IMPACT OF A OF VARIABLE RES IN THE EUROPEAN POWER SYSTEM FOR 2050 – A TECHNICAL AND ECONOMIC ANALYSIS AS PART OF EU-SYSFLEX PROJECT

Bono Caroline, EDF R&D, 7 boulevard Gaspard Monge, 91120 Palaiseau, France, +33 1 78 19 40 15, caroline.bono@edf.fr

Cany Camille, EDF R&D, EDF R&D, 7 boulevard Gaspard Monge, 91120 Palaiseau, France, +33 1 78 19 39 42, camille.cany@edf.fr

Debregeas Anne, EDF R&D, 7 boulevard Gaspard Monge, 91120 Palaiseau, France, +33 1 78 19 39 36, anne.debregeas@edf.fr

Saguan Marcelo, EDF R&D, 7 boulevard Gaspard Monge, 91120 Palaiseau, France , +33 1 78 19 33 15, marcelo.saguan@edf.fr

1 INTRODUCTION

The *European Green Deal* has been launched in Europe to provide a holistic framework in the fight against climate change. It aims at decarbonizing all sectors of the economy to meet carbon neutrality by 2050 in an sustainable manner (European commission, 2019). Europe is thus undertaking its energy transition which will, for a significant part, be directed towards the electricity and heat sector which accounts for the first contribution to EU's greenhouse gas emissions (Dussud et al., 2016). This transition will materialise by decarbonising the power sector (from around 300 gCO2/kWh today (European Environment Agency, 2019) to around 50 gCO2/kWh by 2050) and enhancing the use in mobility and smart building. In 2019, the share of renewable energy sources (RES) reached 18% of final energy consumption in the EU (European Union) in 2018, on a path to the 2020 target of 20% (Eurostat, 2020), and to the 2030 target of 32% (European Commission, 2017).

This paper presents results from EU-SysFlex (*Pan-**Eu**ropean **Sys**tem with an efficient coordinated use of **Flex**ibilities for the integration of a large share of RES"*), a EU-funded H2020 project from the Low Carbon Europe call LCE-04 (2017-2021). The goal of EU-SysFlex is to identify issues and solutions associated with integrating large-scale renewable energy into the European power system (i.e more than 50% RES) as well as provide practical assistance to power system operators across Europe. This should ultimately lead to identification of a long-term roadmap to facilitate the large-scale integration of renewable energy across Europe, in the most dynamic, resilient, stable manner and cost-effective for citizens ("EU-SysFlex," 2020). This study by EDF R&D is part of work package 2, which is a prospective work package through simulations, and has three main objectives. At first, the objective of this study is to provide a quantitative technical and economic assessment of the impacts of different shares of variable renewable energy (VRE) (wind and solar PV) in the European power system power system composition and operation at horizon 2030 and 2050. Secondly, a cost-benefit analysis is performed on VRE to evaluate the gap between costs and revenues on the energy market. Thirdly it focuses on CO_2 emissions, trying to give an estimate of reduction driven by the introduction of VRE.

To meet European RES targets, VRE will be the main driver since hydro potential has limited opportunities of development. A high volume of VRE poses major challenges to the power system. VRE generation cannot be dispatched or well-ahead forecasted and are prioritized in the merit order due to low variable costs. Furthermore, it is not synchronous (OECD/IEA, 2014). Therefore, their contribution to system reliability is challenging, and is looked at separately in EU-SysFlex.

The issue of VRE integration into power systems is nourishing an extensive literature. One part of the literature deals with the evaluation of the impacts of VRE on residual power systems[1] in the short term (the residual power system has not been adapted) and in the long term (the residual power system has been adapted) (see for example (Burtin and Silva, 2015), (Fürstenwerth et al., 2015), (Keppler and Cometto, 2012), (Hand et al., 2012), (OECD/IEA, 2014), (OECD/NEA, 2019)). Another part is focusing on ways of adaptation to alleviate their integration cost into power systems. These can be operational measures to provide flexibility

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[1] Power production net of wind and solar PV generation

or market designs and regulations (Green and Léautier, 2015) (OECD/IEA, 2014) (OECD/NEA, 2019). Operational flexible options refer to dispatchable power plants, grid reinforcement, storage, demand-side management or coupling between energy sectors (for exemple, one can refer to (Brouwer et al., 2015), (Cany et al., 2017), (Finn et al., 2012), (Hirth, 2013a), (OECD/IEA, 2014), (Burtin and Silva, 2015), (Mikkola and Lund, 2016), (OECD/IEA, 2018a)).

Additional integration costs induced by VRE are summarized into the concept of “system LCOE” (Ueckerdt et al., 2013) which reconciles the bottom-up perspective (standard LCOE) and the top-down perspective focusing on market value of technologies. As defined by Joskow, (2011), the market value of VRE is the revenue that generators can earn on markets, without income from subsidies. Under the assumption of pure and perfect competition, VRE market values can be evaluated thanks to simulated projected market prices. This approach was undertaken by a number of authors in the literature for different regions or countries : North-west Europe (Hirth, 2013b), (Hirth, 2015), California (Mills and Wiser, 2012), Germany (Nicolosi, 2011) or for Continental Europe (Burtin and Silva, 2015). All authors show that the market value of VRE decreases with their penetration level (the so-called “self-cannibalization effect”). According to Green and Léautier, (2015), this effect could yield an important need for subsidies if no changes were to be undertaken on market designs and regulation. Suna and Resch, (2016) examines the dynamic of subsidies needed for VRE in the EU 28 up to 2050. It shows that subsidies would decline from 2025 due to a reduction of investment costs before leveling off, thus reflecting their market value loss.

The integration costs of VRE into power systems can’t however be generalized from one system to another. It depends on the characteristic of the power mix existing before the integration of VRE (i.e as well as its evolution as a consequence of regulation), its geographic size and its inherent level of flexibility, as well as the characteristic of the VRE fleet added to the system (penetration level and type of technologies) (Huber et al., 2014).

In this respect, this work encompasses a detailed and realistic modeling of the European power mix by 2050, based on the consensual European Commission's EU Reference Scenario 2016 (European commission, 2016). In the continuity of the work that was carried out internally by (Burtin and Silva, 2015), the modeling approach is based on a rigorous representation of offshore, onshore wind, solar PV and demand profiles, spread out over 20 interconnected countries and 55 historical weather conditions. This extensive modelling, which is seldom seen in literature, allows to capture their spatial and temporal effects, along with uncertainties, to appropriately perform expansion planning and optimize the hourly dispatch of the European-wide generation of thermal, nuclear and hydro plants and reserves.

The proposed methodology is explained in section 2. It includes scenario design, hypothesis and modeling approach. Results are then presented in section 3. First, we examine and discuss the impact of VRE on the European power system composition and operation with a focus on gas power plants. We then evaluate the economics of VRE for different penetration levels through the revenues earned on the energy market as well as needs for subsidies. Finally, we evaluate to what extent integrating different shares of VRE into the power system allows for a reduction of CO_2 emissions.

2 METHODOLOGY AND DATA

The methodology developed for this study involves several steps: building up sensitivity scenarios and modelling the prospective European power system with different exogenous shares of VRE. Hypothesis are presented in section 2.1.2.

2.1 SCENARIO DESIGN

2.1.1 Baseline scenarios and sensitivities

Two baseline scenarios are constructed as part as the Eu-SysFlex project for 2030 and 2050.

The two scenarios were taken from the publicly available EU-Reference scenario 2016. EU-Reference scenario 2016 provides a trajectory for the European power system in 5-year increment until 2050 detailed by country based on the vision of national experts across all EU countries (European commission, 2016). The 2030 scenario developed for EU-SysFlex, called *Energy Transition*, has a share of 23% of VRE (52% of RES in total demand) while the 2050 scenario, called *Renewable Ambition*, has a share of 34% of VRE (66% of RES in total demand) (Nolan et al., 2018).

The EU-Reference scenario 2016 serves as a reference point to evaluate new public policy proposals. It is based on the European policy framework as of December 2014, and meets the 2020 renewable energy targets set by the European Commission. In addition, it assumes the successful implementation of the EU ETS and meet the CO2 reduction targets for the projected years. It is the result of a series of interlinked models based on PRIMES energy system model, widely used and established in studies linked to the transition of the EU energy system (E3M-Lab and National Technical University of Athens, 2013). It sets out generation, demand, storage and interconnection portfolios which are used in the development of EU-SysFlex scenarios (European commission, 2016).

The RES projections from the EU Reference Scenarios 2016, taken as the basis for the two core scenarios, integrate the projection trajectories of Member States of the RES shares by sector as expressed in the respective National Renewable Energy Action Plans (NREAPs). The framework integrates known direct RES feed-in tariffs and other RES enabling policies, such as priority access, grid development and streamlined authorization procedures. The binding targets on RES for 2020 (20% share of gross final energy consumption from RES by 2020 and 10% of the transport sectors gross final energy consumption from RES by 2020) are assumed to be achieved. Beyond 2020, the RES development continues despite the fact that direct incentives are phased out because some RES technologies are becoming economically competitive; the carbon price is increasing through the ETS scheme; and the extension of the grid and the improvement in market balancing allows for higher RES penetration.

One of the main differences between *Energy Transition* (2030) and *Renewable Ambition* (2050) is the decommissioning of a large share of coal-fired plants at the European level. The remaining coal-fired plants are converted to carbon capture and storage (CCS) technologies. Combined heat and power (CHP) units from gas, coal and biomass generation represent 11% of total European production for 2030 and 12% for 2050. The share of VRE increases from 23% to 34% between 2030 and 2050 in the total annual production, while low-carbon production increases from 67% to 74%. While these figures are the Europe-wide average percentages modelled as part of the EU-SysFlex scenarios, their proportion is different from one country to the other. Table 1 provides a summary of the carbon-free generation and VRE generation for each of the European country considered in the EU-SysFlex scenarios.

	Energy Transition (2030)				Renewable Ambition (2050)			
Country	**% carbon - free**	**% VRE**	**VRE of which**		**% carbon - free**	**% VRE**	**VRE**	
			% Wind	**% Solar**			**% Wind**	**% Solar**
EU-28	**65**	**24**	**72**	**28**	**73**	**35**	**70**	**30**
AT	78	17	75	25	81	23	75	25
BE	40	32	83	17	41	33	84	16
BG	57	18	63	37	70	23	57	43
HR	64	16	56	44	73	31	46	54
CH	94	13	26	74	100	18	27	73
CY	29	26	32	68	41	38	33	67
CZ	43	4	28	72	70	5	38	62
DK	81	58	96	4	80	58	97	3
EE	21	11	100	0	67	42	100	0
FI	77	8	100	0	91	8	100	0
FR	98	20	67	33	94	38	69	31
DE	44	31	68	32	60	43	70	30
GR	57	46	63	37	78	66	58	42
HU	90	2	90	10	77	9	85	15
IE	42	36	100	0	59	49	100	0
IT	46	21	49	51	65	36	41	59
LV	61	9	100	0	70	19	100	0
LT	81	6	93	7	82	14	97	3
LU	22	14	81	19	18	13	87	13
MT	13	13	-	100	22	20	13	87
NL	40	24	85	15	43	29	88	12
NO	97	10	100	-	99	12	96	4
PL	20	11	100	0	57	18	99	1
PT	87	41	79	21	96	52	71	29
RO	76	21	83	17	75	25	74	26
SK	94	2	4	96	84	4	23	77
SI	67	6	29	71	87	6	31	69
ES	77	42	60	40	86	71	54	46
SE	93	13	100	0	94	14	100	0
UK	71	26	91	9	70	28	93	7

Table 1 : Characteristics of the EU-SysFlex scenarios for the 28 member states, Switzerland and Norway, for carbon-free electricity and VRE energy as part of the electricity production.

The geographical perimeter of the study performed in this paper includes 20 countries: Austria, Belgium, The Czech Republic, Denmark, Finland, France, Germany, Hungary, Ireland, Italy, Luxembourg, The Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, and the United Kingdom.

A sensitivity analysis is performed on VRE shares for the 2050 reference scenario (taken as a starting point) to investigate the impact of increasing shares of VRE in the European power system. We economically adapt the power mix by adjusting combined cycle gas turbines (CCGT) and open cycle gas turbine (OCGT) power plants from the *Renewable Ambition* scenario, given exogenous shares of VRE: 23%, 34%, 45% and 55% of total production, so as to meet a reliability target level of 3 hours per year for each country[2,3]. The 23% variant corresponds to the share of *Energy Transition* and the 34% share corresponds to the one from *Renewable Ambition* scenario. With the exception of OCGT and CCGT installed capacities and VRE penetration level, the sensitivities use the same hypotheses as *Renewable Ambition* (*i.e.* demand, CO2 price, commodity prices). For each sensitivity, VRE installed capacities were increased uniformly by country for the entire European system. As shown in Table 2, the 55% variant accounts for 86% of carbon free generation and 73% RES generation whereas the 23% variant has a 65% carbon free generation.

	Sensitivities on VRE penetration			
	23%	**34% (reference)**	**45%**	**55%**
% VRE	23%	34%	42%	49%
PV	*7%*	*10.5%*	*13%*	*15%*
Wind	*16%*	*23.5%*	*29%*	*34%*
% RES	48%	58%	66%	73%
% carbon free	65%	75%	81%	86%

Table 2 : Shares of VRE, RES and carbon free generation out of total annual electricity production in each sensitivity scenario

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[2] The installed capacity of other free carbon technologies (e.g., hydro, nuclear, CCS) are kept constant for all sensitivity scenarios.

[3] Based on supply and demand equilibrium, other risks linked to system stability (inertia) are not included in this study. This topic is part of Task 2.4 of EU SysFlex project.

2.1.2 Common hypothesis

To build the scenarios, some data was not available in the EU Reference Scenario 2016: for example data regarding Switzerland and Norway. We used additional publicly available data, mainly from the European Network of Transmission System Operators for Electricity (ENTSO-E) data set for missing data. For Switzerland and Norway, data was taken from the scenario *Sustainable transition* from the Ten Year National Development Plan (TYNDP) in which the existing network infrastructure is used at its maximum.

Demand profiles integrate Electric Vehicles (EV) projected consumption profiles. To do so, EV projections per countries were taken from the TYNDP *Distributed Generation* scenario 2030 and 2040 extrapolated to 2050 (i.e a share of 46% of EV in the European vehicle fleet) (ENTSO-E, 2018). Mean annual consumption of an EV was taken at 0.17 kWh/km with a mean number of 12750 km/year per vehicles (2.3 MWh par vehicle per year) (RTE, 2017). As proposed by RTE (RTE, 2017), three different charging strategies were considered: natural, on price signal and optimized with a Battery Management System (BMS). This strategies are weighted to 40%, 30% and 30% respectively, and EV power profiles are integrated to the demand curve. The corresponding projected annual profiles are exposed on Figure 1. See Table 3 for detailed assumptions on the number of EV.

	2050
AT	1.81
BE	1.28
CH	4.65
CZ	2.29
DE	19.03
DK	1.10
ES	8.54
FI	0.92
FR	17.50
HU	0.50
IE	0.79
IT	25.17
NL	2.14
NO	2.92
PL	8.04
PT	1.86
SK	0.79
SE	1.72
UK	12.57
Total Europe	113.62

Table 3 : Number of EV (in Million) by country in the four sensitivity scenarios, adapted from (ENTSO-E, 2018)

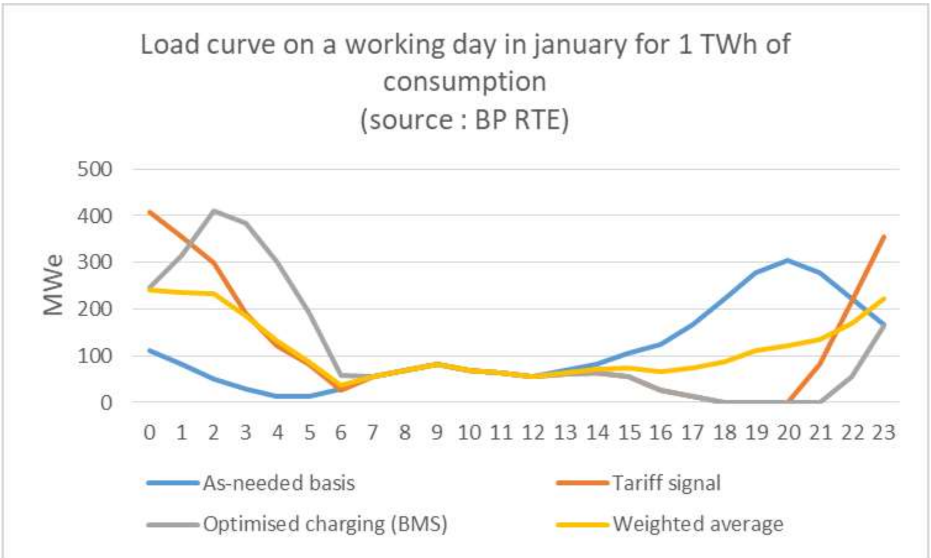

Figure 1 : Different load curve profiles for electric vehicles (RTE, 2017)

Techno-economic data for thermal power plants on variable costs, efficiency rate, maintenance rates, forced outage rates and CO_2 emission rates was taken from (ENTSO-E, 2018).

Gas, coal and CO_2 prices were taken from the EU reference scenario in 2050 (European commission, 2016), with a conversion rate of $/€1.30. For uranium and lignite, prices were taken from (ENTSO-E, 2018) data set, whose prices are kept constant over the different scenarios and extracted from (OECD/IEA, 2016). See Table 4 for detailed assumptions.

CO_2 (Euro/tonne)	90
Coal (Euro/MWh_{th})	11.8
Gas (Euro/MWh_{th})	35.4
Lignite (Euro/MWh_{th})	4.0
Uranium (Euro/MWh_{th})	1.7

Table 4: Commodity and CO2 prices in the 2050 sensitivity scenarios

When it comes to Net Transfer Capacities (NTC), hypothesis come from e-Highway scenarios (e-Highway 2050, 2015), and more specifically from the scenario *Big&Market* which is a median scenario, close to EU Reference scenario in terms of demand and RES development. However, since e-Highway scenarios are optimistic for grid development, we retain the 2040 e-Highway *Big&Market scenario* for the interconnections at horizon 2050. Refer to annex for detailed figures on NTC.

The costs are computed using O&M and investment costs assumptions coming from (OECD/IEA, 2018b) and (RTE, 2017). They are displayed on Table 5. Cost hypotheses for VRE come from the WEO 2018 New Policy Scenario at horizon 2040 and take into account updated prospective costs for RES investment and maintenance costs.

	Overnight cost (€/kW)	Lifetime (years)	Discount rate	Investment annuity (€/kW.an)	O&M cost (€/kW.y)
CCGT	830.0	30	7%	66.9	36.0
OCGT	450.0	30	7%	36.3	26.0
Offshore wind	2509.8	30	7%	202.3	65.3
Onshore wind	1513.0	30	7%	121.9	39.2
PV large scale	676.4	25	7%	58.0	16.02
PV buildings	890	25	7%	76.4	19.58

Table 5: Costs assumptions for power plants ((OECD/IEA, 2019),(RTE, 2017))

2.2 Modeling the European power system thanks to Continental, a state-of-the-Art Unit Commitment Model

The European power system is modeled with a state-of-the-art unit commitment model, Continental model, developed by EDF R&D. Continental model was also used for an extensive publicly available study on integrating 60% Renewable Energy into the European System (Burtin and Silva, 2015). Continental model optimizes hourly the dispatch of power plants available in the European power system (exogenous data) to address power consumption while minimizing total cost given a range of economic and technical constraints. The power generation mix available for dispatch is adjusted as a first step in the most cost-effective way ensuring that a reliability target level is met per country. In this study, we chose a criteria of maximum 3 hours of loss of load.

The uncertainty coming from weather patterns for VRE generation and the associated demand is modeled through time series in Continental model. Having enough representative weather patterns is essential to get an accurate dimensioning of the European power system. For each country, 55 years of historical data for consumption profiles as well as wind speeds, temperature and solar radiation are used to compute the VRE generation and their installed capacity defined in the scenarios for EU-Sysflex defined in part 2.1.1. It is to be noted that the temporal correlation between VRE and demand is kept, which highly influences needs for flexibility.

Installed power plants are defined for each country. Thermal power plants (coal-fired, gas-fired, oil-fired, nuclear, CHP) and hydroelectric facilities (weekly, seasonal reservoirs and pumped hydro storage (PHS)) are described thanks to technical and economic input data. They include efficiency rate, variable cost, forced outage rate and maintenance schedules (which optionally can be optimized). RES power plants include run-of-river, wind and solar power, decentralized biomass and marginally other kind of RES technologies (tidal, geothermal). Depending on the setting, this generation can be possibly dispatched down (or curtailed) if it turns out to be cost-effective for the system. Constraints related to reserve procurement are also implemented for each country and units involved in, and VRE generation can participate to these reserve procurements.

The outputs of Continental model include dispatching production plans, reserve provided and direct emissions. For each zone, the marginal cost is calculated for energy as well as the duration of unserved energy and curtailed RES energy. Energy marginal cost will be used in this paper to compute energy market revenues of different technologies. Indeed, in theory, under perfect competition assumption, prices should be equal to marginal cost.

This set of tools allows carrying out detailed technical and economic studies of a system with a large amount of VRE. The overall Continental methodology is summarized in the Figure 2.

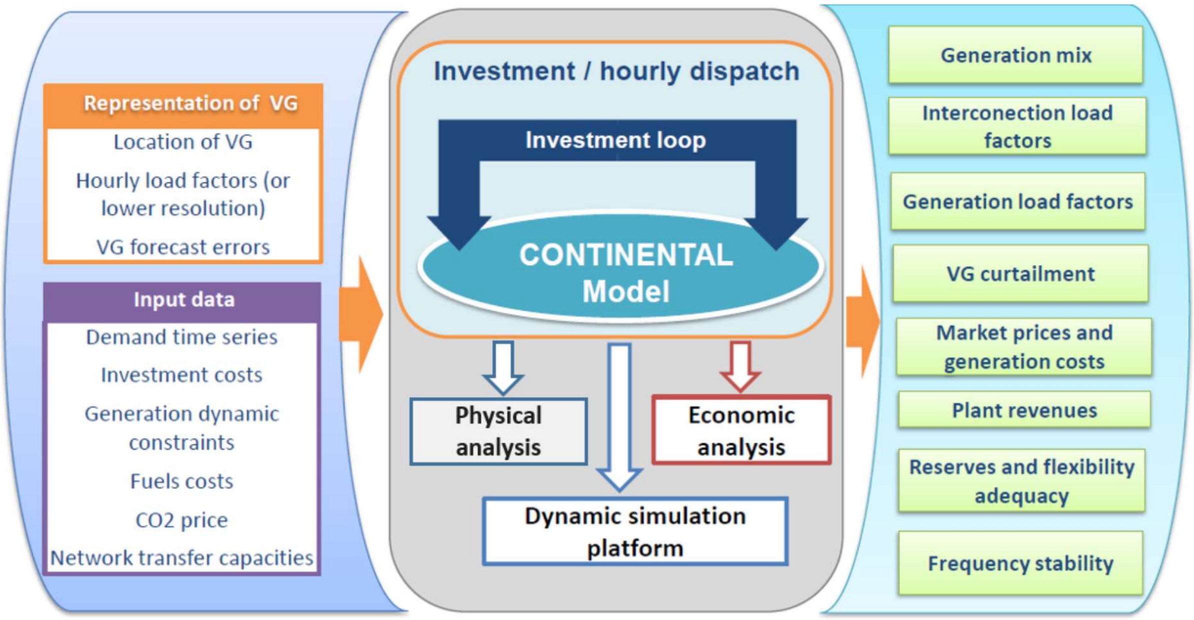

Figure 2: Continental methodology (VG: variable generation)

3 Results and discussion

By implementing the methodology that was presented we examine: i/ the transformation of the European power system with increasing VRE shares with a particular focus on gas power plants ; ii/ the potential needs for subsidies for VRE with increasing shares by carrying out a comparison between market revenues and costs ; iii/ The evolution of CO_2 emissions with higher VRE shares.

3.1 The power system is transformed by VRE, with a particular impact for gas power plants

The European power system will be transformed in the long term by increased penetration levels of VRE. As explained in section 2.1.1, comparison is carried out between adapted European power mixes with CCGT and OCGT depending on VRE penetration levels. Other installed capacities are kept identical between the scenarios, i.e hydro, biomass, CCS, geothermal, CHP and nuclear capacities. The impact of integrating VRE on the composition of the optimal power mix is shown on Figure 3**Erreur ! Source du renvoi introuvable.**.

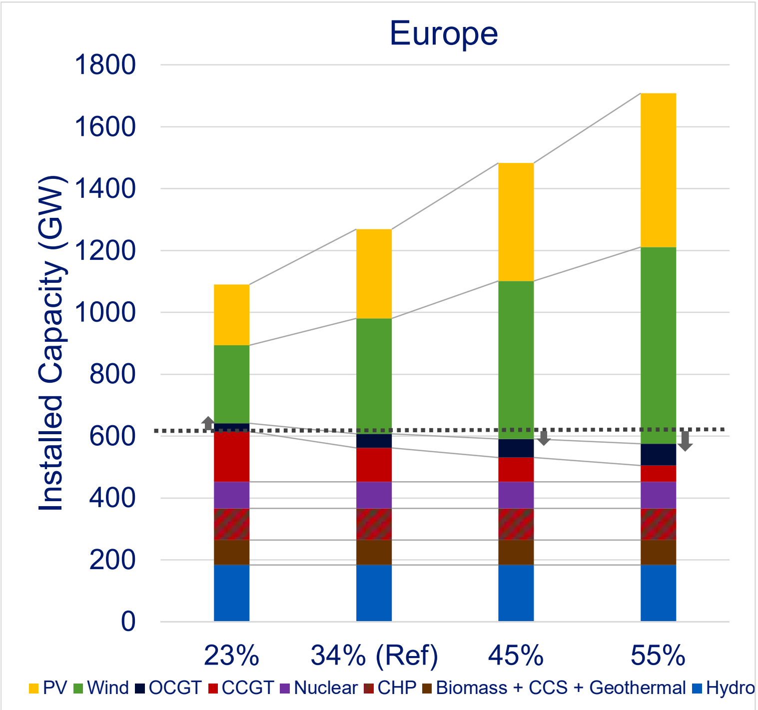

Figure 3: Installed capacity by technology depending on the VRE share in the European power system

As shown on Figure 3, increasing VRE shares in the European power system yields an increase in total installed capacity. This increase is driven by VRE capacities which largely exceed the decrease in dispatchable power plant capacities. As illustrated on the figure, the decrease of dispatchable power plants (CCGT and OCGT) amounts to 65 GW compared to an additional 700 GW of VRE capacities from 23% to 55% VRE. This results in a 57% increase of total installed capacities. It shows that additional VRE capacity replaces gas power plants capacity but not on a 1-to-1 ratio, thus highlighting the low capacity credits of VRE, i.e their low contribution to system reliability target level (OECD/NEA, 2019). Moreover, the capacity credit of VRE tends to decrease with higher penetration levels. On average, the ratio is about 1 GW of decommissioned gas power plants for 6 GW of newly installed wind and solar capacity from 23% to 34% VRE. A ratio which decreases to a 1 to 16 basis from 45% to 55% VRE. These results are in line with the literature on capacity credits (Gross et al., 2006), (Keane et al., 2011). If VRE power profile are correlated, their capacity credit tends to decrease with increasing rates because the higher the proportion of VRE in the power mix, the higher the probability that they do not produce at the same time, in particular during peak hours where reliability needs are the highest. This means that relative needs for capacity back-up increase with the penetration rate of VRE.

Furthermore, increasing VRE would change the composition of the power mix and the ratio between OCGT and CCGT power plants, as well as their operating time. CCGT and OCGT installed capacities and load factors are displayed on Table 6 for the different VRE shares.

		Scenario			
		23%	**34% (ref)**	**45%**	**55%**
CCGT	Installed Capacity (GW)	163	111	79	52
	Load Factor	57%	44%	27%	16%
OCGT	Installed Capacity (GW)	27	45	60	71
	Load Factor	1.1%	2.2%	2.2%	2.5%

Table 6 : Installed capacities and load factors for CCGt and OCGT depending on VRE shares

As pointed out in Table 6, increasing VRE share yields a decrease of gas installed capacity, with a shift towards more OCGT, which have lower investment costs and are more flexible to supplement VRE, but have higher CO_2 emission rates. For a 23% share, there is 1 GW of OCGT for 6 GW of CCGT, whereas for a 55% VRE share, this ratio is inverted with 36% more OCGT than CCGT. The total running time for gas plants would not allow for a larger installed capacity of less carbon intensive CCGT to cover their costs despite a 90€/tCO2 carbon price for 2050. Therefore, the capacity of OCGT is increasing with variable RES share (+45 GW between 23% and 55% variable RES share). Their load factors increase as well: OCGT load factor is multiplied by more than 2 and increases from 1 % to 2.5 %.At the same time, CCGT installed capacities and load factors are decreasing sharply. CCGT load factors plummet from 57 % to 16 % when the VRE share increases from 23 % to 55 %. This result underlines the fact that it will be harder for CCGT to balance economics in a power system with a large share of VRE with an increased exposure to market risk. Also, because peaking plants have higher CO_2

emissions than CCGT plants, it is expected that CO_2 emissions reductions will taper off as the share of VRE increases. This will be shown in section 3.3.

Another important parameter which is often looked into when exploring power systems with high shares of VRE is the occurrence of episodes with VRE generation exceeds the demand, including pumping and export capacities. This can occur because VRE installed capacity can be very large as it is scaled up to reach the target percentage with low capacity factor. The number of hours of curtailment increases as a consequence, despite favorable interconnections assumptions to pool RES production and customer demand at a European level: as an example, 10% of the VRE production is curtailed at a share of 55% VRE. Even if general tendencies would remain the same, these results would be slightly depending on hypotheses made on storage.

3.2 MARKET REVENUES FOR VRE DO NOT COVER COSTS AT HIGH SHARES OF VRE

At first, the transformation described above leads to a change in cost structure of the power system. Comparing cost structure (fixed -O&M and investments costs- and variable costs -i.e. mostly fuel and CO2 costs-) associated with the four sensitivity scenarios for 2050 shows a shift towards being overwhelmingly dominated by fixed costs as the VRE share increases. The fixed costs represent 60% of the costs for a 23% VRE share while it represents upwards of 90% for a 55% VRE share. Furthermore, additional necessary network reinforcement, interconnections, or smart technologies deployment costs were not assessed but would reinforce the fixed costs share. One of the main implications of a power system mainly composed by capital-intensive technologies and high shares of fixed cost is its exposure to risk issues in the energy-only market. This raises the question of appropriate market designs to address the shift of system cost structure, so as to properly share the risks and promote necessary investments.

In the meantime energy-only revenues are decreasing with higher VRE shares, in particular around the solar hours. As an example, the yearly average system marginal cost for Germany drops sharply from €95/MWh to €55MWh as the share of VRE in the European system increases. This is partly explained by the fact that the share of hours with zero marginal cost increases sharply with the share of VRE. It can also be explained by “the merit order effect”, which reflects the fact that VRE generation displaces the merit order curve to the right, thus eliminating technologies with high variable costs, which tends to reduce market revenues as their shares increase. While in the 34% VRE scenario, there are very few hours in the year where the marginal cost is zero, with 55% VRE, the marginal cost is zero roughly 10% of the year. This will translate into lower revenues for all generation plants in an energy-only market environment (no subsidies), that must bear at the same time a higher uncertainty and risk level. This calls for looking in detail the economics of VRE.

The “market value factor” of VRE has been computed and reflects a part of their integration cost[4]. It represents the ratio between VRE market value averaged over a year and the yearly average price. Figure 4 shows the European-wide market value factor for solar, onshore and offshore wind depending on VRE shares as well as the average marginal cost (baseload price).

[4] The network integration costs are not taken into account in this study.

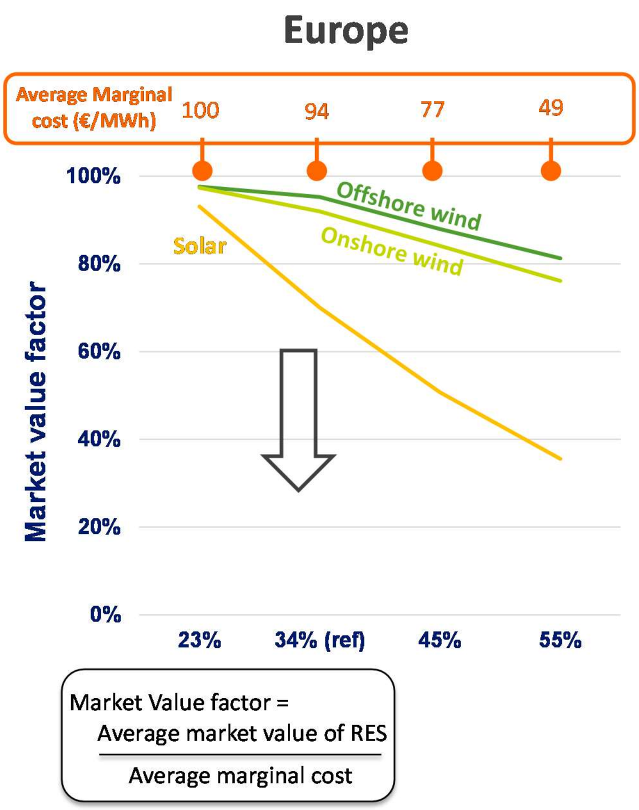

Figure 4 : Market value factor for solar, onshore wind and offshore wind and average marginal cost, depending on the share of VRE in the European power system

The market value factor drops sharply with increasing shares of VRE, in a more pronounced way for solar, given assumptions made on storage assets. It is divided by 2.5 between a scenario with 23% VRE and 55% VRE at the European level. As wind generation is more spread out during the day, market value for onshore (offshore) wind is divided by 1.3 (1.2) from 23% to 55% VRE. This well-known phenomenon as the “self-cannibalization effect” induces that the market revenues of wind and solar units drop more strongly than the average market price with their increasing shares in the power mix. This is explained by the fact that VRE generation of the same type are correlated, thus leading to a production which is statistically biased towards periods when market prices are lower than the average price (for a certain type of technologies in specific countries, this could lead to higher market value factors).

This phenomenon is to be coupled with the decreasing averaged energy-only marginal cost with VRE penetration levels. As shown on Figure 4, the average marginal cost is divided by 2 from a 23% to a 55% VRE share. This means that, not only VRE would benefit from lower prices than the baseload prices but also that the average market prices themselves would be diminished. This implies that if the policy target level of VRE is higher than economic optimal share based on prices received by technologies, subsidies will be needed to ensure necessary VRE investments. Results presented in this section illustrate an assumption often hidden in the market design discussions. Energy only market design only works (i.e., ensure cost recovery) if the energy power mix (in particular the share of RES) is freely defined by the market. If the share of RES is imposed exogenously (for instance by political will), other long-term mechanisms should be added to the market design to ensure cost recovery.

Therefore, as a next step, the profitability of wind and solar PV technologies on the energy-only market is evaluated thanks to a comparison between their revenues on the energy-only market to their fixed costs (annualized investment cost and operational fixed costs).

Figure 5 shows the difference between energy-only market revenues (bars) and annual fixed costs on average for Europe for each VRE technology[5]. It shows that, using 2040 cost assumptions (OCDE/IAE 2018), the market revenues do not allow them to cover their costs when the share is higher than 34% of VRE. For higher shares, the need for subsidies can become large despite the high carbon price taken as input (i.e. 90 €/tCO2). A lower carbon price would have resulted in even more needs for subsidies for a lower share of VRE. A lower assumption of VRE investment costs will of course reduce the needs for subsidies but the self-cannibalization effect being so strong for high shares of VRE that the needs for subsidies would not disappear.

[5] The graph is shown with capped prices at 3000€/MWh. Uncapping the prices leads to the same conclusions but the gap is marginally reduced.

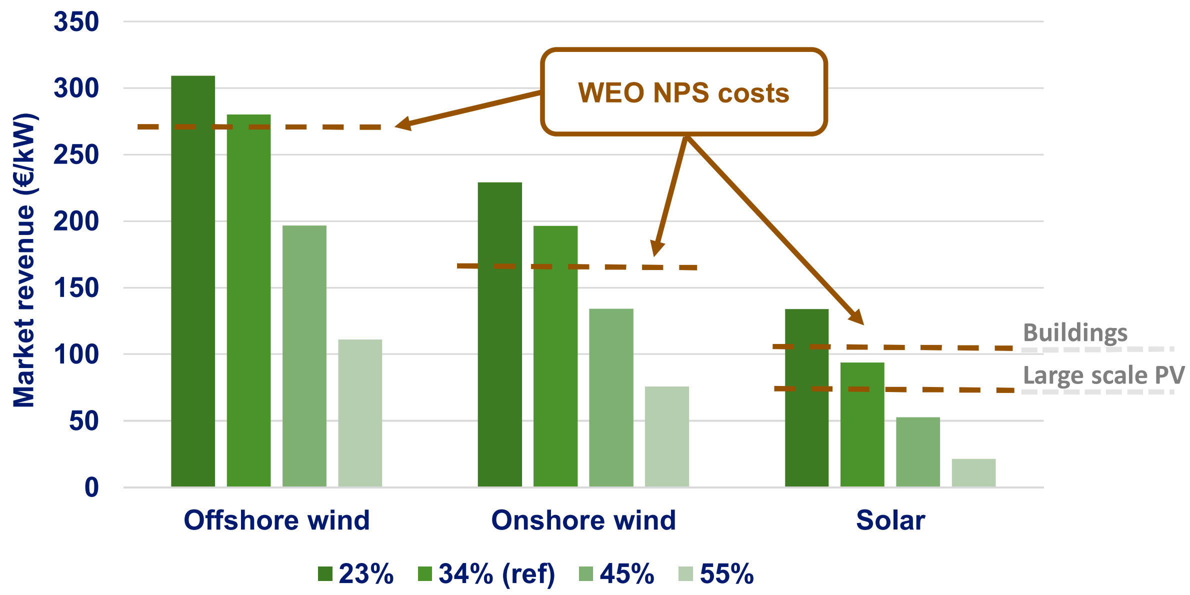

Figure 5 : Average marginal cost/benefit value of offshore and onshore wind and solar PV depending on sensitivity scenarios (costs are taken from the *(OECD/IEA, 2018b; RTE, 2017)*

3.3 The reduction of direct CO2 emissions by adding VRE is tapering off when the power system is already low carbon

A significant benefit of renewables and a significant positive impact that they have on the power system relates to carbon emission reduction. Simply adding extra renewable capacity succeeds in displacing carbon intensive fossil fuel generation. This section discusses the CO_2 emissions analysis performed using the EU-SysFlex scenarios and sensitivities. The change in CO_2 emissions is illustrated in Figure 6.

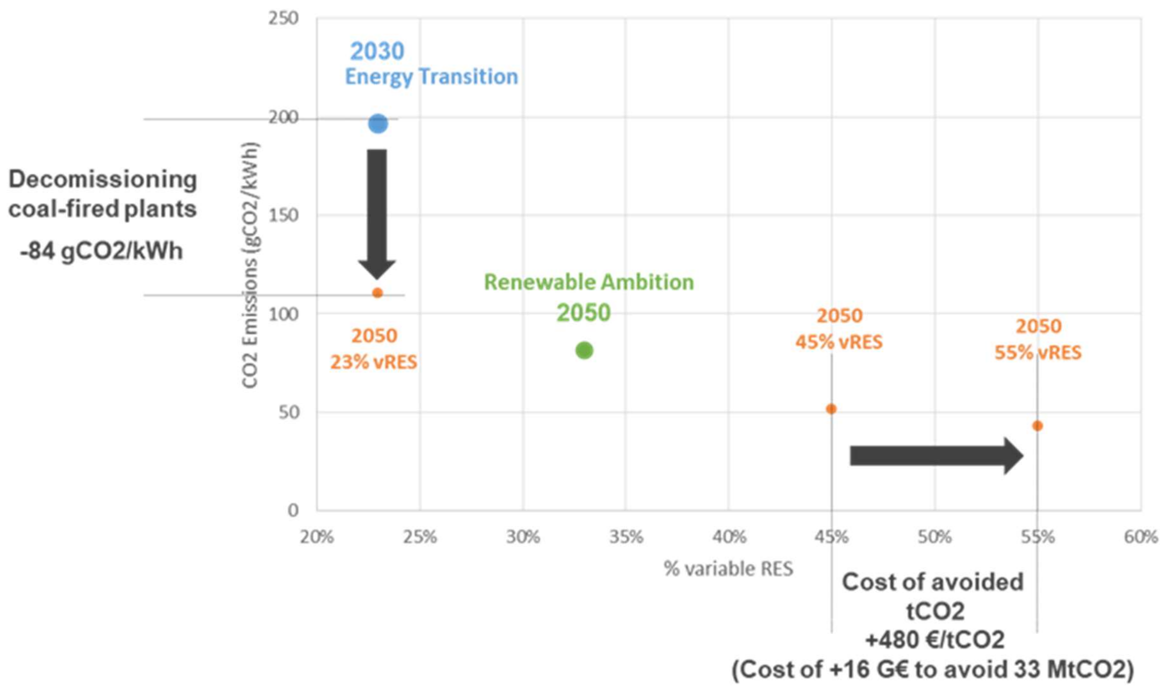

Figure 6: Direct CO_2 emissions per kWh[6] depending on the VRE share in the European Power system

The EU-SysFlex scenarios are 2030 *Energy Transition* and 2050 *Renewable Ambition*. The first difference is the share of VRE but additional first order drivers are at play. The CO_2 price increases from 27€/tCO2 in 2030 *Energy Transition* to 90€/tCO2 in 2050 *Renewable Ambition*. The higher CO_2 price combined with a longer time horizon allows for less carbon intensive plants in Europe, with a reduction of 40% of direct emissions. One of the main differences between the two scenarios is the decommissioning of a large share of coal-fired plants at the European level, which accounts for a 84 gCO_2/kWh decrease of CO2 intensity. As the share of VRE increases the reduction of CO_2 emissions tapers off partly because of a higher capacity in peaking plants. Between a VRE share of 45% and 55%, the difference is 8g CO_2/kWh.

[6] From the EU-Reference scenarios, the 2020 figure for carbon emissions for the power sector is around 260 gCO_2/kWh.

Computing the total cost difference[7] between the two power systems, the cost of avoided CO_2 is €480/ton which emphasizes the message from the IEA on deep decarbonisation (OECD/IEA, 2019). There is no single or simple solution to reach deep decarbonisation. The most efficient way to lower CO2 emissions is to pool carbon-free technologies together in all sectors of economy in a drastic way.

4 CONCLUSION

The study conducted for the EU-SysFlex European project highlights some of the technical and economic challenges of operating a system with high shares of VRE.

At first, the integration of VRE deeply transforms the power system in the long term. With higher shares of VRE, the optimal residual power mix would rely more and more on peaking units (OCGT) to the detrimental of mid-load technologies. CCGT operating time, which is decreasing sharply with higher shares of VRE, would not be sufficient to offset their high capital cost. Even a high CO_2 price appears to be not enough to shift away from carbon intensive OCGT.

Secondly, we have highlighted that a European power system with high VRE shares would be shifted to capex intensive technologies, while at the same time be exposed to a decrease of energy-only market revenues, thus leading to market risk exposure. Besides, it has been illustrated that the cumulated effect of reduced average market prices and self-cannibalization effect would penalize the economics of VRE as their share increase. Even with a high carbon pricing, the energy-only market would not provide sufficient revenues for VRE to cover investments costs at high penetration levels.

[7] The total cost difference between the two systems takes into account the difference in CAPEX from new investments in variable RES and peaking plants as well as avoided investments in conventional plants and reductions in operating costs.

In this context, this sets out the issue of market and regulation signals needed to send appropriate incentives for investments to reach carbon targets in the most cost-effective way. A recent OECD/NEA publication has precisely exposed policy recommendations to provide stability and confidence for investors in this transition context (OECD/NEA, 2019). It points out the need of long term signals to guide the right investments as well as internalizing externalities into market mechanisms, which includes not only a carbon price at a sufficient level but also giving incentives for flexibility via market signals in the short term. However, some adjustments would be necessary by country given the VRE specifics.

VRE do lower the carbon footprint of the European power system when combined with decommissioning of carbon intensive plants and carbon-free baseload plants. However, even if OCGT and CCGT are relied upon for providing the required flexibility at high penetrations of VRE, the potential carbon emission reduction benefits from the VRE may be impacted and could taper off at high levels of VRE.

As a consequence, to reach deep decabonization, the most efficient way would be to pool carbon-free technologies together as advocated by the latest WEO (OECD/IEA, 2019). Furthermore, a mix of complementary flexibility solutions should be encouraged to reduce the need for carbon intensive peaking plants (OECD/IEA, 2014) (OECD/IEA, 2018b). Additional flexibility options will be incorporated in future work, as part as EU-Sysflex project.

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7 ANNEX

From/To (MW)	DE	AT	BE	CH	CZ	DK	ES	FI	FR	UK	HU	IE	IT	NL	NO	PL	PT	SE	SK
DE		10800	1000	6000	3700	5600			3900					8500	4400	7100		4200	
AT	10800			2400	2100						1600		4300						
BE	1000								4600	1000				3500					
CH	6000	2400							9500				8500						
CZ	3700	2100														2100	0		2700
DK	5600													700	1700			2440	
ES									11900								3550		
FI															50			3150	
FR	3900		4600	9500			11900			11000		2700	5800						
UK			1000						11000			1600		1000	1400				
HU		1600																	5400
IE									2700	1600									
IT		4300		8500					700										
NL	8500		3500			700				1000					3700				
NO	4400					1700		50		1400				3700				4098	
PL	7100				2100													600	600
PT							3550												
SK	4200					2440		3150							4098	600			
SE					2700						5400					600			

Table 7 : Net Transfert Capacities in the European power sytem in 2050 (e-Highway 2040, 2015)