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Can liberalised electricity markets support decarbonised portfolios in line with the Paris Agreement? A case study of Central Western Europe

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ABSTRACT

We model the evolution of the Central Western Europe power system until 2040 with an increasing carbon price and strong growth of variable renewable energy sources (vRES) for four electricity market designs: the current energy-only market, a reformed energy-only market, both also with the addition of a capacity market. Each design is modelled for two decarbonisation pathways: one targeting net-zero emissions by 2040 for a 2 °C warming limit, and the other targeting −850 Mt CO_2 y^{-} for a 1.5 °C warming limit. We compare these scenarios against the high-level objectives of delivering low-carbon electricity reliably to consumers at the lowest possible cost. Our results suggest that both 2 °C and 1.5 °C compliant systems could be achieved and deliver electricity reliably. In terms of cost, we find the 1.5 °C warming scenarios lead to system costs which are twice as high as the 2 °C scenarios due to the high cost of negative emission technologies – in particular direct air carbon capture (DAC). To make a 1.5 °C target more affordable, policymakers should investigate lower cost alternatives in other sectors, and increase research and development in DAC to reduce its cost.

1. Introduction

In order to achieve the European Union's (EU) long-term goal of reducing greenhouse gas (GHG) emissions by 80–95% by 2050 compared to 1990 levels, the power sector will need to fully decarbonise by 2050, or even deliver net negative GHG emissions if the objective of the Paris Agreement to limit global warming to well below 2 °C is to be met (EC, 2011; UNFCCC, 2017; EC, 2018). As a result, policies have been implemented to increase the share of renewable energy sources (RES) in electricity supply. These have been largely successful, with installed wind capacity in the EU tripling from 60 to 180 GW between 2008 and 2018, and solar photovoltaic (PV) capacity increasing tenfold from 10 to 115 GW over the same period (Eurostat, 2017; EurObserv'ER, 2019; EurObserv'ER, 2018; SolarPower Europe, 2019). As wind and PV are variable renewable energy sources (vRES) with nearly zero short-run marginal costs (SRMC), this additional capacity has displaced more costly thermal generators in the merit order, reduced electricity prices, and the operating hours of thermal plants (Hirth, 2018).[1] Also known as the "merit-order" effect, this makes it more difficult for thermal plants in energy-only electricity markets (EOMs) to recover their fixed costs, negatively affects the business case for new investments, and threatens security of supply (Joskow, 2008; Clò et al., 2015; Paraschiv et al., 2014; EC, 2016a; Hu et al., 2018).

In response to concerns about security of supply, and scenarios showing that up to 60% of electricity generated in the EU by 2040 could be provided by vRES,[2] several countries have implemented capacity remuneration mechanisms (CRMs) of various designs to supplement generator revenues from the EOM.[3] However, there is little empirical evidence of the need for CRMs. For example, many EU countries

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[1] For example, day-ahead prices in Germany and Sweden in 2015 were nearly 50% lower than in 2011 (Hirth, 2018; Bublitz et al., 2017). However, aside from vRES, generation overcapacity, lower fuel and carbon prices perhaps had an even more significant effect on prices (Hirth, 2018; EC, 2016a; Bublitz et al., 2017).

[2] VRES represented 15% of total EU28 generation in 2017 (Eurostat, 2019). The Joint Research Centre's EU Reference Scenario 2016 considers 35% for the EU28 by 2050 (EC, 2016c), while the European Commission Energy Roadmap 2050 considers between 32% and 65% (EC, 2011). Meanwhile, ENTSO-E scenarios consider vRES shares between 31% and 39% already in 2030, rising to 45–58% by 2040 (ENTSO-E and ENTSO-G, 2018). EU Commission scenarios consider up to 70% by 2050 (EC, 2018).

[3] As of 2017, twelve EU countries operated EOMs, while fifteen had implemented CRMs. A capacity market was in place in the UK; a capacity payment in Portugal, Spain, Ireland, Italy and Greece; a strategic reserve in Belgium, Germany, Poland, Sweden, Finland, Latvia, and Lithuania; a reliability obligation in France; and a capacity tender in Bulgaria. The remaining EU countries, Switzerland and Norway operate EOMs (ACER and CEER, 2017). For a detailed explanation of CRM designs, the reader is directed to significant literature on this topic e.g. (EC, 2016b; Bublitz et al., 2018; EC, 2015; Cramton et al., 2013).

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Abbreviations

BE	Belgium
BECCS	Bioelectricity with carbon capture and storage
Bn	Billion (10^9)
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CHP	Combined heat and power
CCGT	Combined cycle gas turbine
CRM	Capacity remuneration mechanism
CM	Capacity market
CWE	Central Western Europe
DA	Day-ahead
DAC	Direct air capture
DE	Germany
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EOM	Energy-only market
ETS	Emissions Trading Scheme
EU	European Union
FOM	Fixed operating and maintenance
FR	France
GHG	Greenhouse gas
GT	Open-cycle gas turbine
IPCC	Intergovernmental Panel on Climate Change
LT	Long term
LRMC	Long-run marginal cost
NET	Negative emission technology
NL	The Netherlands
NPV	Net present value
NTC	Net transfer capacity
OCC	Overnight capital cost
PSM	Power system model
PV	Photovoltaic
RES	Renewable energy source
SR	Strategic reserve
SRMC	Short-run marginal cost
ST	Short term
TCR	Total capital requirement
TSO	Transmission System Operator
TYNDP	Ten-year Network Development Plan
UCED	Unit commitment and economic dispatch
VoLL	Value of lost load
VOM	Variable operating and maintenance
vRES	Variable renewable energy source
WEO	World Energy Outlook

continue to operate EOMs with no significant reliability problems.[4] Moreover, the fall in market prices observed between 2010 and 2015 – which triggered much of the debate in the EU on the need for CRMs – may have been a sign of EOMs reacting as intended in response to an oversupply of generation capacity (Hirth and Ueckerdt, 2014). In recent years, prices have also shown signs of recovery.[5] Turning to the literature, whether EOMs alone can provide sufficient incentives for investment in thermal generation or if CRMs are necessary has long been a subject of debate, with no clear resolution (Pollitt and Chyong, 2018). Some argue that CRMs are undesirable as they distort EOMs, instead suggesting that if so-called 'market failures' hindering the formation of scarcity prices are resolved, EOMs should be capable of ensuring security of supply (Hirth and Ueckerdt, 2014; EC, 2016b; Cramton and Ockenfels, 2012; Bucksteeg et al., 2017; Henriot and Glachant, 2013).[6] Others posit that CRMs are necessary due to uncertain scarcity prices, and the risk-averse nature of investors (Petitet et al., 2017). Less attention has been given to the future profitability of vRES generators, whose investments to date have largely been driven by government subsidies (Ecorys, 2017). While there are signs that subsidy-free vRES investments are now possible, with continued vRES deployment the merit-order effect may become so great that vRES cannibalise even their own revenues (Brouwer et al., 2016a; Zipp, 2017; Netherlands Enterprise Agency, 2019).

Previous studies have investigated market designs to support both thermal and high levels of vRES capacity in a qualitative way (e.g. (Henriot and Glachant, 2013; Ecorys, 2017; Poudineh and Peng, 2017; Newbery et al., 2018; Finon and Roques, 2013; Billimoria and Poudineh, 2018; Philipsen et al., 2019; Keay, 2016)), but relatively few quantitative studies have been performed. Brouwer et al., 2016a, 2016b find that the current EOM would not provide sufficient revenues for most thermal, vRES or other low-carbon technologies from 2030 onwards, while Pollitt & Chyong (Pollitt and Chyong, 2018) find that mid-merit plants could be profitable with more vRES if fuel and carbon prices were to rise; while vRES would still need subsidies or further cost reductions. Levin & Botterund (Levin and Botterud, 2015) compare various CRMs, finding that market prices collapse under all designs and reduce the profitability of baseload and wind plants, while mid-merit and peak generators are less affected. Market designs have been evaluated based on a wide variety of criteria, usually based on the author's (often implicit) definition on the objectives of electricity market design. For example, Poudineh and Peng (2017) give the purpose of market design as *"[to provide] signals for efficient operation and investment in the power sector"*. Some other evaluation criteria that have been used in the literature are reliability (Ecorys, 2017; Newbery et al., 2018; Kraan et al., 2019), adequacy (Petitet et al., 2017), market-based (Ecorys, 2017), efficiency (Poudineh and Peng, 2017), flexibility (Ecorys, 2017), complexity (Ecorys, 2017), affordability (Ecorys, 2017; Newbery et al., 2018), clean (Newbery et al., 2018), renewable (Kraan et al., 2019), sustainability (Kraan et al., 2019), and social efficiency (Petitet et al., 2017).

Despite the existing literature, we find several areas where research is lacking. Firstly, previous studies look mainly at snapshots of the market after the transition to a low-carbon future has taken place (e.g.

[4] Based on ENTSO-E's 2018/2019 system adequacy outlook (ENTSO-E, 2018d), there is no clear correlation between system adequacy concerns in those countries with CRMs and those without (including Denmark, which has the highest vRES penetration of all EU countries).

[5] Recent data shows the German average annual spot price rose 40% between 2015 and 2018, restoring it to a similar level as in 2011 (ENTSO-E, 2018).

[6] 'Failures' refer to deviations from the assumptions underlying an ideal theoretical market such as perfect competition (e.g. all firms are price-taking, no barriers to entry or exit, an inelastic demand side), or distortions which prevent EOMs from working effectively such as (e.g. market price caps, out-of-market interventions by transmissions system operators (TSOs), price-inelastic demand) price caps, which lead to the so-called "missing money" problem (Biggar and Hesamzadeh, 2014; Lin and Magnago, 2017). However, examining historical day-ahead market prices in France, Germany, the Netherlands and Belgium for the years 2015–2018 reveals no periods when the price actually reaches the cap (ENTSO-E, 2018). This may be due to TSOs making out-of-market interventions before scarcity events arise, implicit caps set by other markets, the presence of existing CRMs, or cautious market players restraining bids for fear of being accused of exerting market power (EC, 2016a).

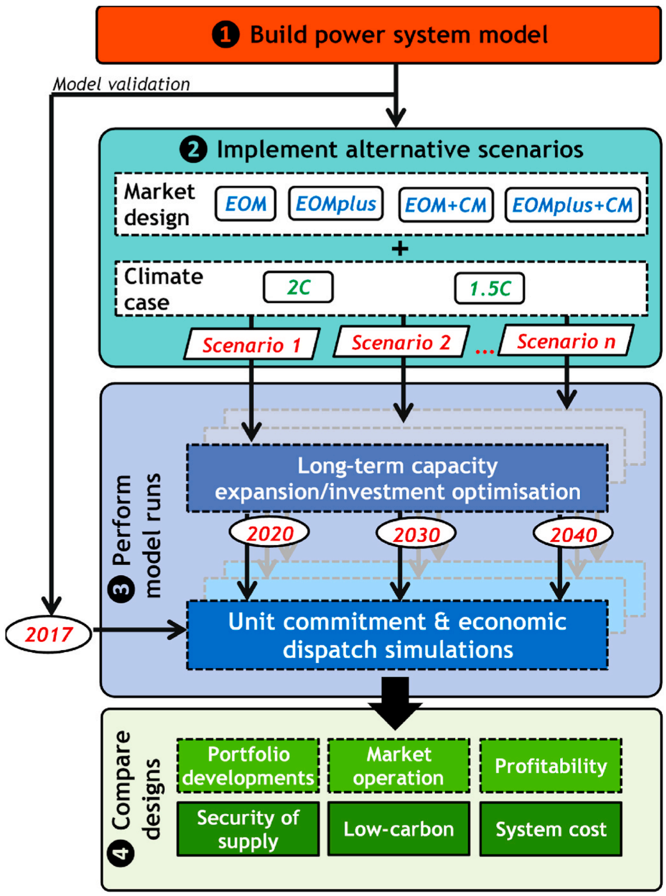

Fig. 1. Overview of study method. The scenario designs are explained in section 2.2.

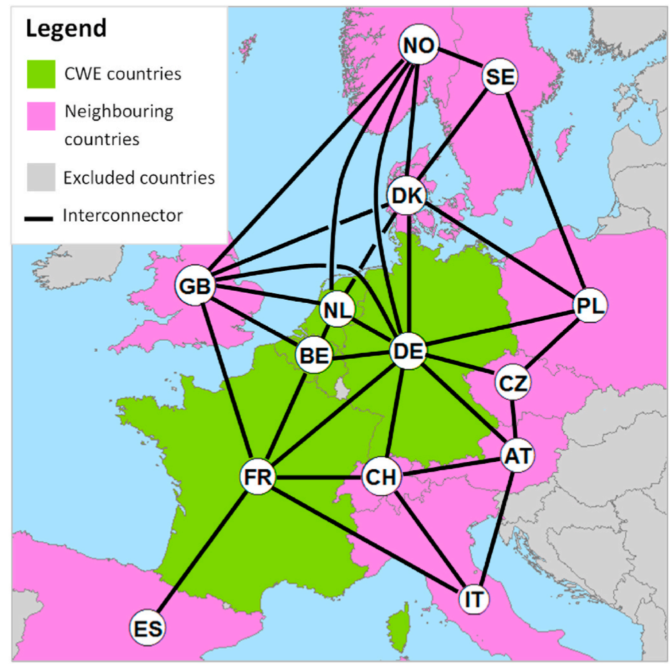

Fig. 2. Overview of the Central Western Europe focus study area (green), directly neighbouring countries (purple), and excluded countries (grey). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

(Ecorys, 2017; Brouwer et al., 2016a; Zappa et al., 2019)), without considering the transition period and the impact of market design on the generation portfolios. Secondly, studies focus on integrating vRES as the primary means of achieving decarbonisation, with net-zero carbon emissions from the power sector seen as the final goal (e.g. (Kraan et al., 2019; Gerbaulet et al., 2019)). However, even a fully renewable net-zero emission system may not be consistent with the decarbonisation ambitions of the Paris Agreement, in which negative emission technologies (NETs) such as bioelectricity with carbon capture and storage (BECCS) and direct air carbon capture (DAC) may be needed (van Vuuren et al., 2017). Thirdly, no studies were found which investigate the economic viability of NETs and their potential impacts on the CWE electricity market.

We seek to address these knowledge gaps with a case study of the electricity markets of France (FR), Belgium (BE), The Netherlands (NL), and Germany (DE) – collectively referred to as Central Western Europe (CWE). We model the CWE power system from 2017 until 2040 and address three main questions: *(i)* how should electricity portfolios develop to supply electricity reliably to consumers at the lowest cost while being consistent with the Paris Agreement? (ii) what effects do different market designs have on the resulting portfolios and the business cases of different technologies? and (iii) how could the deployment of NETs affect the electricity market?

With the aims of our study thus established, in section 2 we outline our method. In section 3 we present our results, and discuss their implications in section 4. We conclude in section 5 with some key findings. Additional appendices containing more detailed methodological explanations and results can be found in the supplementary material available online.

2. Method

Our approach consists of four main steps (Fig. 1). First, a power system model of the CWE region and neighbouring countries is built using the PLEXOS modelling framework (Fig. 2). We model a total of eight scenarios by combining four different market designs with two different decarbonisation trajectories. Assuming that the overarching objective of market design is to supply low-carbon electricity reliably to consumers at the lowest possible cost, we first run a long-term (LT) capacity expansion optimisation to find the least-cost pathway of investment decisions in non-vRES generation capacity from the base year 2017 until 2040, taking the decarbonisation trajectories as a hard constraint. We assume vRES capacity increases exogenously in all scenarios as current policies are pushing the market in this direction, and it is the increasing penetration of vRES which drives current concerns with the existing EOM market design. Based on the resulting portfolios, short-term (ST) hourly unit commitment and economic dispatch (UCED) simulations of the day-ahead market are performed for selected years to yield more detailed results on market prices and system reliability; two indicators used to compare the different market designs.

2.1. Build power system model

Our model is built using PLEXOS, a power system modelling framework based on mixed-integer linear programming.[7] By coupling its LT Plan and ST Schedule modules, PLEXOS can be used to perform both capacity expansion and UCED calculations, considering power plant

[7] PLEXOS is developed by Energy Exemplar (https://energyexemplar.com/).

Table 1
Installed generation capacity, demand, and capacity margin per country for the base year 2017.

Parameter	Country				Total CWE
	BE	DE	FR	NL	
Net generation capacity (GW)[a]	*20.9*	*210.5*	*128.7*	*34.0*	*394.1*
Combined-cycle gas turbine (CCGT)	4.0	9.1	3.4	10.9	*27.4*
Open-cycle gas turbine (GT)	0.1	9.5	0.0	4.6	*14.2*
Coal	0.0	38.7	3.1	5.8	*47.6*
Oil[h]	0.5	7.9	10.2	0.7	*19.3*
Combined heat and power (CHP)	1.4	15.2	3.3	4.0	*23.9*
Nuclear	6.1	10.7	63.1	0.5	*80.5*
Run-of-river and storage hydro (HYDRO)[b]	0.0	4.7	18.6	0.0	*23.2*
Pumped hydro storage (HYDRO-PHS)	1.3	8.7	5.0	0.0	*15.0*
Solid biomass (BIOSOL)[g]	0.7	8.0	0.4	0.5	*9.6*
Onshore wind (ONWIND)	2.0	50.2	13.6	3.3	*69.0*
Offshore wind (OFFWIND)	0.9	5.4	0.0	1.0	*7.3*
Solar photovoltaic (PV)	3.9	42.4	8.0	2.8	*57.0*
Firm generation capacity (GW)[c]	13.6	105.0	96.8	25.3	240.8
Curtailable load (GW)[d]	0	0	2.4	0.75	3.1
Peak load (GW)	13.6	79.1	93.7	19.0	–
Import capacity (GW)	8.0	23.6	10.0	6.9	–
Export capacity (GW)	2.5	18.1	14.7	6.9	–
Net import capacity (GW)[e]	3.8	17.5	7.5	−3.5	–
Capacity margin (%)[f]	28%	55%	14%	19%	–

(a) Sources: ENTSO-E, Elia, Bundesnetzagentur, RTE (ENTSO-E, 2018; Elia, 2018; RTE, 2018; Bundesnetzagentur, 2018).
(b) *Due to poor data availability we aggregate run-of-river (RoR) and storage hydro capacity in this study. Pumped storage is modelled separately.*
(c) *Firm generation capacity is estimated assuming 90% firm capacity for all dispatchable thermal plants, 50% for hydro plants (based on historical availability during peak hours), 7% for wind, and 0% for PV.*
(d) *Source: ENTSO-E (ENTSO-E, 2018).*
(e) *The Net Import Capacity for a country is calculated as the firm capacity of all importing lines, minus the firm capacity of all exporting lines. These values are determined from a calibration run using PLEXOS for the base year 2017, accounting for the fact that the peak load hours in each country may not coincide.*
(f) *Capacity Margin is reported at the time of the region peak load, and includes any potential contribution from transmission with neighbouring countries. It is calculated as: Capacity Margin (%) = (Firm Generation Capacity + Curtailable Load + Net Import Capacity – Peak Load)/(Peak Load).*
(g) *Includes anaerobic digestion (BIOAD).*
(h) *Includes all other non-renewable fuels.*

flexibility limitations and flexible loads. The mathematical formulation underlying PLEXOS' can be found in other published works (e.g. (Brinkerink et al., 2018; Deane et al., 2014)). Transmission between countries is modelled based on net transfer capacities (NTCs), while transmission within countries is treated as copper plate. The main inputs for the model are: (i) the installed capacity of existing generators in the base year (2017), (ii) assumed developments in demand, vRES and transmission capacity, (iii) techno-economic parameters for generation, storage and NETs, and (iv) assumed fuel and carbon prices. These inputs are briefly outlined in the following sections.

2.1.1. Legacy generation fleet

Data on the fleet of power plants operating in the CWE countries in 2017 are taken from a database of more than 700 power plants (Mulder, 2015), validated against the capacity reported by the European Network of Transmission System Operators for Electricity (ENTSO-E) and

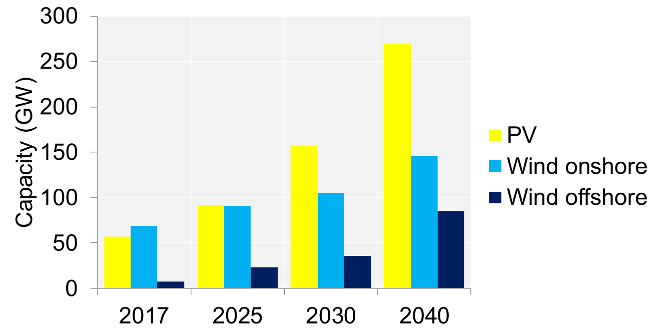

Fig. 3. Assumed deployment of PV and wind capacity in CWE. The 2017 capacity is based on historical data. The installed capacity in 2040 is taken from the *Global Climate Action* scenario in ENTSO-E's Ten Year Network Development Plan 2018 (ENTSO-E and ENTSO-G, 2018). The installed capacity in 2025 is taken from the *Best Estimate* scenario, while the 2030 capacity is taken from the *Distributed Generation* scenario.

national statistics (ENTSO-E, 2018) (Table 1). Plants are aggregated based on their type (e.g. coal, combined cycle gas turbines (CCGT), open cycle gas turbine (GT), nuclear), and decade of commissioning. Generators in neighbouring non-CWE countries are modelled more simply.[8] Several assumptions are made regarding the starting portfolio:

- National phase-outs for coal (FR: 2022, NL: 2030, BE: 2017, DE: 2038) and nuclear power (BE: 2025, DE: 2022) are enforced (Europe Beyond Coal, 2017; World Nuclear News, 2018; Bundesamt für kerntechnis, 2018; Clean Energy Wire, 2019).[9] After the coal phase-out year, coal plants must either retire, be retrofitted with carbon capture and storage (CCS), and/or be converted to run on 100% biomass.
- The efficiency of legacy power plants depends on their age (EPA, 2018).
- If not retrofitted by the model for CCS and/or biomass, plants must retire within five years of their nominal decommissioning year.

2.1.2. Assumptions for electricity demand, vRES and transmission capacity

Future electricity demand, vRES deployment and transmission capacity in CWE are based on the *Global Climate Action* scenario from ENTSO-E's Ten Year Network Development Plan (TYNDP) 2018 (ENTSO-E, 2018a). Starting from the actual 2017 demand of 1170 TWh,

[8] For neighbouring countries, a single generator per type is defined with maximum capacity based on national statistics, with the portfolio following the deployment in ENTSO-E's TYNDP 2018 *Best Estimate* scenarios for the years 2020 and 2025, *Distributed Generation* scenario for 2030 and *Global Climate Agreement* scenario for 2040 (ENTSO-E, 2018a). These scenarios do not provide any information on the split between GTs and CCGTs in natural gas capacity, nor the share of capacity equipped with CCS in neighbouring countries. Thus, we assume a split of 30/70 split between GT/CCGT capacity based on the split in CWE, and do not consider CCS in neighbouring countries.

[9] The future direction of French nuclear policy is unclear. After attempting to legislate in 2014 to limit nuclear capacity to 63 GW and 50% of electricity supply by 2025 with the *Energy Transition for Green Growth* bill, this was met with resistance in the French Senate, and ultimately the decision was delayed until after 2017. In November 2018, a draft of the new policy delayed the target year for reducing the share of nuclear to 50% until 2035 with a plan to close 14 reactors by 2035, but with the option to build new reactors still available (World Nuclear Association, 2018). Given this policy uncertainty, in this study we impose no caps or forced retirements for nuclear power in France and allow new nuclear capacity to be built in both France and the Netherlands if this is optimal.

demand increases to 1256 TWh (+7% vs. 2017) in 2040, and the installed capacities of PV, onshore wind and offshore wind reach 269, 146 and 85 GW respectively in all scenarios (Fig. 3)[10]. As a result of these assumptions, vRES supply approximately 70% of electricity in CWE by 2050. Hourly capacity factors for onshore wind, offshore wind and PV are taken from the Renewables Ninja dataset, with an average profile used per country for each technology (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016). For each simulated year until 2040, a weather year from the period 1980 to 2016 is randomly selected from Renewables Ninja to capture weather variability, and the average capacity factors of wind and solar PV are assumed to increase gradually over time thanks to technology improvements.[11] Cross-border transmission capacity within CWE rises from 9 GW in 2017 to 21 GW in 2040, while transmission between CWE and neighbouring countries rises from 23 to 60 GW.

2.1.3. Techno-economic assumptions

In addition to vRES, a range of dispatchable thermal, storage and NETs is considered (Table 2). Exogenous technological learning is assumed for vRES, CCS, storage and NETs. For example, the overnight capital costs (OCC) of PV, onshore and offshore wind fall 60%, 14% and 34% respectively between 2017 and 2040, based on the most optimistic deployment scenarios from (Tsiropoulos et al., 2018). Battery, electrolyser and DAC costs fall by 80%, 53% and 40% over the same period (Child et al., 2019; Siemens; Keith et al., 2018). Note that the deployment of electrolysers is limited to the generation of green hydrogen to produce electricity, not for use in other sectors. A uniform weighted average cost of capital (WACC) of 8% is assumed to annualise investment costs.[12] Generator ramping constraints, start-up costs, and part-load efficiencies are based on (Brouwer et al., 2015). Deployment of batteries, electrolysers and DAC is limited to 1 GW y^{-1} per country.[13] In addition to completely new investments, two retrofit options are included for existing generators built between 1990 and 2016, and generators built after 2017: (i) retrofitting with CCS (coal, CCGT and solid biomass plants only), and (ii) full biomass conversion (coal plants only).[14] The cost of retrofitting with CCS is assumed to be 60% of the cost of a new-build CCS plant (Gibbins et al., 2011), while the cost of biomass conversion is taken as 700 € kW^{-1} (Drax, 2018; JRC, 2014).

2.1.4. Fuel and carbon prices

We assume fuel prices remain constant at 2017 levels (Table 3). As we consider different climate scenarios by applying annual emission constraints, we do not assume a carbon price in the capacity expansion algorithm. However, in the UCED runs for the years 2020, 2030 and 2040, we assume EU Emission Trading Scheme (ETS) certificate prices of 17, 85 and 120 € t^{-1} respectively, following the *450* scenario from the IEA's World Energy Outlook (WEO) 2016 (IEA, 2016a).[15] Another key assumption we make is that NETs are remunerated for the negative emissions they generate at the same level as the carbon price.

2.2. Implement market scenarios

Eight different market scenarios are modelled by combining four electricity market design scenarios with two decarbonisation scenarios, as explained below.

2.2.1. Market design scenarios

Four different market designs considered:

- ***EOM***: a reference EOM reflecting the 'imperfect' EOM currently operating in most CWE countries. Prices are capped at 3000 € MWh^{-1}, and essentially inelastic to demand (EPEX, 2018).
- ***EOMplus***: a reformed EOM in which two deficiencies in the current EOM are resolved by (i) removing spot market price caps, and (ii) making price more elastic to demand by allowing significant participation of voluntary load shedding.
- ***EOM + CM***: a market in which a quantity-based capacity market (CM) operates alongside the current 'imperfect' EOM.
- ***EOMplus + CM***: the combination of a reformed EOM together with a quantity-based CM.

We make the following assumptions for all scenarios:

- All electricity is traded on the day-ahead market.
- For the base year 2017 we assume the current 'imperfect' EOM market design remains unchanged, and prevent the model from making any new generation investments or retirements in this year to allow validation with historical data.[16]
- The same market design is applied in all countries with marginal pricing applying in all markets, and each country constituting its own bidding zone.[17]

[10] Demand profiles for 2017 are taken from historical data (ENTSO-E, 2018), while demand profiles for the years 2020, 2025, 2030 and 2040 are taken from the *Best Estimate 2020 and 2025*, *Distributed Generation 2030* and *Global Climate Action 2040* scenarios. Demand profiles for the intervening years are interpolated on an hourly basis between the fixed scenario years so that the hourly demand profile also changes from 2017 to 2040. The *Global Climate Action* scenario is the most ambitious of all the TYNDP scenarios in terms of vRES growth. While exogenously specifying vRES capacity means the resulting portfolios are not necessarily least-cost, this is the policy direction many member states are pursuing. We examine the impact of this assumption in the sensitivity analysis (Appendix K).

[11] Further details are provided in Appendix E.

[12] This value reflects the historical WACC of European power companies in the range of 6%–10% (Donovan, 2015; Eurelectric, 2013). At this level, the WACC is higher than the 4% financial discount rate or social discount rate of 3%–5% recommended by (EC, 2014). However, in the sensitivity analysis we find that the discount rate does not have a significant impact on the results when so much vRES capacity is forced in exogenously.

[13] If annual deployments are not limited, the model delays investments in new technologies until the end of the simulation horizon once costs have fallen, leading to very high deployment in a single year. Restricting the deployment rate smooths investments over a longer period, accounting for higher costs in early years. While actual deployment rates are likely to follow a more exponential growth pattern, implementing such complex constraints was not possible in PLEXOS.

[14] Retrofitting with CCS is not considered for CHP plants as these will have less waste heat available for the capture solvent regeneration, and are unlikely to have sufficient full load hours to justify investment in CCS (IEA, 2016b).

[15] Two different carbon prices are used in the model: the shadow price, and the accounting price. The shadow price is the value of the dual variable associated with the carbon emissions constraint applied in the capacity expansion algorithm that is required to meet the decarbonisation trajectory. The accounting price is the assumed economic value of carbon used in the profitability calculations, specified exogenously to follow the IEA's 450 scenario. In the capacity expansion algorithm, we only implement a carbon constraint as implementing both a carbon constraint and exogenous price may lead to inconsistencies. However, when running the UCED runs and performing ex-post calculations on generator costs, revenues and profitability, we use the carbon accounting price. Alternatively, the carbon shadow price could also be used in the UCED model. However, because the scope of our model is limited to the power sector and does not account for feedbacks from other sectors on the CO_2 price, we choose to use the IEA 450 CO_2 price projections which are based on an analysis of the whole energy system. The potential implications of this are discussed in section 4.

[16] For simplicity, we do not include the existing CRMs operating in Germany, French or Belgium. Instead, all new market design scenarios are implemented from the year 2018 onwards, from which point new investments or retirements can be made.

[17] Previous studies (e.g. (Bucksteeg et al., 2017; Västermark et al., 2015; Höschle et al., 2018; Bhagwat et al., 2017; Meyer and Gore, 2015; Mastropietro et al., 2015)) show that asymmetric CRMs between neighbouring countries can lead to perverse outcomes.

Table 2
Techno-economic parameters for technologies in the year 2030. The costs for vRES, CCS, storage and NETs are assumed to fall over time due to technological learning. Full details are provided in Appendix E.

Generator type[a]	OCC[k] (€ kW^{-1})	Build time (y)	Economic life (y)	TCR[k] (€ kW^{-1})	Efficiency[l] (%LHV)	VOM (€ MWh^{-1})	FOM (€ kW^{-1} y^{-1})	Source(s)
Thermal technologies[m]								
COAL*	1600	4	40	1950	48%	3.6	40	(JRC, 2014)
COAL-CCS*[b]	2740	4	40	3300	35%	5.5	69	(Tsiropoulos et al., 2018; JRC, 2014)
GT*	550	2	30	620	43%	11	17	(JRC, 2014)
CCGT*	850	3	30	990	62%	2	21	(JRC, 2014)
CCGT- CCS*[b]	1390	3	30	1620	55%	4	35	(Tsiropoulos et al., 2018; JRC, 2014)
NUCLEAR*	4100	6	60	5410	38%	2.5–16[n]	86	(JRC, 2014)
BIOAD*	2750	2	20	3090	40%	3.1	113	(Tsiropoulos et al., 2018; JRC, 2014)
BIOSOL*[c]	2330	2	25	2620	37%	3.5	42	(Tsiropoulos et al., 2018; JRC, 2014)
Variable renewable energy sources (vRES)								
PV[d]	530	–	25	530	–	0	13	(Tsiropoulos et al., 2018; JRC, 2014)
ONWIND[e]	1190	2	25	1340	–	0	26	(Tsiropoulos et al., 2018; JRC, 2014)
OFFWIND[f]	2310	3	30	2700	–	0	69	(Tsiropoulos et al., 2018; JRC, 2014)
Storage technologies								
BATTERY*[g]	900	–	15	900	90%	0.2	27	Child et al. (2019)
HYDROGEN*[h]	310	–	25	310	75%	1.2	13	(Child et al., 2019; Siemens)
Negative emission technologies (NETs)								
BIOSOL-CCS*[bci]	–	–	25	3800	25%	5.4	61	-
DAC*[j]	17,400	–	25	17,400	–	138.3	–	Keith et al. (2018)

Abbreviations: BIOAD – Biogas from anaerobic digestion, BIOSOL – Solid biomass, CCS – Carbon capture and storage, CCGT – Combined cycle gas turbine, DAC – Direct air (carbon) capture, FOM – Fixed operating and maintenance costs, OCC – Overnight capital cost, GT – Open cycle gas turbine, TCR – Total capital requirement, VOM – Variable operating and maintenance costs.

(a) Technologies indicated with a '*' can be built endogenously by the model in any country, except for nuclear which can only be built in France due to announced nuclear phase-outs in Germany, Belgium, and a low appetite for nuclear in the Netherlands. Solar PV and wind capacity increases exogenously as explained in section 2.1.2.

(b) We assume a uniform CO_2 capture rate for CCS technologies of 90% (JRC, 2014), and fixed CO_2 transport and storage costs of 15 € t^{-1} CO_2 (Zero Emissions Platform, 2011) which are added on top of the other generator VOM costs.

(c) *The total sustainable technical lignocellulosic biomass potential in the CWE region is approximately* 3.9 EJ y^{-1} *(2030), which excludes biomass from protected areas, and considers sustainability standards for agricultural farming and land management* (e.g. *maintaining soil organic carbon), as well as forestry management practices* (Dees et al., 2017). *From this value, we further exclude all stem wood, stumps, and post-consumer waste and assume a maximum potential solid biomass use in the power sector of* 2.9 EJ y^{-1} *for CWE.*

(d) Assuming an average of utility-scale (without tracking) and residential-scale (inclined) PV systems.

(e) Assuming a medium specific capacity (0.3 kW m^{-2}), moderate (100 m) hub height.

(f) *Assuming monopole foundations, moderate (30 to* 60 km*) distance from shore.*

(g) Assumes batteries have 6 h of storage and operate on the wholesale market (i.e. not behind the meter). Efficiency is based on round-trip.

(h) *Hydrogen cost given on the basis of electrolyser electric (input) capacity, including 90 days of storage capacity. We assume that hydrogen can be used in both new and existing natural gas plants with negligible investment cost. The conversion of electricity to hydrogen by electrolysis is assumed to have 75% efficiency* (Siemens, 2014)*, while the conversion from hydrogen back to electricity is the same as for the gas plant. The assumed OCC reductions for electrolysis and storage taken from* (Child et al., 2019) *are on the optimistic side, with costs falling by 55% and 75% respectively between 2015 and 2030.*

(i) *Limited consistent data is available for Biomass-CCS (BECCS) in the literature. Instead, the OCC is set at a level which makes a new BECCS plant slightly cheaper than retrofitting a new BIOSOL plant with CCS, or converting a new COAL-CCS plant to biomass. VOM costs, FOM costs and efficiency are based on the difference between COAL and COAL-CCS plants. While low, the resulting efficiency is comparable with other literature estimates (*e.g. (Fajardy and Mac Dowell, 2018; Bui et al., 2017)*). Higher efficiencies are possible with process improvements (*e.g. *flue gas heat recovery), but would increase costs* (Bui et al., 2017).

(j) Direct air capture (DAC) consumes electricity, thus the capacity is shown as negative, and the OCC given per kW electricity input. DAC is still in pilot phase and cost estimates are uncertain, ranging from 50 to 800 € tCO_2^{-1} (Fuss et al., 2018). The values assumed in this study (~200 € tCO_2^{-1}) are at lower end of these estimates based on Keith et al. (2018), for a plant capturing 1 Mt CO_2 y^{-1} (net) from the air assuming a 90% capacity factor, and a DAC process that requires 0.37 MWh electricity and 5.25 GJ heat per (net) tonne of CO_2 sequestered. We assume this heat is provided by natural gas and include the gas costs in the VOM. Carbon emissions from the natural gas combustion are accounted for in the above capture values, which are reported per net tonne CO_2 sequestered.

(k) *The overnight capital costs (OCC) are taken from* (JRC, 2014) *for conventional technologies, or from* (Tsiropoulos et al., 2018) *for most low-carbon technologies. The cost values shown here are indicative for the year 2030, however the costs for most low-carbon technologies fall over time as explained in Appendix E. The total capital requirement (TCR) includes the OCC plus interest during construction (IDC), calculated based on the assumed build time* (Black and Veatch, 2012)*, economic life* (JRC, 2014)*, and discount rate (8%). For some technologies with more uncertain costs, only the OCC is used.*

(l) Efficiency given at nominal load. Generator, ramping constraints, start-up costs, and part-load efficiencies are based on (Brouwer et al., 2015).

(m) Approximately 10% of conventional thermal capacity are combined heat and power (CHP) plants. We assume these receive additional revenues of 24 € GJ^{-1} for their heat based on average district heating prices (Orita, 2013; Vattenfall, 2017; Werner, 2016). Seasonal thermal demand profiles are based on (Heat Roadmap Europe, 2019).

(n) The VOM of nuclear plants is assumed to range from 2.5 € $MWh^{-1}$for relatively modern plants (<20 years old) based on (JRC, 2014), and 16 € MWh^{-1} for old (>20 years old) plants to account for higher costs for maintenance and life extensions based on (Schneider and Froggatt, 2018).

- We account for approximately 1.6 GW of primary control reserve for CWE, in line with the current 3 GW requirement for Continental Europe (EC, 2017).
- All generators are price-taking profit-maximisers and base their market offers on their SRMC.
- So that we can examine system costs without the effect of subsidies, we do not consider existing or future support schemes for vRES (e.g.

Table 3
Assumed fuel prices in 2017 and carbon intensities.

Commodity	Price (€ GJ^{-1})	Carbon intensity (kg CO_2 GJ^{-1})[b]	Source
Natural gas	5.3	54	EC (2018)
Coal	2.5	96	EC (2018)
Oil	8.5	77	EC (2018)
Nuclear	0.9	0	(Polish Ministry of Economy, 2011; Bles et al., 2011)
Biomass[a]	8	*0/100*	(Thrän et al., 2019; Argus, 2018)

(a) Prices for biomass vary per region and biomass type. In 2017, the spot price of pellets imported to CWE were approximately 9 € GJ^{-1} (Thrän et al., 2019), while wood chips were 7 € GJ^{-1} (Argus, 2018). The value assumed in this study is an average of wood pellets and chips.
(b) These CO_2 intensities are for the raw fuel, before CCS is applied. Note that in the case of biomass, direct emissions are taken as zero, however a carbon content of 100 kg CO_2 GJ^{-1} is used to determine the negative carbon emissions generated when biomass is combined with CCS.

feed-in tariffs) or their impact on bidding behaviour (e.g. negative bids). Moreover, we assume there is no priority dispatch for vRES generators, which must bid into the market like other generators at their SRMC.

- A value of lost load (VoLL) of 10,600 € MWh^{-1} is assumed in the UCED simulations, based on a load-weighted average of VoLL estimates for CWE residential consumers from (CEPA, 2018).[18]

In the *EOMplus* scenarios we assume all market price caps are removed, and the electricity price can rise to the VoLL if the market is unable to clear. We also make demand more elastic to price by including 25 GW (11% of peak CWE demand) of industrial load shedding, with activation prices varying from 220 € MWh^{-1} up to 6000 € MWh^{-1} based on industry-specific VoLL values from (CEPA, 2018).[19]

A quantity-based CM is modelled by applying constraints on the minimum capacity margin in each country, with the capacity price taken as the shadow price of this constraint. Thus, capacity is offered at its marginal cost to the system. The volume of capacity is determined annually from the capacity margins, which are set to remain at 2017 levels under the assumption that the same level of reliability is maintained in the future (Table 1). This capacity can be met by firm generation capacity, transmission, storage, or load-shedding capacity.[20] No constraints are placed on the minimum amount of firm generation capacity per country which must be provided by domestic sources. Thus, we assume countries pursue policies promoting further integration of European electricity markets, rather than nationalistic policies aiming at energy independence.

2.2.2. Decarbonisation scenarios

Two different decarbonisation scenarios are considered. These are derived from global carbon budgets until 2100 published in the Intergovernmental Panel on Climate Change's (IPCC) Fifth Assessment report (IPCC, 2014), following an approach used in a previous work (van Zuijlen et al., 2019) (Fig. 4). The first is a ***2C*** scenario, designed to be consistent with a 66% chance of limiting global warming to 2 °C by the end of the century. In this scenario, CWE power sector emissions fall from 400 Mt CO_2 in 2017 to essentially net-zero by 2040. In the second ***1.5C*** scenario, CWE power sector emissions are consistent with a 66% chance of limiting global warming to 1.5 °C, reaching net −850 Mt CO_2 in 2040.[21] These two trajectories are enforced in the model using annual emission caps.

2.3. Perform model runs

2.3.1. Long-term capacity expansion

The objective function of PLEXOS' investment module is to minimise the net present value (NPV) of the total sum of investment costs, fixed operating and maintenance (FOM) costs, and variable generation costs. Thus, in the absence of any constraints on the capacity margin, the resulting portfolio will be one in which the cost of unmet demand is equal to the marginal cost of an additional unit of generation capacity. It is important to note that the model does not make investments beyond those which achieve minimum system cost, even if those generators may be profitable based on market prices. We solve the capacity expansion module for the whole 34-year horizon in a single step to avoid suboptimal investments which can result in myopic models (Gerbaulet et al., 2019).[22]

2.3.2. Short-term hourly dispatch

Using the portfolios from the capacity expansion module, hourly UCED simulations are performed for the day-ahead market for the years 2020, 2030 and 2040 for each scenario. The UCED module ensures that start costs, fuel costs, and variable operating and maintenance (VOM) costs are minimised, subject to generator ramping constraints.[23] An additional hourly simulation for the year 2017 is performed to validate

[18] A higher VoLL of 100,000 € MWh^{-1} is used in the capacity expansion module as (i) CWE consumers are accustomed to higher reliability levels than implied by a VoLL of 10,600 € MWh^{-1}, (ii) the vast majority of outages are due to faults in the distribution network which is not modelled, and (iii) the capacity expansion module uses a coarser temporal resolution than the UCED simulations. Further explanations are provided in Appendix F.

[19] Further details on the load-shedding assumptions are provided in Appendix F.

[20] Curtailable load is accounted for in the capacity margin but is remunerated based on the amount of energy curtailed and does not receive capacity revenues. Thus, we assume that the capacity costs for load shedding are small in comparison to the energy costs.

[21] The global budgets from 2011 to 2100 for the 2C and 1.5C scenarios are 1000 Gt CO_2 and 400 Gt CO_2 respectively. From these total global budgets, assumed budgets for non-OECD countries, cement production, and already-emitted carbon are subtracted based on Anderson & Broderick (Anderson and Broderick, 2017), with the remaining OECD budgets disaggregated to individual countries based on population. The CWE budgets assume net-zero emissions in the manufacturing, transport and other energy-related sectors by 2050, and that the power sector must deliver all negative emissions required to meet the total energy-related emission target.

[22] The capacity expansion is run with build decisions linearized so that the shadow price on the capacity margin constraint yields a reliable value for the capacity price.

[23] We run the UCED at hourly resolution with a time horizon of one week, plus a one-day look-ahead. To keep the solution time reasonable, we run the UCED simulations with linear relaxation of the unit commitment variables. As a result, minimum stable level, minimum up time and minimum down time constraints are not included. However, literature indicates that ramping constraints have a more significant impact on dispatch and total system costs than the inclusion of binary unit commitment variables (Schwele et al., 2019). Moreover, minimum up and down times which also characterize limitations in the flexibility of power plants are (in many cases) not hard limits, but economic ones (Panos and Lehtilä, 2016). As startup costs are included in the optimisation, this avoids frequent unit startups and shutdowns, which has a similar effect as minimum up and down time constraints.

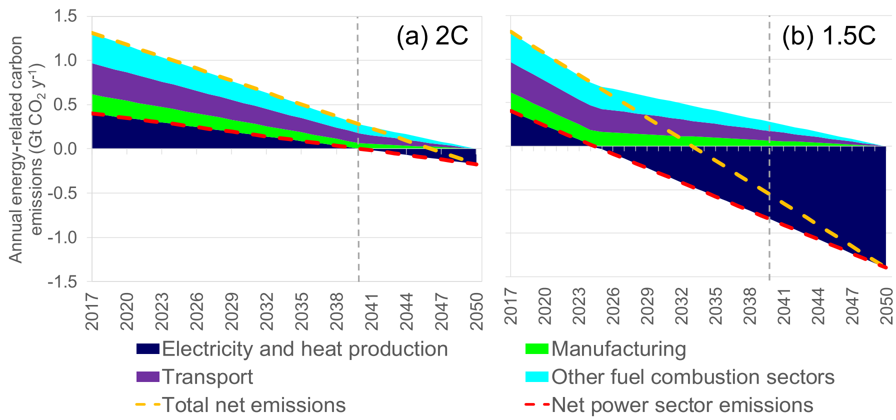

Fig. 4. Assumed decarbonisation trajectories for energy-related emissions in the CWE countries consistent with (a) a 66% chance of limiting global warming to 2 °C and (b) a 66% chance of limiting global warming to 1.5 °C. The dashed orange lines show the total net energy-related carbon emissions. The dashed red lines indicate the net power sector emissions, which are enforced as constraints in the model. The dashed grey lines show the model horizon considered in this study (2040), by which time net power sector emissions reach net zero and −0.85 Gt CO_2 in the 2 °C and 1.5 °C climate scenarios respectively. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

the PLEXOS model with historical data.

2.4. Compare market designs

We consider that the central objectives of electricity market design are to provide low-carbon electricity reliably to consumers, at the lowest possible cost. By *low-carbon*, we mean in a way that is consistent with the assumed global decarbonisation objective. These objectives are interdependent and involve trade-offs. For example, in liberalised electricity markets, system reliability relies on the market providing sufficient signals for investment in new generation capacity, while excess capacity increases total costs to society. A number of quantitative indicators are used to compare the different market design scenarios (Table 4). As the three key objectives described above are rather high level, we also report on several lower-level and complementary indicators related to the general portfolio developments, general market operation, and generator profitability.

Table 4
Main indicators used to compare scenario run results.

Indicator group	Indicator	Description
Portfolio development	Generator builds & retirements	Newly built and retired generation capacity (GW)
	Total installed capacity	Installed capacity (GW)
	Generation	Annual generation (GWh)
Market operation	Electricity prices	Day-ahead electricity prices per country, and the load-weighted annual average CWE day-ahead price (€ MWh^{-1})[a]
	Capacity price	Shadow price of the capacity margin constraint (€ kW^{-1}) (*EOM* + *CM* and *EOMplus* + *CM* scenarios only)
Generator profitability	Specific net profit	Calculated as the total annual generator revenues (including revenues from the spot market, CM and negative emissions), minus the variable costs (including fuel, emission, VOM, FOM, start-up, and pumping/charging costs) and annualised investment costs, divided by installed capacity (€ kW^{-1} y^{-1})
Low carbon	Net carbon emissions	Total net carbon emissions (Mt CO_2)
	Shadow carbon price	Shadow price of the annual carbon constraint in the capacity expansion module (€ t $CO_2{}^{-1}$)
Reliability	Unserved energy	Total demand unmet (GWh)
	Capacity margin	Capacity reserve margin (%)
Total cost	Total cumulative costs	The total sum of investments in generation and NET capacity, fixed and variable generation costs (including for NETs), unserved energy and load shedding over the period 2017 to 2040.[b] (€)

[(a)] *The load-weighted annual average price is calculated from the individual country prices, weighted by the hourly demand* per *country.*
[(b)] *The investment costs for the endogenous vRES deployment are included, while transmission costs are not included.*

3. Results

This section outlines the key modelling results in terms of the defined indicators, with more detailed results provided in Appendix J. Results of the model validation run for the year 2017 can be found in Appendix I. In order to analyse the impact of some of our key assumptions, we also perform a selected sensitivity analysis by varying assumptions on model inputs such as fuel prices and technology costs, as well as the (un) availability of certain technologies given uncertainties around technology developments and social acceptance (section 3.7).

3.1. Portfolio developments

In the period from 2018 to 2022, the investment and retirement decisions in non-vRES technologies for both climate cases under a given market design are similar (Fig. 5). In the *EOM* scenarios, approximately 70 GW of generation capacity – mostly old coal, oil and natural gas plants – is retired at the earliest opportunity in 2018.[24] Retirements are higher in the *EOMplus* scenarios as the additional load-shedding capacity offsets the need for generation capacity. By contrast, the presence of a CM sees much of this thermal capacity remaining online in the *EOM* + *CM* and *EOMplus* + *CM* scenarios until the early 2020s, when the vast majority retires anyway due to age or phase-out.[25] Significant new GT capacity is built to maintain capacity margins at 2017 levels.

From 2023 onwards, the portfolio developments for the two climate

[24] Based on ENTSO-E data (ENTSO-E, 2018d), approximately 32 GW of thermal generation capacity retired from the European power system in the years 2017 and 2018, of which most was coal (17.4 GW), other thermal fossil (9.1 GW) and nuclear (3 GW) plants, while retired gas capacity (2.3 GW) was offset by new investments (2.9 GW). These values are lower than observed in the model results for the year 2018, however the ENTSO-E values do not include plant mothballing, or the fact that in reality some plants may stay online operating a loss, while the model has perfect foresight and will retire plants at the earliest possible opportunity if it is cost effective to do so.

[25] Some existing plants are still online in 2017 even though they exceed their assumed nominal lifetime. This may be due to inaccuracies in the database, life-extending refurbishments which have been performed, or plants simply lasting longer than expected. However, to maintain consistent assumptions within the study, we assume these old plants must retire by 2020.

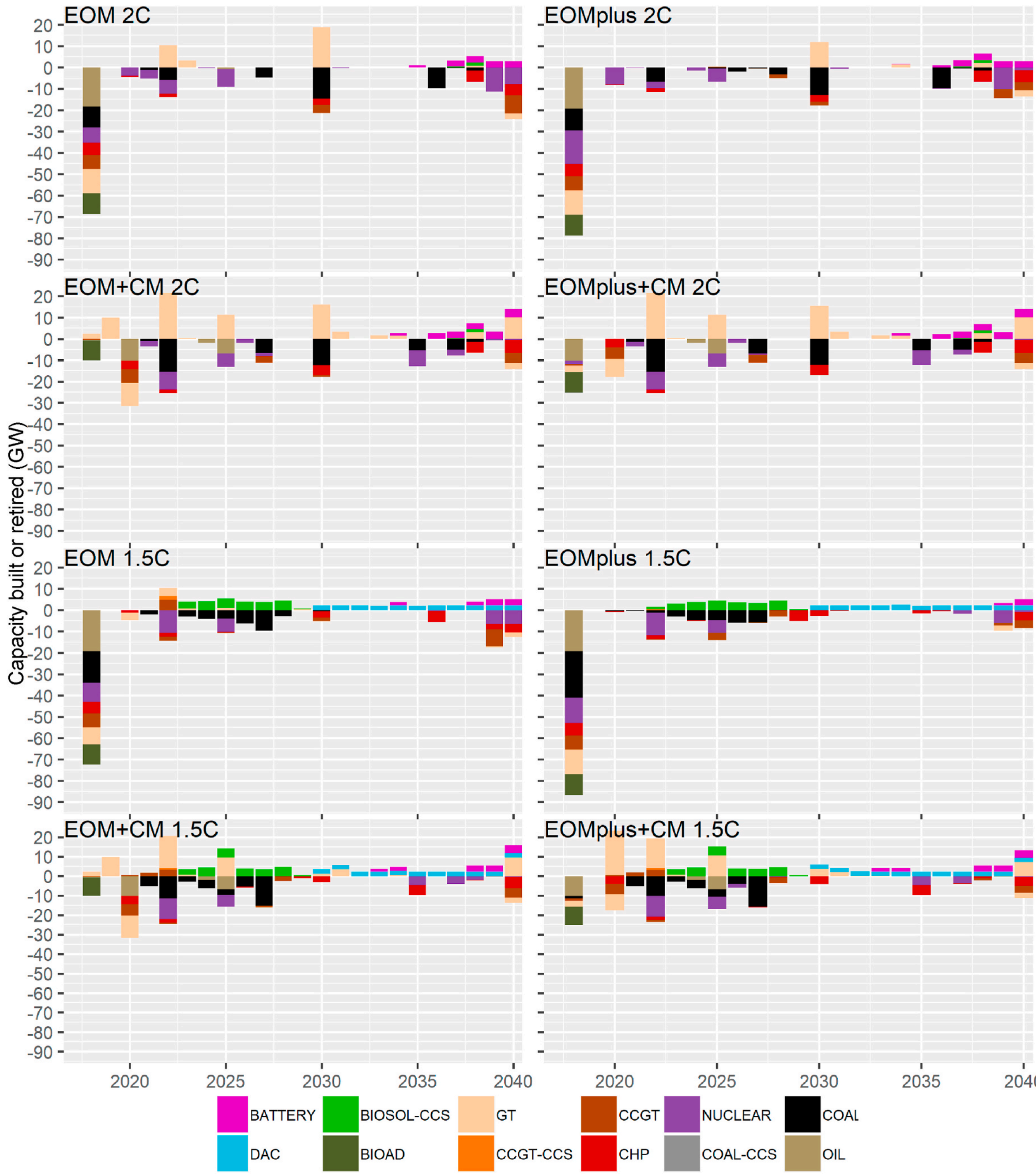

Fig. 5. New investments (positive) and retirements (negative) in non-vRES generation capacity for each market design scenario. Retrofits are shown with the quantity of original plant type retiring type below the axis (e.g. CCGT), and the same amount of the new type (e.g. CCGT-CCS) above the axis. Note that DAC capacity represents additional load on the system, not generation capacity.

cases diverge. In the *2C* climate case, old fossil and nuclear capacity continues to retire due to age and economic reasons. A CM sees most of this capacity replaced by GTs until the early 2030s, by which time batteries have become sufficiently cost-effective to enter the portfolio. While the majority of emission reductions necessary to reach the 2 °C target are delivered by the exogenously increasing vRES capacity, emissions are brought to net zero by the year 2040 by retrofitting approximately 2 GW of coal capacity for BECCS in the late 2030s. In the *1.5C* climate case however, the rate of emission reductions delivered by vRES is insufficient to meet the emissions constraint. As a result, the model converts coal plants to BECCS earlier and, by 2030, nearly 25 GW of BECCS capacity is installed in CWE (17 GW of which are coal retrofits). At this point, BECCS has exploited the available biomass potential and between 2028 and 2040, the model deploys 25 GW (input electricity) of DAC to meet the −850 Mt CO_2 y^{-1} target. Electricity demand for DAC reaches nearly 200 TWh y^{-1} in 2040, met largely by BECCS and nuclear.

Ultimately by 2040, we find that a CM results in approximately 100 GW more capacity in 2040 than in the EOM-only scenarios; mainly from new GTs, higher battery deployment, and a larger fraction of existing nuclear capacity which is kept online (Fig. 6). Despite the nuclear phase-outs in Belgium and Germany, the majority of France's existing nuclear fleet remains online. Batteries help to deal with daily vRES fluctuations and reach a maximum deployment of 17 GW in the *EOM + CM 2C* scenario. Deployment is higher in scenarios with a CM as batteries can substitute GTs as providers of firm capacity while also reducing curtailment. No electrolyser capacity is built in any scenario.

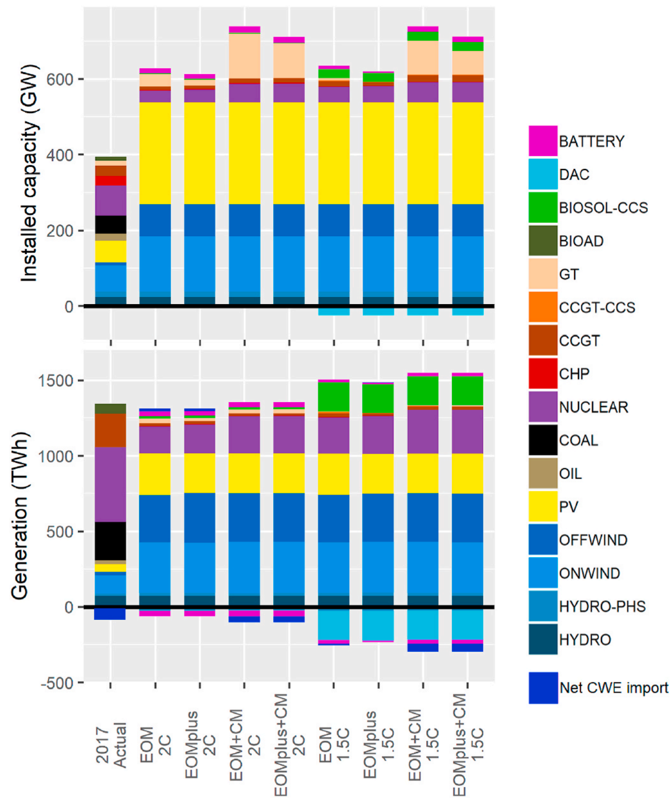

Fig. 6. Installed capacity and generation per technology in 2040 for each market scenario based on the UCED runs. The actual capacity and generation in 2017 from ENTSO-E are also given for comparison (ENTSO-E, 2018). For 2017, biomass generation is aggregated as BIOAD, and gas generation is shown as CCGT. Additional loads on the system from HYDRO-PHS, BATTERY and DAC, as well as net exports from CWE are shown as negative. Net imports to CWE are shown as positive, thus a negative value indicates CWE is a net exporter.

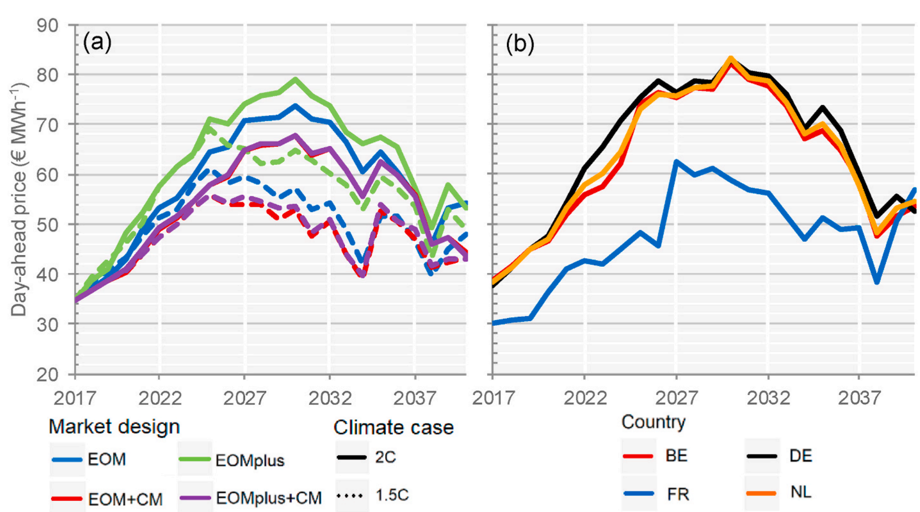

Fig. 7. Development of electricity prices over time from long-term simulations. Figure (a) shows the load-weighted annual average day-ahead price for the whole CWE region in each scenario, while (b) shows the load-weighted annual average price per country for the *EOM 2C* scenario only.

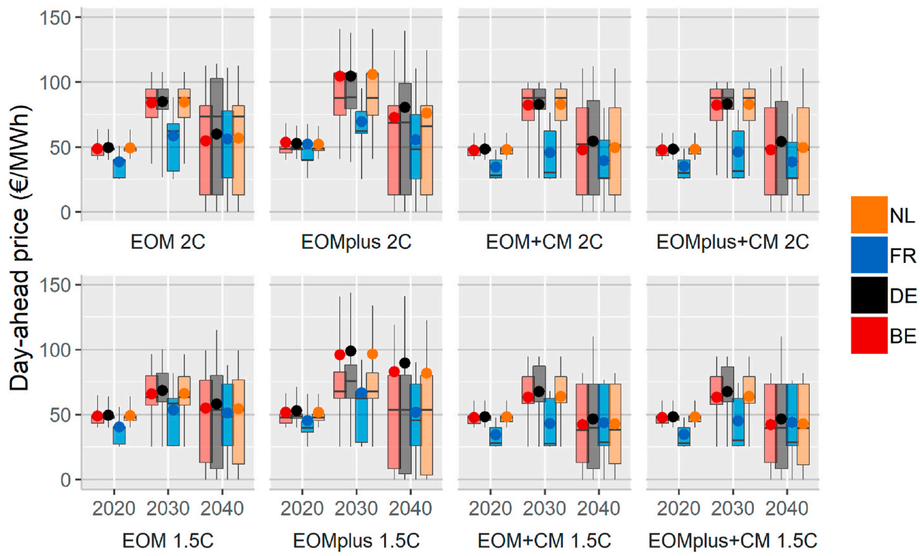

Fig. 8. Boxplots of hourly day-ahead electricity prices for the years 2020, 2030 and 2040 based on hourly UCED simulations. The boxes indicate the 25th, 50th and 75th percentile values, while the whiskers indicate the 5th and 95th percentiles. The coloured circles indicate the load-weighted average prices.

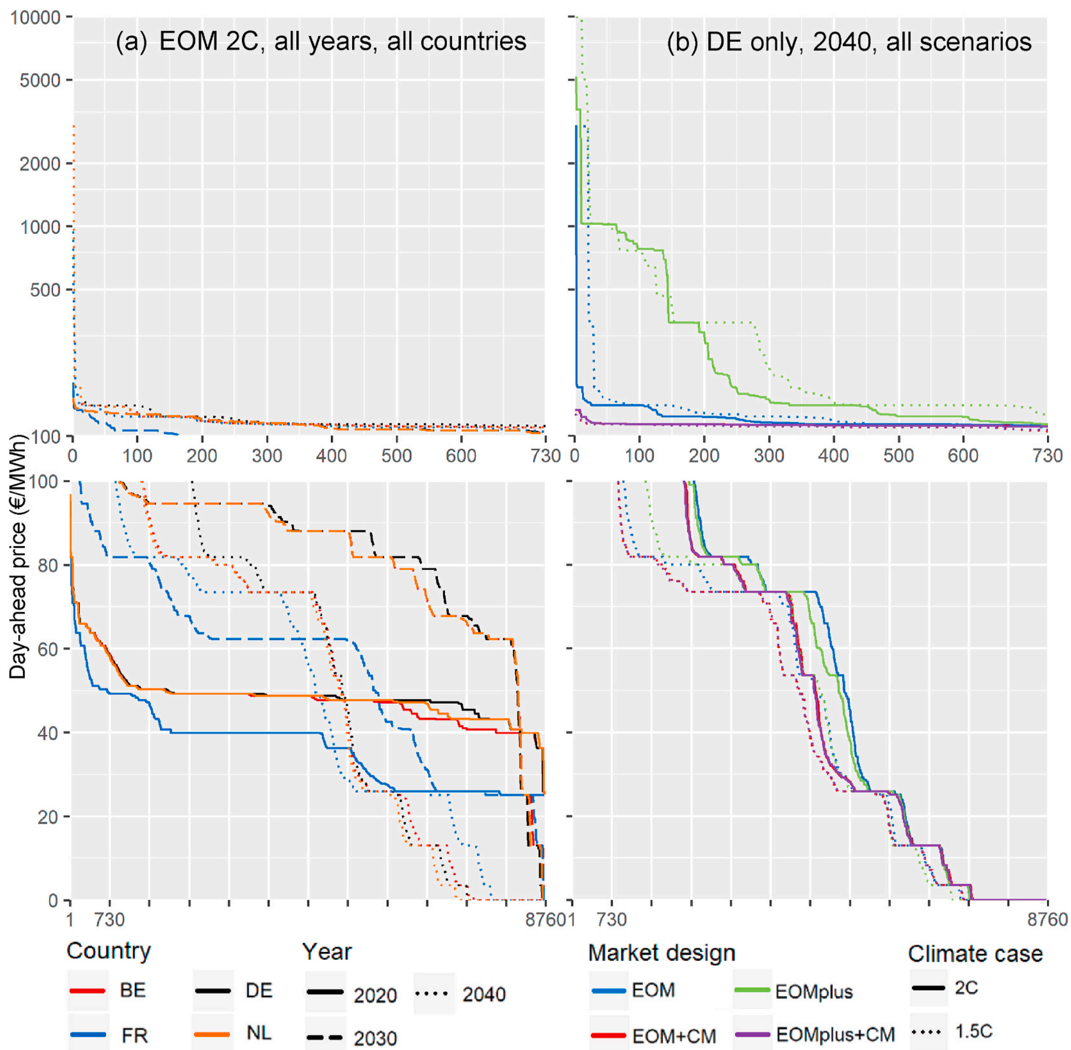

Fig. 9. Price duration curves for (a) the EOM 2C scenario, all countries, 2020, 2030, 2040, and (b) Germany only, 2040 only, all market designs. The lower plots show the curves for the whole year up to a price of 100 € MWh^{-1}, while the upper plots zoom in on the top 730 h with the highest prices.

3.2. Market operation

Starting from an average CWE price of around 35 € MWh^{-1} in 2017, day-ahead prices rise in all scenarios before peaking between 2025 and 2030 in the range of 55–80 € MWh^{-1} (Fig. 7).[26] From 2030 onwards in the *2C* scenarios (2025 in the *1.5C* scenarios), prices trend down and converge in the range of 45–55 € MWh^{-1}. The *EOMplus* design results in the highest prices for both climate cases, while the *EOM* + *CM* design results in the lowest prices.[27] These dynamics are driven by several effects. Firstly, with an increasing carbon price, the SRMC of carbon-intensive mid-merit and peaking generators also increases which bid higher into the market, leading to higher prices in the medium term. Secondly, increasing vRES penetration puts downward pressure on electricity prices due to the merit order effect, offsetting the impact of the higher carbon price. Thirdly, thanks to carbon revenues from net-negative emissions, at a carbon price of 120 € t^{-1} BECCS has a SRMC of approximately −20 € MWh^{-1}. At this level, BECCS can underbid mid-merit and even vRES generators; exacerbating the merit order effect, leading to even lower prices in the *1.5C* scenarios. As France maintains its nuclear dominated portfolio which is unaffected by the rising carbon price, and transmission levels are not sufficient to fully harmonise prices, French electricity prices are the lowest in CWE.

The presence of a CM also puts downward pressure on electricity prices, as higher supply leads to fewer hours with scarcity and higher prices (Fig. 8). Setting the CM to maintain capacity margins at 2017 levels may thus be keeping overcapacity in the system.[28] A reformed EOM results in higher prices than in the EOM as load-shedding sets the market price up to 250 h a year in the *EOMplus 2C* case, and up to 170 h a year in the *EOMplus 1.5C* case (Fig. 9). The presence of a CM not only reduces the frequency of high prices in the *EOM* + *CM* scenario, but also prevents the activation of demand-side resources in the *EOMplus* + *CM* scenario, leading to lower prices than in the *EOM* and *EOMplus* scenarios. This suggests that introducing a CM may undermine efforts to develop efficient demand-side response. Overall, however, the climate case has a stronger impact on prices than the market design.

Price volatility increases over time due to a higher frequency of both low and high prices. Mainly because of the increasing vRES penetration, the electricity price is zero for approximately 1500 h in 2040 in the *2C* scenarios. At the same time, prices exceed 100 € MWh^{-1} up to 2200 h a year in 2040 when fossil plants without CCS become price-setting. In the *1.5C* scenarios, the number of hours with zero price is higher compared to the 2*C* scenarios, while the number of high price hours is lower due to the price-depressing impact of BECCS, leading to lower prices overall. Battery storage appears to reduce price volatility, as the price duration curves for Germany (Fig. 9b) show that the scenario with the lowest battery deployment in 2040 (*EOMplus 1.5C*) exhibits both the highest number of hours with prices at zero, and the highest price spikes across all scenarios.

Capacity prices vary considerably in the range of 0–100 € kW^{-1} with an average of 70 € kW^{-1} and maximum of 300 € kW^{-1} (Fig. 10) as the marginal cost of capacity varies from year to year as determined by new investments, the FOM of existing units, or surplus capacity (i.e. zero capacity price). Total cumulative capacity payments between 2017 and 2040 range from 325 €Bn in the *EOMplus* + *CM 1.5C* scenario up to 425 €Bn in the *EOM* + *CM 2C* scenario. Total capacity payments are lower in the *EOMplus* + *CM* scenarios as capacity prices are slightly lower, and there is less capacity receiving payments. GTs and nuclear plants are the largest beneficiaries of a CM in all scenarios, with each receiving approximately one third of total payments, with the remainder going mostly to hydro, CCGT, coal and BECCS plants.

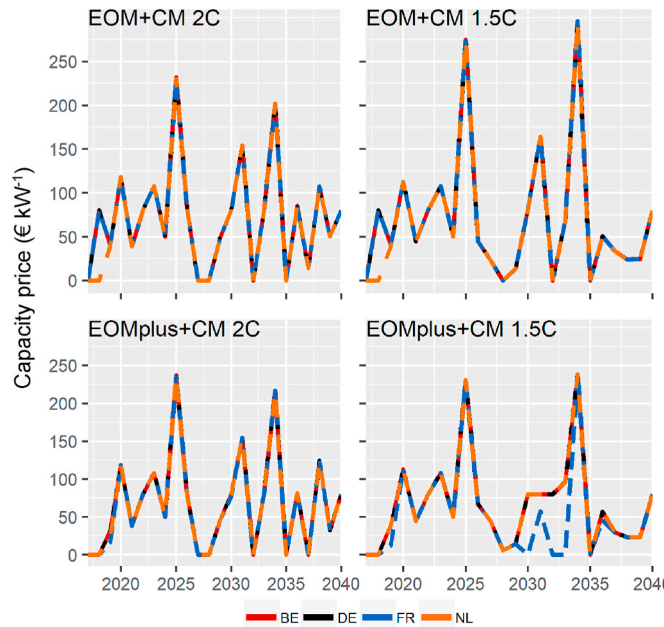

Fig. 10. Capacity market prices per scenario.

3.3. Generator profitability

On the basis of calculated specific net profits, all conventional thermal technologies fail to recover their long-run marginal cost (LRMC[29]) in most years in the *EOM* and *EOMplus* scenarios (Fig. 11).[30] However, if annualised capital expenditure (CAPEX) is excluded (e.g. for existing plants whose investments have already been paid off), nuclear and CCGTs would be profitable in most years (Fig. 12). The profitability of CCGTs and GTs improves in scenarios with a CM thanks to capacity payments, while the profitability of nuclear falls as the additional revenues from the CM are offset by lower energy market revenues. However, even with a CM, volatile capacity prices mean profitability in any given year is not guaranteed and may not provide sufficient incentive for new investments. The profitability of baseload nuclear and mid-merit CCGTs increases in the medium term (2030) thanks to higher infra-marginal rents induced by the effect of a higher carbon price on the SRMC of peak gas generators. By 2040 however, this effect is largely dwarfed by the downward pressure of vRES on market prices.

At an aggregated level, most vRES technologies also fail to recover their CAPEX with day-ahead market revenues alone, apart from a short period around 2030 when the impact of the higher carbon price on market prices is not yet offset by the increasing penetration of vRES. Profitability is lower in the *1.5C* than in the *2C* scenarios due to the lower market prices, principally due to BECCS. The market design scenario has less of an impact on the profitability of vRES than on

[26] The actual CWE load-weighted price in 2017 was 40 € MWh^{-1}. Modelled 2017 day-ahead prices are slightly lower than those seen in reality. The largest discrepancies are seen in France, most likely due to significant nuclear outages in 2017. Accounting for these outages brings modelled prices closer to reality, however they are not included in the base model. See Appendix I for the model validation results.

[27] Note that these prices do not represent the final cost of electricity to consumers, which would also include grid tariffs, taxes and other payments (e.g. to support a CM).

[28] Determining the cost-effective volume of capacity is always a challenge with CRMs. We test the impact of maintaining tighter capacity margins in the sensitivity analysis (Appendix K).

[29] LRMC is equal to the variable costs plus fixed costs, including annualised CAPEX.

[30] Profitability per technology is calculated by aggregating costs and revenues for all plants across the whole of CWE.

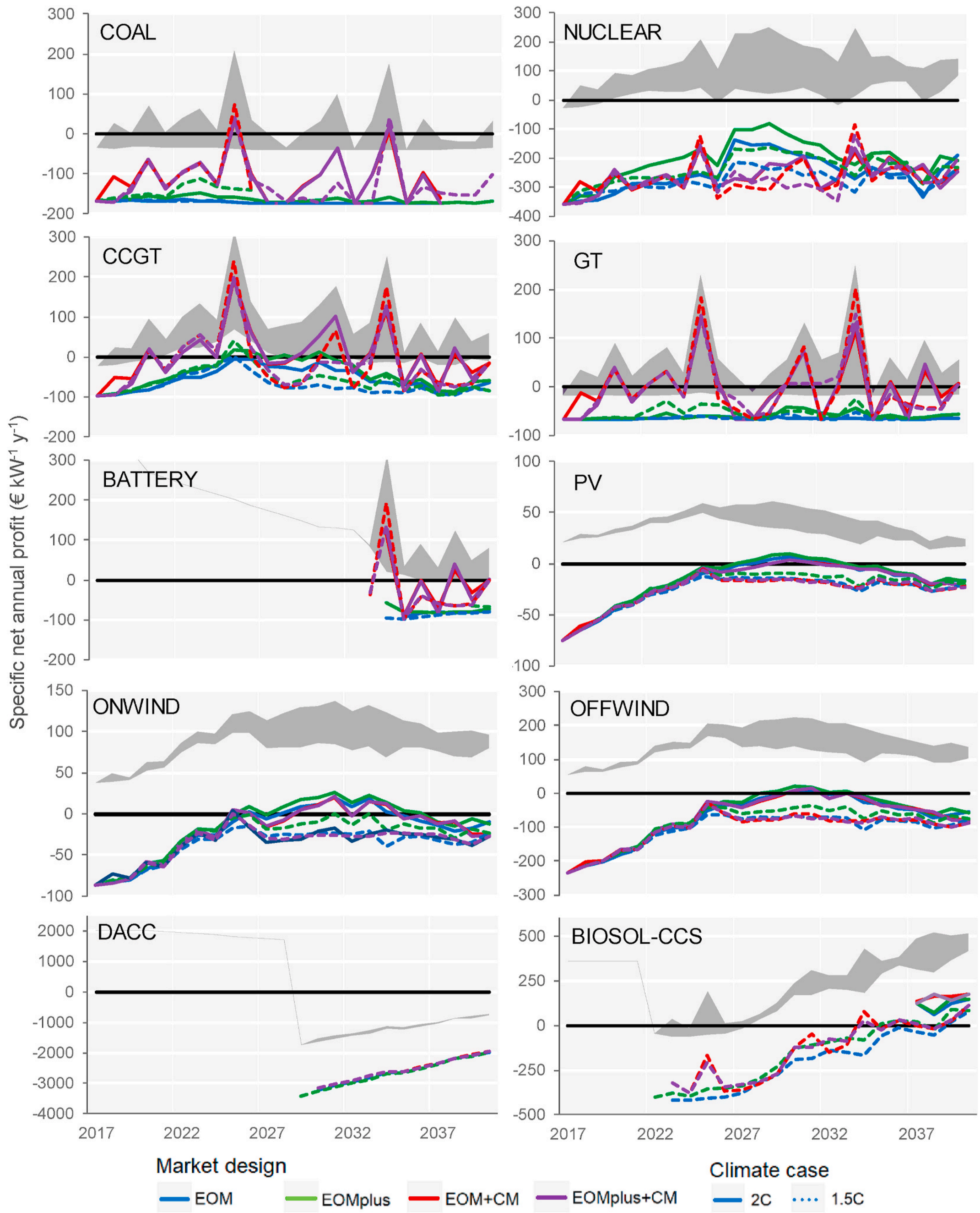

Fig. 11. Specific net annual profit per market scenario for selected technologies based on long-term simulations from 2017 to 2040, accounting for all revenues, variable and fixed costs, including annualised CAPEX. The darker shaded grey area indicates the range of specific profitability across the scenarios excluding annualised CAPEX.

dispatchable technologies as the former are less dependent on scarcity prices and, with low firm capacities, receive only a fraction of the capacity price. Country-specific differences also exist. For example, vRES are less profitable in France than in the other CWE countries due to the lower electricity prices; while in the Netherlands, onshore and offshore wind are more profitable than in the other CWE countries due to higher capacity factors, and are able to recover their CAPEX between 2025 and 2035 in the *2C* scenarios.

Turning to the NETs, BECCS is unable to recover its LRMC until the mid-2030s, once the carbon price has reached around 120 € t^{-1}. When BECCS is deployed in 2037 in the *2C* scenarios however, it is one of the few profitable technologies as it receives not only day-ahead and CM revenues, but also carbon revenues. DAC, on the other hand, is not profitable in any scenario for the period considered due to its high operating and capital costs, even at a carbon price of 120 € t^{-1}.

3.4. Low carbon

Thanks to the increasing vRES capacity and carbon constraints, emissions fall as intended in both climate cases (Fig. 13a). The carbon shadow price in the *2C* scenarios remains far below the *450* scenario price trajectory until the first BECCS capacity is deployed in 2037, when it rises sharply to 100 € t^{-1} (Fig. 13b). This suggests that if vRES capacity increases at the exogenous rate due to government subsidies rather than strong carbon pricing, it will exert significant downward pressure on the carbon price. In contrast to the *2C* case, the carbon shadow price in the

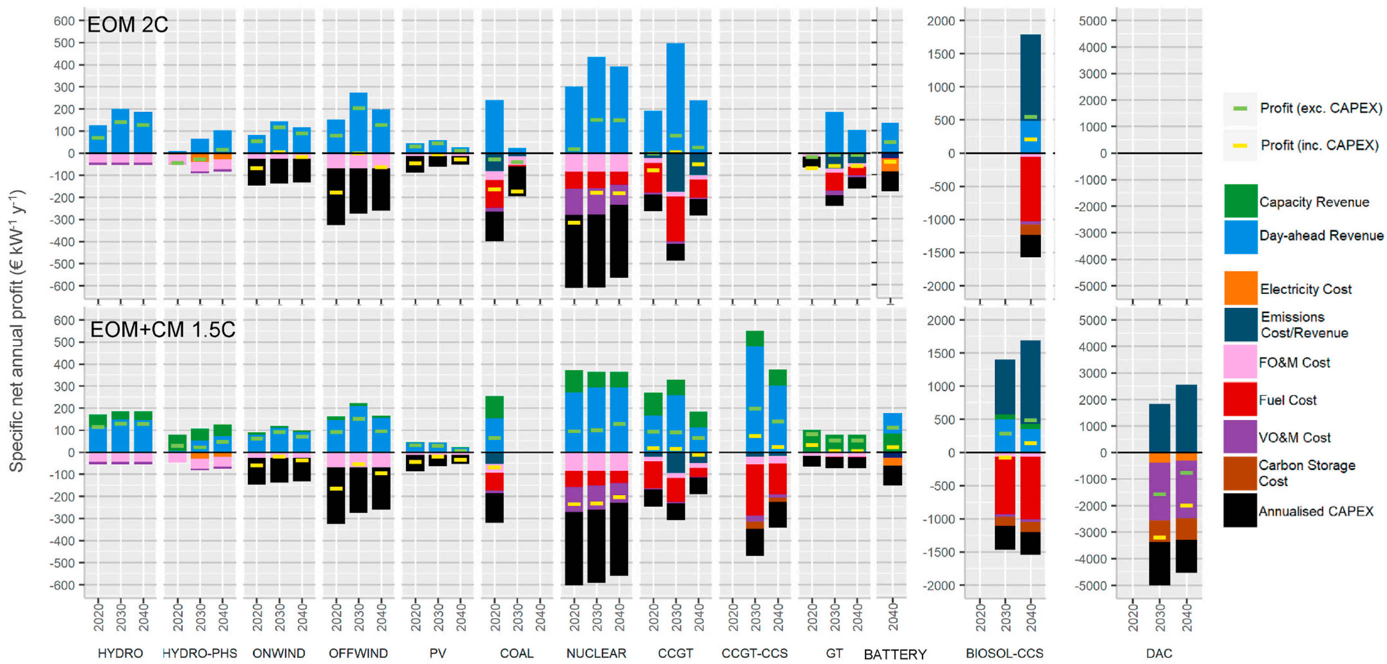

Fig. 12. Specific revenues, costs and profitability per technology aggregated across CWE for the *EOM 2C and EOM + CM 1.5C* scenarios based on short-term UCED simulations. Specific costs and revenues are depicted by the bars, with revenues given as positive and costs as negative. Specific profit is shown by the '–' symbols both excluding (green) and including (yellow) annualised CAPEX. Note the different vertical axis scales for the NETs. Annualised CAPEX is shown for new-build plants, while retrofits will be cheaper. Hydro investment costs are not shown as these vary considerably from one location to another. Electricity cost includes the costs for battery charging, pumping energy for hydro plants, and electricity demand for DAC. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

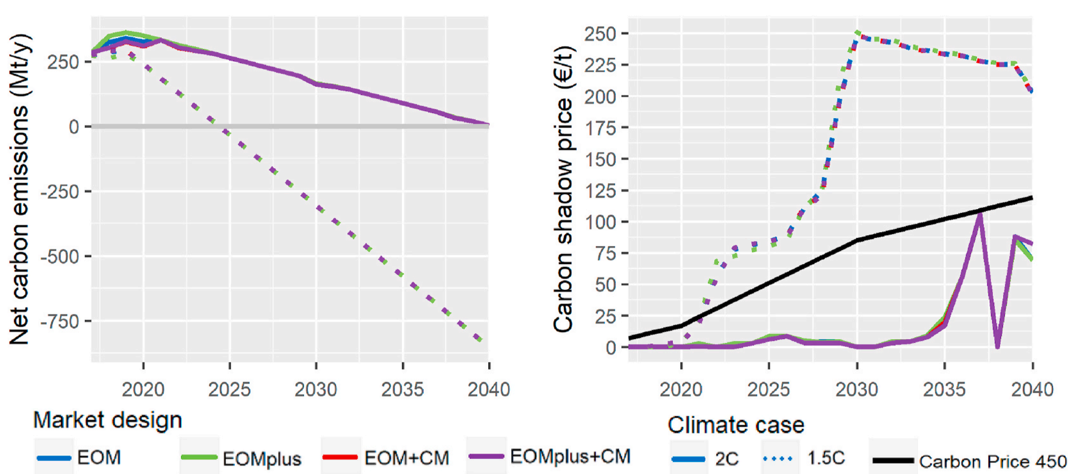

Fig. 13. Net carbon emissions and carbon shadow price for each scenario based on the long-term simulations. The solid black line in the shadow price figure indicates the reference IEA 450 scenario accounting carbon price.

1.5C case surpasses the *450* scenario already in 2022, reaching 90 € t^{-1} in 2023 and 250 € t^{-1} in 2030. These dynamics can be explained by the carbon avoidance costs for BECCS and DAC. With an avoidance cost of around 90 € t^{-1}, deploying BECCS is the cheapest way of meeting the carbon budget from 2037 onwards in the *2C* scenarios, and from 2023 in the *1.5C* scenarios. However, once the allowed biomass potential in the *1.5C* scenarios is used for BECCS (achieving −250 Mt CO_2 y^{-1} net carbon emissions), the model must resort to costlier DAC. The choice of market design has no appreciable effect on the carbon shadow price as the marginal cost of the carbon abatement is higher than the marginal cost of capacity.

3.5. *Security of supply*

Due to the significant retirements in 2018 capacity margins fall sharply in the absence of a CM.[31] Some unserved energy is observed in the EOM scenarios (Fig. 14), while no unserved energy is observed in the CM scenarios. Transmission plays an important role in maintaining security of supply and reducing system costs in all scenarios, with transmission flows within CWE and with neighbouring countries rising from 160 TWh y^{-1} in 2017 to nearly 250 TWh y^{-1} in 2040 (ENTSO-E, 2018). Thus, transmission would play a vital role in maintaining security of

[31] Due to space limitations, capacity margins are reported in Appendix J.

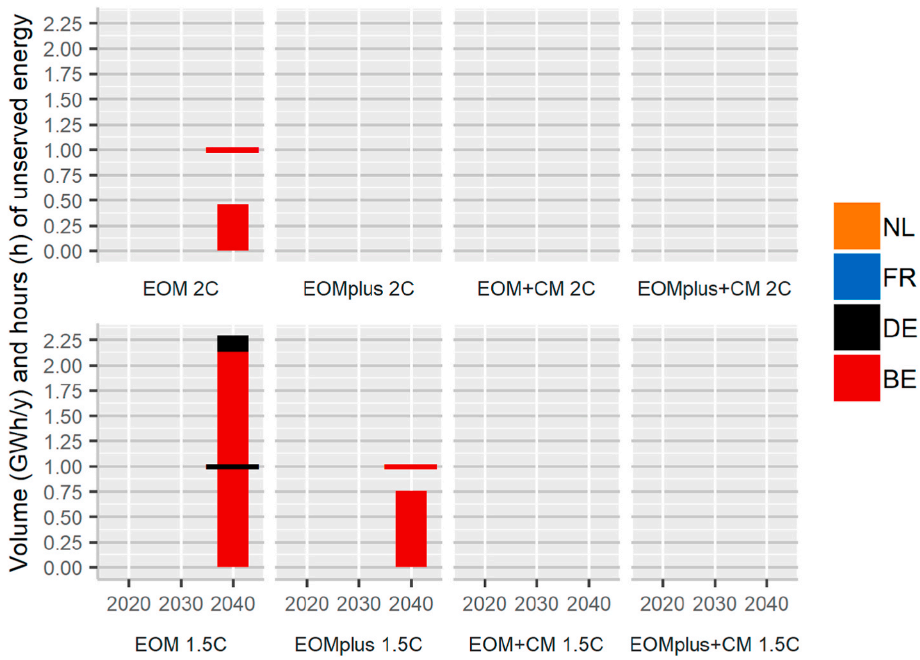

Fig. 14. Volume and hours of unserved energy based on UCED simulations for the years 2020, 2030 and 2040 for each market design scenario. Volumes of unserved energy are shown by the vertical bars, while the number of hours with unserved energy are shown with horizontal lines.

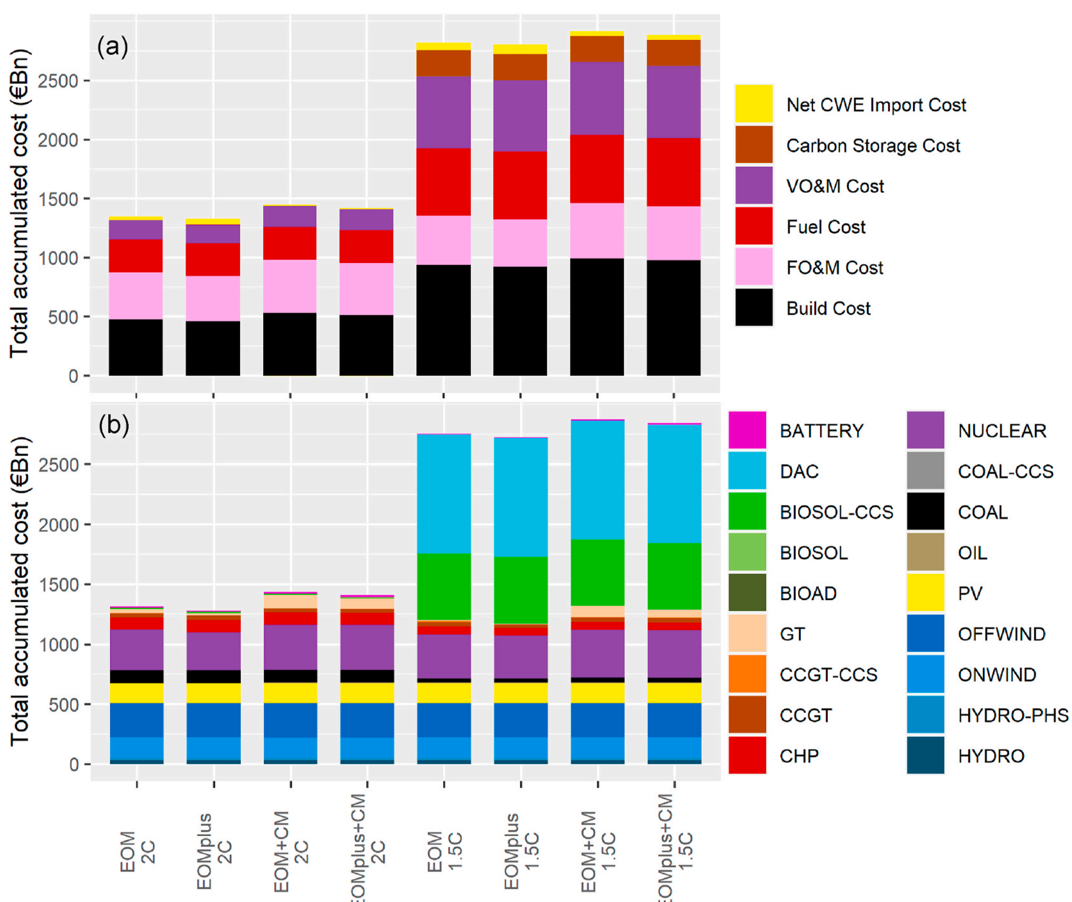

Fig. 15. Total accumulated costs (a) per cost type and (b) per technology for the period 2017–2040 for each scenario. Total costs for load shedding (approx. 4 €Bn), generators start-ups (7 €Bn), and unserved energy (less than 1 €Bn) are relatively small and not shown. Net CWE import cost is the net cost of electricity imports from countries neighbouring CWE, only show in the upper plot. Costs for transmission investments are not included. Capacity payments are not included as these represent a transfer from consumers to producers.

Table 5
Overview of the sensitivity runs performed.

Sensitivity run	Description	Motivation
Higher fossil fuel prices	Instead of keeping fossil fuel prices constant, price trajectory scenarios until 2040 are taken from the *450* Scenario from the IEA's WEO 2016 (IEA, 2016a). The gas price rises 50% to 8 € GJ $^{-1}$ by 2040, while the coal price falls nearly 50% to 1.4 € GJ $^{-1}$. Nuclear and biomass prices remain constant.	Investigate the impact of higher fuel price developments
Higher demand	Assume that electricity demand per CWE country increases with a year-on-year growth rate of 1.3% (Eurelectric, 2018), resulting in a total CWE demand of 1576 TWh in 2040[a].	Many scenarios assume increased demand from electrification is offset by efficiency measures, which may not materialise. Also, electrification of industry, heating and transport may be stronger than assumed in the ENTSO-E scenarios.
Higher battery cost	Battery costs remain at their base 2017 level, assuming significant cost reductions do not take place.	Investigate impact of less favourable battery cost developments.
Higher biomass price	Instead of a fixed biomass price of 8 € GJ $^{-1}$, the biomass price increases over time reaching 12 € GJ $^{-1}$ in 2040 (i.e. +50% vs 2017).	Investigate the impact of increased competition for biomass putting upward pressure on prices.
Blue hydrogen	Assume hydrogen is available at a cost of 13 € GJ $^{-1}$, the minimum required price for blue hydrogen (produced via steam-methane reforming with CCS) to be profitable at the base natural gas price (5.9 € GJ $^{-1}$) (Mulder et al., 2019)	Determine what role blue hydrogen could play in the power system
No retrofits	Exclude the option to retrofit coal (and biomass) plants for BECCS, or natural gas plants with CCS	Determine the potential cost impact of retrofitting existing coal, natural gas and biomass plants
Lower/higherWACC	A lower WACC of 4% is assumed, closer to the social discount rate recommended by (EC, 2014). A higher rate of 12% is also assumed.	Investigate the impact of different discount rates on the analysis.
No biomass limit	The constraint on CWE biomass potential of 3 EJ y^{-1} is removed. *Note: the biomass price remains the same.*	Test the impact of allowing additional biomass supply imported from outside CWE or even outside Europe.
No BECCS	Assume no biomass plants with CCS (BECCS) can be built.	Investigate the impact of political opposition to BECCS.
CCS only with DACC	Assume that CCS can only be used for DAC, not with fossil fuels or biomass.	Investigate the impact of political opposition to CCS, which is only used as a last resort option for DAC.
Optimised vRES	Instead of fixing the minimum (and maximum) annual deployment of vRES exogenously, the model is completely free to optimise vRES from the 2017 starting level.	Determine the consequences of policy-driven vRES growth on the cost-optimum deployment of other portfolio technologies.
Full portfolio optimisation	Similar to the *Optimised vRES* run, with the addition that the model is fully free to retire or invest in any technologies with no restrictions (apart from the starting 2017 vRES capacities which remain fixed). The planned national phase-outs of coal and nuclear capacity assumed in the base runs are ignored, and the model can keep plants online until the end of their technical life.	Determine the unconstrained least-cost generation portfolio development.
Tighter capacity margin (EOM + CM)	Instead of maintaining capacity margins at their 2017 levels, the CM is set to match the yearly margins resulting from the EOM scenarios.	Maintaining margins at 2017 levels could be maintaining overcapacity in the system.
Transmission outages included (UCED only)	Transmission lines between countries are modelled assuming a 10% outage rate (5% planned maintenance, 5% unplanned), based on reported availabilities of Baltic and Nordic HVDC interconnectors (ENTSO-E, 2018b).	Investigate the impact of transmission outages.

(a) *Based on the 'Scenario 2' from Eurelectric's Decarbonisation Pathways study* (Eurelectric, 2018)*. This scenario sees electrification rates (share of final consumption) for transport, buildings and industry in the EU rise from 1% to 43%, 34% to 54% and 33 to 44% between 2015 and 2050 respectively, with the resulting economy-wide electrification rate increasing from 22% in 2015 to 48% in 2050. The electricity demand in 2040 is 26% higher than in 2017.*

supply in a high vRES power system.[32]

3.6. Total cost

Fig. 15a and Fig. 15b depict the total accumulated system costs between 2017 and 2040 per cost type and technology respectively. Comparing the climate cases show that costs in the *1.5C* scenarios, in the order of ~2800 €Bn, are approximately double those of the *2C* scenarios (~1400 €Bn). This is due to the additional CAPEX and operating costs required for NETs and in particular DAC which, with a total cost of ~1000 €Bn, is responsible for 35% of the costs in the *1.5C* scenarios. Thus, when biomass supply is limited, the cost of DAC will largely determine the cost-effectiveness of relying on the power sector to offset more than 250 Mt CO_2y^{-1} emissions from other sectors. Fig. 15b shows that the exogenous vRES deployment also has a major impact on total costs, with vRES representing almost 50% of costs in the *2C* scenarios, and 25% of costs in the *1.5C* scenarios.

For a given climate scenario the *EOM + CM* design results in the highest costs, mostly due to the additional investments triggered by the CM. In both the *2C* and *1.5C* cases, a CM adds approximately 120 €Bn to total costs over the period 2017 to 2040. Load shedding in the reformed EOM marginally reduces total costs, as lower generation costs are largely offset by the cost of load-shedding.

3.7. Sensitivity analysis

An overview and rationale for the runs performed is shown in Table 5. Most runs use only the capacity expansion algorithm to examine the impact on the technologies deployed in the portfolios, rather than performing full UCED simulations. The same exogenous vRES increase is considered for most sensitivity runs but unlike in the base runs, the

[32] In the base runs we do not consider transmission outages. However, when a transmission outage rate of 10% is assumed in the sensitivity analysis (Appendix K), unserved energy up to 60 GWh is observed in Belgium in the year 2030 in the EOM-based scenarios, while none is observed in the scenarios with a CM. Still, even in this more extreme case, less than 0.07% of Belgian demand, or 0.005% of CWE demand is unserved.

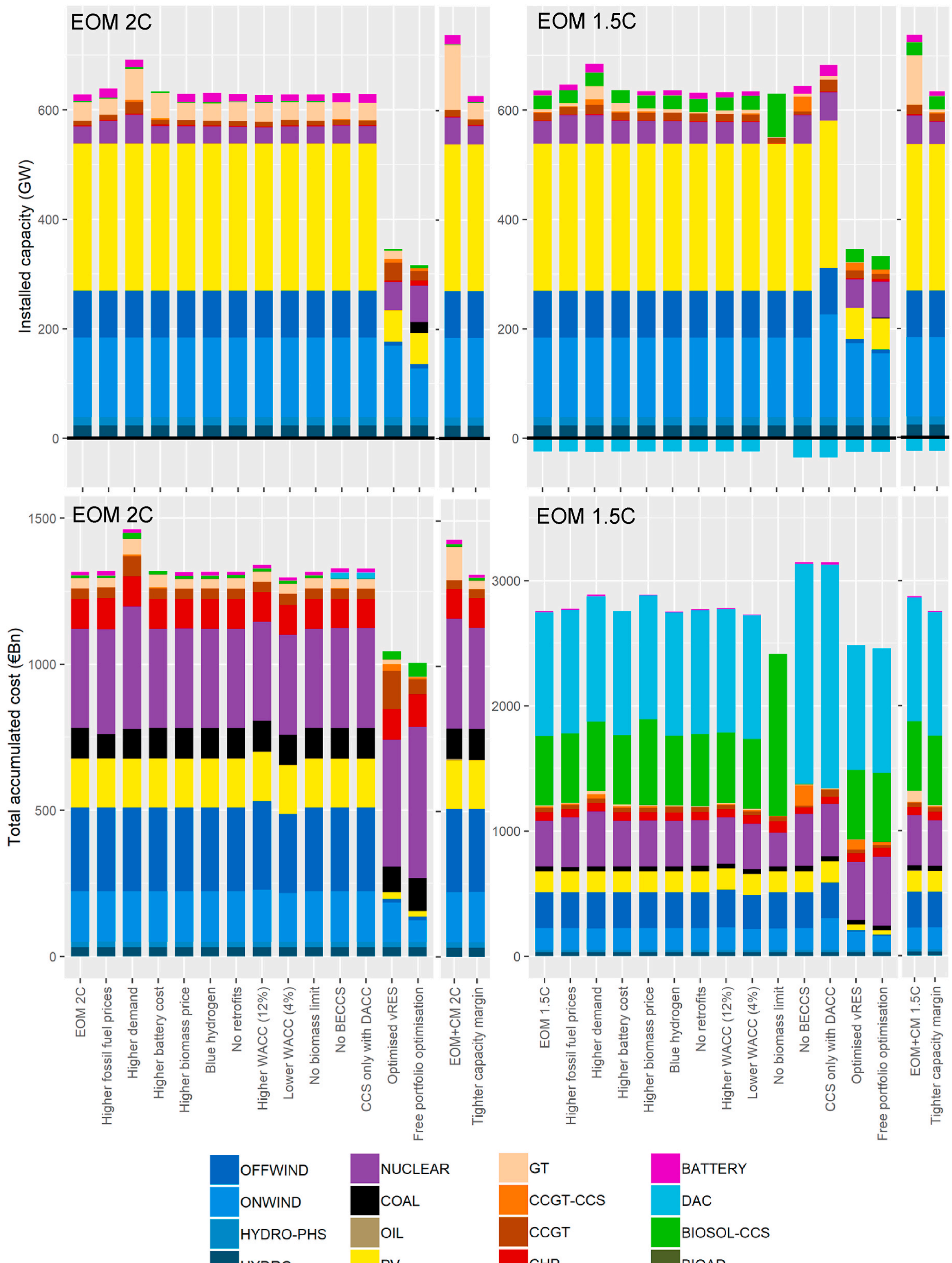

Fig. 16. Installed capacity per technology in 2040 (upper plots), and total accumulated costs for the period 2017–2040 per technology (lower plots) for each sensitivity run. The results of the original EOM(+CM) 2C and EOM(+CM) 1.5C base runs are also shown for reference. Note the different vertical axis scales for the *2C* and *1.5C* cases in the total cost plots.

model is free to invest in more vRES capacity if this is optimal.[33] The sensitivities are based on the *EOM* market design for both the *2C* and *1.5C* climate cases, except for the *Tighter capacity margin* sensitivity which is based on the *EOM + CM* design. Fig. 16 shows the final 2040 generation portfolios and total accumulated costs for each sensitivity run. Additional results are provided in Appendix K. Most sensitivity runs show relatively minor impacts on the portfolios and system costs, though there are some exceptions:

- in the *optimised vRES* runs total costs fall by approximately 20% and 10% compared with the *EOM 2C* and *1.5C* cases respectively. Lower costs are achieved by deploying less vRES and battery capacity, but instead keeping more existing nuclear capacity online and installing more NGCC-CCS and BECCS capacity;
- when the model is given even more freedom in the *free portfolio optimisation*, costs are reduced even further by keeping existing German and Belgian nuclear plants online, deploying less vRES, and installing more BECCS capacity;
- relaxing the upper limit on vRES deployment has no effect, as no sensitivity run results in more vRES capacity installed in 2040 than in the base runs. This observation, and the first two points suggest that electricity for DAC is more cost-effectively supplied by baseload generators such as BECCS and nuclear than vRES, as capital-intensive DAC needs high capacity factors to be effective;
- *increasing the supply of biomass* has no impact on the *2C* case as the biomass constraint is not binding, but reduces total costs by 25% in the *1.5C* case as more BECCS can be deployed instead of DAC. However, biomass demand increases to 9.5 EJ y^{-1} in 2040, or three times the assumed CWE solid biomass potential;
- *excluding BECCS* from the portfolio leads to 20% higher costs in the *1.5C* case due to higher DAC deployment required; and
- applying a *tighter capacity margin* to the *EOM + CM* scenarios results in approximately the same capacity deployment as in the *EOM* scenarios as could be expected, and total costs fall accordingly. However, the resulting capacity prices are also lower with an average of 21 € kW^{-1} in the *2C* case.

4. Discussion

4.1. Implications for vRES and the carbon price

We find that although decreasing vRES investment costs and a higher carbon price improve vRES profitability in the medium term, their market revenues in our scenarios are generally insufficient to cover their investment costs in the long term. Our results therefore suggest that it is unlikely that the vRES penetration of ~70% we assume by 2040 could be achieved by the market without some form of subsidy.[34] In order to ensure our study considers a scenario of large-scale vRES deployment consistent with EU ambitions, we treat vRES capacity as exogenously increasing in the model, which implicitly assumes that this deployment is realised by government intervention in some way such as ongoing subsidisation, or an obligation on retailers to an increasing share of their generation from RES. However, as shown by the near-zero carbon shadow price in the 2 °C scenarios, forcing so much vRES capacity into the system is likely to put downward pressure on the carbon price, undermining its ability to act as a price signal for investment in low-carbon technologies. Because our study does not model the full ETS and competition between sectors for CO_2 emission reductions, we used the 450 scenario carbon prices from the WEO instead of the carbon shadow prices in the hourly simulations and profitability analysis. Using the shadow prices instead would have had an impact on the dispatch and electricity prices. For example, the near-zero shadow prices in the 2 °C scenarios would have resulted in lower electricity prices due to the lower SRMC of fossil plants, and reduced profitability. On the other hand, the higher CO_2 shadow prices in the 1.5 °C scenarios would likely have led to higher electricity prices and improved profitability of most generator types. For the reasons above, policy changes such as redesigning vRES subsidies or more rapid reductions in the volume of auctioned ETS allowances may be necessary to drive the carbon price to the level required for the market to achieve timely decarbonisation.

4.2. Implications for NETs

NETs may have an important role to play to achieve a least-cost decarbonisation pathway, but they will also have several effects on the electricity market. For example, BECCS (retrofits) could lower the cost of decarbonisation by utilising existing coal infrastructure and reducing the need for additional GT capacity, but may also put downward pressure on electricity prices. DAC also has several impacts on market operation. At a carbon price of 120 € t^{-1}, DAC will operate whenever the electricity price is below approximately 135 € MWh^{-1}, leading to additional baseload electricity demand.[35] As DAC would be unprofitable at higher electricity prices, it would not operate during scarcity periods, and would not increase peak demand.

We find that BECCS could be profitable from the mid-2030s onwards, but only under the assumption that plants receive revenue for the negative emissions they deliver. Thus, the incentive for carbon capture and utilisation provided by the EU ETS – avoiding the need to surrender CO_2 allowances – is unlikely to be sufficient to incentivise development of NETs.[36] One possible method to help close the revenue gap for NETs would be to allow them to generate emission allowances. This mechanism would have the advantages of being market based, following the 'polluter pays' principle, and incentivising cost reductions in NETs. However, such a mechanism would need good governance systems to ensure that negative emissions were achieved sustainably, and require the quantity of annual centrally-auctioned certificates to be reduced based on the negative emissions achieved by NETs to prevent oversupply.

While such a mechanism could underpin the business case of BECCS, DAC would still be unprofitable in all scenarios – even when revenues from negative emissions are included. In order to increase carbon prices to the level needed to stimulate DAC by 2030 (~250 € t^{-1}), the volume

[33] The exogenous vRES deployment limits the ability of the model to fully optimise costs in the base runs. There is no minimum vRES deployment enforced in the *Optimised vRES* and *Full portfolio optimisation* sensitivity runs. Upper limits on total vRES deployment potential per technology in CWE are taken as 1300 GW and 540 GW for onshore and offshore wind respectively from (Dalla Longa et al., 2018), and 1000 GW for PV from (Zappa and van den Broek, 2018).

[34] Our sensitivity analysis shows that without this exogeneous vRES deployment not only is far less vRES is deployed, but also that the exogenously increasing vRES may steer away from other low-carbon pathways which could be up to 20% cheaper.

[35] For economic operation, DAC utilisation should be maximised throughout the year, and will operate whenever its SRMC – comprised of VOM costs, electricity costs, and revenues from negative carbon emissions – is negative. However, in the UCED model runs, we force DAC to operate with a minimum capacity factor of 90% to ensure that annual emissions meet the target in the *1.5C* scenarios, and that the additional electricity demand is accounted for.

[36] Recital (14) of the amendments to the EU ETS Directive (European Parliament, 2018) states that "*The main long-term incentive arising from Directive (2003)/87/EC for the capture and storage of CO_2 ('CCS'), for new renewable energy technologies and for breakthrough innovation in low-carbon technologies and processes, including environmentally safe carbon capture and utilisation ('CCU'), is the carbon price signal it creates and the fact that allowances will not need to be surrendered for CO_2 emissions which are avoided or permanently stored.*" Other elements of the EU ETS may also constitute further barriers to NETs and would need to be addressed. For example, "*Projects involving CCU shall deliver a net reduction in emissions and ensure avoidance or permanent storage of CO_2*".

of emission allowances auctioned annually would need to be rapidly reduced,[37] or a carbon price floor could be implemented to top-up the ETS price (Newbery et al., 2019). By the time DAC is deployed, it would predominantly be used to generate carbon allowances to sell to non-energy sectors, as residual power sector emissions are close to zero. Our proposed mechanism would see some of the costs for DAC born by these sectors, but not all. Thus, if DAC is to be deployed at large scale, policymakers would need to decide how society should pay for it in the most equitable way.

4.3. Caveats

Our results should be seen in the context of the scope limitations and uncertainties, as discussed below.

The investments in dispatchable capacity in our study are determined by the least-cost pathway given the exogenous vRES deployment trajectory and emission constraints. However, real-world energy transitions do not necessarily follow the least-cost pathway due to government interventions to achieve other policy goals, externalities not accounted for in investor costs, myopic investors, and imperfect cost assumptions (Trutnevyte, 2016). Instead, it has been argued that transitions follow the most 'investable' path (Trutnevyte, 2016; Gross et al., 2010). Some studies try to account for real investor behaviour by considering 'near-optimal' solutions (Trutnevyte, 2016), or using alternative models such as agent-based (Kraan et al., 2019) or equilibrium competition models (Gurkan et al., 2013; de Maere D'aertrycke et al., 2018). However, our focus is to understand whether different market designs would investment in generation capacity. In this case, we consider cost minimisation a reasonable approach given the key aims of liberalised markets to achieve reliable supply of electricity within environmental limits at minimum costs. Thus, we compare the market designs against the critical fact that investors require a minimum viable business case before they will invest. Given our results show that few technologies are profitable in the long-term based on day-ahead (and capacity) market revenues, if we had included the behaviour of real risk-averse investors, few investments would have been made. In particular, we find that subsidy-driven vRES deployment does not lead to a liberalised market with sufficient incentives for investment in either firm or vRES capacity. The ambition to let a liberalised market drive the transition towards a reliable low-carbon power system primarily based on vRES apparently asks for another design. If the intention is to achieve such a design without subsidies or capacity payments, one option may be to combine a cap on CO_2 emissions with obligations on retailers to source a minimum share of their electricity from vRES while securing enough firm capacity to meet their expected peak demand. However, such a design would likely be dependent on price hedging with long-term bilateral contracts, which was beyond our scope to model in this study.

In a similar vein, other EOM and CRM designs exist which have not been evaluated. For example, the ERCOT market in Texas has implemented a price 'adder', which is administratively added on top of the real-time electricity price during times of scarcity (Potomac Economics, 2018).[38] Strategic reserves, capacity obligations, and reliability options are additional CRM designs that have been implemented in other countries which were not evaluated in this study. Nevertheless, the four archetypal market designs considered in our study likely cover a wider range of design variants and their implications.

Our treatment of internal country flows as copperplate and cross-border capacity based on NTCs ignores the potential impact of grid bottlenecks on curtailment and security of supply. Also, we do not perform an analysis of operational security (e.g. N-1) or redispatch requirements. Addressing these topics would require detailed grid models and flow-based transmission constraints, which was beyond the scope of this study.

We assume a uniform VoLL value for all consumers in the hourly simulations, while studies have shown that consumer's actual willingness to pay to avoid an outage depends on many factors including the country, the timing and duration of the outage, and the notification time (Leahy and Tol, 2011; Devine and Bertsch, 2018; Brijs et al., 2017). While we do account for more demand-side flexibility from industry in this study, we assume that residential and commercial demand remain price inflexible as the flexibility potential and willingness to pay of these sectors remain uncertain. However, a key market reform would be to encourage more price-responsive demand. This could be achieved by full utilisation of smart meter technology and time-of-use retail contracts. For example, proactive consumers willing to expose themselves to market prices could opt for real-time pricing and adjust their consumption patterns accordingly, while others could choose for a fixed tariff, while nominating prices at which their supply may be interrupted (Biggar and Hesamzadeh, 2014). Retail companies could then aggregate these price preferences – effectively customer-differentiated VoLL values – into their market bids. While developments are ongoing in some countries, further regulatory steps are needed to fully exploit demand flexibility in all sectors. Once consumer price preferences are expressed in day-ahead market bidding curves, these data could be included in future market modelling exercises.

Two key assumptions are made in our study which may have resulted in overcapacity in the power system, leading to higher costs than in an optimal system: (i) the use of a higher VoLL in the LT capacity expansion optimisation (100,000 € MWh^{-1}) than the hourly market simulations (10,600 € MWh^{-1}), and (ii) our assumption to maintain capacity margins at 2017 levels in the $EOM + CM$ scenarios. Regarding (i), ideally the same VoLL should be used for the LT and ST runs for consistency; however, we use a higher VoLL for the LT optimisation to account for need to apply temporal simplifications and relax intertemporal constraints, and to reflect that European consumers typically enjoy higher reliability levels in reality than stated national reliability standards (see Appendix F) (ENTSO-E, 2018c; CEER, 2018). One reason for this may be the political cost of lost load that is felt in the event of serious supply interruptions, which makes governments take a conservative approach to security of supply. Only when consumer willingness to pay is fully manifested in wholesale markets will the political cost of lost load fall, and will governments be more inclined to let the market dictate the optimal level of security of supply. For this reason, our inconsistent use of VoLL values may be more reflective of reality. Moreover, the presence of some unserved energy in the *EOM* scenarios shows that our assumptions did not lead to excessive overinvestment. Regarding (ii), several European countries with existing or planned CRMs do not appear to be facing a security of supply issue before 2025, with recent analysis showing their calculated loss of load probability exceeds their national reliability targets (ENTSO-E, 2018c; ACER and CEER, 2018). Thus, countries with CRMs are likely to retain some overcapacity going forward. If 2017 overcapacity levels are maintained, our study suggests that a CM could increase costs by up to 120 €Bn over the period 2017 to 2040. This highlights the challenge of determining the optimal capacity in a centralised volume-based capacity mechanism.

As our study is limited to the day-ahead and CMs the profitability of generators may be underestimated, as generators can also garner additional revenues from hedging, intraday, balancing and ancillary services markets (Pollitt and Chyong, 2018). While the requirements for FCR are included, we do not explicitly model frequency restoration reserves

[37] Most likely this would be far more quickly than the 2.2% annual reduction that will commence from 2021 (Honegger and Reiner, 2018).

[38] The purpose of the adder is to try to incorporate the value of short-term operating reserves into the electricity price, whilst retaining an EOM design. It is based on an operating reserve demand curve originally proposed by Hogan (2013), and is a function of the loss of load probability and VoLL.

(FRR). However, even under the conservative assumption that FRR requirements rise linearly with vRES penetration, the modelled portfolios should be able to account for this.[39] While balancing markets are growing (Tennet, 2018), their monetary value is expected to remain less than 4% of the day-ahead markets – at least up to a vRES penetration of around 30% (Ortner and Totschnig, 2019).

We assume the power sector must deliver all the negative emissions necessary to meet the 2 °C and 1.5 °C carbon budgets, while in fact BECCS may be cheaper to apply in other sectors (e.g. transport) (van Vliet et al., 2011). Moreover, the total costs of DAC in our study are very significant (approximately 33% of total system costs) in the 1.5 °C scenarios, even though our assumed DAC costs (~200 € t CO_2-^{1}) are at the lower end of the range reported in the literature of 50–800 € tCO_2^{-1} (Fuss et al., 2018). Given the uncertainty in DAC costs, it may be wise for policymakers to hedge against very high DAC costs by first exploiting other potentially lower cost NETs based on natural processes such as afforestation or soil carbon sequestration (Smith et al., 2017). However, the IPCC carbon budgets consistent with 1.5 °C warming already assume negative emissions from agriculture, forestry and land use of 1–11 Gt CO_2 y^{-1} globally by 2040, the upper limit of which exceeds the estimated potential of 3.6 Gt CO_2 y^{-1}.[40] By considering both a net-zero and a strongly negative emission scenario, we show the consequences of relying either marginally or strongly on the electricity sector to offset emissions from other sectors. Moreover, investing earlier in NETs in the power sector may also be a prudent insurance policy against climate overshoot as a result of delayed decarbonisation in other sectors, and spreading the cost of negative emissions over a longer period may be more socially equitable (Obersteiner et al., 2018).

We assume the investment costs for PV, onshore and offshore wind fall by 60%, 14% and 34% respectively between 2017 and 2040, in line with the most optimistic RES deployment scenario from (Tsiropoulos et al., 2018). Notwithstanding these reductions, no RES technology fully recovers its annualised CAPEX in 2040. However, we only consider aggregated national capacity factors for vRES, and plants installed at locations with more favourable weather conditions will be more profitable. Generator costs are uncertain and CAPEX assumptions strongly affect their profitability. However, PV, onshore and offshore wind CAPEX would have to fall by a further 50% (to ~200 € kW^{-1}), 20% (to ~900 € kW^{-1}), and 40% (to ~1300 € kW^{-1}) respectively from the assumed 2040 values for them to be able to recover their investment costs from day-ahead market revenues alone. While possible, such reductions would be contingent on the most optimistic learning rates (Tsiropoulos et al., 2018).[41]

5. Conclusion and policy implications

In this study, we compare least-cost pathways to decarbonise the Central Western Europe (CWE) power system until 2040 under the assumption of an increasing share of variable renewable energy sources (vRES), for four different electricity market design scenarios: the current energy-only market, a reformed energy-only market, both also with the addition of a capacity market. Each design is modelled for one decarbonisation pathway targeting net-zero emissions by 2040 consistent with a 2 °C warming limit, and another targeting −850 Mt CO_2 y^{-1} net negative emissions consistent with a 1.5 °C warming limit. We compare these scenarios against the high-level objectives of delivering low-carbon electricity reliably to consumers at the lowest possible cost.

Our model results based on a limited number of weather years and a simplified grid suggest that both 2 °C and 1.5 °C compliant systems could be achieved and deliver electricity reliably. In terms of cost, we find the 1.5 °C warming scenarios lead to system costs which are twice as high as a 2 °C scenarios due to the high cost of negative emission technologies – in particular direct air carbon capture (DAC) – which are needed if the power system must deliver all the negative emissions required to meet a 1.5 °C warming limit. To make achieving a 1.5 °C target more affordable, policymakers should investigate lower cost alternatives in other sectors, and increase research and development in DAC to reduce its cost. Additionally, we find that:

- bioelectricity with carbon capture and storage (BECCS) is a cost-effective way of rapidly decarbonising the power sector, especially when aiming to limit warming to 1.5 °C by mid-century. However, it may put downward pressure on electricity prices;
- baseload generators such as BECCS and nuclear appear to be more cost-effective at supplying electricity for DAC than vRES;
- keeping existing nuclear capacity online may help maintain security of supply, reduce carbon emissions, and lower electricity prices;
- deploying high levels of vRES (up to 70% penetration) could result in up to 1500 h with day-electricity prices of zero by 2040, and undermine the effectiveness of a carbon price as an investment signal for other low-carbon and NETs; and
- policies relying primarily on vRES to decarbonise the power sector could increase costs by some 10%–25% compared to a more diversified portfolio containing vRES, nuclear, natural gas (with CCS) and BECCS plants.

In terms of electricity market design and generator profitability, we find that none of the market designs modelled allow all technologies to recover their investment costs in the long term in either decarbonisation scenario. While a capacity market can improve the profitability of mid-merit and peaking gas plants, it can also undermine the profitability of baseload and vRES generators and is not necessarily a silver bullet for addressing adequacy concerns.

Further research is needed to identify to what extent revenues from futures/forwards, intraday and ancillary services markets can complement day-ahead revenues for flexible generators, which market designs can best capture the potential of demand-side price flexibility and facilitate vRES deployment without reducing the effectiveness of the carbon price, and how large-scale investments in NETs can be supported.

CRediT authorship contribution statement

William Zappa: Conceptualization, Methodology, Software, Formal analysis, Visualization, Writing - original draft. **Martin Junginger:** Conceptualization, Supervision, Writing - review & editing. **Machteld van den Broek:** Conceptualization, Supervision, Resources, Writing - review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

[39] The total contracted volume of FRR (aFRR + mFRR) in CWE in 2017 was almost 7 GW (900 MW in Belgium, 3000 MW in Germany, 1000 MW in The Netherlands, and 2000 MW in France) (Elia, 2019; RTE, 2019; Brinkel, 2018). With a vRES penetration (energy basis) of 17% in 2017 and ~70% in the *EOM 2C* scenario in 2040, a proportional increase in FRR requirements would translate to a need of around 30 GW, which is less than the 85 GW of flexible generation capacity available in 2040. The other scenarios have even more flexible capacity provided by a CM, demand response or BECCS.

[40] In their budgets, Anderson & Broderick (Anderson and Broderick, 2017) assume that emissions from deforestation are matched by additional carbon sequestration through land use, land use change and forestry activities until 2100. In some IPCC scenarios limiting warming to 1.5 °C, even the estimated global BECCS potential of 5 Gt CO_2y^{-1} is exceeded (IPCC, 2018).

[41] The base learning rates assumed in (Tsiropoulos et al., 2018) are 20% for PV, 5% for onshore wind and 11% (2020) falling to 5% (2040) for offshore wind, while the optimistic learning rates are 23%, 10% and 20% (2020) falling to 10% (2040) respectively.

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Appendix A. Supplementary data

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