Documentation of LIMES-EU - A long-term electricity system model for Europe

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This paper presents a detailed documentation of LIMES-EU - the Long-term Investment Model for the Electricity Sector of EUrope. LIMES-EU is a linear optimization model that simultaneously optimizes investment and dispatch decisions for generation, storage and transmission technologies. Its integrated approach together with an intertemporal optimization from 2010 to 2050 allows for analyzing comprehensive scenarios on the cost-efficient future development of the European power system. Despite the model's long-term focus until 2050, LIMES-EU effectively accounts for the short-term variability of electricity demand and the renewable energy sources wind and solar. In order to provide transparency, this paper gives a detailed overview of the model's underlying assumptions, its input data and a full list of the model equations.

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1. Introduction

The Paris Agreement demands strong actions to decarbonise the electricity systems. Policies already in place, namely national renewable support and the European ETS, have not lead to substantial reductions in the last years, and additional efforts are required to meet the targets in the medium and long-term[1]. The target in 2030 (40%) and 2050 (at least 80%) are expected to be missed respectively by 10% (European Commission 2017b) and 40% (European Commission 2016a) under current policies. The required emissions reduction thus translates into huge transformational demand in the energy-related sectors transport, heat and power. In particular, the power sector is expected to contribute more than any other sector as it has the biggest potential for cutting emissions and can almost totally decarbonised (European Commission 2016a). However, there are still numerous open questions of how to achieve such a strong transformation of the electricity system - comprising technical, economic and political aspects.

The core assets of the power sector - electricity generation, storage and transmission technologies - are characterized by long technical lifetimes that span over several decades. Long-term planning by relevant actors such as policy makers, transmission system operators and electricity producers is therefore pivotal. Within the framework of the '20-20-20' targets the European policy makers implemented specific policies to reach the targets with regard to the reduction of CO_2 emissions, the deployment of RES and the reduction of final energy consumptions until 2020. However, for the time after 2020 dedicated policies are yet undecided, both for reaching the long-term target of 80% emission reductions until 2050 as well as intermediate targets for emission reductions and RES deployment. In order to support policy makers in identifying robust policy targets long-term scenarios are needed to explore possible pathways for the European electricity sector that are technically feasible and economically sensible.

The **L**ong-term **I**nvestment **M**odel for the **E**lectricity **S**ector of **EU**rope LIMES-EU was developed to facilitate a long-term assessment of the European power system on aggregate and national level. Incorporating electricity generation, storage and transmission technologies LIMES-EU simultaneously optimizes investment decisions in 5-year steps from 2010 to 2050 for each country in Europe taking into account European-wide and country-specific climate and energy targets. In this way LIMES-EU delivers consistent and cost-efficient scenarios for the future European power system.

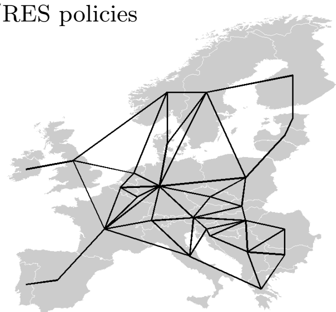
LIMES-EU is especially useful to analyze the integration of variable renewable energy sources (vRES) such as wind and solar into the European power system while considering flexibility operational constraints. Despite its long-term focus it accounts for short-term fluctuations of demand and vRES supply when determining the optimal electricity generation mix. Its comprehensive approach to simultaneously optimize investments in

[1] The 2020 package comprises the targets to ensure the EU meets its climate and energy targets for the year 2020: 20% GHG reduction, 20% share of renewable energy sources (RES) in energy consumption and 20% lower energy demand. The emissions are expected to decrease further by 2020 to 26% below 1990 levels with the measures already in place.

LIMES-EU - The **L**ong-term **I**nvestment **M**odel for the **E**lectricity **S**ector of **EU**rope

Type of model
linear optimization model
implemented in GAMS using the CPLEX Solver

Objective of the model
minimizing the cumulated costs of electricity provision
for a given electricity demand and exogenous CO_2/RES policies
by optimizing investment and dispatch decisions
for generation, storage and transmission capacities



Temporal scope & resolution
from 2010 to 2050 in 5-year steps
6 representative days per year
8 time slices per day
perfect foresight

Geographical scope & resolution
Europe; 29 model regions
all Member States of the European Union (without Malta and Cyprus)
plus Norway, Switzerland and an aggregated region of non-EU Balkan countries

Technologies
generation technologies
nuclear, hard coal, lignite, natural gas (combined cycle / gas turbine), oil
hard coal CCS, lignite CCS, natural gas (combined cycle) CCS, other gases
hydrogen combined cycle, hydrogen combustion turbine, hydrogen fuel cell, waste
hydro, wind onshore, wind offshore, photovoltaic, concentrated solar power, biomass
storage technologies
pumped storage power plants, batteries, hydrogen electrolysis
transmission technologies
net transfer capacities between model regions

Figure 1: LIMES-EU in a nutshell

generation and storage technologies as well as cross-border transmission capacities allows for a sound technological and economic analysis of vRES integration options.

This documentation aims to give a comprehensive and detailed description of LIMES-EU. Many of the parameters used in the model depend on future technological, economic and political developments and are therefore highly uncertain. In order to facilitate a correct interpretation of our model results and to provide a maximum amount of transparency, we aim to disclose all parameter values used for our default scenarios and describe the assumptions on which our parameter choice is based. A large part of the model equations as well as some calibration data did not change from the earlier LIMES-EU$^+$ versions of the model. Though they are already discussed in the supplementary material of the papers in which it has been used (e.g., Haller et al. (2012)) they are stated here again for the sake of comprehensiveness.

The following Section gives an overview about the model and its basic functioning. Section 3 briefly presents a novel approach for efficiently decreasing the intra-annual resolution of the model. It allows for keeping computational demand to a minimum while at the same time correctly reflecting the short-term variability of vRES. A more detailed description of the approach is provided in Nahmmacher et al. (2016). Section 4 and 5 discuss the standard parameter assumptions used to run the model, with Section 4 focusing on technology-specific parameters that are same for every model region and Section 5 focusing on region-specific input data. All prices and cost stated in this paper are given in 2010 prices. An overview about different climate and energy-related policies that can be implemented in LIMES-EU is presented in Section 6. Section 7 provides a validation of the model. A comprehensive list of all model equations can be found in Appendix A. Region names are often abbreviated by a two-letter code in this documentation; an explanation of the codes, which are based on ISO 3166-1, is given in Appendix B.

2. Model Overview

2.1. Objective Function

The model is formulated as an intertemporal social planner problem with perfect foresight. It minimizes the cumulated discounted costs of electricity provision for all model regions over the whole model time span simultaneously (Equation 1). The total system costs C^{tot} are the intertemporal sum of the costs for capacity investments C_t^I, fuel costs C_t^F, operation and maintenance costs C_t^{OM} as well as possible CO_2 emission costs $C_t^{CO_2}$ of each time step t. The factor Δt accounts for the time span between two model years. A salvage value V for the capacity stock that remains at the end of the time horizon is subtracted. All values are discounted to present values using the discount rate ρ which is set to 5% in the standard case. A comprehensive list of all model equations is given in Appendix A.

$$C^{tot} = \sum_t \left(\Delta t \, e^{-\rho(t-t_0)} \left(C_t^I + C_t^F + C_t^{OM} + C_t^{CO_2} \right) \right) - e^{-\rho(t_{end}-t_0)} \, V \qquad (1)$$

The electricity demand is exogenous to the model. The focus is on the supply side of the electricity system and its interactions with the transmission infrastructure. Using a social planner approach, the model abstracts from the nearly infinite amount of heterogeneous players in the electricity sector. The social planner solution is equivalent to the outcome of a decentralized market under perfect market conditions. Thus the model results show how a cost-optimal European electricity system under the given assumptions would look like, not how the European electricity system that faces considerable market distortions will evolve within the next decades.

The model is formulated in GAMS[2] and uses the linear solver CPLEX.

2.2. Geographical Resolution

The current version of LIMES-EU optimizes the electricity system of the EU28 countries[3] plus Switzerland, Norway and the Balkan region. Except for the Balkan region, all countries are modeled as individual entities. They differ with respect to electricity demand, initial generation and storage capacities, natural resource endowments and national energy policies. Natural resource endowments include the availability of lignite and biomass as well as hydro, wind and solar power. Due to the country-specific resolution, energy policy targets can be set on the national level or for a specified group of model regions (e.g. all EU Member States).

2.3. Temporal Resolution

In order to accommodate both long-term investment decisions and short-term fluctuations of wind, solar irradiance and demand, LIMES-EU makes use of two different time scales. The long-term scale ranges from 2010 to 2050 and is subdivided in 5-year *time steps*. The short-term scale subdivides the time steps into multiple *time slices*. Eight time slices - with a length of three hours each - add up to one representative day. A weighting factor is given to each representative day; together they add up to one model year. Assigning different weights to representative days allows for representing both days with common and rare load patterns. Section 3 presents the approach of how to select these representative model days.

While investments in generation, storage and transmission capacities are endogenously determined for each of the 5-year time steps, the balancing of electricity demand and supply, i.e. the dispatch of generation, storage and transmission capacities, is modeled for each time slice. The short-term perspective is needed to correctly value the available investment options by accounting for the intra-year variability of the electricity demand and intermittent renewable resources.

2.4. Technologies

The following briefly introduces the three kinds of technologies represented in LIMES-EU, namely generation, storage and transmission technologies. Section 4 provides a more detailed description of each technology. Power plants, transmission lines and storage facilities are not represented on a single unit basis in LIMES-EU, but are aggregated based on their economic and technical characteristics[4]. Modelling technology classes

[2] General Algebraic Modeling System, http://www.gams.com
[3] excluding Cyprus and Malta
[4] e.g. all hard coal power plants in France are aggregated to one class

rather than individual units considerably simplifies the model, which otherwise could not be solved due to computational constraints.

Generation Technologies Generation technologies convert primary energies to electricity. Lignite, hard coal and gas combined cycle are split in four vintages each one according to the time they were commissioned (before 1980, between 1980 and 1995, between 1995 and 2010, and after 2010) in order to account for the technological development and improve the calibration. Each of the 4 vintages is treated as an individual technologies, in which only efficiency varies across them. There are thus 29 different generation technologies in LIMES-EU that are classified into intermittent and dispatchable generation technologies. Wind onshore, wind offshore, solar photovoltaic (PV) and concentrated solar power (CSP) are intermittent with their availability varying both on a spatial and temporal scale. To account for intra-regional differences in wind and solar resources, the potential and availability of each technology is subdivided into three resource grades per intermittent generation technology. The availability of dispatchable technologies for each model region remains constant throughout the year. Dispatchable technologies in LIMES-EU comprise lignite, hard coal, natural gas combined cycle power plants and gas turbines as well as nuclear, biomass, waste, other gases, oil and hydro power plants. Electricity generation based on lignite, hard coal, natural gas, oil, waste and other gases is associated with CO_2 emissions. Optionally, lignite, hard coal and combined cycle natural gas plants can be enhanced with carbon capture and storage (CCS) technology that reduces their CO_2 emissions by storing them underground.

Transmission Technologies Transmission technologies enable the transfer of electricity between neighboring regions. Transmission is modelled as a transport problem from the center of one region to the center of a neighboring region - with the maximum transmissible amount of electricity being restricted by the installed net transfer capacity (NTC). The transmission of electricity between model regions is associated with losses. Network constraints and transmission losses within a region are not explicitly modelled in LIMES-EU ('copperplate' assumption).

Storage Technologies Demand and supply of electricity have to be balanced in every time slice. Storage technologies may serve as an additional consumer in times of oversupply of electricity from generation technologies and as an additional producer of electricity in times of undersupply. The shift of electricity provision from one time slice to another is subject to storage losses. Three different storage technologies are available in LIMES-EU: pumped storage power plants (PSP), batteries, hydrogen electrolysis. The former two are assumed to do only *intra*day arbitrage and hydrogen electrolysis is allowed to do also *inter*day arbitrage. While intraday storages can only shift electricity provision between time slices of the same day, interday storages are able to shift electricity provision between all time slices of the same year.

3. Time Slice Approach

Long-term models with endogenous investments are computationally demanding, especially when optimizing intertemporally, i.e., optimizing investment decisions for multiple time steps simultaneously. A common way to reduce temporal complexity is to optimize dispatch decisions only for a limited number of representative time slices instead of modelling every hour of the year. However, it is not obvious which time slices should be selected from historic data in order to preserve the characteristic variability of electricity demand and vRES infeed. Most existing approaches for aggregating historic data are only based on demand side fluctuations (Fürsch et al. 2011; Pina et al. 2011; Short et al. 2011) but as vRES technologies gain ever more importance in the European power system, models are required to also correctly accounting for their variability. Consequently, Golling (2012), Nagl et al. (2013), Sisternes Jimenez and Webster (2013), Poncelet et al. (2017) and others developed new approaches for selecting characteristic vRES infeed and demand pattern. However, none of those are satisfyingly applicable to the present model as they either focus on only one RES technology or disregard different spatial compositions of load levels, which is pivotal in a multi-regional model.

We therefore developed a novel and reproducible algorithm to be applied for LIMES-EU (see Nahmmacher et al. 2016). In our case it is used for selecting representative days with a given number of eight diurnal time slices; however it can also be applied for selecting separate representative time slices or other groups of consecutive time slices. Due to its generic design, our method is applicable to all kinds of power system models with multiple fluctuating time series, i.e. models with multiple vRES technologies and/or multiple regions. The algorithm is meant to optimally fulfill three essential requirements, namely that the derived time slices should sufficiently reflect

- the annual electricity demand and average vRES capacity factors for each region,
- the load duration curve of each time series, and
- the spatial and temporal correlation of electricity demand and vRES infeed.

The first requirement ensures that the quality of a region with respect to solar and wind power is correctly reflected. By replicating both common and rare situations of load and vRES infeed as well as their respective frequency of occurrence (second requirement), the time slices neither overestimate nor underestimate single events. This serves to correctly value both base and peak load plants. The third requirement ensures that the characteristics of an interconnected multi-regional electricity system are correctly assessed and features such as large-area pooling and geographic smoothing are taken into account.

Our approach is based on Ward (1963)'s hierarchical clustering algorithm. We apply this algorithm on historic electricity demand and weather data to group days with similar diurnal demand and vRES infeed patterns. As a result, each group of days is reflected by a representative day in the power system model.

3.1. Data

We use ENTSO-E (2016) data for the historic electricity demand levels and historic weather data from ECMWF (2018) for the vRES infeed. Using weather data rather than historic infeed data allows for taking into consideration a longer time span which prevents the overestimation of unusual years. The ECMWF data set comprises 33 years of ground solar irradiance and wind speed levels at 120m height for Europe. For every third hour between 1979 and 2011 the respective information is given for local data points in a spatial resolution of $0.75° \times 0.75°$. The conversion from weather data to vRES capacity factors is subject to the technology-specific power curves given in Section 4.

The three-hourly infeed of vRES technologies is averaged over all weather data grid cells belonging to the same region-specific resource grade. A comparison with real historic onshore wind feed-in levels however shows that realized capacity factors in mountainous countries[5] are much higher than the ones derived from the weather data. The spatial resolution of $0.75° \times 0.75°$ is obviously not high enough to reflect the variations in wind speeds between mountain valleys and ridges. As wind turbines are predominantly installed on ridges rather than in valleys we adjust the wind data in the following way:

$$\{v_{adj}\} = \{v_{era}\} + 0.01\left(\{h_{q3}\} - \{h_{mean}\}\right) \tag{2}$$

$$\text{with } [v] = m/s, [h] = m$$

It is assumed that the representative elevation h_{q3} of wind sites equals the third quartile of the elevation distribution within a weather data grid cell[6]. It is further assumed that the increase in local wind speed $(v_{adj} - v_{era})$ at a point within a grid cell is in direct proportion to the difference in elevation of this point to the average elevation h_{mean} of the grid cell. The increase of $0.01\frac{m/s}{m}$ is chosen in order to best reflect the infeed levels of wind power observed in 2010 and 2011 (derived from EUROSTAT (2018a) and EUROSTAT (2018b)).

Country-specific demand data is retrieved from ENTSO-E (2016) in an hourly resolution. Compared to the vRES infeed, the intra-year demand fluctuations are less stochastic and follow distinct diurnal, intra-week and seasonal patterns. Though the absolute demand levels change between different years due to demographic and economic reasons, the relative intra-year fluctuations remain the same. The hourly demand data of 2010 and 2011 that is available for all model regions is therefore assumed to be representative for the *intra*-year demand side fluctuations between 1979 and 2011. Future *inter*-year growth of annual demand is subject to scenario assumptions (see Sections 5.1 and 6).

[5] Spain in particular but also Austria and Italy

[6] the distribution of elevation within a grid cell is based on NGDC (2013)

3.2. Clustering Approach

To select a limited number of characteristic days from the total of 12053 days between 1979 and 2011 for which the weather data is available we apply an approach based on the hierarchical clustering algorithm described by Ward (1963). The approach ultimately yields a set of representative days that minimizes the sum of squared errors between all observed days and their representatives. By employing a multidimensional clustering algorithm, the approximation of any load duration curve of a region's electricity demand or vRES infeed is optimized while at the same time accounting for the simultaneous load and vRES levels of the other model regions.

The distance between two days (observations) is defined as the Euclidean distance respecting a total of 3016 dimensions[7] per observation. Before starting the clustering algorithm all time series are normalized to their maximum value. Subsequently, the algorithm iteratively groups similar days together until only one cluster containing all days remains. In each step, the clustering is done in a way that minimizes the variance within each cluster. Figure 2 visualizes the clustering procedure of our data.

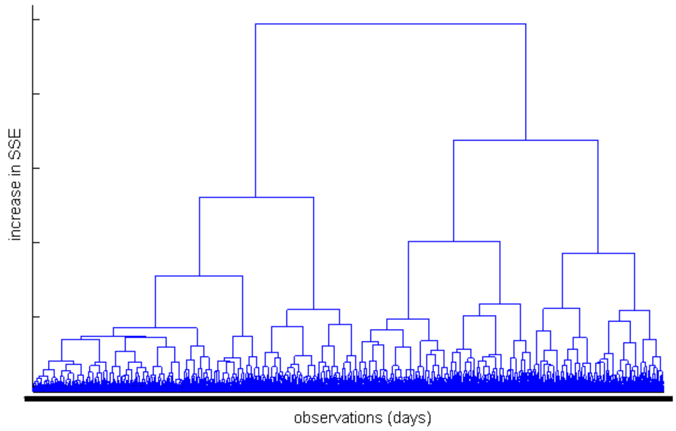


Figure 2: Dendrogram of clustering procedure. *Showing the consecutive grouping of two clusters to a joint cluster and the resulting increase in the overall sum of squared errors (SSE, y-axis). All days (x-axis) are consecutively grouped together until only one cluster is left.* Source: Own computation with model-specific data.

3.3. Resulting Time Slices

Once the clustering algorithm is finished, the model operator is free to choose the amount of clusters to use for the model and thereby trade off temporal resolution against computation time. For each cluster, there is one representative day in the model. We choose

[7]Each observation contains data about 29 regions, 4 technologies, 3 resource grades per technology and region as well as region-specific demand data; each for every third hour of the day.

that day as representative day that is closest to the cluster's mean vector. In the model, a weighting factor is assigned to every representative day according to the number of days within its cluster. To ensure correct average demand levels and capacity factors per technology and region the time series are scaled if necessary.

Nahmmacher et al. (2016) analyze the differences in model results depending on the number of time slices. They show that already 48 time slices, i.e., 6 representative days, are sufficient to reflect the characteristic fluctuations of electricity demand and vRES infeed in LIMES-EU. We therefore use 48 time slices in standard applications of the model.

4. Technology Characteristics

4.1. Generation Technologies

4.1.1. Intermittent Generation Technologies

Intermittent technologies comprise the generation technologies that are based on wind and solar power. For wind power LIMES-EU discerns between onshore and offshore power plants. Solar power technologies are divided into PV cells and CSP plants. Tables 1 and 2 give the techno-economic characteristics of these power plants. As the future development of their investment costs is highly uncertain, it is usually subject to a sensitivity analysis. Based on REMIND[8] Table 2 gives the investment cost assumptions for our default scenario.

Table 1: Characteristics of wind and solar power plants

	Fixed O&M (%/a)	Lifetime (a)
Wind Onshore	3	25
Wind Offshore	5	25
PV	1	25
CSP	3	30

Source: Haller et al. (2012) and own assumptions

The output of intermittent generation technologies is constrained by the region- and time-slice-specific availability of their respective renewable energy sources and subject to technology-specific power curves. Power curves describe the relation between resource availability (wind speed or solar irradiance) and possible electricity production of a respective power plant.

[8]For REMIND detailed harmonized model documentation is available at the Common IAM documentation, https://www.iamcdocumentation.eu/Model_Documentation_-_REMIND

Table 2: Default assumptions for vRES investment costs (€/kW)

	Wind Onshore	Wind Offshore	PV	CSP
2010	1300	4750	2500	6230
2015	1296	4412	1100	5080
2020	1291	4073	950	4760
2025	1262	3790	850	4750
2030	1232	3507	750	4740
2035	1212	3338	650	4590
2040	1191	3168	600	4430
2045	1171	2999	550	4000
2050	1150	2829	500	3560

Source: REMIND data and own assumptions

Turbine-specific wind power curves are published by the respective turbine producers. However, using power curves of commonly installed wind turbines to derive capacity factors from the weather data yields much higher values compared to historically realized full load hours (see Boccard (2009) for possible reasons). We therefore use the following regression to derive an aggregated wind power curve for the model (Equation 3). It is based on 2011-data of hourly German wind power production P_{Wind} (ÜNB 2013b) and installed capacities[9] cap_i (ÜNB 2013a) as well as the ERA-Interim wind speed data v_i (ECMWF 2018) per weather data grid cell i. It is assumed that the power output is proportional to the fifth power of the wind speed[10]. The resulting wind power curve which is defined by the five coefficients β_{1-5} is depicted in Figure 3.

$$P_{Wind} = \sum_i cap_i \left(\beta_1 v_i + \beta_2 v_i^2 + \beta_3 v_i^3 + \beta_4 v_i^4 + \beta_5 v_i^5\right) \tag{3}$$

The output of PV cells is assumed to be in a linear relation to the solar irradiance. In contrast to PV cells that use both direct and diffuse irradiance, CSP plants can only produce electricity from direct solar irradiance. Following Haller et al. (2012), the direct solar irradiance is derived from a simplified approximation which assumes that the direct normal irradiance DNI_i is a function of the global solar irradiance I_i and the latitude lat_i of the weather data grid cell i (Equation 4). This way the DNI share of global irradiance is 75% at a latitude of 30° and decreases for larger latitudes.

$$DNI_i = I_i \left(1 - 0.25 \left(\frac{lat_i}{30}\right)^{1.6}\right) \tag{4}$$

[9] The plant-specific installed capacities are aggregated according to the weather data grid.

[10] The power P of a free flowing wind stream is given by $P = \frac{1}{2}v^2\dot{m} = \frac{1}{2}v^2(vA\rho)$, with $\dot{m}$ denoting the mass flow rate, v the wind speed, ρ the air density and A the flow cross-section. Hence the power *input* of a wind turbine is proportional to the third power of the wind speed. The power *output* however is subject to a wind speed dependent power coefficient which is accounted for by also including the 4th and 5th power of v.

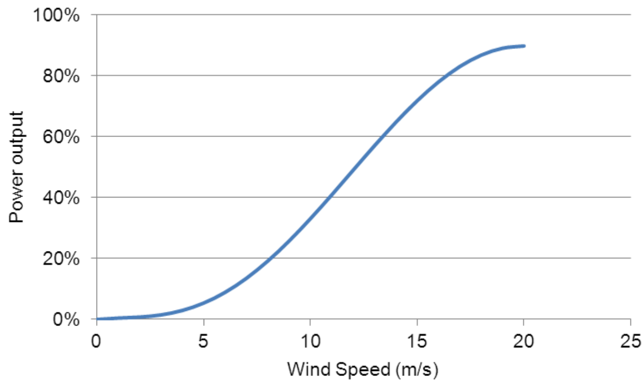


Figure 3: Aggregated wind power curve. Source: Own calculations based on ECMWF (2018) and ÜNB (2013a,b).

As in Haller et al. (2012) CSP plants are modelled with an collector area that is four times the size required to reach nominal output at reference conditions (SM4[11] configuration). Each CSP plant is equipped with an internal thermal storage with a capacity large enough to level out the diurnal fluctuations in solar energy input. Thus, even though solar irradiance varies between time slices, CSP plants are dispatchable within the limits of their daily availability factors that differ across days.

4.1.2. Dispatchable Generation Technologies

Power plants using fossil fuels, uranium, biomass or hydro power as a primary energy source are dispatchable within the limits of their annual availability. Except for hydro[12], the annual availability of these technologies is equal for all model regions (80%). Hourly availability for all technologies is defined as 100% minus the autoconsumption rate (from Agora (2014)). Table 3 gives an overview about the techno-economic characteristics of fuel and hydro based power plants in LIMES-EU.

Power plants with steam turbines are subject to minimum load restrictions and ramping constraints. In order to represent these characteristics operating capacity has to remain constant throughout the day's eight time slices. Their electricity production may not fall below a minimum load and the generation variation from one time slice to the next one within a day cannot exceed the maximum ramping. The minimum load and maximum ramping restrictions are given in Table 3 as the share of the operating capacity constraining the variation in generation within a day. Efficiency losses due to part load operation are disregarded. In addition to the impossibility to vary their generation within a day, operational capacity of nuclear power plants has to remain constant throughout the year.

[11] SM: solar multiple
[12] see Section 5.3.2 for the region-specific availability of hydro power plants (see Table 14)

Table 3: Techno-economic characteristics of thermal and hydro power plants

	Investment Costs (€/kW)	Efficiency (%)	Auto-cons. (%)	Fixed O&M (%/a)	Variable O&M (€/MWh)	Min Load (%)	Max Ramp (%)	Lifetime (a)
Nuclear	7000	33	5	3	2.8	40	-	60
Hard Coal	1800	38-50	8	2	6	30	35	45
Hard Coal CCS	see Table 4	43	8	2	29	30	35	45
Lignite	2100	36-47	8	2	9	50	25	55
Lignite CCS	see Table 4	42	8	2	34	50	25	55
Gas CC	900	54-60	3	3	4	40	50	45
Gas CC CCS	see Table 4	52	3	3	18	40	50	45
Gas GT	400	41	3	3	3	-	100	45
Oil	400	42	9	4	3	-	100	40
Hydrogen CC	1170	58	3	3	4	-	100	40
Hydrogen CT	520	33	3	4	3	-	100	40
Hydrogen FC	see Table 4	45	3	2	3	-	100	40
Waste	2000	22	2	4	3	-	35	40
Other gases	900	76	8	3	3	40	50	40
Biomass	2000	42	5	4	6	-	35	40
Hydro	2500	100	2	2	0	-	100	80

Source: Agora (2014), BMWi (2018), Bundesnetzagentur (2018), Haller et al. (2012), IEA (2016), Markewitz et al. (2018), and UBA (2018); own assumptions

Table 4: Default assumptions for dispatchable technologies with time-dependent investment costs (€/kW)

	Hard Coal CCS	Lignite CCS	Gas CC CCS	Hydrogen FC
2010	3748	3748	2113	2000
2015	3748	3748	2113	1800
2020	3475	3475	1942	1600
2025	3200	3101	1800	1400
2030	3000	2726	1700	1200
2035	2900	2555	1600	1000
2040	2800	2385	1550	900
2045	2700	2215	1500	800
2050	2600	2044	1450	700

Source: REMIND, IEA (2016) and own assumptions

The prices for primary energy sources used in thermal power plants are exogenous to LIMES-EU and thus independent from demand[13]; they are the same for every model region (see Table 5). However, the availability of certain fuels, namely lignite and biomass, differs between model regions (see Section 5.3.2).

Power generation from hard coal, lignite, natural gas, oil, waste and other gases emits greenhouse gases; the CO_2 intensity of these primary energy sources is given in Table 5 as well. The stated emission factors are estimated from the BMWi (2018) and are

[13] i.e. all model regions are assumed to be price takers on the fuel markets

considered equal for every model region for simplicity and due to the lack of sufficient data. In reality, the emission intensity of lignite significantly depends on the site of extraction and differs not only between but also within regions. The emission factors for all the fuels in the model fall nonetheless within the ranges provided by the IPCC (Gomez et al. 2006).

Table 5: Prices and CO_2 intensity of fuels

	Fuel prices (€/GJ)									CO_2 intensity
	2010	2015	2020	2025	2030	2035	2040	2045	2050	(tCO_2/TJ)
Hard Coal	2.2	1.9	2.3	2.4	2.4	2.5	2.6	2.8	3.0	0
Lignite	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	94.6
Natural Gas	5.4	4.9	6.0	6.5	6.8	7.5	8.0	8.2	8.7	101.2
Uranium	0.5	0.6	0.7	0.8	1.0	1.2	1.4	1.7	2.0	56.1
Biomass	6.0	6.0	6.0	6.0	6.3	8.5	11.2	14.5	18.2	0
Oil	9.6	9.8	11.0	12.3	13.3	15.5	15.1	16.7	18.5	80.6
Waste	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	154.0
Hydrogen	12.5	12.5	13.9	13.9	13.9	13.9	13.9	13.9	13.9	0
Other gases	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	202.8

Source: fuel prices taken from respective REMIND runs, emission factors estimated from BMWi (2018); own assumptions

4.2. Transmission Technologies

Transmission expansion between countries is modelled endogenously in LIMES-EU. For enabling the joint optimization of generation, storage and transmission expansion within one model run the transmission grid is represented by 'net transfer capacities' (NTC). The NTC-approach abstracts from the complex power flows of the highly intermeshed European transmission network by stating a simple transport-problem for the electricity exchange between two neighbouring countries. The installed NTC between two countries defines the maximum tradable power flow within a given time slice and remains constant throughout the year. Higher power flows are possible after investing in transmission expansion and thereby increasing the NTC between two countries. Investment costs depend on the additional capacity to be installed and the distance between the two country-centers. Table 6 summarizes the techno-economic characteristics of NTCs applied in the model.

The specific NTC investment cost vary significantly in the literature: Instead of the 1M€/GWkm in Hirth (2013) and LIMES-EU, Schaber et al. (2012) and Fürsch et al. (2013) only assume costs of 0.4M€/GWkm. However, 0.4M€/GWkm rather reflect the costs for thermal transfer capacity than for NTC: NEP (2013) state costs of 1.4M€/km for a 380kV overhead double-circuit. With a transfer capacity of about 1.8GW per circuit, this results in 0.4M€ per GWkm of thermal capacity (cf. DENA 2010; IZES et al. 2011). There are several reasons, why we assume the costs per NTC to be much higher: (1) NTC values are significantly smaller than thermal transfer capacities; (2) the stated costs only cover the lines and do not comprise substations and converters; and (3) costs for underground and sea cables are considerably higher than for overhead lines. We therefore assume that 1M€ per GWkm NTC is an appropriate approximation of the real transmission investment costs.

Table 6: Characteristics of transmission technologies

	Inv. Costs (M€/GWkm)	Availability (%)	Lifetime (a)	Losses (%/1000km)
Net Transfer Capacity	1.0	80	100	7

Source: Haller et al. (2012), NEP (2013), and Short et al. (2011); own assumptions

4.3. Storage Technologies

The purpose of storage technologies is to level out the excess and deficit of electricity over time. In LIMES-EU we consider three storage technologies: PSP and batteries for balancing between time slices of the same day (*intra*day storage), and hydrogen electrolysis for balancing between time slices of the same year (*inter*day storage). The technical and economic features of the three storage options are given in Table 7. We do not account for possible regional constraints, e.g., suitable sites for pumped-hydro storage systems, regarding these specific storage technologies.

Neither the time slices of a respective day nor the representative days themselves are modelled in a fixed order. The capacity of a storage system is therefore only regarded in terms of possible power input and output, not in terms of storage size. While this approach significantly helps to reduce computation time it may overestimate the potential for interday storages by not regarding the required storage size. However, given the assumed cost and efficiency stated in Table 7 *inter*day storages do not play a major role in any scenario outcome.

Table 7: Characteristics of storage technologies

	Inv. Costs (€/kW)	Fixed O&M (%/a)	Variable O&M (€/MWh)	Efficiency (%)	Lifetime (a)
Pumped Storage	1500	1	0	80	80
Batteries	see Table 8	1	0	80	20
Hydrogen Electrolysis	see Table 8	1	3	70	20

Source: Fuchs et al. (2012) and Haller et al. (2012); own assumptions

4.4. Depreciation of installed capacities

All technologies in LIMES-EU are characterized by technology-specific lifetimes. However, even before reaching their maximum lifetime, installed capacities are subject to

Table 8: Storage technologies with time-dependent investment costs

	2010	2015	2020	2025	2030	2035	2040	2045	2050
Batteries	1955	1955	1343	1090	949	857	800	761	735
Hydrogen Electrolysis	1500	1300	1100	900	700	500	400	350	300

Source: IEA (2016); REMIND and own assumptions

degradation. This is implemented via the depreciation factor $\omega_{\tilde{t},te}$ which depends on the lifetime ψ_{te} of a technology te and the time $\tilde{t}$ that has passed since its installation (Equation 5). Only the share $\omega_{\tilde{t},te}$ of the installed capacity can be used for electricity generation, storage or transmission, respectively. Figure 4 visualizes the depreciation factor $\omega_{\tilde{t},te}$ for three different technological lifetimes: 20, 40 and 60 years.

$$\omega_{\tilde{t},te} = 1 - \left(\tilde{t}/\psi_{te}\right)^6 \qquad \forall te, \tilde{t} \leq \psi_{te} \tag{5}$$

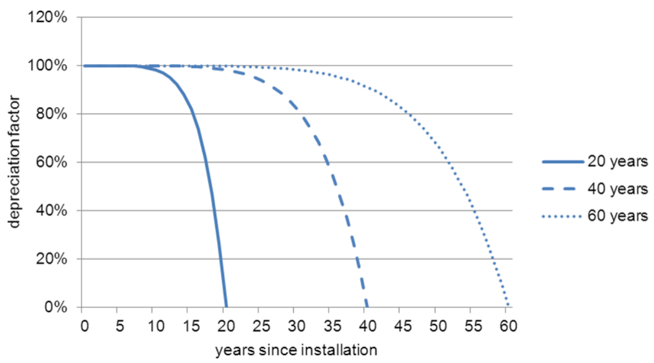


Figure 4: Depreciation factor ω for three different technological lifetimes (20, 40, 60 years). Source: Own assumptions.

5. Region-Specific Input Data

5.1. Electricity Demand

As discussed in Section 3, the intra-year variation of the model regions' electricity consumption is based on ENTSO-E (2016). Final annual electricity consumption for 2010 and 2015 is retrieved from EUROSTAT (2018b) for all countries except Switzerland, for which BFE (2017) is used. Demand projections until 2050 are based on European Commission (2016b) for EU members and BFE (2013) for Switzerland for default scenarios. Future demand for Norway and Balkan countries is estimated based on the growth rates of their neighboring countries for which data is available. Table 9 reports both the historical data for 2010 and 2015, and the default projections for future electricity demand.

Regarding the year 2050, electricity consumption is projected to rise in every model region. However, the relative increase differs strongly across countries, with Switzerland (+4%) and Luxembourg (+94%) being at the lower and upper end, respectively. An explanation of the region codes used in this document is given in Appendix B.

Based on historical data, it is assumed that the required production of electricity has to exceed the reported final electricity consumption by 8% to account for intra-regional transmission and distribution losses.

Table 9: Default assumptions for final electricity demand (in TWh)

	2010	2015	2020	2025	2030	2035	2040	2045	2050
BE	83.4	82.5	84	85.4	89	91.9	97.3	102.9	108.1
BG	27.2	28.3	29.1	30.2	31.1	31.7	32.8	34	35.6
CZ	56.2	56.8	61	64.1	66.1	68.9	71.8	75.7	79.1
DK	32.1	30.7	32.8	34.5	35.7	37.8	39.8	42.2	44.5
DE	532.4	514.7	530.3	545.2	559	561.8	566.2	573.3	579.8
EE	6.9	6.9	7.6	7.8	8.3	8.6	8.9	9.4	9.8
IE	25.3	25.5	26.2	27.3	28.1	29.3	30.6	32.1	33.9
GR	53.1	50.8	53.3	52	50.5	52.9	54.3	55.2	56.4
ES	245.4	232.1	246.6	249.3	256.7	263.2	270.3	279.3	290.9
FR	443.7	421.6	452.2	458	469.3	489.1	508.5	527.1	547.5
HR	15.9	15.3	16.2	16.2	16.4	17.1	17.9	19.1	20.5
IT	299.3	287.5	304.3	306.3	313.7	335.8	359.2	377.5	394.9
LV	6.2	6.5	7.2	7.6	8.1	8.4	9	9.5	9.9
LT	8.3	9.3	10.3	10.4	10.2	10.3	10.5	11.2	11.7
LU	6.6	6.2	6.9	7.5	8.3	9.3	10.4	11.3	12
HU	34.2	37	35.9	38.2	39.1	40.6	42.9	45.6	47.2
NL	107.4	103.6	110.5	114.4	116.3	118.6	123.1	127.5	132.8
AT	60.3	60.8	67.2	69.7	72.5	74.7	77.7	81	82.8
PL	118.7	127.8	142	156	168.3	177.1	185.9	194.5	202.3
PT	49.9	45.8	47.1	47.7	47.8	48.4	49.6	50.5	51
RO	41.5	43.1	47.2	49.2	51.1	53.3	56.3	59.4	62.3
SI	11.9	12.8	13.5	14.7	15.1	15.4	16	16.6	17.2
SK	24.1	24.4	27.1	29.4	31.1	32.2	33	33.7	34.2
FI	83.4	78.4	79.7	82.4	83.9	86.3	88.8	92.5	96.1
SE	131.2	124.9	135.5	139.5	144.2	148.1	152.6	159.6	165.8
GB	329	302.9	322.3	330.1	340.5	355.3	382.6	404	410.3
NO	113.5	110.8	120.2	123.8	128	131.4	135.4	141.6	147.1
CH	59.8	58.2	58.6	58.3	58.1	57.8	58.8	59.8	60.8
Balkan	57.7	57.7	60	61.5	62.2	64.6	67.6	70.4	73.4

Source: BFE (2013, 2017), EUROSTAT (2018b), and European Commission (2016b); own assumptions

5.2. Installed Capacities in 2015

As the model has been recently calibrated to 2015 as base year, installed capacities are set exogenously. The existing capacities of generation and storage technologies (see

Table 13) are derived from Open Power System Data (2018), which aggregates data from different official sources, e.g., ENTSO-E, local TSOs and local ministries. For instance, in the specific case of Germany, data from the BMWi (2018) is used. The age structure of technologies is derived from Platts (2011) and EUROSTAT (2018a). Due to lack of data for the rest of countries, waste and other gases capacities are only considered in Germany.

The cross-border transmission capacities (Table 10) correspond to the average value of NTC's in both directions for each of the existing and potential cross-border links (according to the 2016 Ten Year Network Development Plan - TYNDP ENTSO-E (2015)). The 2010 values are derived from the summer NTC values from 2010 reported by ENTSO-E (2010). The 2015 values are derived from the ACER/CEER (2017) report. For those links for which 2015 NTC's are not reported (countries with market coupling, e.g., FR-BE), the values from 2010 are used. Likewise, when the 2015 value is lower than the 2010 value, the capacity from 2010 is used (disinvestments in transmission are not allowed in the model). The capacities for 2025 and 2030 are derived from the reference capacities presented in the 2016 TYNDP (ENTSO-E 2015). These are used as upper bounds for transmission capacity in the model. As the precise age structure of the transmission network is unknown, we assume that the existing lines in 2010 were either constructed or refurbished after 1985 and that investments into the grid were equally distributed between 1985 and 2010.

5.3. Resource Endowments

5.3.1. Wind & Solar

A country's wind and solar power potential is defined by two determinants: (1) the achievable capacity factors at the respective sites (2) the installable capacity of wind and solar power plants and. The achievable capacity factors allow us to scale the hourly availability factors from Section 4.1.1. For capacity installed before 2015 we use the average annual availability factors between 2010 and 2015 for each technology and country IRENA (2017). For capacity built after 2015, we consider derived capacity factors from NREL (2013) for wind onshore and offshore, Pietzcker et al. (2014) for PV. Given the lack of data, we do not scale further the hourly factors for CSP. The former sources are used to estimate the installable capacity for these technologies. To account for the varying quality of wind and solar sites within a country, we define three resource grades per intermittent renewable technology for every model region. Each resource grade comprises a certain share of the resource potential and its assigned average technology-specific capacity factor of this area. Table 11 shows the technologies' capacity potentials per model region; the corresponding capacity factors per region and resource grade are given in Table 12.

NREL (2013) provides global onshore and offshore wind supply curves based on the National Center for Atmospheric Research's (NCAR) Climate Four Dimensional Data Assimilation (CFDDA) mesoscale climate database. For onshore it provides the resource

Table 10: Transmission capacities between model regions

	2010	2015	2020	2030
AT-CH	0.8	1.0	1.7	1.7
AT-CZ	0.7	0.7	1.1	1.1
AT-DE	1.6	1.6	5.0	7.5
AT-HU	0.4	0.6	1.0	1.0
AT-IT	0.1	0.2	0.5	1.5
AT-SI	0.9	0.9	1.2	1.2
AT-SK	0.0	0.0	0.0	0.0
BE-DE	0.0	0.0	1.0	1.0
BE-FR	2.1	2.1	3.6	3.6
BE-LU	0.0	0.0	0.9	0.9
BE-NL	2.3	2.3	2.4	2.4
BG-GR	0.5	0.5	1.4	1.4
BG-Balkan	0.5	0.5	0.8	0.8
BG-RO	0.4	0.4	1.5	1.5
CH-DE	3.2	3.2	4.0	4.0
CH-FR	2.1	2.1	2.5	2.5
CH-IT	2.5	2.5	5.1	5.1
CZ-PL	1.4	1.4	0.6	0.6
CZ-SK	1.6	1.6	1.6	1.6
DE-CZ	1.5	1.7	1.8	2.3
DE-DK	1.8	1.8	4.0	4.0
DE-FR	2.9	2.9	3.0	4.8
DE-PL	1.0	1.0	2.5	2.5
DE-SE	0.6	0.6	0.6	1.3
DK-NO	1.0	1.4	1.6	1.6
DK-SE	1.9	1.9	2.2	2.2
EE-FI	0.9	0.9	1.0	1.0
EE-LV	0.7	0.7	1.6	1.6
ES-FR	0.9	1.2	5.0	8.0
FI-SE	1.9	2.4	2.4	3.0
FR-GB	2.0	2.0	5.4	5.4
FR-IT	1.6	1.7	3.3	3.3

	2010	2015	2020	2030
AT-CH	0.8	1.0	1.7	1.7
AT-CZ	0.7	0.7	1.1	1.1
AT-DE	1.6	1.6	5.0	7.5
AT-HU	0.4	0.6	1.0	1.0
AT-IT	0.1	0.2	0.5	1.5
AT-SI	0.9	0.9	1.2	1.2
AT-SK	0.0	0.0	0.0	0.0
BE-DE	0.0	0.0	1.0	1.0
BE-FR	2.1	2.1	3.6	3.6
BE-LU	0.0	0.0	0.9	0.9
BE-NL	2.3	2.3	2.4	2.4
BG-GR	0.5	0.5	1.4	1.4
BG-Balkan	0.5	0.5	0.8	0.8
BG-RO	0.4	0.4	1.5	1.5
CH-DE	3.2	3.2	4.0	4.0
CH-FR	2.1	2.1	2.5	2.5
CH-IT	2.5	2.5	5.1	5.1
CZ-PL	1.4	1.4	0.6	0.6
CZ-SK	1.6	1.6	1.6	1.6
DE-CZ	1.5	1.7	1.8	2.3
DE-DK	1.8	1.8	4.0	4.0
DE-FR	2.9	2.9	3.0	4.8
DE-PL	1.0	1.0	2.5	2.5
DE-SE	0.6	0.6	0.6	1.3
DK-NO	1.0	1.4	1.6	1.6
DK-SE	1.9	1.9	2.2	2.2
EE-FI	0.9	0.9	1.0	1.0
EE-LV	0.7	0.7	1.6	1.6
ES-FR	0.9	1.2	5.0	8.0
FI-SE	1.9	2.4	2.4	3.0
FR-GB	2.0	2.0	5.4	5.4
FR-IT	1.6	1.7	3.3	3.3

Source: ACER/CEER (2017) and ENTSO-E (2010, 2015); own assumptions

Table 11: Installable capacities of wind and solar power plants per region and resource grade (in GW)

	Wind Onshore			Wind Offshore			PV			CSP		
	1st	2nd	3rd	1st	2nd	3rd	1st	2nd	3rd	1st	2nd	3rd
FI	-	5	253	-	29	51	69	278	333	0	1	3
NO	63	264	99	1	69	-	169	677	813	0	1	1
SE	-	40	316	-	155	67	92	367	440	1	2	4
EE	-	4	45	-	19	14	9	37	44	0	1	1
LV	-	4	67	-	38	28	19	75	90	0	1	2
LT	-	4	140	-	15	-	36	142	171	1	2	3
DK	-	106	-	74	146	0	31	124	148	1	2	3
GB	17	494	-	87	390	-	233	933	1,120	3	10	21
IE	36	183	-	11	22	-	148	592	710	1	3	5
NL	-	35	44	3	159	-	31	125	150	0	1	2
PL	-	11	753	-	54	11	150	599	719	3	9	18
DE	-	73	496	16	74	2	230	921	1,105	3	10	20
BE	-	6	65	-	16	-	33	131	157	0	1	2
LU	-	-	6	-	-	-	3	11	13	0	0	0
CZ	-	-	175	-	-	-	34	137	165	1	3	5
SK	-	-	105	-	-	-	24	95	114	0	1	2
AT	-	-	163	-	-	-	31	125	150	1	2	4
CH	-	-	60	-	-	-	23	91	109	0	1	2
HU	-	-	304	-	-	-	40	162	194	1	3	6
RO	-	-	653	-	-	48	155	619	743	3	8	17
SI	-	-	32	-	-	0	12	48	58	0	0	1
FR	-	85	1,255	-	98	61	480	1,921	2,305	6	17	35
HR	-	-	135	-	-	36	7	30	36	0	1	2
BG	-	-	281	-	-	20	74	296	355	1	3	6
IT	-	-	700	-	-	77	218	872	1,046	3	9	17
ES	-	11	1,310	-	10	32	773	3,093	3,712	6	17	33
PT	-	-	195	-	-	9	171	685	822	1	2	4
GR	-	5	248	-	0	8	204	817	980	2	5	10
Balkan	-	-	535	-	-	1	37	149	179	2	6	12

Source: ECMWF (2018), FAO (2018), Held (2010), and NREL (2013); own assumptions

Table 12: Maximum capacity factors of wind and solar power plants per region and resource grade (in %)

	Wind Onshore			Wind Offshore			PV			CSP		
	1st	2nd	3rd	1st	2nd	3rd	1st	2nd	3rd	1st	2nd	3rd
FI	-	32	25	-	32	28	13	13	12	10	8	5
NO	40	34	26	40	35	-	11	10	9	12	10	4
SE	-	32	25	-	34	27	12	12	11	15	12	6
EE	-	32	28	-	32	28	13	13	13	13	13	12
LV	-	32	27	-	32	27	13	13	12	15	15	14
LT	-	32	28	-	32	-	13	13	12	17	16	15
DK	-	34	-	40	34	28	12	12	12	18	17	15
GB	40	34	-	40	36	-	12	10	9	23	20	15
IE	40	36	-	40	36	-	11	9	9	21	19	17
NL	-	34	28	40	36	-	11	11	10	22	21	20
PL	-	32	26	-	33	28	11	11	11	23	22	19
DE	-	33	25	40	35	28	12	11	10	26	24	20
BE	-	32	28	-	35	-	12	11	10	24	23	22
LU	-	-	25	-	-	-	11	10	10	24	24	23
CZ	-	-	24	-	-	-	11	11	10	25	24	23
SK	-	-	19	-	-	-	12	12	11	28	27	25
AT	-	-	22	-	-	-	13	12	12	29	28	26
CH	-	-	23	-	-	-	12	12	12	32	31	28
HU	-	-	18	-	-	-	13	12	12	32	31	28
RO	-	-	18	-	-	24	13	13	12	36	34	29
SI	-	-	17	-	-	16	14	13	13	32	31	30
FR	-	32	24	-	33	26	14	12	12	40	35	27
HR	-	-	18	-	-	18	14	13	12	38	35	32
BG	-	-	19	-	-	23	14	13	13	41	39	37
IT	-	-	19	-	-	17	17	15	14	53	44	35
ES	-	34	20	-	32	22	17	16	16	57	52	44
PT	-	-	22	-	-	25	18	16	15	55	52	46
GR	-	32	21	-	32	24	18	17	15	53	49	43
Balkan	-	-	18	-	-	24	14	13	13	43	39	35

Source: ECMWF (2018) and NREL (2013); own assumptions

Table 13: Installed generation and storage capacities in 2015 (in GW)

	Nuclear	Hard Coal	Lignite	Natural Gas CC	Natural Gas GT	Hydro	Wind Onshore	Wind Offshore	PV	PSP	Bio	CSP	Oil	Waste	Other Gases
FI	2.75	4.58	0.00	1.51	0.99	3.25	0.65	0.00	0.00	0.00	2.03	0.00	2.23	0.00	0.00
NO	0.00	0.00	0.00	0.96	0.69	29.94	0.71	0.00	0.00	1.40	0.00	0.00	0.00	0.00	0.00
SE	10.00	0.10	0.00	0.57	0.34	16.23	4.60	0.20	0.00	0.10	4.10	0.00	4.28	0.00	0.00
EE	0.00	2.00	0.00	0.41	0.02	0.01	0.35	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00
LV	0.00	0.00	0.00	1.08	0.04	1.58	0.19	0.00	0.00	0.00	0.12	0.00	0.00	0.00	0.00
LT	0.00	0.00	0.00	2.57	0.02	0.13	0.39	0.00	0.07	0.90	0.09	0.00	0.00	0.00	0.00
DK	0.00	2.41	0.00	1.31	0.81	0.01	3.65	1.27	0.62	0.00	1.42	0.00	0.05	0.00	0.00
GB	9.41	17.93	0.00	28.87	4.14	1.68	8.50	4.25	9.06	2.74	1.79	0.00	1.09	0.00	0.00
IE	0.00	0.88	0.36	3.50	0.78	0.24	2.66	0.03	0.00	0.29	0.03	0.00	0.94	0.00	0.00
NL	0.49	7.54	0.00	18.17	2.65	0.04	2.80	0.35	1.34	0.00	0.41	0.00	0.00	0.00	0.00
PL	0.00	19.48	8.64	1.01	0.08	0.58	3.82	0.00	0.00	1.77	0.73	0.00	0.00	0.00	0.00
DE	10.79	28.83	21.24	22.52	6.65	4.02	41.03	3.28	39.80	6.35	7.36	0.00	2.68	0.77	2.92
BE	5.94	0.49	0.00	5.06	1.31	0.12	2.14	0.87	3.08	1.31	1.40	0.00	0.19	0.00	0.00
LU	0.00	0.00	0.00	0.42	0.10	0.03	0.05	0.00	0.00	1.29	0.02	0.00	0.00	0.00	0.00
CZ	3.72	1.20	8.33	1.33	0.65	1.08	0.36	0.00	2.23	1.17	0.38	0.00	0.05	0.00	0.00
SK	2.30	0.54	0.57	1.03	0.16	1.56	0.00	0.00	0.52	0.98	0.20	0.00	0.34	0.00	0.00
AT	0.00	1.34	0.00	5.06	0.46	9.62	2.49	0.00	0.72	3.37	0.62	0.00	0.20	0.00	0.00
CH	3.33	0.00	0.00	0.10	0.18	11.90	0.06	0.00	1.06	1.82	0.25	0.00	0.00	0.00	0.00
HU	1.89	0.09	0.81	3.47	0.83	0.06	0.58	0.00	0.02	0.00	0.30	0.00	0.41	0.00	0.00
RO	1.30	1.42	4.38	2.64	0.07	5.16	3.00	0.00	2.00	1.31	0.13	0.00	0.00	0.00	0.00
SI	0.70	0.28	1.08	0.05	0.06	1.07	0.06	0.00	0.29	0.18	0.00	0.00	0.00	0.00	0.00
FR	63.13	3.01	0.00	6.41	4.49	21.01	10.31	0.00	6.19	2.46	0.00	0.00	8.65	0.00	0.00
HR	0.00	0.46	0.00	0.95	0.12	1.84	0.40	0.00	0.00	0.28	0.00	0.00	0.46	0.00	0.00
BG	2.00	1.40	4.00	0.98	0.12	2.14	1.10	0.00	1.20	1.05	0.11	0.00	0.00	0.00	0.00
IT	0.00	9.91	0.00	45.23	4.15	17.02	9.60	0.00	19.30	8.16	4.25	0.00	8.14	0.00	0.00
ES	7.58	10.03	1.07	27.53	5.29	13.94	23.03	0.00	4.66	6.40	0.85	2.30	3.48	0.00	0.00
PT	0.00	1.76	0.00	3.36	1.34	4.38	4.83	0.00	0.43	1.78	0.61	0.00	0.05	0.00	0.00
GR	0.00	0.00	4.46	4.03	1.58	2.69	1.80	0.00	2.61	0.70	0.10	0.00	2.45	0.00	0.00
Balkan	0.00	0.00	7.85	0.00	0.00	5.02	0.35	0.00	0.01	3.05	0.03	0.00	0.20	0.00	0.00

Source: BMWi (2018), EUROSTAT (2018a), Open Power System Data (2018), and Platts (2011) potential at different distances (0-50 miles [near], 50-100 miles [transitional] and 100-5000 miles [far]). Each of these areas is broken into nine resource grades according to an average capacity factor (0.16-0.48). Using only the resource potential for "near" areas, we aggregate these into only three resource grades and for each of them estimate the weighted average capacity factor and the total resource potential.

Likewise, for wind offshore, NREL (2013) provides the resource potential at different distances (5-20 miles [near], 20-50 miles [transitional] and 50-100 miles [far]). In this case, we use the data for areas "near" and "transitional" and estimate the capacity factors and resource potentials for three resource grades as for wind onshore.

For PV Pietzcker et al. (2014) provides the capacity factors of 9 resource grades (best 1%, 1% to 5%, etc) and the usable land for two type of areas (1-50 km from settlement and 50-100 km from settlement). We use the "1-50 km from settlement" data to estimate the capacity factors and installable potential of 3 resource grades aggregating the data from 0-5%, 5-25% and 25-100%.

For CSP, the installable capacity is determined by a set of three factors. First, by the area that is suitable for installing a specific technology. We derive the size of this area from land cover data (FAO 2018). However, due to public acceptance and competing usage possibilities only a certain share of this area is actually available for power production; this share is the second determining factor. CSP plants may only be installed on former agricultural area, of which we assume that only the 2% is available for CSP installations (Held 2010). And third, the amount of capacity that can be installed on the available area is subject to technology-specific restrictions. As we assume a SM4 configuration[14] in LIMES-EU, using data from Trieb et al. (2009) and Ong et al. (2013), we estimate the maximum installable capacity area to be 10 MW/km^2 . The allocation of the resource potential into the three grades is made in a way that the first resource grade comprises the best resource sites of a region that together add up to 10% of the region's area. The second resource grade comprises the next best sites that add up to 30% of the region's area. Consequently, the third resource grade contains 60% of a region's area subsuming the sites with the lowest capacity factors.

5.3.2. Fuels & Hydro

As stated in Section 4.1.2, fuel prices are the same for every model region. However, the availability of certain fuels differ between regions. Hard coal, natural gas and uranium are available to every model region in unrestricted quantities. Lignite, biomass, waste and other gases, however, can only be consumed in their country of origin. LIMES-EU does not allow for trade of these fuels as the calorific value of both lignite and many biofuels is too low for a cost-efficient long-distance transport. Not all regions have lignite resources; the consumption of lignite is therefore limited to those countries with existing lignite production in 2010 or 2015. In addition, we assume that new the maximum annual

[14] see Section 4.1.1

consumption of waste and other gases is fixed to the maximum between 2010 and 2015 levels.

The bioenergy potential is based on EEA (2006) which states the environmentally sustainable biomass potential for the EU25 Member States. We assume that two thirds of the environmentally sustainable biomass potential can be deployed at competitive prices and that the transport and heat sector demand about 50% of the available biomass stock. Therefore, only one third of the potential stated in EEA (2006) is considered eligible for electricity production in LIMES-EU. Biomass potentials of countries for which no data is available in EEA (2006) are calculated based on the extent of arable land and forests in these countries (FAO 2018) as well as the land structure and biomass potential of the surrounding countries with available data. In case the potential calculated for a specific country is smaller than its biomass deployment target stated in the NREAPS[15] (European Commission 2013), the potential is adjusted to cover this target[16]. Table 14 shows the maximum deployment of biomass per model region.

The limited availability of sites suitable for deploying hydropower is reflected by a maximum installable capacity of hydro power plants. As the potential for further hydro power capacities is low in most European countries, capacity additions are only allowed up to the maximum between the level needed to fulfill the national targets for electricity production from hydro as stated in the NREAPS (European Commission 2013), the historical capacity in 2010 and 2015, and the expected capacity in 2020 from ENTSO-E (2017a). In addition to the maximum installable capacity, the capacity factors of hydro power plants also vary among model regions. As the availability of hydro power varies significantly between years, we use an average of the realized capacity factors between 2006 and 2015 that are derived from IRENA (2017). Both maximum capacities and capacity factors are given in Table 14.

6. Implementation of Policies

The model allows for implementing climate and energy policy targets by including constraints on CO_2 emissions or on the deployment of certain technologies. Targets can be set for single countries or for aggregate regions such as the EU Member States. A differentiation and analysis of different policy *instruments* is not possible: As LIMES-EU is a social planner optimization model with perfect foresight, policy targets will always be fulfilled in a cost-optimal way. Hence, results from LIMES-EU provide useful benchmarks on the future development of the European electricity system, but potentially underestimate important obstacles such as public acceptance or institutional capacity (cf. Hughes and Strachan 2010).

[15]National Renewable Energy Action Plans (see Section 6)
[16]This is the case for Denmark, the Netherlands, Belgium and Luxemburg

Table 14: Regional biomass and hydropower potential

	Biomass			Hydro	
	Annual primary energy potential (in PJ)			Installable capacity (GW)	Annual availability (%/a)
	2010	2020	2030 -2050		
AT	96	109	121	10	56
BE	97	97	97	1	33
BG	19	33	39	3	22
CZ	53	63	70	1	24
DE	432	472	603	6	54
DK	77	77	77	0	26
EE	21	31	36	0	49
ES	230	307	350	17	26
FI	134	137	131	3	51
FR	438	519	662	23	37
GB	229	265	342	2	36
GR	22	47	53	3	22
HR	34	36	39	2	42
HU	50	63	78	0	47
IE	15	17	18	0	36
IT	226	261	346	17	37
LT	57	106	138	1	43
LU	3	3	3	1	36
LV	18	27	33	2	21
NL	145	145	145	0	31
PL	332	461	548	1	46
PT	50	54	57	6	29
RO	129	165	204	8	30
SE	163	181	188	17	47
SI	25	24	25	1	45
SK	31	33	50	2	31
Balkan	64	92	109	7	41
CH	34	40	49	14	35
NO	103	112	116	34	52

Source: EEA (2006), ENTSO-E (2017a), European Commission (2013), FAO (2018), IRENA (2017), and Open Power System Data (2018); own assumptions

Climate Policy Different policies can be implemented in LIMES (emission intensity, CO_2 taxes, emission caps and budgets, and minimum CO_2 prices) for different countries, regions and primary energy sources.

The standard scenario reflects the CO_2 emission reduction targets set on EU level for the EU ETS. The current EU ETS (a cap-and-trade system) comprises two main sectors: aviation and the stationary sector. The latter comprises electricity and heating production, and industry, which in turn includes energy industries (e.g., petroleum refining), and construction and manufacturing industries (e.g., pulp and paper). Aviation was included in 2012 in the ETS , but the extent to which is covered has changed between 2012 and 2016. This sector has its own cap (set at

210 $MtCO_2$ for each year of the period 2013-2020), but in the event of a shortage, airlines are allowed to buy allowances from the stationary sector (EEA 2016). The cap for the stationary sector was set at 2084 $MtCO_2$ for 2013, after which decreases at a rate of 1.74% until 2020. Then, the decreasing rate for the period of 2021-2030 (4th trading phase of the EU ETS) is 2.2% in order to achieve a 43% reduction of emissions with respect to 2005 (EEA 2016). Although a decreasing rate afterwards is not set yet, emissions are expected to drop 90% by 2050 with respect to 2005 (European Commission 2016c). For the calculation of an electricity-only cap we use only the stationary sector cap despite the allowance for the aviation sector to buy allowances from this sector, i.e., we assume the aviation cap will be set after 2020 according to the decarbonisation possibilities of this sector.

The electricity-only cap will depend thus on the allowances demand from the heating and industry sectors. The emissions from public electricity and heat production decreased from 1366 $MtCO_2$ in 2005 to 1059 $MtCO_2$ in 2015. During the same period, verified emissions from the energy industry (including electricity/heating and industry sectors) covered by the EU ETS decreased from 2014 $MtCO_2$ to 1802 $MtCO_2$. Verified emissions for the remaining energy industries can be thus estimated. Their share in the total verified emissions from energy industries has increased from 32% to 41% during the same period. Given the difficulty to decarbonise such industries, we assume that the share of certificates needed by them will increase linearly to 60% in 2050. Finally, we need to subtract the emissions from heating-only plants. Using the 2015 EU28 energy balance (Eurostat 2017), we are able to estimate the emissions from heating-only plants (125 $MtCO_2$ in 2015, i.e., 7% of the total verified emissions from the energy industries). We assume this share remains constant until 2050. The resulting electricity-only cap is thus estimated to decrease from 866 $MtCO_2$ in 2020 to 54 $MtCO_2$ in 2050. We assume that banking certificates is allowed. The corresponding price of an emission allowance can be derived from the emissions constraint's shadow price, which is part of the model results.

For countries without a dedicated climate policy, e.g., Switzerland and the Balkan, we assume an exogenous CO_2 price. This prevents artifactual model results showing a massive import of electricity into the EU from CO_2 emitting power plants sited in non-policy regions. For Switzerland, we assume that the country implements a CO_2 tax equivalent to the resulting EUA price. For this an iterative approach is needed, as the investment and dispatch decision in Switzerland might alter decisions in the rest of countries. For Balkan we assume a CO_2 tax increasing linearly from 5 eur/tCO_2 in 2020 to 23 eur/tCO_2 in 2050.

Renewable Policy LIMES-EU allows for implementing such technology-specific renewable energy targets for single model regions as well as implementing technology unspecific targets on EU or country level. As stated by the Parliament and Council (2009) the EU Member States are committed to increase the share of renewable energy sources in their energy consumption by 20% until 2020. The Member

States' National Renewable Energy Action Plans (NREAPS) specify how to reach the corresponding targets for the electricity sector on a national level and give technology-specific projections for the electricity generation until 2020 (European Commission 2013). Besides the NREAPS, we assume a RES target for Germany of 40% in 2025, 55% in 2035 and 80% 2050, and interpolate these values for the remaining years of our time-horizon. Targets are implemented as lower bounds on electricity production from these technologies.

Energy Efficiency Policy Energy efficiency translates to less electricity demand as compared to the reference scenario. As the electricity demand is given exogenously its reduction is not part of the optimization but set exogenously as well.

Nuclear, coal & CCS-related Policies In several countries nuclear power plants, coal-fired plants and CCS technology face problems in public acceptance due to environmental risks and uncertain overall costs. In order to accommodate this, their future deployment is constrained by upper limits on investments in the two technologies. These limits can be set for each model region separately.

In the standard scenario we assume a progressive nuclear phase-out to be completed in Belgium by 2025, in Germany by 2022 and in Switzerland by 2044. Investments in coal-fired plants are only allowed in Poland, Greece and Balkan, as these countries did not support the sector's intention of not to build coal-fired power plants after 2020 (UNFCCC 2018). Finally, we do not allow for CCS deployment given the lack of large-scale power plants with integrated CCS in Europe. According to the (European Commission 2017a), all the assessments concerning projects of carbon capture, transport and storage (29 from 7 countries) carried out during the last reporting period turned out to be economically infeasible. On top of that, in countries like Germany there is strong people's opposition towards CCS (Jungjohann and Morris 2014).

Security of supply and reserves Besides the operating constraints considered for dispatchable technologies (minimum load and ramping constraints), in the standard scenario we assume that countries implement measures to ensure secure power system operation by having sufficient overcapacity for an emergency. A 10% capacity margin is considered, i.e., firm capacity (after applying derating factors) and reserves have to exceed demand by at least 10% at any time. Table 15 shows the assumed derating factors and the variables that they multiply in order to estimate the derated capacity, i.e., firm capacity.

Table 15: Derating factors

Dispatchable technologies	1	Capacity
Intermittent technologies	0.25	Max. availability
Storage technologies	0.8	Output
Net imports	0.3	Volume

Source: Own assumptions

7. Model Validation

The purpose of LIMES-EU is to produce cost-efficient scenarios with regard to future investments into the European power system. Validating a long-term social planner model is conceptually challenging as the model does not aim to replicate historic developments but is designed to generate a socially optimal benchmark without considering real world market failures.

According to Schwanitz (2013), the primary aim of a validation is to build trust in the model. In this regard, a comprehensive documentation of the model, its equations and underlying assumptions as pursued in this paper is an important first step. Next to a thorough documentation of the model, a validation may include a discussion of illustrative model results and cross-checking them with stylized facts (Schwanitz 2013). Barlas (1996) suggests that a model is valid if it demonstrates 'the right behavior for the right reason'.

A full-fledged validation is beyond the scope of this document. Nevertheless, complementary to the documentation of the model structure and its parameter values, this Section aims to build further trust in the model and to make its reasoning more accessible.

For the base year 2015, only the dispatch of generation, storage and transmission technologies is optimized by LIMES-EU. The installed capacities are given exogenously. In this Section we compare the dispatch resulting from LIMES-EU with historic electricity production data from ENTSO-E (2017b) (given the lack of fossil-based generation data for the Netherlands, we use data from Mantzos et al. (2018)). In addition, we compare the the modelled carbon emissions with the historic emissions[17] in 2015.

In order to replicate the historic dispatch, we assume an exogenous CO_2 price of 8€/tCO_2 which is consistent with the average price for EU ETS allowances in this year. Figure 5 shows both historic emissions and model results for 2015. Despite the simplifying model assumptions, the fit between historic emissions and model results is quite good. Only model results for France show a large deviation from historic data.

The reason for this deviation can be explained by Figure 6, which gives the historic and model based electricity generation mix of each region and of the EU28 Member States in total. The electricity mix of France is only slightly different between model and reality, with a small share of electricity provided by hard coal and natural gas fired power plants in reality. However, as most of the electricity in France is produced from carbon free energy sources, this difference has a large impact on the absolute emission outcome. The non-existence of fossil fuel based electricity generation in the model results for France can at least partly be explained by the missing representation of combined heat and power

[17]To estimate the electricity-related emissions, we allocate the emissions from CHP according to the share of their gross electricity output in their total output (heat and electricity) using data for the EU from Mantzos et al. (2018). Due to the lack of data, for Norway, Switzerland and Balkan we use emissions from public electricity and heat production from IEA (2017).

(CHP) plants in LIMES-EU. Further development of LIMES is going to be focused on including the heating sector.

Other regional electricity mixes deviate strongly from historic data, e. g. hard coal is overrated in Italy and underrated in Poland. This is due to the fact that the model abstracts from regional differences in prices for primary energy sources as well as taxes and charges. It optimizes the overall European electricity system, without taking into account market failures that might distort the cost-efficient outcome in reality. This certainly is a drawback when aiming at reproducing historic market outcomes, but it is reasonable in order to derive benchmarks for the cost-efficient future development of the European electricity system.

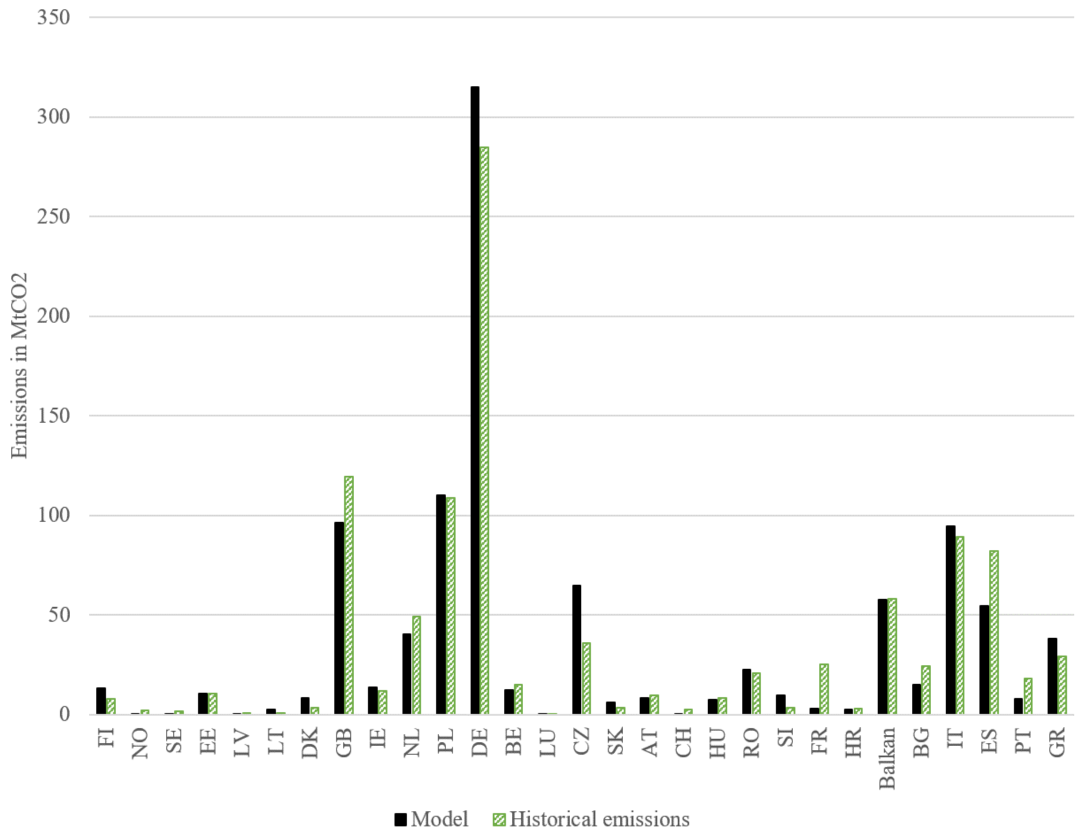


Figure 5: Comparison of historic and modelled region-specific CO_2 emissions in 2015. Source: IEA (2017) and Mantzos et al. (2018); own calculations; own model results.

However, as can be seen on the very left bars in Figure 6, the aggregated electricity mix of the EU28 is well reproduced by the model. Only lignite is somewhat overrated while biomass and vRES generation is lower than in reality. As for the results for France, the result that biomass is used less in LIMES-EU compared to 2015 data can be explained

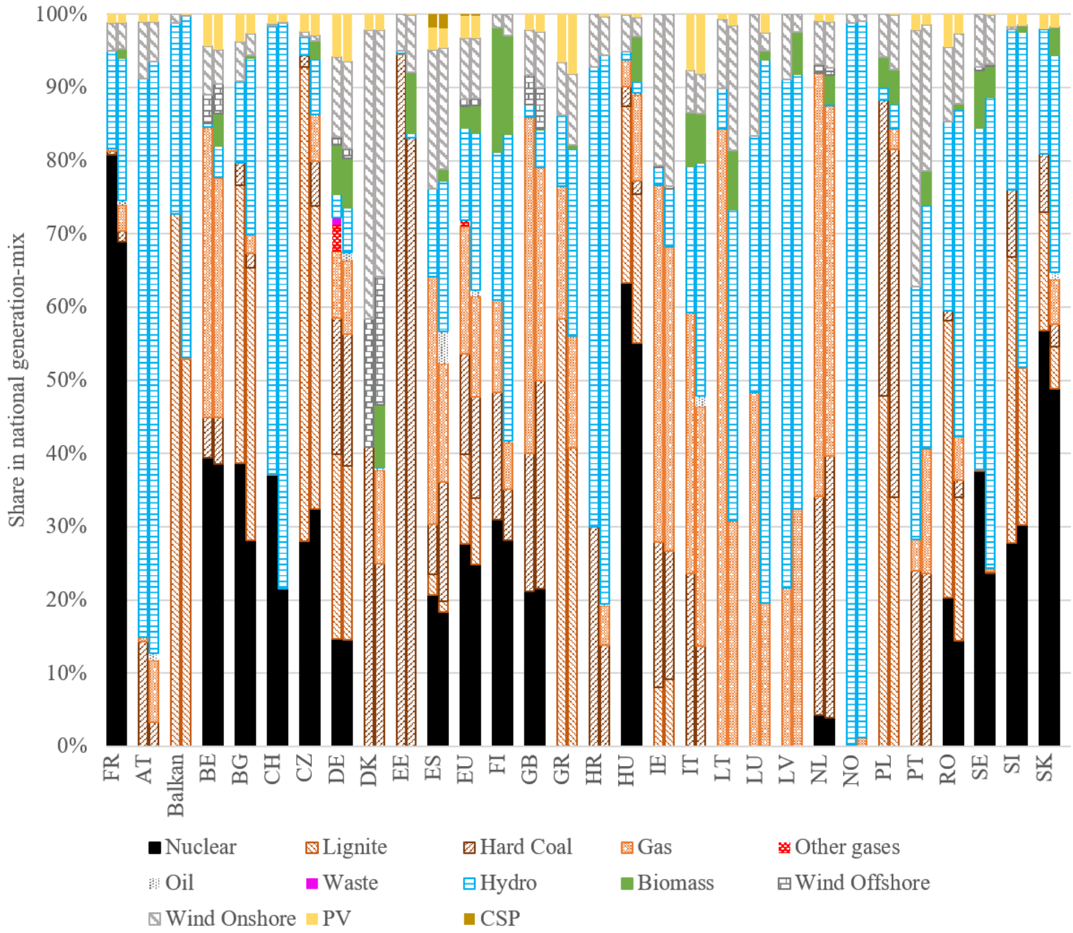


Figure 6: Comparison of the model-derived (*left bar*) and the historic (*right bar*) region-specific electricity generation mix in 2015. Source: ENTSO-E (2017b); own model results.

by the lack of CHP representation in the model. Additionally, biomass is normally subsidized and this is not considered in the model. The lower vRES generation is due to the higher availability factors in 2015 than those used in the model. This is explained by an improvement in technologies efficiency. Recall that we assume for capacity installed before 2015 has annual capacity factors equivalent to the average capacity factors between 2010 and 2015, e.g., the weighted average capacity factor for wind offshore in the EU between 2010 and 2015 was 32.2%, while the value for 2015 was 32.3% (IRENA 2017).

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A. Model Equations

This Section provides a comprehensive list of all model equations. The Tables A.1 to A.4 give an overview about the symbols for indices, sets, parameters and variables used in the equations. All variables are constrained to be non-negative.

Table A.1: Indices

Symbol	Description
t, tt	years
day	days
τ	time slices
r	regions
rg	vRES resource grades
te	electricity generation technologies
st	storage technologies
cn	transmission connections
pe	primary energy types

Table A.2: Sets

Symbol	Description
R	all regions
R^{pol}	regions with a common policy
T	all time slices
T_{day}	time slices of a specific *day*
TE	all electricity generation technologies
TE_{pe}	electricity generation technologies working with *pe*
TE_{pe}^{ccs}	CCS equipped electricity generation technologies working with *pe*
TE^{disp}	dispatchable electricity generation technologies
TE^{ramp}	thermal electricity generation technologies with ramping constraints
TE^{res}	RES technologies
TE^{vres}	vRES technologies
ST	all storage technologies
$ST^{interday}$	interday storage technologies
$ST^{intraday}$	intraday storage technologies
CN	all transmission connections
CN_r^{out}	transmission connections defined as starting in region r
CN_r^{in}	transmission connections defined as ending in region r

Table A.3: Parameters

Symbol	Description
ρ	discount rate
Δt	time span (in years) between model years
l_τ	length of time slice τ
λ_{pe}	emission factor of primary energy pe
ψ_{te}, ψ_{cn}	lifetime of technology te / connection cn
μ_{te}	minimum load of technology te
ϕ_r	minimum share of domestic electricity supply for region r
$c^I_{t,te}$, $c^I_{t,cn}$	capacity-specific investment cost
$c^F_{t,pe}$	energy-specific fuel cost
c^{OMF}_{te}, c^{OMF}_{st}	fixed operation and maintenance cost
c^{OMV}_{te}, c^{OMV}_{st}	variable operation and maintenance cost
$c^{CO_2}_{t,r}$	CO_2 emission cost
$\nu_{\tilde{t},te}$, $\nu_{\tilde{t},cn}$	salvage value factor
$\omega_{\tilde{t},te}$, $\omega_{\tilde{t},cn}$	depreciation factor
$d_{t,\tau,r}$	electricity demand
$\alpha^{vRES}_{\tau,r,te,rg}$, $\alpha_{r,te}$, α_{cn}	availability factor
η_{te}	conversion efficiency
γ_{cn}	transmission losses
$p^{max}_{t,r,pe}$	maximum primary energy consumption
cap^{CCScum}_r	maximum cumulated CCS potential
res_t, $res_{t,te}$, $res_{t,r}$, $res_{t,r,te}$	target for minimum electricity production from RES
$cap^{CO_2}_t$, $cap^{CO_2}_{t,r}$	target for maximum CO_2 emissions
cap^{CO_2cum}, $cap^{CO_2cum}_r$	target for maximum cumulated CO_2 emissions
a_{te}	auto-consumption rate
r_{te}	ramping factor
f_{te}, f_{st}	firm capacity factor
$fimp$	imports availability factor
rm	reserve margin
$maxRK$	maximum share of reserves in demand

A.1. Objective function and its components

Equation A.1: Objective function

$$C^{tot} = \sum_t \left(\Delta t \, e^{-\rho(t-t_0)} \left(C^I_t + C^F_t + C^{OM}_t + C^{CO_2}_t \right) \right) - e^{-\rho(t_{end}-t_0)} \, V \tag{A.1}$$

Equation A.2: Fuel costs

$$C^F_t = \sum_{r,pe} c^F_{t,pe} \sum_\tau l_\tau \, P_{t,\tau,r,pe} \qquad \forall t \tag{A.2}$$

Equation A.3: Investment costs

$$C^I_t = \sum_{r,te} \left(c^I_{t,te} \, \Delta K_{t,r,te} \right) + \sum_{r,st} \left(c^I_{t,st} \, \Delta K_{t,r,st} \right) + \sum_{cn} \left(c^I_{t,cn} \, \Delta K_{t,cn} \right) \qquad \forall t \tag{A.3}$$

Table A.4: Variables

Symbol	Description
C^{tot}	total system cost
C_t^I	investment cost
C_t^F	fuel cost
C_t^{OM}	operation and maintenance cost
$C_t^{CO_2}$	CO_2 emission cost
V	salvage value
$P_{t,\tau,r,pe}$	primary energy consumption
$K_{t,r,te}$, $K_{t,cn}$, $K_{t,r,st}$	installed capacity
$\Delta K_{t,r,te}$, $\Delta K_{t,cn}$, $\Delta K_{t,r,st}$	new capacity
$K_{t,r,te,rg}^{RG}$	installed capacity (resource grade specific)
$\Delta K_{t,r,te,rg}^{RG}$	new capacity (resource grade specific)
$G_{t,\tau,r,te}$	electricity generation
$E_{t,r}^{CO_2}$	CO_2 emissions
$E_{t,r}^{CCS}$	captured CO_2 (via CCS)
$S_{t,\tau,r,te}^{OUT}$	storage output
$S_{t,\tau,r,te}^{IN}$	storage input
$F_{t,\tau,cn}^{+}$, $F_{t,\tau,cn}^{-}$	transmission flow in positive / negative direction
$OP_{t,\tau,r,te}$, $OP_{t,day,r,te}$, $OP_{t,r,te}$	operating (running) capacity
$RK_{t,r,te}$	reserve capacity
$RG_{t,\tau,r,te}$	maximum generation variation between two time slices
$DK_{t,tt,r,te}$	disinvestment in t of capacity built in tt
$DK_{t,tt,r,te}^{RG}$	disinvestment in t of capacity built in tt (resource grade specific)
$B_t^{CO_2}$	emission allowances bank

Equation A.4: Operation and maintenance costs

$$\begin{aligned} C_t^{OM} = & \sum_{r,te} \left(c_{te}^{OMF}\, c_{t,te}^{I}\, \left(K_{t,r,te} + RK_{t,r,te}\right) + c_{te}^{OMV} \sum_{\tau} l_\tau\, G_{t,\tau,r,te} \right) \\ & + \sum_{r,st} \left(c_{st}^{OMF}\, c_{t,st}^{I}\, K_{t,r,st} + c_{te}^{OMV} \sum_{\tau} l_\tau\, S_{t,\tau,r,te}^{OUT} \right) \qquad \forall t \end{aligned} \tag{A.4}$$

Equation A.5: Emission costs

$$C_t^{CO_2} = \sum_{r} c_{t,r}^{CO_2}\, E_{t,r}^{CO_2} \qquad \forall t \tag{A.5}$$

Equation A.6: Salvage value

$$
\begin{aligned}
V = & \Delta t \sum_{te,r} \sum_{\tilde{t}=0}^{\psi_{te}} \nu_{\tilde{t},te}\, c^{I}_{(t_{end}-\tilde{t}),te}\, \Delta K_{(t_{end}-\tilde{t}),r,te} \\
& + \Delta t \sum_{st,r} \sum_{\tilde{t}=0}^{\psi_{st}} \nu_{\tilde{t},st}\, c^{I}_{(t_{end}-\tilde{t}),st}\, \Delta K_{(t_{end}-\tilde{t}),r,st} \\
& + \Delta t \sum_{cn} \sum_{\tilde{t}=0}^{\psi_{cn}} \nu_{\tilde{t},cn}\, c^{I}_{(t_{end}-\tilde{t}),cn}\, \Delta K_{(t_{end}-\tilde{t}),cn}
\end{aligned}
\tag{A.6}
$$

A.2. Electricity balance

Equation A.7: Electricity balance

$$
\begin{aligned}
d_{t,\tau,r} = & \sum_{te} G_{t,\tau,r,te} + \sum_{st} \left(S^{OUT}_{t,\tau,r,st} - S^{IN}_{t,\tau,r,st} \right) \\
& + \sum_{cn \in CN^{in}_{r}} \left((1-\gamma_{cn})\, F^{+}_{t,\tau,cn} - F^{-}_{t,\tau,cn} \right) \\
& + \sum_{cn \in CN^{out}_{r}} \left((1-\gamma_{cn})\, F^{-}_{t,\tau,cn} - F^{+}_{t,\tau,cn} \right) \qquad \forall t, \tau, r
\end{aligned}
\tag{A.7}
$$

A.3. Equations for generation technologies

Equation A.8: Expansion, decommissioning and depreciation of generation technologies

$$
K_{t,r,te} = \Delta t \left(\sum_{\tilde{t}=0}^{\psi_{te}} \omega_{\tilde{t},te} \Delta K_{(t-\tilde{t}),r,te} - \sum_{(tt,\tilde{t}):(\tilde{t} \in (0,\psi_{te}) \,\cap\, tt > t-\tilde{t})} \omega_{\tilde{t},te} DK_{tt,t-\tilde{t},r,te} \right) \qquad \forall t, r, te
\tag{A.8}
$$

Equation A.9: Expansion, decommissioning and depreciation of vRES technologies per resource grade

$$
\begin{aligned}
K^{RG}_{t,r,te,rg} = & \Delta t \sum_{\tilde{t}=0}^{\psi_{te}} \omega_{\tilde{t},te} \Delta K^{RG}_{(t-\tilde{t}),r,te,rg} \\
& - \Delta t \sum_{(tt,\tilde{t}):(\tilde{t} \in (0,\psi_{te}) \,\cap\, tt > t-\tilde{t})} \omega_{\tilde{t},te} DK^{RG}_{tt,t-\tilde{t},r,te,rg} \qquad \forall t, r, te \in TE^{vres}, rg
\end{aligned}
\tag{A.9}
$$

Equation A.10: Expansion of vRES technologies in regions and resource grades

$$
\Delta K_{t,r,te} = \sum_{rg} \Delta K^{RG}_{t,r,te,rg} \qquad \forall t, r, te \in TE^{vres}
\tag{A.10}
$$

Equation A.11: Decommissioning of vRES technologies in regions and resource grades

$$DK_{tt,t,r,te} = \sum_{rg} DK^{RG}_{tt,t,r,te,rg} \qquad \forall tt,t,r,te \in TE^{vres} \tag{A.11}$$

Equation A.12: Constraint on disinvestments

$$\sum_{tt} DK_{tt,t,r,te} \leq \Delta K_{t,r,te} \qquad \forall t,r,te \tag{A.12}$$

Equation A.13: Constraint on disinvestments in resource grades

$$\sum_{tt} DK^{RG}_{tt,t,r,te,rg} \leq \Delta K^{RG}_{t,r,te,rg} \qquad \forall t,r,te \in TE^{vres}, rg \tag{A.13}$$

Equation A.14: Capacity constraint for all generation technologies

$$G_{t,\tau,r,te} \leq K_{t,r,te}(1 - a_{te}) \qquad \forall t,\tau,r,te \tag{A.14}$$

Equation A.15: Availability of Wind Onshore, Wind Offshore and PV

$$G_{t,\tau,r,te} \leq \sum_{rg} \alpha^{vRES}_{\tau,r,te,rg} \, K^{RG}_{t,r,te,rg} \qquad \forall t,\tau,r,te \in \{\mathit{Wind\ Onshore,\ Wind\ Offshore,\ PV}\} \tag{A.15}$$

Equation A.16: Availability of CSP

$$\sum_{\tau \in T_{day}} l_\tau \, G_{t,\tau,r,te} \leq \sum_{\tau \in T_{day}} l_\tau \sum_{rg} \alpha^{vRES}_{\tau,r,te,rg} \, K^{RG}_{t,r,te,rg} \qquad \forall t,day,r,te \in \{CSP\} \tag{A.16}$$

Equation A.17: Availability of Hydro

$$G_{t,\tau,r,te} \leq 1.25 \, \alpha_{r,te} \, K_{t,\tau,r,te} \qquad \forall t,r,te \in \{Hydro\} \tag{A.17}$$

Equation A.18: Annual availability of dispatchable generation technologies

$$\sum_{\tau} l_\tau \, G_{t,\tau,r,te} \leq \sum_{\tau} l_\tau \, \alpha_{r,te} \, K_{t,r,te} \qquad \forall t,r,te \in TE^{disp} \tag{A.18}$$

Equation A.19: Operation constraint for thermal generation technologies

$$OP_{t,\tau,r,te} \leq K_{t,r,te} \qquad \forall t,\tau,r,te \in TE^{ramp} \tag{A.19}$$

Equation A.20: Generation constraint for thermal generation technologies

$$G_{t,\tau,r,te} \leq OP_{t,\tau,r,te} \, (1 - a_{te}) \qquad \forall t,\tau,r,te \in TE^{ramp} \tag{A.20}$$

Equation A.21: Minimum load constraint for thermal generation technologies

$$G_{t,\tau,r,te} \geq \mu_{te}\, OP_{t,\tau,r,te} \qquad \forall t,\tau,r,te \in TE^{ramp} \tag{A.21}$$

Equation A.22: Operating capacity constraint for thermal generation technologies (except nuclear)

$$OP_{t,\tau\in T_{day},r,te} = OP_{t,day,r,te} \qquad \forall t,\tau,r,te\,(te \in TE^{ramp} \wedge te \neq Nuclear) \tag{A.22}$$

Equation A.23: Operating capacity constraint for nuclear power plants

$$OP_{t,\tau,r,te} = OP_{t,r,te} \qquad \forall t,\tau,r,te\,(te = Nuclear) \tag{A.23}$$

Equation A.24: Ramping constraint for thermal generation technologies

$$G_{t,\tau\in T_{day},r,te} = G_{t,\tau+1\in T_{day},r,te} + RG_{t,\tau,r,te} \qquad \forall t,\tau,r,te \in TE^{ramp} \tag{A.24}$$

Equation A.25: Ramping-up and -down constraint for thermal generation technologies

$$-OP_{t,\tau,r,te}\, r_{te} \leq RG_{t,\tau,r,te} \leq OP_{t,\tau,r,te}\, r_{te} \qquad \forall t,\tau,r,te \in TE^{ramp} \tag{A.25}$$

A.4. Equations for transmission technologies

Equation A.26: Expansion and depreciation of transmission capacity

$$K_{t,cn} = \Delta t \sum_{\tilde{t}=0}^{\psi_{cn}} \omega_{\tilde{t},cn} \Delta K_{(t-\tilde{t}),cn} \qquad \forall t, cn \tag{A.26}$$

Equation A.27: Transmission constraint

$$\begin{aligned} F^{+}_{t,\tau,cn} &\leq \alpha_{cn}\, K_{t,cn} \qquad \forall t,\tau,cn \\ F^{-}_{t,\tau,cn} &\leq \alpha_{cn}\, K_{t,cn} \qquad \forall t,\tau,cn \end{aligned} \tag{A.27}$$

A.5. Equations for storage technologies

Equation A.28: Expansion and depreciation of storage technologies

$$K_{t,r,st} = \Delta t \sum_{\tilde{t}=0}^{\psi_{st}} \omega_{\tilde{t},st} \Delta K_{(t-\tilde{t}),r,st} \qquad \forall t, r, st \tag{A.28}$$

Equation A.29: Storage constraint

$$\begin{aligned} S^{IN}_{t,\tau,r,st} &\leq K_{t,r,st} \qquad \forall t,\tau,r,st \\ S^{OUT}_{t,\tau,r,st} &\leq K_{t,r,st} \qquad \forall t,\tau,r,st \end{aligned} \tag{A.29}$$

Equation A.30: Interday storage balance

$$\eta_{st} \sum_{\tau} l_\tau \, S^{IN}_{t,\tau,r,st} = \sum_{\tau} l_\tau \, S^{OUT}_{t,\tau,r,st} \qquad \forall t, r, st \in ST^{interday} \tag{A.30}$$

Equation A.31: Intraday storage balance

$$\eta_{st} \sum_{\tau \in T_{day}} l_\tau \, S^{IN}_{t,\tau,r,st} = \sum_{\tau \in T_{day}} l_\tau \, S^{OUT}_{t,\tau,r,st} \qquad \forall t, day, r, st \in ST^{intraday} \tag{A.31}$$

A.6. Primary energy demand and CO_2 emissions

Equation A.32: Primary energy demand

$$P_{t,\tau,r,pe} = \sum_{te \in TE_{pe}} G_{t,\tau,r,te} / \left(\eta_{te}(1 - a_{te})\right) \qquad \forall t, \tau, r, pe \tag{A.32}$$

Equation A.33: Primary energy constraint

$$\sum_{\tau} l_\tau \, P_{t,\tau,r,pe} \leq p^{max}_{t,r,pe} \qquad \forall t, r, pe \tag{A.33}$$

Equation A.34: CO_2 emissions from electricity generation

$$E^{CO_2}_{t,r} = \sum_{pe} \lambda_{pe} \sum_{\tau} l_\tau \, P_{t,\tau,r,pe} - E^{CCS}_{t,r} \qquad \forall t, r \tag{A.34}$$

Equation A.35: Avoided CO_2 emissions via CCS

$$E^{CCS}_{t,r} = 0.9 \sum_{pe} \lambda_{pe} \sum_{\tau} l_\tau \sum_{te \in TE^{ccs}_{pe}} G_{t,\tau,r,te} / \eta_{te} \qquad \forall t, r \tag{A.35}$$

Equation A.36: CCS storage constraint

$$\Delta t \sum_{t} E^{CCS}_{t,r} \leq cap^{CCScum}_{r} \qquad \forall r \tag{A.36}$$

A.7. Security of supply

Equation A.37: Robustness condition

$$\begin{aligned}
(1 + rm) d_{t,\tau,r} = & \sum_{te \in TE^{disp}} \left(f_{te} K_{t,r,te} + RK_{t,r,te}\right) + \sum_{st} f_{st} S^{OUT}_{t,\tau,r,st} \\
& + \sum_{te \in TE^{vres}} \sum_{rg} \alpha^{vRES}_{\tau,r,te,rg} \, K^{RG}_{t,r,te,rg} \\
& + fimp \sum_{cn \in CN^{in}_r} \left((1 - \gamma_{cn})\, F^{+}_{t,\tau,cn} - F^{-}_{t,\tau,cn}\right) \\
& + fimp \sum_{cn \in CN^{out}_r} \left((1 - \gamma_{cn})\, F^{-}_{t,\tau,cn} - F^{+}_{t,\tau,cn}\right) \qquad \forall t, \tau, r
\end{aligned} \tag{A.37}$$

Equation A.38: Reserves constraint

$$\begin{aligned} RK_{t,r,te} &\leq \Delta t \sum_{tt} \left(DK_{t,tt,r,te} + 0.8 DK_{t-1,tt,r,te} \right) && \forall t, r, te \\ RK_{t,r,te} &\leq RK_{t-1,r,te} + \Delta t \sum_{tt} DK_{t,tt,r,te} && \forall t, r, te \end{aligned} \tag{A.38}$$

Equation A.39: Maximum reserves

$$\sum_{te} RK_{t,r,te} \leq maxRK \; d_{t,\tau,r} \qquad \forall t, \tau, r \tag{A.39}$$

A.8. Policy equations

Equation A.40: CO_2 emission target for a group of regions

$$B_t^{CO_2} = B_{t-1}^{CO_2} + cap_t^{CO_2} - \sum_{r \in R^{pol}} E_{t,r}^{CO_2} \qquad \forall t \tag{A.40}$$

Equation A.41: Target on CO_2 emission intensity of power generation

$$\frac{E_{t,r}^{CO_2}}{\sum_\tau l_\tau \; d_{t,\tau,r}} \leq \frac{E_{t_0,r}^{CO_2}}{\sum_\tau l_\tau \; d_{t_0,\tau,r}} \qquad \forall t > t_0, r \tag{A.41}$$

Equation A.42: CO_2 emission target for a group of regions

$$\sum_{r \in R^{pol}} E_{t,r}^{CO_2} \leq cap_t^{CO_2} \qquad \forall t \tag{A.42}$$

Equation A.43: CO_2 emission target for a single region

$$E_{t,r}^{CO_2} \leq cap_{t,r}^{CO_2} \qquad \forall t, r \tag{A.43}$$

Equation A.44: Cumulated CO_2 emission target for a group of regions

$$\Delta t \sum_{t > t_0} \sum_{r \in R^{pol}} E_{t,r}^{CO_2} \leq cap^{CO_2 cum} \tag{A.44}$$

Equation A.45: Cumulated CO_2 emission target for a single region

$$\Delta t \sum_{t > t_0} E_{t,r}^{CO_2} \leq cap_r^{CO_2 cum} \qquad \forall r \tag{A.45}$$

Equation A.46: National RES target

$$\sum_{\tau} l_\tau \sum_{te \in TE^{res}} G_{t,\tau,r,te} \geq res_{t,r} \qquad \forall t, r \tag{A.46}$$

Equation A.47: National RES target (technology specific)

$$\sum_{\tau} l_\tau \, G_{t,\tau,r,te} \geq res_{t,r,te} \qquad \forall t, r, te \in TE^{res} \tag{A.47}$$

Equation A.48: RES target for a group of regions

$$\sum_{r \in R^{pol}} \sum_{\tau} l_\tau \sum_{te \in TE^{res}} G_{t,\tau,r,te} \geq res_t \qquad \forall t \tag{A.48}$$

Equation A.49: RES target (technology specific) for a group of regions

$$\sum_{r \in R^{pol}} \sum_{\tau} l_\tau \, G_{t,\tau,r,te} \geq res_{t,te} \qquad \forall t, te \in TE^{res} \tag{A.49}$$

Equation A.50: Target on mimimum amount of electricity provided domestically

$$\sum_{\tau} l_\tau \sum_{te} G_{t,\tau,r,te} \geq \phi_r \sum_{\tau} l_\tau \, d_{t,\tau,r} \qquad \forall t, r \tag{A.50}$$

A.9. Minimum CO_2 price

The CO_2 price in LIMES-EU results from the shadow price of the emissions constraint (banking, cap or budget). Given the linear nature of the model, implementing a minimum CO_2 price is not trivial. Fell et al. (2012) formulate a LP model that allows estimating the amount of certificates required to be withdrawn from a cap-and-trade system (e.g., the EU ETS) in order to reach a floor CO_2 price. However, this formulation does not work when only one country or a group of countries within a cap implement a top-up tax in order to reach a floor price, because the total emission constraint results in only one CO_2 price for all the countries in the ETS. We thus developed an iterative process that allows us implement any top-up CO_2 tax in any country within a larger cap (see Figure 7).

To cope with this limitation we implement an iterative approach (see Figure 8). In a first iteration ($i = 1$) the model is run with only the emissions constraint and no exogenous top-up CO_2 tax ($x_{t,c,i} = 0$). If the CO_2 price resulting from the emission constraint ($P_{t,i}$) is lower than the desired minimum CO_2 price ($P^*_{t,c}$) for every country c and time t (considering a tolerance parameter *tol*), the model is run again. In a second iteration We run the model assuming an exogenous CO_2 price, i.e., the needed top-up CO_2 tax, which equals to the difference between $P^*_{t,c}$ and $P_{t,i}$ (see Figure 8). We thus iterate until the resulting CO_2 from two consecutive iterations converge The parameter *tol* is set to 1%.

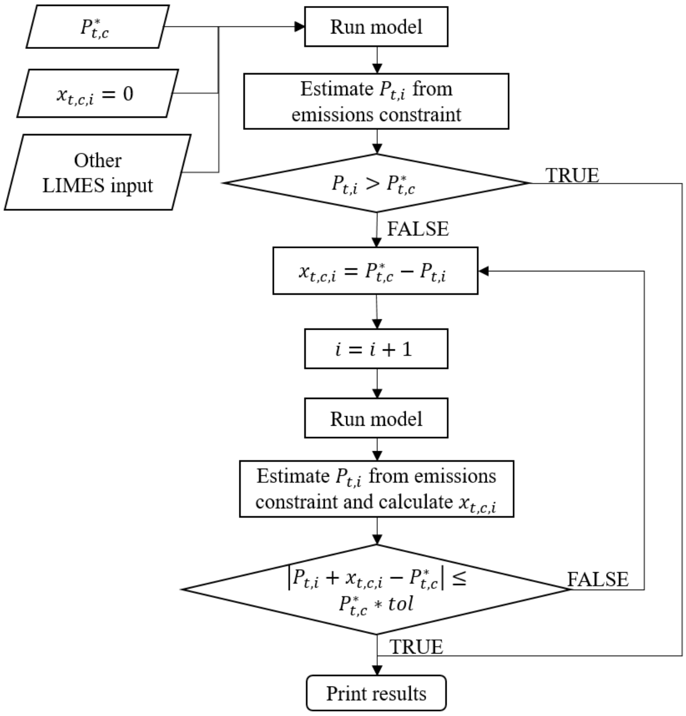

Figure 7: Flow diagram explaining the iterative process formulated to run the model when a minimum CO_2 price is implemented.

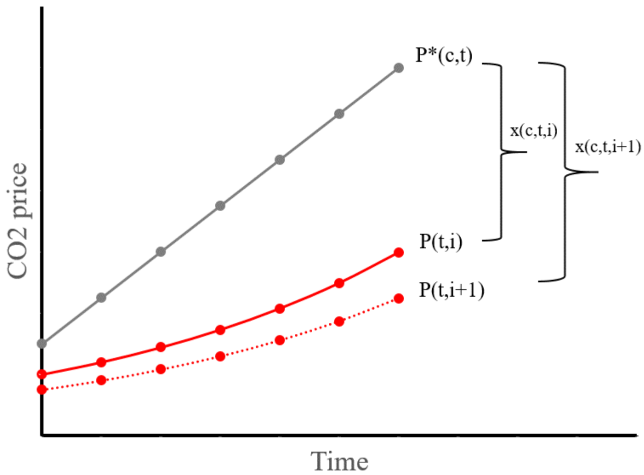

Figure 8: Top-up CO_2 price adjustment between two iterations for countries implementing a minimum CO_2 price.

B. Region Codes

The region codes in this documentation are based on standard ISO 3166-1.

Table B.1: Region codes

Region code	Region name
AT	Austria
BE	Belgium
BG	Bulgaria
CZ	Czech Republic
DE	Germany
DK	Denmark
EE	Estonia
ES	Spain
FI	Finland
FR	France
GB	United Kingdom
GR	Greece
HR	Croatia
HU	Hungary
IE	Ireland
IT	Italy
LT	Lithuania
LU	Luxemburg
LV	Latvia
NL	The Netherlands
PL	Poland
PT	Portugal
RO	Romania
SE	Sweden
SI	Slovenia
SK	Slovakia
Balkan	Albania, Bosnia and Herzegovina, Kosovo, Montenegro, The former Yugoslav Republic of Macedonia, Serbia
CH	Switzerland
NO	Norway