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JEL Classification D47; L94; L98; L51; Q48; Q41; C61

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Chi Kong Chyong†, Michael Pollitt‡ and Reuben Cruise§

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1. Introduction

Europe has made significant progress in the creation of a single electricity market. Successive electricity directives[5] in 1996, 2003 and 2009 have shifted the electricity supply sector from dominance by national monopolies towards a European market dominated by competing pan-European companies whose business models have continued to change dramatically over the past few years.[6]

One early result of the reforms was a reduction in government intervention in the generation investment decisions of companies. This led to widespread market entry and market-driven investment in fossil-fuel based power plants. Over time, industrial and commercial retail tariffs have been almost completely deregulated in most European countries, while many residential customers have shifted to non-regulated tariffs. Wholesale and retail electricity prices moved in line with fossil fuel prices which were the dominant component of wholesale electricity costs.

However renewable energy directives in 2001 and 2009[7] significantly influenced investment in electricity generation. While the 1990s and early 2000s could be unusually characterised by reliance on the wholesale market to finance new generation investment (see Helm, 2002; Pollitt, 2012), since 2002, there has been a significant rise in the share of renewable electricity investment in Europe. This, combined with slow growth in electricity demand, has meant that by 2017 almost all new investment in electricity generation was in the form of subsidised renewables (IEA, 2018). For example, in 2017, the combined global investment in wind and solar PV stood at ca. \$230 bn. This exceeded the investment in distribution (ca. \$220 bn),

[5] Directives 96/92/EC, 03/54/EC and 09/72/EC.
[6] See Pollitt (2019) for a detailed review of progress in the single electricity market.
[7] Namely, the renewable electricity directive (2001/77/EC) and the renewable energy directive (2009/28/EC).

transmission (ca. $80 bn), and conventional thermal generation technologies[8] ($140 bn) (IEA, 2018).

Nevertheless, renewables subsidies (per MWh) have begun to shrink and the EU's climate targets for 2030 now place emissions reductions at the forefront of action, with no new binding renewables targets at the national level[9]. Ambitious climate targets would imply a further step up in the share of renewables in net annual electricity production to at least 55%[10] (E3MLab & IIASA, 2016), which combined with nuclear power, means fossil fuels will only hold a residual role in electricity supply by 2030.

The current market design supported conventional generation technologies from 1990 until around 2010 with lower relative capital costs and higher short-run cost than variable renewable energy (VRE) generation. VRE technologies are characterised by high fixed costs incurred up front and stable annual running costs which do not vary much with output. While the fixed annual running costs of VRE can be considerable, the instantaneous short run marginal cost of a MWh of electricity produced from intermittent renewables is virtually zero.[11]

Near zero marginal cost of VRE gives rise to a "merit-order" effect, depressing average wholesale prices and load factors of conventional generators and, hence reducing their revenues. Further, due to the nature of subsidies such as feed-in-tariffs (FiTs) there is a corresponding economic incentive to generate electricity whenever wind/solar resources are

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[8] coal, gas, oil, and nuclear

[9] See https://ec.europa.eu/clima/policies/strategies/2030_en for the EU's 2030 energy and climate targets.

[10] Based on modelling by E3MLab & IIASA for the 2016 Impact Assessment work of the European Commission (EC). In particular, the 55% figure is based on EUCO3030, which is the most RES ambitious policy scenario modelled for the EC. This scenario envisages 30% of RES share in final energy demand, 30% improvement in energy efficiency and 40% reduction in GHG emissions. Note, however, that the final targets for RES of 32% and for energy efficiency of 32.5% was approved by all EU institutions (the Commission, the Parliament and the Council) and came into force on 24 December 2018 (https://ec.europa.eu/info/news/new-renewables-energy-efficiency-and-governance-legislation-comes-force-24-december-2018-2018-dec-21_en).

[11] This situation is not the same as those where electricity markets with high starting levels of hydro-electricity were 'successfully' liberalised (e.g. Norway, Chile and New Zealand). These systems have been characterised by high peak electricity prices due to hydro shortages, low initial amounts of fossil fuel capacity and public financing of the bulk of the renewable capacity.

available to get guaranteed revenue. Thus, hourly electricity prices can be zero or even negative, reflecting the fact that FiTs are paid regardless of market prices or the capability of the grid to absorb renewable generation. For example, recently, there were many trading periods when several markets in the Central Western Europe area[12] encountered negative hourly prices (DG ENERGY, 2018)[13].

The emergence of a system heavily dependent on upfront capital investment[14] might motivate a redesign of the current set of markets based around fossil fuel-based electricity. Thus, an important question that this paper seeks to address is whether, in the presence of the merit order effect, wholesale energy-only prices can serve as a long-term investment signal for electricity generation technologies (conventional and VRE). For example, looking at the 2015 – September 2018 power prices in Northwest Europe suggest that might not be the case: average wholesale prices covered 71% - 92% of a CCGT's short-run marginal cost in that period. Power prices were not enough to cover fixed OPEX and certainly not the fixed OPEX and CAPEX of new CCGTs. This is a problem If CCGTs are required for system adequacy. If this is the case, the "missing money" does exist within the prevailing structure of costs and power price dynamics.

On the other hand, VRE currently suffer from three market failures: the under-pricing of carbon[15], the need to price the learning externality where future VRE costs are reduced by each MW of VRE installed[16], and the failure of financial markets to properly price capital for long run investment (Grubb et al., 2008). These market failures are the main reason governments

[12] The area consists of Austria, Belgium, France, Germany, the Netherlands and Switzerland.
[13] In total, the first quarter of 2018 saw 70 hours of negative prices in Germany and 8 hours of negative prices in France and Belgium. Markets in the Czech Republic and Denmark, which are also integrated with the German market, saw 25 and 32 hours of negative hourly prices respectively
[14] E.g., in intermittent renewable generation, energy storage and reinforced networks
[15] Technically, the failure to price carbon is a regulatory failure rather than a failure of electricity market design
[16] The argument for the existence of a learning benefit in subsidised roll out of renewables is strong as illustrated by Newbery (2017)

have had to subsidise VRE. However, rapid cost reductions in solar and wind power suggest that a world where governments no longer have to subsidise renewables may be close at hand[17] (see Newbery et al., 2018; Lang, 2018). Thus, the prospect of wind and solar being self-financed through wholesale energy-only prices may be possible provided their costs fall sufficiently and/or wholesale prices (which can be driven by fossil fuel and carbon prices) are high enough.

Therefore, the objective of this paper is twofold: (i) to quantify the impact of VRE on merit order (merit order effect) and the trade-offs between merit order effect of VRE and fossil fuel and carbon prices effect, and (ii) to quantify the impact of higher VRE on '*investability'* in electricity generation under the current market design. As a proxy for the current market design, we take "wholesale energy-only prices" i.e., energy-only market design.

A very high penetration of VRE may pose challenges for the theory of electricity markets due to their variable and 'zero marginal cost' nature (following Rifkin, 2014). The question of whether the current market design can accommodate large shares of VRE without radical changes is at the heart of the current policy and academic debates. This question of the future of market design that addresses the policy trilemma – sustainability, security of supply and affordability – is important not only for electricity and climate policies but also has implications for competition policy.

The rest of this paper proceeds as follows: Section 2 provides a literature review. Here, we focus on both the theoretical literature that goes back to basics in electricity market design as well as on empirical modelling literature that quantifies the impact of VRE on electricity

[17] Recent subsidy-free offshore wind auction results for future projects in Germany and the Netherlands are examples of the potential fall in renewable costs to the extent that they could be self-financed through future energy-only energy prices.

markets. Then, Section 3 presents our research methodology and discusses scenarios developed for the analysis. Section 4 presents main findings and Section 5 offers a conclusion.

2. Literature review

2.1. "Energy only" market and peak load pricing

In the prevailing electricity market design, spot prices are determined by the marginal cost of the most expensive operating power plant. These just cover plants' running (marginal) costs but not their capital costs. Stoft (2002) suggests that under peak load pricing all operating power plants may be able to cover their capacity costs using scarcity rents in a long-run equilibrium as well as inframarginal rents. The scarcity price rise in this situation is only limited by the marginal cost of demand side response or the value of loss load (VoLL). Such an electricity market is referred to as an "energy only" market (EOM).

Security of supply (instant balancing of supply and demand) is supplied by the system operator (SO) through acquisition of a range of ancillary and balancing services. Newbery (2016) noted that capacity adequacy[18] could, in principle, be delivered by competitive EOMs and that this has been envisioned by the Target Electricity Model (TEM), part of the EU Third Package.

The EOM design faces some challenges even in the absence of VRE. Most electricity consumers cannot respond to short-term wholesale price movements and selective curtailment of customers appears difficult. Thus, the market may not clear in times of scarcity, as demand is not elastic enough (Joskow and Tirole, 2007). In addition, the social and political acceptability of scarcity prices may be low. This is exacerbated by the possibility of the exertion of market power by incumbents which can be difficult to distinguish from a true scarcity situation. This leads to a root cause of the "missing money" problem: the imposing of price

[18] sufficient long-term generation capacity

caps in wholesale electricity markets (Hogan, 2005). These dampen price rises and limit the potential for market power abuse.

Wholesale prices are uncertain as result of these considerations. Hence, investors may not able to recoup their capital costs through scarcity rents. The “missing money” problem may still be prevalent in the absence of explicit price caps: investors may expect that under stress and scarcity events, wholesale prices may be capped by regulators or by technical interventions by system operators (Neuhoff et al., 2016).

2.2. “Energy only” market, missing money and reserve “markets”

To address these shortcomings, Hogan (2005) proposed to price scarce reserve at the opportunity cost of energy through a regulated operating reserve demand curve (ORDC). This serves to improve reliability, and hence incentivise investment because better scarcity pricing would contribute to long term resource adequacy (Hogan, 2018). In effect, scarcity pricing relies on a few very high price hours every few years to finance peak capacity.

Joskow (2007) insisted that the missing money problem is often a result of other market imperfections instead of price caps, concluding that a forward capacity market[19] is needed to ensure resource adequacy. If markets were not subject to policy and regulatory interventions, resource adequacy could be delivered by profit-motivated generation investment. Thus, for Joskow (2007) it is not just about price caps but also about policy and regulatory uncertainties more generally. However, absent policy and regulatory uncertainties, investors would need confidence in receiving adequate revenue from energy and ancillary services markets (Newbery, 2016), which is rarely the case as these ancillary services are sometime inadequately remunerated and poorly defined.

[19] which contract capacity availability, for example, one to four years ahead.

Newbery (2018) noted that the need for long-term capacity markets is due to a lack of liquidity in forward "energy-only" markets that would otherwise allow market participants to hedge against long-term political and regulatory uncertainty.

However, according to Hogan (2018), capacity markets do not create the correct incentives to respond to short-run scarcity conditions (Hogan, 2018). This can lead to lower security of supply, which may be due to lack of high enough penalties for non-delivery. This highlights that there is inevitably a need for high prices (in the form of positive or negative payments) to incentivise delivery in real time when supply is scarce.

Bidwell (2005) considered that instead of capacity markets, retailers should contract for reliability options with generators, where generators agree to provide reliability at fixed prices during stress events and effectively forego price spike revenues. This addresses the market manipulation problem which may arise in capacity markets.

Hogan argues (2005, 2018) that a short run ORDC renders a longer run capacity market obsolete. However, this is premised on the ORDC market being a predictable source of funding over a multi-year period.

2.3. VRE and the need for a market re-design

The currently prevailing electricity market design in Europe has evolved naturally to support the operation of, and investment in, fossil fuel power generation technologies. The missing money problem has been limited to the issues of robustness of demand-side management (market clearing under scarcity conditions), the possibility of market power exertion at peak demand periods by conventional generators and resultant regulatory interventions in the form of price caps and/or technical interventions by SOs.

However, with the rise of VRE, the missing money problem may be exacerbated. VRE can be seen as completely price-inelastic negative demand (due to zero marginal cost) and thus it intensifies price volatility and demand fluctuations (Cramton et al. 2013). This exposes fossil fuel generators to volatile income streams in the energy-only and ancillary markets. With the rise of VRE, the attractiveness of investments in conventional generation capacity reduces due to the "merit order" effect of VRE (see Section 2.4 below). This is because new fossil fuel investments no longer start off as base load investments with maximum load factors, as they did in the past.

Thus, as VRE penetration increases, the capability of the current EOM to provide adequate long-run price signals to guide investment decisions in generation capacity must be considered. This increase leads to a need for flexible reserve capacity to meet the unpredictable nature of VRE generation. Hence, the discussion around "energy only" with better scarcity pricing such as ORDC has been renewed in the context of supporting higher VRE as well as arguing that the existing EOM can – with appropriate ancillary service markets - accommodate a large amount of zero-marginal cost VRE (Hogan, 2018).

2.4. Quantitative analyses and modelling: impact of VRE on electricity systems

The impact of high share of VRE on electricity systems is well researched in the empirical and economic modelling literature. Here, we only focus on the impact of VRE on wholesale prices and empirical modelling of electricity markets with high VRE. The survey here is not meant to be exhaustive but to merely show the well-established empirical finding that higher VRE production leads to lower wholesale prices.

In this regard, both Würzburg et al. (2013) and Bublitz et al. (2017) provide excellent surveys of the literature on price impacts of renewable generation. For example, Würzburg et al. (2013) surveying 20 research papers found price impact of -0.24 €/MWh to -9.90 €/MWh for each additional GWh of renewable energy produced. The range depends on methods (e.g., statistical and econometric analysis or simulation modelling), geographical scope (e.g., most of studies they surveyed focused on Germany), and time period (e.g., whether this is a single year, multi-year time series or simulation of counterfactual or future impacts). Similarly, Bublitz et al. (2017) surveyed 9 publications (some of which were also mentioned in Würzburg et al. (2013)) and found that the merit-order effect ranges from -0.55 €/MWh to -15 €/MWh, again, depending on modelling assumptions, RES technology (e.g., wind, solar, biomass, etc.), location (e.g., Germany, Spain, Ireland) and methodology.

Thus, the merit-order effect of VRE is well-documented empirically. Also, the joint impact of fossil fuel input prices and VRE production on wholesale prices is also well-researched. Bublitz et al. (2017) modelling results suggest that carbon and coal prices caused electricity prices to decline (2011-2015) in Europe and that VRE contributed only to a small part of that decline (Bublitz et al., 2017). Paraschiv et al. (2014) found that wholesale prices are negatively correlated to the proportion of renewable generation in the mix, while the prices are positively correlated to the performance and price of coal, oil and gas plants. Wiser et al. (2017) found that negative prices in the US concentrated in areas with significant VRE or nuclear generation, as well as during periods of lower total system load. However, it was deduced that declining natural gas prices were the dominant cause of declining average annual wholesale prices from 2008 – 2016. They found that bar a few specific instances, there has been little or no relationship between VRE penetration and recent closure of thermal power plants.

However, it is worth noting that there is rather limited empirical research on the rate of changes in wholesale prices as the result of more VRE production. For example, Kyritsis et al. (2017) found that the reduction rates of wholesale prices remained relatively constant with respect to market penetration of VRE. Further, the empirical literature mentioned earlier only focuses on day-ahead market price impact whereas, for example, Gianfreda et al. (2018) found that while day-ahead prices are likely to decline as VRE production increases, the effects on balancing market prices (intra-day energy prices which reward adjustments near real time) are more ambiguous.

Lastly, the importance of distributional impact of VRE cannot be underestimated for good energy policy design. For example, Cludius et al. (2014) found that in Germany some energy-intensive industries are benefiting from lower wholesale electricity prices whilst being largely exempted from contributing to the costs of funding VRE deployment. Further, the uptake of VRE might have a negative distributional impact if, for example, network tariff charges are inappropriately designed for a system with high share of VRE production. For example, Küfeoğlu and Pollitt (2019) showed that as PV penetration increases in the GB electricity market, the distribution tariffs increase for all customers regardless of whether someone owns a PV or not. This is due to the GB's current network charges calculation structure, which largely depends on a volume-based charge.

While the impact of VRE on electricity systems is well researched in the empirical literature several authors have also looked at the operation of an electricity market with a very high share of VRE using applied economic modelling. For example, Riesz et al. (2016) concluded that existing energy-only market mechanisms could potentially operate effectively under complete VRE penetration (100%) provided there is a derivative contracts market that allows generators to hedge increased market risks. In addition, there would need to be either an increase in the market price cap[20], or demand side participation allowing customers to select a level of reliability at an associated cost.

Bhagwat et al. (2016) analysed the effectiveness of strategic reserves in the presence of a growing VRE mix, concluding that with no VRE, strategic reserves increase the cost of electricity for consumers. But, with a large amount of VRE they stabilise investment in thermal

[20] from $13,500/MWh to $60,000 – 80,000/MWh in Australia's NEM.

generation and hence reduce the cost to the consumer while the effectiveness of the reserves at maintaining generation adequacy decreases.

Focusing on ERCOT (in Texas), Levin and Botterund (2015) analysed and modelled three market policies: ORDC, Fixed Reserve Scarcity Prices (FRSP) and fixed capacity payments (CP). They found that optimal expansion plans are comparable between the ORDC and FRSP implementations, while CP may lead to excess capacity. Under FRSP there are more frequent reserve scarcity events, while prices under ORDC tend to be smoother. For all policies average wholesale prices decrease with increasing wind penetration.

Papavasiliou and Smeers (2017) found that ORDC could provide flexible electricity generation in the Belgian market that were not viable given historical energy and ancillary services prices. They concluded that it is important to have an efficient short-term market (such as provided by the ORDC) for sending the right signal on scarcity of capacity, which could make the capacity market redundant.

3. Methodology and scenarios

The survey of literature suggest that a well-designed energy-only electricity market can accommodate high share of non-dispatchable VRE. In practice, this would require political commitments not to intervene to allow scarcity prices to approach VoLL (or very high energy-only prices and liquid and "bankable" ancillary services markets). As Europe moves towards decarbonization of its power sector this implies a rather high share of VRE in the electricity system by 2030. We are not aware of any empirical and modelling research exploring whether a new market design for electricity in Europe would be required by 2030 in line with those policy objectives. The empirical literature on the effects of VRE on wholesale electricity prices suggest that increasing levels of VRE have a negative impact on average prices and thus could potentially undermine the role of energy-only prices in guiding long-term investments in generation.

Thus, our research aims to close this gap in the literature by quantifying the impact of higher VRE on wholesale prices and volatility of those prices in interconnected power markets of Europe. We model several scenarios which are in line with EU's 2030 objectives to see if wholesale energy-only prices would support investments in conventional and VRE generation. By doing so we also contribute to the recent debate on "subsidy-free" offshore wind auction results in leading power markets in Europe.

3.1. Pan-European electricity dispatch model

For this research, we employ our own economic dispatch model and calibrate it to simulate the interconnected power markets of North Western Europe (for details see the Supplementary material). The model simulates European power markets at hourly resolution and at plant level. Its objective is to minimise total costs (fuel and carbon costs and variable OPEX) of meeting hourly demand, while respecting many techno-economic constraints of power plants such as ramping constraints and operating reserve constraints (spinning up and down reserve requirement). We assume completely inelastic demand curves, but we price country-specific VoLL in the model (CEPA, 2018). Thus, as the supply margin reduces, possibly violating the operating reserve constraints and the system demand constraint, the wholesale prices would approach VoLL. The model also endogenously optimises the operations of hydro pumped storage units. Thus, it optimises operational decisions – such as dispatch, pumping and discharge – and does not look at investment and divestment decisions explicitly. For this research, we have modelled coal, gas and oil-fired power stations, while assuming all other technologies to be exogenous. These other technologies are onshore and offshore wind, solar PV, biomass, hydro run-of-river, nuclear and other (e.g. geothermal) generation technologies.

The model was calibrated to 2015 data to simulate SEM (in Ireland), Great Britain (GB), France (FR), Belgium (BE), the Netherlands (NL), Switzerland (CH), Germany (DE), Austria (AT), Italy (IT), Denmark (DK), Norway (NO) and Sweden (SE). Italy, Denmark, Norway and Sweden were subsequently divided into their respective bidding zones[21]. In total, 25 market bidding zones were modelled explicitly, considering their interconnection capacity. Hence, the model assumes efficient coupling of these market zones.

3.2. Scenarios and assumptions

We model electricity markets in a near-future time frame, recognising the reality that it takes time to change electricity markets, especially at the level of the whole EU single electricity market. We are motivated by the sort of electricity market that might be necessary by 2030 but recognise that this market will itself be decided in 2025, based on the electricity market conditions that might have emerged by then.

To meet our research objective, the following scenarios have been developed and modelled (see Table 1 for details):

1. **Baseline –** assumes same level of wind (both onshore and offshore) and solar PV capacity as in 2015 but that commodity prices will increase to the expected level in 2025.
2. **Scenario A –** increase of 50% of wind (both onshore and offshore) and solar PV capacity relative to 2015 for all markets considered in the model.[22]
3. **Scenario B –** increase of 100% of wind (both onshore and offshore) and solar PV capacity relative to 2015 for all markets in the model.

[21] IT-N (north), IT-CN (centre north), IT-CS (centre south), IT-S (south), IT-SA (Sardinia), IT-SI (Sicily), DK1, DK2, NO1, NO2, NO3, NO4, NO5, SE1, SE2, SE3, SE4. See ENTSO-E transparency platform - https://transparency.entsoe.eu/
[22] This is a near-term target (which has already been reached in some of the countries we consider here, such as GB)

4. **Scenario C –** as in scenario B but assumes higher fossil fuel prices than the projected prices for 2025. We "bring forward" the commodity prices projected by IEA (2018) for 2040 to the year 2025, thus assuming a situation whereby commodity markets could become tighter sooner.
5. **Scenario D –** as in scenario C but assumes higher carbon cost on top of higher fossil fuel prices.
6. **Scenario E –** as in scenario B but assumes "unlimited" interconnection capacity between all the market zones in the model.
7. **Scenario F –** same as in Scenario B but closing unprofitable dispatchable plants.

By comparing Scenario A and B with the Baseline scenario, we quantify the impact of additional VRE capacity on wholesale power prices (the merit order effect) and their volatilities. By looking at the differences between Scenario C (D) and B we quantify the impact of higher generation cost (fuel and carbon) on power prices; in particular, will increase in generation cost cancel out the merit order effect? The interactions between the merit order effect and the generation cost effect are very specific to the local market context, as these depend on the generation mix of each market as well as their interconnection level.

Table 1: Input parameters and assumptions for modelled scenarios.

Scenarios	**VRE capacity**		**Fossil fuel capacity**	**Interconnection capacity**	**Fossil fuel prices (€/MWh)**			**Carbon cost, €/tCO$_2$**
	wind	**solar**			**Gas**	**Coal**	**Oil**	
Baseline	2015 level		2015	2015	23.9	9.8	40.2	25
Scenario A	50% > baseline		2015	2015	23.9	9.8	40.2	25
Scenario B	100% > baseline		2015	2015	23.9	9.8	40.2	25
Scenario C	100% > baseline		2015	2015	29	10.3	51.1	25
Scenario D	100% > baseline		2015	2015	29	10.3	51.1	57

Scenario E	100% > baseline	2015	unlimited	23.9	9.8	40.2	25
Scenario F	100% > baseline	closure based on "missing money"	2015	23.9	9.8	40.2	25

Source: fossil fuel prices are from IEA's (2018) New Policies Scenario; all costs and prices are in 2017 Euro

The merit order effect also depends on existing interconnection between considered market zones. Comparing Scenario E with B, we would expect wholesale prices to stabilise (less volatility) under high VRE share because of potential negative co-variances in supply and demand across large distances in Europe.

A large increase in VRE capacity (Scenario B) may negatively impact the profitability of conventional generation. Thus, an optimal capacity expansion problem, given exogenous (large) increase in VRE, could mean substantially lower optimal conventional generation and effects on equilibrium wholesale prices. We examine this issue in our Scenario F.

Finally, we assume that generation from biomass, hydro run-of-river and other (e.g. geothermal) technologies as well as electricity demand stay at the level of 2015. As for nuclear generation, we assume that only Germany will completely phase-out nuclear by 2025 while nuclear generation in other countries in the model are fixed to 2015 level. Under the most ambitious VRE (and energy efficiency) impact assessment scenario ('EUCO3030') done by E3MLab and IIASA (2016) for the Commission, the EU28 electricity demand is expected to increase by 3.5% by 2030 relative to the 2015 level. Also, under the ECO3030 policy scenario the role of biomass, hydro, geothermal and other RES remain largely unchanged (i.e., their shares in total generation is the same[23] as in 2015, see E3MLab and IIASA, (2016)). Hence, the Commission expects that wind and solar generation will play a central role in fulfilling the 30% RES target.

[23] Except for biomass, for which the projection from the EUCO3030 scenario shows a marginal increase from 6% in 2015 to 9% in 2030 in EU's generation mix (E3MLab and IIASA, 2016).

3.2.1. VRE scenarios

Capros et al. (2018) modelled two core policy scenarios[24] used in European Commission's official Impact Assessment (IA) of its 2030 policy package "Clean Energy for All Europeans". They model EU's optimal generation mix needed to achieve a 27% contribution from RES to total energy demand. They have also modelled several sensitivities, one of which is a 30% contribution from RES to total energy demand ('EUCO3030'). Table 2 compares our VRE scenarios (A and B) with the EU's IA policy scenarios and sensitivities.

Table 2: Modelled Wind and Solar Penetration (Scenario A and B) vs European Commission's Impact Assessment (IA) scenarios

	Wind share in demand				**Solar share in demand**			
	Scenario A	**Scenario B**	**EU* IA 27% RES**	**EU IA 30% RES**	**Scenario A**	**Scenario B**	**EU IA 27% RES**	**EU IA 30% RES**
2015	11%	11%	9%	9%	4%	4%	3%	3%
2030	18%	26%	20%	24%	6%	9%	9%	10%

*Note: * EU's 2030 climate & energy target is for the entire EU while we model just the 25 zones mentioned in section 3.1. this will lead to a small difference in starting penetration.*
Source: EU IA scenarios are based on Capros et. al. (2018) and E3MLab&IIASA (2016).

From Table 2 it can be inferred that if scenario A was applied across the entire EU until 2030 it would not be sufficient to reach the 2030 policy goals for either wind or solar generation. For scenario B on the other hand, the desired 2030 wind capacity would be reached by 2025 while the annual solar capacity additions would only need to increase by 12% which would be achievable. We should note that the final targets for RES of 32% was approved by all EU institutions (the Commission, the Parliament and the Council) and came into force in December 2018.[25] Thus, the final target is just 2% higher than the IA scenario of 30% RES and hence our Scenario B is in line with the most recent EU's 2030 RES policy objectives.

[24] The differences between the two core policy scenarios (EUCO27 and EUCO30) is the energy efficiency target: in EUCO27 the target is 27% while in EUCO30 it is 30%; all climate and renewables targets in those two core scenarios are similar: 27% RES share and at least 40% cuts in greenhouse gas emissions.
[25] see https://ec.europa.eu/info/news/new-renewables-energy-efficiency-and-governance-legislation-comes-force-24-december-2018-2018-dec-21_en

3.2.2. Fossil fuel and carbon prices

We use IEA's New Policies Scenario (NPS) for our analysis. IEA assumes that NPS includes policies and targets announced by government to achieve climate targets. IEA also produces two other scenarios – Sustainable Development Scenario (SDS) and Current Policies Scenario (CPS). The differences in fossil fuel price projections for 2025 under these three scenarios are not drastically different: for crude oil, the range is 84% (SDS) to 115% (CPS) relative to the NPS crude oil prices; for natural gas, the range is 96% (SDS) to 101% (CPS), while for steam coal, the range is 86% (SDS) to 105% (CPS). We consider that using NPS is valid because: (i) our scenarios cover a broad range of fossil fuel and carbon prices, (ii) we are more interested in relative impact of costs on prices rather than focusing on predictions of global future energy and climate policies as such.

In some European markets (e.g. Germany) coal power plants may use bituminous coal or lignite coal; the coal price in Table 1 is for bituminous coal[26]. For lignite, we assume a constant price (for all scenarios considered) of €16.5/tonne, which is an average price (and energy content[27]) of lignite in Germany (Booz & Co, 2012).

One can also see from Table 1 that the price differential between coal and gas widens in favour of coal, especially considering indigenously produced low cost lignite in Europe. Thus, it would require a relatively high carbon price to support phase-out of inefficient coal-fired generation as well as incentivising investments in low-carbon generation technologies. Indeed, the EU 2030 policy package stipulates a binding target – at least 40% reduction in CO_2 emissions by 2030 relative to the 1990 level. The EU relies on its emissions trading system (ETS) to deliver a carbon price consistent with these decarbonization objectives. The EC (2014) impact assessment suggests that ETS price in the reference scenario should be 53 €/tCO_2

[26] IEA assumes coal's energy content of 6000 kcal/kg (IEA, 2018)
[27] average energy content of lignite is 2305 kcal/kg (Booz & Co, 2012)

to achieve 40% reduction in CO_2 emissions. Our carbon price scenario of 25 €/tCO_2 is the ETS price as of end of December 2018.[28] But our 57 €/tCO_2 carbon price scenario (D) is equivalent to the price projected under the EU's reference scenario (with adjustment to inflation as 53 €/tCO_2 is likely the 2013/14 prices whereas our modelling uses 2017 prices).

3.2.3. VRE and further market interconnection

A key challenge with VRE is its volatility. Table 3 and Table 4 show correlations between different countries in Europe for wind and solar generation respectively. Thus, solar generation is relatively highly correlated across Europe, while high correlation of wind generation is more geographically concentrated. This gives rise to the question of whether higher interconnection between markets would reduce volatility in a world with increased renewables by exploiting potential negative co-variances in supply and demand conditions across a larger area.

The benefits of interconnection considering high share of VRE has been examined before. For example, Newbery et. al. (2016) looked at the benefit of coupling interconnectors to increase the efficiency of trading day-ahead, intra-day and balancing services across borders. Further, Green et al. (2016) found that if countries focused on renewables most suited to their own endowments and expanded international trade (i.e., having more electricity interconnection), system costs could reduce by 5% (€15bn per year).

Roques et. al. (2010) also found that correlation between wind output decreases with distance between two wind sources concluding that geographic diversification of wind farms can smooth out fluctuations in wind power generation and reduce the associated system balancing and reliability costs. Annan-Phan and Roques (2018) investigated how the effects of VRE is affected by market expansion across France and Germany. They found that added wind production lowers prices and increases volatility both locally and across borders. It was

[28] Note that the average EU ETS price in March 2019 is ca. 22 €/tCO_2 (see https://sandbag.org.uk/carbon-price-viewer/)

concluded however that increased interconnection would decrease price volatility in both countries as the benefit of a larger market outweighs local VRE volatility.

Thus, in order to investigate the performance of the European market under increase in VRE, we consider another scenario E, in which interconnection capacities are considered infinite.

Table 3: Correlation of wind generation (hourly resolution under normal weather condition).

	GB_T	**GB_D**	**SEM**	**AT**	**BE**	**DE**	**FR**	**IT**	**NL**	**PT**
GB_T	1									
GB_D	.968	1								
SEM	.941	.980	1							
AT	.779	.850	.860	1						
BE	.906	.966	.976	.848	1					
DE	.914	.967	.964	.892	.981	1				
FR	.915	.950	.968	.826	.969	.960	1			
IT	.754	.781	.800	.851	.783	.829	.846	1		
NL	.912	.960	.966	.793	.968	.958	.969	.759	1	
PT	.904	.831	.816	.641	.756	.750	.794	.646	.748	1

Note: all correlations are significant at the 0.01 level; "GB_T" means GB transmission level connected wind while GB_D - means GB Distribution level connected wind.
Source: own calculations based on data from Thomson Reuters Eikon Terminal

Table 4: Correlation of solar PV generation (hourly resolution under normal weather condition).

	GB	**FR**	**DE**	**NL**	**BE**	**IT**	**ES**	**CZ**	**RO**	**GR**
GB	1									
FR	.992	1								
DE	.964	.965	1							
NL	.988	.988	.981	1						
BE	.993	.986	.983	.994	1					
IT	.947	.970	.977	.965	.955	1				
ES	.969	.989	.937	.965	.956	.968	1			
CZ	.928	.940	.989	.959	.955	.980	.917	1		
RO	.971	.985	.980	.982	.973	.992	.979	.971	1	
GR	.882	.916	.946	.918	.900	.981	.924	.967	.959	1

Note: all correlations are significant at the 0.01 level
Source: own calculations based on data from Thomson Reuters Eikon Terminal

3.2.4. VRE and potential overcapacity in the generation

In equilibrium, an increase in VRE capacity could mean closure of some dispatchable plants, if the impact on their profitability is substantial. Below is a summary of our methodology to address this issue (for details see Supplementary material):

1. We first calculate operating profit[29] for each dispatchable plant (that has at least been dispatched once in 2025);
2. then, we rank all the plants according to their profitability with the most profitable one first to the least profitable last;
3. based on this profitability ranking, we then calculate cumulative capacity;
4. finally, we plot the residual demand curve for a peak demand hour, also considering operating reserve (spinning up) requirement for that hour and divest all plants that lie to the right of the residual demand curve (RD3), because they are unprofitable and do not contribute to system security[30] (see Figure 1).

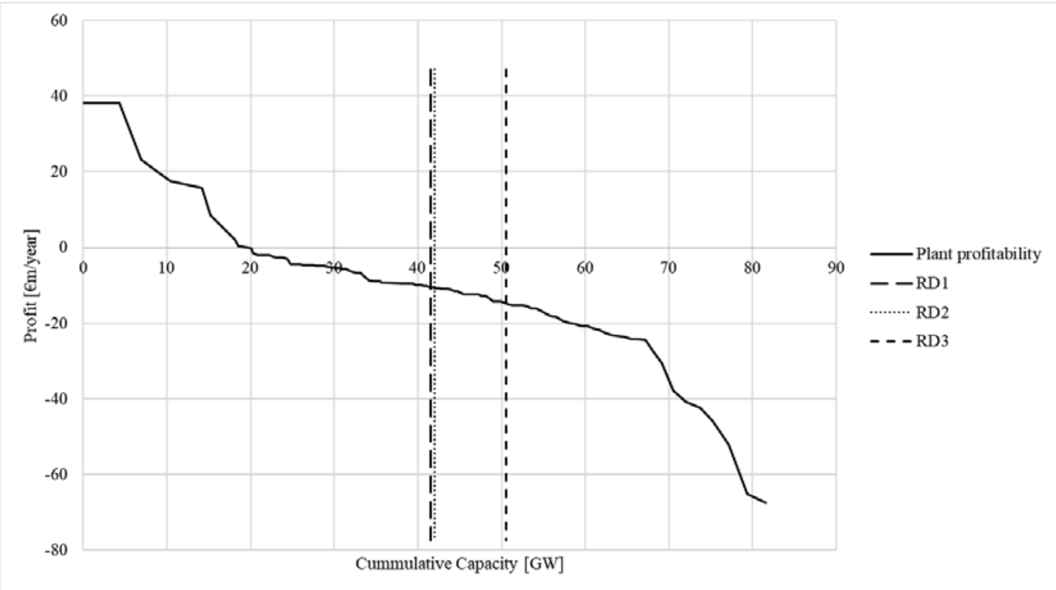

Figure 1: An example of profitability of conventional plants in Germany.
Note: "RD1-3" = residual demand for three peak demand hours.

[29] The profit of a plant is defined here as wholesale price times generation less fuel and carbon costs as well as variable and fixed OPEX.
[30] being understood here narrowly as meeting peak hour demand plus spinning up reserve requirement for that peak hour

4. Modelling Results

We first present the results (see Table 5) of the merit order effect, the role of generation cost and interconnection in driving power prices and hence long-term investment signals in a 2025 electricity system (Section 4.1). Since the model only looks at operational decisions, we have attempted to address the question of potential overcapacity as VRE capacity increases in Section 4.2. Lastly, in Section 4.3 we bring all our modelling results to further analyse if and under what conditions/scenarios our projected power prices serve as a long-term investment signal for both conventional and VRE generation taking Germany as an example[31].

Table 5: Modelled wholesale prices (€/MWh).

		BE	**DE**	**FR****	**IT**	**IT-N***	**GB**
Baseline	**Price**	**50.12**	**49.68**	**49.79**	**50.91**	**51.16**	**50.07**
	coefficient variation	11%	9%	12%	9%	9%	9%
Scenario A	**Price**	**49.02**	**48.23**	**48.37**	**49.77**	**50.23**	**49.11**
	coefficient variation	12%	11%	14%	11%	10%	10%
Scenario B	**Price**	**47.90**	**46.34**	**46.42**	**47.05**	**49.00**	**48.21**
	coefficient variation	13%	15%	18%	22%	13%	11%
Scenario C	**Price**	**49.95**	**47.97**	**48.28**	**50.70**	**52.91**	**50.40**
	coefficient variation	15%	17%	22%	22%	16%	14%
Scenario D	**Price**	**73.20**	**71.63**	**71.40**	**70.98**	**72.88**	**73.36**
	coefficient variation	6%	9%	14%	14%	7%	4%
Scenario E	**Price**	**47.45**	**47.40**	**47.43**	**47.44**	**47.47**	**47.46**
	coefficient variation	13%	13%	13%	13%	13%	12%
Scenario F	**Price**	**57.42**	**54.86**	**55.55**	**53.28**	**56.24**	**75.95**
	coefficient variation	23%	26%	26%	25%	22%	61%

*Note: prices (in 2017 Euro) are average for the entire year; * IT-N stands for Italy North region (a separate bidding zone in Italy) representing more than half of Italy's annual electricity demand; ** excludes three hours of very high prices due to insufficient operating reserve capacity under high VRE scenarios.*

[31] but our modelling results could be applied to other markets

4.1. “Merit order”, generation cost and interconnection under high VRE

The results (Table 5) show that the magnitude of the merit order effect is different for markets considered. For Belgium, Germany, France and Great Britain the effect of more VRE is rather modest – a reduction in the average annual wholesale price of between 1.9 - 4 €/MWh when wind and solar capacity are doubled (Scenario B vs Baseline).

However, the effect is relatively more pronounced for Italy: the merit order effect is ca. 5.7 €/MWh reduction in average annual price (Scenario B vs Baseline). This is because in some of IT’s bidding zones the share of VRE will be very high relative to respective demand in those regions increasing power price volatilities and curtailments (more “0” price hours in 2025). That said, the merit order effect for IT-N is comparable to those obtained for other markets. Thus, treating Italy as a single bidding zone may produce a comparable merit order effect to other markets (e.g. GB or BE), but that would ignore the effect of the increase in VRE on balancing cost (e.g. either via increased re-dispatch cost due to internal constraints, or else via increased transmission expansion cost).

As for the impact on price volatility, more VRE also means higher price volatility. Price volatility increases from 2 p.p. (Belgium and GB) to 22 p.p. (for Italy as a whole) implying higher financing costs and potentially higher fixed price contracts and hence retail prices.

Further, the impact of more VRE in France and Italy is more ‘pronounced’ in that every additional percentage point increase in VRE causes average power prices to decline by more than in countries such as Germany and Great Britain (Figure 3).

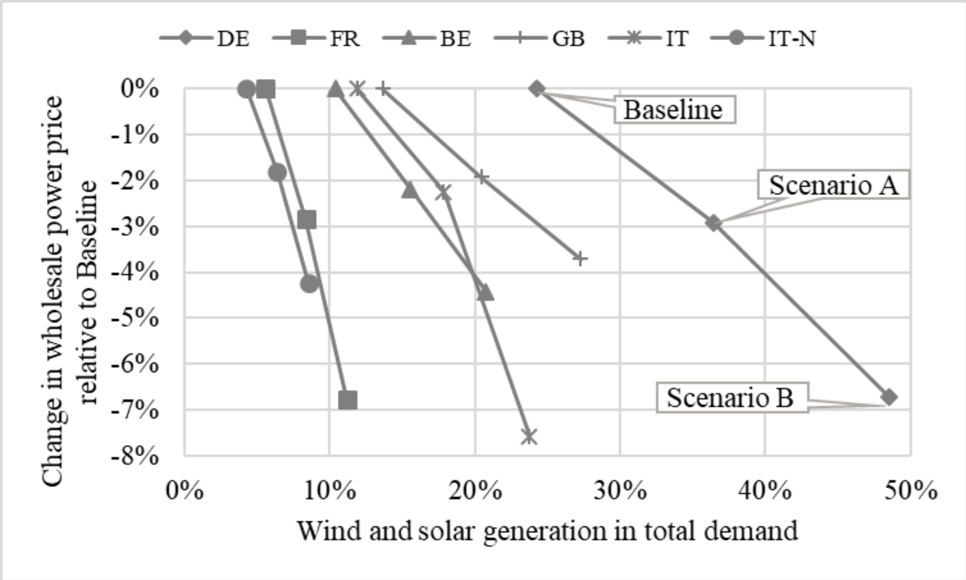

Figure 2: Relative impact of VRE on wholesale power prices.

The reason for this difference is due to the shape of conventional supply curves (see Figure 3). As VRE capacity is increased, the maximum and minimum residual demand shift to the left. Potential drops in wholesale price are hence contained within these shaded areas. In Germany, the supply curve is relatively flat compared to France, meaning that an increase in VRE (reducing residual demand) is likely to have a smaller effect on wholesale prices.

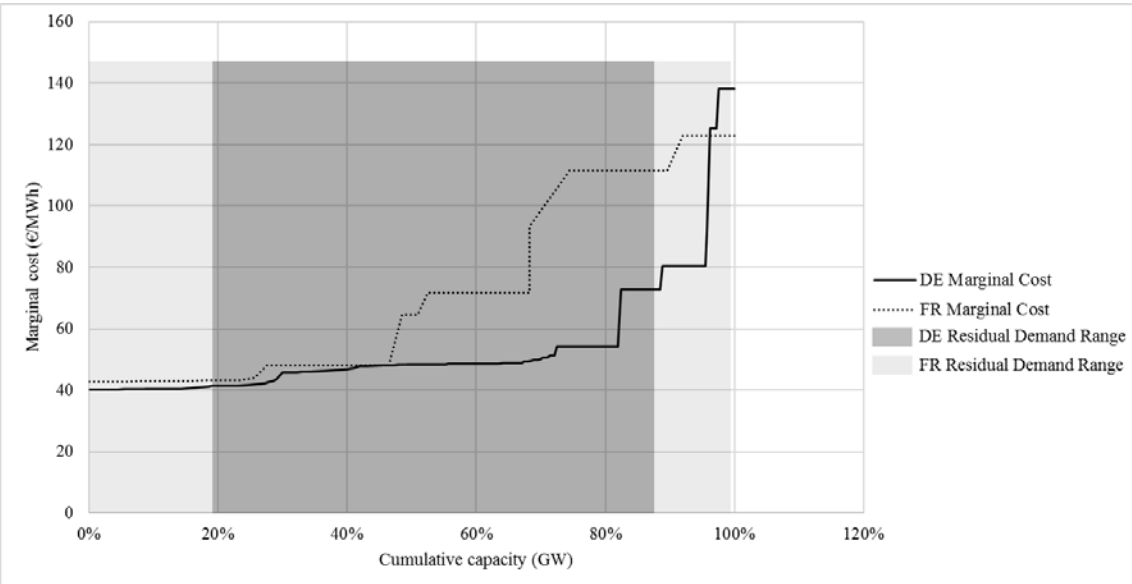

Figure 3: The supply and residual demand curves for Germany and France in the baseline scenario.

As for fossil fuel price effects, higher commodity prices (Scenario C) increase average annual prices by around 5% (or ca. 2.5 €/MWh) relative to prices in Scenario B. Italy seems to be an exception, again, as commodity prices have a higher impact on annual average prices there – the increase is ca. 8% (3.4 €/MWh) relative to Scenario B. The supply curve for Italy is very steep in the relevant region (where peak demand will likely intersect with the supply curve), thus the peaking plants could be inefficient gas and/or diesel generators.

It is worth noting that higher commodity prices cancel the merit order effect in Italy and GB, as annual prices in the high commodity price scenario are now back to the level of prices observed in the baseline scenario. Moreover, the Italy North bidding zone has an average annual price exceeding the average price under the baseline scenario (52.91 €/MWh vs 51.16 €/MWh) – fossil fuel price effect is more pronounced than the merit order effect of VRE in that bidding region.

In Germany, France and Belgium, average prices under high commodity prices are still below the average prices under the baseline, indicating a stronger merit order effect of VRE than the higher fossil fuel price effect there.

Further, high carbon price (57 €/tCO_2) dramatically increases annual average wholesale power prices in all markets. On average, across all our markets, power prices increase by 52% relative to annual average price in Scenario B, with Italy North seeing an increase of 49% and Germany of 55%. It is worth noting also that price volatility reduces under high carbon price scenario (D).

Our results underline the importance of developing further interconnection between European power markets to enable more VRE. More interconnections stabilise wholesale prices: there is complete convergence between key markets in Europe both in terms of price level but also the price variations are reduced significantly. Thus, further interconnections may help reduce risks in hence financing cost for both conventional and VRE technologies.

4.2. Impact of more VRE on "missing money" of conventional plants and system overcapacity

More VRE on the system depressess wholesale prices and affects running hours of dispatchable plants. Figure 4 shows total profit of conventional plants by fuel types in Germany under all scenarios.

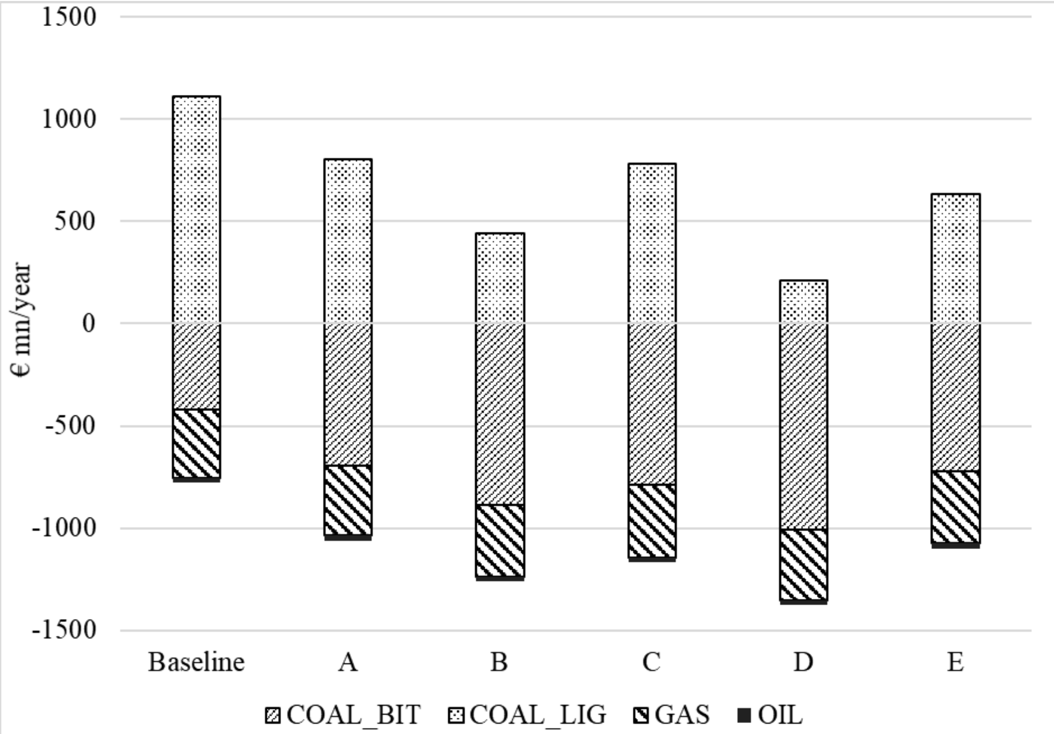

Figure 4: The size of the "Missing Money" problem under various modelled scenarios in Germany.

As we put more VRE on the system (Scenarios A and B), the size of the "missing money" problem increases – under Scenario B the total profit[32] of all existing conventional plants that we model for Germany is ca. -820 €mn/year. One can also see that higher fossil fuel prices (Scenario C) indeed help to imrpove overall profitability, but this still remain largely negative.

[32] Note that operating profit does not consider plant cycling costs such as start-up and shut down as we do not model star up and shut down decisions. Hence, plant profitability shown here might represent an upper bound of real profitability.

It is worth mentioning that coal lignite plants are profitable in all scenarios but with higher carbon cost the aggregate profitability of lignite plants reduced dramaticaly. Lastly, with unlimited interconnecion capacity, the economics of existing coventional plants improves, but rather marginally.

Removing all unprofitable plants (see Section 3.2.3) will impact the merit order and hence the equilibrium wholesale prices. Figure 5 shows the supply curve before and after decomissioning of all unprofitable plants: the most unprofitable plants are in the lower flat part of the original marginal cost curve. They are indeed in the region where peak demand occurs and hence, they also set prices. Removing these plants from the system will alter the cost curve – peak demand hours are now being met by higher cost plants and the peak hour prices could increase significantly compared to the system with overcapacity.

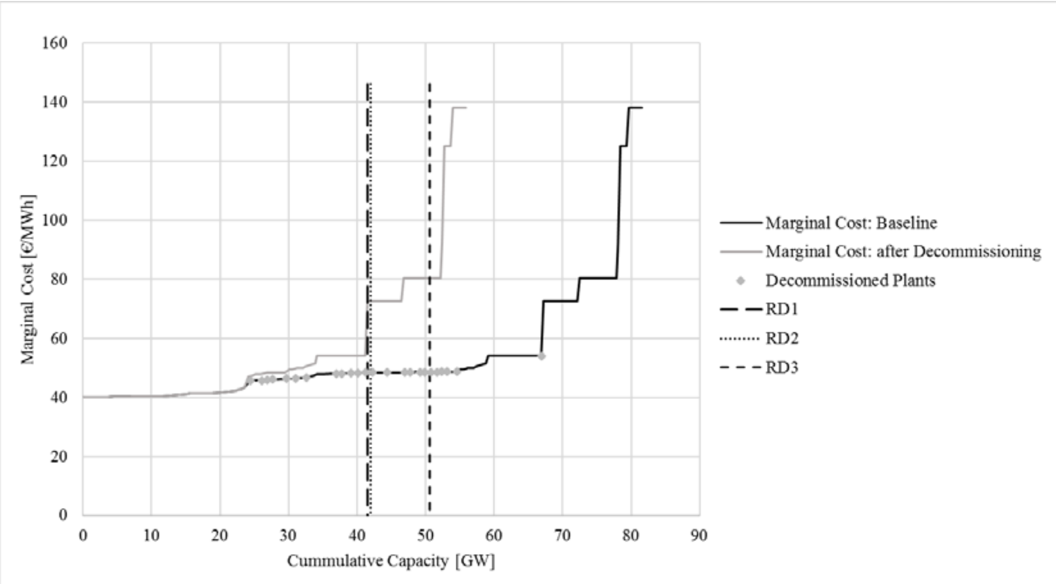

Figure 5: Marginal cost curves before and after decommissioning of all unprofitable plants in Germany (Scenario B).

Applying this analysis for all other markets for Scenario B results in 90.4 GW of conventional capacity being decommissioned, which is 43% of the total capacity of conventional power plants that we model (Table 6).[33]

Table 6: Installed capacity (MW) by technology before (Scenario B) and after (Scenario F) decommissioning.

	DE		FR		GB	
Technology	**B**	**F**	**B**	**F**	**B**	**F**
Coal	58783	33843	5798	500	20223	759
Gas CCGT	8080	7370	4690	0	21604	5888
Gas GT	4309	4309	3274	2389	2475	2475
Gas ST	5269	5269	1036	0	1623	303
Gas CT	1419	1419	634	0	983	983
Oil GT	1820	1820	1649	1649	1237	1237
Oil ST	1193	1193	4821	4821	464	464
Oil CT	447	447	705	705	856	856
Oil CC	229	229	0	0	0	0
Total	**81549**	**55899**	**22607**	**10064**	**49465**	**12965**

Note: GT – gas turbine; ST – steam turbine; CT – combustion turbine; in addition, NL and SEM decommission one 2196 MW bituminous coal plant and one 638 MW CCGT plant respectively.

Thus, we remove those decommissioned plants and we re-ran our model for Scenario B (which we called Scenario F). As expected, removing unprofitable plants from the power system will shift respective merit orders and hence power prices – average prices are now amongst the highest in all scenarios considered (exception being very high fossil fuel and carbon price, Scenario D). One can also see that with increased wholesale power prices due to much tighter capacity margins[34], price volatilities have also increased substantially. In fact, volatilities are the highest in all our scenarios.

[33] Note that we only model coal, gas and oil-fired power generation while other technologies and their 2015 actual generation are assumed to be exogenous and constant in the model.

[34] we have divested all unprofitable plants such that the remaining capacity is just enough to cover peak demand and the required operating reserve margin

4.3. The economics of investing in conventional generation and VRE

The power prices arising from all considered scenarios seem to no longer serve as a good long-run investment signal to bring new CCGT capacity on line. Of all scenarios analysed, it is only under relatively high fossil fuel and carbon prices (Scenario D) or when there is no overcapacity (Scenario F) there are improvements in operations of existing CCGTs as their running hours are relatively high compared to other scenarios and compared to the actual 2015-2018 capacity factors (Table 7). Under all other scenarios, neither investment in new CCGTs nor the operation of existing ones seems viable via participation in the energy market alone: profit considering CAPEX is negative. Apart from Scenario F, the inframarginal rent is almost zero implying that CCGTs are setting prices most of the time due to load duration curve being less peaky as VRE production increases; only in Scenario F, where we divest unprofitable plants, peaking plants are less efficient gas turbines (GTs) and hence CCGTs earn inframarginal rent. Our modelling does not include strategic behaviour when CCGTs (or GTs) can set prices above SRMC to recover their ongoing fixed cost.

Table 7: Economics of investing in a 450 MW CCGT plant in Germany: actual market data for 2015-18 and for 2025 under all simulated scenarios.

	Baseline	Scenarios						Actual market data			
		A	**B**	**C**	**D**	**E**	**F**	**2015**	**2016**	**2017**	**2018***
MAX power prices	71.7	62.0	60.1	63.1	91.4	72.7	244.0	99.8	105.0	163.5	98.2
Average power prices	44.2	48.2	46.3	48.0	71.6	47.4	53.1	31.8	29.0	34.2	41.7
MIN power prices	34.4	36.7	-89.6	-89.6	-63.4	34.5	-89.6	-79.9	-130.1	-83.1	-76.0
Instances of negative prices	0	0	6	6	6	0	6	98	98	149	110
Natural gas price**	23.0	23.0	23.0	28.0	28.0	23.9	23.0	21.1	15.7	17.3	25.3
Carbon price***	24.7	24.7	24.7	24.7	57.5	24.7	24.7	7.5	5.0	5.5	20.5
Short-run marginal cost of a CCGT	54.1	54.1	54.1	63.1	73.8	55.7	54.1	44.9	34.2	37.3	56.8
N hours prices ≥ SRMC	13	379	179	5	3235	1	3172	1276	701	1404	2859
Implied capacity factor	**0%**	**4%**	**2%**	**0%**	**37%**	**0%**	**36%**	**15%**	**8%**	**16%**	**33%**

Inframarginal rent	0.0	0.0	0.0	0.0	1.1	0.0	14.2	4.0	3.0	9.0	14.0
Profit	**-40.1**	**-40.1**	**-40.1**	**-40.1**	**-39.0**	**-40.1**	**-25.9**	**-45.2**	**-46.0**	**-39.7**	**-35.2**

*Note: hourly power prices in €/MWh-e, gas prices in €/MWh-th, Carbon prices in €/tCO_2, Short-run marginal cost of a CCGT in €/MWh-e, inframarginal rent and profit in € mn/year; * data until Sept-2018; ** for 2015-2018 this is annual average TTF gas prices; *** for 2015-2018 this is annual average EU ETS prices apart from 2018 where the price is average Sept-2018 EU ETS price; power prices for Scenarios A-F are in 2017 Euro.*

Note, that when we remove all unprofitable plants (Scenario F) then the wholesale electricity prices are very high, making some of the removed plants profitable, had they stayed in the market. Indeed, some existing CCGTs might be profitable as their running hours and profitability are improved under Scenario F (Table 7). That is, the 'optimal' marginal cost (MC) curve for Scenario F should be somewhere between the two MC curves shown in Figure 5. If some plants could be profitable staying in the market, then we will have lower wholesale electricity prices than the prices under Scenario F. This will reinforce our conclusion that with further penetration of VRE wholesale prices may no longer serve as a long-run investment signal for conventional generating capacity (CCGT, for example) or indeed serve to retain a large fraction of the existing dispatchable capacity.

As for VRE technologies, it is important to distinguish between wholesale power prices that a dispatchable plant can get and the revenues that a "subsidy-free" wind and solar generator could get, solely based on wholesale prices. Within a day, wind and solar capacity factors and price profiles will have different effects on captured prices for onshore, offshore and solar PV, due to their inherently different resource base. Solar generation seems to peak at a time when power prices could also peak; thereby creating the so-called "cannibalisation" effect (more solar PV means less revenue due to the depressing price effect at peak times when solar PV generates electricity). Wind resources and especially offshore wind is more reliable in this sense – within a day, capacity factors are rather stable. There may also be a strong seasonal effect as European power prices (on average) are lower in the summer than in the winter, thus favouring wind and penalising solar relative to conventional plants.[35]

Table 8 shows “captured” average prices for three VRE generation technologies – onshore wind, offshore wind and solar PV – taking Germany and Italy as an example. Captured prices by a VRE technology are its total revenue over the course of the year (2025), from wholesale energy only prices divided by total generation over the same period. Thus, this captured price depends on hourly generation profiles and achieved capacity factors for onshore, offshore wind and solar PV.

Table 8: "Captured" prices by wind and solar in Germany and Italy (€/MWh).

	DE				**IT**		
	Onshore wind	Offshore wind	Solar PV	Average wholesale price	Onshore wind	Solar PV	Average wholesale price
Baseline	44.17	44.67	43.86	49.68	45.24	45.29	50.68
Scenario A	47.87	48.86	46.39	48.23	48.96	46.76	49.32
Scenario B	45.48	47.39	42.59	46.34	43.19	33.43	45.01
Scenario C	46.95	49.32	43.66	47.97	46.57	36.50	48.40
Scenario D	70.76	72.67	67.64	71.63	67.13	57.39	69.00
Scenario E	46.91	47.19	44.35	47.40	47.31	44.72	47.44

Source: calculations based on our modelling results; prices are in 2017 Euro

The results suggest that offshore wind can consistently achieve prices above the average wholesale prices (but this is rather marginal). Onshore wind captured prices are quite close to the actual annual average prices whereas solar, as one would expect, achieves lower prices than the actual wholesale prices. What is striking, but perhaps not surprising, is that more wind and solar capacity means lower captured prices for solar PV: doubling of wind and solar capacity (Scenario B) means a drop of ca. 1.3 €/MWh from average captured prices by solar PV, whereas the captured power prices by wind (onshore and offshore) increased. Similarly, an

[35] See DG ENERGY (2018).

increase in commodity prices (Scenario C and D) helps wind generation, especially offshore, more than it helps solar PV.

Finally, we look at the potential economics of "subsidy-free" wind and solar PV investment, taking Germany as an example. Figure 7 plots the required reduction in CAPEX for all three VRE technologies assuming a 10% return on investment (ROI) and a 20-year payback period. For onshore wind to be "subsidy-free", we would expect the CAPEX to fall by 50-70% from the existing (IEA, 2017) level by 2025, depending on the scenarios analysed. For offshore, by 35-60%; for solar PV, by 56%-72%. For example, a high fossil fuel and carbon price market condition (Scenario D) CAPEX for offshore wind would just need to go down by 35% for the technology to breakeven, using energy-only wholesale power prices alone. Recent offshore wind auction results suggest that this is possible, but challenging.

To put this required reduction in CAPEX in a historical context: according to IRENA (2018), onshore wind costs dropped by approximately 25%, or 561,000 €/MW between 2008 and 2017. Offshore wind costs have remained quite volatile, and peaked around 2016; while solar PV costs in Europe have dropped by 83% from 2010-2017, although this is not linear. There has been a linear drop of about 168,000 €/MW between 2015 and 2017.

We should point out that the presented calculations (Figure 7) are rather simplistic in the sense that we have not taken into account such important aspects as technical degradation of wind turbines and fixed and variable OPEX, which could be rather substantial, at least for wind technologies. This means that our estimation of breakeven CAPEX reduction is a lower bound and, for example, considering fixed running OPEX would further deteriorate the "subsidy-free" economics of VRE investments.

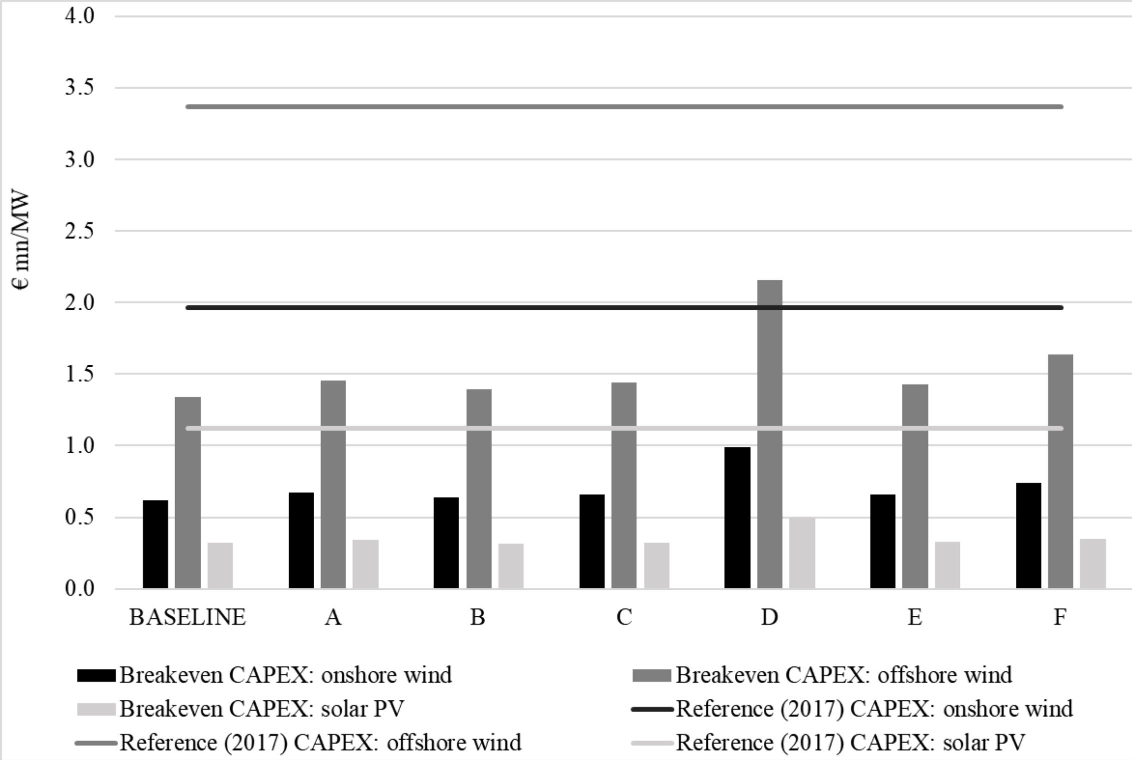

Figure 6: Reduction in CAPEX needed to breakeven for "subsidy-free" VRE under all scenarios in Germany; reference CAPEX are taken from (IEA, 2017); breakeven CAPEX is based on our modelling results for respective scenarios.

5. Conclusions

All in all, with our modelling, we quantified: (1) the merit order effect of VRE, (2) the impact of fossil fuel and carbon prices on wholesale power prices, (3) the role of further interconnection between European market zones under high VRE production, and (4) the potential problem of overcapacity when VRE capacity is significantly increased. It seems that carbon prices and overcapacity (or tighter supply/demand market condition) have the most influence on power prices. By contrast, the other three factors (the merit order effect, fossil fuel prices and improved interconnections) have relatively modest impacts on average power prices.

We found that wholesale power prices may no longer serve as a long-run investment signal for conventional generating capacity (CCGT, for example) in conditions where conventional generation will not be required to produce base-load electricity but will be required for system adequacy. Even at a very high level of commodity prices, our results show no clear prospects for new capacity addition. However, there could be an improvement in profitability of existing CCGTs under a high fossil fuel price and high carbon price scenario. With further penetration of VRE, our results show the negative impact on profitability of CCGTs, exacerbating their missing money problem further.

If wind and solar are to be self-financing by 2025 under the current European electricity market design, they would need to be operating in circumstances which combine much lower capital cost and/or much higher fossil fuel and carbon prices. In the absence of these favourable conditions for VRE, long term subsidy mechanisms in the form of auctions would need to continue in order to meet European renewable electricity targets.

However, we do find that wind, particularly offshore, is likely to suffer less from the cannibalisation of its market than solar. This is because wind output is better able to capture the average annual wholesale price of electricity.

A move away from feed-in-tariffs for wind and solar to market prices will also expose generators to increased price volatility, which would raise their investors' target rates of return. The question of the need for a fundamental market redesign to let the market guide generation investments in both renewables and conventional generation investment would seem to remain.

Our modelling results also show the importance of further interconnection between markets in Europe – which may be very expensive/difficult to achieve – as this allows near complete convergence of power prices (both baseload and peak prices) and more importantly stabilises these prices (reducing volatility) and hence reduces potentially higher market risks due to more VRE. However, increased interconnection does not change the picture we paint on the '*financeability*' of subsidy-free VRE and fossil fuel investments via energy-only markets by 2025.

If there was to be sufficient closures of fossil fuel power plants, in response to low profitability, that would make a difference to market prices but would put more pressure on ancillary services markets to support adequate amounts of generation for system stability. Many of the currently existing fossil fuel plants would still be required to provide adequacy and other services to the system in the presence of much higher penetration of VRE. By contrast, a significant rise in carbon prices would improve the ability of a low carbon electricity system to be self-financing. Raising carbon prices thus remains a good policy for promoting unsubsidised low carbon generation within the current market design.

Thus, interventions to create capacity markets or sharpen ancillary services markets payments can help address the problems of the current market design by creating the incentives for the optimal addition and retention of power plants to the system. However, these mechanisms are problematic to design, and investments supported by them will likely have higher costs of capital, given the volatile and difficult to predict income streams that they give rise to. This is because ancillary services markets are subject to fundamentally different governance arrangements relative to energy markets, making them expensive to rely on as a source of long-run funding for generation investment.

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