Technische Universität Berlin
Fakultät VII - Volkswirtschaftslehre und Wirtschaftsrecht
Fachgebiet Wirtschafts- und Infrastrukturpolitik

Energy Economics – Energy Sector Modeling

European Security of Supply and Weather Effects

Student:	Christian Gentsch	Claudia Günther	Richard Hauschild
Matr. Nr.:	349596	576419	358081

Prüfer:	Prof. von Hirschhausen	Jens Weibezahn	Richard Weinhold

Berlin, October 1, 2018

Contents

List of Figures

List of Tables

Abbreviations

CCGT	combined cycle gas turbine
FOM	fixed operation and maintenance
MC	marginal cost
NTC	network transfer capacity
PV	photovoltaics
RES	renewable energy source
VRE	variable renewable energy

1 Introduction

The decarbonisation of the power sector is a major task required to meet European climate targets under the 2015 Paris Agreement. The European Member States have agreed upon a target share of energy from renewables of at least 32 % of the EU's electricity consumption in 2030, which is likely to be revised upward. Wind energy and photovoltaics (PV) are expected to play a key role in providing large shares of future electricity generation in Europe, as the potential of other renewable energy sources is limited.[1] Due to their nature of high variability, flexibility options provided by storages or additional transmission capacity are necessary in order to include large shares of VRE and assure system security at all times. The future requirement of peak, base and storage capacity depends on the assumed generation from renewable energy plants. Robust capacity planning for future power systems with a high share of renewable energy thus calls for analysis of European climate patterns.

This paper examines the impact of different weather years on future generation and storage capacities. An investment and dispatch model is set up, using the programming language Julia. The model covers nine European countries and assumes a greenfield perspective for the investment. Each country will be treated as a single node with fixed transmission capacities to its neighbouring countries. The objective is to minimize total system and investment costs, while taking fixed and variable cost into account. Apart from the investment into generation and storage technologies, the optimal dispatch will be calculated for each hour for the target year 2030.
To analyse the disparities of the calculated optimal capacities as a result of different weather conditions, a deterministic and stochastic version of the model is implemented, which takes multiple weather years into account. The deterministic model contains five extreme weather years and calculates the optimal solution for each year separately whereas the stochastic model will take the probability of certain weather events into account and thus cover a wide range of possible weather situations at the same time. Furthermore both versions are run on a renewable energy source (RES)-share of 40 % and 80 % to analyse it's impact.

The remainder of this paper is structured as follows: Chapter 2 gives an overview on the methodology of the present analysis. This includes all scenario assumptions and parameters, the input data and derivation of weather scenarios. The following chapter introduces the deterministic and stochastic model setup. In chapter 4 the storage requirements and installed generation capacity as a result of weather effects is presented for the target year, before the conclusion is drawn in chapter 5.

2 Methodology

2.1 Assumptions and Parameters

2.1.1 Electricity Demand

There are multiple scenarios for the development of the electricity demand in Europe. On the one hand it is likely that the demand will decrease due to technological progress and the accompanied increase of efficiency. On the other hand sector coupling will play an increasingly important role in the future. This will lead to an increase of demand, as electricity is needed in sectors which are based on fossil fuels today.[2] As it is unclear how fast sector coupling will take place and if the accompanied increasing demand can be compensated or even reversed by efficiency gains, we assume the electricity demand in 2030 as high as today. In addition it is assumed that the hourly resolved demand-time-series won't change till 2030 as well.

[1] See Zerrahn, Schill, and Kemfert, 2018, p. 1.
[2] See Kirchner et al., 2016, p. 4. The stated source shows the expected electricity demand only for Germany but the mentioned arguments can be applied to Europe too.

2.1.2 Technical and Economic Parameters

The model uses a simplified set of technologies which consist of three conventional-, two renewable- and two storage technologies. As conventional technologies lignite- and coal-fired power plants as well as combined cycle gas turbine (CCGT) gas-fired power plants are considered. As renewable technologies wind and solar PV are taken into account which are further subdivided in $\text{Wind}_{\text{Onshore}}$ and $\text{Wind}_{\text{Offshore}}$ as well as PV_{Roof} and $\text{PV}_{\text{Ground}}$. As storage technologies pumped- and battery storages are taken into account. Other power plant and storage types are not taken into account to reduce complexity and computation time. Table 1 gives a summary of the assumed technical and economic parameters for the target year 2030. The calculation of the technology specific annuity is further discussed in paragraph 2.1.3.

Table 1: Expected Technical and Economic Parameters of Generation Technologies in 2030[3]

Technology	Investment costs [€/kW]	FOM cost [€/kWa]	Technical lifetime [a]	Annuity [€/kWa]	MC [€/MWh]	η [–]
Lignite	1596	49.50	45	139.29	52.38	0.39
Coal	1957	52.00	45	162.10	55.01	0.415
Gas (CCGT)	928	26.50	45	78.71	74.12	0.495
Wind onshore	1548	13.00	25	122.83	0	1
Wind offshore	2473	93.00	25	268.47	0	1
PV Ground	774	15.00	25	69.92	0	1
PV Roof	972	17.00	25	85.97	0	1

Table 2: Expected Technical and Economic Parameters of Storage Technologies in 2030[4]

Technology	Investment costs		FOM cost	Technical	Annuity		MC	η
	[€/kW]	[€/kWh]	[€/kW(h)]	lifetime [a]	[€/kWa]	[€/kWh]	[€/MWh]	[–]
Pumped Storage	1220	10	12.00	60	76.45	22.56	78.95	0.76
Battery Storage	131	450	10.00	20	20.51	732.18	66.67	0.9

2.1.3 Considered Cost and Calculation

The model equally considers fixed and vairable costs. Former consist of investment cost and cost for fixed operation and maintenance (FOM) e.g. for staff or insurance. In the case of storage technologies, which are displayed in table 2, the investment cost are additionally distinguished in energy (€/kWh) and power (€/kW). The total cost are calculated as: $Cost_{total} = Cost_{fix} + Cost_{var}$.
To calculate the investment cost for a single year which includes interest rates as well, it's annuity based on the technical life time and the FOM-cost will be used. In the case of storages FOM-cost are taken into account for an investment into energy as well as for power to avoid a distortion of the cost

[3] See Peter and Wagner, 2018, pp. 30 f. If ranges were given, the arithmetic mean was used to calculate a single number. Annuities were calculated according to equation 1 on page 5.

[4] See Peter and Wagner, 2018, pp. 30 f. and Pape et al., 2014, p. 54. If ranges were given, the arithmetic mean was used to calculate a single number. Annuities were calculated according to equation 1 on page 5.

structure.[5] The annuity is calculated as follows:[6]

$$\text{Annuity}_{\text{Inv}}[\frac{€}{\text{MW}}] = \text{AF} \cdot \text{I} = \frac{(1+\text{i})^{\text{n}} \cdot \text{i}}{(1+\text{i})^{\text{n}} - 1} \cdot \text{I} \tag{1}$$

$$\text{Annuity}_{\text{tot}}[\frac{€}{\text{MW}}] = \text{Annuity}_{\text{Inv}} + \text{FOM} \tag{2}$$

with: AF = Annuity Factor, i= interest rate=5 %, n= technical life time in years, I= Investment in €. As variable cost expenditures for fuel and CO2-emissions are taken into account and calculated as follows:

$$\text{Cost}_{\text{var}}[\frac{€}{\text{MWh}}] = \frac{\text{FuelPrice}[\frac{€}{\text{MWh}_{\text{th}}}] + \left(\text{CarbonContent}_{\text{fuel}}[\frac{\text{t}}{\text{MWh}_{\text{th}}}] \cdot \text{CO}_2\text{Price}[\frac{€}{\text{t}}]\right)}{\eta_{\text{powerplant}}[\frac{\text{MWh}}{\text{MWh}_{\text{th}}}]}$$

The expected fuel prices in 2030 and their carbon content are given in table 3. As in Nagl, Fürsch, and Lindenberger (2012, p. 23) the cost of CO2 in 2030 is assumed to 40 €/t. Furthermore it will be assumed that the carbon capture transport and storage technology won't be available as there are no development projects in Europe at the moment and it can't be expected that the technology will be available until 2030.[7] The marginal cost (MC) of storages are implemented as follows:

$$\text{MC}_{\text{Storage}} = \frac{\text{P}_{\text{Electricity}}}{\eta_{\text{Storage}}}$$

As displayed in equation 3 on page 11 the objective function only considers cost for produced energy. That's why it has to be assured, that the cost of charging the storage is included in the objective function through the MC[8] of the storage. Therefore the spot market price, which contains no taxes or other expenses, is assumed to $P_{\text{electricity,spot}} = 40$ €/MWh.[9] As storages are not exempted from paying these surcharges, the spot market price is increased by 50 % to account for these expenditures. The cost of electricity for storage use is thus assumed to 60 €/MWh.

Table 3: Fuel Prices in 2030 and Carbon Content[10]

Technology	Price [€/MWh_{th}]	Carbon Content [t/MWh_{th}]
Lignite	6.03	0.36
Coal	8.83	0.35
Gas	28.69	0.2

2.1.4 Technical Potentials

Table 4 contains the assumed technical space potentials for the installation of wind turbines and PV. The available area for PV_{roof} is directly taken from Jacobson et al. (2017, pp. 82–85) whereas the $\text{PV}_{\text{Ground}}$-potential was calculated by using the given capacity factor of 151 MW/km^2.[12] As in Bruninx

[5] If FOM-cost would only be considered for an investment into power the model would overestimate the necessary investments into energy, as it is cheaper than investing into power.

[6] See Götze, Northcott, and Schuster, 2015, p. 49.

[7] See Hirschhausen et al., 2012, p. 3.

[8] MC are displayed as vc_{tech} in equation 3 on page 11.

[9] EPEX yearly average ELIX base price in 2017. See EPEX SPOT SE, 2017, p. 6.

[10] Prices: See Gerbaulet and Lorenz, 2016a, sheet: fuels.

[11] PV_{Roof}-potential: See Jacobson et al., 2017, pp. 82–85; $\text{PV}_{\text{Ground}}$-potential: Bruninx et al., 2014, pp. 18 f., 157 f.; $\text{Wind}_{\text{Onshore}}$-potential: Bruninx et al., 2014, pp. 24, 157 f.; $\text{Wind}_{\text{Offshore}}$-potential: Arent et al., 2012, pp. 19–24.

[12] See Bruninx et al., 2014, p. 19.

Table 4: Technical Potential for PV and Wind per Country in km^2, full country list[11]

Country	ID	PV_{Roof}	PV_{Groud}	$Wind_{Onshore}$	$Wind_{Offshore}$
Belgium	BE	41	19.87	1714.29	3132
Denmark	DK	63	46.36	3428.57	45578
France	FR	1046	655.63	25714.29	36228
Germany	DE	952	258.28	15714.29	24850
Luxembourg	LU	4	0	142.86	0
Netherlands	NL	75	39.74	2571.43	52208
Portugal	PT	211	125.83	1428.57	2396
Spain	ES	823	907.28	10142.86	6256
United Kingdom	UK	530	973.51	18142.86	126248

et al. (2014, p. 19) only semi natural land such as grass land and agricultural land is considered for PV_{Ground} use. It is assumed that 0.1 % of semi natural land and 2 % of agricultural land can be converted into PV farms. The technical potential for onshore wind farms was calculated by using the given capacity factor of 7 MW/km^2.[13] For the offshore potential only sites with a water depth of less then 60 m were considered. To calculate the available area for offshore wind farms in km^2, the given capacity factor of 5 MW/km^2 was applied.[14]

The total potential for the installation of pumped storage plants in 2030 is shown in table 5 and consists of the already installed capacities according to International Hydropower Association (2018) and the installation potential for new plants as stated in Gerbaulet and Lorenz (2016a). The installation potential of battery storages will be assumed as infinite.

Table 5: Installed Pumped Storage Capacity per Country (2018) in MW, aggregated country list[15]

Country	Installed Capacity	Installation Potential	Total Potential
DK	0	0	0
FR	6985	7250	14235
DE	6806	125	6931
IB	5942	38625	44567
LU	2603	625	3228
UK	2744	3250	5994

2.1.5 Specific Assumptions Wind and PV

To calculate the installation potential for PV and Wind on the basis of the available area, some further assumptions are necessary which are shown in table 6. As spacing area for each wind turbine it assumed that: $A = 4D \cdot 11D$ where D is the rotor diameter. This spacing parameter is also used in Jacobson et al. (2017, p. 40) and was calculated as a compromise of multiple studies of already existing on- and offshore wind farms. The parameter will thus be used for on- and offshore wind farms. The rotor diameter will be assumed as 130 m and the capacity per wind turbine as 8 MW. The given capacity is a compromise of onshore and offshore turbines as former are expected to have

[13]See Bruninx et al., 2014, p. 24.

[14]See Arent et al., 2012, pp. 5, 20–24.

[15] Own calculation on the basis of: Installed Capacity: See International Hydropower Association, 2018, p. 99; installation potential: Gerbaulet and Lorenz, 2016a, sheet: country. The identifier LU contains the countries BE, NL and Lu; IB contains ES and PL.

lower capacities then 8 MW and the latter higher capacities of about 10 MW. The given capacity density can be calculated by dividing capacity through required area, which is then used to calculate the potential in MW. The power output of the installed wind turbines will be calculated as follows: $P_{out,wind} = \text{availability} \cdot \text{capacity}_{installed} \cdot \eta_{turbine}$

Table 6: Technical Assumptions for PV and Wind[16]

	Capacity	Area	Capacity density [MW/km^2]	Efficiency [%]	Diameter [m]
Wind	8 MW	0.7436 km^2	10.76	80	130
PV, ground	352.4 W	1.63 m^2	216.61	14	–
PV, roof	352.4 W	1.63 m^2	216.61	14	–

The density of PV-farms and rooftop-PV is calculated on the basis of a SunPower E20-327 solar panel from 2015 which will be assumed as the standard PV-panel. It has a rating of 327 W and a size of 1.046 m by 1.558 m which equals a power density of 201 W/m^2. To calculate the power density in 2030, it will be assumed that the power output at constant panel size will increase by 0.5 % p.a.[17] which leads to a power density of 216.61 MW/km^2.[18] The calculated density will be applied to PV_{Ground} and PV_{Roof}. As space for maintenance or vehicles in between PV_{Ground}-rows is not taken into account, the PV_{Ground} potential is slightly overrated.

Table 7: Technical Potential for PV and Wind in MW, aggregated country list[19]

Country	$Wind_{Offshore}$	$Wind_{Onshore}$	PV_{Groud}	PV_{Roof}
DK	490,419	36,891	10,041	13,646
FR	389,813	276,685	142,015	226,574
DE	267,386	169,085	55,945	206,212
IB	93,095	124,508	223,782	223,974
LU	595,458	47,651	12,910	25,993
UK	1,358,428	195,217	210,871	114,803

2.1.6 NTC Capacities

The model will take network transfer capacity (NTC) into account which are stated in table 8 and taken from Gerbaulet and Lorenz (2016b). For the case of LU, the available NTC of each country were added up where appropriate. The capacities are at the level of 2016 and are assumed as constant till 2030. As it can be expected that the NTC will be expended by some degree till 2030, the model will slightly overestimate the necessary storage capacities. Furthermore average transmission loss per km will be assumed to zero.

[16] Nagl, Fürsch, and Lindenberger, 2012, p. 12.
[17] See Jacobson et al., 2017, p. 51.
[18] $1.005^{15} \cdot 201\,\text{W/m}^2 = 216.61\,\text{W/m}^2 \triangleq 216.61\,\text{MW/km}^2$
[19] Own calculation on the basis of: PV_{Roof}-potential: See Jacobson et al., 2017, pp. 82–85; PV_{Ground}-potential: Bruninx et al., 2014, pp. 18 f., 157 f.; $Wind_{Onshore}$-potential: Bruninx et al., 2014, pp. 24, 157 f.; $Wind_{Offshore}$-potential: Arent et al., 2012, pp. 19–24.
[20] See Gerbaulet and Lorenz, 2016b. In the case of IB and LU the capacities of the underlying countries were added up.

Table 8: Assumed NTC-Capacities in MW[20]

Country	DK	FR	DE	IB	LU	UK
DK	-	0	1091.25	0	0	0
FR	0	-	1800	1241.67	2600	2000
DE	2075	1675	-	0	3830	0
IB	0	1070.83	0	-	0	0
LU	0	1500	3380	0	-	1016
UK	0	2000	0	0	1016	-

2.2 Input Data

Two different types of time series are used as input data for the model. Country-specific hourly load data is taken from the time series package of the Open Power System Platform[21], which is based on data from European Transmission System Operators. Spanish and Portuguese as well as Belgian, Dutch and Luxembourgian load is summed up since these countries are represented as a single node in the model. As for VRE time series, imput data relies on the renewables.ninja data set, which offers simulated historical time series data for wind and PV capacity factors in hourly resolution for European countries. These time series are based on weather data from NASA's global meteorological reanalysis model MERRA-2 (wind, PV) and the satellite dataset CM-SAF SARAH (PV), which provide hourly wind speed, temperature and solar irradiance.[22] Renewables.ninja applies a series of calculations to translate weather data to renewable output (availability) and uses metered time series to correct for systematic bias. In order to aggregate Spanish and Portuguese as well as Belgian, Dutch and Luxembourgian VRE time series, a weighted average based on country area is used. No offshore time series is available for the Iberian Peninsula, meaning that offshore turbines deployment was excluded for this region in the subsequent modelling. Figure 1 displays the variation in annual mean availability

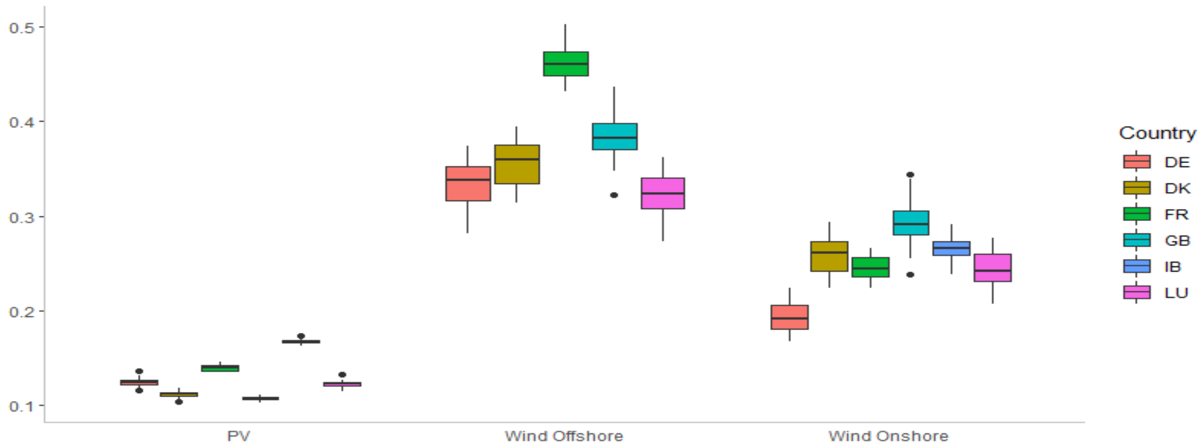

Figure 1: Annual Mean availabilities per Region

for PV, onshore and offshore wind between 1985 and 2015. Variations between regions are apparent for all technologies. Full load hours for PV do not vary much between years. The opposite holds true for offshore and onshore wind.

[21]Open Power System Data, 2018.
[22]See Pfenninger and Staffell, 2016, Staffell and Pfenninger, 2016.

2.3 Weather Scenario Approach

Weather data on onshore wind, offshore wind and PV over a time period of 32 years from 1985 to 2016 is used. This allows covering a large set of different weather patterns in order to attain robust model results. We assume that the underlying weather data covers all possible weather events and is thus representative of European weather conditions today[23]. This seems plausible as the 32-year time period is longer than the base period used to compute the climatological standard normals by the World Meteorological Organization.[24] Altered weather patterns that are likely to occur in the future as a results of climate change are beyond the scope of this paper. Due to the computational constraints imposed by our multi-regional model set up, data reduction of the high dimensional data set is necessary.

For this task the approach described by Nahmmacher et al. (2016) of selecting representative time slices for each region for VRE infeed is used. Their approach is advantageous because it allows to adequately represent regional demand patterns (load duration) and VRE infeed curves as well as the spatial and temporal correlation between them.[25]. The 280,320 hourly PV and wind values of 32 years are reduced to a total of 32 time slices. In line with Nahmmacher et al. (2016), demand data from the base year 2015 is used by reason of data availability issues and since the main research interest lies within VRE patterns. This means that only intra-year and no inter-year demand fluctuations are considered. Each representative time slice is a vector of 168 h for demand, PV, onshore and offshore wind for each region, thus representing an entire week. Daily time slices, which are frequently found in the literature, weren't used because weather patterns beyond the daily fluctuations might be relevant for certain robust model results like storage deployment.

Time slices are derived based on ward's clustering method with the euclidean distance measure.[26] All input time series are normalized to their maximum value before clustering. From each cluster, the cluster medoid (observation closest to cluster mean) is selected to represent the entire cluster. The cluster centroid is not uses because a special interest lays in finding representative time slices with extreme load and VRE patterns. Using the cluster means would average out these extreme values. The derived cluster medoids with a 168 h resolution serve as input scenarios for the stochastic model which is further described in paragraph 3.2. The occurrence probability is derived from the relative cluster size, which gives the empirical relative frequency.

A number of 30 scenarios was chosen since this is still computationally feasible within the used modelling framework on the one hand and represents the diverse weather patterns fairly well. The derived scenario frequencies are relatively balanced, with the highest and lowest occurrence probabilities being 7 % and 1 % respectively.

Figure 2 displays the original German load duration curve for the underlying 32-year period alongside the reproduced load duration curve with 30 scenarios. The figure shows that the overall representation of the load structure is very suitable. The original and reproduced availability curves for PV and wind can be seen in figure 3 and 4 respectively. Representation of PV availability is sound except for high availability hours. The same holds true for onshore wind. This means that generation from those technologies will be slightly under-represented, which is acceptable in light of the research objective.

[23]See Nagl, Fürsch, and Lindenberger, 2012, p. 12.
[24]World Meteorological Organization, 2018.
[25]See Nahmmacher et al., 2016, p. 431.
[26]See Nahmmacher et al., 2016.

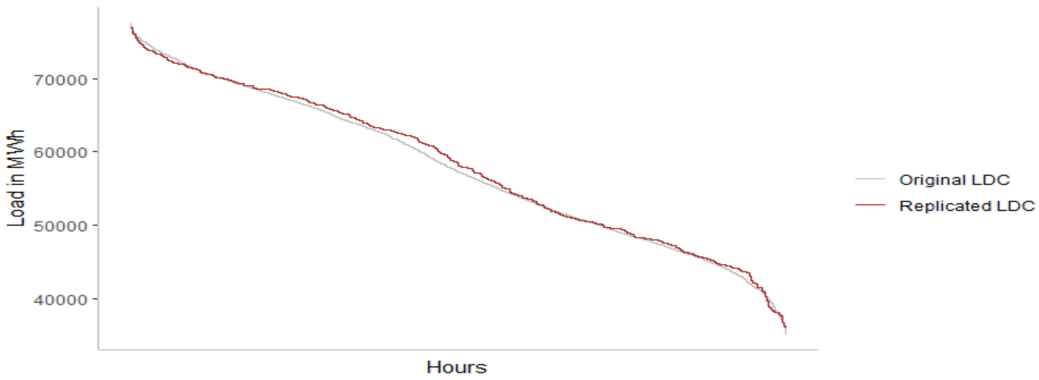

Figure 2: German Electricity Demand 1985–2016

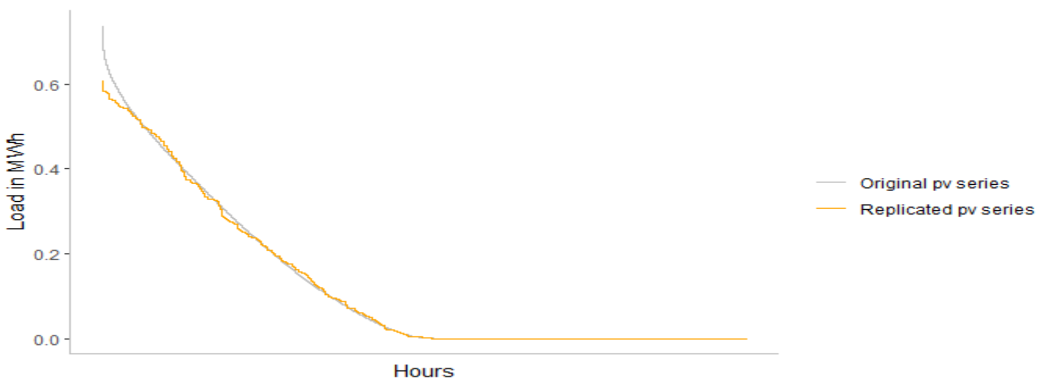

Figure 3: German PV Availability 1985–2016

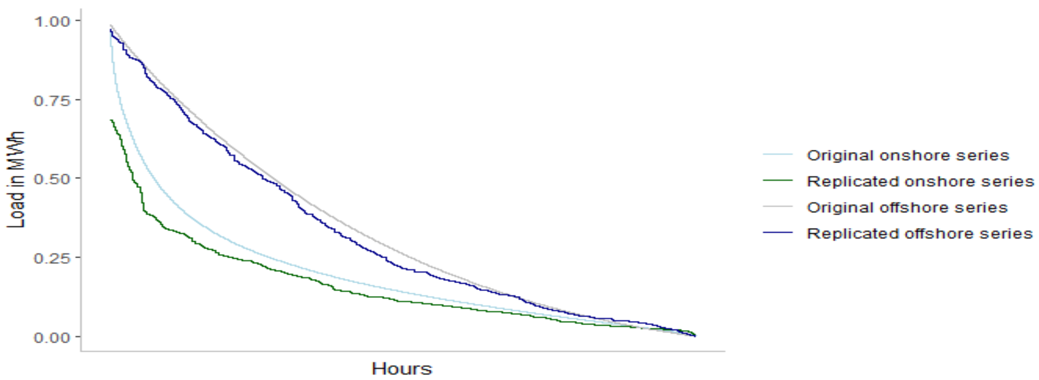

Figure 4: German Wind Availability 1985–2016

3 Model

The two developed models both minimize the total system costs, consisting of annualized investment costs as well as fixed and variable costs for each technology, excluding VRE. As for storages, seperate investments for storage energy and storage power are made in the models. Furthermore a total number of nine countries are employed in the model, so that a cohesive area of Europe is sufficiently covered. This decision is based on mainly two reasons, the first one being able to achieve comparable results to Nagl, Fürsch, and Lindenberger (2012, p. 3). The second reason is a limitation of computational power. Moreover, only six out of the original nine countries are included as explicit nodes in the model. Spain and Portugal (IB), as well as Luxembourg, Belgium and Netherlands (LU) are aggregated as single nodes. By this aggregation, computational time is saved while not diminishing the model's results.

The deterministic model used in the present analysis is a one-shot dispatch and investment model based on a greenfield perspective. This model class serves the purpose of long-term generation, storage and transmission capacity planning.

Stochastic programming is a well known technique in the context of capacity and generation planning models. It allows to incorporate both demand and supply side uncertainties like the availabilities of VRE. The basic idea behind stochastic programming is to model a probability distribution of the uncertain model element (Kunz, Setje-Eilers, and Kendziorski, 2017). In this context, it means specifying a set of different renewable generation and load situations (scenarios) with a certain occurrence probability. These weather scenarios are representative of 32 different years and thus reflect diverse weather and load situations (see subsection 2.3). Hence the stochastic model is composed of a two-stage stochastic setup.

A detailed nomenclature of both model's sets, parameters and variables can be found in table 9.

3.1 Deterministic Base Model

The model's objective is to minimize total system costs over a full year by simultaneously determining generation, storage and cross-border flows capacity as well as hourly dispatch, where $N_{zone,tech}$ is the installed capacity for each technology T and each region Z with associated annualized investment costs $c_{conv}^{\text{annuity}}$. Likewise, $N_{zone,tech}^{\text{energy}}$ and $N_{zone,tech}^{\text{power}}$ represent zonal storage energy and power capacity, with corresponding annuities $ic_{stor}^{\text{energy}}$ and ic_{stor}^{power}. These costs represent the investment costs to be optimized by the model. The costs resulting from dispatch over the set of hours are given by the technology-specific variable costs vc_{tech} and multiplied by the energy generation $G_{h,zone,tech}$ for each zone.

$$\begin{aligned} \min \text{COST} = \sum_{Z} \sum_{C} c_{tech}^{\text{annuity}} \cdot N_{zone,tech} \\ + \sum_{Z} \sum_{S} \frac{1}{2} \cdot \left(ic_{stor}^{\text{energy}} \cdot N_{zone,stor}^{\text{energy}} + ic_{stor}^{\text{power}} \cdot N_{zone,stor}^{power} \right) \\ + \sum_{H} \sum_{Z} \left(\sum_{C} vc_{conv} \cdot G_{h,zone,tech} + \sum_{S} vc_{stor} \cdot G_{h,zone,stor} \right) \end{aligned} \tag{3}$$

The energy balance assures that regional generation $G_{h,zone,tech}$ net exports ($EX_{h,to,from} - EX_{h,from,to}$) matches regional demand for direct consumption $d_{h,zone}$ and demand for storage load $D_{h,zone,stor}$ at any given hour.

$$
\begin{aligned}
\sum_{tech} G_{h,zone,tech} + \sum_{stor} G^{\text{stor}}_{h,zone,stor} = \\
+D_{h,zone,stor} + \sum_{stor} D_{h,zone,stor} \\
- \sum_{from \in Z} EX_{h,from,zone} + \sum_{to \in Z} EX_{h,zone,to} \\
\forall\ h \text{ in } H,\ zone \text{ in } Z
\end{aligned}
\tag{4}
$$

Regional generation of dispatchable technologies is limited by installed capacity.

$$
\begin{gathered}
G_{h,zone,tech} \leq N_{zone,tech} \\
\forall\ h \text{ in } H,\ zone \text{ in } Z,\ tech \text{ in } T \setminus R
\end{gathered}
\tag{5}
$$

Generation from non-dispatchable technologies, i.e. variable renewable energy sources, cannot exceed installed capacity multiplied by regional, hourly availability parameter $\delta^{avail}_{h,zone,res}$, which lies in the unit interval. If equality does not hold, this means that renewable generation is curtailed.

$$
\begin{gathered}
G_{h,zone,res} \leq \delta^{avail}_{h,zone,res} \cdot N_{zone,res} \\
\forall\ h \text{ in } H,\ zone \text{ in } Z,\ res \text{ in } R
\end{gathered}
\tag{6}
$$

A constraint on total generation of VRE to assure a minimum RES share in the overall European energy mix is imposed, in order to represent EU energy transition targets. Specifically, a given share ζ^{RES} of total load across all regions must be satisfied from generation of VRE. A total RES share of 40 % and 80 % for the baseline model is assumed.

$$
\sum_{H} \sum_{Z} \sum_{R} G_{h,zone,res} \geq \zeta^{\text{RES}} \cdot \sum_{H} \sum_{Z} d_{h,zone}
\tag{7}
$$

Regarding the cross-regional flow representation, a transport model set up is adopted. This means that we abstract from detailed power flow representation and limit cross-border flows based on net transfer capacities *ntc* between zones:

$$
\begin{gathered}
EX_{h,from,to} \leq ntc_{from,zo} \\
\forall\ h \text{ in } H,\ (from, to) \text{ in } Z
\end{gathered}
\tag{8}
$$

This means that the resulting dispatch might not be feasible for every given hour due to transmission constraints. However, this simplification is being used, because the main interest lies in the generation and storage capacity structure and its dependencies on weather. Furthermore, inter-country power flow constraints are considered to be subordinate to intra-country transmission constraints, from which an abstraction is made due to limited computation power.

Since the high share of VRE requires flexibility options in the power system, different types of power technology for balancing must be included. The model endogenously determines technology and country-specific E/P-ratios as it is allowed to invest in storage energy and power capacity seperately.

The change in storage level in a given period is charging ($D_{h,zone,stor}$) and discharging ($G_{h,zone,stor}$) activities. The parameter $\gamma^{\text{eff}}_{stor}$ accounts for overall storage efficiency. For means of simplicity, only overall storage efficiency is accounted for. There is no differentiation between charging and discharging losses.

$$\begin{aligned} L_{h,zone,stor} - L_{h-1,zone,stor} = \\ \gamma^{\text{eff}}_{stor} \cdot D_{h,zone,stor} - G_{h,zone,stor} \\ \forall\ h \text{ in } H,\ zone \text{ in } Z,\ stor \text{ in } S \\ \\ L_{h_1,zone,stor} = L_{h_{\text{end}},zone,stor} \\ \forall\ zone \text{ in } Z,\ stor \text{ in } S \end{aligned} \tag{9}$$

Storage generation and consumption have to be determined for each modeling hour, zone and storage technology. Constraint 10 shows that the overall storage generation is bounded by its level in the previous hour. Storage consumption on the other hand is bounded by the total installed energy capacity substracted by the previous state of charge.

$$\begin{aligned} G_{h,zone,stor} \leq L_{h-1,zone,stor} \\ \forall\ h \text{ in } H,\ zone \text{ in } Z,\ stor \text{ in } S \\ D_{h,zone,stor} \leq N^{\text{E}}_{zone,stor} - L_{h-1,zone,stor} \\ \forall\ h \text{ in } H,\ zone \text{ in } Z,\ stor \text{ in } S \end{aligned} \tag{10}$$

Storage level $L_{h,zone,stor}$ is bounded from above by installed energy capacity $N^{\text{E}}_{zone,stor}$. Similarly, power generation from storage ($G_{h,zone,stor}$) and storage loading ($D_{h,zone,stor}$) are limited by storage power capacity $N^{\text{P}}_{zone,stor}$.

$$\begin{aligned} L_{h,zone,stor} \leq N^{\text{E}}_{zone,stor} \\ G_{h,zone,stor} \leq N^{\text{P}}_{zone,stor} \\ D_{h,zone,stor} \leq N^{\text{P}}_{zone,stor} \\ \forall\ h \text{ in } H,\ zone \text{ in } Z,\ stor \text{ in } S \end{aligned} \tag{11}$$

Respecting regional technical potentials, a limitating constraint for VRE and storage capacities in each country is employed. These regional potentials mainly involve available area for each technology.

$$\begin{aligned} N_{zone,tech} \leq pot_{zone,tech} \\ \forall\ zone \text{ in } Z,\ tech \text{ in } T \end{aligned} \tag{12}$$

Regarding temporal resolution, the deterministic model is calculated with 4380 h due to computational limitations. Variable costs are adjusted accordingly to avoid a distortion of variable and fixed costs for technologies. As the model abstracts from ramping constraints, we consider this approach suitable.

3.2 Stochastic Model

The objective of the stochastic model is to minimize investment costs in its first stage and the expected variable costs from dispatch over all scenarios in its second stage, as presented in equation 13.

$$
\begin{aligned}
\min \mathrm{COST} = \sum_{Z}\sum_{T} c_{tech}^{\text{annuity}} \cdot N_{zone,tech} \\
+ \sum_{Z}\sum_{S} \frac{1}{2} \cdot \left(ic_{stor}^{\text{energy}} \cdot N_{zone,tech}^{\text{energy}} + ic_{stor}^{\text{power}} \cdot N_{zone,tech}^{\text{power}} \right) \\
+ \sum_{sc \in \Omega} p(sc) \left(\sum_{H}\sum_{Z}\sum_{T} vc_{tech} \cdot G_{h,zone,tech} \right)
\end{aligned}
\tag{13}
$$

The parameter $p(sc)$ is the occurence probability of scenario sc in the entire scenario set Ω. Further risk measurements are not included in this model, since the model doesn't face high risk decision making, i.e. costly scenarios with very low occurrence probabilities (Kunz, Setje-Eilers, and Kendziorski, 2017). Instead, the scenarios are rather balanced (see subsection 2.3). The renewable energy target must be fulfilled across all weighted scenarios.

$$
\sum_{sc \in \Omega}\sum_{H}\sum_{Z}\sum_{R} p(sc) * G_{scen,h,zone,res} \geq \zeta^{\text{RES}} \sum_{sc \in \Omega}\sum_{H}\sum_{Z} p(sc) * d_{scen,h,zone} \tag{14}
$$

4 Results

The main findings from our stylized model is that high shares of renewables are feasible given the specified VRE and pumped storage potentials. Furthermore, capacity deployment for most technologies varies with the underlying weather years considerably. Technologies like hard coal and battery storage do not play any role in our model simulations because of their unfavourable cost structure. Our results regarding integration of VRE and storage requirements are in line with Zerrahn and Schill, 2017, who carry out a model result review on the question of storage capacity requirement for power systems with high shares of VRE. They find that storages play an important role for VRE integration, though their deployment is moderate up to RES shares between 50% and 70%. This holds also true for the model results presented here. In the 40 % renewable scenario with the weather year 2015, which results in highest storage deployment, less than 50 GW of pumped storage power in all six regions are required, from which less than 5 GW are allocated to Germany. This is in the same magnitude as the findings from Zerrahn, Schill, and Kemfert, 2018, who report German storage energy and power capacity requirements of 8 GWh and 3 GW for the 40 % scenario in their stylized model.

4.1 Deterministic Base Model

In order to assess the effect of European weather effects on capacity deployment,five different weather years with diverging renewable patterns are chosen. Figure 5 gives an overview on mean annual PV and wind availabilities of the chosen years, whose data is taken directly from table 15.

The years 1987, 2003 and 2010 are all low-wind years, with annual mean availability below 25 % for onshore and 36 % for offshore (except for France). 1998 and 2015 in contrast have high full load hours for wind. Mean availabilities for onshore lie between 17 % (DE 2003 and 2010) and 32 % (GB 2015), whereas offshore availabilities range between 29 % (LU 2010) and 49 % (FR 1998).

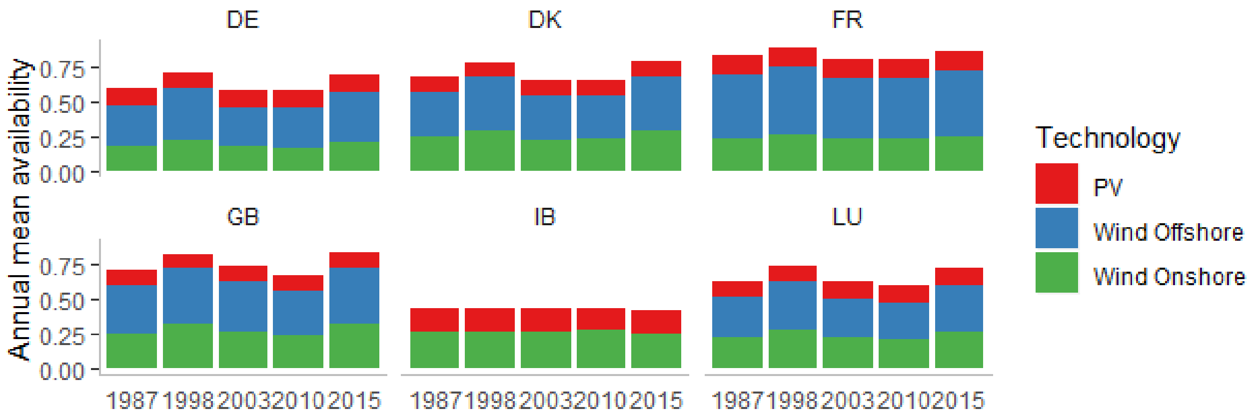

Figure 5: Annual Mean Availabilities per Region for Selected Weather Years

PV availability is more constant across years. 2010 represents a year with average PV availability (between 11 % and 16 % for all countries). 2003 and 2005, in contrast, reflect full annual load hours above average with up to 17 % availability, whereas the opposite holds true for 1998 (except for Spain) and 1987. The difference of the minimum and maximum PV availability over the considered time period is 7 %. This is compared to 15 % for onshore wind and 22 % for offshore wind quite small.

As the deterministic model calculates the optimal solution for each year individually it is expected that the different weather years will play an important role for capacity deployment. The model will built capacities according to the weather years. The variations of installed renewable capacities should increase with RES-share since the model then has to compensate low wind or PV availability with higher VRE capacities. Likewise, the installed capacity of storages should increase in the high-VRE-scenario to avoid large scale curtailment by storing power for hours with low direct generation from wind and PV.

4.1.1 40%-RES-Scenario

Figure 6 shows the installed conventional capacities for the 40 % scenario. The exact results for all technologies are displayed in table 11 and 12 on page 23. As expected, base capacity represented by lignite stays largely unchanged throughout different weather years, with roughly 55 GW of lignite-fired plants installed in Germany. This is because the same baseline load data (2015) is used for each year, meaning that the identical number of base load hours has to be satisfied. Gas and storage capacities, in contrast, are affected by the different weather years.[27] Different mechanisms affect the interplay between their capacity deployment. First, high renewable feed in at peak hours (especially relevant for PV) can offset some otherwise needed gas capacities. Second, at a given RES target, the viability of storage capacity deployment depends on a mismatch between VRE generation and loads (intra-annual availability). In order to avoid curtailment, VRE generation can be stored and released later on to offset gas generation.

Figure 7 shows the optimal VRE capacity for the 40 % renewable scenario.[28] The installed cumulative PV capacity varies as expected with different weather years, though capacity variation differ considerably between countries. While PV deployment in Germany varies between 12 GW and 56 GW, installed capacity on the Iberian Peninsula ranges between 37 GW and 48 GW. This is due to the higher and less fluctuating availability of southern PV compared to the German case. The low PV

[27]The installed capacity of hard coal isn't displayed in the results as no capacity is deployed in the 40 % scenario.
[28]Rooftop PV is not displayed in the results as no capacity is deployed in the 40 % scenario.

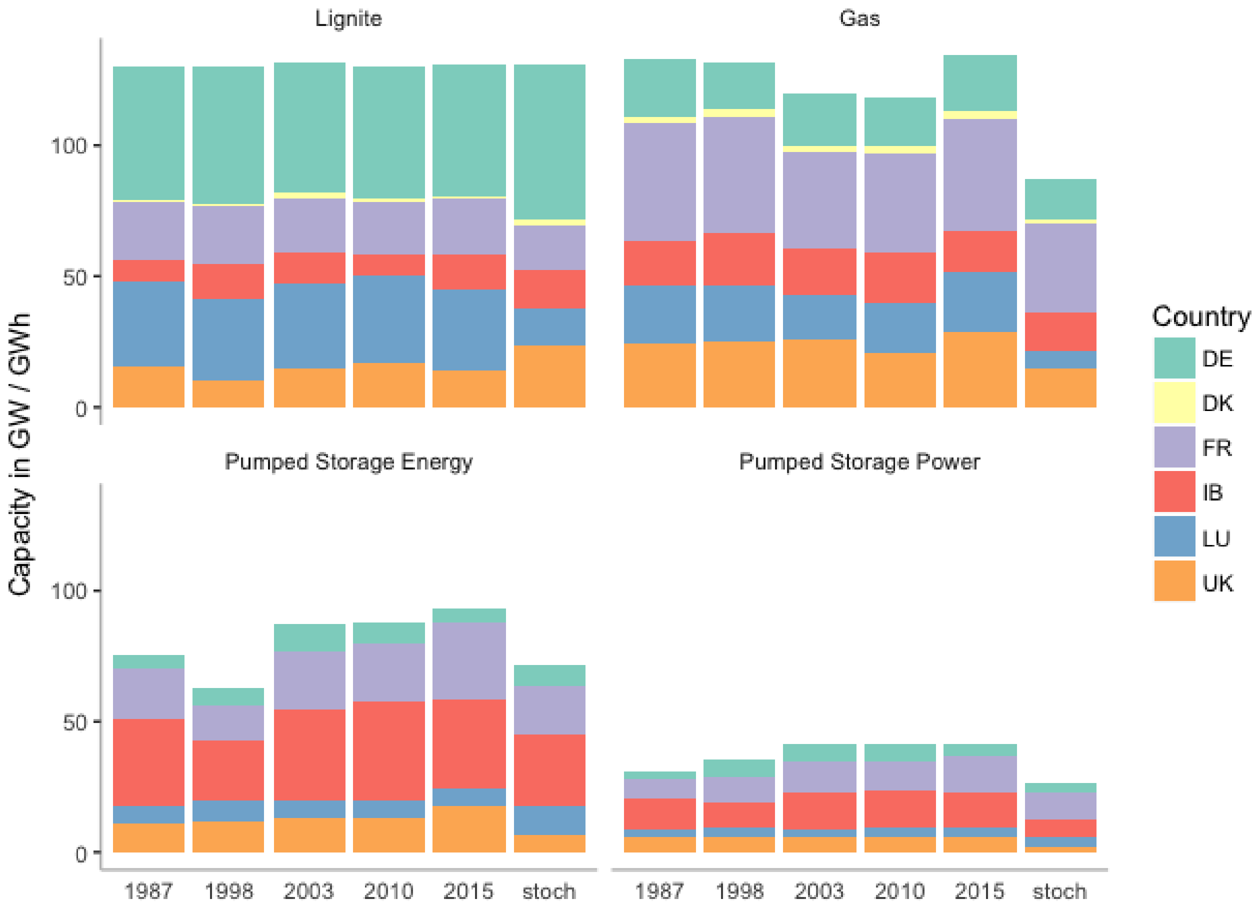

Figure 6: Installed Capacities Conventional and Storage Technologies, 40 % VRE-share

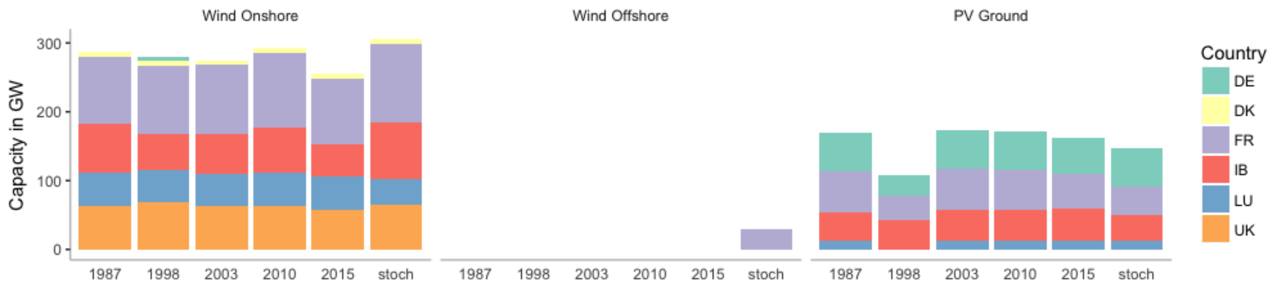

Figure 7: Installed Capacities VRE Technologies, 40 % VRE-share

year 1998 has a significant influence on cumulative installed PV. Compared to the other weather years the sharp decrease of total capacity of roughly 50 GW is yet surprising, as the difference in PV availability is moderate compared to wind. This could be explained by the RES-target which can be fulfilled comparatively easier through wind farms with high load hours. Contrary to expectations, the cumulative installed capacity of onshore wind is relatively stable and only varies by roughly 35 GW between minimum and maximum deployment, with a median of 270 GW installed throughout the considered weather years. The low variability can by explained by the RES-target. As it is moderate, changes in weather years can be compensated by gas and storage capacities. Though the inter-year variations of wind availability are considerably more pronounced than those of PV, capacity deployment of wind is surprisingly constant throughout the weather years, while the opposite holds true for PV. This result can be explained by the higher full load hours of wind in general in combination with the low VRE-target of 40 %. In the high wind year 1998, for example, the RES-target can be achieved with lower PV capacities as the installed wind plants generate considerable more power. In general, however, the overall changes in installed VRE-capacity can still be considered as moderate.

4.1.2 80%-RES-Scenario

Figure 8 shows the installed conventional capacities for the 80 %-RES-scenario. The exact results for all technologies are displayed in table 13 and 14 on page 24. Opposing to the 40 % scenario, the base load

Figure 8: Installed Capacities Conventional and Storage Technologies, 80 % VRE Share

is not fulfilled by lignite anymore as its share in the generation portfolio shrank drastically throughout all weather years by nearly 100 GW. Gas on the other hand, has overtaken lignite by means of installed capacity. Moreover Gas capacities reach nearly 200 GW in most of the scenarios. Although, gas capacity deployment is consistently high throughout the weather years, the aforementioned interplay of high renewable feed in at peak load hours and the deployment depending on the mismatch of VRE generation and load, cause minor differences. Also installed pumped storage energy nearly quadrupled, while storage power almost doubled its installed capacity in each weather year. Naturally, this is caused by the doubled RES-share in this scenario.

In contrast to the prior scenario, wind offshore capacities are deployed in Belgium, Netherlands and France for the first time, next to twice the amount of installed onshore capacities regarding the 40 %

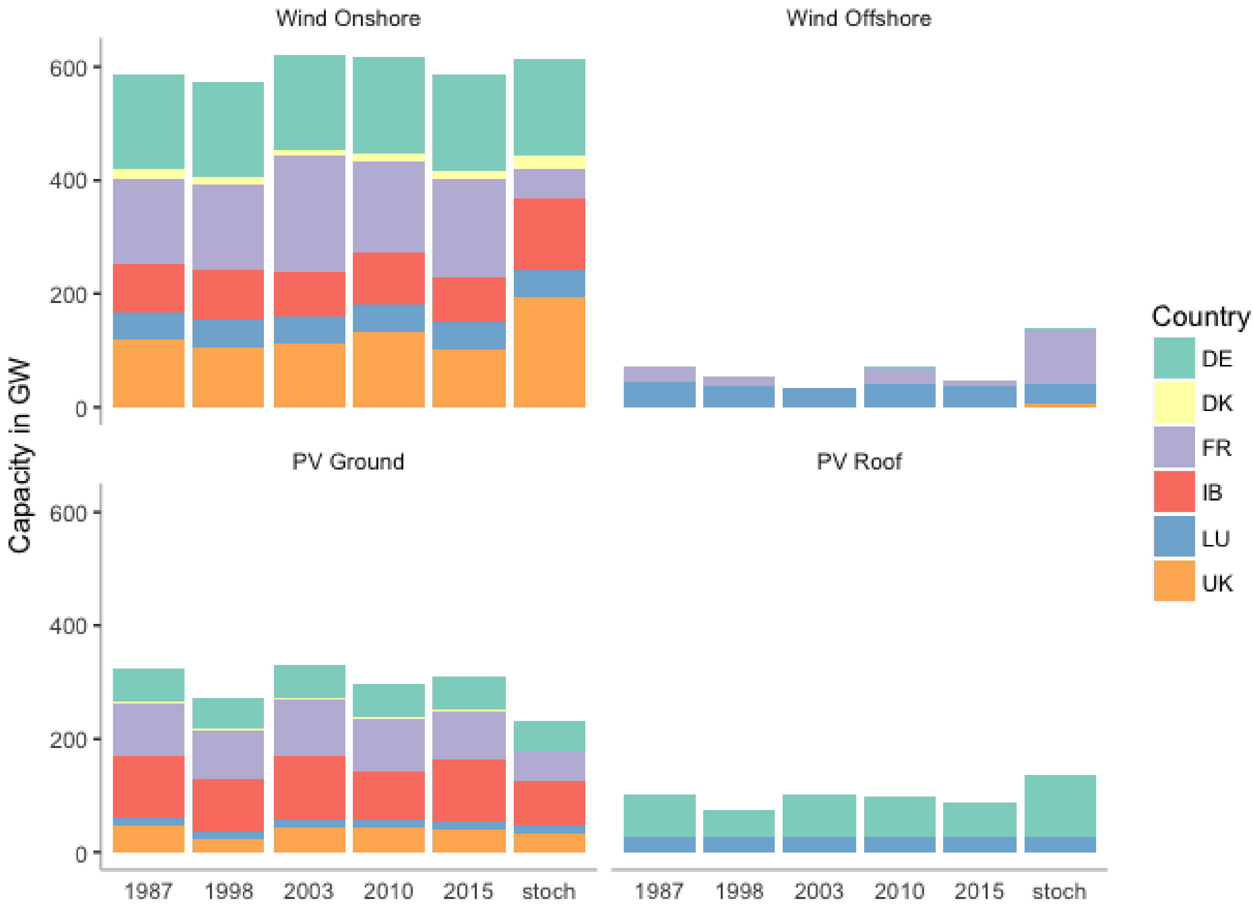

Figure 9: Installed Capacities VRE Technologies, 80 % VRE Share

scenario. Contrary to expectations the installed onshore capacities remain relatively constant throughout different weather years. Onshore wind only varies 47 GW with a median deployment of roughly 600 GW. Given the high RES target, these variations can be considered as very moderate. In contrast, Offshore wind varies by 38 GW with a median of 63 GW, which can be considered as a significant change.

PV roof capacities of nearly 100 GW in most scenarios (except the year 1998 with sparse sun penetration) are build, though PV ground capacities are still more favorable due to their cost structure. The reason why PV roof and wind offshore capacities are built, would be the high VRE-share-target of 80 %, which cannot be satisfied by onshore wind and PV ground capacities alone. The installed PV ground capacity varies by 97 GW between minimum and maximum with a median deployment of roughly 300 GW. PV roof installation vary by 60 GW with a median of 100 GW.

The 80 % scenario showed an almost constant wind capacity deployment, while PV capacities varied throughout the weather years. The capacities for onshore and offshore wind as well as PV ground and roof are distinctively affected by their underlying weather years.

4.2 Stochastic Version

In contrast to the deterministic model, the stochastic model does not only take one extreme weather year into account but a wide range of possible situations and their associated relative occurrence probabilities. The model faces a trade-off between finding a capacity portfolio that can assure supply security in all 30 scenarios and the associated variables costs of each scenario. Thus, the model needs to provide enough conventional generation and storage capacity to cope with extreme weather scenarios. On the other hand, extreme weather scenarios have less impact on the overall outcome as they are weighted with the occurrence probability. This is why the model is expected to build at least the same base capacity of conventional generation compared to the deterministic model. The built storage and gas capacities should on the other hand vary significantly compared to the deterministic 80 %-RES-scenarios as these capacities were sensitive to the underlying weather year.

4.2.1 40%-RES-Scenario

As expected, lignite capacity installation is largely unchanged, with a regional shift in generation patterns. Surprisingly storage and gas capacities are considerably lower compared to the deterministic scenarios as can be seen in 6. This could be explained by the deployment of wind capacities which are displayed in figure 7. Onshore wind capacity is higher than in all deterministic scenarios and offshore-wind is additionally built. PV deployment is in contrast remarkably low. This indicates that part of the gas generation might be offset by power from wind farms.

4.2.2 80%-RES-Scenario

The portfolio regarding lignite, gas and storage has changed compared to the 40 % scenario as can be seen in 8. Lignite capacity is considerably higher (mostly attributable to Germany), while gas capacity is again lower compared to the deterministic scenarios. Pumped storage capacities, however, now occupy a middle position compare to the deterministic capacities.
As for the stochastic 80 %-VRE-scenario, the diverging patterns in the generation portfolio are different. As can be seen in figure 9, PV plays a more prominent role, with cumulative capacity exceeding 400 GW. Total wind capacity is again above all deterministic scenarios, with large capacities of offshore wind.

A key result from the stochastic model is that wind plays a more prominent role than suggested by the deterministic model. The same holds true for PV in the high RES scenario. This is because more VRE capacity is needed to reach the RES target. At the same time, VRE generation and load seem to match more frequently in the stochastic scenarios, calling for less balancing from gas and storage. The results of the stochastic model are somewhat surprising since the match between load and VRE generation should not diverge drastically from the inspected weather years. However, these results indicated that either peak hours (residual load) are unrepresented or that the regional correlation between load and availabilities is biased. The same holds true for the high German lignite capacities, possibly indicating a bias of base load hours in Germany. A higher number of scenarios could mitigate this bias and should be revised for future research.

5 Conclusion

This paper has examined the effect of different weather years on future generation and storage capacities. For this purpose, an investment and dispatch model was introduced. To analyse the disparities of the calculated optimal capacities as a result of different weather conditions, two model versions were presented. The deterministic baseline model was used to derive optimal generation and storage capacities based on different weather years. These were selected from a total of 32 European weather years to reflect diverging VRE patterns. Since the resulting capacity portfolios were not robust and instead varied considerably with underlying weather years, a stochastic model approach was also introduced. This stochastic model accounts for the probability of certain weather events and thus covers a wide range of possible weather situations at the same time. Both model versions were run for a 40 % and 80 % renewable energy share.

Several conclusions can be drawn from the model outcomes. First, the optimal base capacity (lignite) is largely independent of weather patterns. In this regard deterministic model scenarios can coherently derive robust results. Second, optimal deployment of VRE sources, gas and storage technologies are considerable influenced by weather years in combination with exogenous renewable targets. Deterministic model approaches cannot robustly determine long-term optimal capacities. A stochastic modelling approach should therefore be preferred.
However, the variations in installed onshore wind capacities were even in the 80 %-RES-scenario relatively moderate. This is largely due to a large increase in pumped storage capacities. As no battery storages were built, it can be concluded that the technical pumped storage potentials and existing country to country NTC are sufficiently high enough to compensate weather effects.
For future research, analysis of tempo-spatial smoothing potential on the European level should be carried out. By increasing cross-border flow capacities and thus increasing exchange possibilities, integration of VRE might be facilitated and the effect of diverging weather patterns could be mitigated. Furthermore, the stochastic modelling approach could be refined by including additional parameters to reflect risk aversion and security of supply concerns.

References

Arent, D., P. Sullivan, D. Heimiller, A. Lopez, K. Eurek, J. Badger, H. E. Jorgensen, M. Kelly, L. Clarke, and P. Luckow (2012). *Improved Offshore Wind Resource Assessment in Global Climate Stabilization Scenarios: Technical Report.*

Bruninx, K., D. Orlic, D. Couckuyt, N. Grisey, and T. Anderski (2014). *e-HIGHWAY 2050: Modular Development Plan of the Pan-European Transmission System 2050.*

EPEX SPOT SE (2017). *EPEX SPOT Annual Market Review 2017: Press Release.*

Gerbaulet, C. and C. Lorenz (2016a). *dynELMOD: A Dynamic Investment and Dispatch Model for the Future European Electricity Market: Data_EU_ref_2016.* Berlin.

— (2016b). *dynELMOD: A Dynamic Investment and Dispatch Model for the Future European Electricity Market: NTC.* Berlin.

Götze, U., D. Northcott, and P. Schuster (2015). *Investment appraisal: Methods and models.* 2. ed. Springer texts in business and economics. Heidelberg et al.: Springer.

Hirschhausen, C. R. v., J. Herold, P.-y. Oei, and C. Haftendorn (2012). "CCTS-Technologie ein Fehlschlag: Umdenken in der Energiewende notwendig". In: *DIW-Wochenbericht : Wirtschaft, Politik, Wissenschaft* 79.6, pp. 3–9.

International Hydropower Association (2018). *Hydropower Status Report: Sector Trends and Insights.*

Jacobson, M. Z. et al. (2017). "100\,% Clean and Renewable Wind, Water, and Sunlight All-Sector Energy Roadmaps for 139 Countries of the World: Supplemental Information". In: *JOUL* 1.

Kirchner, A., S. Koziel, N. Mayer, and C. Kunz (2016). *Metaanalyse: Flexibilität durch Kopplung von Strom, Wärme & Verkehr.*

Kunz, F., M. Setje-Eilers, and M. Kendziorski (2017). "Generation expansion planning under uncertainty: An application of stochastic methods to the German electricity system". In: *Heading Towards Sustainable Energy Systems: Evolution or Revolution?, 15th IAEE European Conference, Sept 3–6, 2017.* International Association for Energy Economics.

Nagl, S. N., M. Fürsch, and D. Lindenberger (2012). *The costs of electricity systems with a high share of fluctuating renewables: A stochastic investment and dispatch optimization model for Europe.* Cologne.

Nahmmacher, P., E. Schmid, L. Hirth, and B. Knopf (2016). "Carpe diem: A novel approach to select representative days for long-term power system modeling". In: *Energy* 112, pp. 430–442.

Open Power System Data (2018). *Time series Data Package. Release 2018-06-30.*

Pape, C., N. Gerhardt, P. Härtel, A. Scholz, R. Schwinn, T. Drees, Maaz Andreas, and J. Sprey (2014). *Roadmap Speicher: Speicherbedarf für Erneuerbare Energien – Speicheralternativen – Speicheranreiz – Überwindung rechtlicher Hemmnisse: Endbericht.* Hannover and Kassel: Techn. Informationsbibl. und Univ.-Bibl and IWES.

Peter, J. and J. Wagner (2018). *Optimal Allocation of Variable Renewable Energy Considering Contributions to Security of Supply.*

Pfenninger, S. and I. Staffell (2016). "Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data". In: *Energy* 114, pp. 1251–1265.

Staffell, I. and S. Pfenninger (2016). "Using bias-corrected reanalysis to simulate current and future wind power output". In: *Energy* 114, pp. 1224–1239.

World Meteorological Organization (2018). *WMO Climatological Normals.*

Zerrahn, A. and W.-P. Schill (2017). "Long-run power storage requirements for high shares of renewables: review and a new model". In: *Renewable and Sustainable Energy Reviews* 79, pp. 1518–1534.

Zerrahn, A., W.-P. Schill, and C. Kemfert (2018). *On the economics of electrical storage for variable renewable energy sources.*

Appendix

Table 9: Model Sets, Parameters and Variables

Abbreviation	Dimension	Description
Sets		
$h \in H$		Hours
$tech \in T$		Technologies
$con \in C \subset T$		Conventional technologies
$res \in R \subset T$		Renewable energy technologies,
$stor \in S \subset T$		Storage technologies
$zone \in Z$		Zones (countries)
$sc \in \Omega$		Scenarios
Parameters		
ic^{annuity}	€/MW	Annuity of investment cost including FOM-cost and interest rates for generation technologies
ic^{power}	€/MW	Annuity of investment cost for power including FOM-cost and interest rates for storage technologies
ic^{energy}	€/MWh	Annuity of investment cost for energy including FOM-cost and interest rates for storage technologies
γ^{eff}	%	Efficiency of technologies
vc	€/MWh	Variable cost of generation technologies, consisting of cost for fuel and CO_2
ntc	MW	Available country to country network transfer capacities
d	MW	Hourly demand for each zone
p		Occurence probability of scenario sc
pot	MW	Technical potentials of generation technologies
ζ^{RES}	%	Assumed share of renewable energies in dispatch
δ^{avail}	–	Availability of nondispatchable technologies
Variables		
$\mathrm{N}_{zone,tech}$	MW	Installed capacity
$\mathrm{G}_{h,zone,tech}$	MWh	Generation of technologies
$\mathrm{D}_{h,zone,stor}$	MW	Demand from storage technologies
$\mathrm{L}_{h,zone,stor}$	MW	Storage level
$\mathrm{EX}_{h,zone}$	MW	Net exports
$\mathrm{N}^{\mathrm{E}}_{zone,stor}$	MWh	Installed energy capacity of storages
$\mathrm{N}^{\mathrm{P}}_{zone,stor}$	MW	Installed power capacity of storages

Table 11: Installed Generation Capacities 40%-VRE-scenario in MW

ID	Year	Lignite	Coal	Gas	WindOnshore	WindOffshore	PVGround	PVRoof

DE	1987	51041.24	0.00	22155.19	0.00	0.00	55945.63	0.00
DE	1998	53032.11	0.00	17744.29	5327.47	0.00	29244.71	0.00
DE	2003	49500.81	0.00	20482.76	0.00	0.00	55945.63	0.00
DE	2010	50289.76	0.00	18596.99	0.00	0.00	55945.63	0.00
DE	2015	50411.04	0.00	21417.67	0.00	0.00	52348.76	0.00
DE	stoch	59010.48	0.00	15543.27	0.00	0.00	55945.63	0.00
DK	1987	1237.97	0.00	2310.62	7873.06	0.00	0.00	0.00
DK	1998	723.63	0.00	2772.94	8044.64	0.00	0.00	0.00
DK	2003	1885.73	0.00	1886.23	6079.53	0.00	0.00	0.00
DK	2010	1195.16	0.00	2361.13	9053.31	0.00	0.00	0.00
DK	2015	877.53	0.00	2701.35	7980.75	0.00	0.00	0.00
DK	stoch	2379.10	0.00	1091.81	6119.43	0.00	0.00	0.00
FR	1987	21750.62	0.00	44710.51	97906.95	0.00	60554.70	0.00
FR	1998	21993.61	0.00	44795.55	98118.68	0.00	35819.87	0.00
FR	2003	21065.93	0.00	37264.69	100964.32	0.00	59804.57	0.00
FR	2010	20016.75	0.00	38094.29	107982.11	0.00	58798.41	0.00
FR	2015	21067.07	0.00	42710.17	95404.13	0.00	50195.48	0.00
FR	stoch	16991.30	0.00	34592.05	114252.97	29538.08	42632.00	0.00
IB	1987	8319.72	0.00	17366.20	71285.40	0.00	40704.58	0.00
IB	1998	13081.24	0.00	19678.31	52833.82	0.00	42413.72	0.00
IB	2003	11377.27	0.00	17336.25	56870.18	0.00	45124.44	0.00
IB	2010	8525.28	0.00	19205.26	65319.99	0.00	44353.32	0.00
IB	2015	13797.42	0.00	15935.61	46823.63	0.00	48436.10	0.00
IB	stoch	14350.19	0.00	14497.20	82115.62	0.00	36158.89	0.00
LU	1987	32444.27	0.00	21989.30	47651.43	0.00	12910.53	0.00
LU	1998	31014.06	0.00	21865.84	47651.43	0.00	0.00	0.00
LU	2003	32878.66	0.00	17169.58	47651.43	0.00	12910.53	0.00
LU	2010	32846.14	0.00	18839.63	47651.43	0.00	12910.53	0.00
LU	2015	30953.22	0.00	22916.74	47651.43	0.00	11698.46	0.00
LU	stoch	14478.17	0.00	6836.29	38406.41	0.00	12910.53	0.00
UK	1987	15663.36	0.00	24484.44	63266.61	0.00	0.00	0.00
UK	1998	10570.18	0.00	24900.87	67960.51	0.00	0.00	0.00
UK	2003	14720.01	0.00	25755.95	62900.03	0.00	0.00	0.00
UK	2010	17093.47	0.00	20936.58	63787.26	0.00	0.00	0.00
UK	2015	13968.94	0.00	28576.79	57741.30	0.00	0.00	0.00
UK	stoch	23413.60	0.00	14496.60	64166.03	0.00	0.00	0.00

Table 12: Installed Storage Capacities 40%-VRE-Scenario

ID	Year	PumpedStorage E [MWh]	Battery E [MWh]	PumpedStorage P [MW]	Battery P [MW]
DE	1987	4949.04	0.00	2686.61	0.00
DE	1998	6713.81	0.00	6669.95	0.00
DE	2003	10299.91	0.00	6931.00	0.00
DE	2010	7917.60	0.00	6931.00	0.00
DE	2015	4845.81	0.00	4408.74	0.00
DE	stoch	8267.84	0.00	3860.60	0.00
DK	1987	0.00	0.00	0.00	0.00

DK	1998	0.00	0.00	0.00	0.00
DK	2003	0.00	0.00	0.00	0.00
DK	2010	0.00	0.00	0.00	0.00
DK	2015	0.00	0.00	0.00	0.00
DK	stoch	0.00	0.00	0.00	0.00
FR	1987	18805.35	0.00	7852.23	0.00
FR	1998	12999.72	0.00	9430.77	0.00
FR	2003	22234.69	0.00	11641.06	0.00
FR	2010	22539.09	0.00	10954.07	0.00
FR	2015	29442.68	0.00	14235.00	0.00
FR	stoch	18395.90	0.00	10224.78	0.00
IB	1987	33452.50	0.00	11660.01	0.00
IB	1998	23612.27	0.00	9751.32	0.00
IB	2003	35241.04	0.00	13757.94	0.00
IB	2010	37638.75	0.00	14532.00	0.00
IB	2015	34580.33	0.00	13436.50	0.00
IB	stoch	27362.81	0.00	6987.03	0.00
LU	1987	6456.00	0.00	3228.00	0.00
LU	1998	7662.35	0.00	3228.00	0.00
LU	2003	6459.23	0.00	3228.00	0.00
LU	2010	6456.02	0.00	3228.00	0.00
LU	2015	6456.00	0.00	3228.00	0.00
LU	stoch	10703.64	0.00	3228.00	0.00
UK	1987	11331.12	0.00	5528.11	0.00
UK	1998	11878.42	0.00	5994.00	0.00
UK	2003	13110.92	0.00	5711.05	0.00
UK	2010	13501.93	0.00	5994.00	0.00
UK	2015	17639.55	0.00	5994.00	0.00
UK	stoch	6886.38	0.00	2253.51	0.00

Table 13: Installed Generation Capacities 80%-VRE-Scenario in MW

ID	Year	Lignite	Coal	Gas	WindOnshore	WindOffshore	PVGround	PVRoof
DE	1987	14336.43	0.00	49791.05	169085.71	0.00	55945.63	77121.49
DE	1998	9688.92	0.00	56211.89	169085.71	0.00	55945.63	48635.09
DE	2003	15648.31	0.00	44780.87	164578.36	0.00	55945.63	75140.48
DE	2010	13227.99	0.00	49677.38	169085.71	4086.50	55945.63	71118.97
DE	2015	10209.18	0.00	52911.19	168926.52	0.00	55945.63	62755.27
DE	stoch	32380.97	0.00	34377.05	169085.71	3012.22	55945.63	109055.85
DK	1987	0.00	0.00	5161.78	15299.57	0.00	4679.79	0.00
DK	1998	0.00	0.00	6181.24	13560.15	0.00	1977.79	0.00
DK	2003	0.00	0.00	5952.08	12797.87	0.00	5449.95	0.00
DK	2010	0.00	0.00	3322.49	16722.69	0.00	4720.73	0.00
DK	2015	0.00	0.00	5841.24	13287.99	0.00	3306.97	0.00
DK	stoch	837.90	0.00	2267.14	25965.04	0.00	0.00	0.00
FR	1987	0.00	0.00	56742.96	151215.40	28011.77	91652.97	0.00
FR	1998	0.00	0.00	55188.54	147375.81	18704.41	86152.88	0.00

FR	2003	0.00	0.00	48688.38	202749.73	0.00	98830.88	0.00
FR	2010	0.00	0.00	44693.52	157641.76	27170.55	91234.78	0.00
FR	2015	0.00	0.00	54603.55	173453.71	11805.77	87833.70	0.00
FR	stoch	1594.18	0.00	56006.70	51090.13	96708.60	50666.62	0.00
IB	1987	0.00	0.00	15085.31	84885.38	0.00	110681.81	0.00
IB	1998	0.00	0.00	15371.44	88596.92	0.00	92770.37	0.00
IB	2003	0.00	0.00	15940.65	78994.89	0.00	112229.59	0.00
IB	2010	0.00	0.00	14606.03	94153.80	0.00	87355.54	0.00
IB	2015	0.00	0.00	15172.00	81427.37	0.00	108256.35	0.00
IB	stoch	2727.34	0.00	20099.29	124508.57	0.00	79466.86	0.00
LU	1987	17336.65	0.00	36287.25	47651.43	43568.08	12910.53	25993.20
LU	1998	14974.54	0.00	36539.91	47651.43	35646.37	12910.53	25993.20
LU	2003	19969.51	0.00	27518.05	47651.43	34939.53	12910.53	25993.20
LU	2010	18808.66	0.00	30150.21	47651.43	41604.56	12910.53	25993.20
LU	2015	16149.58	0.00	37692.70	47651.43	36411.59	12910.53	25993.20
LU	stoch	5892.57	0.00	13106.50	47651.43	33955.03	12910.53	25993.20
UK	1987	0.00	0.00	37789.91	119409.19	0.00	47467.13	0.00
UK	1998	0.00	0.00	32843.29	107064.13	0.00	22776.57	0.00
UK	2003	0.00	0.00	38641.24	112909.43	0.00	44322.07	0.00
UK	2010	0.00	0.00	33056.20	132297.46	0.00	43117.99	0.00
UK	2015	0.00	0.00	36723.90	100790.70	0.00	40562.47	0.00
UK	stoch	2259.16	0.00	25911.17	195217.14	5608.47	33721.16	0.00

Table 14: Installed Storage Capacities 80%-VRE-Scenario

ID	Year	PumpedStorage E [MWh]	Battery E [MWh]	PumpedStorage P [MW]	Battery P [MW]
DE	1987	39478.30	0.00	6931.00	-0.00
DE	1998	31663.25	0.00	6931.00	0.00
DE	2003	30278.88	0.00	6931.00	0.00
DE	2010	30330.68	0.00	6931.00	0.00
DE	2015	27459.79	0.00	6931.00	0.00
DE	stoch	22662.62	0.00	6931.00	0.00
DK	1987	0.00	0.00	0.00	0.00
DK	1998	0.00	0.00	0.00	0.00
DK	2003	0.00	0.00	0.00	0.00
DK	2010	0.00	0.00	0.00	0.00
DK	2015	0.00	0.00	0.00	0.00
DK	stoch	0.00	0.00	0.00	0.00
FR	1987	130033.59	0.00	14235.00	0.00
FR	1998	86054.64	0.00	14235.00	0.00
FR	2003	106750.31	0.00	14235.00	0.00
FR	2010	109135.63	0.00	14235.00	0.00
FR	2015	99678.94	0.00	14235.00	0.00
FR	stoch	143448.22	0.00	14235.00	0.00
IB	1987	148235.17	0.00	37554.76	0.00
IB	1998	167262.41	0.00	27992.59	0.00
IB	2003	147260.35	0.00	37673.95	0.00
IB	2010	181971.56	0.00	26521.85	0.00

IB	2015	150626.90	0.00	33915.13	0.00
IB	stoch	118679.42	0.00	44567.00	0.00
LU	1987	20400.96	0.00	3228.00	0.00
LU	1998	13041.12	0.00	3228.00	0.00
LU	2003	10587.84	0.00	3228.00	0.00
LU	2010	12033.62	0.00	3228.00	0.00
LU	2015	13041.12	0.00	3228.00	0.00
LU	stoch	9449.31	0.00	3228.00	0.00
UK	1987	65540.10	0.00	5994.00	0.00
UK	1998	51000.89	0.00	5994.00	0.00
UK	2003	47968.19	0.00	5994.00	0.00
UK	2010	59443.52	0.00	5994.00	0.00
UK	2015	46212.11	0.00	5994.00	0.00
UK	stoch	59876.49	0.00	5994.00	0.00

Table 15: Mean Availabilities for PV, Wind Onshore and Wind Offshore per Country and Year

Year	Country	PV	Wind offshore	Wind onshore
1987	DE	0.12	0.30	0.18
1987	DK	0.11	0.33	0.24
1987	FR	0.14	0.46	0.24
1987	GB	0.11	0.35	0.26
1987	IB	0.16	–	0.27
1987	LU	0.12	0.29	0.22
1998	DE	0.12	0.37	0.22
1998	DK	0.10	0.39	0.28
1998	FR	0.14	0.49	0.26
1998	GB	0.10	0.41	0.31
1998	IB	0.17	–	0.27
1998	LU	0.11	0.36	0.27
2003	DE	0.14	0.28	0.17
2003	DK	0.12	0.31	0.22
2003	FR	0.14	0.43	0.23
2003	GB	0.11	0.36	0.27
2003	IB	0.16	–	0.27
2003	LU	0.13	0.29	0.22
2010	DE	0.12	0.29	0.17
2010	DK	0.11	0.32	0.23
2010	FR	0.14	0.44	0.23
2010	GB	0.11	0.32	0.24
2010	IB	0.16	–	0.27
2010	LU	0.12	0.27	0.21
2015	DE	0.13	0.36	0.21
2015	DK	0.11	0.39	0.29
2015	FR	0.14	0.47	0.25
2015	GB	0.11	0.41	0.32
2015	IB	0.17	–	0.25
2015	LU	0.13	0.34	0.26

Table 10: Installed pumped storage capacity per country (2018) in MW, full country list[29]

Country	Installed Capacity [MW]	Installation Potential [MW]	Total Potential [MW]
BE	1307	625	1932
DK	0	0	0
FR	6985	7250	14235
DE	6806	125	6931
LU	1296	0	1296
NL	0	0	0
PT	2613	875	3488
ES	3329	37750	41079
UK	2744	3250	5994