Decarbonization Scenarios for the EU and MENA Power System: Considering Spatial Distribution and Short Term Dynamics of Renewable Generation
Supplementary material

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Contents

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symbol	description
t	long term time step (long term time scale)
τ	time slice (short term time scale)
r	region
i	technology
g	renewable resource grade
f	fuel type
k	storage group

Table 1: List of indices

symbol	description
i_{gen}	generation technologies
i_{stor}	storage technologies
i_{trans}	transmission technologies
i_{ren}	renewable generation technologies
i_{conv}	conventional technologies
i_{fluc}	generation technologies with fluctuating output
i_{nfluc}	dispatchable generation technologies

Table 2: List of sets.

This text provides background information to the abovementioned article. It presents the algebraic formulation and the parameterization of the LIMES-EU^{+} model.

1 Model formulation

1.1 General remarks

A list of all used symbols can be found in the appendix (Tab. 12). Barring some exceptions, large Latin characters represent control variables, and Greek characters represent parameters. Small Latin characters are used to represent indices.

As LIMES is a multi scale model, the indices of parameters as well as control variables can sometimes be confusing. Tab. 1 show the indices used in this documentation. The model uses two distinct temporal scales. The terms *time steps* and *time slices* are used for the discretization of long term and short term time scales, respectively.

Elements of the model (e.g. technologies, regions, and fuel types) are assigned to groups with different characters. In GAMS syntax, these groups are called *sets*. This term is used in the documentation as well; they are listed in Tab. 2.

1.2 Model equations

1.2.1 Objective function and costs

Objective function The objective function of the model is the minimization of total system costs C^{tot}, defined as the sum of costs at each time step t, discounted to present values using discount rate ρ. Total system costs at each time step t are the sum of investment costs C^I, fuel costs C^F and operation and maintenance costs C^{OM}, minus a salvage value V for each technology i to account for capital stocks that remain at the end of the time horizon.

$$C^{\text{tot}} = \Delta t \sum_t e^{-\rho t} \left(C_t^I + C_t^F + C_t^{OM} \right) - e^{-\rho (t_{\text{end}} - t_0)} \sum_i V_i \tag{1}$$

Fuel costs Fuel prices for each primary energy type f and time step t are defined exogenously. Fuel costs C_t^F are the product of fuel price σ, primary energy consumption P, and time slice length l_τ, aggregated over all fuel types, regions, and time slices. Fuel prices are a function of time t.

$$C_t^F = \sum_{r,\tau,f} (\sigma_{t,f} P_{r,t,\tau,f} l_\tau) \qquad \forall t \tag{2}$$

Investment costs For generation and storage technologies, investment costs are the product of specific investment costs α and capacity additions ΔK. For transmission technologies, investment costs are the product of specific transmission investments costs α^T, transmission capacity additions K^T and transmission corridor length l^T.[1] For learning technologies specific investment costs α are a function of time t, for other technologies they are constant over time. Total investment costs C^I are calculated by aggregating over all regions, connections and technologies.

$$C_t^I = \underbrace{\sum_{r,i} (\alpha_{t,i} \Delta K_{t,r,i})}_{\text{generation and storage}} + \underbrace{\sum_{c,i} (\alpha_{t,i}^T l_c^T \Delta K_{t,c,i}^T)}_{\text{transmission}} \qquad \forall t \tag{3}$$

Operation and maintenance costs The model considers fixed and variable operation and mainentance costs. Fixed operation and mainentance costs β are given as a percentage of investment costs per year; variable operation and mainentance costs γ are correlated with power generation G. Total operation and mainentance costs C^{OM} are the sum of both terms, aggregated over all regions, technologies and time slices.

[1] Capacities of transmission technologies need to be treated separatly as they are indexed over connections c instead of regions r.

$$C_t^{OM} = \underbrace{\sum_{r,i}(\beta_i \alpha_{t,i} \Delta K_{t,c,i}}_{\text{fixed}} + \underbrace{\sum_{\tau,r,i} \gamma_i G_{t,\tau,r,i})}_{\text{variable}} \qquad \forall t \tag{4}$$

Salvage values The salvage value V for each technology i represents the value of capacities that are still operation after the last time step t_{end}. It depends on the capacity additions ΔK made before t_{end}, takes into account the specific investment costs α at the time step the capacity additions were made, and is subtracted from the system costs in the objective function.

$$V_i = \Delta t \sum_{\tilde{t}=0}^{\psi_i} \left(1 - \frac{1 - e^{\rho \Delta t(\tilde{t}+1)}}{1 - e^{\rho \psi_i}}\right) \alpha_{t_{\text{end}}-\tilde{t},i} \Delta K_{t_{\text{end}}-\tilde{t},r,i} \tag{5}$$

1.2.2 Energy balances and capacities

Electricity balance For each time step, region and time slice, the sum of generation G, storage charge S^{in}, storage discharge S^{out}, imports and exports F^T need to be equal to demand D. In this equation c^{in} and c^{out} represent the sets of all connections entering and leaving the actual region r. Transmission losses are subtracted from all flows that enter a region. Losses are represented by transmission loss coefficient ι^T. They are a linear function of transmission line length l^T.

$$D_{t,\tau,r} = \sum_{i \in i^{\text{gen}}} G_{t,r,\tau,i} + \sum_{i \in i^{\text{stor}}} (S^{\text{out}}_{t,r,\tau,i} - S^{\text{in}}_{t,r,\tau,i}) + \sum_{c \in c^{\text{in}}} \left((1 - \iota_i^T l_c^T) F^T_{t,c,i}\right) - \sum_{c \in c^{\text{out}}} F^T_{t,c,i} \qquad \forall t, r, \tau \tag{6}$$

Storage balance Time slices are associated with storage groups k. Storage can be used to shift power between time slices that belong to the same storage group. For each region, time step and storage group, the sum of storage charge S^{in} and discharge S^{out} need to be balanced (taking into account the round trip efficiency η.)

$$0 = \sum_{\tau \in k} l_\tau \left(\eta S^{\text{in}}_{r,t,\tau} - S^{\text{out}}_{r,t,\tau}\right) \qquad \forall r, t, k \tag{7}$$

Fuel consumption The ratio between fuel consumption P and power generation G is defined by the technology specific conversion efficiency η:

$$P_{t,r,\tau,f} = \sum_{i \in (i \to f)} \frac{1}{\eta_i} G_{t,r,\tau,i} \qquad \forall t, r, f \tag{8}$$

Capacity constraints Electricity generation by non fluctuating generation technologies technologies, transmission, storage charge and storage discharge flows $G, T, S^{\text{in}}, S^{\text{out}}$ are constrained by installed generation, transmission and storage capacities K and K^T. Fluctuating renewable generation is constrained by maximum generation $G^{\max}$, a control variable that is a function of region, time slice, and resource grade. Availabile transmission capacity K^T is scaled down with a security margin κ.

$$G_{r,t,\tau,i} \leq K_{r,t,i} \qquad \forall r, t, \tau, i \in i_{\text{nfluc}} \tag{9}$$
$$G_{r,t,\tau,i} \leq G^{\max}_{t,r,\tau,i} \qquad \forall r, t, \tau, i \in i_{\text{fluc}} \tag{10}$$
$$T_{c,t,\tau,i} \leq \kappa_i K^T_{c,t,i} \qquad \forall c, t, \tau, i \in i_{\text{trans}} \tag{11}$$
$$S^{\text{in}}_{r,t,\tau,i} \leq K^S_{r,t,i} \qquad \forall r, t, \tau, i \in i_{\text{stor}} \tag{12}$$
$$S^{\text{out}}_{r,t,\tau,i} \leq K^S_{r,t,i} \qquad \forall r, t, \tau, i \in i_{\text{stor}} \tag{13}$$

Cumulated annual availability of capacities To take planned and unplanned outages into account, we define an average annual availability factor ν for each dispatchable generation technology and for each storage technology. For each time step, region and technology, generation G aggregated over all time slices must not exceed installed capacity K times the availability factor ν. For hydro power, this availability factor is different for each meteorological season, and Eq. 14 is formulated for each season separately.

$$\sum_{\tau} (l_\tau G_{t,r,\tau,i}) \leq \nu_i \sum_{\tau} l_\tau \; K_{t,r,i} \qquad \forall t, r, i \tag{14}$$

Expansion and depreciation of capacities Each technology has a maximum lifetime ψ. Installed capacities are taken out of service according to technology specific depreciation curves which decline to zero once their maximum lifetimes are reached. These depreciation curves are described by depreciation coefficients ω. Available capacities K for each technology i, region r and time step t are the sum of previous capacity additions ΔK, scaled down with the depreciation coefficients. Available transmission capacities K^T are calculated in an equivalent equation (not shown here).

$$K_{t,r,i} = \Delta t \sum_{\tilde{t}=0}^{\psi_i} \left(\omega_{i,\tilde{t}} \Delta K_{t-\tilde{t},r,i} \right) \qquad \forall t, r, i \in (i_{\text{gen}} + i_{\text{stor}}) \tag{15}$$

1.2.3 Fluctuating renewable supply

For each fluctuating RE generation technology we define a discrete number of resource grades k. These resource grades are defined by a maximum installable generation capacity per region and grade $K^{\text{G,max}}$ and a maximum capacity factor λ which differs across region, time slice and resource grade.

The total installed capacity of fluctuating RE generation technologies K is the sum of the capacities in each grade K^G:

$$K_{t,r,i} = \sum_k K^G_{t,r,i,k} \qquad \forall t, r, i \in i_{\text{fluc}} \tag{16}$$

Capacities in each grade K^G are constrained by the maximum installable capacity per grade:

$$K^G_{t,r,i,k} \leq K^{\text{G,max}}_{r,i,k} \qquad \forall t, r, i \in i_{\text{fluc}} \tag{17}$$

Maximum generation is the sum over all grades k of installed capacities K^G times the grade specific maximum capacity factor λ:

$$G^{\max}_{t,r,\tau,i} = \sum_k (\lambda_{r,\tau,i,k} K^G_{t,r,i,k}) \qquad \forall t, r, \tau, i \in i_{\text{fluc}} \tag{18}$$

1.2.4 Other equations

Emissions Total CO_2 emissions are the product of fossil fuel consumption P and the fuel specific emission coefficient δ, aggregated over all regions, time slices, and fuel types.

$$E_t = \sum_{r,\tau,f} (\delta_f \; l_\tau \; P_{t,r,\tau,f}) \qquad \forall t \tag{19}$$

Constraint on biomass consumption For each time step and region, consumption of biomass is constrained by region and time specific biomass potential $P^{\max}$:

$$\sum_\tau (l_\tau P_{t,r,f}) \leq P^{\max}_{t,r,f} \qquad \forall t, r, f \in f^{\text{bio}} \tag{20}$$

Emission constraints Emissions for each time step E_t are constrained by emission caps $E^{\max}_t$:

$$E_t \leq E^{\max}_t \qquad \forall t \tag{21}$$

2 Parameters and calibration

This section documents how the input parameters for the LIMES-EU$^+$ model were derived.

2.1 Potentials of fluctuating renewable resources

For fluctuating renewable energy sources (wind onshore and offshore, photovoltaic, and CSP), gridded meteorological data sets have been used to estimate installable capacities per region, average annual capacities per region and capacity factors per region and time slice.

2.1.1 Matching data grids and model regions

The geographic boundaries of model regions are defined based on ADM-0 administrative boundaries.[2] Islands have been excluded. The model region has been limited to the geographical extents 27°N - 67°N / 15°W - 45°E, and all shapefiles have been cropped accordingly.

For each region an offshore buffer zone of 50km around the coastline has been created. These offshore areas are used to assess offshore wind potentials.

2.1.2 From meteorological data to capacity factors

The NCEP/NCAR 40-year reanalysis project [9] has been used to parameterize wind onshore, wind offshore, PV and CSP potentials.[3] The data set contains 6h average wind speed in 10m height, on a global grid with a spatial resolution of 1.5° x1.5°. The current calibration uses data for the year 2009.

All NCEP grid cells have been mapped to the onshore surface areas an offshore buffers of the model regions. We define the coefficients $A^{\text{onshore}}_{c,r}$ and $A^{\text{offshore}}_{c,r}$, which for each grid cell c gives the intersecting surface area with land and offshore area of region r, respectively.

Wind turbine capacity factors Wind speed data is based on the NCEP data sets `uwnd` and `vwnd` (wind speeds in north-south and east-west direction), and overall wind speed is calculated as

$$v_{t,c} = \sqrt{\text{uwnd}^2_{t,c} + \text{vwnd}^2_{t,c}}. \tag{22}$$

Offshore wind speeds are generally higher than onshore wind speeds. This is reflected in Fig. 1, which shows – for all grid cells – the relationship between the cell's offshore to onshore surface ratio and it's average annual wind speed. Based on this relationship, we derive offshore and onshore wind speeds from each cell's average wind speed:

$$v_{t,c} = \frac{A^{\text{onshore}}_{c,r} v^{\text{onshore}}_{t,c} + A^{\text{offshore}}_{c,r} v^{\text{offshore}}_{t,c}}{A^{\text{onshore}}_{c,r} + A^{\text{offshore}}_{c,r}} \tag{23}$$

$$v^{\text{offshore}}_{t,c} = 1.85 \cdot v^{\text{onshore}}_{t,c} \tag{24}$$

The methodology to convert wind speeds to capacity factors follows [5]. Wind speeds are scaled up from measurement heigth (10m) to hub height using equation 25. Wind speeds at hub height are converted to capacity factors using equation 26, which also takes into account turbine availability and turbine array efficiency. The coefficients used are summarized in table 3.

$$v^{\text{hub}}_{t,c} = \frac{\ln(h^{\text{hub}}/z_0)}{\ln(h^{\text{data}}/z_0)} \tag{25}$$

[2]Shapefiles available online `http://www.gadm.org/`. Accessed on July 5, 2010.

[3]The data is available in netCDF format at `http://www.esrl.noaa.gov/psd/data/gridded/data.ncep.reanalysis.html` (accessed october 2010).

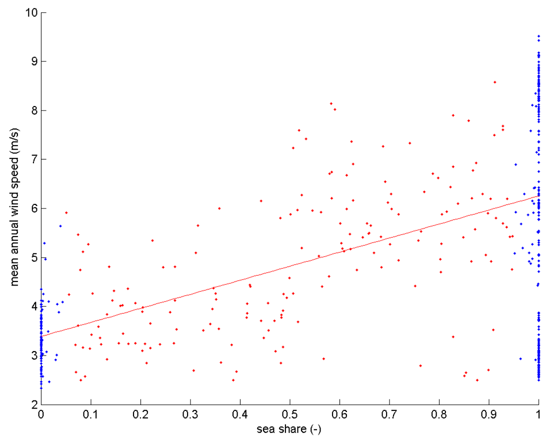

Figure 1: NCEP/NCAR wind speed data: Relationship between the cell's offshore to onshore surface ratio and average annual wind speed.

$$\epsilon_{t,c} = \epsilon^{\text{array}} \epsilon^{\text{turbine}} (\lambda_1 v_{t,c}^{\text{hub}} - \lambda_2) \tag{26}$$

Table 3: Parameters for capacity factor determination of wind onshore and offshore turbines [5].

Parameter	Unit	Onshore	Offshore
hub height h^{hub}	m	80	120
roughness length z_0	m	0.25	0.001
array efficiency ϵ^{array}	-	0.925	0.90
turbine availability $\epsilon^{\text{turbine}}$	-	0.97	0.90
fitting parameter λ_1	sh/ma	626.51	626.51
fitting parameter λ_2	h/a	1901	1901

PV and CSP capacity factors The NCEP dataset `dswrf` (downward solar radiation flux) has been used to parameterize PV and CSP potentials. We assume that this parameter equals global irradiance I.

The actual capacity factor of PV plants is the relationship between actual global irradiance $I_{t,c}$ and irradiance under reference conditions $I^{\text{ref}} = 1000W/m^2$, corrected with a system efficiency $\epsilon^{\text{system}} = 0.75$ [6].

$$\epsilon_{t,c} = \epsilon^{\text{system}} \frac{I_{t,c}}{I^{\text{ref}}} \tag{27}$$

Whereas PV plants can utilize both direct and diffuse irradiance, CSP plants can only convert direct irradiance. We use the following empirical correlation to derive direct normal irradiance DNI data from global irradiance data:

$$DNI_{t,c} = I_{t,c}\left(1 - 0.25\left(\frac{lat_c}{30}\right)^{1.6}\right) \tag{28}$$

This assumes that the DNI share of global irradiance is 0.75 at a latitude of 30°, and that it decreases for larger latitudes.

CSP plants are modeled with internal thermal storage. We assume a SM4 (Solar Multiple 4) configuration [12] where the collector area is four times the size required to reach nominal output at reference conditions, and the thermal storage capacity is large enough to run the plant at nominal output for 18 hours if the storage is completely filled. We therefore assume that the maximum capacity factor for CSP plants differs between days, but that it is equal for all four time slices within a single day. It is calculated as the mean value of each time slice's capacity factor, multiplied with four:

$$\epsilon_{t,c} = 4\frac{\sum_{i=1}^{n_i} \frac{DNI_{i,c}}{DNI^{\text{ref}}}}{n_i} \tag{29}$$

2.1.3 Maximum installable capacities of fluctuating RE

The maximum generation capacity K that can be installed per grid cell c correlates with the cell's surface area A:

$$K_c = DfA_c \tag{30}$$

The power density factor D defines how many GW nameplate capacity can be installed per km^2 of land or sea area. The land suitability factor f defines the share of surface area that is available to be used for generation capacity installation. Technology specific, uniform values are used for both parameters (Tab. 4).

Table 4: Parameters for determination of installable generation capacity per area ([6], own calculations).

	Power density D (MW/km^2)	suitability factor f (-)
Wind onshore	4	0.20
Wind offshore	4	0.20
PV	70	0.025
CSP	70	0.025

2.1.4 Resource grades

The derived data on capacity factors and installable capacity per grid cell (see Sec. 2.1.2 and 2.1.3) is aggregated to parameterize resource grades for each model region. For each region, we define three resource grades for each technology, each with an average annual capacity factor and a maximum installable

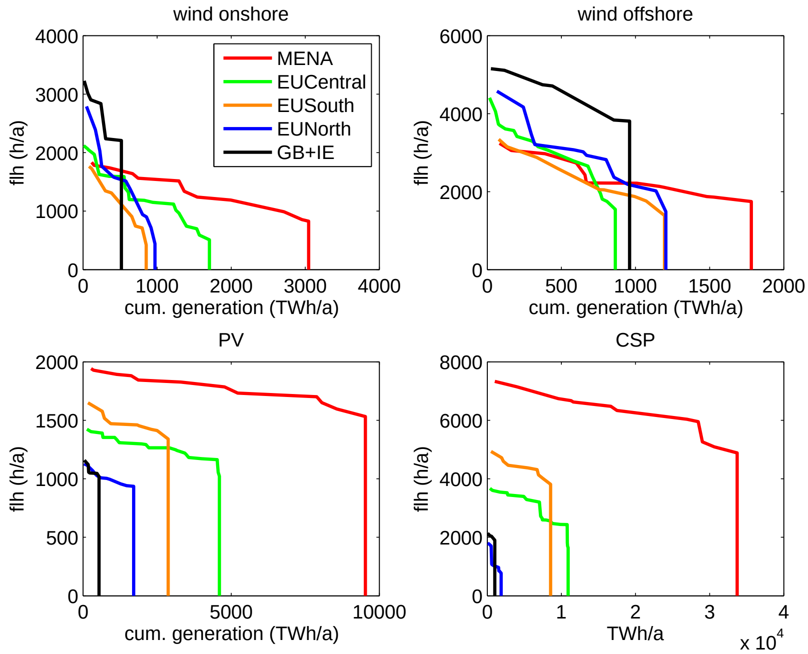

Figure 2: Regional potentials for fluctuating renewable energy resources.

capacity. Fig. 2 shows supply curves (marginal full load hours over total generated power) derived by sorting these grades, for five model region groups. The detailed data is show in Tables 6 and A.

2.1.5 Time slices and choice of characteristical days

The model features 49 time slices to represent short term fluctuations of supply and demand. In each time slice, supply and demand need to be balanced given the currently installed generation, storage and transmission capacities. The time slice scheme is shown in Tab. 5. There are four seasons and three RE supply regimes, which results in 12 characteristical days. Each day is represented by four time slices, each one with a length of six hours (starting at 0.00am). An additional super peak time slice represents high demand and low RE supply.

Fluctuations of RE supply are represented by the technology specific capacity factors which differ across region, resource grade and time slice.

1. For each region, a average wind speed duration curve is constructed (by all data points of the complete one-year time series by descending average wind speed.)
2. Out of the 365 days of the year, two candidates are determined for each of the twelve characteristical days, based on the average wind speed for this

Table 5: Time slice scheme and numbers of time slices.

	RE supply		
	low	medium	high
spring (3/01 – 5/31)	4	4	4
summer (6/01 – 8/31)	4	4	4
autumn (9/01 – 11/30)	4	4	4
winter (12/01 – 2/28)	4	4	4
super peak		1	

day, across all grid cells (e.g. the two spring days with the lowest average wind speed, the two spring days with the highest average wind speed, and the two spring days during which wind speed deviation from average wind speeds in spring is smallest.)

3. Out of these 24 candidates, a set of all possible combinations is constructed.

4. For each of these 512 combinations, a wind speed duration curve for each model region is constructed.

5. For each combination, wind speeds are scaled up so that their regional averages equal the regional averages of the complete time series.

6. The scaled regional wind speed duration curves (each one consisting of only 48 data points) are compared with the complete time series curves by calculating the coefficient of determination R^2 for each combination and region.

7. The combination with the largest sum of regional R^2 values is chosen for parameterization of the time slices.

2.2 Biomass potentials

Tab. 9 shows regional biomass potentials. The data is based on [4]. The reference gives primary energy potentials until 2030 for EU-25 member countries (for most countries, potentials increase over time due to efficiency increases and increased land utilization). Potentials are assumed to remain constant after 2030. For countries outside EU-25 a biomass potential of zero is assumed due to their endowment with other renewable resources (wind and hydro power resources for Norway, PV and CSP resources for MENA countries).

2.3 Seasonal availability of hydropower

To reflect the seasonal availability of hydro power resources, average capacity factors of hydro power capacities are constrained by season specific availability factors (see Tab. 10). Seasonal availabilities have been estimated based on average monthly power generation by hydro power plants published by entso-e[4] and installed capacities from [10]. They are assumed to be region independent.

Hydro power capacities are limited to current levels (data from [10]). Although studies claim that the potential for hydro power generation in Europe is not yet fully utilized (e.g. [3]) it is assumed that remaining potentials will rather be used for pumped hydro storage.

2.4 Power demand

2.4.1 Average annual demand until 2050

Tab. 8 shows demand projections for all model regions until 2050. For EU-27 member countries, we use the reference scenario from [2]. The reference gives empirical data from 1990-2009 and annual projections from 2010-2030. Demand from 2035-2050 has been extrapolated from this data. For countries outside EU-27 we calculate average annual demand growth rates for 1990-2008 from [7, 8]. We assume that demand growth rates for these countries linearly decrease to zero until 2050.

2.4.2 Demand fluctuations across time slices

Power demand across time slices is based on hourly load data published by ENTSO-E[5]. This data has been scaled to match average annual power demand published by IEA [7, 8]. Time slice demand is the average of hourly demands matching the respective time slice. For MENA countries hourly demand data was not available. Demand profiles have been created by scaling the demand profiles of neighbouring countries to match annual power demand published by IEA.

2.5 Initial generation and storage capacities

Ta. 11 shows generation and storage capacities in 2010. For EU-27 member countries, Norway and Switzerland, the data has been aggregated from the Chalmers Energy Infrastructure Database [10]. For other countries, generation capacities have been estimated based on the power mix for 2008 given in [7, 8].

2.6 Initial transmission capacities

Initial transmission capacities are based on Net Transfer Capacities (NTC's) published by ENTSO-E[6] In case where involved TSOs state different NTC values for a connection, the average of both values was used. Initial transmission

[4] Detailed monthly production tables for 2009, available online (`www.entsoe.eu/resources/data-portal/production`). Accessed on July 26,2011.

[5] System vertical load for 2009, available online (`www.entsoe.net`). Accessed on February 1, 2011.

[6] NTC values summer 2009, available online (`www.entsoe.eu/resources/ntc-values/ntc-matrix`). Accessed on December 1, 2010.

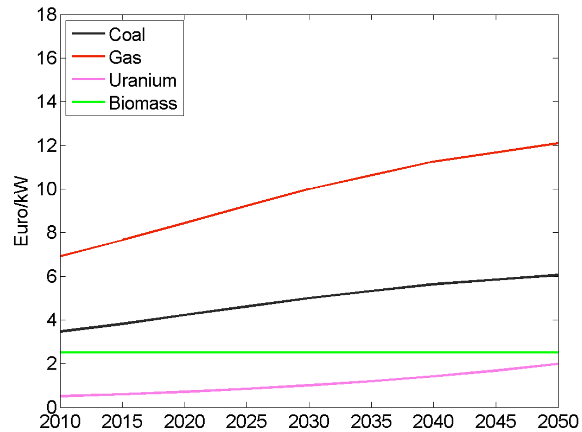

Figure 3: Price paths for fossil fuels, uranium and biomass.

capacities between MENA countries (which are not published by ENTSO-E) are assumed to be zero.

2.7 Fuel prices

Fig. 3 shows fuel prices for coal, natural gas, uranium and biomass. Coal, gas and uranium price scenarios are from [1]. For biomass a constant price of 2 5€/GJ is used.

2.8 Investment costs over time

Fig. 4 shows investment cost time paths for learning technologies. This data has been taken from the REMIND model [11]. The underlying scenario assumes that global emissions are reduced sufficiently to limit global mean temperature increases to 2°C until 2100, which results in ambitious RE expansion in the power sector. For other technologies, costs are assumed to be constant over time. The values are given in the paper.

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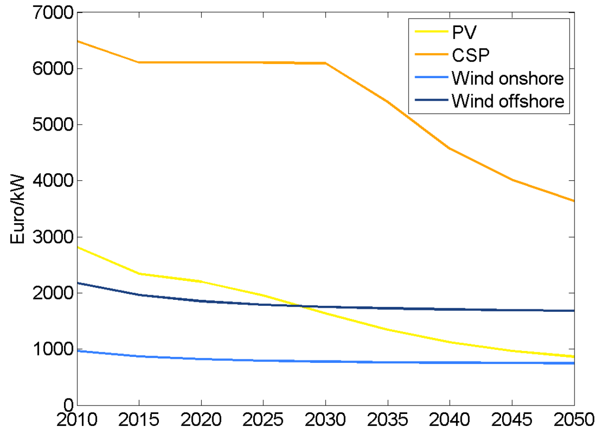

Figure 4: Investment cost time paths for learning technologies.

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A Data tables

Table 6: Average annual capacity factors for RE resource grades (%).

	Wind onshore			Wind offshore			PV			CSP		
Grade	1	2	3	1	2	3	1	2	3	1	2	3
NO	32	27	18	52	48	35	12	11	11	12	12	11
SE	23	17	11	39	32	23	12	11	11	12	12	11
DK	23	21	16	50	46	35	13	12	12	21	19	19
FI	18	10	5	33	27	17	12	12	11	10	10	9
Baltic	20	16	8	37	34	25	13	13	12	20	20	19
GB	34	32	25	58	54	44	13	13	12	24	23	22
IE	37	33	26	59	54	43	12	12	12	24	24	23
DE	24	18	14	43	41	31	15	14	13	31	30	28
East	15	13	8	30	27	22	14	14	13	30	29	28
BalkanN	11	8	6	21	20	18	16	15	15	42	40	39
BalkanS	10	9	5	23	20	16	17	17	16	52	51	49
FR	22	18	13	41	38	32	16	16	14	41	40	37
Benelux	24	21	19	42	39	36	14	14	13	30	29	28
CH+AT	14	12	7	0	0	0	15	15	15	39	39	38
IT	20	15	8	36	30	21	17	16	15	47	46	44
ES+PT	20	15	11	38	33	23	19	18	17	56	54	50
TR	18	14	10	28	24	20	19	18	17	60	58	56
MENAW	20	17	11	35	31	21	21	21	19	76	74	69
MENAC	21	19	14	37	34	25	22	22	20	84	82	77
MENAE	20	15	9	25	24	21	22	21	20	76	72	68

Table 7: Installable capacities for RE resource grades (GW).

	Wind onshore			Wind offshore			PV			CSP		
Grade	1	2	3	1	2	3	1	2	3	1	2	3
NO	16.8	50.3	100.6	14.2	42.7	85.4	34.8	104.4	208.8	34.8	104.4	208.8
SE	29.6	88.8	177.6	15.7	47.1	94.3	64.4	193.2	386.4	64.4	193.2	386.4
DK	1.6	4.9	9.9	3.3	10.0	20.0	7.2	21.6	43.2	7.2	21.6	43.2
FI	19.8	59.4	118.7	7.4	22.3	44.5	42.9	128.8	257.6	42.9	128.8	257.6
Baltic	14.4	43.1	86.1	7.1	21.4	42.7	30.0	90.0	180.0	30.0	90.0	180.0
GB	16.1	48.4	96.7	18.0	54.0	108.0	39.2	117.6	235.2	39.2	117.6	235.2
IE	4.7	14.1	28.1	4.7	14.1	28.1	11.3	33.9	67.9	11.3	33.9	67.9
DE	28.3	84.9	169.8	5.4	16.1	32.2	62.1	186.4	372.8	62.1	186.4	372.8
East	33.4	100.3	200.6	4.5	13.5	27.0	75.7	227.1	454.2	75.7	227.1	454.2
BalkanN	44.3	133.0	266.0	6.1	18.3	36.5	97.3	292.0	584.1	97.3	292.0	584.1
BalkanS	21.9	65.7	131.4	14.8	44.3	88.7	47.9	143.7	287.4	47.9	143.7	287.4
FR	42.0	125.9	251.7	10.6	31.8	63.5	91.1	273.4	546.8	91.1	273.4	546.8
Benelux	3.7	11.2	22.4	2.0	6.1	12.2	12.2	36.6	73.3	12.2	36.6	73.3
CH+AT	10.0	30.1	60.2	0.0	0.0	0.0	18.2	54.7	109.3	18.2	54.7	109.3
IT	21.0	62.9	125.8	18.4	55.2	110.4	46.6	139.8	279.7	46.6	139.8	279.7
ES+PT	45.5	136.6	273.3	22.9	68.7	137.4	101.7	305.2	610.5	101.7	305.2	610.5
TR	47.4	142.1	284.2	24.2	72.7	145.4	105.3	315.8	631.7	105.3	315.8	631.7
MENAW	121.0	363.0	726.1	25.8	77.4	154.8	261.1	783.2	1566.4	261.1	783.2	1566.4
MENAC	63.1	189.3	378.6	25.5	76.5	153.1	138.3	414.9	829.8	138.3	414.9	829.8
MENAE	18.1	54.3	108.6	4.2	12.6	25.3	42.8	128.3	256.5	42.8	128.3	256.5

Table 8: Average annual demand projections until 2050 (TWh/a).

	2010	2015	2020	2025	2030	2035	2040	2045	2050
NO	142.7	146.4	149.8	152.6	155.0	156.9	158.2	159.0	159.2
SE	149.4	152.5	155.5	158.4	161.3	164.0	166.8	169.4	172.0
DK	36.8	37.9	39.2	40.5	42.0	43.6	45.4	47.2	49.2
FI	79.0	82.2	84.1	84.7	83.9	81.8	78.3	73.6	67.5
Baltic	30.4	33.4	36.3	39.2	42.0	44.7	47.4	50.0	52.5
GB	391.1	404.2	415.5	424.9	432.5	438.3	442.2	444.3	444.5
IE	30.7	34.0	36.9	39.5	41.8	43.8	45.6	47.0	48.1
DE	641.2	662.5	679.1	690.8	697.6	699.7	697.0	689.4	677.0
East	276.8	301.9	329.7	360.2	393.4	429.4	468.2	509.6	553.8
BalkanN	189.3	204.4	220.9	238.6	257.7	278.0	299.7	322.7	347.1
BalkanS	121.6	131.7	142.3	153.2	164.5	176.3	188.4	200.9	213.8
FR	585.3	623.0	661.2	699.8	739.0	778.7	818.9	859.6	900.8
Benelux	198.6	209.4	219.5	228.6	237.0	244.5	251.2	257.0	262.0
CH+AT	134.7	142.6	150.0	156.8	163.0	168.5	173.2	177.1	180.2
IT	321.9	341.7	360.4	378.0	394.5	409.7	423.9	436.9	448.7
ES+PT	373.8	412.7	446.0	473.8	495.9	512.4	523.4	528.7	528.5
TR	219.9	278.2	341.1	405.3	466.7	520.6	562.5	588.6	596.3
MENAW	83.3	101.5	120.5	139.4	157.0	172.2	183.9	191.1	193.2
MENAC	178.3	229.7	286.4	345.5	403.0	454.3	494.6	519.9	527.4
MENAE	131.4	156.4	182.6	208.7	233.2	254.5	270.8	280.9	283.9

Table 9: Biomass consumption constraints (PJ/a).

	2010	2015	2020	2025	2030	2035	2040	2045	2050
NO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SE	24.1	35.4	46.8	52.5	58.3	58.3	58.3	58.3	58.3
DK	15.7	9.1	2.5	2.8	3.0	3.0	3.0	3.0	3.0
FI	78.4	76.9	75.4	64.7	54.0	54.0	54.0	54.0	54.0
Baltic	116.6	219.2	321.7	387.4	453.0	453.0	453.0	453.0	453.0
GB	141.6	255.7	369.8	493.2	616.5	616.5	616.5	616.5	616.5
IE	0.0	2.4	4.8	5.4	5.9	5.9	5.9	5.9	5.9
DE	76.4	59.5	42.6	49.4	56.1	56.1	56.1	56.1	56.1
East	649.4	869.6	1089.9	1239.8	1389.6	1389.6	1389.6	1389.6	1389.6
BalkanN	52.0	73.4	94.8	117.3	139.7	139.7	139.7	139.7	139.7
BalkanS	0.0	35.7	71.4	81.2	91.0	91.0	91.0	91.0	91.0
FR	112.9	119.5	126.0	95.9	65.7	65.7	65.7	65.7	65.7
Benelux	11.3	17.7	24.1	28.1	32.1	32.1	32.1	32.1	32.1
CH+AT	25.5	42.8	60.1	73.3	86.4	86.4	86.4	86.4	86.4
IT	170.4	271.1	371.9	504.2	636.5	636.5	636.5	636.5	636.5
ES+PT	354.7	464.8	574.9	639.9	704.8	704.8	704.8	704.8	704.8
TR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MENAW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MENAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MENAE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 10: Seasonal hydro power availability (maximum average capacity factor per season).

spring	summer	autumn	winter
0.37	0.35	0.33	0.41

Table 11: Initial generation and storage capacities (GW).

	Nuclear	Coal	Gas	Hydro run-off	Wind onshore	Wind offshore	SPV	Hydro PS	Bio	CSP
NO	0.0	0.0	1.2	26.7	0.4	0.0	0.0	1.1	0.0	0.0
SE	9.3	0.6	1.0	15.8	1.5	0.2	0.0	0.0	1.9	0.0
DK	0.0	4.9	2.5	0.0	2.7	0.9	0.0	0.0	0.4	0.0
FI	2.7	5.4	2.3	2.8	0.1	0.1	0.0	0.0	1.8	0.0
Baltic	0.0	3.0	2.8	1.7	0.2	0.0	0.0	0.8	0.0	0.0
GB	10.1	29.1	34.9	1.5	3.6	1.3	0.0	2.8	0.5	0.0
IE	0.0	1.4	4.1	0.2	1.4	0.0	0.0	0.3	0.0	0.0
DE	20.5	47.4	25.3	2.9	25.6	0.1	10.1	6.8	1.3	0.0
East	5.4	40.9	2.4	2.6	1.0	0.0	0.1	4.0	0.1	0.0
BalkanN	3.9	9.1	8.7	6.7	0.5	0.0	0.0	0.3	0.2	0.0
BalkanS	1.9	10.5	4.2	3.8	1.2	0.0	0.0	2.1	0.0	0.0
FR	63.1	8.2	6.3	14.6	4.5	0.0	0.1	5.5	0.2	0.0
Benelux	6.4	5.8	20.4	0.1	2.0	0.3	0.1	2.4	0.5	0.0
CH+AT	3.2	1.5	2.5	20.6	1.0	0.0	0.0	6.3	0.1	0.0
IT	0.0	9.8	46.9	12.1	4.8	0.0	0.1	6.8	0.4	0.0
ES+PT	7.5	14.0	31.3	18.0	21.8	0.0	1.2	4.0	0.6	0.7
TR	0.0	9.4	17.3	7.6	0.0	0.0	0.0	0.0	0.0	0.0
MENAW	0.0	1.9	10.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0
MENAC	0.0	0.0	23.5	3.4	0.0	0.0	0.0	0.0	0.0	0.0
MENAE	0.0	5.8	13.5	0.8	0.0	0.0	0.0	0.0	0.0	0.0

Table 12: List of symbols used in the model description. Symbols used for indices and sets are listed in Tab. 1 and 2.

symbol	unit	description
D	GW	demand
G	GW	generation
P	GW	primary energy consumption
S^{in}	GW	storage charge
S^{out}	GW	storage discharge
F^T	GW	transmission flow
C^{tot}	€	total system costs (objective function)
C^I	€	investment costs
C^F	€	fuel costs
C^{OM}	€	operation and maintenance costs
K	GW	available capacity (generation and storage)
ΔK	GW	capacity additions (generation and storage)
K^T	GW	available capacity (transmission)
ΔK^T	GW	capacity additions (transmission)
E	$GtCO_2$	emissions
l_τ	h	time slice length
α	€/kW	specific investment costs (generation and storage)
α^T	€/kWkm	specific investment costs (transmission)
β		fixed operation and maintenance costs
γ		variable operation and maintentance costs
δ		emission coefficient
η	-	conversion efficiency
ι^T	%/km	transmission losses
κ	-	security margin for utilization of transmission capacities
ω	-	depreciation coefficient
ψ	a	technical lifetime
ρ	%/a	discount rate
σ	€/GJ	specific fuel costs
l^T	km	transmission line length
Δt	a	time step length