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Comparing policy routes for low-carbon power technology deployment in EU – an energy system analysis

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ABSTRACT

The optimization energy system model JRC-EU-TIMES is used to support energy technology R & D design by analysing power technologies deployment till 2050 and their sensitivity to different decarbonisation exogenous policy routes. The policy routes are based on the decarbonised scenarios of the EU Energy Roadmap 2050 combining energy efficiency, renewables, nuclear or carbon capture and storage (CCS). A "reference" and seven decarbonised scenarios are modelled for EU28. We conclude on the importance of policy decisions for the configuration of the low carbon power sector, especially on nuclear acceptance and available sites for new RES plants. Differently from typical analysis focussing on technology portfolio for each route, we analyse the deployment of each technology across policy routes, for optimising technology R & D. R & D priority should be given to those less-policy-sensitive technologies that are in any case deployed rapidly across the modelled time horizon (e.g. PV), but also to those deployed up to their technical potentials and typically less sensitive to exogenous policy routes. For these 'no regret' technologies (e.g. geothermal), R & D efforts should focus on increasing their technical potential. For possibly cost-effective technologies very sensitive to the policy routes (e.g. CSP and marine), R & D efforts should be directed to improving their techno-economic performance.

1. Introduction

The power sector is a large player in energy related CO_2 mitigation and thus has been an important target within several European Union (EU) energy and climate policy initiatives. The key EU policy initiatives are summarised in Table 1. Correspondingly, the possible long term future layout of a low-carbon EU power sector and its technology mixes have been widely covered in scientific literature by using a number of models. For instance, Capros et al. (2012a) and Capros et al. (2012b) used the PRIMES partial equilibrium energy system model to assess the decarbonisation of the EU energy system until 2050. They conclude that it is feasible for the EU power sector to reduce its CO_2 emissions by 98% with respect to1990 levels by replacing coal and gas power plants with renewable energy resources (RES) based electricity (notably wind and solar PV) and carbon capture and storage (CCS) gas plants. This would be accompanied by an increase in electricity prices of 1.7–8.7% compared to a non-decarbonised scenario. A more recent study (Capros et al., 2014) performed a multi model analysis with partial and general equilibrium models to explore the required energy system transformations to reduce GHG emissions in 2050 to less 80% than 1990 levels. The authors conclude that decarbonising the EU power sector is a cost effective strategy to meet such a stringent emission cap, achievable via an increase in the share RES electricity, nuclear and CCS.

Similarly, an analysis of the Roadmap for moving to a low-carbon economy in 2050 undertaken with the general equilibrium model PACE (Hübler and Löschel, 2013) conclude that the electricity sector is crucial for decarbonisation but would lead to estimated increases in electricity prices between 18–67% in 2050 from 2005 values. Partial multi-region electricity sector models have also been used to develop decarbonised scenarios for the EU, such as Haller et al. (2012) concluding that a near complete decarbonisation can be achieved at "moderate costs" via solar PV, CSP and wind with expansion in transmission capacity within the EU. Jägemann et al. (2013) used an optimization model for the electricity sector to evaluate the economic implications of alternative energy policies for the EU's power sector, in particular assessing the implications of a nuclear phase out, CCS deployment and targets on the share of RES electricity, focusing on the synergies and competition among the three. At global level, the IPCC AR5 (Pachauri and Meyer, 2015) compares global climate mitigation pathways for the power sector and assesses mitigation cost increases in scenarios with limited availability of the following low-carbon technologies: CCS, solar/wind, bioenergy and nuclear, concluding that total discounted mitigation costs in 2015–2100, increase from 6% to 138%

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Table 1
Overview of key EU policy initiatives on energy and climate change with relevance to the power sector.

Policy initiative	Short description and role of power sector
Directive 2001/77/EC	National targets for increasing the electricity produced from renewable energy sources (RES) (European Communities, 2001).
Directive 2003/87/EC **Directive 2009/29/EC**	Important role of the power sector played within the EU greenhouse gas (GHG) emissions allowance trading scheme (EU ETS) including a possibility for free allocation of allowances in the first two phases (European Communities, 2003) and for transitional power plants in the current phase (European Communities, 2009a).
Directive 2009/28/EC	Special consideration of RES electricity in transport within the directive on the promotion of use of final energy from RES (European Communities, 2009b).
COM(2011) 112 final	The highest sectoral reductions for power sector CO_2 emissions (less 93–99% in 2050 compared to 1990) in the Roadmap for moving to a competitive low-carbon economy (European Commission, 2011b).
COM(2011) 885 final	The important role of the power sector in long term satisfaction of final energy demand and CO_2 mitigation in EU is clearly stated in the Energy Roadmap 2050 (European Commission, 2011a).
COM(2014) 15 final	The policy framework for climate and energy in the period 2020–2030 (European Commission, 2014) highlights that ensuring competition in integrated electricity (and gas) markets is necessary to implement energy policy objectives in a cost-efficient manner.

relative to default technology assumptions. Limited CCS has the biggest impact in mitigation costs increases, followed by limited bioenergy, nuclear phase out and limited solar/wind. All the authors seem to agree that the EU power sector will have to undertake major changes to meet strict decarbonisation targets and that the future portfolio of the EU power technologies will vary depending on factors such as climate policy decisions, electricity technology characteristics and sector policies (Jägemann et al., 2013).

In support to the EU decarbonisation objectives in this field of research, the EU Strategic Energy Technology Plan (SET Plan) (European Commission, 2007) established an energy technology policy for Europe aiming to accelerate the development and deployment of cost-effective low-carbon technologies. The SET Plan covers electricity generation technologies, such as RES, sustainable nuclear fission and advanced fossil fuels. Furthermore, it addresses electricity grids, smart cities, hydrogen and fuel cells, energy efficiency, and low-carbon industrial processes across a range of sectors. Under the 2020 climate & energy policy package, the SET Plan has increased EU-wide R & D investments in energy technologies from €3.2 to €5.4 billion per year (European Commission, 2014), but according to the 2030 climate & energy policy framework the EU will have to step up its efforts on research and innovation policy to support the post-2020 climate and energy framework. For this purpose, it is necessary to reflect on how and with which priorities R & D investments should be allocated (European Commission, 2014).

This paper takes into account this call for priority setting regarding energy technologies and goes beyond current literature by comparing how different 'exogenous policy routes' for decarbonisation affect the deployment of the SET Plan power sector technologies across scenarios. The EU Energy Roadmap 2050 (European Commission, 2011a) used decarbonised scenarios to explore "routes towards decarbonisation of the energy system" that combine "four main policy directions to decarbonisation": energy efficiency, renewables, nuclear or CCS. Similarly, in the context of this paper, 'exogenous policy routes' are exogenous assumptions introduced into the modelling exercise as decarbonised scenarios reflecting energy policy topics affecting power decarbonisation, akin to the scenarios of the EU Energy Roadmap 2050. However, whereas the EU Energy Roadmap 2050 and current literature typically present results as portfolios of low-carbon power technologies for each decarbonised scenario (Capros et al., 2012a, 2014), this paper also looks into the technologies' cost-effectiveness across scenarios. This is useful for assessing how the assumed 'policy routes' affect the interplay between low-carbon power technologies thus informing energy technology policy-making and identifying 'no-regrets' options. The former approach (Capros et al., 2012b, 2014) is possibly more adequate for supporting less technology specific climate mitigation targets. In addition, long-term energy system modelling exercises are subject to uncertainty from assumptions and from the definition of boundary conditions. Thus, understanding how sensitive the results are to the scenarios' design assumptions is as vital as analysing the interplay of technology substitution.

For this analysis, the energy system model JRC-EU-TIMES for the EU28 from 2005 till 2050 is used to model in total eight scenarios, one of which is used as reference (Current Policy Initiatives scenario, hereafter named CPI) and includes the 20-20-20 policy targets. All other seven scenarios are decarbonised scenarios since they all have a CO_2 reduction cap of 85% below 1990 values in 2050. The CAP85 scenario only has this CO_2 reduction cap. The other six decarbonised scenarios were designed to reflect 'exogenous policy routes' assumptions in addition to the CO_2 cap. The assumptions direct the model towards different technological routes for decarbonisation as follows: smaller contribution of CCS (DCCS); higher social acceptance and facilitated permitting of RES plants (HRES); higher social acceptance of nuclear plants (HNUC); stricter and more effective end-use energy efficiency requirements (LEN); lower biomass availability for the energy system following concerns with nature conservation and food production (LBIO); and higher concerns with ensuring the reliability of transmission and distribution, reducing the share of intermittent variable solar and wind electricity (LSW). The CAP85 scenario is left without a policy route other than carbon mitigation to serve as a benchmark for comparing technology deployment in a long-term decarbonisation context. The paper is structured as follows: in the following section methods and assumptions underlying the modelling are detailed. Section 3 and Section 4 respectively present results and discuss its limitations, while Section 5 concludes.

2. Methods

2.1. Overview of the JRC-EU-TIMES model

JRC-EU-TIMES is a linear optimization bottom-up energy system model generated with the TIMES model generator from Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency (Loulou et al., 2005a, 2005b). The spatial coverage of JRC-EU-TIMES is the EU28 energy system plus Switzerland, Iceland and Norway (hereafter referred to as EU28+), where each country is specifically modelled. Timewise, the model covers the period from 2005 to 2050 and each year is divided in 12 time-slices that represent an average of day, night and peak demand for every one of the four seasons of the year. More information on the model, including a detailed description of its inputs, can be found in Simoes et al. (2013).

The equilibrium is driven by the maximization (via linear programming) of the discounted present value of total surplus, representing the sum of producers and consumers surplus, which acts as a proxy for welfare in each region of the model. The maximization is subject to constraints, such as: supply bounds for the primary resources, technical constraints governing the deployment of each technology, balance constraints for all energy forms and emissions, timing of investment payments and other cash flows, and the satisfaction of a set of exogenous demands for energy services in the modelled sectors of the economy, namely: industry; residential; commercial; agriculture; and transport. These demands drive the activity of the primary energy supply and electricity generation sectors, which are endogenous to the model.

As a partial equilibrium model, JRC-EU-TIMES does not model the economic interactions outside of the energy sector, although it considers price elasticities of the energy service demands. JRC-EU-TIMES also does not consider non-rational aspects that condition investment in new and more efficient technologies.

The most relevant model outputs are the deployment of energy supply and demand technologies for each region and period (e.g. annual stock and activity), with associated energy and material flows including emissions to air and fuel consumption for each energy carrier. Besides these, the model computes annual operation and maintenance costs, investment costs, and energy and materials commodities prices.

2.2. Major inputs of JRC-EU-TIMES

The model is supported by a detailed database, with the following main exogenous inputs: (1) end-use energy services and materials demand; (2) characteristics of the existing and future energy related technologies, such as efficiency, stock, availability, investment costs, operation and maintenance costs, and discount rate; (3) present and future sources of primary energy supply and their potentials; and (4) policy constraints and assumptions. The latter set of exogenous assumptions is the one studied in this paper to compare exogenous policy routes influencing low-carbon power technologies deployment.

In this section is presented a condensed version of the detailed model inputs which are fully described in Simoes et al. (2013).

2.2.1. Energy services and materials demand

The materials and energy demand projections for each country are differentiated by economic sector and end-use energy service, using as a starting point historical 2005 data and macroeconomic projections from the GEM-E3 model (Russ et al., 2009) as detailed in Simoes et al. (2013), and in line with the values considered in the EU Energy Roadmap 2050 reference scenario (European Commission, 2011a). From 2005 till 2050 the exogenous useful energy services demand (detailed in Appendix A) grows 32% for agriculture, 56% for commercial buildings, 28% for other industry, 24% for passenger mobility and almost doubles (97%) for freight mobility. On the other hand, the exogenous useful energy services demand for residential buildings is 12% lower in 2050 than in 2005 due to the assumptions on building stock improvements. JRC-EU-TIMES also models energy intensive industry sectors, starting from exogenous services demands in Mt for materials production Appendix A). The evolution of exogenous demand inputs into the model varies depending on the material, following GEM-E3 different sector gross added values projections.

2.2.2. Energy supply and demand technologies focussing on electricity generation

Energy consumption data from Eurostat are used to derive country and sector-specific energy balances, which determine the characterisation of energy technology profiles for supply and demand technologies in the base year. Beyond the base year, possible new energy supply and demand technologies are compiled in an extensive database with detailed technical and economic characteristics based on Tzimas (2011) and summarised in Appendix B. More information on aspects as CO_2 storage capacity and transport can be found in Simoes et al. (2013). The model uses country-specific wind and solar annual availability profiles for an average year for the 12 modelled time-slices from Brancucci Martínez-Anido et al. (2013).

Technology-specific discount rates using the values considered in the PRIMES model as in (European Commission, 2011a) are used, including a discount rate of 5% for social discounting. Following the PRIMES model assumptions, for centralised electricity generation a discount rate of 8% is considered, for CHP and energy-intensive industry 12%[2]; 14% for other industry and commercial sector; 11% for freight transport, busses and trains; 17% for the residential sector, and 18% for passenger cars.

Concerning electricity grids, JRC-EU-TIMES considers both import/export processes regarding the existing infrastructures (capacity and flows) and possible new investments, both within EU28+ and with the rest of the world. There are three levels of electricity voltage and conversion between levels. Transmission grids among EU28+ consider different connection possibilities, depending on the countries: asynchronous, radial, synchronous or no connections. Electricity exchanges (network use) are endogenously modelled based on DC load flow calculations and cost optimization of grid investments. Distribution grids have an associated cost in euros/kW based on the electricity transport tariff for 2011 for each country from Eurostat. The electricity trade outside EU28+ is bounded with an upper limit following the assumptions made in Lavagno and Auer (2009). A detailed list of these assumptions, including the investments required for additional capacity, can be found at Simoes et al. (2013). As in every regional model, the – internal and external – trade capacity hypothesis are key assumptions with potential high impact on the results. Depending on the scope of future analysis, sensitivity analysis should be considered on them.

2.2.3. Primary energy potentials and costs

The model considers current and future sources (potentials and costs) of primary energy and their constraints for each country. In this paper the reference fossil primary energy import prices into EU are considered as in as in the Energy 2050 Roadmap (European Commission, 2011a) (Table 2), and a sensitivity analysis on them is performed (see Section 4.1).

Besides energy import, JRC-EU-TIMES also models extraction of primary energy resources (RES and fossil) and conversion into final energy carriers within the EU28+. The prices of these commodities are endogenous, and depend on country-specific resource extraction and conversion costs. More information on fuel mining and on the considered nuclear fuel chain can be found on Simoes et al. (2013). At this moment unconventional gas in Europe is not considered. Endogenous production of bioenergy is modelled considering different agricultural and forestry products and residues, biodegradable fraction of municipal solid waste, agricultural biogas, landfill gas and sewage sludge. These can be used to satisfy energy demand in buildings, industry, transport biofuels and electricity generation. At this stage, import of biofuels into EU28+ are not considered due to lack of reliable data. As with electricity trade assumptions, assumptions on biofuels imports have potentially high impact on the results. Thus, a sensitivity analysis is however undertaken to explore this source of uncertainty in the behaviour of the model in the CPI scenario. Depending on the focus of further work it might be important to extend such analysis to also the decarbonised scenarios for the specific case of biofuel import assumptions. Nonetheless, there is the possibility to import forestry residues from outside EU, which can be converted to second generation biofuels or used as direct inputs in other processes. More information on first and second generation biofuels can be found at Simoes et al. (2013).

Finally, a number of assumptions and sources are adopted to derive the RES potentials in EU28+ for wind, solar, geothermal, marine and hydro, as detailed in Table 3. The potentials for electricity from RES up to 2020 are based on the maximum yearly electricity production provided by RES2020 (RES2020 Project Consortium, 2009), updated during the REALISEGRID (Lavagno and Auer, 2009) EU projects and complemented with other sources detailed in Simoes et al. (2013). It should be highlighted that in this version of the JRC-EU-TIMES, the reliability of data on the RES potentials is not uniform across countries because of the diversity of sources, some using detailed national or EU-wide studies, and some based on assumptions.

2.2.4. Policy constraints and assumptions

Different decarbonised scenarios were modelled to reflect ‘exogenous policy routes’ assumptions directing the model towards different technological routes for decarbonisation from 2005 until 2050, similarly to the EU Energy Roadmap 2050 (European Commission, 2011a). Nonetheless, a direct comparison of the results has to take into account that there are substantial differences in details in assumptions, in input data and in

[2] Although for some countries (namely the Nordic countries) the discount rate for CHP is lower than the one for centralized electricity generation since CHP plants are frequently owned by a municipal energy company and not a private industry, in other countries CHP plants are owned by industry and/or energy supply companies. In this paper we have maintained PRIMES assumptions on discount rates.

Table 2
Primary energy import prices into EU considered in JRC-EU-TIMES in USD_{2008}/boe.

Fuel	2010	2020	2030	2040	2050
Oil	84.6	88.4	105.9	116.2	126.8
Gas	53.5	62.1	76.6	86.8	98.4
Coal	22.6	28.7	32.6	32.6	33.5

Table 3
Overview of the technical RES potential considered in JRC-EU-TIMES.

RES	Methods	Main data sources	Assumed maximum possible technical potential capacity/activity for EU28+
Wind onshore	Maximum activity and capacity restrictions disaggregated for different types of wind onshore technologies, considering different wind speed categories	RES2020 Project Consortium (2009) until 2020 followed by JRC-IET own assumptions	205 GW in 2020 and 283 GW in 2050
Wind offshore	Maximum activity and capacity restrictions disaggregated for different types of wind offshore technologies, considering different wind speed categories	RES2020 Project Consortium (2009) until 2020 followed by JRC-IET own assumptions	52 GW in 2020 and 158 GW in 2050
PV and CSP	Maximum activity and capacity restrictions disaggregated for different types of PV and for CSP	Adaptation from JRC-IET on RES2020 Project Consortium (2009)	115 GW and 1970 TW h in 2020 and 1288 GW in 2050 for PV; 9 GW in 2020 and 10 GW in 2050 for CSP
Geothermal electricity	Maximum capacity restriction in GW, aggregated for both EGS and hydrothermal with flash power plants	RES2020 Project Consortium (2009) until 2020 followed by JRC-IET own assumptions	1.6 GW in 2020 and 2.9 GW in 2050 for hot dry rock; 1.5 GW in 2020 and 1.9 GW in 2050 for dry steam & flash plants. 301 TW h generated in 2020 and 447 TW h in 2050
Ocean	Maximum activity restriction in TW h, aggregated for both tidal and wave	RES2020 Project Consortium (2009) until 2020 followed by JRC-IET own assumptions	117 TW h in 2020 and 170 TW h in 2050
Hydro	Maximum capacity restriction in GW, disaggregated for run-of-river and lake plants	EURELECTRIC (2011)	22 GW in 2020 and 40 GW in 2050 for run-of-river. 197 GW in 2020 and 2050 for lake. 449 TW h generated in 2020 and 462 TW h in 2050

modelling approach.

The scenarios considered in this analysis are summarised in Table 4. Except if otherwise mentioned, all scenarios have in common the following assumptions: (i) No consideration of the specific policy incentives to RES (e.g. feed-in tariffs, green certificates) since the objective is to assess deployment based solely on cost-effectiveness; (ii) a maximum of 50% electricity that can be generated from variable solar and wind to account for concerns related to system adequacy and variable RES. Because of its relevance, for two of the scenarios, this assumption is varied (HRES and LSW). Moreover, wind and solar PV cannot operate during the winter peak time slice to account for reserve capacity considerations; and (iii) countries currently without nuclear power plants (NPPs) will not have these in the future (Austria, Portugal, Greece, Cyprus, Malta, Italy, Denmark, Croatia, Norway and Iceland). NPPs in Germany are not operating after 2020 and Belgium NPPs are not operating after 2025.

Table 4
Scenarios modelled in JRC-EU-TIMES.

Scenario name	20-20-20 targets[a]	Long term CO_2 cap	Other assumptions
Current Policy (CPI)	Yes, ETS till 2050	No	Until 2025 the only new NPPs to be deployed in EU28 are the ones being built in FI and FR and under discussion in BG, CZ, SK, RO and UK[b]. After 2025 all plants under discussion can be deployed but no other. Maximum 50% electricity can be generated from wind and solar in 2050.
Current Policies with CAP (CAP85)	As CPI	85% less CO2 emissions in 2050 than 1990 levels[c]	As CPI.
Delayed CCS (DCCS)	As CPI	As CAP85	As CPI & CCS is only commercially available in 2040 instead of 2020 and has 40% higher costs.
High Renewables (HRES)	As CPI	As CAP85	As CPI & 30% higher RES potentials, plus maximum of 90% electricity that can be generated from solar and wind reflecting higher number of available sites. Maximum 90% electricity can be generated from wind and solar in 2050.
High Nuclear (HNUC)	As CPI	As CAP85	Until 2025 the only new NPPs to be deployed in EU28 are the ones being built in FI and FR and under discussion in BG, CZ, SK, RO and UK[b] After 2025 there is no limit on new NPP except for the countries where specific policy decision were taken (as in the text).
Low Energy (LEN)	As CPI	As CAP85	As CPI & 30% less final energy consumption than in the CAP85 scenario from 2035 till 2050.
Low Biomass (LBIO)	As CPI	As CAP85	As CPI & 30% less biomass available.
Low Solar and Wind (LSW)	As CPI	As CAP85	As CPI, with exception from an assumption of a maximum of 25% electricity that can be generated from variable solar and wind in 2050.

[a] The EU ETS target is assumed to continue until 2050. The national RES targets are implemented for 2020 and 2030 (the target for 2030 is the same as in 2020). There are no such targets after 2030. The minimum share of biofuels in transport is implemented from 2020 and maintained constant until 2050.
[b] This corresponds to the following plants: in Bulgaria (Belene-1, Belene-2); Czech Republic (Temelin-3, Temelin-4), Finland (Olkiluoto-3), France (Flamanville-3, Penly-3), Hungary (Paks-5, Paks-6), Romania (Cernavoda-3, Cernavoda-4), Slovakia (Mochovce-3, Mochovce-4) and UK (Hinkleypoint-C1, Hinkleypoint-C2, Sizewell-C1, Sizewell-C2).
[c] The 85% cap includes CO_2 emissions from international aviation and navigation.

3. Results

This section presents the results obtained with the JRC-EU-TIMES

Table 5
Portfolio of power technologies in EU28 for 2030 and 2050 in terms of generated electricity (TW h) derived from JRC-EU-TIMES for the studied scenarios.

TW h	2005 CPI	2030 CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	2050 CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
Nuclear	870	548	660	685	643	1107	656	688	629	762	934	934	934	2959	934	934	934
Hydro	412	398	414	414	448	411	411	414	414	412	428	428	507	425	428	431	450
Wind onshore	55	235	255	279	325	241	247	269	234	193	315	332	516	241	297	339	229
Wind offshore	1	41	65	75	70	37	43	71	44	193	271	266	476	118	277	298	141
Solar PV	2	303	318	317	378	274	270	325	138	670	1328	1273	1383	944	936	1372	662
CSP	0	8	8	8	8	8	8	8	12	0	13	11	0	2	2	13	16
Geothermal	0	19	19	19	23	19	19	19	19	19	19	19	24	19	19	19	19
Marine	0	0	0	0	0	0	0	0	0	0	154	154	84	45	153	154	170
Bioenergy	56	466	526	568	594	467	581	368	542	446	205	215	220	167	326	163	251
Coal & gas no CCS	1585	1208	525	692	509	449	453	474	545	800	57	59	63	51	31	58	53
CCS	0	0	403	0	226	203	369	528	688	7	845	790	351	497	555	976	1309
Total	2982	3227	3193	3058	3225	3218	3058	3163	3266	3502	4571	4483	4558	5468	3958	4758	4234

model for the low-carbon power sector technologies, for the CPI and the seven decarbonised scenarios for the EU28, as summarised in Table 5. An overview of the overall trends in the power sector is firstly presented, followed by a comparison of how the different exogenous policy routes underlying each decarbonised scenario affect the deployment of the individual SET Plan low-carbon power technologies.

3.1. Overall electricity generation trends

The electricity generation and installed capacity are presented in the Table 5 and in Fig. 1. Meeting a long term CO_2 emission reduction target of 85% compared to 1990 levels requires the electrification of the energy system: all the decarbonised scenarios show a substantially higher electricity generation than the CPI scenario. Moreover, in 2050 generated electricity increases by 33–83% compared to 2005. Note that between 2020 and 2030 there is a decrease in total electricity generation in all scenarios, including CPI, mainly due to the assumed shutdown of NPPs in Germany after 2020. This shutdown leads to a reduction of roughly 240 TWh in generated electricity from nuclear in EU28 between 2020 and 2030. After 2030, the 2050 CO_2 cap becomes increasingly binding and electricity generation grows in all scenarios.

Similar trends are observed in the increasing installed capacity (Fig. 1). The rate of investment in new power plants accelerates from 2030/2035 onwards. This is due to the combination of the following factors: (a) increasing stringency of the 2050 CO_2 cap, (b) retirement of power plants installed before 2005 in the period of 2030–2040, (c) assumption on nuclear shutdown in Germany from 2020 onwards in all scenarios, and d) design of exogenous policy routes. The latter is more evident for the LEN scenario, where the lower final energy bound is implemented from 2035. In the

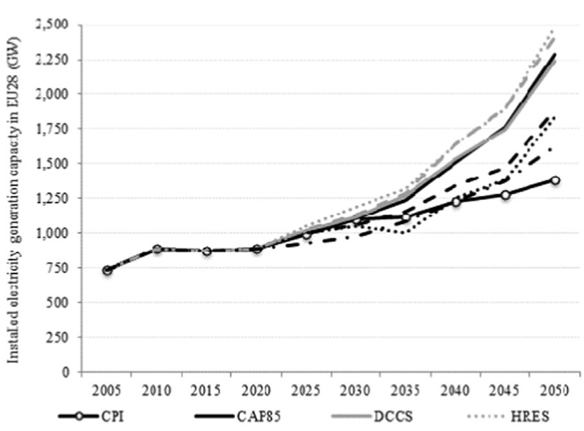

Fig. 1. Evolution of installed capacity for electricity generation in EU28 from JRC-EU-TIMES for the studied scenarios (2010 is a model output not reflecting historical consumption).

period of 2030–2040, a substantial part of the power plants installed prior to 2005 are decommissioned as they reach the end of their life. This is particularly relevant for wind onshore plants (in 2040 all capacity prior to 2005 is decommissioned), for PV (in 2040 only half of the capacity prior to 2005 remains), gas CCGT, and for some of the coal and lignite plants (roughly one third of the capacity prior to 2005 is operational in 2040). Thus, a rapid investment in new plants is made between 2030 and 2040, and then slowed down in 2045. The different decarbonised exogenous policy route show variations in total net generation capacity in 2050 from 1625 GW (in LSW) to 2476 GW (in HRES) and in total generated electricity from 3958 TW h (in LEN) to 5468 TW h (in HNUC).

Generated electricity from hydro, wind and solar PV plays a major role in all scenarios, except for HNUC and LSW (hydro, wind and PV represent 49–63% of generated electricity in 2050, with only 32% and 35%, respectively for HNUC and LSW). The share of variable electricity (wind and PV) remains below the maximum share possible while ensuring system stability (50%), except for HRES. The remaining electricity demand is satisfied via gas, with 7–28% of total generated electricity, nuclear with 20–54% of total generated electricity, and other RES (4–13% generated electricity).

In these scenarios storage systems play an important role. In particular, the pumped hydro storage technologies already installed in 2005 continue their activity until 2050. Investment in new storage technologies only becomes cost-effective from 2030 onwards in the decarbonised scenarios. Batteries and CAES are more cost-effective than new pumped hydro or hydrogen storage, due to the higher investment costs of the latter. Between 8% and 20% of the variable electricity in 2050 will be stored or, to a smaller extent, curtailed. Because of space limitations storage is not discussed further in this paper and the authors instead refer to their publication (Nijs et al., 2014) which focuses on more detail on the role of electricity storage. It is interesting to note that coal and gas play a relatively small role in 2050 even in the CPI scenario because of their higher costs compared to the nuclear and renewable options whose investment costs decrease over the time horizon, following the considered exogenous techno-economic assumptions.

Because electricity generated from RES (RES-e) plays an increasingly important role over time in all scenarios, irrespective of the CO_2 cap, the interplay between competing electricity-generation technologies determine RES-e deployment. Higher social acceptance of nuclear plants leads to a significantly lower deployment of RES-e, indicating strong competition (36% RES-e in 2050). On the other hand, higher RES potentials and higher allowed share of variable electricity in the grid significantly increase the deployment of RES-e to 70% in 2050. With limited solar and wind availability, more marginal RES-e technologies, such as biomass, marine and geothermal, have a higher share in total RES-e (23% of RES-e in 2050 vs. 10–20% in the other decarbonised scenarios).

In the long term, gas and electricity storage deliver the flexibility needs of the power system to deal with the increasing share of variable electricity. In all scenarios (including CPI), coal IGCC plants with pre-combustion capture are deployed, although the installed capacity varies across scenario (to a maximum of 40.1 GW in 2050). Regarding natural gas CCS technologies, only natural gas combined-cycle plants with post-combustion capture are deployed and only in the decarbonised scenarios up to 208.5 GW in 2050. The annual full load hours of coal and gas plants are in CPI in 2050 are on average 6000 h and 1500 h respectively. In CAP85, CCS coal plants operate on average 6500 h until 2040 and 3500 h in 2050. Coal plants without CCS operate only 1000 h in 2050. For the same year, gas plants without CCS operate only 250 h per year, while CCS gas plants operate on average 5000 h.

The net imported electricity from outside EU28 increases gradually in all scenarios, from 5.5 to 55.5 TW h in 2030, following the trade assumptions described in the Methods section. After 2030, the biggest imports are from Russia and Ukraine. In terms of the EU28+ grid infrastructure, the total installed transboundary capacity increases from roughly 122 GW in 2005 to 193–195 GW in 2025 (approximately 57–60% more from 2005) and up to 202–205 GW in 2050 (approximately 4–6% more from 2025). Until 2025, the planned increases in the grid as reported by ENTSO-E are almost sufficient to ensure cost-effective electricity trade until 2050 and thus practically no additional investment is made in increased grid capacity. The differences between scenarios are lower than 4%.

3.2. Comparing the policy routes effects on the deployment of the SET Plan electricity generation technologies

The comparison between the power technologies portfolio in the CPI and decarbonised scenarios in the previous section shows that, from 2030 onwards, the strict long-term CO_2 cap is the major policy route affecting the deployment of CCS plants, nuclear and wind offshore. The deployment of these technologies increases by more than 20% in the CAP85 compared to the CPI (see also Table 6). In this section, the focus is on assessing the impact of the policy routes assumptions underlying the variants of the CAP85 on the deployment of individual power technologies. This is done from two perspectives: (i) looking at each technology systematically to assess interplay between low-carbon options, and (ii) looking at each policy route to identify the ones with higher impact in low-carbon power technologies. For the first case, the relative difference between the generated electricity in TW h from the CAP85 and the other decarbonised scenarios is shown in Fig. 2, whereas the second case relies on the Table 6 that presents an overview of how each policy routes affects deployment. When the model captures country specific conditions for each technology, the analysis below will also include national specific results.

Fig. 2 shows that the cost-effectiveness of technologies such as *geothermal and hydropower* is robust across the decarbonised scenarios and corresponding policy route assumptions. Irrespective of the policy route, their maximum technical potentials are almost completely exploited already in 2030 in most countries. This highlights the relevance of accurately assessing the maximum future RES potential for hydro (eventually also considering repowering) and for geothermal. The only change observed in their deployment is in the HRES scenario, where assumed 30% higher technical RES potentials lead to 20% more electricity generated from hydro and geothermal in 2050. When hydro power and geothermal increase deployment in HRES, CCS, marine and CSP generate 30% less electricity (Table 6). Note that the decrease is not only due to increased hydro and geothermal, but also to the increase of all other renewables in particular wind on-shore and offshore, as described below. In 2050 hydro power plants are deployed in all member states, except Malta and Cyprus. The only country where hydro power deployment is different for other policy routes than for CAP85 is France and only for LSW. This is because in France there are mostly three main low-carbon power technologies in 2050 in CAP85: nuclear, solar PV and hydro (together they generate 89% of electricity in the country in 2050), whereas in the other countries CAP85 has a more diversified technology portfolio. Geothermal is deployed only in Italy, Germany, Bulgaria and Portugal in 2050, bearing in mind that enhanced deep geothermal is not included in this version of JRC-EU-TIMES.

A similar, although less stable, behaviour occurs for *nuclear power plants* (NPP) whose deployment varies in a range of 20% for the period 2030–2045, compensating for the delay in CCS power plants in DCCS or with reduced activity in LEN when there is less demand for electricity. Naturally, in the HNUC scenario, NPP activity increases by more than 60% since more unplanned NPP plants are allowed into the energy system. Thus, the main competing technologies affecting deployment of NPP in this analysis are bioenergy electricity plants and CCS coal and gas plants. This is especially the case for the medium term in the modelling horizon. In 2050 nuclear is deployed in the Bulgaria, Czech Republic, Finland, France, Lithuania, The Netherlands, Romania, Slovakia, Slovenia, Spain, Sweden and United Kingdom.

On the contrary to these more "mature" low-carbon power technologies, CCS, marine and, to a less extent, CSP's relative position in the cost-effectiveness ranking are extremely variable depending on the policy routes and subsequent activity of other low-carbon technologies.

In the case of *marine* there are variations from CAP85 of above 60% as a response to practically all the modelled policy routes, from higher nuclear to higher RES, particularly in the period 2035–2045. In that period, whenever there is an "opportunity window", either via a lower bioenergy contribution, lower solar and wind or delayed CCS, electricity generated from oceans becomes cost-effective. This seems to indicate the high relevance of further investigating the techno-economic characteristics of these technologies. In 2050, the deployment of marine technologies is basically affected by increased deployment of nuclear (in HNUC marine-based electricity is 76% lower), wind, hydro and to a smaller extent solar PV (in HRES and LSW marine-based electricity is 46% lower and 10% higher). Only tidal energy stream and range technologies (cheaper than wave) are deployed. Deployment is slow in 2035–2045, but increases significantly in 2050. The deployment path is smoother in the policy routes with limited potential for other RES (LBIO and LSW) and for DCCS, where there is a higher penetration of tidal in earlier periods. In CAP85 in 2050 most marine power is deployed in United Kingdom, Ireland, Portugal, Spain, Poland, Greece and Denmark, with some smaller contribution from other countries. With the increased deployment of wind onshore, wind offshore and hydro in HRES, marine power plants are not deployed in countries as Denmark, Greece, Portugal and Spain and very much reduced in the other.

Regarding *CSP*, the technologies that mostly affect its relative cost-effectiveness and subsequent deployment are wind, hydro and nuclear. Across policy routes, until 2050 there is practically no new installed CSP capacity. CSP plants currently installed are maintained and gradually decommissioned from 2035 onwards. For DCCS and LBIO there are small exceptions only for some southern EU countries (Spain and Portugal) where new CSP becomes cost effective due to higher capacity factors than northern countries. In LSW, where the deployment of wind (and PV) is limited, CSP becomes cost-effective in additional countries and before 2050 (Greece and Cyprus).

The most relevant technologies impacting the deployment of *coal and gas power plants with CCS* are wind, hydro, solar PV and to a lesser extent, nuclear, especially in 2050. In LSW CCS increases deployment by 55% in 2050 compared to CAP85, in HRES it is 61% lower and in HNUC is 41% lower. In 2050 CCS is deployed in all member states in all policy routes, with the exception of Cyprus, Estonia, Finland, Lithuania and Malta. The highest variations seen across policy routes at country level are in Czech Republic and Romania (both in HRES and HNUC), in Denmark, Germany, Ireland, Italy, Poland and in The Netherlands (all for the HRES). In the LBIO scenario, the less available biomass is more cost-effective for the end-use sectors (as industry and transport), thus creating an opportunity window for CCS, especially in Romania, Germany, Poland and United Kingdom. Similarly to nuclear, the cost-effectiveness of CCS coal and gas is more sensitive to the policy route in the intermediate periods when the CO_2 cap is not as strict as in 2050.

Table 6
Overview of policy routes affecting deployment of low-carbon power technologies estimated as % difference in generated electricity from CAP85 in 2050.

Power technology group	Delayed CCS (DCCS)	Higher social acceptance and facilitated permitting of RES plants (HRES)	Higher social acceptance of nuclear plants (HNUC)	Stricter and more effective end-use energy efficiency requirements (LEN)	Lower biomass availability (LBIO)	Higher concerns with reliability of transmission & distribution, reducing the share of variable solar & wind (LSW)
Overall ranking of impact (*)	6	2	1	3	5	4
Nuclear	–	–	↑↑↑	–	–	–
Hydro	–	↑↑	↓	–	↑	↑
Wind onshore	↑	↑↑↑	↓↓	↓	↑	↓↓
Wind offshore	↓	↑↑	↓↓↓	↑	↑	↓↓↓
Solar PV	↓	↑	↓↓↓	↓↓↓	↑	↓↓↓
CSP	↓↓	↓↓↓	↓↓↓	↓↓↓	↑	↑↑
Geothermal	–	↑↑	–	–	–	–
Marine	–	↓↓↓	↓↓↓	↓	–	↑
Bioenergy	↑	↑	↓↓	↑↑↑	↓↓	↑
Coal & gas no CCS	↑	↑↑	↓	↓↓↓	↑	↓
CCS	↓	↓↓↓	↓↓↓	↓↓↓	↑↑	↑↑↑

↑ /↓ - increase/reduction in generated electricity higher/lower than 10% compared to CAP85; ↑↑ /↓↓- increase/reduction in generated electricity between 10–30% higher/lower than CAP85; ↑↑↑ /↓↓↓- increase/reduction in generated electricity 30% higher/lower than CAP85; - small difference in generated electricity (between +10% and −10%).
* The ranking is based on the number of arrows, each reflecting at least a 10% change in the power production of a single technology. When there are more arrows the impact is higher from 1 (highest impact) to 6 (least impact).

Wind technologies (*onshore and offshore*) are moderately sensitive to the relative cost-effectiveness of the other low-carbon technologies and policy routes. This means that electricity generated by wind power plants varies across some policy routes by more than 30% compared to CAP85. *Wind offshore* activity is particularly affected by nuclear deployment (less 57% generated electricity from wind offshore in HNUC in 2050), and not significantly by the other low-carbon options. This indicates that wind offshore electricity is competing in terms of cost-effectiveness with mainly nuclear power, since variations in offshore generated electricity across the other policy routes are below 10% in 2050. *Wind onshore*, shows the same behaviour, although with a smaller reduction in activity, when nuclear power is increased (less 27% generated electricity from wind onshore in HNUC in 2050). Wind onshore in CAP85 2050 is deployed in all member states except for Slovenia, Estonia, Slovakia, Finland, Malta and Poland. Across the policy routes, the major variations in activity take place in Czech Republic and Sweden (in HNUC), France (in HNUC and LBIO), and in Germany (in LBIO). In the JRC-EU-TIMES model the deployment of *wind offshore* starts from 2020 onwards in all scenarios. In 2050 most of the installed capacity is in Germany, The Netherlands, Spain, Sweden, United Kingdom, Finland, Belgium, Denmark and Greece. Of these countries, the ones where wind offshore deployment is most affected by increased nuclear are The Netherlands, Finland, Denmark Spain, Sweden and United Kingdom. Among the different offshore technologies (from IEC class I to IV), wind offshore class I (lowest wind) is less cost effective. In all scenarios, the cumulative installed capacity is highest for the high availability floating option.

Solar PV is less responsive than wind technologies and its activity is mostly affected by the deployment of nuclear and of bioenergy power plants; in 2050 there is less 29% and 20% generated electricity from *PV* in HNUC and LBIO, respectively. In 2050 solar PV is deployed in all member states except Estonia. In the LSW policy route solar PV is not deployed in Ireland and only to a small extent in Denmark and Cyprus. With increased nuclear, the countries where most change in generated electricity occurs in 2050 are France, Bulgaria, Germany, Czech Republic, Italy, Lithuania, United Kingdom, Poland and Romania. The specific PV deployed technologies are medium sized roof PV, followed by plant size PV. Roof PV, although marginally more expensive than plant-size, delivers low voltage electricity, thus avoiding conversion losses and becoming more cost-effective. In JRC-EU-TIMES the electricity conversion processes between voltage levels are included with associated efficiency losses. Therefore, if the cost difference between generating technologies is small, it can be more cost-effective to generate electricity directly to end-use consumers and thus avoid losses. It should be noted that the high PV deployment is accompanied by electricity storage due to the way variable intermittent electricity technologies are modelled.

From the analysis in Table 6, in a decarbonised EU28, not studied policy routes have the same effect in the cost-effective deployment of the SET Plan low-carbon power technologies. The most impacting policy routes are on the level of deployment of NPP and on the available sites for which there are adequate technical conditions for deploying new RES power plants. These are followed by policy routes with an intermediate impact in the power system configuration: the end-use energy efficiency requirements (or demand for electricity) and the capability of the power system to deal with high shares of variable solar and wind electricity. Changes in these, here modelled as exogenous policy routes assumptions, lead to changes in the generated electricity from at least one source higher than 30% compared to a CAP85. Policy routes such as availability of CCS technologies and of biomass for power generation do not play such an important role in the cost-effectiveness of electricity generation technologies as they lead to small differences (below 10%) in generated electricity compared to CAP85.

4. Sensitivity analysis, comparison with similar studies and limitations

4.1. Sensitivity analysis for other exogenous assumptions in the CPI scenario

The outcome of sensitivity analysis on the model results to selected exogenous model inputs for the CPI scenario are presented in Table 7. The CPI scenario was selected to perform the sensitivity analysis instead of CAP85 because when a model is under a severe CO_2 mitigation target it inherently responds less to some of the varied parameters. This is the case of fossil fuel import prices, since these are no longer used in 2050 in the power sector. With a few exceptions, the variations in the sensitivity parameters by 20% lead to changes smaller than 12% in results compared to the CPI scenario. While the conclusions would be different for the decarbonised scenarios, this section helps to provide further understanding on the behaviour of the model in its reference scenario.

Regarding fuel prices, the results are aligned with expectations: lower (higher) prices lead to higher (lower) FEC, and to a shift away from (towards) RES. Changes in the price of fuel on either ends do not

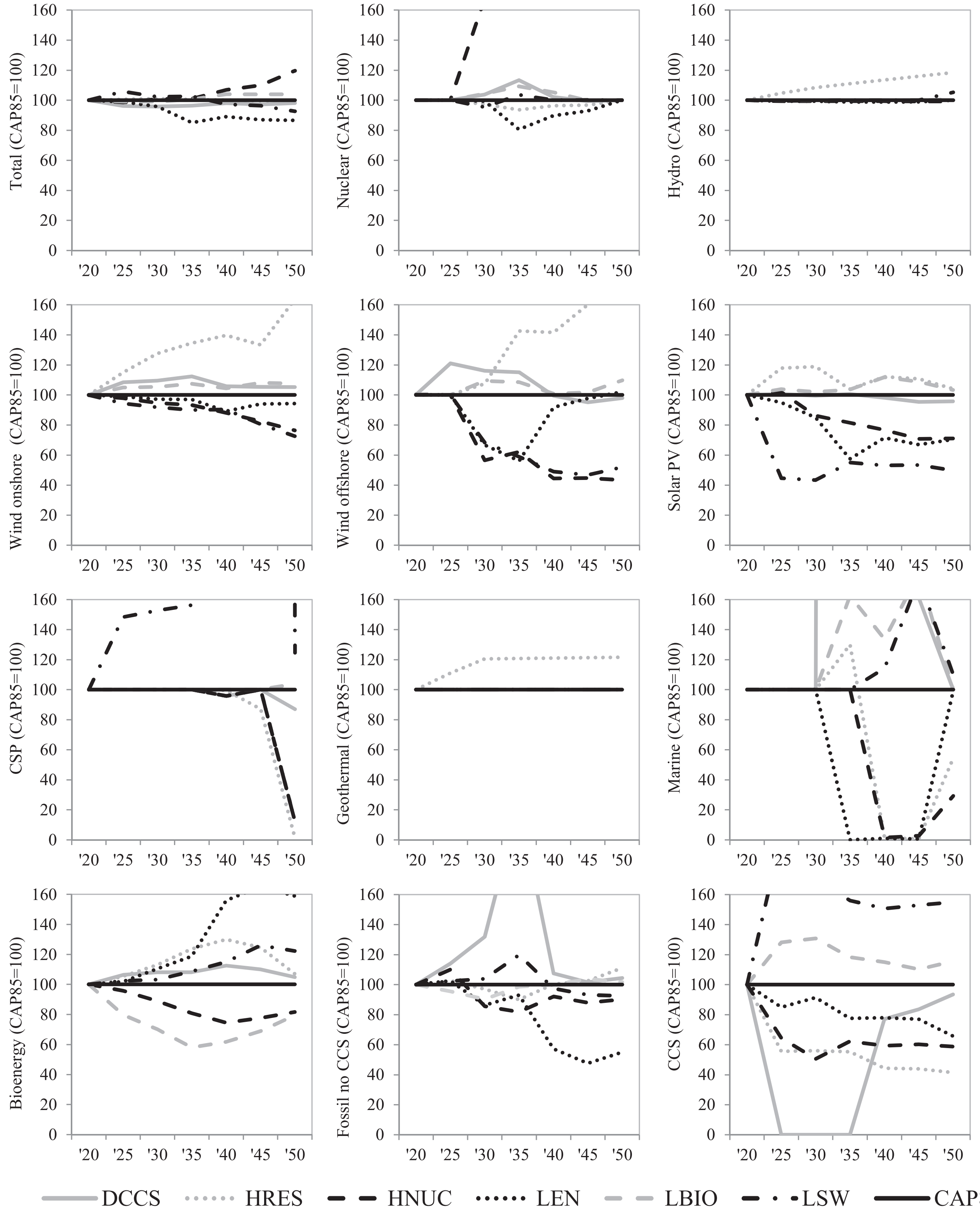

Fig. 2. Comparison of generated electricity across time and decarbonised scenarios from 2020 till 2050 for the different technologies calculated as a relative difference to the CAP85 scenario.Fig. 2.

impact significantly the composition of energy carriers – and therefore FEC. CO_2 emissions also move in the expected direction, with higher emissions linked to lower prices through the increase in consumption of oil and gas. A similar behaviour is observed for the other variations in model inputs. The only notable exception is, in the case of coal, an increase in CO_2 emissions with higher coal prices and a decrease with lower coal prices, which is linked to a wider deployment of CCS coal co-firing with biomass in the case of higher coal prices.

The model is more sensitive (i.e. changes in results higher than 12%) to changes in the exogenous energy services demand, where results on all the assessed parameters but for % RES in FEC can vary up to 15% more than in the CPI scenario. The other case where changes in results are higher than 12% compared to CPI is the amount of captured CO_2 for all the variations in primary energy prices (changes up to ± 100% in captured emissions). Note, however, that the absolute magnitude of the difference in captured CO_2 is relatively small: ± 16Mt

Table 7
Overall results of the sensitivity analysis in % change compared to the CPI scenario in 2050.

Exogenous model input	Magnitude of variation	Final energy consumption (FEC)	% RES in FEC	Generated electricity	% RES in generated electricity	Total System Cost (disc.)	Annual cost in 2050	CO_2 emissions	CO_2 captured
Oil price	−20%	0.3	−6.8	−0.3	−2.1	−2.5	−2.1	2.5	−21
	+20%	−0.6	3.2	0.7	0.4	2.1	1.9	−2.0	1
Gas price	−20%	0.3	−11.1	0.1	−3.4	−1.2	−0.8	2.6	−100
	+20%	−0.4	5.2	−0.1	0.7	0.7	0.2	−1.3	104
Coal price	−20%	0.1	0.1	−0.2	0.7	−0.3	−0.3	−0.1	20
	+20%	0.1	0.7	0	−0.0	0.3	0.1	0.2	−21
Oil, coal and gas prices	−20%	0.3	−12.3	−0.5	−3.2	−3.2	−2.5	3.2	−100
	+20%	−1.6	8.8	0.2	2	3.1	1.8	−3.8	144
Oil and gas prices	−20%	0.3	−11.9	−0.3	−3.1	−0.3	−2.3	3.3	−100
	+20%	−1.3	8.4	0.3	1.7	2.7	1.8	−3.8	97
Tech. specific discount rate	−20%	−0.12	0.6	+0.6	0.4	−6.7	−7.6	−0.7	−1
	+20%	−1.1	−2.0	−3.0	0.6	6.8	7.5	0.2	4
Biomass potential	−20%	0	−9.3	0.2	−1.7	0.1	0.2	1.4	−6
	+20%	0	7.3	0	1.6	−0.1	−0.2	−1.1	−2
Energy services demand	−20%	−20.3	4.9	−20.2	−7.6	−15.3	−21.4	−15.0	14
	+20%	18.2	−8.8	18.4	4.8	15	21.9	14.6	28

of CO_2 in the case of the gas prices scenarios. The interplay between coal, gas and oil causes the changes in CCS related results, which mostly happen in the industry sector. There, CCS is deployed in the production of cement, and an increase in the prices of oil or a decrease in the prices of coal lead to a higher use of coal in the production process. In the power sector, high gas prices and low coal prices lead to an increase in the deployment of CCS integrated gas combustion plants, thus further increasing the quantity of CO_2 captured.

Similarly, the portfolio of electricity generation technologies (Table 8) is not very sensitive to the considered changes in the input parameters for the sensitivity analysis. The changes in the relative share of coal and lignite, oil, gas, nuclear, hydro, solar, wind and other RES are smaller than 12% compared to the CPI scenario (in fact they are below 2%). The changes of ±20% energy services demand lead to changes in the share of energy carriers below 12%. Within the limited changes in magnitude of results, the higher fossil fuels prices, the lower discount rate and variation in biomass lead to a marginally higher deployment of solar and wind power in 2050, and to tidal energy becoming competitive in 2050.

4.2. Comparison with similar studies and limitations

A comparison of this paper's results with other studies is made (Table 9) focusing on the differences between the CAP85 and the work of Capros et al. (2014) that includes results from seven well known EU models focusing on their basic decarbonisation scenario (AM5S2). This papers' values are in line with the outputs of the other seven models. The most relevant difference is for the 2050 CO_2 price, which is substantially higher than the values derived from PRIMES or the TIMES-PanEU model. There are three possible causes for this difference: (i) JRC-EU-TIMES mitigation possibilities in 2050 are more limited to go beyond an 85% CO_2 reduction target; this would call for reviewing the mitigation options currently available and possibly enlarge them, particularly for refineries and aviation for which currently there are no mitigation options in our model, (ii) in this comparison is shown JRC-EU-TIMES marginal CO_2 price which is substantially higher than JRC-EU-TIMES average CO_2 price in 2050 of 81 euros $_{2005}$/tCO_2, and (iii) the model inputs, the policy scenarios and underlying assumptions are substantially different (see Duerinck et al. (2011) for a further discussion of these). Finally, the comparison shown in the table refers only to the basic decarbonised scenario from Capros et al. (2014). For the other decarbonised scenarios in their multi-model analysis, the CO_2 price in 2050 can go up to 1600 euros$_{2005}$/tCO_2 in GEM-E3 or up to 1043 euros$_{2005}$/tCO_2 in the TIMES-PanEU model.

There are several areas for improvement in the analysis made in this paper. The high cost-effectiveness of RES electricity technologies is influenced by the fact that JRC-EU-TIMES, as most energy system models, has limited time resolution and, thus, concerns with integration of variable RES are dealt with in a simplified manner.

In terms of overall exogenous model assumptions (and not only the modelled exogenous policy routes in this study), it was found that the overall CO_2 cap plays a major role, followed by RES potentials and restriction on variable RES electricity produced from solar and wind, as well as the costs for solar PV and NPPs.

The portfolio of RES electricity technologies in JRC-EU-TIMES is found to be very much dependent on the assumed the RES potentials for EU28+ and which are highly uncertain for some countries. At the same time, the RES potentials considered in the JRC-EU-TIMES are somewhat conservative, especially for wind.

Furthermore, the very high share of solar PV electricity is only possible if cheap and highly flexible small scale storage solutions are available. Modelling variability and flexibility of the power system requires finer time resolution and merits further work, for example by soft-linking JRC-EU-TIMES with a dispatch model with higher temporal resolution and introducing a constraint on the trade-off between storage and interconnectivity (derived from the dispatch model).

Another factor that critically affects RES technologies electricity deployment in our results is the role of nuclear power plants. In this paper relatively optimistic cost assumptions were used for new "unplanned" NPP, which lead to their very high cost-effectiveness, especially in the HNUC scenario. An important future development is to assess the extent to which uncertain investment and O & M costs in nuclear power plants and other low-carbon power technologies affect results by testing different cost evolution scenarios.

Finally, for some of the electricity generation technologies (notably CCS plants) there is an extremely rapid annual deployment which will only be feasible in reality if very special policy incentives or conditions are in place, similarly to what has happened in several member states in the last decade regarding solar and wind technologies and natural gas CCGT, or similar to nuclear deployment in the seventies. A future development would be to analyse the effect of an upper bound on maximum feasible annual deployment rates as a consideration of limitations in human capital to engineer and build new installations,

Table 8
Results of the sensitivity analysis in % share of energy carriers in the power sector compared to the CPI scenario in 2050.

% share of energy carriers in generated electricity	CPI	High/Low oil price	High/Low gas price	High/Low coal price	High/Low oil, coal and gas prices	High/Low oil and gas prices	High/Low biomass potential	High/Low discount rate	High/Low energy services demand
Coal	18	17/18	17/18	18/17	16/18	17/18	19	18/17	14/24
Gas	6	6	5/7	6/5	5/6	5/7	6	6/5	6/5
Oil	0	0	0	0	0	0	0	0	0
Nuclear	22	22/23	23/22	22	22	22/23	23/24	21/23	24/23
Hydro	12	12	12	12	12	12	12/13	12	11/15
Wind	10	10	11/10	10	11/10	11/10	5	10/11	6/4
Solar	19	19	20/18	19	20/18	20/19	20	19	23/15
Other RES	14	14/13	14/13	14	14	14/13	16/12	15/13	15/13

bottlenecks in the supply chain or limitations for the generators to access financing for the new plants.

5. Conclusions and policy implications

In this paper we modelled the EU28 power sector till 2050 using the JRC-EU-TIMES energy system model for comparing how exogenously defined policy routes affect the deployment of SET Plan technologies. It was found that, in line with other studies, almost all SET Plan low carbon power technologies are necessary to comply with the CO_2 caps, in both the reference scenario (CPI) and the decarbonised scenarios. The exceptions to this are CSP, marine and CCS technologies which are only cost-effective in the decarbonised scenarios. Looking at the amount of generated electricity in 2050, nuclear and solar PV are key low carbon technologies. They generate 38–71% of the total generated electricity, depending on the considered policy route. Except for CSP, all the other SET Plan technologies are deployed in all decarbonised scenarios. Their relevance for total generated electricity (after nuclear and PV) is as follows (from more to less relevant): coal and gas CCS technologies, hydro, wind onshore, wind offshore, bioenergy, marine and geothermal. Other studies on decarbonised scenarios for the power sector show similar results as portfolios of power technologies.

We conclude on the importance of a certain policy decision for the configuration of the low carbon power sector. In terms of the most influential exogenous policy routes, besides the CO_2 cap, the configuration of the decarbonised power sector in 2050 will depend on: (listed in decreasing order of influence) the level of deployment of NPP, available sites for which there are adequate conditions for new RES power plants, end-use energy efficiency requirements, and the capability of the power system to deal with high shares of variable solar and wind electricity. On the less influential side, exogenous policy routes on acceptability of CCS technologies and on use of biomass for power generation, play a less important role in the cost-effectiveness of other electricity generation technologies. This provides useful support for deciding on the level of detail that can be used in subsequent design and analysis of future energy scenarios, at least from the perspective of cost-effective CO2 mitigation. It is worth to mention that ultimately these policy routes reflect public acceptance to perceived technology risks, land use change and energy security concerns. Consequently, R & D efforts targeting public acceptance issues can play an important role for keeping all options open. Even the increased end-use energy efficiency route can also be seen as expectations on the capability of consumers to adopt new technologies and/or behaviour.

Traditionally, results on low-carbon pathways for the EU power sector are normally analysed within scenarios and then compared, for example, by assessing aggregated technology deployment (e.g. RES technologies) or impact on cost *for each scenario*. This approach is very useful for informing climate mitigation policies and/or energy policies and has been used for supporting EU's energy and climate policies. However, in order to more effectively informing R & D policies focusing on energy technology, this paper presents a complementary approach that systematically and explicitly assesses the deployment of more disaggregated power technologies *across scenarios*. Our approach allows to take the analysis of the low-carbon power portfolio further, identifying and comparing how different technology policy routes affect the deployment of *individual* technologies. Such analysis contributes to assessing underlying uncertainty of the results, complementing other uncertainty management approaches. Moreover, the interplay between the roles of low-carbon power technologies in the energy system becomes more evident, and can thus be more clearly communicated to energy technology R & D policy makers, who have to decide on allocation of limited human and capital resources across the broad group of low carbon technologies. In this context it can be critical to understand the way in which, under a cost-effective approach, the increased deployment of a certain technology can, in some cases, affect the relative cost-effectiveness of other(s). We implement this approach to the individual SET Plan technologies.

Regarding the sensitivity of the technologies deployment to the

Table 9
Comparison of selected results for 2030 and 2050 with similar studies.

		PEC (EJ)	Power sector CO_2 emissions ($MtCO_2$)	CO_2 prices ($euros_{2005}/tCO_2$)	% RES electricity	% intermittent RES electricity	% electricity in FEC	% CCS in electricity generation
2030	CAP85	65	349	101	50	20	22	13
	Capros et al. (2014) for AM5S2	48–70[a]	n.a.	21[a]–91	41[a]–52	n.a.	18–29	n.a.
2050	CAP85	57	90	1438	60	42	42	18
	Capros et al. (2014) for AM5S2	50–68[a]	9–58[a]	243–565[a]	48[a]–63	24–45	24–38	20–21

Notes: n.a. – not available;
[a] Result of the TIMES-PanEU model used in this study.

studied exogenous policy routes, CSP, marine and CCS are found to be the technologies most sensitive. As they are marginal technologies, they become cost-effective whenever there are 'windows of opportunity' created by limited deployment of other low-carbon technologies, such as limited availability of biomass or lower solar and wind available sites. On the other hand, nuclear, hydro and geothermal technologies are found to be the less sensitive technologies to the exogenous policy routes. Whereas hydro and nuclear have a 'well established role' in decarbonising EU's power system, the finding is new for geothermal, which in absolute terms contributes to a minor share of the total generated electricity (0.5% or less in 2050).

Regarding interdependences between the SET Plan technologies across the exogenous policy routes, it was found that technologies are competing differently depending on the policy routes. While the limited set of results of this paper do not allow a broad extrapolation, it can already be concluded that there is a positive correlation between the deployment of wind offshore and onshore, as well as between wind technologies and solar PV. This implies that policies favourable for supporting one technology group will also have positive incremental effect on the other, bringing forward a sort of 'double dividend'.

In terms of implications for energy technology policy making, and considering the SET Plan goal of accelerating deployment of low-carbon technologies, our results suggest that by combining both traditional scenario analysis with the cross-policy routes approach presented, R & D can be tailored to depending on how sensitive technologies are to the policy routes. R & D priority should be given to those technologies that are in any case deployed rapidly across the modelled time horizon (as PV) as this could significantly reduce the energy system costs, but also to those that are deployed up to their maximum technical potentials and that are typically less sensitive to exogenous policy routes (as hydro and geothermal). For these 'no regret' technologies, R & D efforts could be mainly directed to increase their technical potential for implementation. For yet 'sensitive' to exogenous policy routes technologies (as CSP and marine), efforts should be assigned to improving their techno-economic characteristics such as capacity factors or associated costs.

This paper has focused on analysing how different decarbonised exogenous policy routes assumptions affect the deployment of the low carbon power technologies within the whole energy system, while the expected evolution of their techno-economic parameters (such as investment and operation costs or efficiencies) was considered the same across policy routes. As a next step, it is relevant to assess to what extent plausible future variations in such parameters affect technological deployment. Such information can provide useful insights in designing energy technology policies setting priorities for allocation of research and development funding with a view towards a decarbonised EU power sector.

Acknowledgement

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Appendix A

See Table A1.

Appendix B

See Table B1.

Table A1
Exogenous useful energy services and materials demand input into JRC-EU-TIMES for EU28.

Year	Agric. (PJ)	H & C comm. (PJ)	Other comm. (PJ)	H & C resid. (PJ)	Other resid. (PJ)	Al (Mt)	NH_3 (Mt)	Cl. (Mt)	Other industry (PJ)	Cement (Mt)	Cu (Mt)	Glass (Mt)	Iron & steel (Mt)	Paper (Mt)	Passenger mobility[a] (Bp km)	Freight mobility[a] (Bt km)
2005	1302	3567	3496	8591	2593	6	12	2006	6959	236	2	31	196	100	6577	2,132,426
2006	1317	3670	3575	8599	2659	6	12	2028	6930	240	2	32	192	101	6646	2,170,503
2010	1353	3784	3777	8434	2834	6	12	2091	6886	251	2	33	185	101	6815	2,264,363
2015	1376	3973	4027	8282	3180	7	13	2215	7375	269	2	36	195	104	7128	2,547,882
2020	1435	4155	4284	7998	3317	7	14	2483	7984	298	2	41	197	111	7361	2,844,396
2025	1492	4292	4511	7660	3449	7	15	2613	8188	340	2	47	194	125	7558	3,062,411
2030	1540	4476	4790	7368	3554	7	16	2683	8340	363	2	52	186	134	7748	3,316,167
2035	1601	4669	5048	7075	3571	8	16	2670	8321	389	2	57	186	142	7898	3,570,264
2040	1618	4861	5304	6790	3602	7	17	2820	8503	417	2	62	187	153	8012	3,780,567
2045	1639	5007	5518	6482	3597	7	18	2912	8504	437	2	68	183	160	8078	3,965,027
2050	1724	5230	5803	6273	3622	7	20	3117	8924	475	2	75	173	170	8176	4,191,499

Note: H & C stands for heating and cooling including space heating and cooling plus sanitary water heating. Al stands for aluminium production; NH_3 for ammonia production, Cl for chlorine production and Cu for copper production.
[a] Passenger and freight mobility in this table does not include aviation and navigation as these are represented in the model in PJ not in p km or t km.

Table B1
Assumptions on techno-economic characteristics for electricity generation technologies considered in JRC-EU-TIMES (excludes CHP).

Fuel	Technology	Specific investments costs (overnight) (eur_{2010}/kW)				Fixed operating and maintenance costs (eur_{2010}/kW)				Electric net efficiency (condensing mode) (%)				Tech. life (yr.)	Availability factor (%)	CO_2 capture rate (%)
		2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
Hard coal/ lignite 600 MW-el	Subcritical	1365/1552	1365/1552	1365/1552	1365/1552	27/33	27/33	27/33	27/33	37/35	38/35	39/37	41/38	35	80/75	0
	Supercritical	1705/1552	1700/1856	1700/1856	1700/1856	34/39	34/39	34/43	33/45	45/43	46/45	49/47	49/49	35	80/75	0
	Fluidized bed	2507/2758	2507/2489	2507/2247	2507/1830	50/55	50/50	50/45	50/37	40/36	41/37	44/40	46/43	35	75/75	0
	IGCC	2758/3009	2489/2716	2247/2451	1830/1996	55/48	50/43	45/39	37/32	45/42	46/44	48/48	50/51	30	80/75	0
	Supercritical+post comb. capture		2450/2555	2209/2479	2018/2381		43/49	41/43	34/38	30/29	32/31	36/35	39/38	35	75/75	88
	Supercritical+oxy-fuelling capture		3028/3330	2287/2516	1876/2063		38/45	37/41	31/35	28/27	31/30	36/35	40/39	35	75/75	90
	IGCC pre-comb capture		2689/2953	2447/2366	2030/2006		47/71	40/64	38/58	31/30	33/32	39/38	44/42	30	75/75	89
Natural gas 550 MW-el	Steam turbine	750	750	750	750	19	19	19	19	42	42	42	43	35	45	0
	OCGT Peak device advanced	568	568	568	568	17	17	17	17	42	45	45	45	15	20	0
	Combined-cycle	855	855	855	855	26	21	20	20	58	60	62	64	25	60	0
	Combined-cycle +post comb. capture		1244	1155	1093		44	41	39	42	44	49	53	25	55	88
	OCGT Peak device conventional	486	486	476	472	12	12	12	12	39	39	40	41	15	20	0
Nuclear 1000 M-Wel	3rd generation LWR planned	5000	5000	5000	5000	specific values for each reactor from IAEA										
	3rd generation non-planned	5000	4625	4250	3500	43	43	42	42	34	34	36	36	50	82	
	4th generation Fast reactor				4400	91	85	80	69	34	34	36	40	50	82	
Wind onshore	Wind onshore 1 low/ 2 medium (IEC class III/II)	1300/1400	1200/1270	1050/1190	950/1110	32/34	25/27	23/24	20/21	100	100	100	100	25	16/21	
	Wind onshore 3 high/very high (IEC class I/S)	1600/1700	1380/1430	1270/1320	1190/1240	36/40	29/32	27/29	25/27	100	100	100	100	25	30/40	
Wind offshore	Wind offshore 1 low/medium (IEC class II)	2500/3000	2000/2600	1800/2380	1500/1950	106/106	80/80	63/63	54/54	100	100	100	100	25	15/32	
	Wind offshore 3 high deeper waters (IEC class I)/ 4 very high floating	4300/6000	3400/4200	2700/3300	2100/2700	130/170	95/120	75/90	60/70	100	100	100	100	25	40/51	
Hydro	Lake very small hydroelectricity < 1 MW	7300/1800	7300/1800	7300/1800	7300/1800	73/18	73/18	73/18	73/18	100	100	100	100	75	42	
	Lake medium scale hydroelectricity 1–10 MW	5500/1400	5500/1400	5500/1400	5500/1400	55/14	55/14	55/14	55/14	100	100	100	100	75	42	
	Lake large scale hydroelectricity > 10 MW	4600/1200	4600/1200	4600/1200	4600/1200	46/12	46/12	46/12	46/12	100	100	100	100	75	38	
	Run of River hydroelectricity	1454	1712	1575	1575	15	17	16	16	100	100	100	100	75	36	
Solar	Solar PV utility scale fixed systems > 10 MW	3165	895	805	650	47	13	12	10	100	100	100	100	30	24	
	Solar PV roof < 0.1 MWp/0.1–10 MWp	3663/3378	1420/1065	1135/850	775/675	55/51	21/16	17/13	12/10	100	100	100	100	30	24	
	Solar PV high concentration	6959	2698	2157	1473	104	40	32	22	100	100	100	100	30	27	
	Solar CSP 50 MWel	5200	2960	2400	1840	104	89	72	37	100	100	100	100	30	35	
Biomass	Steam turbine biomass solid conventional	3069	2595	2306	2018	107	91	81	71	34	35	36	38	20	90	0
	IGCC Biomass 100 MWel	3960	3574	3225	2627	139	125	113	92	37	37	43	48	20	90	0
	Biomass with carbon sequestration	4297	3373	2652	2321	150	118	93	81	33	34	35	36	20	61	85
	Anaerobic dig. biogas+gas engine	3713	3639	3566	3426	130	127	125	120	36	38	40	45	25	80	0

(continued on next page)

Table B1 *(continued)*

Fuel	Technology	Specific investments costs (overnight) (eur_{2010}/kW)				Fixed operating and maintenance costs (eur_{2010}/kW)				Electric net efficiency (condensing mode) (%)				Tech. life (yr.)	Availability factor (%)	CO_2 capture rate (%)
		2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
Geothermal	3 MWel Geo hydrothermal with flash power plants	2400	2200	2000	2000	84	77	70	70	100	100	100	100	30	90	
	Enhanced geothermal systems	10,000	8000	6000	6000	350	280	210	210	100	100	100	100	30	90	
Ocean	Wave 5 MWel	5650	4070	3350	2200	86	76	67	47	100	100	100	100	30	22	
	Tidal energy stream and range 10 MWel	4340	3285	2960	2200	66	62	59	47	100	100	100	100	30	22	

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