Exploring the feasibility of Europe's renewable expansion plans based on their profitability in the market

Highlights

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- Optimised European power system in 2030 based on renewable targets
- Profitability of solar PV, onshore and offshore wind compared across Europe
- With national targets, renewable investments are mostly not profitable in the market
- Profitability driven by political, financial, market and natural conditions
- Given renewable targets, carbon emissions differ greatly driven by CO_2 and gas prices

Exploring the feasibility of Europe's 2030 renewable expansion plans based on their profitability in the market

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Abstract

Different policies aim at transforming the European energy sector. To support decision making in this context, energy system models with a central-planning approach are frequently used. However, private sector investments are required to realise this transformation and there is a shift towards more market revenue-based paradigms. Therefore, this paper assesses the market-based profitability of renewables in 2030 across Europe in the presence of current policies, in particular renewable share targets. As several key assumptions drive the system design and profitability likewise, we carry out an expansion planning to obtain a European least-cost electricity system for 2030 and market prices as marginal costs to meet demand in order to determine internal rates of return and net present values. We find that the profitability of solar PV, on- and offshore wind varies significantly across Europe in 2030, mainly driven by the renewables' market values, financial and natural resource conditions. In a least-cost system fulfilling existing national targets, renewables are mostly not profitable in the market. Therefore, policy action is required to achieve climate goals, e.g. by moving towards EU-wide renewable targets, market-based policy instruments or providing additional revenue sources.

Keywords: Renewable energy policy, Energy system modelling, Merit order effect, Renewable market value, Profitability, Emission reduction

1. Introduction

Energy systems around the world are undergoing a process of fundamental change and transformation aimed at reducing greenhouse gas (GHG) emissions and combating climate change. In Europe, this goal shall be achieved mainly through investment in energy efficiency and renewable energies. More specifically, the European Union (EU) set the target to increase the share of renewables in its gross electricity consumption from 37 % in 2020 to at least 65 % by 2030 (European Commission, 2020b) to eventually achieve climate neutrality by 2050 (European Commission, 2019). Recent plans of the European Commission to become independent from Russian oil, coal and gas as well as the RE-Power EU programme[1] released in March 2022 further emphasise the importance of expanding renewable generation capacities in the following years.

In order to support decision makers in governments and companies in the context of planning such fundamental

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[1] https://ec.europa.eu/commission/presscorner/detail/en/ip_22_1511 [last accessed 13.09.2022]

changes, energy systems models (ESMs) have been developed and used for several decades. While these models are well suited to analyse and understand interdependencies in complex energy systems, they typically take a central-planning approach (e.g., Pfenninger et al., 2014). In liberalised energy markets, such as the EU internal electricity market, however, private-sector investments in renewables are required to achieve the EU's targets. Hence, in order to support managerial decision making of investors in renewables, information on the profitability of investment projects, e.g., measured by well-known metrics such as the internal rate of return (IRR) or the net present value (NPV), is needed. Such insights are also relevant for policy makers or regulators, whose task it is to create market conditions where investors have an interest to invest so that renewable targets can be achieved in reality.

Originally, as a market-based instrument aimed at reducing GHG emissions in the energy sector, the EU launched its Emissions Trading System (ETS) in 2005. The ETS is an EU-wide "cap and trade" mechanism that seeks to provide economically efficient incentives for and coordinate investments in clean(er) energy technologies.[2] For more than a decade after its introduction, CO_2 prices in the ETS were relatively low, partly because of a rather high cap and the allocation of large amounts of free emission allowances. At the same time, technology costs for renewables were still relatively high, so that the ETS did not create profitable market conditions for investors in renewables. Many countries have therefore established additional plans and measures at the national level, such as national renewable share targets and other renewable support schemes (e.g., feed-in tariffs – FITs – for renewable electricity generation). This lead to a strong increase in renewables investments (Cambini and Rondi, 2010; Edenhofer et al., 2013; Winkler et al., 2016) and, in turn, to a strong decrease in technology costs of renewables (compare e.g. IRENA (2013) and Pietzcker et al. (2021)). At the same time, the ETS cap and the allocation of free emission allowances have decreased strongly since the introduction leading to increased CO_2 prices over time. Altogether, there is an increasingly broad consensus in the EU that renewables have reached market maturity and that it is time to move away from FITs (e.g. Huntington et al., 2017).

However, while there is theoretical evidence showing their negative effects (e.g. Brown and Reichenberg, 2021), national renewable share targets are yet maintained and further national-level measures, such as phase-out plans for coal power plants have been added and are reported by all Member States to the European Commission in 2019 as part of their National Energy and Climate Plans (NECPs, see (European Union, 2019)). We therefore study the market-based profitability of renewables across Europe in the presence of these plans, in particular national renewable share targets. We compare and contrast our findings to a case with a European renewable share target only, which is achieved by a CO_2 price.

While earlier research has discussed strengths and weaknesses of FIT-based renewable support schemes vs. quota-based schemes with renewable certificate trading (e.g. Toke, 2008; Perez et al., 2016; Green et al., 2016), we focus on analysing the impacts of national vs. European renewable targets on the market values and profitability of renewables. Profitability as measured by well-known metrics such as the IRR or NPV is mainly driven by costs and revenues. On the cost side, technology costs of renewables have decreased significantly in the past decade as mentioned above and are spatially rather homogeneous, whereas capital costs, influenced by investment risk and further factors, can vary significantly between technologies and countries (Steffen, 2020). On the revenue side, spot

[2]See e.g. `https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets_en`

market revenues are driven by the very heterogeneously distributed natural resource conditions, but in a post-FIT world also largely by the generation profiles and market prices or, more specifically, the so-called market values of renewables (Hirth, 2013). Renewables' market values in turn depend strongly on the system design, for example via the merit order or "cannibalisation" effect (Åsa Grytli Tveten et al., 2013; Paraschiv et al., 2014; Clò et al., 2015; Bublitz et al., 2017; Benhmad and Percebois, 2018; López Prol et al., 2020).

Existing studies in the context of renewable expansion typically fall into either one of the following three categories: (i) system studies that consider the development of a future power system using an ESM but focus mainly on the technology mix in a least-cost system, (ii) studies that calculate and compare some metric aimed at assessing the economic feasibility from a private-sector perspective but not exactly the profitability, e.g. the levelised cost of electricity (LCOE, see International Energy Agency and Nuclear Energy Agency (2020) for example), market values or uncovered costs and (iii) studies that assess the profitability but use rather static assumptions on market prices or feed-in tariffs when calculating revenues as opposed to considering market dynamics such as the merit order or cannibalisation effect using an ESM.

As for the first category, several studies (e.g., Zappa et al., 2019, 2021; Pietzcker et al., 2021) analyse the development of the European power system until 2050 focusing on the technology mix in a renewables-dominated system. However, these studies do not consider the profitability of the capacity additions required.

As for the second category, Kost et al. (2021) for instance compare the LCOE of different renewable electricity generation technologies for Europe. While the LCOE is a suitable indicator for comparing costs of electricity generation across sets of diverse technologies, however, it is not well-suited to support investment decision making since it only considers the cost side, whereas (market-based) revenues are ignored (Tao and Finenko, 2016). Alternatively, some recent studies (e.g., Ruhnau et al., 2020; Bernath et al., 2021; Böttger and Härtel, 2022) use marginal electricity generation costs from ESMs to analyse market values and their development. Finally, some studies consider uncovered costs of renewable investments. Devlin et al. (2018) study the gap between market revenues and prices, averaged for Europe with cost assumptions for the year 2040 and renewable shares below 55 %. Gillich and Hufendiek (2022) describe an iterative approach aimed at generating technology mixes with reduced uncovered costs compared to a least-cost system. However, their analysis considers Germany in 2020 only. No study in one of the first two categories calculates metrics such as the IRR or NPV explicitly.

As for the third category, Tu et al. (2019) compare the profitability of solar and wind power projects in China based on given assumptions for a feed-in tariff. Other studies analyse the profitability of renewables in terms of IRRs on a much smaller scale, which prevents considering market dynamics endogenously and therefore leads to using static feed-in tariffs and electricity prices. López Prol and Steininger (2017, 2020) study prosumers' PV installations in Spain while Bertsch et al. (2017) investigate households' PV investments in Germany and Ireland. However, feed-in tariff systems have been or are phased out in many countries globally and an exogenous assumption of future market prices is critical since the relevant future power systems under consideration, which drive market prices and values, are yet unknown. Therefore, the profitability assessment should not be carried out against a static system. Moreover, the temporal fluctuations of power prices have a strong effect on revenues in the wholesale market.

Literature comparing profitability metrics used in practice across Europe against a yet unknown future power system, whose development depends on different key market conditions / assumptions, is rare. In order to close

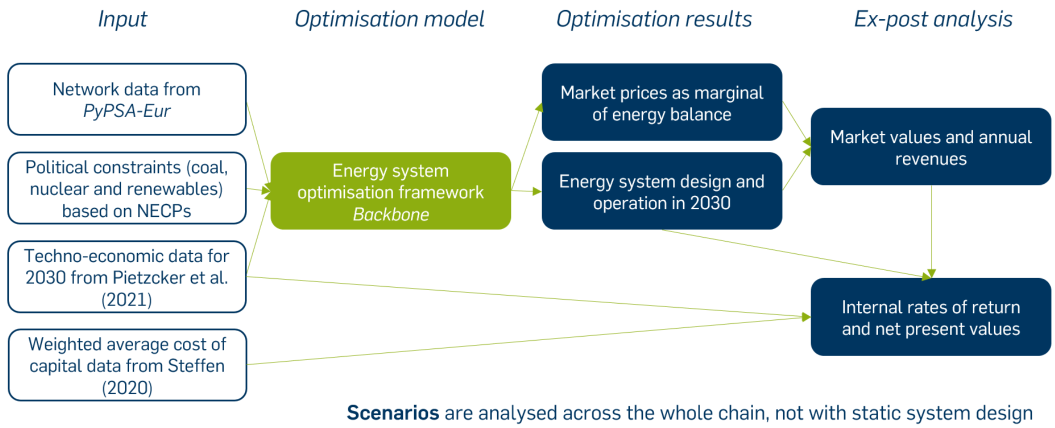

Figure 1: This paper's methodology.

this gap, we assess the market-based profitability of renewable electricity generation technologies across Europe not against some static "background" system, but present an approach for jointly carrying out an endogenous investment planning and profitability assessment for 2030. We use this approach to compare and contrast cases with national renewable share targets vs. a case where an appropriate CO_2 price ensures that a common European target is achieved to study the corresponding impact on the profitability of renewables. In addition, we explore under which conditions the EU energy policy targets for renewables deliver in terms of emission reduction, since the majority of energy system studies typically focuses strongly on the renewables targets, while omitting an explicit analysis of the emission impacts, particularly for varying input parameters. This is particularly important during the transition phase, where the composition and use of non-renewable generation capacities and thus carbon emissions can vary significantly depending on market conditions / scenario assumptions.

To summarise, this paper focuses on the following research questions:

- Are renewables profitable in 2030 across Europe based on national renewable expansion targets and how does the profitability compare to a case where a common European target is achieved by an appropriate CO_2 price?
- What are the main drivers of their profitability?
- How do renewable share targets deliver in terms of emission reduction under different CO_2 and gas price assumptions?

The remainder of this paper is organised as follows. Section 2 describes the methodology and data, Section 3 presents and discusses results and Section 4 concludes and derives policy implications.

2. Methodology and data

The methodology comprises two main steps as sketched in Figure 1. First, an energy system optimisation model is used for an investment and operation planning in order to obtain a European least-cost electricity system for the year 2030 fulfilling current renewable share targets. Second, the profitability of renewable electricity sources (RES-E) in that future system, differentiated by technology and country, is assessed in terms of IRRs and NPVs.

2.1. Energy system optimisation framework

The open-source energy system optimisation framework Backbone (Helistö et al., 2019) can be used for operation and investment planning of a broad range of energy systems. In this study, we use Backbone to carry out a cost-minimising investment and operation planning for the European electricity sector in the year 2030. New investments in solar photovoltaic (PV), onshore wind and offshore wind as well as closed cycle gas turbine (CCGT) units are allowed, while the generation and storage capacities of the other technologies (fossil-fuelled, nuclear, hydro, bioenergy and pumped hydro storages (PHS)) are assumed to be fixed[3]. However, the operation of all generation and storage units is optimised by the model. For energy reservoirs, i.e. PHS and hydro reservoirs, the energy level at the start and end of the modelling horizon is variable, as long as both values are the same. Line investments are not allowed, but the Ten Year Network Development Plan is included in the data.

To incorporate RES-E expansion targets, we introduce a constraint to ensure that, in a country c, invested capacities are sufficient to generate a certain share $p_c^{\text{RES}-\text{E}\%}$ of the national annual electricity demand $p_c^{\text{annualDemand}}$ by renewable technologies $r \in R$:

$$p_c^{\text{RES}-\text{E}\%} \cdot p_c^{\text{annualDemand}} \leq \sum_{r \in R} v_{c,r}^{\text{investCapacity}} \cdot p_{c,r}^{\text{fullLoadHours}} \tag{1}$$

As such, it influences the variables for newly invested capacities $v_{c,r}^{\text{investCapacity}}$ based on the meteorologically available full load hours $p_{c,r}^{\text{fullLoadHours}}$ without taking into account potential curtailment. Among other benefits, this prevents unintended storage cycling and related adverse effects on the expansion planning and market prices (Kittel and Schill, 2022).

2.2. Energy system model data

The European power system model in this study is largely based on data from the open-source model PyPSA-Eur (Hörsch et al., 2018). PyPSA-Eur collects and aggregates power system data from various open sources, which includes but is not limited to grid infrastructure and network topology (including the Ten Year Network Development Plan), capacities for coal, nuclear, gas, bioenergy, hydro and PHS power plants, time series for demand and weather and available areas for new power plant installations. The natural full load hours of solar PV, on- and offshore wind for each country are displayed in Table C.2 in the Appendix. Our model includes the EU Member States, except Cyprus and Malta, and additionally Norway, Switzerland and the United Kingdom (UK). Most countries are aggregated to one node each. Large countries (France, Germany, Italy, Portugal, Spain and the UK) have two nodes each and some areas (Corsica, Northern Ireland and Zealand) separated from the main territory of their country have a separate node. The Balearic islands are excluded. A map of the aggregated regions is shown in Figure 2. We use demand and weather time series from the year 2018 and model one year at hourly resolution.

Other techno-economic data, in particular on technology and fuel costs for the year 2030, are mainly taken from Pietzcker et al. (2021) and displayed in Table 1. Total annual electricity demands per country for the year

[3] We tested battery storages as an additional investment option. However, in the base scenario, battery investments were only made in Italy (0.4 GW), Portugal (7.2 GW) and Spain (2.0 GW) and only the internal rates of return in Portugal and Spain were affected significantly (+0.9 % points for solar PV in both countries and +0.7 % points for onshore wind in Portugal). Therefore, no storage investments are considered in this paper.

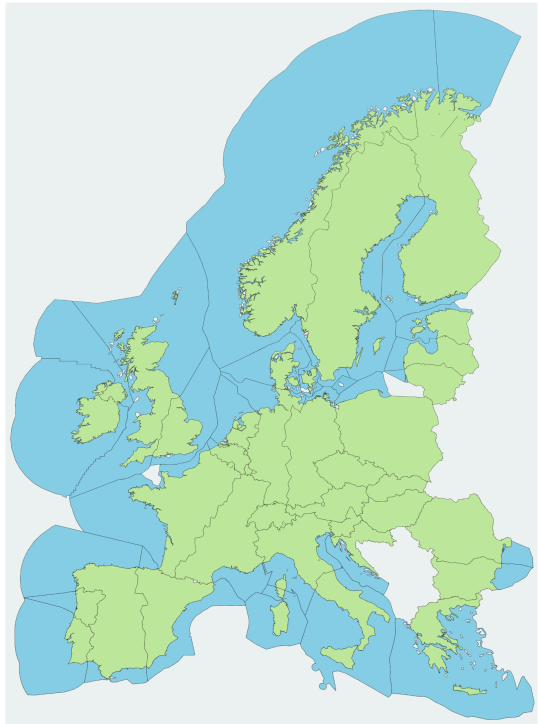

Figure 2: Geographical scope of European energy system model. Each green land region is aggregated to one node together with the adjacent blue sea region for offshore wind.

2030 from the same reference are used to scale up the demand profiles from 2018. We use a CO_2 price of 129 €/t, which is also based on Pietzcker et al. (2021) for the EU ETS in the year 2030 under policy targets consistent with our assumptions. To determine the annual share of investment costs in the expansion planning, we use a discount rate of 7 % for all countries and technologies. For CO_2 emissions from biomass combustion we use a value of zero, because they are discussed controversially (e.g. by Millward-Hopkins and Purnell, 2019) and do not count towards the EU ETS (Pietzcker et al., 2021). Other specific CO_2 emissions are taken from Pietzcker et al. (2021). For run of river plants, we use standard data from PyPSA-Eur.

To reflect future policies, coal[4] and nuclear exits communicated by the EU Member States to the European Commission in 2019 as part of their National Energy and Climate Plans (NECPs) are taken into account (European Commission, 2020a). Following these plans, no EU Member State except Bulgaria, Croatia, Czechia, Germany, Poland, Romania and Slovenia use coal for electricity generation in 2030. For the UK, a coal exit in 2024 is considered[5]. Also according to the NECPs, nuclear exits in Belgium, Germany and Spain are assumed.

To integrate renewable generation expansion plans into the model, we constrain national RES-E share targets as per Equation (1). The values for EU Member States for the year 2030 are taken from the NECPs (European Union, 2019) from 2019. These national shares are based on the EU-wide plans from 2018 that have been updated in 2020, but not yet translated to the national level. Therefore, we scale the national targets from 2018 up with a factor of

[4]Throughout this paper, coal refers to hard coal and lignite.

[5]See for example the government's press release at `https://www.gov.uk/government/news/end-of-coal-power-to-be-brought-forward-in-drive-towards-net-zero` [last accessed 13.09.2022]

Table 1: Selected techno-economic data for power generation and storage units as well as fuels for the year 2030. The superscript and subscript values refer to the years 2040 and 2020, respectively, and are used for sensitivity analyses. The data is mostly taken from Pietzcker et al. (2021). Abbreviations: O&M = operation and maintenance, PV = photovoltaic, n.a. = not applicable, CCGT = closed cycle gas turbine, OCGT = open cycle gas turbine, n.i. = not investable

Technology	Investment cost (EUR / kW)	Fixed O&M (% / yr)	Lifetime (yr)	Variable O&M (EUR / MWh)	Efficiency (%)	Fuel cost (EUR / MWh)	Fuel emissions ($kg\,CO_2 / MWh_{th}$)
Solar PV	395^{340}_{703}	1	25	0	n.a.	n.a.	n.a.
Onshore wind	1137^{987}_{1257}	3	25	0	n.a.	n.a.	n.a.
Offshore wind	2102^{1900}_{2736}	3	25	0	n.a.	n.a.	n.a.
CCGT	900	3	45	4	57	25.56	200
OCGT	n.i.	n.i.	n.i.	3	41	25.56	200
Hard coal	n.i.	n.i.	n.i.	6	44	10.80	347
Lignite	n.i.	n.i.	n.i.	9	41.5	3.60	387
Oil	n.i.	n.i.	n.i.	3	42	51.48	290
Nuclear	n.i.	n.i.	n.i.	5	33	3.60	0
Biomass	n.i.	n.i.	n.i.	6	42	21.60	0
Hydro	n.i.	n.i.	n.i.	0	100	n.a.	n.a.
Run of river	n.i.	n.i.	n.i.	0	90	n.a.	n.a.
Pumped hydro	n.i.	n.i.	n.i.	0	100	n.a.	n.a.

1.08, which equals the EU-wide target share from 2020 divided by the EU-wide target share from 2018 (European Commission, 2020b). For Norway[6] and Switzerland[7], RES-E targets of 100 % and 80 % are used, respectively. For the UK, we use a capacity target of 40 GW for offshore wind instead of a RES-E share[8]. As a lower bound for new investments in solar PV, onshore and offshore wind units, we use the generation capacities existing in 2019 as reported by the International Renewable Energy Agency (IRENA, 2020). To ease the profitability assessment, a minimum investment of 1 MW is enforced in each country and technology, apart from offshore wind in land-bound countries.

2.3. Market-based profitability assessment

The net present value (NPV) of a set of cash flows CF_t at different times $t \in T$ is the sum of all cash flows, where each cash flow is discounted, possibly multiple times, with the discount rate i, depending on its time. The

[6]In Norway, 100 % have already been achieved, see e.g. `https://irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jul/IRENA_Renewable_Energy_Statistics_2020.pdf` [last accessed 13.09.2022].

[7]In Switzerland, 37.4 TWh hydro power and 4 TWh other renewables were generated in 2018. The target for 2035 is constant hydro power and an increase to 17 TWh for other renewables. Linear interpolation leads to a total of 46.5 TWh renewables in 2030, representing 80 % of the projected demand. See `https://www.bfs.admin.ch/bfs/en/home/statistics/sustainable-development/monet-2030/all-indicators/7-energie/electricity-production-renewable-energies.html` [last accessed 13.09.2022] for more information.

[8]Based on the Energy White Paper "Powering our Net Zero Future" from December 2020, see `https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/945899/201216_BEIS_EWP_Command_Paper_Accessible.pdf` [last accessed 13.09.2022]

internal rate of return (IRR) of a set of cash flows is the interest rate i that leads to an NPV of zero:

$$\mathrm{IRR} = i \qquad \text{s.t.} \qquad \mathrm{NPV} = \sum_{t \in T} \frac{1}{(1+i)^t} \mathrm{CF}_t = 0 \tag{2}$$

In this study, we calculate NPVs and IRRs for renewable energy projects of different RES-E technologies r in different countries c. As cash flows, we consider the initial investment $\mathrm{CF}_{c,r,t=0} < 0$ and annual revenues, which are assumed to be constant for each year of the project's life time T. Annual revenues are calculated from the ESM output as follows. The generation $r^{\mathrm{gen}}_{c,r,ts}$ of a renewable technology r in country c at model time step ts is multiplied with the market price $r^{\mathrm{marketPrice}}_{c,ts}$ in this country at this time step. Fixed $r^{\mathrm{FOM}}_{c,r}$ as well as variable $r^{\mathrm{VOM}}_{c,r}$ operation and maintenance costs are then subtracted:

$$\mathrm{CF}_{c,r,t} = \sum_{ts} \left(r^{\mathrm{gen}}_{c,r,ts} \cdot r^{\mathrm{marketPrice}}_{c,ts} \right) - r^{\mathrm{FOM}}_{c,r} - r^{\mathrm{VOM}}_{c,r} \qquad \text{for } 1 \leq t \leq T \tag{3}$$

Market prices at each model time step and country are obtained from the ESM as the marginal cost to meet electricity demand, also known as *shadow prices*.

When calculating NPVs, we additionally use weighted average cost of capital (WACC) for renewable power projects as the discount rate i. It reflects capital risks and varies significantly between countries and technologies[9] with a trend of increasing cost of capital from solar PV to onshore to offshore wind. Where available, we use empirically founded country- and technology-specific WACC data reported by Steffen (2020). For the remaining countries and technologies, we do not calculate NPVs.

Generation-averaged market prices of a technology r at a grid node n are also known as its market value $\mathrm{MV}_{r,n}$. If needed, we aggregate market values for a group of nodes in a country c or a group of technologies $r \in R$ via

$$\mathrm{MV}_{R,c} = \frac{\sum_{n \in c, r \in R} \sum_{ts} r^{\mathrm{gen}}_{n,r,ts} \cdot r^{\mathrm{marketPrice}}_{n,ts}}{\sum_{n \in c, r \in R} \sum_{ts} r^{\mathrm{gen}}_{n,r,ts}}. \tag{4}$$

The same aggregation applies to time-averaged market prices.

2.4. Scenarios and sensitivities

In addition to the base scenario, we study a second scenario, where RES-E share targets and not enforced for each EU Member State at a national level, but as one EU-wide constraint. The RES-E share for the EU is assumed to be 65 % in accordance with the EU's updated climate targets from 2020 (European Commission, 2020b).

Additionally, we vary gas prices, CO_2 prices as well as investment costs for renewable technologies as parameter sensitivities of the base scenario. In the *medium gas price* and *high gas price* scenarios, we assume gas prices of 50 €/MWh and 100 €/MWh, respectively. In the *low CO_2 price* and *high CO_2 price* scenarios, values of 100 €/t and 160 €/t are used, respectively. Investment costs for renewable technologies are studied in two scenarios based on the values reported by Pietzcker et al. (2021) for the years 2020 and 2040. This approach follows the idea of

[9] We use country- and technology-specific WACC only for the ex-post calculation of NPVs. For the expansion planning, we use a homogeneous discount rate of 7 %. We are aware of this potential shortcoming. However, there is no comprehensive WACC data available for solar PV, onshore and offshore wind across the 28 countries studied. We therefore use a "standard" value in the expansion planning, where we are forced to include all countries and technologies. In the ex-post NPV calculations, where it is possible to only analyse a subset of technologies and countries, we used the real, more accurate and heterogeneous WACC data available.

learning curves describing cost declines of maturing technologies. In the *low wind, high solar* (LWHS) scenario, investment costs are lowered for wind (to 2040's values) and increased for solar power (to 2020's values). In the *low solar, high wind* (LSHW) scenario, the opposite happens. The costs used are displayed in Table 1, where superscript values refer to the year 2040 and subscript values refer to the year 2020.

To further analyse how varying CO_2 prices impact the CO_2 emissions based on the same RES-E share targets, additional scenarios with CO_2 prices of 10 €/t, 40 €/t and 70 €/t are studied.

3. Results and discussion

We present and discuss results of the investment and operational planning as well as the profitability assessment for the base scenario in Sections 3.1 and 3.2, respectively. Analyses of the scenario with an EU-wide renewable target and the parameter sensitivities are presented in Sections 3.3 and 3.4, respectively. A reflection on limitations in Section 3.5 concludes. Throughout this section, results are aggregated to a country level for countries with multiple nodes and to a single offshore wind technology.[10]

3.1. Energy system design and operation

The generation mix for the year 2030 is shown in Figure 3 at the national and in Figure A.10 at a system-wide level. Generation and the electricity released from PHSs over the whole year are normalised to annual demands and RES-E share targets are displayed as well. Each of the available renewable technologies is used to a significant extent for electricity generation with EU-wide generation shares of approximately 23 % for solar PV, 14 % for onshore wind, 19 % for offshore wind and 16 % for other RES, including hydro and biomass. Nowhere, significant amounts of coal are used for electricity generation. In about ten countries, the RES-E share clearly exceeds the national target, while in three countries, it is a few percentage points below the latter. This is possible due to curtailment and the capacity-based constraint formulation. However, the system-wide RES-E share of 71.5 % exceeds the EU target, mainly driven by CO_2 prices. Balanced over the whole year, Belgium, Czechia, Hungary, Lithuania and Luxembourg only generate about half of their annual demand, whereas ten other counties generate more than 100 % of it. Nuclear generation may only partially explain this result. Generally, exporting countries are rich in renewables.

3.2. Market-based profitability assessment

IRRs and NPVs for the base scenario are shown in Figure 4. To analyse and interpret these results, we refer to time-averaged market prices and market values displayed in Figure 5 and full load hours presented in Table C.2 in Appendix C. No calculations are made for offshore wind in land-locked countries and for NPVs when WACC are not reported by Steffen (2020). Overall, IRRs are positive in many countries and for solar PV they are more homogeneous across Europe than for wind. NPVs are generally negative, mainly due to high WACC values, which are not reflected in the IRRs. In more detail, there are five broad categories in which the countries can be grouped taking the market-based profitability of renewables into account.

[10] PyPSA-Eur distinguishes between plants with direct and alternating current connections

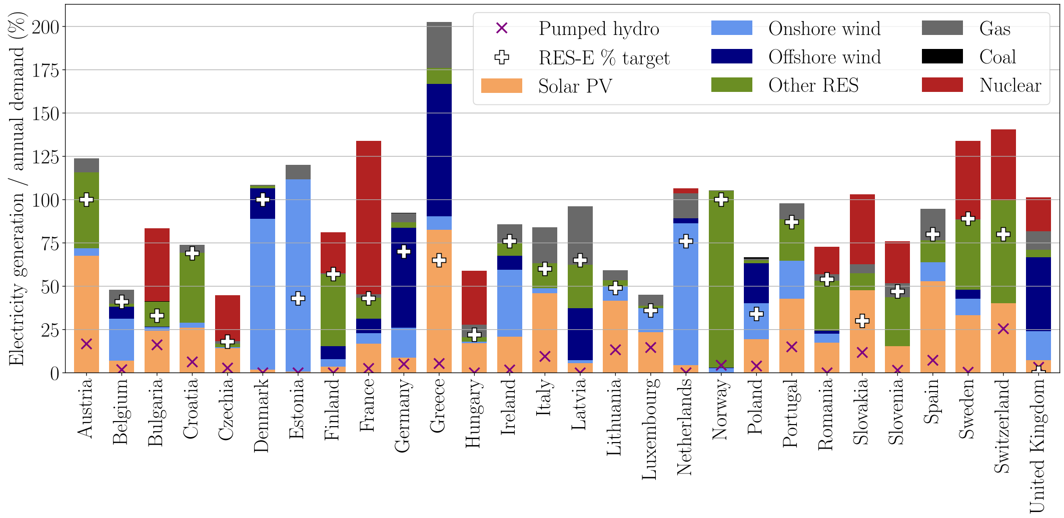

Figure 3: Generation mix, pumped hydro storage usage and RES-E share target per country. Electricity generation is normalised to the annual demand per country. The realised RES-E share per country is given by the upper edge of the green "Other RES" area.

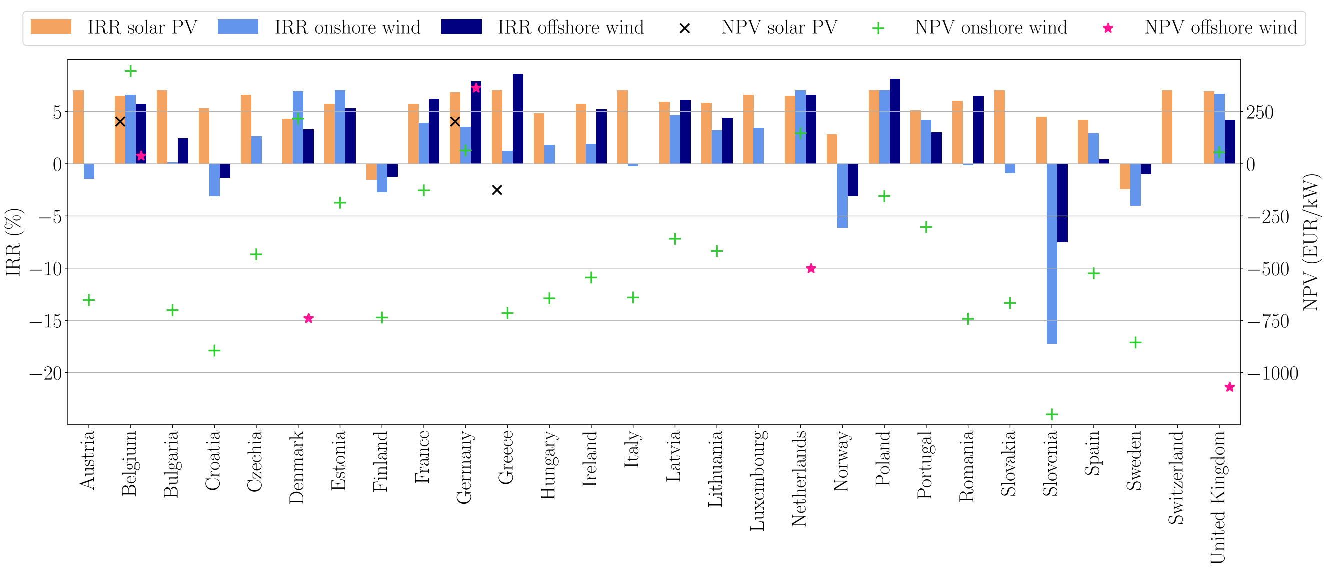

Figure 4: Internal rates of return (IRRs) and net present values (NPVs) by country and technology. IRRs are indicated by bars and refer to the left y-axis while NPVs are indicated by markers and refer to the right y-axis.

In the *first* group, countries have negative or low IRRs and NPVs associated with on- and offshore wind due to poor natural resource conditions, i.e. low full load hours. Countries in this group are Austria, Bulgaria, Croatia, Hungary, Italy, Romania, Slovakia, Slovenia and Switzerland[11] with below 1200 h and Greece and Spain with below 1500 h for onshore wind. Similarly, this extends to offshore wind for Bulgaria, Croatia, Italy, Portugal and Slovenia with below 2500 h. Differences between countries in this group, e.g. for onshore wind between Greece and Spain, can to some extent be explained by market values. However, even relative market values above 100 %, as seen for example in Italy and Slovenia, can often not compensate for poor natural conditions. Poor natural conditions cause low profitability and poor cost-efficiency likewise. Therefore, almost no wind turbine investments are seen

[11] In Switzerland, full load hours are so low that the annual cash flow is negative and thus the IRR ill-defined.

in the least-cost system design in the countries discussed above. In that sense, there is a congruence between the market-based and the central-planning approaches.

Countries in the *second* group have low relative market values for some technologies and therefore exhibit relatively low IRRs and NPVs despite favourable natural resources conditions. This holds for wind (onshore or offshore) in Denmark, Ireland, the Netherlands and the UK. Apart from offshore wind in Germany, these are the countries with highest full load hours for both on- and offshore wind. However, their IRRs are exceeded or at least matched by many other countries. Similarly, Greece, Portugal and Spain exhibit the best natural conditions but not the highest IRRs for solar power. In contrast to the first group, this group exhibits a conflict between the market-based and central-planning approaches: The high cost-efficiency of certain technologies in certain countries leads to high investments in the least-cost system, which in turn are the reason for low relative market values and IRRs via the merit order effect.

Third, there is a group of countries, the Scandinavian countries, with negative IRRs and NPVs associated with wind and solar PV. In these countries, market prices, and thus values, are generally very low due to very high shares of renewables and nuclear power, the latter of which has by far the lowest marginal costs among the non-renewable technologies. Comparably low market values are only rarely observed in other countries, e.g. in Ireland and Denmark for onshore wind. However, these countries have significantly higher full load hours and thus profitability. One exception in this group is solar PV in Norway with a positive IRR that is due to an unusually high relative market value of 100 %. Because there is no endogenous PV investment in Norway, but only the 2019 value of 90 MW is enforced, this market value is not affected by cannibalisation.

The *fourth* group consists of countries with exceptionally high NPVs (Belgium, Denmark, Germany, the Netherlands and the UK). For Belgium and Germany, high IRRs translate into high NPVs for all technologies due to WACC that are the lowest among all countries, arguably due to low investment risks caused by high economic and political stability and (formerly) existing support schemes. In the other three countries, only onshore wind NPVs are positive due to relatively (but not exceptionally) low WACC together with relatively high IRRs.

In the *fifth* group, countries have positive IRRs but negative NPVs (for onshore wind). In this group are Czechia, Estonia, France, Greece, Hungary, Ireland, Latvia, Lithuania, Poland, Portugal and Spain. With the exception of France, all of them have relatively high WACC ranging from 7.4 % to 11.7 %. The difference between the two profitability measures may therefore be explained by high country-specific capital risks, i.e. low financial stability. This is illustrated when comparing this group to the previous one, e.g. Estonia to Denmark or Poland to the Netherlands. Some other countries, e.g. Croatia, Romania and Slovenia, do not fall into this group due to already negative IRRs, although their NPVs are disproportionally low (compared to the IRR) due to high WACC.

3.3. Scenario with CO_2 price ensuring EU-wide renewable target

Results for the scenario without national RES-E share targets are shown in Figures 6 and A.10. The EU-wide renewable share target is achieved and exceeded in this scenario, mainly driven by the CO_2 price. Therefore, the enforced EU-wide RES-E share target of 65 % remains without an effect on the results and the model can be considered as not being constrained by it.

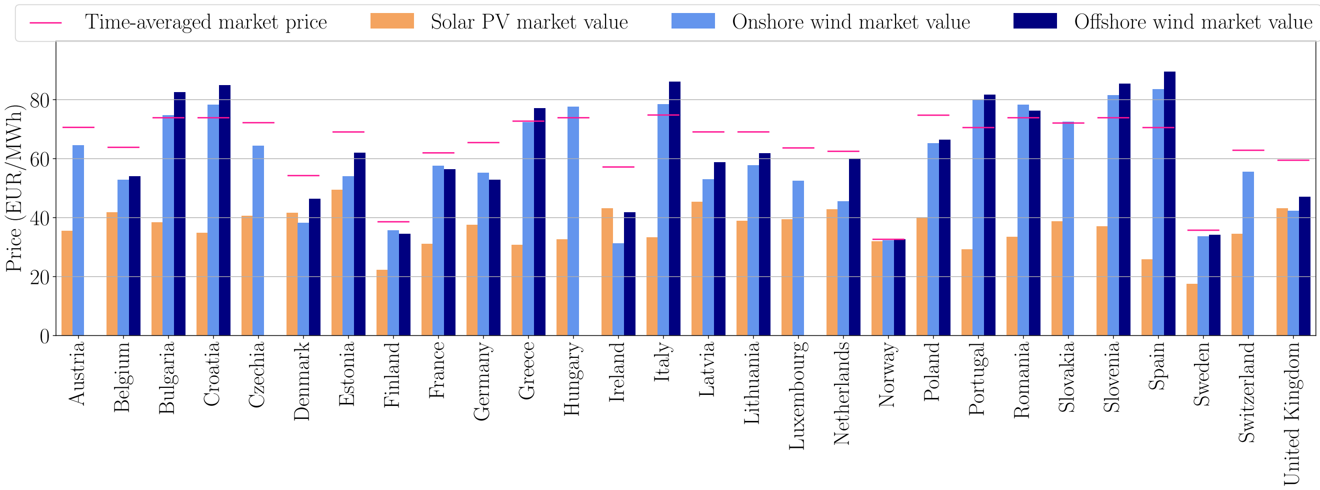

Figure 5: Time-averaged market prices and market values for solar PV, onshore wind and offshore wind across different countries.

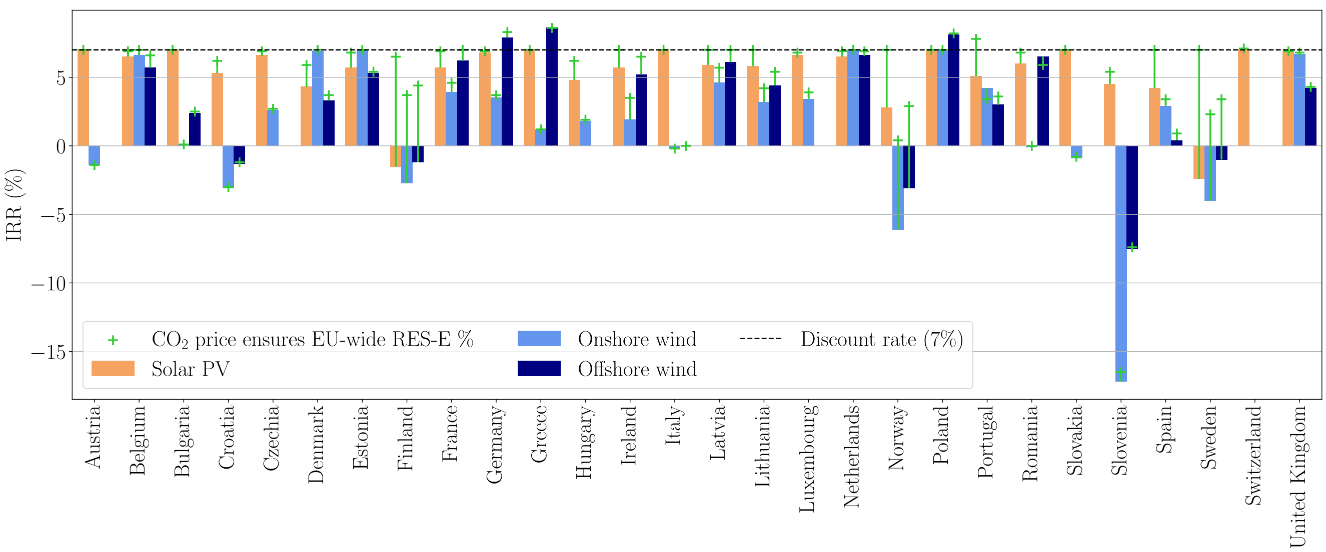

Figure 6: Sensitivity of internal rates of return by country and technology under varying the RES-E share constraint. Bars represent the base scenario with national RES-E share targets, while green error bars with the + symbol refer to the scenario where an EU-wide RES-E share target is achieved by the CO_2 price. The black dashed line indicates the discount rate of 7 % used for the expansion planning.

In Finland, Norway and Sweden, all IRRs rise by more than 5 % points, which can be explained by a significant increase of time-averaged market prices and market values in these countries by almost 60 %. In France, Ireland, Latvia and Lithuania, the same phenomenon can be observed, but to a lesser extent. In Denmark, Estonia, Portugal and Spain, IRRs only for solar PV increase and so do the corresponding market values. The only decrease in IRRs can be observed for onshore wind in Portugal and offshore wind in Romania, where the change is less than 1 % point. In the other countries, IRRs increase slightly or remain unchanged. The country-specific generation mixes for this scenario are not shown in detail. However, it can be observed that Croatia, Czechia, Finland, France, Hungary, Ireland, Lithuania, Luxembourg, Romania, Slovenia, Spain and Sweden fall short of their national RES-E share targets, while Bulgaria, Denmark, Estonia, Latvia and Switzerland increase their renewable generation significantly as compared to the base scenario. The overall generation per country changes with a similar pattern and is positively correlated with the respective national renewable generation. In contrast, there is no clear correlation between national (renewable) generation and changing IRRs. The system-wide generation mix, RES-E share and CO_2 emissions remain almost unchanged as compared to the base scenario, i.e. the same target is achieved with a different spatial distribution. Overall, substituting national with EU-wide RES-E share constraints improves the IRRs of renewables across countries and technologies. In contrast, one could argue that the opposite effect would be expected: Weakening a constraint reduces total system costs (in this case by 0.5 %) and average LCOE, which could suggest lowering prices and thus profitability. However, market values of renewables generally increase, highlighting that moving towards EU-wide renewable targets is economically beneficial not only from a market perspective, but also from a central-planning perspective in terms of total system costs.

As a consistency check, we compare the IRRs to the assumed discount rate of 7 %. As discussed, e.g., by Brown and Reichenberg (2021), IRRs should be at least equal to the discount rate in a linear optimisation model without additional constraints deviating from the techno-economic optimum, like e.g. renewable shares. In the EU-wide RES-E share scenario, the EU-wide RES-E share target of 65 % is exceeded and renewable investments for some countries and technologies exceed the amount installed in 2019. In that sense, these investments, and hence the system marginal costs, can be considered as virtually free from the kind of constraints discussed above. As expected, the countries and technologies with IRRs of 7 % (green + symbols in Figure 6) are exactly the ones exceeding the renewable constraints. For some countries and technologies exceeding their renewable constraints, this effect cannot clearly be analysed as it is disturbed by aggregation of either multiple nodes (for PV in Portugal as well as PV and onshore wind in the UK) or the two offshore wind technologies (in Belgium, France, Germany, Greece, Ireland, Latvia, Poland, Netherlands and UK).

3.4. Parameter sensitivities

For the different parameter sensitivities studied, IRRs are shown in Figures 7, 8 and B.11, while system-wide generation mixes, CO_2 emissions and RES-E shares are presented in Figures 9 and A.10.

For the *medium gas price* and *high gas price* scenarios, consider Figures 7 and A.10. For most countries and technologies, the IRRs remain unchanged as compared to the base scenario. Gas-based generation is largely removed from the system and replaced by renewable, mainly offshore wind, and coal-based generation, as compared to the base scenario. While some gas is still used for a price of 50 €/MWh, it is almost entirely replaced at 100 €/MWh. This results in slightly higher RES-E shares and approximately 30 % higher GHG emissions. Overall, there are only small differences between the medium and high gas price scenarios and for the high gas price, even small amounts of oil are used for electricity generation.

For higher gas prices, increasing market prices and hence profitability can therefore generally be expected as a result of higher marginal costs of price-setting units[12]. This effect can be observed in countries that use coal (Bulgaria, Croatia, Romania and Slovenia) or gas (Ireland and Italy) in the medium and high gas price scenarios. It is also "exported" to other countries. Even without significant amounts of domestic coal- or gas-based generation,

[12]Marginal costs are 94 €/MWh, 136 €/MWh and 224 €/MWh for CCGT units in the base, medium and high gas price scenarios, respectively, and 132 €/MWh for hard coal in all three scenarios.

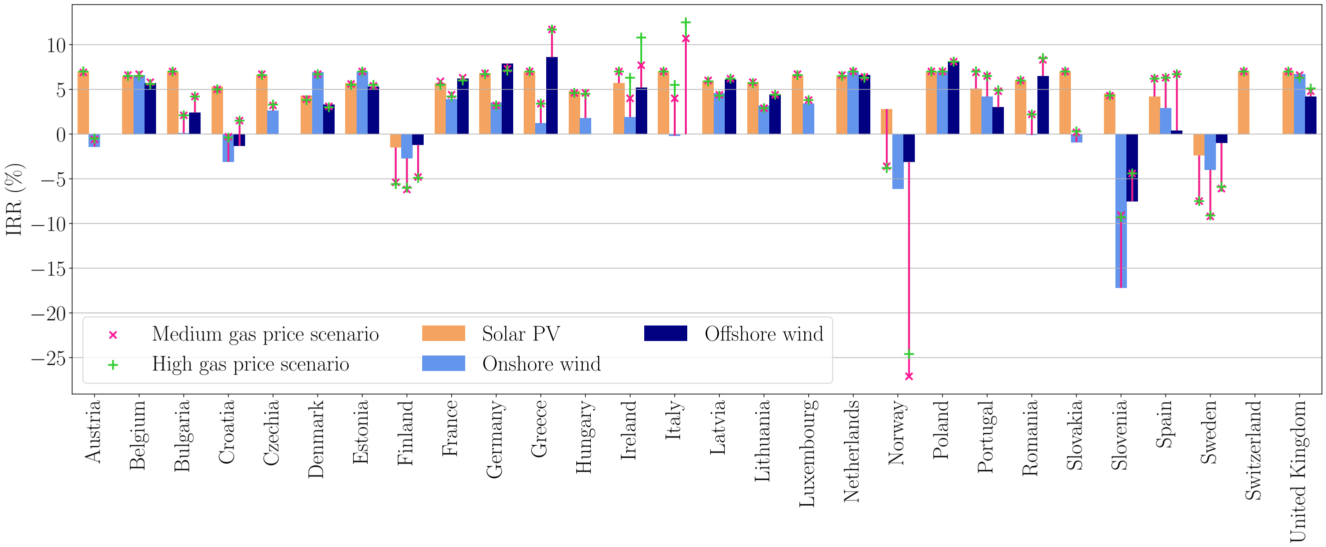

Figure 7: Sensitivity of internal rates of return by country and technology under varying natural gas prices. Bars represent the base scenario, while pink error bars with the × symbol refer to the medium gas price and green error bars with the + symbol to the high gas price scenario. The assumed prices for natural gas are 25.56 €/MWh for the base, 50 €/MWh for the medium gas price and 100 €/MWh for the high gas price scenario.

IRRs for wind increase in Greece and Hungary as a result of increased market prices and values, following the pattern of their neighbouring countries Bulgaria, Romania and Slovenia. In all three scenarios, the price duration curves of these five countries are almost the same. Furthermore, the effect is stronger, where gas units are price-setting more often. Where there is a significant, but rather weak effect, gas is typically price-setting for about 6500 h in the base scenario. In the four countries with the strongest effect, gas remains price-setting, even in the high gas price scenario, for a time of 1000 h in Portugal and Spain, 1500 h in Italy and 3500 h in Ireland, while in other countries, gas sets the electricity price for only a few hundred hours when gas prices reach 100 €/MWh. Italy and Ireland are therefore also the only countries with a significant difference between the medium and high gas prices.

In countries, where IRRs are unchanged, e.g. Belgium, Denmark, Latvia and the Netherlands, gas is price-setting for only 4000 h to 5500 h in the base scenario and hardly ever price-setting for higher gas prices. Generally, but particularly in these countries, increased marginals through gas and coal are counter-balanced by decreased marginals through nuclear and renewable power. The overall increasing renewable share leads to increased hours with zero marginals and although the total amount of nuclear power remains constant, the time increases, in which nuclear power is price-setting. Overall, the effect does not affect all technologies equally, but wind much stronger than solar PV: due to its higher temporal concurrence, it is more often affected by times of zero or very low marginals, i.e. when residual load is zero or can be covered by nuclear power plants. These times increase in the scenarios with higher gas prices. Therefore, market values and profitability of solar power are less affected by the increased gas and coal marginals. For example, in Italy and Romania, time-averaged market prices and wind market values increase to approximately 110 €/MWh and 90 €/MWh, respectively, in the high gas price scenario, while solar market values remain at about 33 €/MWh. IRRs only decrease in Finland, Norway and Sweden and for all three technologies due to a decrease of market prices and values. With a decrease from 32 €/MWh to 18 €/MWh, it is strongest in Norway. However, it is not always possible to fully explain the mechanisms underlying increased (decreased) market values due to the model's complexity in terms of influences on and of investment decisions, shifting across borders (transmission) and time (storage) as well as renewable target constraints.

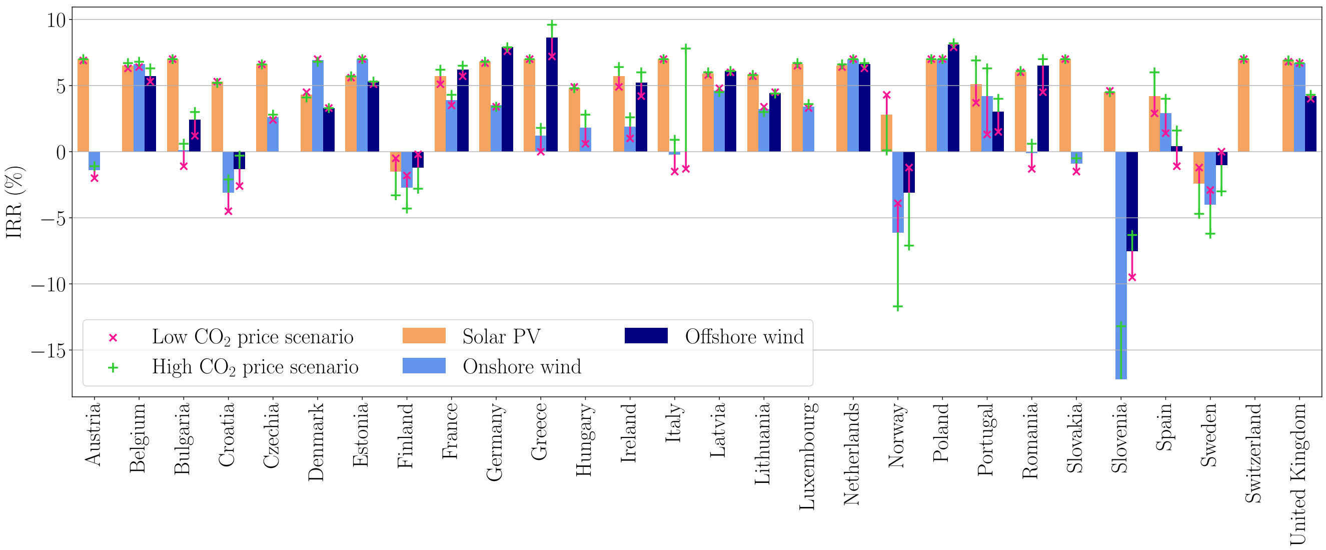

Figure 8: Sensitivity of internal rates of return by country and technology under varying CO_2 prices. Bars represent the base scenario, while pink error bars with the $\times$ symbol refer to the low CO_2 price and green error bars with the $+$ symbol to the high CO_2 price scenario. The assumed prices are 129 €/t for the base, 100 €/t for the low CO_2 price and 160 €/t for the high CO_2 price scenario.

For the *low CO_2 price* and *high CO_2 price* scenarios, consider Figures 8 and 9. For more than half of the countries and technologies, a varying CO_2 price has no or a minor effect on the IRRs. In the other countries, higher (lower) CO_2 prices result in higher (lower) IRRs. This effect is similar to the one described above for higher gas prices: higher (lower) CO_2 prices lead to higher (lower) marginal costs of price-setting units[13], higher (lower) market prices and eventually higher (lower) profitability. Therefore, the same ten countries are affected in the gas price scenarios as in the CO_2 price scenarios. The same countries exhibit the strongest effects and it is also lower for solar PV than for wind power. More precisely, it occurs in some countries comparably strong for all technologies, while in others, it is observed only for wind. The opposite effect is again observed in Finland, Norway and Sweden, where increasing (decreasing) CO_2 prices lead to decreasing (increasing) market prices and values. For the low CO_2 price scenario, the IRR for onshore wind in Slovenia is ill-defined, because the annual cash flow becomes negative.

Profitability results for the *low solar, high wind* (LSHW) investment costs and the *low wind, high solar* (LWHS) investment cost scenarios are shown and explained in more detail in Figure B.11 in Appendix B. Generation mixes are included in Figure A.10. Briefly summarised, the variation of investment costs has no or modest impact on IRRs for half the countries and technologies. In many other countries, IRRs are negatively correlated with IRRs via the direct effect of investment costs as a cash flow in Equation (2). However, this effect can generally be counterbalanced or overcompensated by changing market values: with increasing investment costs, invested capacities may decrease, because the technology becomes less cost-efficient from a central planning perspective. This can lead to increasing market values due to a weaker merit order effect and eventually to increasing IRRs.

[13]Marginal costs of CCGT units are 84 €/MWh, 94 €/MWh and 105 €/MWh for CO_2 prices of 100 €/t, 129 €/t and 160 €/t, respectively.

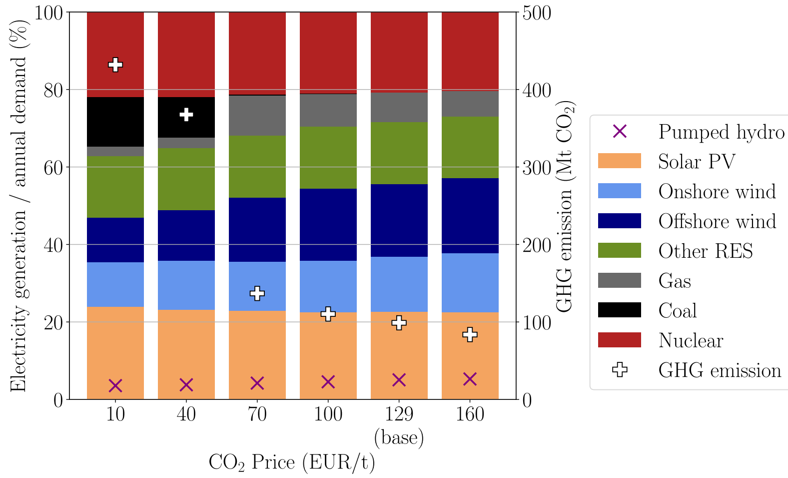

Figure 9: Generation mix, PHS use and CO_2 emissions under varying CO_2 prices from 10 €/t to 160 €/t for the same national RES-E % target. Electricity generation and PHS use, referring to the left ordinate, is aggregated over all countries and the whole modelling time frame and normalised to the demand. CO_2 emissions are indicated by black and white + symbols and refer to the right ordinate. The CO_2 prices of 100, 129 and 160 €/t correspond to the *low CO_2 price*, *base* and *high CO_2 price* scenarios, respectively.

In addition to the *high* and *low CO_2 price* scenarios, the system-wide generation mix, RES-E share and CO_2 emissions resulting from CO_2 prices of 10, 40 and 70 €/t are shown in Figure 9. The generation from coal, natural gas and offshore wind changes significantly across the scenarios, while the others remain largely unchanged. As a general trend, for increasing CO_2 prices, first coal is replaced by offshore wind and gas and then, gas is further replaced by offshore wind and small amounts of onshore wind. CO_2 emissions range from 80 t to 450 t and decrease with increasing CO_2 prices. The coal phase-out is completed for a CO_2 price between 40 €/t and 70 €/t and comes with a sharp decline in CO_2 emissions from 368 Mt to 137 Mt. Further increases of CO_2 prices reduce emissions less than proportionally, i.e. the steepness of the emission decline is generally decreasing with higher CO_2 prices. The RES-E share ranges from 63 % to 73 %. It correlates positively and almost linearly with CO_2 prices. This means that there is no direct or linear relation between renewable shares and GHG emissions. Much rather, similar renewable shares can, driven by CO_2 prices, result in significantly different emissions, depending on the additional use of fossil fuels.

3.5. Limitations

Generally, our modelling results are driven by the assumptions and data. Despite the different scenarios and sensitivities studied, systematic as well as parametric uncertainties remain. Aggregating large areas to a coarse spatial resolution can have an effect on natural resource conditions, in particular on full load hours and generation profiles of renewables, and thereby also on market values. In our model, larger countries are therefore represented by two nodes instead of one. However, this could still underestimate full load hours at favourable sites and overestimate the cannibalisation effect. Furthermore, this deviates from current market design as uniform pricing within larger countries is not guaranteed. Using marginal costs for meeting the electricity demand as market prices is a simplification of real electricity markets. It fails to distinguish between future and spot markets and neglects other contract structures like power purchase agreements and generation for own use. For example, solar PV investments on a residential scale may have higher costs but also better profitability due to higher retail prices, as compared to wholesale prices on the utility level. Furthermore, the potentially price-forming effects of strategic bidding behaviour and demand side management as well as other revenue sources, e.g. capacity and balancing markets, are not represented. Preventing investments in bioenergy generation capacities can affect the energy system design and lead to higher shares of intermittent renewables. Possibly amplified by preventing transmission line investments and resulting curtailment, this could underestimate revenues for renewable projects. For the profitability assessment, we consider the year 2030 as a snapshot and assume revenues to remain constant over the whole life time. However, within the life time of 25 years, revenues can vary significantly, for example due to changing climatic conditions, renewable penetrations or advancing sector coupling. Finally, using country- and technology-specific WACC only in the ex-post profitability analysis neglects the existing heterogeneously distributed risk associated with renewable investments in the expansion planning. If comprehensive data was available, real WACC should be used for the investment planning.

4. Conclusion and policy implications

A number of policy plans aim at expanding renewable electricity generation capacities across Europe. While various instruments are and have been used to realise this expansion, a shift towards more market-based approaches can be observed, highlighting the importance of profitability of renewables based on market revenues. At the same time, current policies still contain national renewable share targets, e.g. for the year 2030. Therefore, we assess the profitability of solar PV, on- and offshore wind in a 2030 European electricity system fulfilling current renewable share targets, based on revenues from the spot market.

Three key messages can be derived from our analysis, each addressing one research question posed in the introduction. First, our findings reveal that in a least-cost system fulfilling renewable targets at a national level, renewables are mostly not profitable in the market. Moving towards purely market-based revenues of renewables while maintaining renewable targets at a national level will therefore not be feasible in the privatised sector and put the achievement of climate goals at risk. More precisely, our analysis shows that national-level targets may lead to reduced market values and consequently to IRRs below the WACC as demonstrated particularly for countries with good natural resource conditions for certain technologies, such as solar PV in Spain and Portugal or onshore wind in Ireland.

In contrast, the scenario where a common European target is achieved by an appropriate CO_2 price reveals that the same renewable shares at the European level can be achieved together with significantly increased market-based profitability of renewables, if their expansion is driven less by national expansion targets and more by EU-wide market-based instruments.

Second, the profitability of renewables varies significantly across countries and technologies. The main factors influencing the profitability can be grouped into drivers on the revenue as well as the cost side.

On the revenue side, profitability is mainly driven by natural resource conditions and market values. While natural conditions cannot be influenced directly, market values are, besides the policies mentioned above, driven by prices of CO_2 and fuel. We observe as a general trend that gas and CO_2 prices correlate positively with the profitability of renewables. However, through the influence of these factors on investment decisions and the optimal energy system design, even the opposite effect occurs in some countries. More generally, our results show that low market values and thus low profitability can appear as a result of low overall market prices or low relative market values. However, under national renewable targets, the effect of gas and CO_2 prices on renewables' profitability is rather limited and not evenly spread between countries and technologies. Increasing gas and CO_2 prices lead to significantly higher profitability only in few countries and almost exclusively for wind technologies. A reason for the plateauing return for solar power might be that PV, due to its spatially homogeneous profiles and negative "natural" correlation with demand, any measure increasing the marginal cost of fossil-fuelled units only has a limited effect on market prices in hours where solar generation is dominant. This is consistent with the general observation that solar PV is more heavily affected by the merit order effect than wind.

Concerning the main drives on the cost side, we find that technology costs, which have already seen a sharp decline in the past decades, correlate negatively with IRRs and, given national renewable targets, have a rather small effect on the profitabilty. The analysis of NPVs, however, highlights the role of capital costs as another important driver of investments in renewables. Low WACC benefit and high WACC degrade the profitability of renewables, regardless of the amount and sources of revenues. WACC are distributed heterogeneously across countries and technologies and can be influenced by policies in order to increase the feasibility of market-based renewable generation.

On the one hand, the differences in capital costs are to some extent a consequence of (national) policies affecting investments risks, e.g. guarantees for renewable projects and their stability. Recent plans[14] for a direct market intervention by introducing a cap for renewables' revenues at 180 €/MWh, years after investment decisions have been made on the basis of different policies and expectations, have set a precedent. Investors may be concerned that the state could intervene again later, which means that the capital cost of renewables is likely to increase because there would be higher risk premiums for financing.

On the other hand, the cost of capital for renewable projects is likely to change in the near future because of the EU taxonomy, which is a classification system establishing a list of environmentally sustainable economic activities. Investments in technologies polluting directly or indirectly the environment are penalised in the taxonomy through a higher cost of capital. Some technologies are particularly rich in rare materials, whose extraction may damage the surrounding environment. This could affect capital costs across the whole EU generally, but also some technologies much stronger than others. Therefore, new criteria to determine whether renewables use "green" or "brown" materials are necessary to assess their cost of capital in the future and, thus, their profitability. The analysis of the costs associated with rare materials and the impact of the EU taxonomy deserves further analysis.

Third, our calculations emphasise that, not surprisingly, GHG emissions are neither a direct result of nor linearly dependent on renewable shares only. Much more, CO_2 and, to a lesser extent, gas prices are key drivers of the non-renewable generation mix and therefore of GHG emissions. While a coal-exit and thus a sharp decline in emissions can be achieved at CO_2 prices between 40 €/t and 70 €/t, CO_2 prices above 100 €/t show a decreasing effect on emissions. With high gas prices, not only renewables but also coal-based generation increases, raising up the level of GHG emissions from 100 Mt to above 130 Mt. However, increasing CO_2 prices may mitigate this effect.

In summary, our findings show that in order to make renewable investments profitable under market conditions,

[14] `https://ec.europa.eu/commission/presscorner/detail/en/IP_22_5489` [last accessed 07.10.2022]

governments will need to take action; either by providing additional revenues, e.g. premia on top of market prices (the costs of which will ultimately have to be borne by the consumers) or by shifting from national renewable expansion targets towards EU-wide market-based mechanisms (such as an appropriate, minimum CO_2 price). The findings also show that the latter would come along with advantages in terms of increasing the CO_2 emission reduction potential of renewables – even at times of high gas prices.

For policy makers, this emphasises yet again the importance of a suitable market design for systems with high renewable penetration. Analysing the effect of different market designs on the profitability of renewables should therefore be subject to future research. Moreover, using different modelling and optimisation methods can also impact recommendations for energy system design and operation and thus the profitability. Future work should therefore aim at improving energy system models in order to consider the market-based profitability explicitly in the models and thus increase the feasibility of model outcomes. Moreover, future analysis should include the demand side and its flexibility more explicitly to study costs and benefits associated with market prices and supply-side profitability from a more holistic welfare perspective. This is important to provide an integrated perspective on the trade-off between the profitability of renewables (producer profits) and consumer welfare, which is particularly important for vulnerable consumer groups.

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Author contributions

Jonas Finke: Conceptualisation, Formal analysis, Investigation, Methodology, Visualisation, Writing – original draft, Writing – review & editing; **Valentin Bertsch:** Conceptualisation, Methodology, Supervision, Writing – original draft, Writing – review & editing; **Valeria Di Cosmo:** Writing – original draft, Writing – review & editing.

Declaration of 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.

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Data availability

To the best of the authors' knowledge, all data used is from openly available sources as described in Section 2. Backbone is openly available from `https://gitlab.vtt.fi/backbone/backbone`.

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Appendix A. System-wide generation mix for scenarios

Similar to Figure 9, the system-wide generation mix, use of PHS and GHG emissions are displayed in Figure A.10 for some additional scenarios.

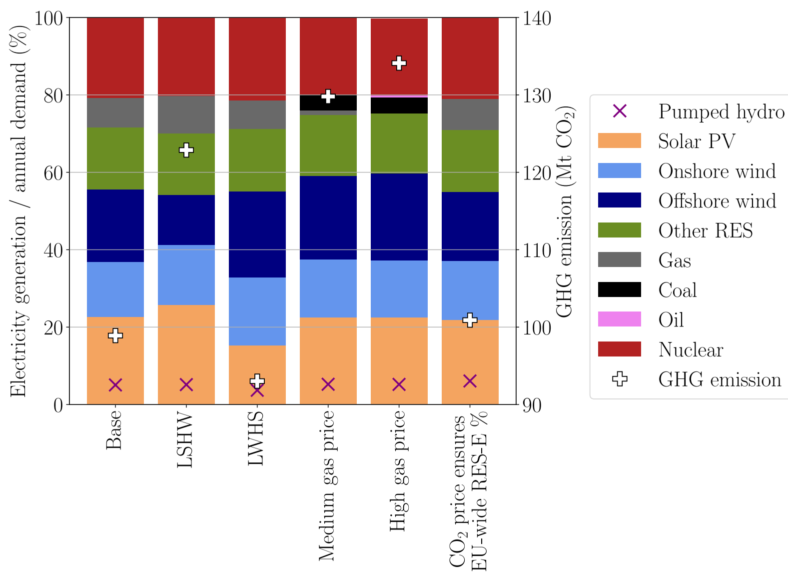

Figure A.10: Generation mix, PHS use and CO_2 emissions for diffenrent scenarios for the same national RES-E % target. Electricity generation and PHS use, referring to the left ordinate, is aggregated over all countries and the whole modelling time frame and normalised to the demand. CO_2 emissions are indicated by black and white + symbols and refer to the right ordinate.

Appendix B. Sensitivity analysis for investment costs

In the following, the positive correlation between investment costs and IRRs observed in some cases in Figure B.11 is described in more detail. In the LWHS scenario, system-wide solar generation decreases, because it is less cost-efficient from a central-planning perspective. Therefore, solar market values increase significantly almost everywhere, arguably due to a weaker merit order effect. This can for example be observed in Croatia, Hungary, Lithuania, Poland and Slovenia as well as Greece, where, compared to the base scenario, invested solar capacity decreases by 25 % and the market value increases by more than 60 %, leading to a constant IRR. When market values are affected more than proportionally via the merit order effect, the same mechanism causes decreasing IRRs for decreasing investment costs, e.g. for offshore wind in France and onshore wind and solar PV in Ireland and Latvia. Wherever higher (lower) IRRs result from higher (lower) investment costs, these are associated with higher (lower) market values. This also holds for wind in the Scandinavian countries.

Generally, it should be noted that variations in investment costs are not necessarily the same or proportional between the technologies and the high and low values. Therefore, the effect strength cannot easily be compared between those.

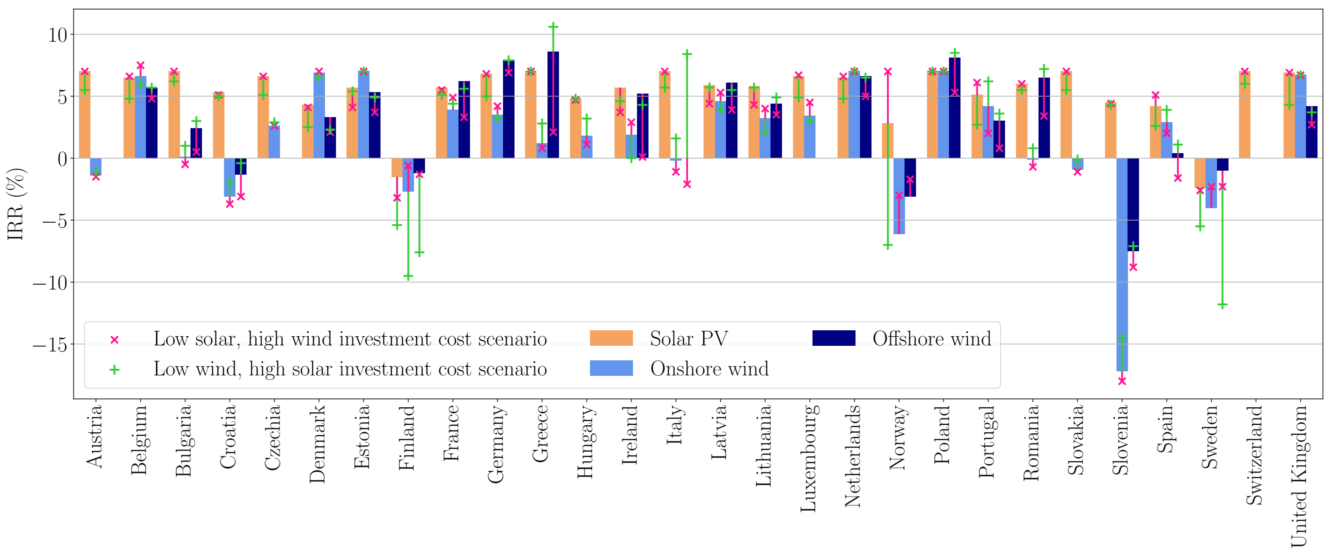

Figure B.11: Sensitivity of internal rates of return by country and technology under varying renewable investment costs. Bars represent the base scenario, while pink error bars with the × symbol refer to the *LSHW* and green error bars with the + symbol to the *LWHS* scenario. The assumed investment costs are displayed in Table 1 as sub- and superscript values.

Appendix C. Full load hours

To illustrate the natural resource conditions of renewable technologies in different countries, the full load hours used in our model are displayed in Table C.2. These values are the theoretically possible full load hours and purely based on weather data, i.e. curtailment is not taken into account.

Table C.2: Full load hours per country and technology for solar PV, onshore and offshore wind. Aggregation of nodes and technologies was done by weighting with installed capacities from the base scenario.

	Solar PV	Onshore wind	Offshore wind
Austria	1072	1114	
Belgium	992	2486	4147
Bulgaria	1158	1075	2355
Croatia	1080	816	1691
Czechia	995	1513	
Denmark	945	3488	4587
Estonia	871	2499	3823
Finland	763	1827	3914
France	1112	1876	4138
Germany	1000	1898	4879
Greece	1256	1256	3749
Hungary	1044	1177	
Ireland	818	2975	5204
Italy	1197	1032	1906
Latvia	894	2145	4007
Lithuania	906	1895	3582
Luxembourg	1018	1969	
Netherlands	980	2927	4717
Norway	820	1621	3602
Poland	963	2058	4058
Portugal	1341	1466	2493
Romania	1088	1026	3086
Slovakia	1005	1110	
Slovenia	1025	477	1119
Spain	1315	1370	2091
Sweden	887	1822	4081
Switzerland	1159	425	
United Kingdom	898	3150	4399