally, a similar procedure is followed for the marine economic exclusive zones of each country [88]. The locations where IRES is placed are limited by a water depth [89] of maximum 50 m and cannot be placed in protected nature areas [90]. Finally, for all possible grid cells, the land use [37] is considered to determine the possible installed capacity of IRES in each grid cell. This methodology is similar to one used by the European Environment Agency to determine the onshore and offshore wind capacity in Europe [91].

All IRES generation profiles are based on the 55% IRES scenario, with IRES capacities based on the ‘large scale RES’ scenario from the e-Highway project [33]. The installed capacity is scaled down based on the difference in electricity demand in the ‘large scale RES’ scenario and electricity demand in this study. The installed capacities per country for each technology are checked with the maximum potential determined previously and adjusted if necessary. The resulting installed capacities per country are shown in Table 13 below. Additionally, Table 13 also shows the assumed distribution of IRES in the 70% IRES scenario, based on the ‘Global climate action’ scenario in the ten year network development plan of the ENTSO-E [26]. For each grid cell, the historic capacity factor is calculated based on historic weather data [92,93]. The renewable capacity is then distributed over the grid cells with the highest historical capacity factors.

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\(^{11}\) Excluding process emissions from the cement industry; assuming that emissions from deforestation are fully compensated by sequestration from among others afforestation activities. Including emissions from international aviation and shipping.

\(^{12}\) The EC-Earth model is an Earth System Model (ESM) which includes various additional subsystems compared to traditional general circulation models. The model was developed by a large number of members of the European Centre for Medium-range Weather Forecast (ECMWF). More information about the EC-Earth model is discussed by KNMI [94].
Appendix F. Capacity factors

In Table 14 below, the average capacity factor per technology is given for all scenarios. When no data is presented, the technology is absent in the scenario.

### Table 13
Minimum installed capacity of IRES in the 55\% IRES and the 70\% IRES scenarios in 2050 based on [26,33].

| (GW) | Onshore wind | Offshore wind | Roof PV | Utility PV |
|------|--------------|---------------|---------|------------|
|      | 55\% | 70\% | 55\% | 70\% | 55\% | 70\% | 55\% | 70\% |
| AT   | 7.9  | 8.3  | 0.0  | 0.0  | 4.5  | 5.7  | 1.2  | 1.5  |
| BE   | 4.5  | 4.5  | 1.6  | 4.1  | 6.1  | 26.1 | 0.5  | 2.3  |
| CH   | 4.0  | 4.6  | 0.0  | 0.0  | 6.7  | 13.2 | 1.6  | 3.0  |
| DE   | 45.2 | 45.2 | 15.9 | 43.8 | 34.5 | 145.9| 8.5  | 36.1 |
| DK   | 8.8  | 8.8  | 24.7 | 12.5 | 1.3  | 6.1  | 0.8  | 3.5  |
| ES   | 75.2 | 76.2 | 0.0  | 4.8  | 20.8 | 61.2 | 13.0 | 38.2 |
| FR   | 78.5 | 79.7 | 12.7 | 26.3 | 17.9 | 54.3 | 7.6  | 23.1 |
| IE   | 12.9 | 12.2 | 2.7  | 3.3  | 0.1  | 1.0  | 0.1  | 1.6  |
| IT   | 43.2 | 40.0 | 3.9  | 15.4 | 16.5 | 57.2 | 5.2  | 18.0 |
| LU   | 0.3  | 0.3  | 0.0  | 0.0  | 0.1  | 1.2  | 0.0  | 0.2  |
| NL   | 6.8  | 6.8  | 7.1  | 28.0 | 4.1  | 49.5 | 0.8  | 9.9  |
| NO   | 26.2 | 28.3 | 0.5  | 1.4  | 0.1  | 1.4  | 0.2  | 2.4  |
| PT   | 10.5 | 11.0 | 0.1  | 3.4  | 2.6  | 17.5 | 0.8  | 5.2  |
| SE   | 17.5 | 17.5 | 0.5  | 3.7  | 0.9  | 6.2  | 0.4  | 2.4  |
| UK   | 37.8 | 33.6 | 31.7 | 39.8 | 3.7  | 37.3 | 1.3  | 13.0 |
| TOTAL| 379.2| 376.8| 101.4| 186.4| 120.1| 483.8| 42.1 | 160.6|
Table 14
Overview of capacity factors per technology in the main scenarios.

| Technology       | No CCS favourable | No CCS unfavourable | Low nuclear favourable | Low nuclear unfavourable |
|------------------|-------------------|---------------------|------------------------|-------------------------|
| OCGT (biogas)    | 82%               | 81%                 | 83%                    | 81%                     |
| CCGT (natural gas) | 42%             | 36%                 | 46%                    | 37%                     |
| Hydrogen storage | 9%                | 10%                 | 1%                     | 1%                      |
| DAC              | 91%               | 99%                 |                        |                         |
| EV Battery       | 12%               | 13%                 | 18%                    | 20%                     |
| CCGT CCS (natural gas) | 42%     | 35%                 |                        |                         |
| Offshore wind    | 33%               | 37%                 | 38%                    | 43%                     |
| Roof PV          | 12%               | 13%                 | 11%                    | 12%                     |
| Utility PV       | 11%               | 12%                 | 11%                    | 12%                     |
| Geothermal       | 8%                | 7%                  | 14%                    | 17%                     |
| Hydrogen (P(H))  | 28%               | 28%                 | 26%                    | 25%                     |
| Hydrogen (RO)    | 28%               | 28%                 | 29%                    | 29%                     |
| Hydrogen (ST)    | 38%               | 38%                 | 38%                    | 38%                     |

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LHV: Lower heating value
LT: Long term
NAO: North Atlantic oscillation
OCGT: Open cycle gas turbine
PCSC: Pulverised coal super critical
PHS: Pumped hydro storage
PV: Photovoltaics
ROR: Run-of-river

ST: Short term
STO: Dam storage (hydro power)
TCR: Total capital requirement
TYNDP: Ten-year network development plan (ENTSO-E)
UCED: Unit commitment and economic dispatch
VOLL: Value of lost load
VOM: Variable operation and maintenance (costs)