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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Contents

1. Introduction

The Member States of the European Union (EU) have repeatedly stated their will to reduce greenhouse gas emissions in order to contribute to global climate change mitigation (European Council 2007, 2009, 2011). The aspiration to reduce CO_2 emissions until 2050 by 80% compared to 1990 levels translates to huge transformational demand in the energy-related sectors transport, heat and power. According to the European Commission's Low Carbon Roadmap (European Commission 2013a) the power sector has to decarbonize faster and stronger than both the transport and heat sector, reaching 95-99% CO_2 reduction in the year 2050. 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 renewable energy sources (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.

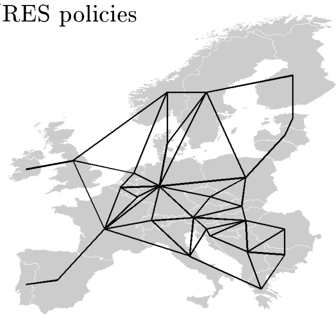
LIMES-EU is especially useful to analyze the integration of variable renewable energy sources (vRES) such as wind and solar into the European power system. Despite its long-term focus it accounts for short-term fluctuations of demand and vRES supply when determining the optimal electricity generation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

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)
hard coal CCS, lignite CCS, natural gas (combined cycle) CCS
hydro, wind onshore, wind offshore, photovoltaic, concentrated solar power, biomass
storage technologies
intraday, interday
transmission technologies
net transfer capacities between model regions

Figure 1: LIMES-EU in a nutshell

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 are same to the earlier LIMES-EU$^+$ version of the model. Though they are already discussed in the supplementary material of 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. (2014). 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 that 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.

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

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[1] and uses the linear solver CPLEX.

2.2. Geographical Resolution

The current version of LIMES-EU optimizes the electricity system of the EU28 countries[2] plus Switzerland, Norway and the Balkan region. Except for the Balkan region,

[1]General Algebraic Modeling System, http://www.gams.com
[2]excluding Cyprus and Malta

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[3]. Modelling technology classes 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. There are 13 different generation technologies in LIMES-EU that classify 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

[3] e.g. all hard coal power plants in France are aggregated to one class

for intra-regional differences in wind and solar resources, each model region 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 and hydro power plants. Electricity generation based on lignite, hard coal and natural gas is associated with CO_2 emissions. Optionally, those power 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. Two different storage technologies are available in LIMES-EU: *intra*day and *inter*day storage. 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. Compared to intraday storage, interday storage is subject to higher investment costs and higher storage losses.

3. Time Slice Approach

Long-term models with endogenous investments are computationally demanding, especially when optimizing intertemporally[4]. 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, Blanford and Niemeyer (2011), Golling (2012), Nagl et al. (2013), Sisternes

[4] i.e. optimizing investment decisions for multiple time steps simultaneously

and Webster (2013) and others recently developed new approaches for selecting characteristic vRES infeed and demand situations. 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. 2014). 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 fulfil 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's (1963) 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 (2013) data for the historic electricity demand levels and historic weather data from ECMWF (2012) 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:

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

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

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 (2013c) and EUROSTAT (2013b)).

Country-specific demand data is retrieved from ENTSO-E (2013a) 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).

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.

[5] Spain in particular but also Austria and Italy
[6] the distribution of elevation within a grid cell is based on NGDC (2013)

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.

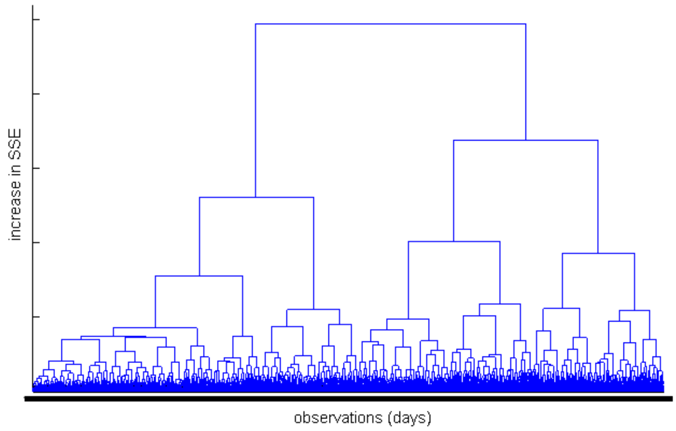


Figure 2: Dendrogram of clustering procedure. *Showing the consecutive grouping of two clusters to a joint cluster and the resulting increase in the overall sum of squared errors (SSE, y-axis). All days (x-axis) are consecutively grouped together until only one cluster is left.* Source: Own computation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

In Nahmmacher et al. (2014) we analyze the differences in model results depending on the number of time slices. We show that already 48 time slices[8] 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.

[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.

[8]i.e. 6 representative days

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 European Commission (2014) 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

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

	Wind Onshore	Wind Offshore	PV	CSP
2010	1300	4750	2500	5500
2015	1296	4412	1700	4329
2020	1291	4073	1508	3158
2025	1262	3790	1297	2859
2030	1232	3507	1085	2560
2035	1212	3338	1011	2411
2040	1191	3168	937	2262
2045	1171	2999	862	2112
2050	1150	2829	788	1963

Source: European Commission (2014) 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.

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 2012) 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.

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

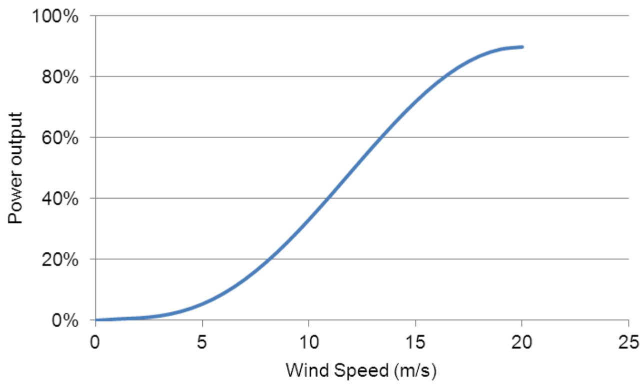


Figure 3: Aggregated wind power curve. Source: Own calculations based on ECMWF (2012); ÜNB (2013a,b).

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.

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. Table 3 gives an overview about the techno-economic characteristics of fuel and hydro based power plants in LIMES-EU.

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

	Investment Costs (€/kW)	Efficiency new (old) (%)	Annual Availability (%/a)	Fixed O&M (%/a)	Variable O&M (ct/kWh)	Minimum Load (%)	Lifetime (a)
Nuclear	4000	33	80	3	2.8	40	60
Hard Coal	1500	44 (37.4)	80	2	6.9	30	50
Hard Coal CCS	2600	38	80	2	11.4	30	50
Lignite	1800	43 (36.6)	80	2	9.1	50	50
Lignite CCS	3000	37	80	2	14.6	50	50
Gas CC	800	60	80	6	0.5	40	40
Gas CC CCS	1600	52	80	6	5.5	40	40
Gas GT	400	35	80	4	0.5	-	40
Biomass	2000	42	80	4	2.9	-	40
Hydro	2500	100	see Table 13	2	0	-	80

Source: European Commission (2014); Haller et al. (2012); Schmid et al. (2012); Schröder et al. (2013); own assumptions

Power plants with steam turbines are subject to minimum load restrictions and ramping constraints. In order to represent these characteristics in LIMES-EU, ramping of hard coal, lignite and natural gas combined cycle technologies is only allowed between model days. Within a model day their operating capacity has to remain constant throughout the day's eight time slices. Additionally, their electricity production may not fall below a minimum load that is defined as a share of operating capacity. Efficiency losses due to part load operation are disregarded. The operation of nuclear power plants is modelled in the same way. However, their operational capacity has to remain constant throughout the year. The minimum load restrictions are given in Table 3. Power plants with gas turbines are assumed to be able to ramp up and down within the time span of a single

[11] SM: solar multiple

[12] see Section 5.3.2 for the region-specific availability of hydro power plants

time slice. Minimum load restrictions for these generation technologies are therefore not considered.

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 4). 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 and natural gas is associated with greenhouse gas emissions; the CO_2 intensity of these primary energy sources is given in Table 4 as well. The stated emission factors are drawn from IPCC (1996) and are equal for every model region. In reality, the emission intensity of lignite significantly depends on the site of extraction and differs not only between but also within regions. However, for simplicity and due to the lack of sufficient data, we abstract from region-specific emission factors and adopt the approximation by IPCC (1996).

Table 4: 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)
Uranium	0.5	0.6	0.7	0.8	1.0	1.2	1.4	1.7	2.0	0
Hard Coal	1.8	2.2	2.6	2.6	2.7	2.9	3.1	3.3	3.5	94.6
Lignite	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	101.2
Natural Gas	5.3	6.2	6.9	7.1	7.3	7.2	7.2	7.1	7.0	56.1
Biomass	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0

Source: European Commission (2014); IPCC (1996); 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 5 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.

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

(2013) only assume costs of 0.4M€/GWkm. However, 0.4M€/GWkm rather reflect the costs for thermal capactiy 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 5: Characteristics of transmission technologies

	Inv. Costs (M€/GWkm)	Availability (%)	Lifetime (a)	Losses (%/1000km)
Net Transfer Capacity	1.0	80	50	7

Source: Haller et al. (2012); NEP (2013); 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 two generic storage technologies: *intra*day storage for balancing between time slices of the same day and the more expensive as well as less efficient *inter*day storage for balancing between time slices of the same year. The technical and economic features of the two storage options are given in Table 6. They are based on existing storage technologies, namely pumped-hydro for intraday storage and power-to-gas for interday storage. However, the parameters of these storage technologies only serve as a guidance for the two storage options in LIMES-EU. That is, we do not account for possible regional constraints[14] regarding these specific storage technologies, but implicitly assume that further options for intraday and interday storage with similar technical and economic parameters are available or will be in the future.

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 6 interday storages do not play a major role in any scenario outcome.

[14] e.g. suitable sites for pumped-hydro storage systems

Table 6: Characteristics of storage technologies

	Inv. Costs (€/kW)	Fixed O&M (%/a)	Efficiency (%)	Lifetime (a)
Intraday Storage	1500	1.0	80	80
Interday Storage	2000	1.0	40	40

Source: Fuchs et al. (2012); 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 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.

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

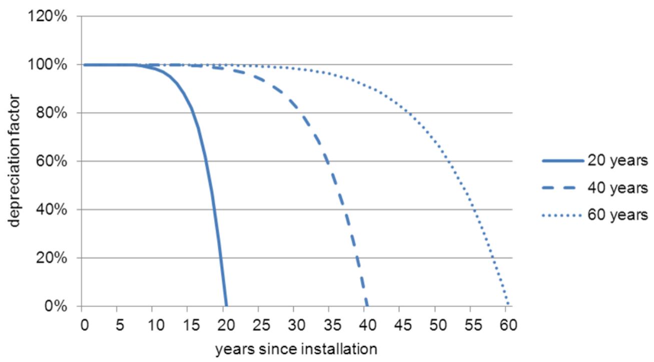


Figure 4: Depreciation factor ω for three different technological lifetimes (20, 40, 60 years). Source: Own assumptions.

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 (2013a). Final annual electricity demand for 2010 is retrieved from EUROSTAT (2013a) and IEA (2012b). Demand projections until 2050 are based on European Commission (2014) for default scenarios. Growth rates for model regions not mentioned in European Commission (2014) are estimated based on the growth rates of their neighboring countries for which data is available. Table 7 reports both the data for the base year 2010 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 Germany (+12%) and Poland (+78%) being at the lower and upper end, respectively. An explanation of the region codes used in this document is given in Appendix B.

To account for intra-regional transmission and distribution losses, it is assumed that the required production of electricity has to exceed the reported final electricity consumption by 15% (cf. EUROSTAT 2014).

Table 7: Default assumptions for final electricity demand (in TWh)

	2010	2015	2020	2025	2030	2035	2040	2045	2050
AT	61.3	61.9	62.8	65.5	68	70	73	75.5	78.4
BE	83.3	84.7	83.6	83.5	87.2	90.4	96	101.8	105.3
BG	27.1	30.4	31.2	31.9	33.4	35.1	37.7	40.1	42.6
CZ	57.2	58.2	58.8	60.3	62.9	66	68.5	71.8	76.4
DE	529	529.5	522.6	526.2	541.5	546.3	557.3	575.7	591.6
DK	32.1	31.1	28.9	29.3	30.3	32.3	34.7	37.9	40.5
EE	6.9	8	8.3	8.6	9	9.4	9.6	10.2	10.7
ES	244.8	275.8	284.9	310	327.8	342.8	354	366.6	374
FI	83.5	81.7	82.2	82.4	84.3	87.9	91.9	95.9	100.4
FR	444.1	463.9	458	484.9	516.9	540.8	565.3	599.4	615.4
GB	328.3	333	322.3	330.1	340.5	355.3	382.6	404	410.3
GR	53.1	52.7	55	55.6	57	60.5	62.9	64.7	66.8
HR	15.9	16.4	17.4	17	18.1	19.1	20	21.3	22.2
HU	34.2	34.5	35.2	37.8	40.5	42	43.5	46.8	48.8
IE	25.2	26.7	27.1	29.5	32.4	35.4	37.7	40.1	42.7
IT	299.3	312.3	311.3	318.5	329.5	345.6	369.6	392	407.9
LT	8.3	9	9.1	9.5	10.5	11.2	12.1	12.8	13.4
LU	6.6	6.5	6.5	6.8	7.2	7.4	7.4	7.6	7.7
LV	6.2	7	7.3	7.9	8.3	8.9	9.7	10	10.1
NL	106.9	116.8	113.3	113.5	116.6	119.1	124.6	129.4	132.1
PL	118.5	137.2	158.6	168.1	175.3	182.8	193.1	207.2	212
PT	49.9	50.3	51.9	52.9	55.8	59.1	60.8	62.9	64.4
RO	41.3	48.1	51.2	52.8	54.7	57.8	60.4	65.2	66.7
SE	131.2	136.9	133.6	137.3	139.4	140.7	143.3	147.2	149.9
SI	12	13.6	14.7	15	15.3	15.4	15.9	16	16.3
SK	24.1	27.5	29.9	31.6	33.7	34.8	35.4	36.8	37.1
Balkan	57.7	61.4	64	66	68.8	72.4	75.7	80.3	83.3
CH	59.8	61.3	60.7	62.5	65.2	67.3	70.1	73.6	75.9
NO	113.5	118.4	115.5	118.7	120.5	121.6	123.9	127.2	129.6

Source: EUROSTAT (2013a); European Commission (2014); IEA (2012b); own assumptions

5.2. Installed Capacities in Base Year

For the model's base year 2010, installed capacities are set exogenously. The existing capacities of generation and storage technologies (see Table 8) as well as their age structure is derived from Platts (2011) and EUROSTAT (2013b). The base year's transmission network (Table 9) is reflected by the NTC summmer values of 2010 as reported by ENTSO-E (2013b). As the precise age structure of the transmission network is unknown, we assume that the existing lines were either constructed or refurbished after 1985 and that invesmtents into the grid were equally distributed between 1985 and 2010.

Table 8: Installed generation and storage capacities in 2010 (in GW)

	Intraday Storage	Nuclear	Hard Coal	Lignite	Natural Gas CC	Natural Gas GT	Hydro	Bio	Wind Onshore	Wind Offshore	PV	CSP
AT	2.01	0.00	1.41	0.00	4.79	0.46	10.07	0.46	1.00	0.00	0.10	0.00
BE	1.21	6.04	1.80	0.00	6.17	1.60	0.11	0.45	0.76	0.15	0.91	0.00
BG	1.06	2.00	2.04	3.32	0.52	0.12	1.87	0.01	0.50	0.00	0.03	0.00
CZ	1.15	3.90	1.75	7.21	0.54	0.65	0.98	0.03	0.22	0.00	1.97	0.00
DE	6.78	21.51	30.10	21.25	25.44	7.51	3.84	1.43	27.81	0.18	17.34	0.00
DK	0.00	0.00	4.57	0.00	2.76	1.70	0.00	0.52	2.81	0.84	0.01	0.00
EE	0.00	0.00	0.00	2.86	0.20	0.02	0.01	0.06	0.11	0.00	0.00	0.00
ES	4.01	7.73	9.72	0.00	30.39	5.83	14.04	0.50	22.65	0.00	4.03	0.68
FI	0.00	2.84	3.79	0.06	2.80	1.83	3.07	3.06	0.19	0.00	0.01	0.00
FR	4.52	65.88	7.48	0.00	8.88	6.22	19.98	0.15	4.59	0.00	0.89	0.00
GB	2.95	12.61	29.84	0.00	39.34	5.65	1.64	0.39	4.03	1.35	0.08	0.00
GR	0.62	0.00	0.00	5.13	5.21	2.04	2.51	0.01	1.38	0.00	0.21	0.00
HR	0.28	0.00	0.34	0.00	1.42	0.18	1.83	0.00	0.08	0.00	0.00	0.00
HU	0.00	2.00	0.09	1.10	3.62	0.87	0.05	0.14	0.29	0.00	0.00	0.00
IE	0.29	0.00	0.92	0.00	4.59	1.02	0.24	0.40	1.39	0.03	0.00	0.00
IT	5.94	0.00	12.27	0.00	62.64	5.75	15.33	0.84	6.02	0.00	3.69	0.00
LT	0.80	0.00	0.00	0.00	2.71	0.02	0.11	0.00	0.13	0.00	0.00	0.00
LU	1.10	0.00	0.00	0.00	0.39	0.10	0.04	0.00	0.04	0.00	0.03	0.00
LV	0.00	0.00	0.00	0.00	0.89	0.04	1.52	0.01	0.03	0.00	0.00	0.00
NL	0.00	0.50	4.02	0.00	14.64	2.65	0.04	0.16	2.05	0.25	0.09	0.00
PL	1.47	0.00	23.16	9.00	1.31	0.11	0.81	0.06	1.15	0.00	0.00	0.00
PT	0.97	0.00	1.88	0.00	4.49	1.79	3.95	0.16	3.80	0.00	0.13	0.00
RO	0.00	1.44	2.03	5.98	5.51	0.14	6.58	0.01	0.39	0.00	0.00	0.00
SE	0.43	9.63	0.36	0.00	3.33	2.00	16.48	2.19	1.88	0.13	0.01	0.00
SI	0.19	0.73	0.12	0.84	0.25	0.31	0.97	0.01	0.00	0.00	0.01	0.00
SK	0.86	1.95	0.61	0.56	1.21	0.19	1.56	0.00	0.00	0.00	0.02	0.00
Balkan	1.06	0.00	0.34	8.72	1.07	0.11	6.54	0.00	0.00	0.00	0.00	0.00
CH	1.42	3.34	0.00	0.00	0.15	0.27	12.48	0.03	0.04	0.00	0.11	0.00
NO	0.83	0.00	0.01	0.00	0.71	0.69	28.45	0.01	0.42	0.00	0.00	0.00

Source: EUROSTAT (2013b); Platts (2011)

Table 9: Transmission capacities between model regions

	Regions to which transmission connections are possible (existing net transfer capacities of 2010 in GW)
AT	CH (0.77), CZ (0.70), DE (1.60), HU (0.43), IT (0.14), SI (0.90), SK (0.00)
BE	DE (0.00), FR (2.10), LU (0.00), NL (2.25)
BG	Balkan (0.50), GR (0.45), RO (0.40)
CZ	AT (0.70), DE (1.45), PL (1.35), SK (1.60)
DE	AT (1.60), BE (0.00), CH (3.23), CZ (1.45), DK (1.83), FR (2.90), LU (0.98), NL (3.95), PL (1.00), SE (0.60)
DK	DE (1.83), NO (0.95), SE (1.86)
EE	FI (0.35), LV (0.50)
ES	FR (0.85), PT (1.20)
FI	EE (0.35), SE (1.85)
FR	BE (2.10), CH (2.05), DE (2.90), ES (0.85), GB (2.00), IT (1.64), LU (0.00)
GB	FR (2.00), IE (0.25), NL (0.00), NO (0.00)
GR	Balkan (0.28), BG (0.45), IT (0.50)
HU	AT (0.43), Balkan (0.60), HR (0.75), RO (0.55), SI (0.00), SK (0.83)
HR	Balkan (0.88), HU (0.75), SI (0.75)
IE	GB (0.25)
IT	AT (0.14), CH (2.45), FR (1.64), GR (0.50), SI (0.23)
LT	LV (1.18), PL (0.00)
LU	BE (0.00), DE (0.98), FR (0.00)
LV	EE (0.50), LT (1.18)
NL	BE (2.25), DE (3.95), GB (0), NO (0.7)
PL	CZ (1.35), DE (1.00), LT (0.00), SE (0.30), SK (0.55)
PT	ES (1.20)
RO	Balkan (0.45), BG (0.40), HU (0.55)
SE	DE (0.60), DK (1.86), FI (1.85), NO (3.62), PL (0.30)
SI	AT (0.90), HR (0.75), HU (0.00), IT (0.23)
SK	AT (0.00), CZ (1.60), HU (0.83), PL (0.55)
Balkan	BG (0.50), GR (0.28), HR (0.88), HU (0.60), RO (0.45)
CH	AT (0.77), DE (3.23), FR (2.05), IT (2.45)
NO	DK (0.95), GB (0.00), NL (0.70), SE (3.62)

Source: ENTSO-E (2013b); own assumptions

5.3. Resource Endowments

5.3.1. Wind & Solar

A country's wind and solar power potential is defined by two determinants: (1) the installable capacity of wind and solar power plants and (2) the achievable capacity factors at the respective sites.

The installable capacity is again 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 (FAO 2013) and elevation (NGDC 2013) data. 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. And third, the amount of capacity that can be installed on the available area is subject to technology-specific restrictions. Table 10 summarizes the parameters used to calculate the capacity potential for each technology.

Table 10: Assumptions for the approximation of regional wind and solar power potentials

	Suitable areas	Share of suitable areas available for RES	Maximum capacity density (MW/km^2) on available area
Wind Onshore	Agricultural areas Forest areas	30% 5%	4
Wind Offshore	Marine areas - max. depth: 50m - max. distance to shore: 55km - within exclusive economic zone	50%	6
PV	Agricultural areas Roof-tops & facades	2% 50% ($12m^2$/capita)	30 100
CSP	Agricultural areas	2%	10

Note: Agricultural areas include cropland, meadows and pastures as well as fallow land.
Source: FAO (2013); Held (2010); IEA (2002); NGDC (2013); Trieb et al. (2009); VLIZ (2012); Denholm et al. (2009); Ong et al. (2013); own assumptions

Onshore wind turbines can be installed in forests and agricultural areas, which include cropland, meadows and pastures as well as fallow land (FAO 2013). The share of these areas that is available for wind power is mainly limited by public acceptance and nature reserves. Additional usage, such as food production on agricultural land, is still possible as the wake effect[15] considerably limits the maximum density of wind turbines per square kilometer.

Sites eligible for offshore wind power plants lie within a distance of less than 55km to the mainland and belong to the exclusive economic zone (VLIZ 2012) of the respective model region. Sites with a water depth of more than 50m are excluded. Additionally only a share of the resulting area may be used for offshore wind power to prevent wind turbines from being installed too close to the mainland shore or smaller islands as well as to account for shipping corridors.

In order to assess the installable capacity of solar PV, two kinds of PV systems are considered: large systems that are installed on agricultural areas and small PV systems mounted on rooftops and facades. In contrast to onshore wind power no other use of the land dedicated to solar power is possible, as the PV cells and the associated infrastructure cover most of the ground. For that reason, only a small share of a model region's agricultural area is eligible for large PV systems. Following IEA (2002) the available rooftop and facade area for small PV systems is approximated based on a model region's population. However, to account for the deployment of solar heating panels only half of the area potential stated in IEA (2002) is available for solar PV (cf. Held 2010).

[15] The wake effect describes the turbulence of the wind stream behind a turbine. This turbulence prohibits the installation of wind turbines in too close proximity.

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

	Wind Onshore	Wind Offshore	PV	CSP
AT	45.8	0.0	29.2	6.3
BE	17.7	9.1	21.4	2.7
BG	68.5	11.6	39.6	10.1
CZ	56.1	0.0	38.3	8.5
DE	222.6	83.6	200.4	33.4
DK	32.6	149.0	22.5	5.3
EE	15.8	55.9	7.3	1.9
ES	366.9	55.0	221.6	55.1
FI	71.8	130.5	20.3	4.6
FR	381.7	133.7	251.8	58.3
GB	212.5	312.4	179.3	34.4
GR	105.6	27.6	62.8	16.3
HR	19.8	47.1	13.4	2.7
HU	68.2	0.0	44.3	10.7
IE	56.3	52.2	32.9	9.1
IT	190.2	77.7	159.9	28.6
LT	37.6	9.2	20.7	5.5
LU	1.7	0.0	1.4	0.3
LV	28.4	43.1	13.6	3.6
NL	23.6	57.1	31.8	3.8
PL	193.9	40.7	134.4	29.2
PT	51.0	16.7	35.1	7.4
RO	183.0	24.3	111.2	28.3
SE	93.4	167.7	30.0	6.2
SI	8.3	0.3	5.4	1.0
SK	27.2	0.0	18.3	3.9
Balkan	134.7	5.3	83.7	20.1
CH	20.8	0.0	18.7	3.0
NO	32.2	122.2	12.0	2.0

Source: FAO (2013); Held (2010); IEA (2002); NGDC (2013); Trieb et al. (2009); VLIZ (2012); Denholm et al. (2009); Ong et al. (2013); own assumptions

Similar to large solar PV systems, CSP plants may only be installed on former agricultural area. However, as we assume a SM4 configuration[16] in LIMES-EU the maximum installable capacity per square kilometer is much smaller compared to PV systems.

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 region's area and is assigned the average technology-specific capacity factor of this area[17]. The assignment 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. The assignment

[16] see Section 4.1.1

[17] based on the data presented in Section 3.1 and the power curves from Section 4.1.1

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
AT	19	16	12	-	-	-	12	12	11	6	6	5
BE	23	22	20	32	31	25	11	11	10	5	5	4
BG	21	14	9	20	18	16	14	14	13	8	8	7
CZ	20	18	16	-	-	-	11	11	11	5	5	5
DE	24	20	16	35	33	27	11	11	10	5	5	4
DK	33	31	26	36	33	29	11	10	10	4	3	3
EE	29	22	17	31	30	25	10	9	9	3	3	2
ES	25	16	11	32	22	11	17	17	15	11	10	9
FI	21	14	12	32	29	22	9	8	7	2	2	1
FR	28	21	14	33	29	21	14	13	12	8	7	5
GB	39	32	26	41	37	31	11	10	9	5	4	3
GR	19	14	8	28	21	11	16	16	15	11	10	9
HR	21	16	8	17	14	10	14	13	12	8	7	6
HU	14	12	9	-	-	-	13	13	12	6	6	6
IE	40	34	25	42	40	34	10	10	9	4	4	3
IT	20	15	9	18	15	10	17	15	13	11	9	7
LT	21	19	17	29	28	23	10	10	9	3	3	3
LU	21	21	20	-	-	-	11	11	11	5	5	5
LV	25	21	17	29	29	25	10	10	9	3	3	3
NL	29	25	20	35	33	29	11	11	10	4	4	4
PL	24	19	17	33	30	26	11	10	10	5	4	4
PT	21	16	12	26	23	19	17	17	16	11	10	9
RO	18	13	9	20	19	17	13	13	12	7	7	6
SE	24	18	13	32	30	23	10	9	8	3	2	1
SI	12	11	8	4	4	4	13	12	12	6	6	6
SK	16	15	13	-	-	-	12	11	11	6	5	5
Balkan	18	14	9	15	13	8	14	14	13	9	8	7
CH	19	15	9	-	-	-	13	12	12	6	6	6
NO	29	23	16	35	31	23	9	8	7	2	2	1

Source: ECMWF (2012); own assumptions

of resource grades is done separately for every technology that is based on wind and solar power. Table 11 shows the technologies' capacity potentials per model region; the corresponding capacity factors per region and resource grade are given in Table 12.

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 and biomass, 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

Table 13: Regional biomass and hydro potential

	Biomass			Hydro	
	Annual primary energy potential (in PJ)			Installable capacity (GW)	Annual availability (%/a)
	2010	2020	2030 -2050		
AT	96	109	121	11.1	44
BE	97	97	97	0.1	37
BG	19	33	39	2.2	20
CZ	53	63	70	1.2	26
DE	432	472	603	3.9	60
DK	77	77	77	0.0	30
EE	21	31	36	0.0	49
ES	230	307	350	14.7	25
FI	134	137	131	3.4	50
FR	438	519	662	22.6	37
GB	229	265	342	2.2	34
GR	22	47	53	2.5	23
HR	34	36	39	1.8	39
HU	50	63	78	0.1	46
IE	15	17	18	0.2	37
IT	226	261	346	15.3	35
LT	57	106	138	0.1	43
LU	3	3	3	0.0	39
LV	18	27	33	1.5	23
NL	145	145	145	0.1	32
PL	332	461	548	1.2	29
PT	50	54	57	5.5	30
RO	129	165	204	7.4	31
SE	163	181	188	17.2	46
SI	25	24	25	1.4	44
SK	31	33	50	2.0	32
Balkan	64	92	109	6.5	30
CH	34	40	49	12.5	34
NO	103	112	116	30.2	52

Source: EEA (2006); EUROSTAT (2013b,c); European Commission (2013b); FAO (2013); own assumptions

of lignite is therefore limited to those countries with existing lignite mines in 2010. In addition, we assume that new open-cast mines for lignite extraction are only opened when others are closed; hence, the maximum annual consumption of lignite is fixed to 2010 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 2013) 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[18] (European Commission 2013b), the potential is adjusted to cover this target[19]. Table 13 shows the maximum deployment of biomass per model region.

The limited availability of sites suitable for deploying hydro power 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 level needed to fulfil the national targets for electricity production from hydro as stated in the NREAPS (European Commission 2013b). 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 2010 that are derived from EUROSTAT (2013c) and EUROSTAT (2013b). Both maximum capacities and capacity factors are given in Table 13.

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 obstactles such as public acceptance or institutional capacity (cf. Hughes and Strachan 2010).

Climate Policy The standard scenario reflects the CO_2 emission reduction targets set on EU level as stated in the EU Low Carbon Roadmap (European Commission 2011a). For the electricity sector the Roadmap targets translate to an emission reduction of about 95% below 1990 levels[20] until 2050 (European Commission 2011b). If the non-EU model regions Norway, Switzerland and Balkan are not subject to these emission reduction commitments, individual targets can be defined for those regions. Alternatively, an emission intensity constraint can be set for regions without a dedicated climate policy. In such a case, a region's emission intensity (based on the region's domestic consumption of electricity) is limited to its 2010 level. This prevents artifactual model results showing a massive import of electricity into the

[18]National Renewable Energy Action Plans (see Section 6)
[19]This is the case for Denmark, the Netherlands, Belgium and Luxemburg
[20]1990 emission levels of the model regions' electricity sector have been calculated based on IEA (2012a)

EU from CO_2 emitting power plants sited in non-policy regions. Instead of constraining the CO_2 emissions for single countries or aggregated regions, LIMES-EU also allows for setting a region-speicfic price on CO_2 emissions. If a constraint on CO_2 emissions is set, the corresponding price of an emission allowance can be derived from the constraint's shadow price, which is part of the model results.

Renewable Policy As stated by the European Parliament and European 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 2013b). 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. 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 & CCS Policy In several countries nuclear power plants and CCS technology face problems in public acceptance due to environmental risks and uncertain overall costs. In order to accomodate 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.

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. First, we compare model results for the base year 2010 with historic data, namely the electricity generation mix and CO_2 emissions. In a second step, we compare long-term scenarios - the main focus of LIMES-EU - with results from other long-term models.

7.1. Comparison with Historic Data

For the base year 2010, 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 EUROSTAT (2014) and IEA (2014). In addition, we compare the resulting national CO_2 emissions with the historic emissions of 2010 (IEA 2012a).

In order to replicate the historic dispatch, we constrain the aggregated CO_2 emissions of the EU ETS countries according to their actual electricity sector emissions in 2010. The shadow price of this constraint amounts to 15.24€ which is consistent with the price for EU ETS allowances in this year: The average clearing price of emission allowance auctions in Germany was 14.36€ in 2010 (DEHSt 2010). Figure 5 shows both historic emissions and model results for 2010. 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 absolute the 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 (CHP) plants in LIMES-EU. We refrain from including it in LIMES-EU as a sound implementation of CHP would make the model considerably more complex. However, in case CHP is assumed to be an important pillar of the future European electricity system, it could be approximated in LIMES-EU by a must run constraint of selected thermal power generation technologies.

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 hydro is used less compared to reality. The result that hydro power is used less in LIMES-EU compared to 2010 data can be explained by the fact that the availability factor of hydro power in LIMES-EU is based on the years 2006 to 2010. However, 2010 was an exceptionally good year for hydro power, with a capacity factor of 45% instead of the average 30% in Portugal and 51% instead of 39% in Croatia (EUROSTAT 2013b,c).

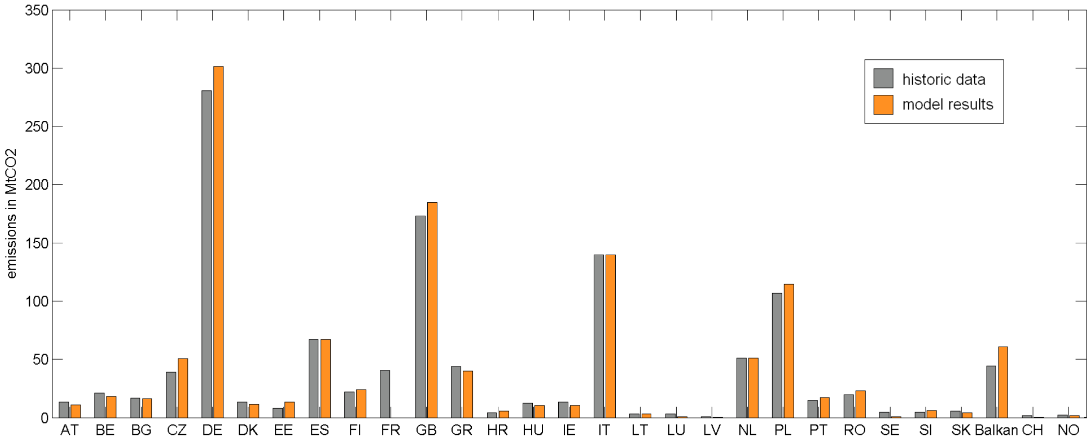


Figure 5: Comparison of historic and model-derived region-specific CO_2 emissions in 2010. Source: IEA (2012a); own model results.

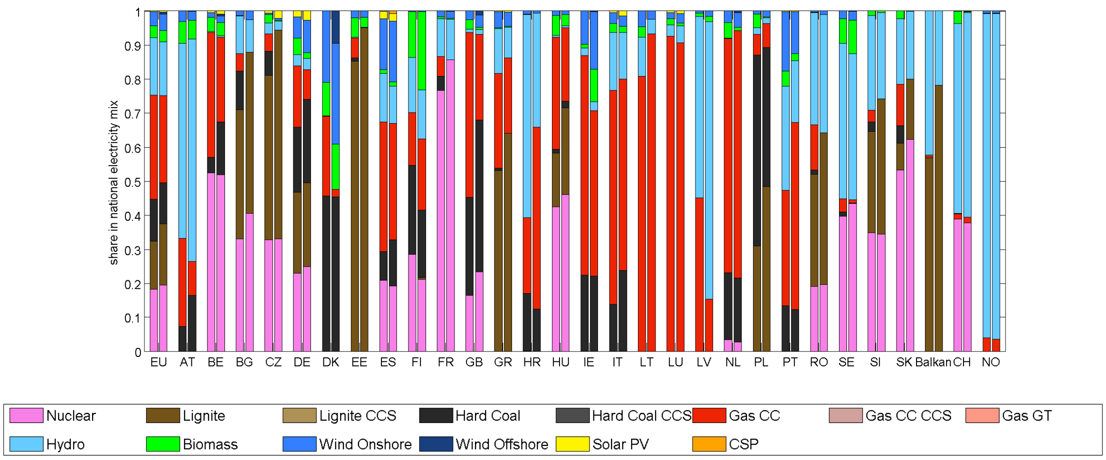


Figure 6: Comparison of the historic (*left bar*) and the model-derived (*right bar*) region-specific electricity generation mix in 2010. Source: EUROSTAT (2014); IEA (2014); own model results.

However, some regional electricity mixes deviate strongly from historic data, e. g. natural gas is overrated in Croatia but underrated in the United Kingdom. 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.

7.2. Comparison with Other Models

In this Section we compare results derived from LIMES-EU with results from six other long-term models[21] with a distinct representation of the European electricity sector. As there is no real data about future years, setting the results of LIMES-EU into context with those of other models is deemed to be an appropriate way in order to build further trust in the model. The models we consider were part of a model comparison performed by the Energy Modeling Forum 28 (EMF28) focusing on scenarios for reducing Europe's CO_2 emissions until 2050 by 80%[22] (Knopf et al. 2013). Further scenario assumptions such as investment and fuel costs were not harmonized among the models. For LIMES-EU we therefore use the default parameter assumptions as stated in this documentation.

Figure 7 shows the cost-efficient capacity investment and electricity generation pathway until 2050 for the given CO_2 reduction target and the presented parameter assumptions. Note that the deployment of natural gas fired power plants is very sensitive to the price spread between natural gas and hard coal and should typically be covered by a sensitivity analysis. However, as Knopf et al. (2013) only give results for the year 2050, we do only compare results for this year; and the dominant role of natural gas has already passed at that time.

Figure 8 presents a comparison of regional model results from LIMES-EU and Knopf et al. (2013) for the year 2050. It shows the share of different generation technologies in the electricity mix of selected countries - namely France, Germany, Italy, Sweden and the United Kingdom. In addition, the Figure indicates the average EU28 shares derived from LIMES-EU in comparison to the shares stated in European Commission (2014).

The regional results from LIMES-EU fit very well into the range of the other models. Also the average EU28 shares are consistent with those from European Commission (2014); only solar power is significantly higher in LIMES-EU. The high share of solar in 2050 is based on a substantial addition of PV and CSP capacities after 2035 (cf. Figure 7). This rapid capacity addition is cost-efficient under the given assumptions, but may be deemed infeasible in reality. In this case, it is possible to set constraints on the maximum annual investments per region and technology in LIMES-EU.

Overall, the results suggest that LIMES-EU is well suited for generating meaningful long-term scenarios for the European electricity sector. Moreover, the model not only produces long-term results; the intertemporal optimization allows for analyzing the entire investment pathway from today until 2050. A sound assessment of the technologies' cost-efficient role in the future European power system is ensured by effectively accounting for short-term variability in the long-term optimization.

[21] FARM EU, POLES, PRIMES, TIMES PanEU, PET and EMELIE-ESY

[22] translating to about 95% for the electricity sector

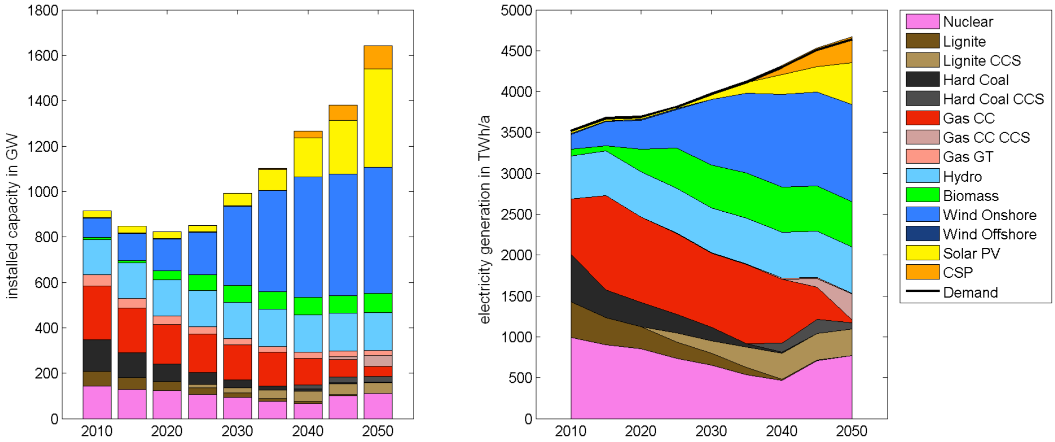


Figure 7: Cost-efficient pathway of the capacity and generation mix from 2010 to 2050. Source: Own model results.

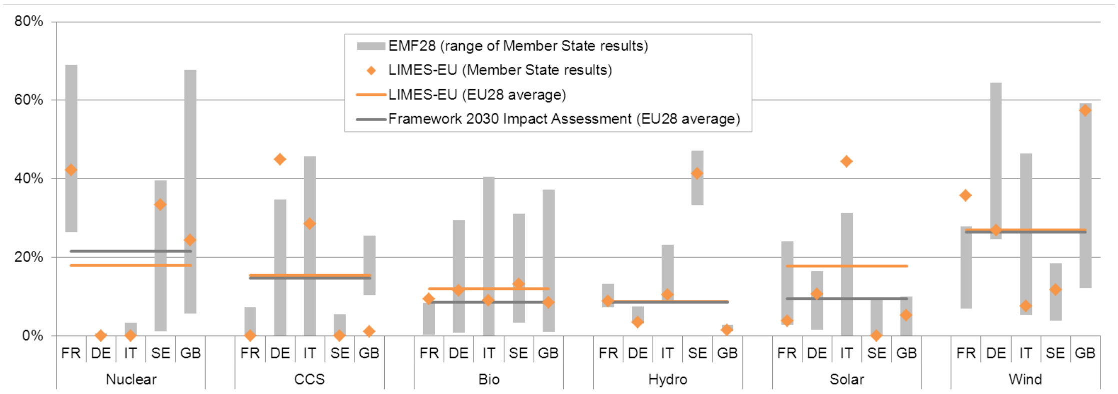


Figure 8: Share of generation technologies in the 2050 electricity mix. Source: European Commission (2014); Knopf et al. (2013); own model results.

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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	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}	fixed operation and maintenance cost
c^{OMV}_{te}	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

Table A.4: Variables

Symbol	Description
C^{tot}	total system cost
C^I_t	investment cost
C^F_t	fuel cost
C^{OM}_t	operation and maintenance cost
$C^{CO_2}_t$	CO_2 emission cost
V	salvage value
$P_{t,\tau,r,pe}$	primary energy consumption
$K_{t,r,te}$, $K_{t,cn}$	installed capacity
$\Delta K_{t,r,te}$, $\Delta K_{t,cn}$	new capacity
$K^{RG}_{t,r,te,rg}$	installed capacity (resource grade specific)
$\Delta K^{RG}_{t,r,te,rg}$	new capacity (resource grade specific)
$G_{t,\tau,r,te}$	electricity generation
$E^{CO_2}_{t,r}$	CO_2 emissions
$E^{CCS}_{t,r}$	captured CO_2 (via CCS)
$S^{OUT}_{t,\tau,r,te}$	storage output
$S^{IN}_{t,\tau,r,te}$	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

A.1. Objective function and its components

Equation A.1: Objective function

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

Equation A.2: Fuel costs

$$C_t^F = \sum_{r,pe} c_{t,pe}^F \sum_\tau l_\tau \, P_{t,\tau,r,pe} \qquad \forall t \tag{A.2}$$

Equation A.3: Investment costs

$$C_t^I = \sum_{r,te} \left(c_{t,te}^I \, \Delta K_{t,r,te} \right) + \sum_{r,st} \left(c_{t,st}^I \, \Delta K_{t,r,st} \right) + \sum_{cn} \left(c_{t,cn}^I \, \Delta K_{t,cn} \right) \qquad \forall t \tag{A.3}$$

Equation A.4: Operation and maintenance costs

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

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

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

A.2. Electricity balance

Equation A.7: Electricity balance

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

A.3. Equations for generation technologies

Equation A.8: Expansion and depreciation of generation technologies

$$
K_{t,r,te} = \Delta t \sum_{\tilde{t}=0}^{\psi_{te}} \omega_{\tilde{t},te} \Delta K_{(t-\tilde{t}),r,te} \qquad \forall t,r,te \tag{A.8}
$$

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

$$
K^{RG}_{t,r,te,rg} = \Delta t \sum_{\tilde{t}=0}^{\psi_{te}} \omega_{\tilde{t},te} \Delta K^{RG}_{(t-\tilde{t}),r,te,rg} \qquad \forall t,r,te \in TE^{vres}, rg \tag{A.9}
$$

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: Capacity constraint for all generation technologies

$$
G_{t,\tau,r,te} \leq K_{t,r,te} \qquad \forall t,\tau,r,te \tag{A.11}
$$

Equation A.12: Availability of Wind Onshore, Wind Offshore and PV

$$
G_{t,\tau,r,te} \leq \sum_{rg} \alpha^{vRES}_{\tau,r,te,rg} K^{RG}_{t,r,te,rg} \qquad \forall t,\tau,r,te \in \{\mathit{Wind\ Onshore,\ Wind\ Offshore,\ PV}\} \tag{A.12}
$$

Equation A.13: Availability of CSP

$$
\sum_{\tau \in T_{day}} l_\tau \, G_{t,\tau,r,te} \leq \sum_{\tau \in T_{day}} l_\tau \sum_{rg} \alpha^{vRES}_{\tau,r,te,rg} K^{RG}_{t,r,te,rg} \qquad \forall t, day, r, te \in \{CSP\} \tag{A.13}
$$

Equation A.14: Availability of Hydro

$$G_{t,\tau,r,te} \leq 1.25\, \alpha_{r,te}\, K_{t,\tau,r,te} \qquad \forall t, r, te \in \{\mathit{Hydro}\} \tag{A.14}$$

Equation A.15: Annual availability of dispatchable generation technologies

$$\sum_{\tau} l_\tau\, G_{t,\tau,r,te} \leq \sum_{\tau} l_\tau\, \alpha_{r,te}\, K_{t,r,te} \qquad \forall t, r, te \in TE^{disp} \tag{A.15}$$

Equation A.16: Operation constraint for thermal generation technologies

$$OP_{t,\tau,r,te} \leq K_{t,r,te} \qquad \forall t, \tau, r, te \in TE^{ramp} \tag{A.16}$$

Equation A.17: Generation constraint for thermal generation technologies

$$G_{t,\tau,r,te} \leq OP_{t,\tau,r,te} \qquad \forall t, \tau, r, te \in TE^{ramp} \tag{A.17}$$

Equation A.18: Minimum load constraint for thermal generation technologies

$$G_{t,\tau,r,te} \geq \mu_{te}\, OP_{t,\tau,r,te} \qquad \forall t, \tau, r, te \in TE^{ramp} \tag{A.18}$$

Equation A.19: Ramping constraint for hard coal, lignite and natural gas combined cycle power plants

$$OP_{t,\tau \in T_{day},r,te} = OP_{t,day,r,te} \qquad \forall t, \tau, r, te \in \{\mathit{Hard\ Coal,\ Lignite,\ Natural\ Gas\ CC}\} \tag{A.19}$$

Equation A.20: Ramping constraint for nuclear power plants

$$OP_{t,\tau,r,te} = OP_{t,r,te} \qquad \forall t, \tau, r, te \in \{\mathit{Nuclear}\} \tag{A.20}$$

A.4. Equations for transmission technologies

Equation A.21: Expansion and depreciation of transmission capacity

$$K_{t,cn} = \Delta t \sum_{\tilde{t}=0}^{\psi_{cn}} \omega_{\tilde{t},cn} \Delta K_{t,cn} \qquad \forall t, cn \tag{A.21}$$

Equation A.22: Transmission constraint

$$\begin{aligned} F^{+}_{t,\tau,cn} &\leq \alpha_{cn}\, K_{t,cn} \qquad \forall t, \tau, cn \\ F^{-}_{t,\tau,cn} &\leq \alpha_{cn}\, K_{t,cn} \qquad \forall t, \tau, cn \end{aligned} \tag{A.22}$$

A.5. Equations for storage technologies

Equation A.23: Expansion and depreciation of storage technologies

$$K_{t,r,st} = \Delta t \sum_{\tilde{t}=0}^{\psi_{st}} \omega_{\tilde{t},st} \Delta K_{(t-\tilde{t}),r,st} \qquad \forall t, r, st \tag{A.23}$$

Equation A.24: Storage constraint

$$\begin{aligned} S^{IN}_{t,\tau,r,st} &\leq K_{t,r,st} \qquad \forall t, \tau, r, st \\ S^{OUT}_{t,\tau,r,st} &\leq K_{t,r,st} \qquad \forall t, \tau, r, st \end{aligned} \tag{A.24}$$

Equation A.25: Interday storage balance

$$\eta_{st} \sum_{\tau} l_\tau \; S^{IN}_{t,\tau,r,st} = \sum_{\tau} l_\tau \; S^{OUT}_{t,\tau,r,st} \qquad \forall t, r, st \in ST^{interday} \tag{A.25}$$

Equation A.26: Intraday storage balance

$$\eta_{st} \sum_{\tau \in T_{day}} l_\tau \; S^{IN}_{t,\tau,r,st} = \sum_{\tau \in T_{day}} l_\tau \; S^{OUT}_{t,\tau,r,st} \qquad \forall t, day, r, st \in ST^{intraday} \tag{A.26}$$

A.6. Primary energy demand and CO_2 emissions

Equation A.27: Primary energy demand

$$P_{t,\tau,r,pe} = \sum_{te \in TE_{pe}} G_{t,\tau,r,te} / \eta_{te} \qquad \forall t, \tau, r, pe \tag{A.27}$$

Equation A.28: Primary energy constraint

$$\sum_{\tau} l_\tau \; P_{t,\tau,r,pe} \leq p^{max}_{t,r,pe} \qquad \forall t, r, pe \tag{A.28}$$

Equation A.29: CO_2 emissions from electricity generation

$$E^{CO_2}_{t,r} = \sum_{pe} \lambda_{pe} \sum_{\tau} l_\tau \; P_{t,\tau,r,pe} - E^{CCS}_{t,r} \qquad \forall t, r \tag{A.29}$$

Equation A.30: Avoided CO_2 emissions via CCS

$$E^{CCS}_{t,r} = 0.9 \sum_{pe} \lambda_{pe} \sum_{\tau} l_\tau \sum_{te \in TE^{ccs}_{pe}} G_{t,\tau,r,te} / \eta_{te} \qquad \forall t, r \tag{A.30}$$

Equation A.31: CCS constraint

$$\Delta t \sum_{t} E_{t,r}^{CCS} \leq cap_{r}^{CCScum} \qquad \forall r \tag{A.31}$$

A.7. Policy equations

Equation A.32: Target on CO_2 emission intensity of power generation

$$\frac{E_{t,r}^{CO_2}}{\sum_{\tau} l_{\tau}\, d_{t,\tau,r}} \leq \frac{E_{t_0,r}^{CO_2}}{\sum_{\tau} l_{\tau}\, d_{t_0,\tau,r}} \qquad \forall t > t_0, r \tag{A.32}$$

Equation A.33: CO_2 emission target for a group of regions

$$\sum_{r \in R^{pol}} E_{t,r}^{CO_2} \leq cap_{t}^{CO_2} \qquad \forall t \tag{A.33}$$

Equation A.34: CO_2 emission target for a single region

$$E_{t,r}^{CO_2} \leq cap_{t,r}^{CO_2} \qquad \forall t, r \tag{A.34}$$

Equation A.35: Cumulated CO_2 emission target for a group of regions

$$\Delta t \sum_{t > t_0} \sum_{r \in R^{pol}} E_{t,r}^{CO_2} \leq cap^{CO_2 cum} \tag{A.35}$$

Equation A.36: Cumulated CO_2 emission target for a single region

$$\Delta t \sum_{t > t_0} E_{t,r}^{CO_2} \leq cap_{r}^{CO_2 cum} \qquad \forall r \tag{A.36}$$

Equation A.37: National RES target

$$\sum_{\tau} l_{\tau} \sum_{te \in TE^{res}} G_{t,\tau,r,te} \geq res_{t,r} \qquad \forall t, r \tag{A.37}$$

Equation A.38: National RES target (technology specific)

$$\sum_{\tau} l_{\tau}\, G_{t,\tau,r,te} \geq res_{t,r,te} \qquad \forall t, r, te \in TE^{res} \tag{A.38}$$

Equation A.39: RES target for a group of regions

$$\sum_{r \in R^{pol}} \sum_{\tau} l_{\tau} \sum_{te \in TE^{res}} G_{t,\tau,r,te} \geq res_{t} \qquad \forall t \tag{A.39}$$

Equation A.40: RES target (technology specific) for a group of regions

$$\sum_{r \in R^{pol}} \sum_{\tau} l_\tau \, G_{t,\tau,r,te} \geq res_{t,te} \qquad \forall t, te \in TE^{res} \tag{A.40}$$

Equation A.41: Target on mimimum amount of electricity provided domestically

$$\sum_{\tau} l_\tau \sum_{te} G_{t,\tau,r,te} \geq \phi_r \sum_{\tau} l_\tau \, d_{t,\tau,r} \qquad \forall t, r \tag{A.41}$$

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