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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 $MtCO_2\,yr^{-1}$ 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 $GtCO_2$ 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 $GtCO_2$ and 420 $GtCO_2$ 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 CO_2 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.

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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 $MtCO_2\,yr^{-1}$ [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 CO_2 (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 focusses 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 CO_2 emissions from public heat and power generation in this geographical region were 684 $MtCO_2$ 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/).

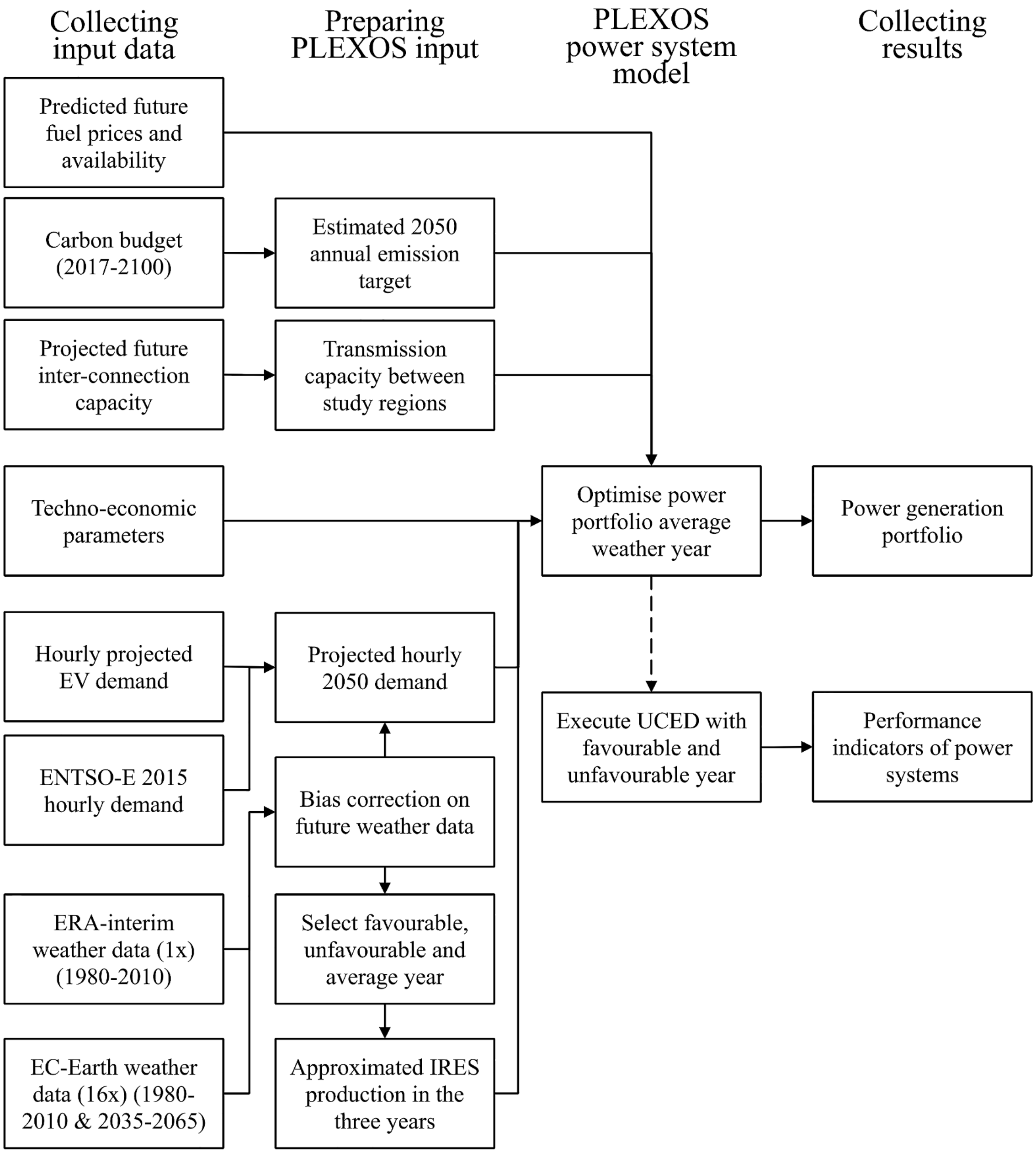

Fig. 1. Overview of methodology.

is stimulated. The *No CCS* scenario is similar to the *Reference* scenario, but the application of CCS technologies is not allowed.[2] 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 CO_2 emissions in 2050 are constrained to zero. However, in the *−1.1 Gt* scenario, a more ambitious emission cap of -1.1 $GtCO_2$ 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 H_2 storage* scenario, 22 TWh of hydrogen storage capacity is exogenously forced into the portfolio, in line with the potential indicated in the Hyunder project [34]. With this sensitivity run, the potential contribution of seasonal hydrogen storage for IRES integration can be studied. In the *Higher*

[2] As the emission target is 0.0 $GtCO_2\,yr^{-1}$ and in this study negative emissions could only be achieved with CCS technologies (BECCS and DAC), only zero emission power sources can be used.

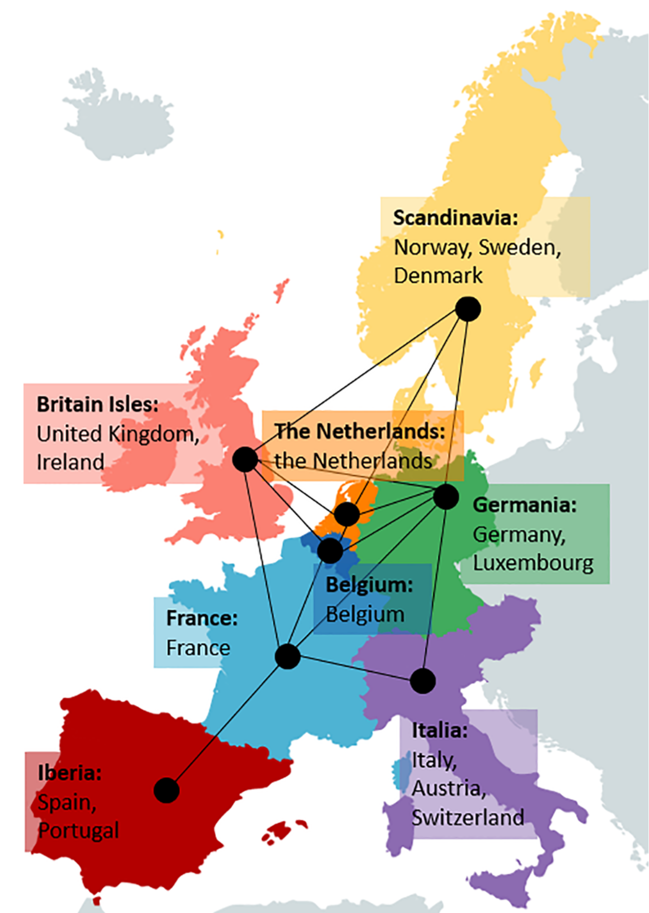

Fig. 2. Regions and countries modelled in this study. The cross-border transmission lines are indicated by the black lines.

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

Table 1
Overview of the modelled scenarios and their most important constraints.

	Model run	IRES capacity (GW)	Demand (TWh)	Hydrogen storage (TWh)	CCS allowed	Nuclear capacity (GW)	Fossil capacity (GW)	Transmission capacity (GW)	Net CO_2 (Gt yr^{-1})
Core scenarios	Reference	Freely optimised	3400	Freely optimised	Yes	Freely optimised	Freely optimised	63	0.0
	70% IRES	1385	3400	Freely optimised	Yes	Freely optimised	Freely optimised	63	0.0
	No CCS	Freely optimised	3400	Freely optimised	No	Freely optimised	Freely optimised	63	0.0
	Low nuclear	Freely optimised	3400	Freely optimised	Yes	51	Freely optimised	63	0.0
	−1.1Gt	Freely optimised	3400	Freely optimised	Yes	Freely optimised	Freely optimised	63	−1.1
Sensitivity runs	Optimised transmission	Freely optimised	3400	Freely optimised	Yes	Freely optimised	Freely optimised	Freely optimised	0.0
	55% IRES	994	3400	Freely optimised	Yes	Freely optimised	Freely optimised	63	0.0
	Fixed H_2 storage	Freely optimised	3400	22.4	Yes	Freely optimised	Freely optimised	63	0.0
	Higher demand	Freely optimised	5300	Freely optimised	Yes	Freely optimised	Freely optimised	63	0.0

solar irradiation over Western Europe. In the selection, equal weighting is given to solar irradiation and wind speed (see Appendix A). The weather parameters for the three years (i.e. average, favourable and unfavourable) are converted to electricity based heat demand and IRES generation profiles using theoretical approximations (see Appendices B and C). The maximum IRES potential per model region is based on current land use [37] similarly to [5].

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.[3] 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.[4] 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 m^3 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_{H2}^{-1} and FOM costs of 39 € kW_{H2}^{-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 CO_2 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.

[3] 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.

Table 2
Techno-economic parameters for the 2050 portfolio of electricity generation technologies used in the PLEXOS model.

Type	Technology	TCR[a] (€ kW^{-1})	FOM costs (€ kW^{-1} yr^{-1})	VOM costs (€ MWh^{-1})	Efficiency[b] (–)	Lifetime (yr)	Build time (yr)
Firm (low-carbon)	PCSC[d]	2000	41	3.7	48.0%	40	4
	PCSC-CCS[c,d]	3300	65	5.6	38.0%	40	5
	IGCC (coal)[d]	3000	59	5.1	47.0%	35	5
	IGCC-CCS (coal)[c,d]	3700	85	6.1	41.0%	35	6
	OCGT (natural gas)	600	17	11.0	44.0%	30	1
	OCGT (biogas)[l]	600	16	11.0	44.0%	30	1
	CCGT (natural gas)	1000	22	2.5	62.0%	30	3
	CCGT (hydrogen)[h]	1000	19	2.5	62.0%	30	3
	CCGT-CCS (natural gas)[c]	1600	33	4.0	55.0%	30	4
	Nuclear[e]	5300	66	2.5	38.0%	60	7
	BE[g]	2500	38	3.9	38.0%	25	3
	BECCS[c,k]	4100	49	5.9	30.1%	25	4
	Geothermal	3500	60	0.0	–	30	3
	Hydropower (PH.S & STO)	4000	51	5.1	–	60	3
	Hydropower (ROR)	3500	38	5.0	–	60	3
Fuel saving	Onshore Wind	1300	35	0.0	–	25	1
	Offshore Wind[f]	2600	49	0.0	–	30	1
	Utility PV	500	8	0.0	–	25	1
	Roof PV	600	12	0.0	–	25	1
Other	Hydrogen electrolyser[i,j]	400	7	0.0	65.5%	10	1
	DAC[j,m,n]	42,500	–	137.0	–	20	1

Abbreviations: TCR: total capital requirement, FOM: fixed operation and maintenance costs, VOM: variable operation and maintenance costs, OCGT: open cycle gas turbine, CCGT: Combined cycle gas turbine, PCSC: Pulverised coal super critical, IGCC: Integrated gasification combined cycle, PV: Photovoltaics, BE: Bioenergy, PHS: Pumped hydro storage, STO: dam storage, ROR: Run-of-river, CCS: Carbon capture and storage; DAC: Direct air capture of CO_2; BECCS: Bioenergy with carbon capture and storage.

[a] The total capital requirement (TCR) is calculated based on the total overnight costs, the build time and interest rate. The interest during construction is included assuming that the investments costs are distributed equally over the construction time.

[b] The efficiency is defined as net efficiency at full load power and at lower heating value (LHV).The efficiencies of PV and wind technologies are discussed in Appendix C.

[c] A capture ratio of 90% is assumed. Costs for CO_2 transport and storage are assumed to be 13.5 € $kgCO_2{}^{-1}$.

[d] Although coal fired generation is an option in the optimisation, in none of the model runs any coal generation is used.

[e] Costs for decommissioning are not specifically included.

[f] These costs include the costs for the connection of offshore wind to the grid.

[g] It is assumed that fluidised bed technology is used for bioenergy.

[h] The techno-economic parameters are taken to be same as the Based on CCGT data.

[i] Based on Siemens Silyzer projections [44].

[j] In this case, kW and MWh refers to the electric input capacity.

[k] Based on the bioenergy data and the relative cost increases and efficiency drop between PCSC and PCSC-CCS.

[l] Based on the OCGT natural gas fired power plants. Biogas fired OCGT might often have smaller capacities than their natural gas fired counterparts, however, techno-economic parameters are assumed to be similar.

[m] Based on the literature overview of PBL [3] and detailed data from Socolow et al. [45], inferred from investments of 425 € $tCO_2{}^{-1}$ and operation costs of 240 € $tCO_2{}^{-1}$ assuming a 100% capacity factor. Additionally, DAC's capture 2000 $kgCO_2$ MWh^{-1}.

[n] Next to electricity demand, DAC also requires 6 GJ $tCO_2{}^{-1}$ heat. The source of this heat is not considered. Consequently, no additional costs and associated emissions are considered.

Table 3
Techno-economic parameters of archetypical hydrogen storage sites. Costs are based on the techno-economic parameters of electrolysers, salt cavern hydrogen storage and hydrogen turbines combined in one storage facility.

Type	Max power (MW_{H2})	Available storage capacity (days)	Total investment costs (M€ $site^{-1}$)	Capital costs (€ $kW_{H2}{}^{-1}$)
I	360	15	613	1700
II	185	30	333	1800
III	62	90	130	2100

3.7. Parameters in sensitivity analysis

Aside from the sensitivity model runs, further sensitivity analysis is performed with alternative techno-economic parameters (Table 5). For the IRES technologies, parameters lowering overall costs are assumed. On the other hand, higher costs are assumed for nuclear power generation, which would be more realistic if nuclear power will only play a limited role in the future electricity supply. Finally, a novel technology, the Allam cycle gas turbine[5] (ACGT-CCS) is added in the sensitivity analysis. This technology is still under development, but could provide relatively cheap electricity based on natural gas without emissions [52].

A uniform discount rate of 8% is used. The discount rate affects the weighing of the investment costs. Analysis of the past development of the UK electricity system showed that using an 8% discount rate for cost optimisation resulted in smaller deviations from the real world development than a social discount rate of 3.5% [53]. Private energy companies make investments in the power system and they are generally working with higher discount rates. However, often social discount rates are often used in these types of studies. Therefore, a sensitivity analysis is performed with a discount rate as low as 3% being the lower bound of social discount rates used in scenario studies and policy making by governments [54–56].

[5] The Allam cycle is a natural gas fired cycle with CO_2 as the working fluid, making a near 100% capture rate of CO_2 possible whilst achieving high electric efficiency.

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	Germania	Scandinavia	France	Iberia	Italia	British Isles	Total
The Netherlands		3400	5000	1400				3800	13,600
Belgium	3400		1430		3550			1000	9380
Germania	5000	1430		6700	4690		11,950	1400	31,170
Scandinavia	1400		6700					1400	9500
France		3550	4690			5000	5930	6800	25,970
Iberia					5000				5000
Italia			11,950		5930				17,880
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

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

Fuel	Price[a] (€ GJ^{-1})	Maximum fuel usage[b] (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[c]	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].

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 H_2 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.

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
Roof PV	400	8	0.0	–	30	1
ACGT-CCS[a]	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.

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

In the *Low Nuclear* scenario there is a considerable increase in IRES capacity compared with the *Reference* scenario, mostly from PV as well as some offshore wind. Additionally, a mix of BECCS, CCGT and OCGT capacity takes over some of the generation previously provided by nuclear power.

In the *−1.1 Gt* scenario, there is not sufficient biomass for BECCS to generate enough negative emissions to meet the more ambitious net-negative carbon cap. All CCGT plants from the *Reference* scenario are replaced by CCGT-CCS capacity to minimise the amount of emissions

[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.

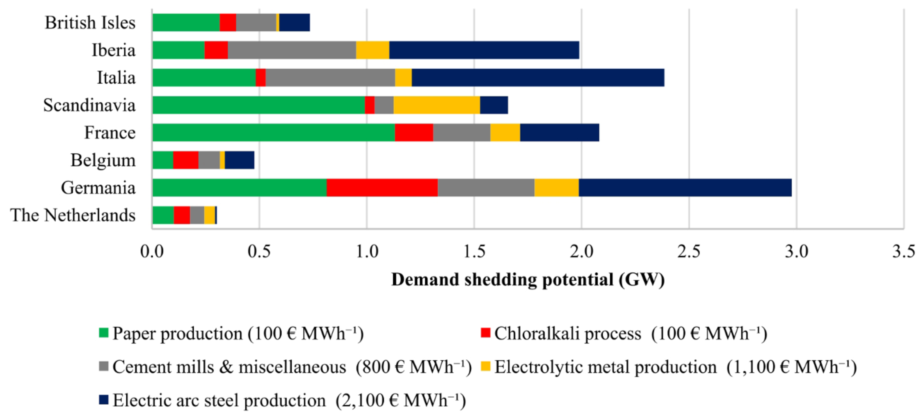

Fig. 3. Demand shedding potential for different industrial processes in the modelled regions in 2050, based on [9,51].

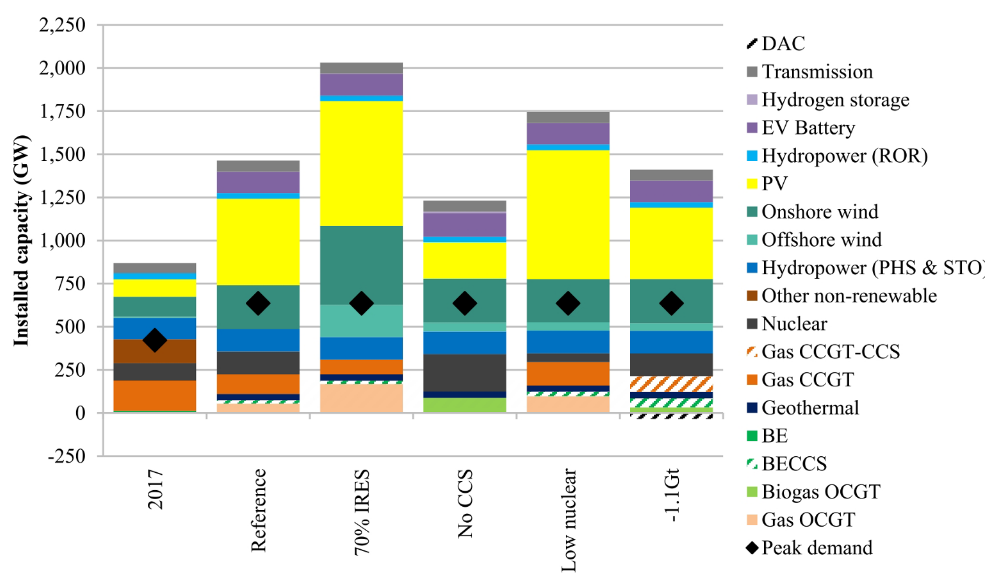

Fig. 4. The installed capacity per technology in 2050 in Western Europe for different scenarios.

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. Annual costs in the *No CCS* and *Low nuclear* scenarios are only 5% and 1% higher than the *Reference* scenario respectively. 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[7]. 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

[7] E.g. assuming BECCS would replace nuclear capacity, both operating at a 75% capacity factor, additional negative emissions can be reached at a cost of 57 € tCO_2^{-1}.

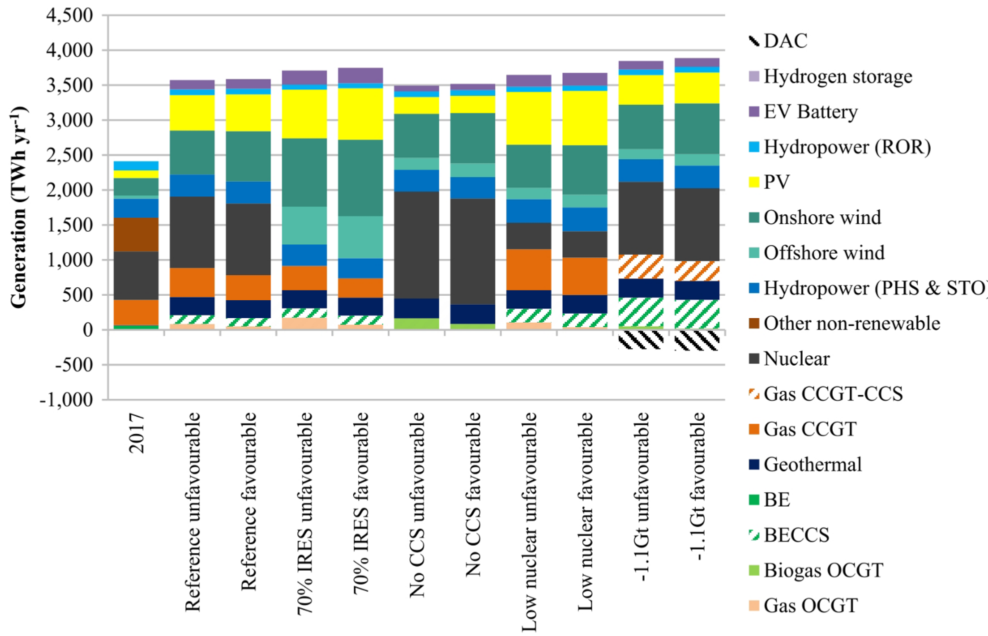

Fig. 5. Annual power generation in 2050 by source in Western Europe for both the favourable and unfavourable weather year in the different scenarios.

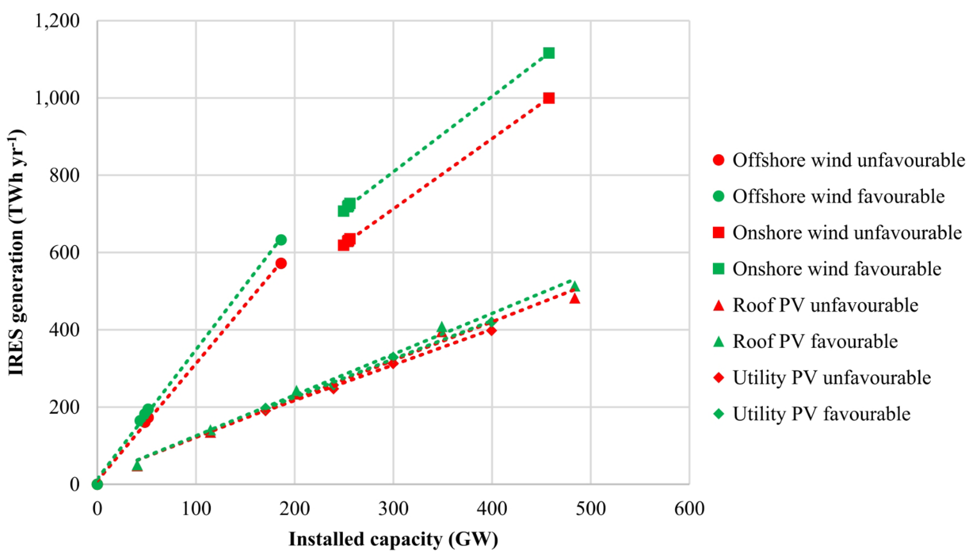

Fig. 6. Difference between IRES generation in the favourable and unfavourable weather year for the different IRES technologies.

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 $MtCO_2\,yr^{-1}$, while the difference in the *Reference* scenario is 26 $MtCO_2\,yr^{-1}$. 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 ($MtCO_2\,yr^{-1}$)	Curtailed IRES generation ($TWh\,yr^{-1}$)	Total system costs[a] (billion € yr^{-1})	Variable system[b] 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	−1030	31	393	133
	Favourable	−1075	36	388	128

[a] System costs do include fixed and operational costs, but do not include cost of unserved energy.
[b] Variable system costs consist of generator VOM costs, fuel costs, CO_2 transport and storage costs, generator start and shutdown costs and demand curtailment costs.

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

Scenario	Weather year	CCS capacity (GW)	Emissions stored with CCS ($MtCO_2\,yr^{-1}$)	Total negative emissions[a] ($MtCO_2\,yr^{-1}$)
Reference	Unfavourable	20	150	150
	Favourable		142	142
70% IRES	Unfavourable	19	159	159
	Favourable		157	157
No CCS	Unfavourable	0	0	0
	Favourable		0	0
Low nuclear	Unfavourable	25	232	232
	Favourable		233	233
−1.1Gt	Unfavourable	179	1155	1043
	Favourable		1179	1086

[a] Note that there are also positive emissions in most of the scenarios. The net emissions per scenario can be found in Table 7.

4.4. CCS deployment

With 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 CCGT-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.[8] 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

Table 9
Use of electricity storage in batteries in Western Europa in the core runs for 2050.

Scenario	Weather year	Electricity supplied from batteries in Western Europe ($TWh\,yr^{-1}$)
Reference	Unfavourable	135
	Favourable	139
70% IRES	Unfavourable	201
	Favourable	220
No CCS	Unfavourable	80
	Favourable	87
Low nuclear	Unfavourable	169
	Favourable	182
−1.1Gt	Unfavourable	122
	Favourable	127

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

[8] When CCS technologies are excluded, this effectively excludes all fossil technologies which emit CO_2, since even small positive CO_2 emissions cannot be offset using negative emission technologies, as these rely on CCS.

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%
2017[a]	n/a	0	0	0	0	42.6%

[a] Based on [38,57].

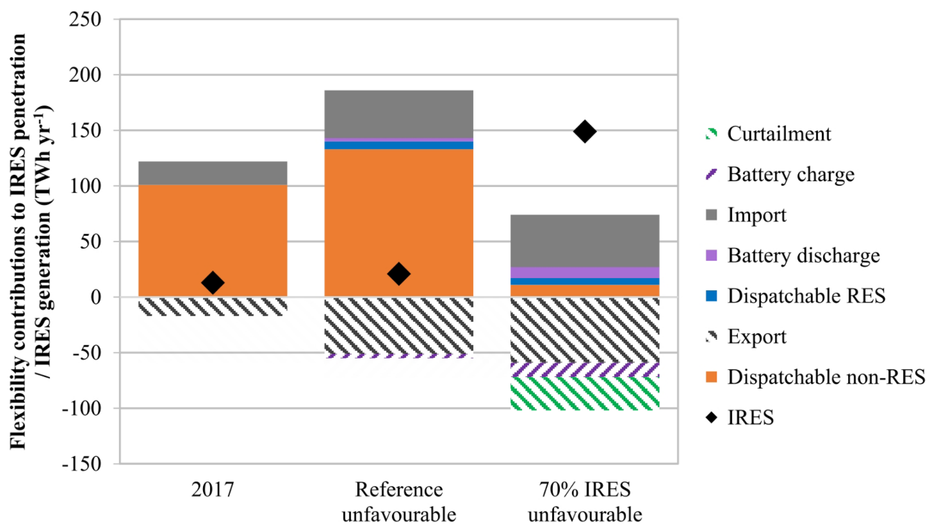

Fig. 7. Total flexibility contributions and IRES generation in the 2017 Dutch power system and in the *Reference* unfavourable and *70% IRES* unfavourable scenarios.

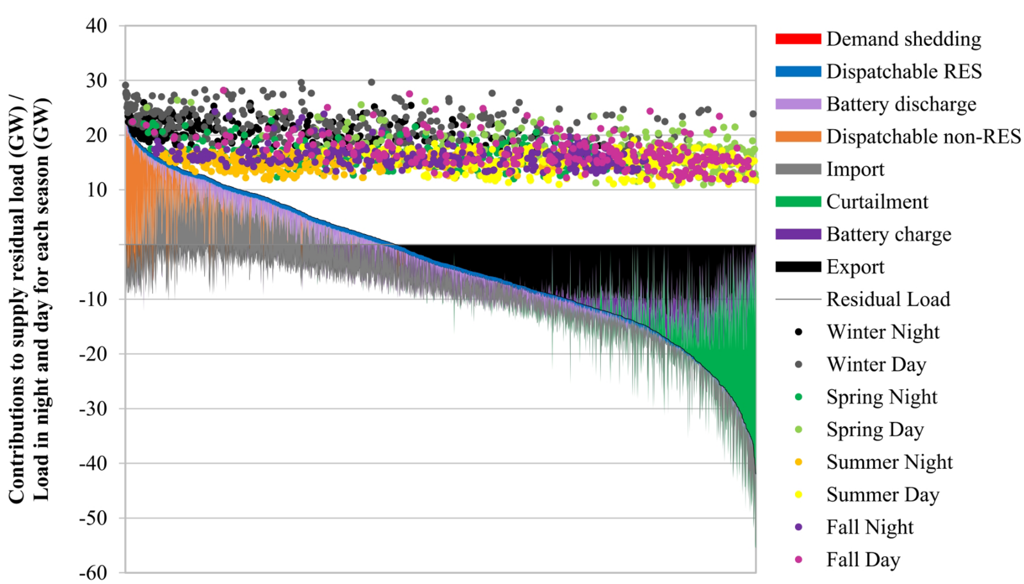

Fig. 8. Residual load duration curve with demand at days and flexibility contributions in the *70% IRES unfavourable* run.

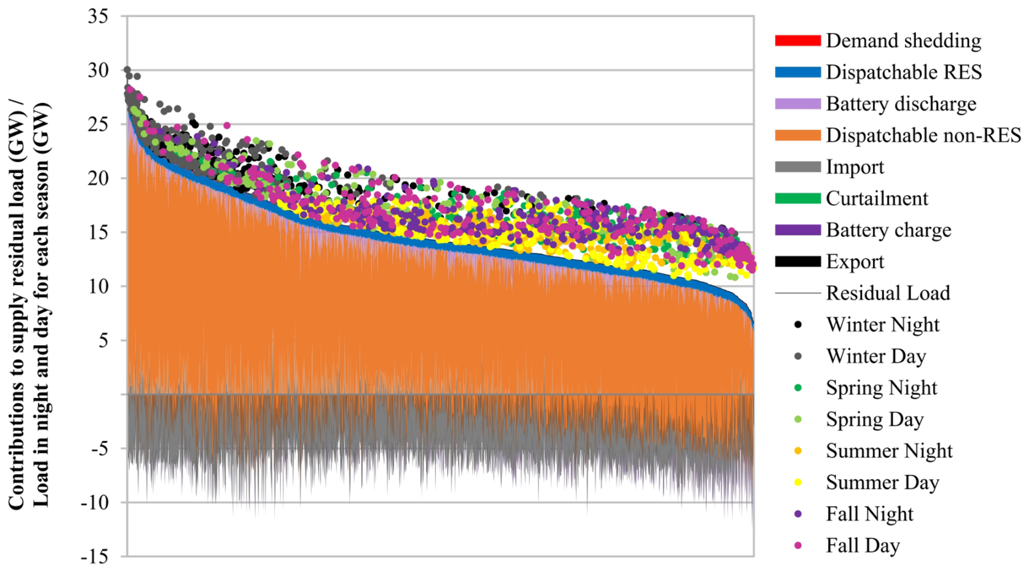

Fig. 9. Residual load duration curve with demand at days and flexibility contributions in the *Reference unfavourable* run.

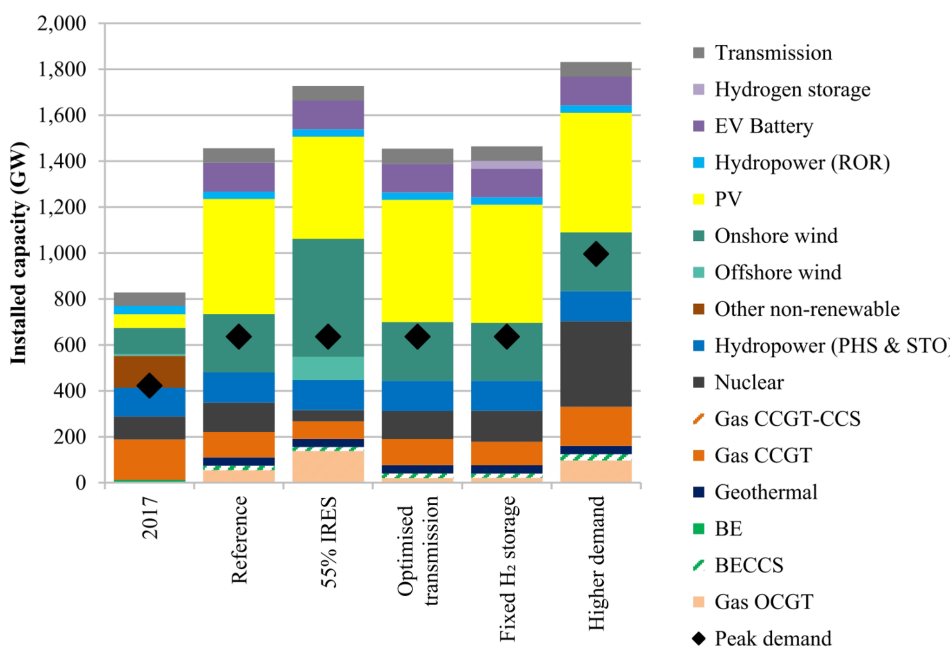

Fig. 10. Western European power generation portfolio in the sensitivity runs for the year 2050. The portfolios in the sensitivity runs are not tested with an hourly simulation.

not typically deliver ancillary services, such as frequency and voltage control and balancing reserves at present [16,58],[9] 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].

[9] These services are currently provided by conventional dispatchable generation units such as gas and coal power plants.

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* H_2 *storage* sensitivity run, gas turbine (OCGT) peaking

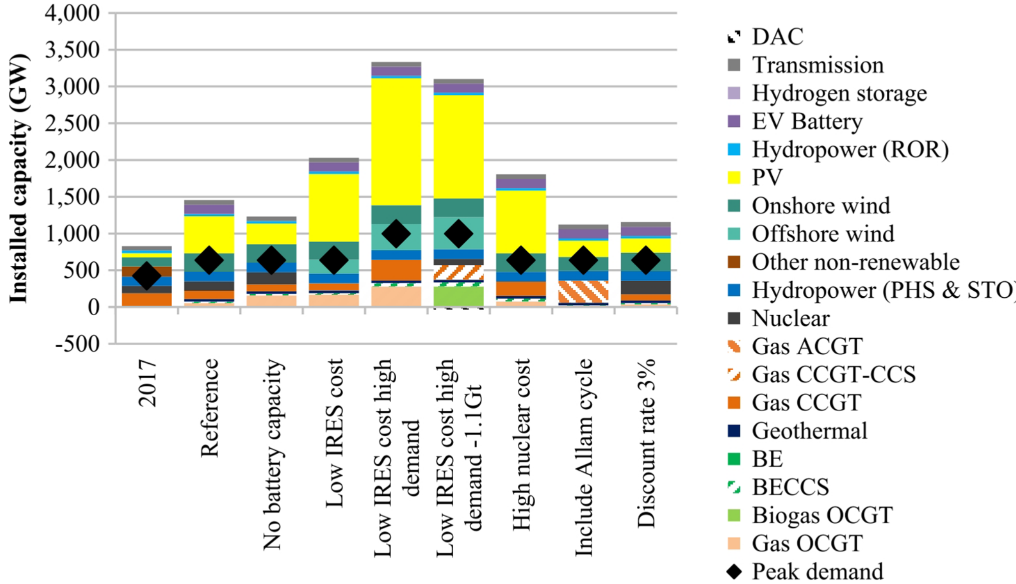

Fig. 11. Western European power generation portfolio in 2050 assuming alternative techno-economic parameters (see Table 6). The portfolios in the sensitivity runs are not tested with an hourly simulation.

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 132 GW in 2017 to 378 GW 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 125 GW 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 502 GW in Western Europe to 281 GW (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 280 GW 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 128 GW to 184 GW while PV capacity decreases by 61% from 502 GW to only 195 GW. 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

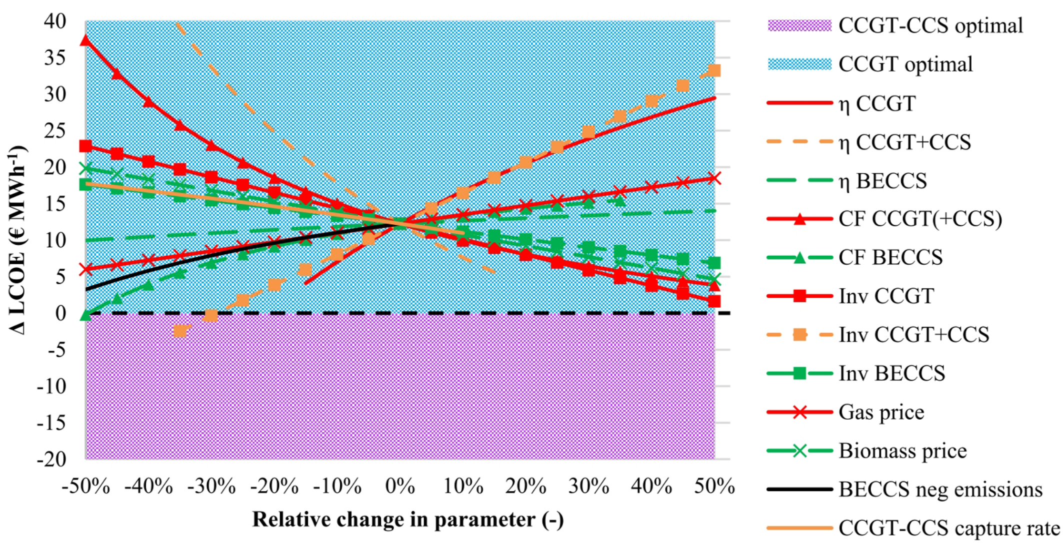

Fig. 12. Sensitivity of favourability of BECCS + CCGT vs BECCS + CCGT-CCS. Below the zero line, the combination of CCGT-CCS with BECCS is more favourable. η: efficiency, CF: capacity factor, Inv: Investment costs. The assumed capacity factors are taken as average of the ST simulation results and are 75% for BECCS and 37.5% for both CCGT and CCGT-CCS. BECCS achieves negative emissions of 1.2 $tCO_2\,MWh^{-1}$. Other techno-economic parameters are discussed in Section 3.2 and 1.1. Note that some changes in parameters are limited to a smaller range than [−50%, +50%] to maintain a coherent set of parameters.

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.

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 transport may still be a viable option. The amount of curtailed energy differs per scenario but averages at around 50 $GWh\,yr^{-1}$. If otherwise curtailed electricity would be used for hydrogen production, this amount would only provide minor potential for hydrogen production. In the *70% IRES* scenario, however, curtailed electricity is much higher than in the other scenarios. Moreover, the occurrence of curtailed energy over the year is higher than in the other scenarios (6300 $h\,yr^{-1}$ vs. 5100 $h\,yr^{-1}$). This may provide an opportunity for hydrogen 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 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 CO_2 also becomes relevant. Estimates of CO_2 storage capacity in saline aquifers, hydrocarbon fields and coal fields add up to 95 $GtCO_2$ 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 CO_2 stored in the *−1.1 Gt* scenario and the *Reference* scenario, it is estimated that in a zero emission power system, roughly 8 $GtCO_2$ needs to be stored in total until 2100, whereas in the *−1.1 Gt* scenario a total of 66 $GtCO_2$ 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 fulfil 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. Daggash, 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 $MtCO_2\,yr^1$, 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.

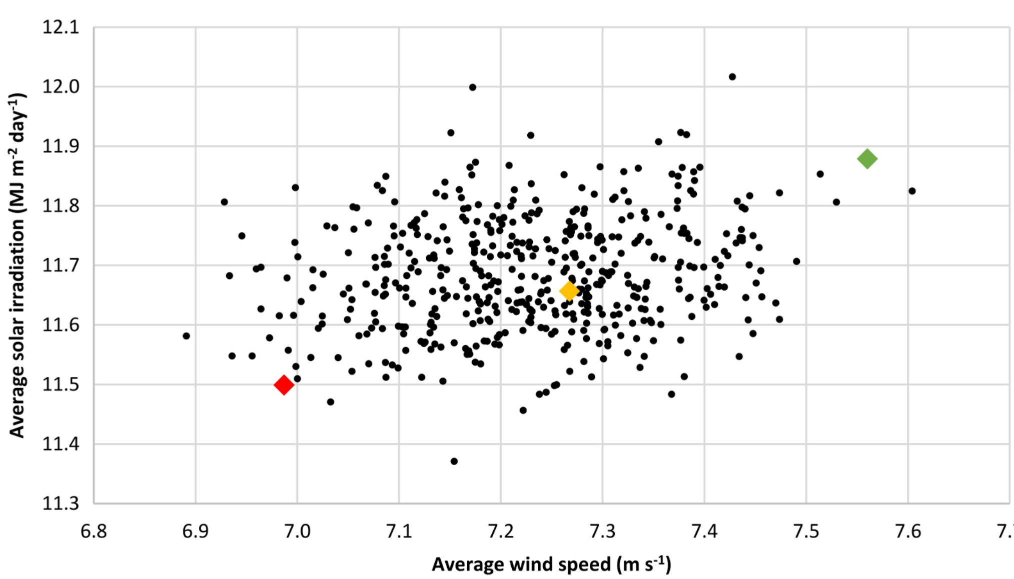

Fig. 13. Average daily solar irradiation and average wind speed for All 480 Weather years. The unfavourable (red), average (yellow) and favourable (green) weather years are also indicated.

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

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	Germania	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	Germania	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
Germania	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	239.8	386.2

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 710 TWh for the whole of the European Union.[10] 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 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:

$$HDHweighted_{c,h} = \frac{\sum_g (HDH_{h,g} * pop_{c,g})}{\sum_g pop_{c,g}} \tag{E1}$$

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):

[10] Since not all member states are covered (also note that Switzerland and Norway are included in the scope but are not EU28 member states) the total demand for EVs is smaller within this study.

$$HDH_{h,g} = \begin{cases} Tref_h - T_{h,g} & for \quad Tref_h \geq T_{h,g} \\ 0 & for \quad Tref_h < T_{h,g} \end{cases} \tag{E2}$$

Where the reference temperature is lower at night-time to reflect that most people are asleep and commercial buildings are generally unoccupied:

$$Tref_h = \begin{cases} 18 \quad for \quad ((h \quad mod \quad 24) > 6AND(h \quad mod \quad 24) < 10) \\ 12 \quad for \quad ((h \quad mod \quad 24) \leq 6OR(h \quad mod \quad 24) \geq 10) \end{cases} \tag{E3}$$

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:

$$P_{pv,t} = P_{STC}\left(\frac{G_{panel,t}}{G_{STC}}\right)(1 - \delta(T_{NOCT} - T_{cell,t}))PR \tag{E4}$$

$$T_{cell,t} = T_{mod,t}\left(\frac{G_{panel,t}}{G_{STC}}\right)\Delta T_{cond} \tag{E5}$$

$$T_{mod,t} = G_{panel,t} \times e^{a+b\times w_t} + T_t \tag{E6}$$

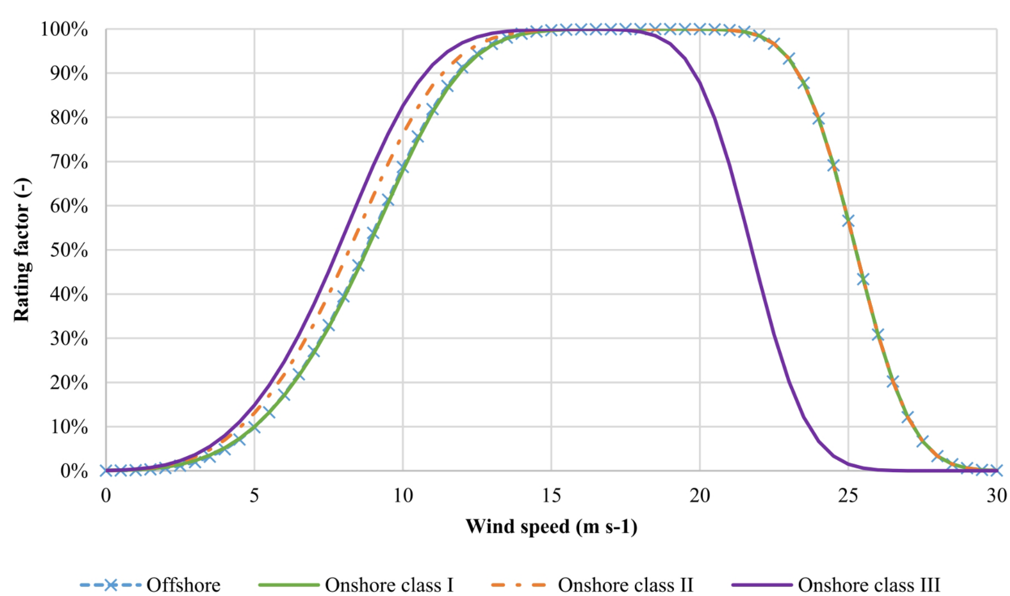

Fig. 14. Assumed multi wind turbine power curves.

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.

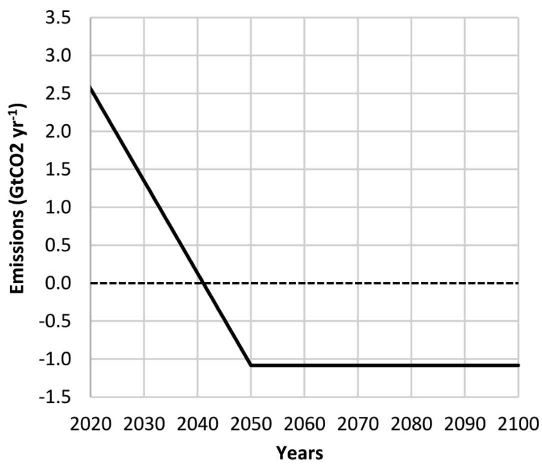

Fig. 15. Assumed emission pathway to achieve a 33% chance of staying below 1.5 °C global temperature increase for the countries in the scope of this research.

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.

[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].

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	
Scenario	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

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 14
Overview of capacity factors per technology in the main scenarios.

	Reference unfavourable	Reference favourable	70% IRES unfavourable	70% IRES favourable	No CCS unfavourable	No CCS favourable	Low nuclear unfavourable	Low nuclear favourable	−1.1Gt unfavourable	−1.1Gt favourable
OCGT (natural gas)	17%	10%	12%	5%			12%	4%		
OCGT (biogas)					21%	11%			17%	6%
BECCS	71%	67%	79%	79%			86%	87%	88%	88%
BE										
Geothermal	82%	81%	83%	81%	90%	90%	84%	84%	86%	86%
CCGT (natural gas)	42%	36%	46%	37%			49%	45%	35%	31%
CCGT CCS (natural gas)									42%	35%
Nuclear	88%	89%			80%	79%	85%	84%	87%	87%
Offshore wind			33%	37%	38%	43%	38%	43%	38%	43%
Onshore wind	28%	32%	24%	27%	28%	32%	28%	32%	28%	32%
Roof PV	12%	13%	11%	12%	14%	14%	12%	13%	12%	13%
Utility PV	11%	12%	11%	12%	13%	13%	11%	11%	11%	12%
Hydropower (PHS)	9%	9%	14%	17%	7%	7%	14%	15%	10%	11%
Hydropower (ROR)	28%	28%	26%	25%	29%	29%	27%	26%	28%	28%
Hydropower (STO)	38%	37%	33%	30%	38%	37%	38%	38%	38%	38%
DAC									91%	99%
EV Battery	12%	13%	18%	20%	7%	7%	15%	17%	11%	12%
Hydrogen storage			9%	10%	1%	1%				

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Glossary

ACGT: Allam cycle gas turbine
BE: Bioenergy
BECCS: Bioenergy with carbon capture and storage
CCGT: Combined cycle gas turbine
CCS: Carbon capture and storage
CCU: Carbon capture and utilisation
CSP: Concentrated solar power
DAC: Direct air capture of CO_2
ESM: Earth system model
EV: Electric vehicle
FOM: Fixed operation and maintenance (costs)
GHG: Greenhouse gas
HP: Heat pump
IGCC: Integrated gasification combined cycle
IRES: Intermittent renewable energy sources
LCOE: Levelised cost of electricity

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)