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The JRC-EU-TIMES model

Assessing the long-term role of the SET Plan Energy technologies

Sofia Simoes, Wouter Nijs, Pablo Ruiz, Alessandra Sgobbi, Daniela Radu, Pelin Bolat, Christian Thiel, Stathis Peteves

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Joint Research Centre

European Commission
Joint Research Centre
Institute for Energy and Transport
Contact information
Christian Thiel
Address: Joint Research Centre, Westerduinweg 3, 1755LE Petten, The Netherlands
E-mail: christian.thiel @ec.europa.eu
Tel.: +31-224-565143
Fax: + 31-224-565616

http://iet.jrc.ec.europa.eu/
http://www.jrc.ec.europa.eu/

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The JRC-EU-TIMES model

Assessing the long-term role of the SET Plan
Energy technologies

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GLOSSARY of TERMS and ACRONYMS

Balkans countries	Albania, Bosnia and Herzegovina, The Former Yugoslav Republic of Macedonia, Montenegro, and Serbia
Base year	The year for which the model is calibrated. In the case of JRC-EU-TIMES model 2005 is the base year
BEV	Battery electric vehicle
Bottom-up approach	The method of explicitly representing technologies and their use based on the disaggregated information on their specific internal processes
CAES	Compressed air energy storage
Calibration	The process of adjusting the model to reflect a defined situation. JRC-EU-TIMES model is calibrated using official energy statistics from the year 2005 (Eurostat 2011 version)
CHP	Combined heat and power
CCS	Carbon Capture and Storage. Set of technologies that allow the capturing of CO_2, its transportation and future storage, in order to reduce greenhouse gases emissions
CNG	Compressed natural gas
Decarbonised scenarios	Those scenarios that assume a total reduction of CO_2 emissions by 85% with respect to 1990
DH	District heating
Endogenous assumptions	Assumptions used to describe elements within the system. Some variables can be exogenous or endogenous, depending on their use, such as CO_2 price
Energy intensity	The energy used relative to the total output. In the JR-EU-TIMES report, it is used as a measure for the energy efficiency of an economy, calculated in energy units per unit of GDP

Energy system	A combined set of energy processes, covering all sectors, that are connected via their inputs and outputs and finally are supplying end-use energy services
Energy system cost	The total of all energy expenses in an energy system. It can be decomposed into investment, fixed and variable costs (these are discounted based on technology specific discount rates). Moreover, energy system costs are estimated as a Net Present Value based on a exogenously defined social discount rate
EU28	All European Union countries (including Croatia)
EU27	All European Union countries except Croatia
EU28+	All European Union countries (including Croatia) plus Iceland, Norway, Switzerland, and Western Balkan countries
Exogenous assumptions	Assumptions used to describe variables affecting the system but that are not part of it, for example, fuels prices or target percentage of Renewable
GEM-E3	General equilibrium model of the European Union used by the JRC
GW	Gigawatt is a unit derived from energy, used for measuring energy capacity. It is equal to 1 billion watts
IEA-ETP	Energy Technology Perspectives publication from the International Energy Agency
ICE	Internal Combustion Engine
IGCC	Integrated Gasification Combined Cycle
JET	JRC-EU-TIMES
OCGT	Open cycle gas turbine
PHEV	Plug-in hybrid electric vehicle
PHS	Pumped hydro storage
POLES	Partial equilibrium energy system simulation model used by the JRC

PRIMES	Energy system model used in the EU Roadmap 2050, developed by the National Technical University of Athens
Reference energy system	A graphical model of the studied system, describing the energy technologies and flows of energy. Usually to identify the processes required to supply the end-use activities
Reference scenario	The baseline scenario, based on current implemented policies
RES potentials	Renewable energy sources potentials including both carriers not directly used for electricity generation (bioenergy, buildings solar thermal, geothermal for heating) and used for electricity production. In the former the potentials are assumed as the maximum energy content (in PJ) that a RES technology can provide within a country. In the latter the potentials are the assumed maximum electrical capacity or power generation that a renewable energy technology can provide within a country
TIMES	The Integrated MARKAL-EFOM System

1 Introduction

The JRC-EU-TIMES model has been developed over the last years in a combined effort of two of the JRC Institutes, IPTS and IET. This report aims at providing an overview on the main data inputs and major assumptions of the JRC-EU-TIMES model. Furthermore, it describes a number of model outputs from exemplary runs in order to display how the model reacts to different scenarios.

The report has been written to facilitate a validation process by external experts. The experts who participated in the validation are:

Anna Krook - Lulea University of Technology

Bob van der Zwaan - ECN

Chris Heaton - ETI Energy Technologies Institute

Dominique Lafond - EDF

George Giannakidis - ETSAP, CRES

Martin Wietschel - Fraunhofer ISI

Maryse Labriet – ENERIS Environment Energy Consultants

Tom Kober - ECN

Uwe Remme - IEA ETP.

The JRC-EU-TIMES model is one of the models currently pursued and developed in the JRC under the auspices of the JRC Modelling Taskforce. The JRC-EU-TIMES model is designed for analysing the role of energy technologies and their innovation for meeting Europe's energy and climate change related policy objectives. It models technologies uptake and deployment and their interaction with the energy infrastructure in an energy systems perspective. It is a relevant tool to support impact assessment studies in the energy policy field that require quantitative modelling at an energy system level with a high technology detail. The scenarios described in this report do not represent a quantified view of the European Commission on the future EU energy mix nor do they represent the opinion of the experts participating in the validation. They are thus not meant to inform policy decisions, but simply to test the JRC-EU-TIMES model response.

The main objective of this report is to present the main inputs and assumptions currently used in the JRC-EU-TIMES model. The JRC-EU-TIMES model, as the majority of energy system models, uses very large data sets which subsequently require continuous improvement. One of the motives for making this report public is to obtain constructive feedback aiming to improve the model's inputs. Suggestions and comments can be sent to JRC-EU-TIMES@ec.europa.eu.

2 General model overview

2.1 Structure overview

The JRC-EU-TIMES model is a linear optimisation bottom-up technology model generated with the TIMES model generator from ETSAP[1] of the International Energy Agency. More information on TIMES can be found in [(Loulou, Remme, Kanudia, Lehtila, & Goldstein, 2005a),(Loulou, Remme, Kanudia, Lehtila, & Goldstein, 2005b)]. The JRC-EU-TIMES represents the EU 28 energy system and neighbouring countries from 2005 to 2050, where each country is one region. The JRC-EU-TIMES model was developed as an evolution of the Pan European TIMES (PET) model of the RES2020 project[2], followed up within the REALISEGRID[3] and REACCESS[4] European research projects (Loulou, et al., 2005a, 2005b).

The equilibrium is driven by the maximization (via linear programming) of the discounted present value of total surplus, representing the sum of surplus of producers and consumers, which acts as a proxy for welfare in each region of the model (practically, the linear programming minimizes the negative surplus, which is then called the system cost). The maximization is subject to many constraints, such as: supply bounds (in the form of supply curves) for the primary resources, technical constraints governing the creation, operation, and abandonment of each technology, balance constraints for all energy forms and emissions, timing of investment payments and other cash flows, and the satisfaction of a set of demands for energy services in all sectors of the economy.

The JRC-EU-TIMES model considers both the supply and demand sides and includes the following seven sectors: primary energy supply; electricity generation; industry; residential; commercial; agriculture; and transport (Figure 1).

[1] Energy Technology Systems Analysis Programme

[2] http://www.cres.gr/res2020

[3] http://realisegrid.rse-web.it/

[4] http://reaccess.epu.ntua.gr/

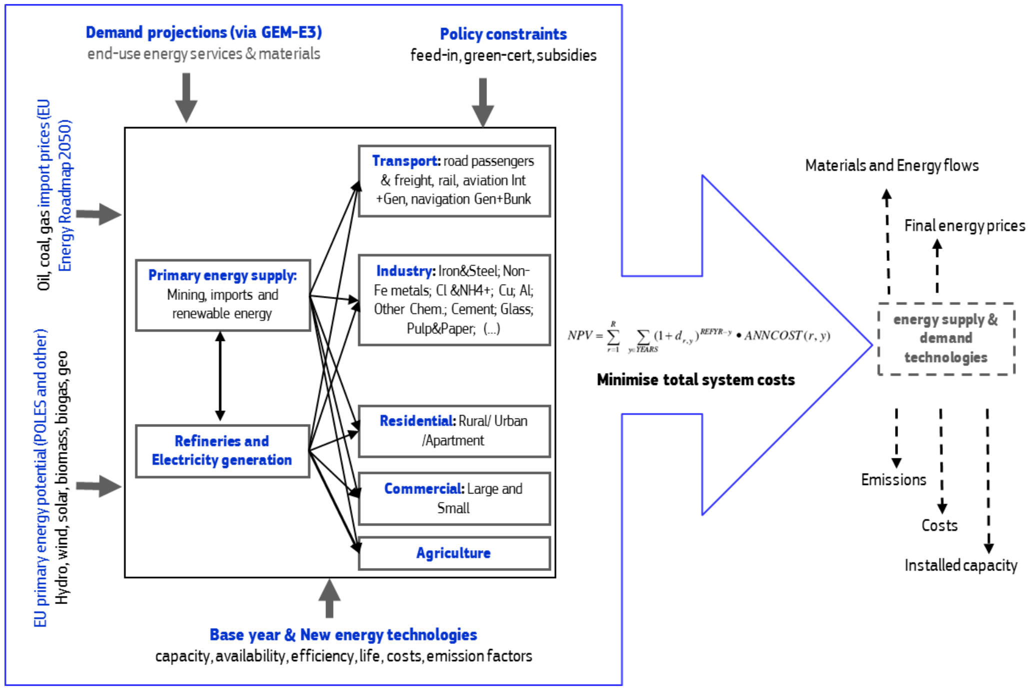

Figure 1- Simplified structure of the JRC-EU-TIMES model

Reference: Adapted from (Simoes, Cleto, Fortes, Seixas, & Huppes, 2008)

As mentioned, the ultimate objective of a TIMES model is the satisfaction of the demand for energy services at minimum system cost. For this, TIMES simultaneously decides on equipment investment and operation, primary energy supply and energy trade, according to the following equation (Loulou, et al., 2005a): [2]

$$NPV = \sum_{r=1}^{R} \sum_{y \in YEARS} \left(1 + d_{r,y}\right)^{REFYR-y} . ANNCOST\,(r, y)$$

Where NPV: net present value of the total costs

ANNCOST: Total annual cost

d: general discount rate (note that although here d is depicted as varying across regions and years, it is also possible to have variable discount rates per technology)

REFYR: reference year for discounting

YEARS: set of years for which there are costs

R: region

As a partial equilibrium model, JRC-EU-TIMES does not model the economic interactions outside of the energy sector. However, the macro-economic feedback between the economy and energy systems is considered through price elasticities of service demands (see Section 4). Moreover, it does not consider in detail the mathematical formulation underlying demand curves functioning and non-rational aspects that condition investment in new and more efficient technologies. Such issues have to be dealt with via exogenous constraints to represent non-rational decisions.

The most relevant model outputs are the annual stock and activity of energy supply and demand technologies for each region and period. This is accompanied by associated energy and material flows including emissions to air and fuel consumption, detailed for each energy carrier. Besides technical outputs, the associated operation and maintenance costs, the investment costs for new technologies, all energy and materials commodities prices (including for emissions if an emission cap is considered), are obtained for every time step.

2.2 Overview of major inputs

The model is supported by a detailed database, with the following main exogenous inputs: (1) end-use energy services and materials demand, such as residential lighting, demand for machine drive or steel; (2) characteristics of the existing and future energy related technologies, such as efficiency, stock, availability, investment costs, operation and maintenance costs, and discount rate; (3) present and future sources of primary energy supply and their potentials; and (4) policy constraints and assumptions. In this section we present a short overview of these major inputs which are further detailed in the following sections. An overview of these major inputs and how JRC-EU-TIMES interacts with other energy models is depicted in Figure 2.

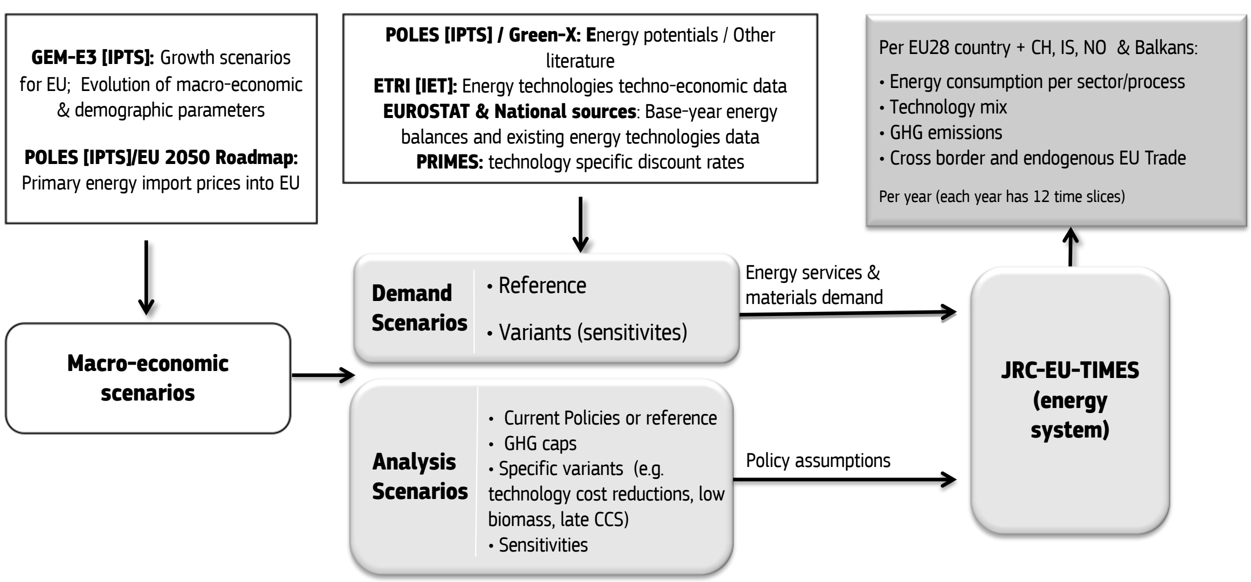

Figure 2 – Overview of JRC-EU-TIMES model interactions with other energy models

(1) The materials and energy demand projections for each country are differentiated according to economic sector and end-use energy service. At this moment they were generated by JRC IPTS with

the aid of the macroeconomic projections from their GEM-E3 model. For an EU-wide GDP growth target, GEM-E3 combines projections of population growth, world energy prices, technical progress, energy intensity and labour productivity evolution, generating a series of national macroeconomic drivers. These are: GDP growth; private consumption as a proxy for disposable income; price evolution and sector production growth for industry, services, transports and agriculture. In JRC-EU-TIMES, these macroeconomic drivers are transformed into the different final annual end-use demand projections. The residential sector requires a more detailed approach to generate the demands for heat, cooling and hot water, since they depend on the characteristics of the dwellings.

(2) The *energy supply and demand technologies for the base-year (2005)* are characterised considering the energy consumption data from Eurostat to set sector specific energy balances to which the technologies profiles must comply. Information on installed capacity, efficiency, availability factor, and input/output ratio were introduced using diverse national sources. This was followed by a bottom-up approach that adjusted the technologies specifications to achieve coherence with official energy statistics. This bottom-up approach was very relevant for the residential and commercial sectors, for which there is less detailed information available on existing technologies. The energy supply and demand *technologies beyond the base year* are compiled in an extensive database with detailed technical and economic characteristics of new energy technologies. The two most relevant sources of this database are the Energy Technology Database (for electricity generation) hosted at JRC-IET and the 2012 JRC Scientific Report "Best Available Technologies for the heat and cooling market in the European Union" "(Pardo, Vatoupoulos, Krook-Riekkola, Perez-Lopez, & Olsen, 2012). The technology-specific discount rates are the ones used in the PRIMES model for the EU Energy Roadmap 2050.

(3) The present and future sources (potentials and costs) of primary energy and their constraints for each country are from the GREEN-X model[5] and the POLES model, as well as from the RES2020 (n.d.) EU funded project, as updated in the REALISEGRID project.

(4) The policy constraints such as CO_2 emission caps, taxes, subsidies and emission trading are user-defined and can be tailored for each particular policy question.

2.3 Temporal and spatial resolution

The JRC-EU-TIMES includes 36 regions connected by energy / emissions trade as follows: EU (Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Germany, Denmark, Estonia, Spain, Finland, France, Greece, Hungary, Ireland, Italy, Lithuania, Luxemburg, Latvia, Malta, the Netherlands, Poland, Portugal, Romania, Sweden, Slovenia, Slovakia and United Kingdom) and Non-EU countries (Switzerland, Iceland, Norway, Albania, Bosnia and Herzegovina, The Former Yugoslav Republic of Macedonia, Montenegro, and Serbia). Each country is represented as one single region (Figure 3 and Table 1).

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[5] http://www.green-x.at/

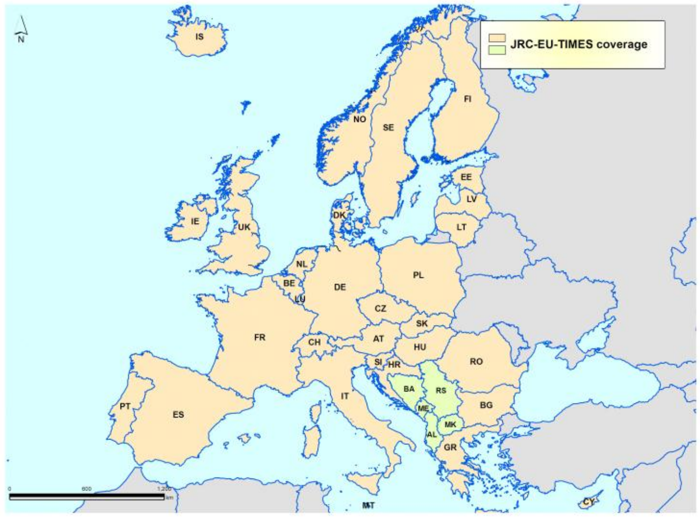


Figure 3 – Regions considered in JRC-EU-TIMES

Table 1 – Regions considered in JRC-EU-TIMES and respective ISO codes

Country	ISO code	Country	ISO code
Austria	AT	Malta	MT
Belgium	BE	Netherlands	NL
Bulgaria	BG	Norway	NO
Croatia	HR	Poland	PL
Cyprus	CY	Portugal	PT
Czech Rep.	CZ	Romania	RO
Denmark	DK	Slovakia	SK
Estonia	EE	Slovenia	SI
Finland	FI	Spain	ES
France	FR	Sweden	SE
Germany	DE	United Kingdom	UK
Greece	GR	Albania	AL
Hungary	HU	Bosnia	BA

Country	ISO code	Country	ISO code
Ireland	IE	FYROM	MK
Italy	IT	Iceland	IS
Latvia	LV	Montenegro	ME
Lithuania	LT	Serbia	RS
Luxembourg	LU	Switzerland	CH

In addition to the detailed treatment of the above regions, in JRC-EU-TIMES, interactions with other regions are also considered through trade in primary energy, electricity, and emissions (see Section 7.2).

The model is built with a time horizon 2005 – 2075 (calibrated to 2005 issued in 2011), with optimisation accounting for annual and sub-annual operations. JRC-EU-TIMES provides annual outputs from 2005 until 2075 for every 5 year time step (e.g. 2005, 2010, 2015, etc.). At this stage 2075 is being used as a "dummy" year to avoid end of period distortions when obtaining results for 2050. This means that from 2020 till 2075 the model is run with a "dummy" demand for energy services and materials.

Each year is divided in 12 time-slices that represent an average of day, night and peak demand for every one of the four seasons of the year (e.g. summer day, summer night and summer peak, etc.). The exact formulation of the time-slices is presented in Table 2 and Table 3.

Table 2 – Definition of time-slices in JRC-EU-TIMES

Seasons	No. of days	Fraction of the year	Duration of the season (day/month)
R	75	0.205	15/03-31/05
S	101	0.277	01/06-30/08
F	79	0.216	31/08-15/11
W	110	0.301	16/11-14/03
Total	**365**	**1**	
Daily time-slices (no. of hours)	**D (day)**	**N (night)**	**P (peak)**
R	11	12	1
S	11	12	1
F	11	12	1
W	11	12	1

Table 3 – Fraction of the year allocated to each time-slice in JRC-EU-TIMES

Code of Time-slice	Description	Fraction of the year
RD	Spring Day	0.094
RN	Spring Night	0.103
RP	Spring Peak	0.009
SD	Summer Day	0.127
SN	Summer Night	0.138
SP	Summer Peak	0.012
FD	Fall Day	0.099
FN	Fall Night	0.108
FP	Fall Peak	0.009
WD	Winter Day	0.138
WN	Winter Night	0.151
WP	Winter Peak	0.013

The definition of seasons is fixed for all countries, which is realistic when thinking of Europe as a whole. Because the total demands for each time-slice are defined apart they can reflect different demand dynamics per time-slice across countries. The beginning and the end for time of the day (day, night, and peak) remain flexible for the different countries.

2.4 Emissions considered in JRC-EU-TIMES

The JRC-EU-TIMES model estimates the following emissions: carbon dioxide (CO_2), carbon monoxide (CO), methane (CH_4), sulphur dioxide (SO_2), nitrogen oxides (NO_x), nitrous oxide (NO_2), particulate (PM 2.5 and PM 10), volatile organic compounds (VOC), sulphur hexafluoride (SF_6) and Fluor carbons (C_xF_y). For combustion emissions, coefficients are declared by fuel, and in some cases by region, resulting in emissions at each process that consumes them. For process-specific emissions, coefficients are declared at the process level and vary with the process' activity (e.g. Mt on produced cement clinker). This is the case of process emissions for cement, glass, ammonia and steel production and for the refining, transport and distribution of petroleum products. Land-use emissions are not considered in the model.

The emission coefficients considered in the model are the ones used in several national emission inventories. In the case of the industrial process emissions, the CO_2 emission coefficients will be technology dependent and will vary according to technologies' performance. The main references for these are the Best Available Techniques Reference Document (BREFs) developed within the IPPC (Integrated pollution prevention and control) Directive.

The emission factors used in JRC-EU-TIMES are presented in Annex 16.7.

2.5 Approaches for dealing with uncertainty

Uncertainty surrounding key input parameters can undermine the confidence in complex models such as the JRC-EU-TIMES. By characterising how the model behaves in response to changes in key parameters, sensitivity analysis provides useful insights into these uncertainties and contributes to the robustness of modelling results.

Besides performing sensitivity analysis with systematic variation in exogenous parameters, TIMES models in general are equipped with several endogenous approaches allowing dealing with uncertainty. These include the following possibilities that can be implemented in JRC-EU-TIMES: running in stochastic mode, running in myopic mode, performing Monte Carlo analysis and using the endogenous technology learning module. More information on these possibilities in TIMES models can be found on the ETSAP website[6]. The relatively short running time of JRC-EU-TIMES allows for the implementation of these features without substantial major effort.

[6] http://www.iea-etsap.org/web/Documentation.asp

3 Macro-economic assumptions

3.1 GDP and population scenarios

The GDP and population assumptions underlying the energy services demand that is a JRC-EU-TIMES input are presented in the following figures. The population scenario considered at the moment is from Eurostat, whereas the GDP scenario, as internally defined from the GEM-E3 modelling team at JRC-IPTS, considers an average annual EU GDP growth rate of 1.5 to 2% until 2050 (Table 4).

Table 4 – Annual growth rate of the EU GDP considered currently in JRC-EU-TIMES

2006-2010	2011-2015	2016-2020	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
0.9%	2.1%	2.0%	1.8%	1.7%	1.5%	1.5%	1.5%	1.4%

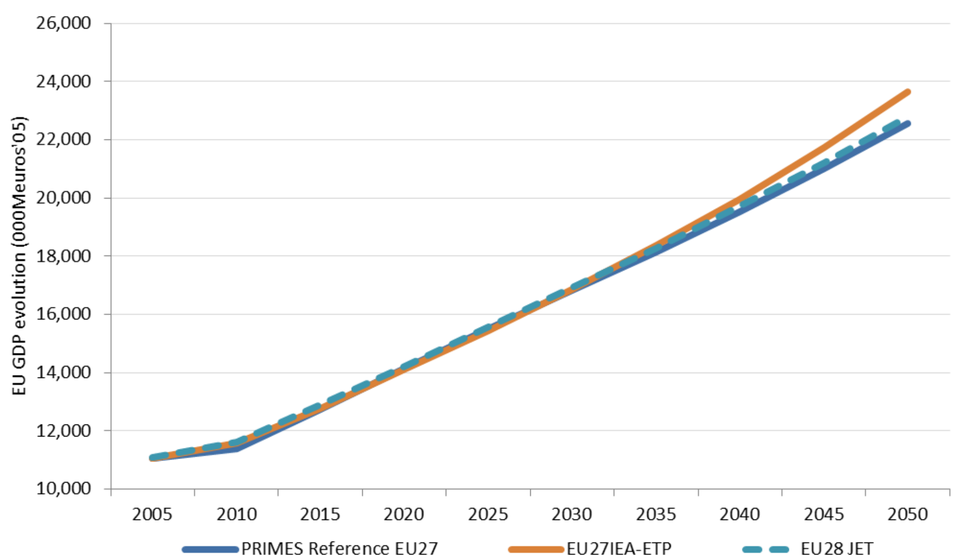


Figure 4 – GDP evolution considered in JRC-EU-TIMES model and comparison with GDP scenarios considered in other models

Note: Primes Reference from EU Energy Roadmap 2050 for EU27 SEC (2011)1565; IEA-ETP from Energy Technologies Perspectives of the IEA (2012)

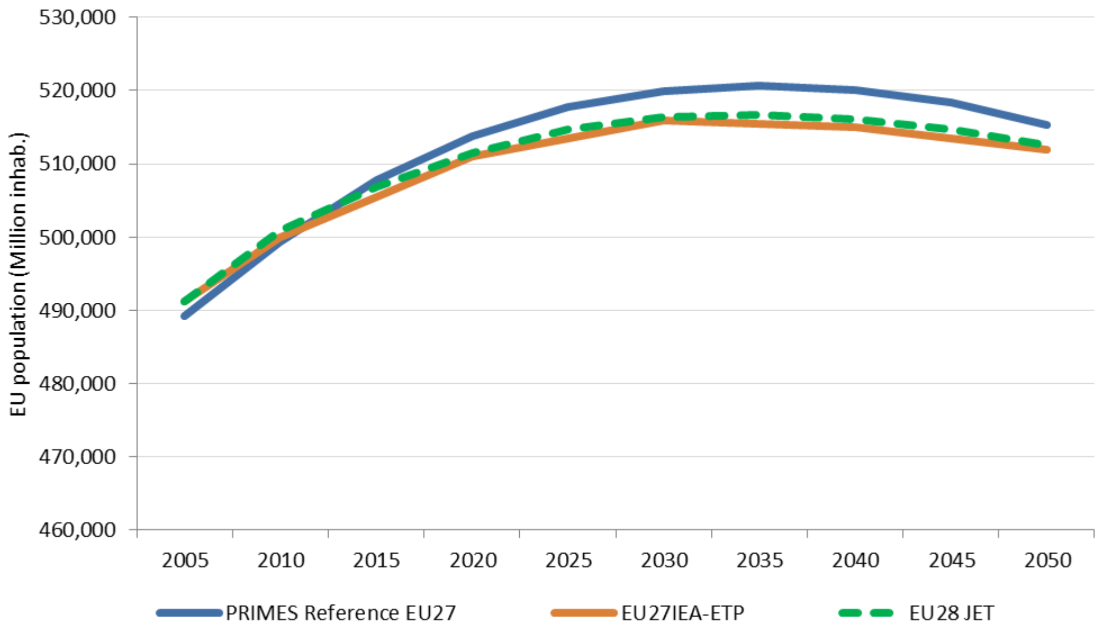


Figure 5 – Population evolution considered in JRC-EU-TIMES model and comparison with population scenarios considered in other models

3.2 Primary energy import prices

3.2.1 Oil, coal and gas

We considered the primary energy import prices[7] into EU as in the reference case of the Energy 2050 Roadmap (European Commission, 2011b) (Table 5). Besides energy import, JRC-EU-TIMES also includes extraction of primary energy resources (both renewables and fossil) and conversion into final energy carriers done within the modelled regions (EU and neighbouring countries). The prices of these commodities are endogenous to the model and depend on the country specific resource extraction and conversion (e.g. for refineries or biodiesel production) costs.

[7] To process JRC-EU-TIMES monetary inputs data the Eurostat price indexes are used (GDP and main components - Price indices [namq_gdp_p], Gross domestic product at market prices - Seasonally adjusted and adjusted data by working days).

Table 5 – Primary energy import prices considered into EU in JRC-EU-TIMES in USD_{2008}/boe

	2010	2020	2030	2040	2050
Oil					
Reference*	84.6	88.4	105.9	116.2	126.8
High prices	84.6	132.2	149.3	148.8	162.3
Low price	84.6	78.8	91.5	87.9	83.9
Gas					
Reference*	53.5	62.1	76.6	86.8	98.4
High prices	53.5	85.5	101.5	111.6	129.0
Low price	53.5	43.7	50.9	49.9	54.1
Coal					
Reference*	22.6	28.7	32.6	32.6	33.5
High prices	22.6	39.3	45.7	42	40
Low price	22.6	21.9	23.8	22.2	23.1

*Input to JRC-EU-TIMES model

3.2.2 Biomass

The same approach is considered for biofuels in particular and bioenergy in general. We do not consider import of biofuels (e.g. ethanol) due to lack of data at the moment. A scenario analysis based on different levels of potentials as presented further in this report is a temporary (yet relevant) approach to deal with this lack of information for imports. Regarding endogenous resources, we model biofuels generation in EU28+ from starch, sugar or lignocellulosic biomass. There is however, the possibility to import forestry residues from outside EU, which can be converted to second generation of biofuels, as well as used as direct inputs in other processes. The potential for bioenergy use in the EU is modelled considering the endogenous production of bioenergy as done in the RES2020 project (RES2020 Project Consortium, 2009) (see Section 5.2). The assumptions on endogenous biomass provision and on possibilities to import it are also presented in section 6.2. We consider an import price of biomass into EU of approximately 6.5 $euros_{2005}$/GJ in 2006 and of 8.3 $euros_{2005}$/GJ in 2050. These price assumptions are obtained from the POLES model.

3.3 Discounting for the cost of finance

In the JRC-EU-TIMES model, a discount rate is used for both the cost of finance and for social discounting. The first is to be compared with concepts like "hurdle rate" or "rate of return" that are usually calculated in accordance to an annual return on investment. Social discounting is used to reflect the valuation on well-being in the near future versus well-being in the longer term. Social discounting is not discussed here but in the next section.

For the cost of finance, the discount is the expected annual return on investment. Each individual investment physically occurring in year k, results in a stream of annual payments spread over several years in the future. The stream starts in year k and covers years k, k+1, …, k+ELIFE-1, where ELIFE is the economic life.

The higher the cost of finance (or hurdle rate), the higher the annual payments spread over the lifetime of an investment and thus the higher the total cost. The hurdle rate affects only the investment costs so the impact is bigger for capital intensive technologies like nuclear and most renewable technologies. We consider differentiated hurdle discount rates for different groups of energy supply and demand technologies as in the following table. These are the same as considered in the PRIMES model (E3MLab, 2008) and used in the EU Energy Roadmap 2050 (2011a). For all other technologies, a fixed 5% cost of finance is assumed.

Table 6 – Discount rates considered in JRC-EU-TIMES

Sector/groups of technologies	Discount rate	Other literature values
Passenger cars	18%	5[8]-35[9]%
Residential	17%	
Freight transport, busses and passengers trains	11%	12% [8% low sensitivity, 16% high]
CHP and large industry	12%	
Other industry and commercial	14%	
Centralised electricity generation	8%	
Energy distribution (including grids)	7%	

[8] According to (NERA-AEA, 2009) for households with access to benefited credit or in social housing.

[9] According to (BERR, 2005) values from 30-35% are reported in a survey on investment on microgeneration technologies. On the other hand econometric studies focussing on energy efficient appliances indicate even higher values (Hausman, 1979). Nonetheless, such empirical studies have limited applicability due to very specific conditions in which they are developed (NERA-AEA, 2009).

These values are in line with several other studies in the literature, namely in (NERA-AEA, 2009), (BERR, 2005), (Hausman, 1979), (McLaney, 2004).

3.4 Social discounting

We consider a social discount rate of 5%. This corresponds to a so-called social discount rate reflecting the public sector approach in the policy evaluation with TIMES. This 5% represents a real discount rate. Social discounting is used to reflect the valuation on well-being in the near future versus well-being in the longer term.

There are two underlying concepts determining the social discount rate. The first is the time preference for consuming. It is the rate at which individuals discount future consumption over present consumption ceteris paribus, so assuming a fixed per capita consumption. The second concept is the expectation of the per capita consumption change in the future. When increasing, a lower marginal utility is assumed for the additional future consumption. The higher the social discount rate, the lower the impact of future additional costs. Social discounting affects all costs in the model, including operational costs.

3. Macro-economic assumptions

4 Energy services demand

4.1 Overview of energy services demand generation methodology

The energy services demand is generated for each country in the model using the methodology described in (Kanudia & Regemorter, 2006). The demand projections used in JRC-EU-TIMES are based on economic growth drivers from the general equilibrium model GEM-E3 (E3MLab, 2010). The model combines exogenous assumptions on macroeconomic development such as population growth, world energy prices, technical progress, energy intensity, labour productivity evolution and GDP growth targets. At this moment the energy services demand considered in the model was developed by JRC IPTS following the methodology described in the next sections.

The following drivers generated by GEM-E3 are used to generate the energy services demand:

- GDP and GDP per capita growth
- Private consumption as a proxy for disposable income
- Sectorial production growth with a distinction between energy intensive sectors (e.g. ferrous and non-ferrous metals, chemical sector, etc.), other industries and services (transport, residential, commercial, etc.).

A special GAMS[10] program has been written by (Kanudia & Regemorter, 2006) to convert the projections based on GEM-E3 results, into specific assumptions and base year calibration data for the JRC-EU-TIMES.

The projection, derived from GEM-E3, provides the demand driver's evolution that is then used to compute the evolution of the demand for the various energy services. The demand for energy services or useful energy demand projections DEM_{rjt} by region (r), sector (j) and time step is projected with the following equation in (Kanudia & Regemorter, 2006) :

$$DEM_{rjt} = DEM_{rj(t-1)} * (1 + DRGR_{rjt}{*}ELASI_{rj}) * (1 + PRGR_{rjt} * ELASP_{rj}) * (1 - AEEI_{rjt})$$

The drivers by demand category $DRGR_{rjt}$ are defined from GEM-E3. Their elasticities ($ELASI_{rj}$ for income elasticity and $ELASP_{rj}$ for price elasticity) are exogenous assumptions based on literature data. The initial value of the energy services DEM_{rj0} are derived from the base year historical data (mainly Eurostat) and the base-year template calibration. The price evolution $PRGR_{rjt}$ is also derived from GEM-E3 and is used for some demand categories to take into account the price effect in the reference scenario. The last term $AEEI_{rjt}$ defines the price independent demand change due to autonomous efficiency improvements, and is an expert-based assumption. This is mainly used in

[10] www.gams.com

the industrial sector to reflect intra-sectorial structural evolution not directly linked to the energy price evolution.

The evolution of the demand for energy services is linked to the demand drivers' projections through elasticities. These elasticities are meant to reflect changing patterns in energy service demand in relation to economic growth, such as saturation in some energy end-use demand, increased urbanization or changes in consumption patterns once the basic needs are satisfied. Price elasticities range from 0 to 1 and the lower the elasticity the less influence of the driver on the energy demand service. The income elasticities used for our model are summarized in Table 7.

These elasticity drivers, used to calculate the energy services demand, reflect the following assumptions (Kanudia & Regemorter, 2006):

- Passenger transport: there is shift from public transport towards private cars with increasing income; greater urbanisation would also contribute to a lesser increase in the passenger-km demand.
- Freight transport: accompanies more closely the growth of GDP with a slight model shift from road transport to other freight transport means.
- Residential demand: for space heating and cooling and for water heating the drivers are a combination of the evolution in the number of households, the population growth and disposable income per household. This combination is done after the GEM-E3 outcome. Within GEM-E3 the driver for the residential sector is only disposable income. For the other demand categories, the evolution in income is the dominant factor. In the long run, certain saturation and changes in consumption patterns will weaken this link.
- Commercial demand: follows the sectorial activity but with a decreasing link.
- Industrial and agriculture demand: the demand follows the sectorial production evolution.

Demands for energy services are exogenously defined in the reference scenario, as described above. In policy scenarios, they are endogenously adjusted via price elasticities, as described in Section 4.8.

The general approach described above is used for the commercial, transport and industrial sectors. For the residential sector the approach is more specific and is described in the next sections.

Table 7 – Drivers from GEM-E3 and income elasticities used to generate the energy services demand used in JRC-EU-TIMES

Demand Category	Driver	Driver elasticity
Transportation demand		
Passenger transport		
Autos long distance	Disposable income per household	0.9 – 0.6

Autos short distance and buses	Population growth	1
Two/three wheelers		0.7
Passengers rail transportation		0.8
Domestic and international aviation	Domestic product growth	1.3
Freight transport		
Trucks	Sectoral production	0.7
Freight rail transportation		1
Internal navigation		1
Residential demand		
Space heating	Disposable income per household	0.5 – 0.2
Space cooling		0.8 – 0.3
Hot water		0.5 – 0.2
Lighting		1 – 0.2
Cooking		0.1
Refrigerators and freezers		0.1
Cloth washers		0.6 – 0.2
Cloth dryers		0.6 – 0.2
Dish washers		0.6 – 0.2
Miscellaneous electric energy		1.5 – 0.2
Other energy uses		1.5– 0.2
Commercial demand		
Space heating	Service sector production	0.5
Space cooling		0.8
Hot water heating		0.5
Lighting, Cooking, Refrigerators and Freezers		0.8
Electric equipment		0.8
Other energy uses		0.5

Agriculture	Agriculture production	0.8
Industrial demand		
Iron and steel	Sectorial production	0.8
Nonferrous metals		0.8
Chemicals		0.8
Pulp and paper		0.8
Non-metal minerals		0.8
Other industries		0.8

Reference: (Kanudia & Regemorter, 2006)

4.2 Commercial sector

The energy service demands considered in the commercial sector are quite similar to the residential sector and include space heating, space cooling, water heating, cooking, refrigeration, lighting, public lighting, other electric uses (equipment) and other energy uses. Furthermore, the energy service demands for space heating, space cooling and water heating in commercial buildings are divided into two building categories, namely small and large commercial buildings.

The energy services demands considered in JRC-EU-TIMES are calculated following the procedure described above, respecting the evolution from the base year demand as a function of driver growth, energy price evolution and elasticities.

4.3 Residential sector

The energy service demands considered in the residential sector are detailed as follows: space heating, space cooling, water heating, cooking, refrigeration, lighting, cloth washing, cloth drying, dish washing, other electric uses (equipment) and other energy uses, further described below. In order to achieve a more detailed description, the demands for space heating and space cooling are disaggregated into three categories of buildings: multi-family apartment buildings, single houses in urban areas and single houses in rural areas.

The heat/cooling/water demand relates to the characteristics of the dwellings. Therefore the projection for the residential sector is done in the following three steps (Kanudia & Regemorter, 2006):

1. Projection of the number of dwellings and its allocation by category
2. Projection of the heat/cooling/hot water demand per dwelling by category

3. Projection of the total demand

The projection of the number of households is derived from the population growth, used in GEM-E3, and assumptions regarding the evolution of the number of persons per household (Table 8). The stock of existing dwellings in the base year is taken from the calibrated template files (based on Eurostat data, where available, and on national experts input when not available). The number of remaining dwellings in each period is then computed assuming a demolishing rate differentiated per dwellings category (Table 8).

The number of new dwellings is computed given the projected number of households and the stock of existing dwellings remaining in each period. The allocation of the total stock between building type is done with exogenous shares based on assumptions such as urbanisation trends and age pattern evolution (Table 8). These assumptions were made by the several national experts involved in the NEEDS[11] and RES2020[12] research projects.

This approach used for JRC-EU-TIMES follows closely the approach developed by (Kanudia & Regemorter, 2006). The starting point is to generate the heating and cooling demand per dwelling in the base year as calibrated in the residential template for each region in the model. This is then followed by the temperature correction of the demand for heat (from Eurostat). This is relevant since for some countries in EU28+ 2005 was not an average year regarding heating and/or cooling degree days. At this moment the computation does not consider the possible impacts of future climate change on heating and cooling.

From the base year demand the future evolution is derived as follows:

1) Generate the unit heat demand per existing dwelling: this evolution depends on two elements: building stock structure and growth of the building stock based on population evolution. For each country in JRC-EU-TIMES, we consider a building stock structure in terms of construction year based on information supplied by national experts within the NEEDS and RES2020 European projects (Table 8 and Table 9).

It is assumed that demolishing mainly affects the oldest dwellings with the highest unit heat demand thus inducing an 'efficiency' improvement for the average stock. In JRC-EU-TIMES a mixed approach was used to compute an efficiency improvement factor for existing stock. For countries for which detailed survey data on the housing stock structure and the demolishing rate is available, a specific factor was used. For other countries, the efficiency factor was estimated based on the assumption that there is no distinction for type of dwelling. For the evolution of the heating and cooling demand per existing dwelling, population is used as the driver, as described in the previous section, combined with the energy price evolution. The impact of these drivers on the demand evolution is a function of the income and price elasticities.

2) Generate the unit heat demand per new dwelling: for new constructions the heat demand depends on the regulation in place regarding efficiency requirements (e.g. K-norms) and the

[11] http://www.needs-project.org/

[12] http://www.cres.gr/res2020/

average surface of new dwellings. For the first period after the base year (2006 in JRC-EU-TIMES) the heat demand is computed based on the heat demand per dwelling constructed in the base year. For future periods, this heat demand takes into account improvements due to regulation in place. Possible future regulations could be included in shell improvement technologies and could be integrated in the underlying assumptions on the evolution of energy demand for new dwellings. As for existing dwellings, to project the evolution of the heating and cooling demand per new dwelling population combined with energy price evolution are used as drivers.

The same approach is used for hot water demand but taking into account the evolution in the number of persons per household. For cooling, the base year cooling demand per dwelling is complemented with the share of dwellings with cooling. The evolution of the penetration rate is computed based on the maximum penetration rate and the number of years for reaching this rate.

The projection of heat/cooling/hot water demand in existing/new dwellings is then derived by multiplying the demand per dwelling by the number of dwellings in each category.

As described in Table 8, the following assumptions for generating the heating/cooling/hot water considered in JRC-EU-TIMES have these main sources:

- Statistics on Heating/Cooling Degree Days (from Eurostat);
- Efficiency improvement in existing dwelling stock because of demolishing dwellings with lower than average efficiency (expert assumption);
- Efficiency improvement of new dwellings compared to existing (expert assumption);
- Price and Income elasticities (described in the previous section);
- Base year penetration rate of cooling, maximum penetration rate and years required to reach the maximum (expert assumption).

The building stock assumptions to generate the energy services demand in JRC-EU-TIMES were last updated in 2011. Finally, at this moment, Croatia building stock assumptions were presumed as identical to Romania, due to the lack of data.

Table 8 – Assumptions on residential buildings considered in JRC-EU-TIMES - Part I

Country	Dwelling stock in 2005 (1000')			Share of cooling per dwelling type in 2005			Number of years for achieving max % of cooling from 2005	Max share of households with cooling	Temp correction factor for average HDD[13] from 2005 values	Number of persons per household	Annual evolution of number of persons per household		
	Rural house	Urban house	Apart-ments	Rural house	Urban house	Apart-ments				2005	2010-2014	2015-2019	2020-2050
AT	1402	1262	841	0.05	0.05	0.05	50	0.20	1.12	2.40	-0.004	-0.003	-0.002
BE	1578	2014	1229	0.05	0.05	0.05	50	0.20	1.14	2.51	-0.004	-0.003	-0.002
BG	1492	344	1033	0.01	0.01	0.01	50	0.20	1.10	2.69	-0.004	-0.003	-0.002
CY	63	147	83	0.5	0.5	0.9	50	0.90	1.08	2.20	-0.004	-0.003	-0.002
CZ	1366	869	1904	0.03	0.03	0.03	50	0.20	0.97	3.06	-0.004	-0.003	-0.002
DE	5878	15284	18027	0.02	0.02	0.02	50	0.20	1.15	2.90	-0.004	-0.003	-0.002
DK	603	818	944	0.02	0.02	0.02	50	0.10	1.16	2.20	-0.004	-0.003	-0.002
EE	111	60	367	0.01	0.01	0.01	50	0.20	1.12	2.30	-0.004	-0.003	-0.002
ES	6754	4921	11536	0.22	0.28	0.29	50	0.50	1.14	2.30	-0.004	-0.003	-0.002
FI	845	579	989	0.02	0.02	0.02	50	0.20	1.02	2.79	-0.004	-0.003	-0.002
FR	7205	7624	11371	0.03	0.03	0.03	50	0.20	1.12	2.60	-0.008	-0.005	-0.006
GR	1305	1299	2694	0.52	0.52	0.52	50	0.90	1.11	2.30	-0.004	-0.003	-0.002

[13] Heating Degree Days, correction factor estimated from Eurostat HDD historical values per country.

Country	Dwelling stock in 2005 (1000')			Share of cooling per dwelling type in 2005			Number of years for achieving max % of cooling from 2005	Max share of households with cooling	Temp correction factor for average HDD[13] from 2005 values	Number of persons per household	Annual evolution of number of persons per household		
	Rural house	Urban house	Apart-ments	Rural house	Urban house	Apart-ments				2005	2010-2014	2015-2019	2020-2050
HU	1220	648	1944	0.02	0.02	0.02	50	0.20	1.05	2.73	-0.004	-0.003	-0.004
IE	520	748	147	0	0	0	50	0.20	1.18	3.00	-0.004	-0.003	-0.002
IT	1617	4300	15736	0.13	0.13	0.13	50	0.50	1.03	2.90	-0.006	-0.006	-0.007
LT	397	228	579	0.03	0.03	0.03	50	0.30	0.12	2.00	-0.004	-0.003	-0.002
LU	60	69	56	0.01	0.01	0.01	50	0.05	1.16	2.50	-0.007	-0.006	-0.003
LV	250	180	620	0.04	0.04	0.04	50	0.30	1.15	2.30	-0.004	-0.003	-0.002
MT	6	63	57	0.5	0.5	0.5	50	0.90	1.14	2.60	-0.004	-0.003	-0.002
NL	2922	1935	2074	0.05	0.05	0.05	50	0.20	1.14	2.30	-0.004	-0.003	-0.002
PL	4086	5235	3448	0.01	0.01	0.01	50	0.20	1.19	2.90	-0.004	-0.003	-0.002
PT	1613	700	1602	0.07	0.07	0.08	50	0.50	1.16	2.30	-0.010	-0.013	-0.008
RO	3998	1281	2922	0.08	0.08	0.08	50	0.20	1.08	2.30	-0.004	-0.003	-0.002
SE	1512	501	2391	0.01	0.01	0.01	50	0.05	1.18	3.20	-0.004	-0.003	-0.002
SI	365	157	232	0.08	0.08	0.08	50	0.20	1.01	2.80	-0.036	-0.036	-0.036
SK	546	461	699	0.01	0.01	0.01	50	0.10	1.12	2.95	-0.004	-0.003	-0.002
UK	2096	18310	5789	0.04	0.04	0.04	50	0.20	1.10	2.40	-0.004	-0.003	-0.002

Country	Dwelling stock in 2005 (1000')			Share of cooling per dwelling type in 2005			Number of years for achieving max % of cooling from 2005	Max share of households with cooling	Temp correction factor for average HDD[13] from 2005 values	Number of persons per household	Annual evolution of number of persons per household		
	Rural house	Urban house	Apart-ments	Rural house	Urban house	Apart-ments				2005	2010-2014	2015-2019	2020-2050
CH	1213	785	1794	0.01	0.01	0.01	50	0.20	1.18	2.95	-0.005	-0.004	-0.002
IS	0	140	20	0	0	0	50	0.10	1.15	3.19	-0.004	-0.003	-0.002
NO	450	601	960	0.02	0.02	0.02	50	0.20	1.04	2.70	-0.004	-0.003	-0.002

Table 9 – Assumptions on residential buildings considered in JRC-EU-TIMES - Part II

Country	Annual fraction of demolished /existing dwellings	Allocation of demolition fraction per type of dwelling			Ratio of the heat demand between new dwelling and existing dwelling (<1 since it reflects improved building quality)			Construction share per type of building			Annual efficiency improvement in existing dwelling stock due to demolishing of last efficient dwellings and other improvements independent of energy savings
		Rural house	Urban house	Apartments	Rural house	Urban house	Apartments	Rural house	Urban house	Apartments	
AT	0.01	0.4	0.36	0.24	0.63	0.58	0.37	0.40	0.36	0.24	0.010
BE	0.003	0.26	0.54	0.2	0.63	0.58	0.37	0.11	0.36	0.53	0.005
BG	0.01	0.52	0.12	0.36	0.63	0.58	0.37	0.52	0.12	0.36	0.010
CY	0.005	0.1	0.6	0.3	0.9	0.58	0.37	0.11	0.36	0.53	0.010
CZ	0.01	0.33	0.21	0.46	0.63	0.90	0.85	0.11	0.26	0.63	0.005
DE	0.01	0.15	0.39	0.46	0.63	0.58	0.37	0.33	0.21	0.46	0.010
DK	0.002	0.26	0.54	0.2	0.63	0.58	0.37	0.15	0.39	0.46	0.010
EE	0.01	0.26	0.24	0.5	0.63	0.58	0.37	0.11	0.36	0.53	0.010
ES	0.002	0.26	0.54	0.2	0.63	0.58	0.37	0.11	0.36	0.53	0.010
FI	0.004	0.23	0.16	0.61	0.73	0.58	0.37	0.11	0.36	0.53	0.010
FR	0.01	0.26	0.54	0.2	0.63	0.73	0.73	0.19	0.13	0.68	0.010
GR	0.005	0.25	0.55	0.2	0.9	0.58	0.37	0.11	0.36	0.53	0.010
HU	0.01	0.32	0.17	0.51	0.63	0.90	0.90	0.11	0.26	0.63	0.001

Country	Annual fraction of demolished /existing dwellings	Allocation of demolition fraction per type of dwelling			Ratio of the heat demand between new dwelling and existing dwelling (<1 since it reflects improved building quality)			Construction share per type of building			Annual efficiency improvement in existing dwelling stock due to demolishing of last efficient dwellings and other improvements independent of energy savings
		Rural house	Urban house	Apartments	Rural house	Urban house	Apartments	Rural house	Urban house	Apartments	
IE	0.013	0.87	0.02	0.11	0.9	0.58	0.37	0.32	0.17	0.51	0.010
IT	0.005	0.26	0.54	0.2	0.63	0.85	0.90	0.68	0.12	0.20	0.010
LT	0.005	0.36	0.44	0.2	0.63	0.58	0.37	0.11	0.36	0.53	0.010
LU	0.01	0.26	0.54	0.2	0.7	0.56	0.41	0.11	0.36	0.53	0.010
LV	0.005	0.36	0.44	0.2	0.63	0.58	0.37	0.11	0.36	0.53	0.010
MT	0.005	0.1	0.6	0.3	0.9	0.70	0.70	0.11	0.36	0.53	0.005
NL	0.002	0.22	0.11	0.67	0.8	0.58	0.37	0.11	0.36	0.53	0.010
PL	0.01	0.32	0.41	0.27	0.63	0.90	0.90	0.11	0.26	0.63	0.005
PT	0.005	0.26	0.54	0.2	0.63	0.90	0.85	0.18	0.58	0.24	0.020
RO	0.01	0.41	0.24	0.35	0.63	0.58	0.37	0.11	0.36	0.53	0.010
SE	0.001	0.26	0.54	0.2	0.63	0.58	0.37	0.32	0.41	0.27	0.010
SI	0.01	0.26	0.54	0.2	0.63	0.58	0.37	0.58	0.23	0.18	0.010
SK	0.01	0.32	0.27	0.41	0.63	0.58	0.37	0.11	0.36	0.53	0.020

Country	Annual fraction of demolished /existing dwellings	Allocation of demolition fraction per type of dwelling			Ratio of the heat demand between new dwelling and existing dwelling (<1 since it reflects improved building quality)			Construction share per type of building			Annual efficiency improvement in existing dwelling stock due to demolishing of last efficient dwellings and other improvements independent of energy savings
		Rural house	Urban house	Apartments	Rural house	Urban house	Apartments	Rural house	Urban house	Apartments	
UK	0.004	0.08	0.7	0.22	0.63	0.58	0.37	0.11	0.36	0.53	0.010
CH	0.002	0.26	0.54	0.2	0.63	0.58	0.37	0.11	0.36	0.53	0.010
IS	0.01	0	0.8	0.2	0.63	0.58	0.37	0.32	0.27	0.41	0.010
NO	0.003	0.66	0.14	0.2	0.63	0.58	0.37	0.08	0.70	0.22	0.009

4.4 Transport

While transport is explicitly included in the JRC-EU-TIMES, the level of details and technology richness with which the sector is modelled is lower than for other elements of the energy system. For instance, modal shift is modelled exogenously. Moreover, the underlying optimisation rule – namly, cost minimisation – may not be the most suitable decision making rule for decisions in transport, where other considerations, such as convenience, play a critical role. Nonetheless, the JRC-EU-TIMES model can provide useful insights into the evolution of the energy services demand in the transport sector.

The JRC-EU-TIMES considers four transport modes: road, rail, navigation, and aviation, each one can provide passenger and freight transport. For road transport, the following transport modes (demands) are considered, namely for passenger transport: cars, motorbikes, buses (divided in urban and long-distance); for freight transport: trucks which is subdivided in light duty trucks and heavy duty trucks. For rail, passenger trains, freight trains, and light trains are considered. For navigation and aviation, the JRC-EU-TIMES considers inland and maritime navigation, domestic and international aviation.

The split of mobility between transport modes (*e.g.* from cars to buses or trains) is an exogenous model input. Each country has its own transport sector profile, based on Eurostat and TREMOVE (TREMOVE) historical data, with varying long distance and short distance demands.

Modelling road transport in JRC-EU-TIMES requires the following data for the base-year:

1. Demand values for Passenger/Tonne Kilometers (million).
2. The Stock of Vehicles (thousand).
3. The Kilometers per Vehicle per annum.
4. The Passenger/Tonne per Vehicle to compute the load, which is equal to Demand /Total vehicle-kilometers.

The main source for this was the TREMOVE model (TREMOVE), which was also used for disaggregating road freight transport into light and heavy duty trucks.

For passenger cars, since the JRC-EU-TIMES model considers separately long and short distance mobility, it was necessary to disaggregate TREMOVE data into these categories. For this we assumed that short distance transport corresponds to distances below 30 km. Based on a JRC study for France, Germany, Italy, Poland, Spain, and United Kingdom (Pasaoglu et al., 2012) we estimated the split between short and long distance transport for passenger cars for these countries. For all the other countries, due to the lack of data, at this stage the model considers the following assumptions as in the following table.

Table 10 – Transport, fraction of the km travelled in journeys shorter or equal to 30 km, i.e. in "short distance" for the JRC-EU-TIMES model

Country	Short distance	Assumption
AT	0.409	as Germany
BE	0.469	as France
BG	0.303	as Poland
CY	0.8	assumption based on expert opinion since this is a small country
CZ	0.303	as Poland
DE	0.409	original data
DK	0.409	as Germany
EE	0.409	as Germany
ES	0.313	original data
FI	0.409	as Germany
FR	0.531	original data
GR	0.462	as Italy
HR	0.409	as Germany
HU	0.303	as Poland
IE	0.512	as UK
IT	0.462	original data
LT	0.409	as Germany
LU	0.8	assumption based on expert opinion since this is a small country
LV	0.409	as Germany
MT	0.8	assumption based on expert opinion since this is a small country
NL	0.469	as France
PL	0.303	original data

Country	Short distance	Assumption
PT	0.313	as Spain
RO	0.409	as Germany
SE	0.409	as Germany
SI	0.409	as Germany
SK	0.409	as Germany
UK	0.512	original data
AL	0.303	as Poland
BA	0.303	as Poland
CH	0.409	as Germany
IS	0.8	assumption based on expert opinion since this is a small country
ME	0.303	as Poland
MK	0.303	as Poland
NO	0.409	as Germany
RS	0.303	as Poland

For the other transport modes, the passenger kilometre (pkm) and tonne kilometre (tkm) demand considered in JRC-EU-TIMES is calculated following the procedure described above, respecting the evolution of demand from the base year, as a function of growth, energy price evolution and elasticities drivers.

Aviation and navigation are not analysed in detail, and instead are represented as a single energy service demand satisfied by a single technology that consumes a fuel mix. Energy consumption for international aviation and navigation are included in the model. Improving the modelling detail for these two sub-sectors is a priority for further JRC-EU-TIMES model disaggregation (discussed in Section 13).

4.5 Industry

For industry two types of exogenous demands are considered in JRC-EU-TIMES: materials demand in Mt for the case of the energy intensive industries (cement, steel, glass, ammonia, aluminium, paper and chlorine) and useful energy demand for specific energy services in other industry: other non-ferrous metals, other chemical and petrochemical, other non-metallic minerals, food, beverages and tobacco, textile and leather, transport equipment, machinery, mining and quarrying and other non-energy-intensive industries. For these the following exogenous demands for energy services are considered: steam, process heat, machine drive, electrochemical processes and other processes. Each of the industry sub-sectors has a specific demand for each of these energy services (e.g. machine drive for other industry or process heat for other chemicals).

The demand is calculated following the generic procedure described above, respecting the evolution from the base year demand as a function of the demand drivers.

4.6 Agriculture

The agricultural sector is not analysed in detail, but is represented as a single energy service demand satisfied by a single technology that consumes a fuel mix, and that can improve its final energy consumption up to 10% over time. There are limited possibilities for fuel shifts for these generic technologies as follows:

- an increase in biomass consumption in the agriculture sector up to 30% of the total sector final energy consumption;
- an increase in derived heat consumption in the agriculture sector up to 30% of the total sector final energy consumption;
- an increase in geothermal heat consumption in the agriculture sector up to 30% of the total sector final energy consumption;
- an increase in solar energy consumption in the agriculture sector up to 20% of the total sector final energy consumption;
- the share of natural gas consumption in the agriculture sector has to be at least the one that occurred in 2005. In the future it can increase up to the combined share of coal and oil in 2005.

4.7 Resulting demand for energy services in the JRC-EU-TIMES model

The energy services demands currently used as an exogenous input into the JRC-EU-TIMES, as described in the previous parts of this section, are briefly discussed in this Section. The detailed demand projections for each category of demand are presented in Annex 16.1. At the outset, it is important to note that demand projections are long term and, as such, they do not consider short-term economic fluctuations.

4.7.1 Commercial and residential demand for energy services – space and water heating

Energy demand for heating of space and water in buildings, both commercial and residential, declines over the time horizon, from 11,327 PJ to 10,254 PJ (-9%). As shown in Figure 6, the decline in demand is driven mostly by a drop in residential demand – which, in turn, is driven by assumptions related to renewal and efficiency improvement of the building stock. Indeed, demand for space and water heating in the commercial sector increases between 2005 and 2050 by 44%. Over the same time horizon, per capita demand for heating in building declines by 28%.

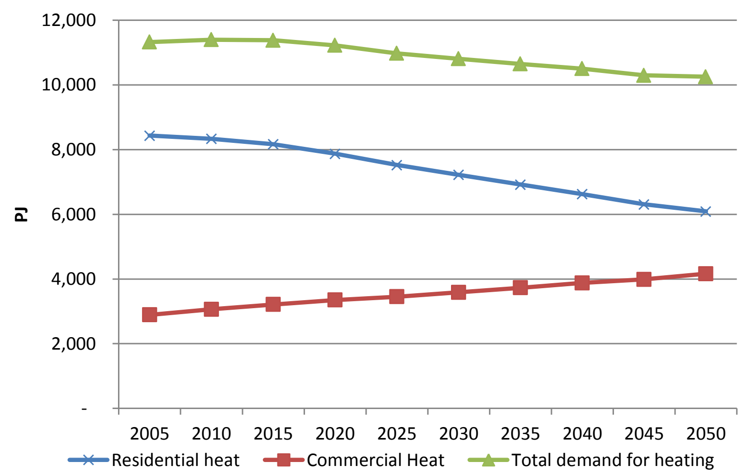


Figure 6 – Evolution of demand for heat in buildings (space and water) in the EU28

Table 11 – Per capita demand for heat in building (space and water): total (left panel) and residential and commercial (right panel)

	Total demand for heat in buildings (PJ/000 person)	Total demand for heat in buildings (PJ/000 person) (2005=100)	Residential heat (PJ/000 person)	Residential heat (PJ/000 person) (2005=100)	Commercial Heat (PJ/000 person)	Commercial Heat (PJ/000 person) (2005=100)
2005	23	100	17	100	6	100
2010	23	99	17	97	6	104
2015	22	97	16	94	6	107
2020	22	95	15	89	6	111
2025	21	92	14	84	7	113
2030	21	90	14	81	7	117
2035	20	88	13	77	7	121
2040	20	87	13	73	7	125
2045	20	85	12	70	8	129
2050	19	85	12	68	8	135

4.7.2 Transport

Demand for passenger transport (short and long distance car, motorcycle, bus, and rail) and goods transport (heavy and light duty vehicles and rail freight) evolve over time as shown in Figure 7. Aviation and maritime transport are not included, as they are not modelled in detail (see Section 6.8).

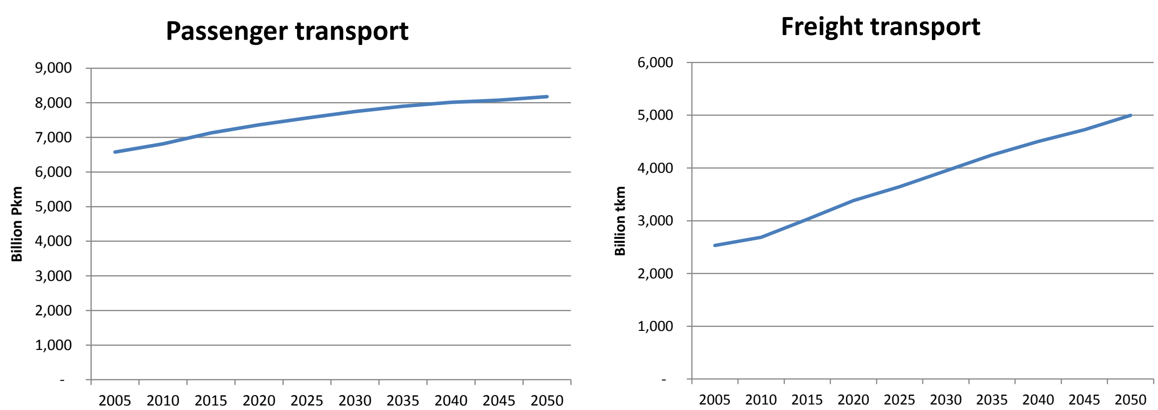


Figure 7 – Evolution of demand for passenger (left) and freight (right) transport

Demand for passenger and freight transport increases over time, by 24% and 97% between 2005 and 2050 respectively. The indicators Demand for passenger kilometres per capita, however, increases over time, from 13,320 pkm/capita in 2005 to 15,530 pkm/capita in 2050 (an increase of 17%). At the same time, freight activity per unit of GDP declines over the same period, from 228 tkm/000 Euro to 219 tkm/000 Euro (-4%). This is shown in Table 12.

Table 12 – Per capita demand for passenger transport and freight activity per unit of GDP

	Freight transport (tkm/000 Euro)	Freight transport (tkm/000 Euro) (2005=100)	Passenger transport (km/capita)	Passenger transport (km/capita) (2005=100)
2005	228	100	13,320	100
2010	231	101	13,531	102
2015	235	103	13,954	105
2020	238	104	14,238	107
2025	234	103	14,487	109
2030	233	102	14,760	111
2035	233	102	14,985	113
2040	228	100	15,168	114
2045	223	98	15,297	115
2050	219	96	15,530	117

4.7.3 Industry

The evolution of demand for selected materials (cement and steel) is presented in Figure 8. While demand for cement increases in a nearly constant rate over time, reaching 475Mt in 2050 (an increase of 101% with respect to 2005 levels), demand for iron and steel declines in 2050 by 12% with respect to 2005 values, stabilising at around 185Mt in the 2030-2050 period. The per capita consumption of both commodities follow similar patterns, though the changes with respect to the baseline year are more marked for cement (+89%) and less marked for iron and steel (-17%): in 2005, the per capita consumption of cement is 478 kg/per capita, as compared to 396 kg/per capita for iron and steel. In 2050, on the other hand, the per capita consumption of cement reaches 902 kg/per capita, while iron and steel per capita consumption reaches 328 kg/per capita (see Table 14).

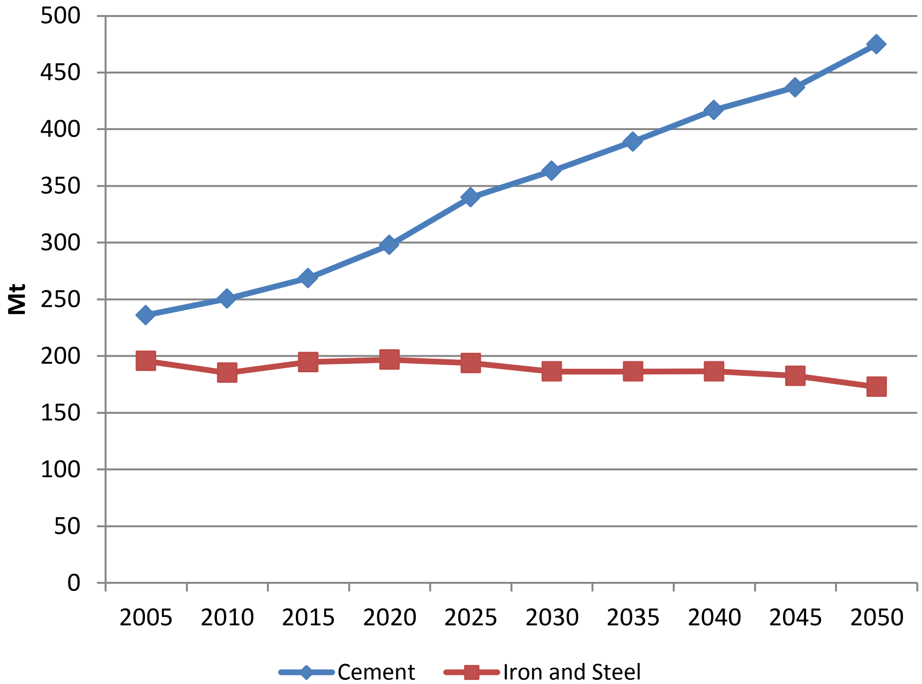


Figure 8 – Evolution of demand for selected materials

Table 13 – Per capita consumption of selected materials

	Cement (kg/capita)	Iron & steel (kg/capita)	Aluminium (kg/capita)
2005	478	396	18
2010	498	368	16
2015	526	381	18
2020	576	381	18
2025	651	372	18
2030	692	355	17
2035	738	354	17
2040	789	353	17
2045	827	346	17
2050	902	328	16

4.8 Price elasticity of demands endogenous to JRC-EU-TIMES

TIMES models in general compute an inter-temporal dynamic partial equilibrium on energy markets using the exogenously specified demands for energy services for the reference case. Within JRC-EU-TIMES, these demands are sensitive to price changes in alternate scenarios via a set of own-price elasticities in each period. Although TIMES does not encompass all macroeconomic variables beyond the energy sector, accounting for price elasticity of demands captures a major element of feedback effects between the energy system and the economy.

Information on the price elasticities of energy service demands is very limited with no comprehensive studies developed across European countries and the whole set of energy services considered in JRC-EU-TIMES. Therefore, the energy demand price elasticities used in JRC-EU-TIMES are the ones considered by (Kanudia & Regemorter, 2006) – a description is included in Annex 16.2. More information can also be found in (Duerinck & Regemorter, 2011).

Based on the relations and assumptions regarding the energy demand price elasticities and substitution possibilities the following energy services demand price elasticities are used in the JRC-EU-TIMES model, as in Table 14.

Table 14 – Price elasticities for energy services demand considered in JRC-EU-TIMES

Sector	Demand	Elasticity type		Demand	Elasticity type	
Residential	Heating/ cooling/ hot water	EDelas	-0.45	Cooking & refrigerator	EDelas	-0.35
		SUBelas	0.7		SUBelas	0.4
		Share EN	0.8		Share EN	0.8
		ESelas	-0.39		ESelas	-0.34
Commercial	Heating/ cooling/ hot water	EDelas	-0.55	Cooking & refrigerator	EDelas	-0.4
		SUBelas	0.7		SUBelas	0.4
		Share EN	0.8		Share EN	0.8
		ESelas	-0.51		ESelas	-0.40
Industry	Energy intensive	EDelas	-0.7	Other energy use in industry	EDelas	-0.4
		SUBelas	1		SUBelas	0.4
		Share EN	0.7		Share EN	0.8
		ESelas	-0.57		ESelas	-0.40

Reference: (Kanudia & Regemorter, 2006)

Notes: Share EN refers to the share of energy costs in the total cost of the energy service;

EDelas to energy demand price elasticity; ESelas to energy service price elasticity, and SUBElas to substitution elasticity

For transport there are estimates of the price elasticities of demand, although they do not cover all the regions and are sometimes related to the cost of energy and not the total transport cost. The values considered in JRC-EU-TIMES are from average figures for long term elasticities in OECD countries as in the following table.

Table 15 – Price-elasticity of transport demands used in JRC-EU-TIMES

Passenger		Freight	
Private car	-0.7	Trucks	-0.9
Bus	-0.2	Train	-0.2
Train	-0.2	Navigation	-0.2
Motorized two-wheelers	-0.3		
Navigation	-0.1		
Air	-0.7		

Reference: OECD in (Kanudia & Regemorter, 2006)

5 Energy resources

5.1 Supply sector

The JRC-EU-TIMES considers the following fossil primary resources: crude oil, natural gas, hard coal, and lignite. These can be mined and processed within the modelled regions or imported from outside the modelled regions. The mining activities are modelled by a supply curve with several cost steps for the following three types of sources: located reserves (or producing pools), reserves growth (or enhanced recovery), and new discoveries. The considered values for such reserves are presented in Annex 16.6.

Also, the nuclear fuel chain, from uranium ore to enrichment and fuel fabrication, is modelled in JRC-EU-TIMES. At this moment, JRC-EU-TIMES does not consider unconventional gas in Europe.

5.2 Biofuels and bioenergy

Regarding bioenergy, JRC-EU-TIMES considers the following different crop types, waste and residues sources that can be used in buildings, industry, production of transport biofuels and also electricity generation: agricultural products, agricultural residues, forestry products, forestry residues, biodegradable fraction of municipal solid waste (MSW), agricultural biogas, landfill gas and sewage sludge. This aggregation is in line with the POLES model and the data assumptions were updated during 2011, including GREEN-X outputs.

5.2.1 Bioenergy excluding biofuels

Bioenergy other than biofuels is described in detail in the JRC-EU-TIMES model. Efficiencies of bioenergy conversion as well as emissions of CO_2 and other pollutants are specified for the various processes.

Besides imports, woody biomass (BIOWOO) can come from EU28+ countries from grassy and woody crop production (MINBIOCRP31, MINBIOCRP41 and MINBIOCRP41a respectively), agricultural residues (MINBIOAGRW1), wood products (MINBIOWOO and MINBIOWOOa) and wood processing residues (MINBIOWOOW1 and MINBIOWOOW1a), as well as forestry residues (MINBIOFRSR1 and MINBIOFRSR1a). Trade in woody biomass is also modelled, both within the EU and with the rest of the world (see section 3.2.2).

The following end-use options for woody biomass are modelled in the JRC-EU-TIMES model:

- Commercial and residential sectors (COMBIO and RSDBIO): direct use for space heating (via pellet-based boilers and, in the residential sector, biomass stoves and fireplaces) and water heating (wood pellet boilers). Biodiesel boilers for space heating and water heating are also modelled.

- Industrial sector (INDBIO): direct use to generate heat in production processes (for iron and steel, chemicals, copper, glass, and lime), and for cogeneration of heat and electricity. Woody biomass is also a direct input to the production of pulp and paper, while chemical pulp production generates pulp residues as a by-product that can be re-used for heat generation in the industrial sector.
- Transport: lignocellulosic feedstock for FT-diesel and ethanol production (described in more detail in the next section).
- Primary energy conversion: direct input for generation of methane and hydrogen through gasification. Pyrolysis processes for hydrogen can also use woody biomass.
- Electricity (ELCWOO): electricity can be generated via technologies with woody biomass as input (steam turbines, biomass gasification, organic rankine cycle, 100MW IGCC, and thermal combustion). CHP technologies are also modelled (steam turbines), and so are district heating technologies using woody biomass.
- Agriculture sector: generic technology that can use woody biomass as input.

In the model, biogas (BIOGAS) groups methane generated from various forms of biomass, namely: gasification of black liquors (BBLQGAS110) and woody biomass (BWOOGAS110), as well as decomposition of industrial waste and sludge. Gasification processes also generate high temperature heat. Black liquor in turn is a by-product of chemical pulp production industrial processes that can also be used for CHP in industry.

The following end-uses of biogas are considered in JRC-EU-TIMES:

- Commercial: biogas (COMBGS) is used as input into internal combustion CHPs for co-generation of low temperature heat and electricity.
- Industrial sector: biogas (INDBGS) can be used in autoproducer CHP technologies (fuel cells, internal combustion engines).
- Electricity generation: biogas (ELCBGS) can be used for generating electricity via several CHP technologies (steam and gas turbines, combined-cycle, internal combustion engines, anaerobic digestion). District heating technologies using biogas are also modelled.
- Agriculture sector: generic technology that can use biogas as input.

Municipal waste (BIOMUN) and industrial waste and sludge (BIOSLU) are included in the model and can be used in the following technologies:

- Commercial: co-generation of low temperature heat and electricity (anaerobic digestion).
- Industrial sector: autoproducer CHP technologies (steam turbine condensing). Industrial sludge can also be used as input for generic kiln technologies for cement production.
- Primary energy conversion: industrial sludge can be used to generate methane via decomposition.
- Electricity generation: municipal waste and industrial waste and sludge can be used for generating electricity (steam turbines, including CHP, and anaerobic digestion) as well as for district heating.

5.2.2 Biofuels for transport

JRC-EU-TIMES modelling of biofuels is based on the approach used at the IFP (Lorne & Tchung-Ming, 2012), but extended to the whole production chain, as shown in Figure 9.

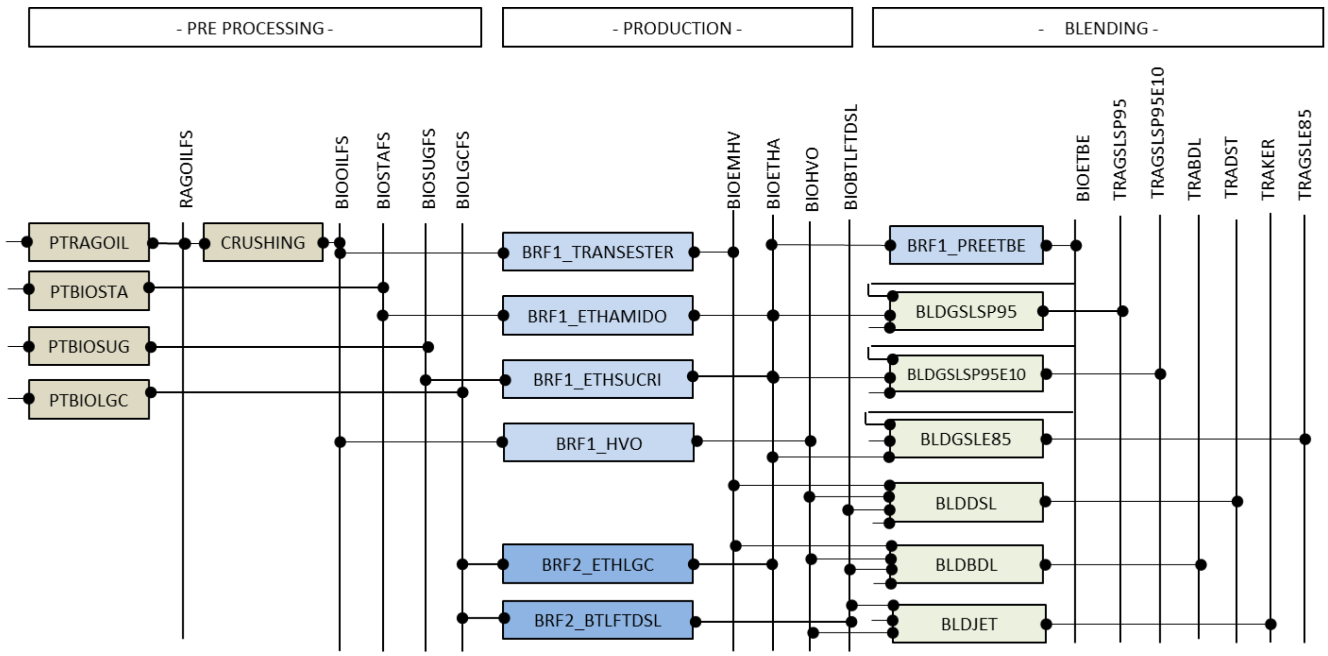


Figure 9 – RES for the production of biofuel in JRC-EU-TIMES

The production chain is divided in the pre-processing of the raw materials; the production processes, and the set of possible options of blending of the different basic biofuels.

Figure 9 shows the main (biofuel related) inputs and outputs of the processed modelled.

The pre-processing pathways include the transport and blending of oilseed (PTRAGOIL), the transport and blending of starch grain (PTBIOSTA), the transport and blending of sugar crops (PTBIOSUG) and the transport and blending of lignocellulosic feedstock's (PTBIOLGC). The energy consumption of the transport processes is estimated for an assumed average distance of 150 km. Downstream, the oilseeds are also processed in the crushing (CRUSHING) process. In this way vegetable oil, starch grain, sugar beet and lignocellulosic feedstock's are made available as for the production processes.

The core biofuel production processes are grouped in first generation and second generation biofuel processes.

- First generation biofuel production processes in JRC-EU-TIMES include:

- *Trans esterification of vegetable oils (BRF1_TRANSESTER)*. The trans-esterification process turns the chemical properties of the input vegetable oils (BIOOILFS) into FAMEs (Fatty Acid Methyl Esters) (BIOEMHV) which have similar properties to those of conventional diesel fuel.
- *Ethanol production from starch crops (BRF1_ETHAMIDO*). The bioethanol process uses enzymatic reactions and yeast fermentation to transform the starch grains (BIOSTAFS) into bioethanol (BIOETHA) which can be then further processed with isobutene in the etherification (BRF1_PREETBE) to produce ETBE (BIOETBE). The ETBE has several blending pathways with conventional fuels and biofuels.
- *Ethanol production from sugar crops (BRF1_ETHSUCRI)*. The production is fed with sugar-rich input (BIOSUGFS) to be fermented (BRF1_ETHSUCRI) obtaining bioethanol. Compared with starch fermentation, the sugar enriched process is more efficient, as it does not require enzymatic action to transform the starch into fermentable sugars.
- *Hydro treating of vegetable oils (BRF1_HVO)*. Hydro treating is an alternative process to esterification process and produces Hydro treated Vegetable Oils (HVO).

* Second generation production processes in JRC-EU-TIMES include:
    - Ethanol production from lignocellulosic biomass (BRF2_ETHLCGC): improved enzymatic action enables to ferment lignocellulosic biomass (BIOLGCFS) (agricultural products, agricultural residues, forestry products, forestry residues) to produce bioethanol. This allows using a much wider portfolio of biomass inputs to the production, which have also higher harvesting density.
    - Diesel production from lignocellulosic biomass (BRF2_BTLFTDS): this process models the production of biofuels starting with lignocellulosic biomass (BIOLGCFS) gasification and followed by a Gas-To-Liquid (GtL) process (mainly Fischer-Tropsch (FT)) which converts mixes of carbon monoxide and hydrogen into liquid hydrocarbons.

First generation biofuels are produced via better known technologies with lower investment costs than second generation (starting from 0.056 M€/kt in 2010 for trans esterification of vegetable oils, and 0.065 M€/kt in 2010 for ethanol production from starch crops). Second generation technologies, currently in pilot and demonstration phases, are assumed to become commercially available from 2020 onwards, with an investment cost that starts at approximately 1 M€/kt and 2.9 M€/kt, and declines over time, reaching 0.9 M€/kt and 2M€/kt for bioethanol and FT diesel respectively.

Biofuels production technologies with lignocellulosic biomass as input can coproduce significant quantities of electricity. This is modelled in JRC-EU-TIMES for both ethanol and FT diesel production processes.

Following the general biomass modelling approach of the JRC-EU-TIMES model, biomass use does not produce emissions. The CO_2 emissions of the production processes are due only to the fossil energy input that each process requires. In addition to the primary input, the production processes of bioethanol, FAME and ETBE may require electricity and high temperature heat, as well as non-energetic inputs. Water requirements are explicitly modelled, considering estimate of water used to produce crops which can be converted into biofuels. The production processes result in by-products, including CO_2 emissions, as well as glycerine and saponified fatty acids (resulting from the trans esterification of vegetable oils), and pulp and other distillates from the production of bioethanol.

The following table summarizes the main parameters of the biofuels implemented in the model.

Table 16 – Biofuels production process key parameters

Technology	Feedstock	Biofuel	Co-products	Investment cost M€/kt		
				2010	2020	2030
1st generation biofuels						
Trans esterification of vegetable oils	Vegetable oils	FAME	Glycerine by-product from esterif., Saponified fatty acids by-product from esterif.	0.056	0.05	0.048
Ethanol production from starch crops	Starch grain feedstock's	Bioethanol	Distillers Grains with Solubles by-product from ethamido.	0.606	0.501	0.4217
Ethanol production from sugar crops	Sugar beet feedstock's	Bioethanol	Sugar beet pulp by-product from ethsucri., Stillage by-product	0.2203	0.1820	0.1533
ETBE production	Ethanol	BioETBE	-	-	-	-
2nd generation biofuels						
Hydro treated vegetable oil	Vegetable oil feedstock's from crushing unit	Hydro treated vegetable oil]	Propane by-product from HVO	-	0.24604	0.18453
Ethanol production from lignocellulosic biomass	Lignocellulosic feedstock's	Bioethanol	Electricity - High Voltage	-	1.0829	0.77968
FT-diesel production from lignocellulosic biomass	Lignocellulosic feedstock's	FT-diesel from lignocellulosic biomass	Electricity - High Voltage, Naphtha	-	2.9945	2.03629

Finally, as it is also shown in Figure 10, the following blending options are modelled with the primary outputs from the main production processes. The exact amount of blended biofuels is decided endogenously depending on the fuel prices:

- Blending of gasoline SP95 fuels (BLDGSLSP95). Bioethanol and bioETBE are blended with gasoline in a proportion below 5% to model current gasoline including a low percentage of bioethanol.
- Blending of gasoline SP95-E10 fuels (BLDGSLSP95E10). Bioethanol and bioETBE are blended with gasoline in a proportion higher than 5% and below 10% (TRAGSLSP95E10).
- Blending of gasoline SP95-E85 fuels (BLDGSLE85). Bioethanol and bioETBE are blended with gasoline in a proportion up to 85% (TRAGSLE85).
- Blending of diesel fuels (BLDDSL). This process mixes the different biodiesel basic products, producing standard fuel (TRADST).
- Blending of diesel fuels B30 (BLDBDL). Mix of different biodiesel basic products, producing biodiesel (TRABDL) up to a maximum 30% of biofuels.
- Blending of jet fuels (BLDJET). Mix of the biodiesel products (hydro treated vegetable oils and biodiesel from lignocellulosic biomass) with kerosene (up to a 53%) to obtain a fuel for aviation transport (TRAKKER).

The model considers that diesel, gasoline and jet fuels in the market can have a variable share of blended biofuels. This share varies depending on the fuel as well as over time, to reflect improved or new technologies, engines and regulations.

Table 17 – Biofuels Maximum and minimum shares in blending processes

Technology	Input	MIN %	MAX 2005 %	MAX 2010 %	MAX 2020 %	MAX 2050 %
Blending of gasoline SP95 fuels	BIOETBE	7.6	15	15	15	15
	BIOETHA	4	5	5	5	5
Blending of diesel fuels B30	OILDSTkt	52				
	BIOEMHV	31.2	31.3	31.3	31.3	90
	BIOHVO				48.4	90

Technology	Input	MIN %	MAX 2005 %	MAX 2010 %	MAX 2020 %	MAX 2050 %
Blending of diesel fuels	OILDSTkt	52				
	BIOEMHV	3	7.4	7.4	10.5	90
	BIOHVO				4.8	90
Blending of jet fuels	OILKERkt	52.8				
Blending of gasoline SP95-E85 fuels	BIOETHA	76.3	85.9	85.9	85.9	85.9
	BIOETBE	22.3	22.3	22.3	22.3	22.3

Figure 10 represents the distribution and end-use options for the different biofuels blends:

- The low ethanol mix of conventional gasoline (TRAGSLSP95) can be used in common gasoline vehicles: buses, cars, trucks and motorbikes without any adaptation to its systems. Flexi-fuel ethanol cars (TCARMET101) can use it as well.
- The medium gasoline blend (TRAGSLSP95E10) can also be input to gasoline based conventional vehicles (cars, trucks and buses) and to those adapted to higher concentration of bioethanol (TCARMET101).
- The blending of diesel fuels (TRADST) can be fuelled to conventional diesel vehicles (buses, cars and trucks) and to first generation diesel hybrid cars and trucks (TCARMDSTHYB110 and TFREHDSTHYB110 / TFRELMDSTHYB110) can run on it as well. It is also used in ships and trains.
- The blend of biodiesels (TRABDL) can be distributed to biodiesel adapted hybrid cars and truck (TCARMBDLHYB110 and TFREHBDLHYB110) and to biodiesel fuelled buses, cars and trucks (TBISBDL101/ TBUSBDL101, TCARMBDL101, TFREHBDL101).
- Kerosene blend of biofuel (TRAKER) is used in aviation.
- Advanced mix of bioethanol (TRAGSLE85) can be used in ethanol adapted hybrid cars (TCARMETHHYB101) and ethanol designed buses cars and trucks (TBISETH101 / TBUSETH101, TCARMETH101, TFREHETH110).

Also Freight Light Duty Trucks (TFRELM) (for Urban Vans) have been modelled matching all the categories for medium cars (TCAR) so there is an equivalent TFREML vehicle category and fuel use for every TCAR already described. They have been omitted in Figure 10 and precedent text for the sake of readability.

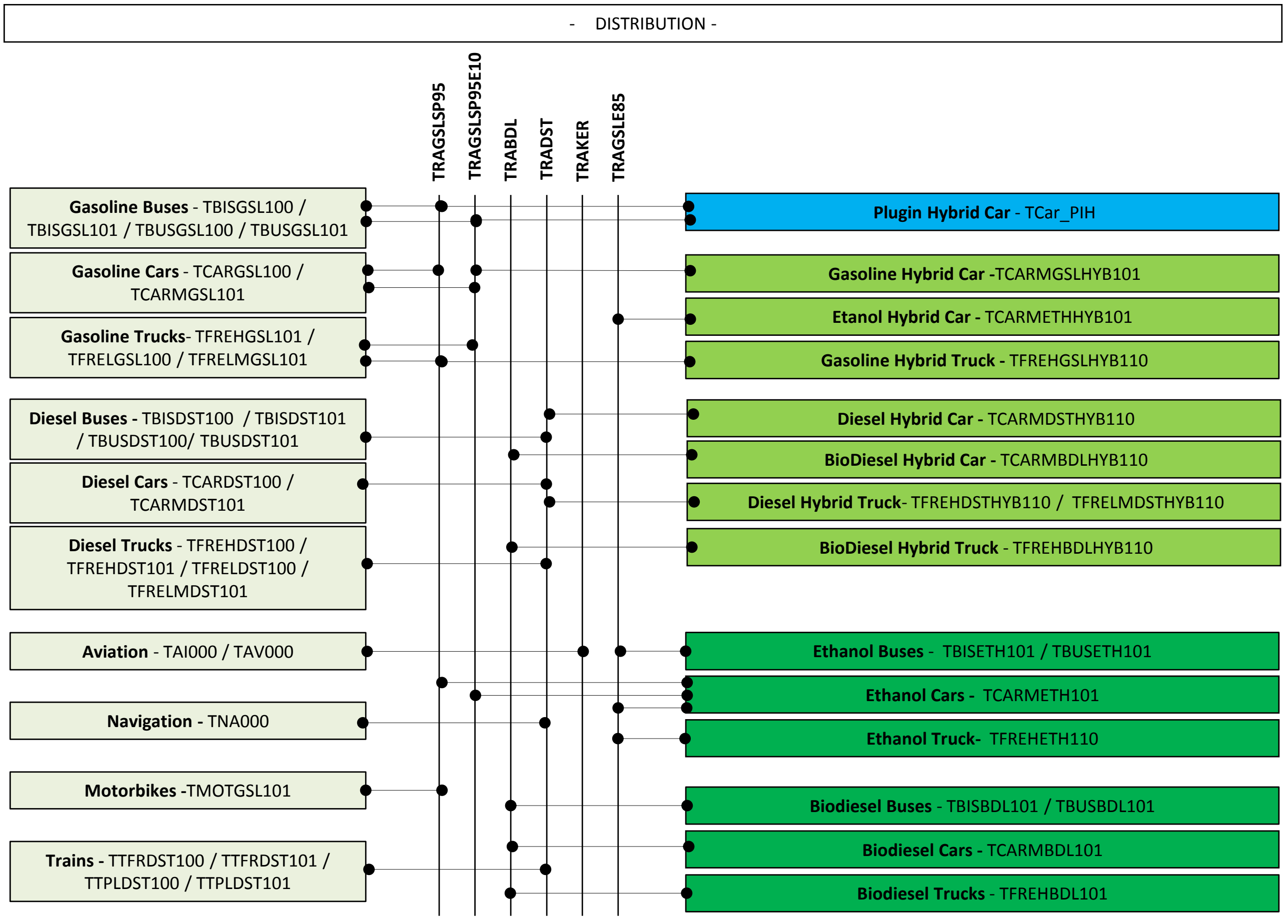


Figure 10 – RES for the distribution and use of biofuels

5.3 Technical potentials for generating renewable electricity

One of the most relevant exogenous inputs in the JRC-EU-TIMES model is the renewable energy potentials per technology and per country. Currently for electricity generation from renewable sources JRC-EU-TIMES includes data updated in 2013 as described in Table 18. For bioenergy, the assumptions in JRC-EU-TIMES are based on the POLES model, in a combined modelling effort developed by IPTS-JRC and including Green-X outputs. Due to the proprietary nature of the Green-X and POLES derived data, the RES potentials for bioenergy cannot be presented here. Note that, at this moment, the effects of climate change on resource availability are not considered in any of the technical potentials.

Table 18 – Overview of the technical renewable energy potential considered in JRC-EU2-TIMES

Resource	Methods	Main data sources
Wind onshore	Maximum activity and capacity restrictions disaggregated for different types of wind onshore technologies, considering different wind speed categories	(RES2020 Project Consortium, 2009) until 2020 followed by JRC-IET own assumptions
Wind offshore	Maximum activity and capacity restrictions disaggregated for different types of wind offshore technologies, considering different wind speed categories	(RES2020 Project Consortium, 2009) until 2020 followed by JRC-IET own assumptions
PV and CSP	Maximum activity and capacity restrictions disaggregated for different types of PV and for CSP	Adaptation from JRC-IET on (RES2020 Project Consortium, 2009)
Geothermal electricity	Maximum capacity restriction in GW, aggregated for both EGS and hydrothermal with flash power plants	(RES2020 Project Consortium, 2009) until 2020 followed by JRC-IET own assumptions
Ocean	Maximum capacity restriction in GW, aggregated for both tidal and wave	(RES2020 Project Consortium, 2009) until 2020 followed by JRC-IET own assumptions
Hydro	Maximum capacity restriction in GW, disaggregated for run-of-river and lake plants	(EURELECTRIC, 2011)

The potentials for electricity from renewable sources up to 2020 are based on maximum yearly electricity production provided by RES2020 (RES2020 Project Consortium, 2009) and updated during the REALISEGRID (Lavagno & Auer, 2009) EU projects.

Table 19 - Wind onshore maximum technical potential considered in JRC-EU-TIMES

COUNTRY	Wind onshore capacity potentials	
	Estimated maximum installed capacity for 2020	Estimated maximum installed capacity for 2050
	GWe	GWe
AT	4.02	7.17
BE	1.53	2.29

COUNTRY	Wind onshore capacity potentials	
	Estimated maximum installed capacity for 2020	Estimated maximum installed capacity for 2050
	GWe	GWe
BG	1.15	3.45
CH	0.60	1.10
CY	0.25	0.35
CZ	1.72	5.12
DE	43.46	55.88
DK	4.10	4.10
EE	0.30	0.92
ES	33.19	44.20
FI	0.90	2.64
FR	36.63	49.45
GR	8.50	10.00
HU	0.93	1.72
IE	5.65	6.90
IS	0.00	0.00
IT	19.00	23.00
LT	0.70	1.37
LU	0.13	0.21
LV	0.43	0.65
MT	0.20	0.20
NL	4.10	5.17
NO	4.77	14.31
PL	2.99	9.03
PT	7.60	9.45

COUNTRY	Wind onshore capacity potentials	
	Estimated maximum installed capacity for 2020	Estimated maximum installed capacity for 2050
	GWe	GWe
RO	2.50	3.70
SE	4.50	13.59
SI	0.56	0.86
SK	0.93	1.15
UK	18.27	19.36
AL	8.50	12.04
BA	0.60	2.00
HR	1.00	1.30
ME	0.10	0.19
MK	1.15	2.20
RS	1.21	2.31

Table 20 - Wind offshore maximum technical potential considered in JRC-EU-TIMES

COUNTRY	Wind offshore capacity potentials	
	Estimated maximum installed capacity for 2020	Estimated maximum installed capacity for 2050
	GWe	GWe
AT	0.00	0.00
BE	1.50	3.86
BG	0.00	0.00
CH	0.00	0.00
CY	0.00	0.00
CZ	0.00	0.00

COUNTRY	Wind offshore capacity potentials	
	Estimated maximum installed capacity for 2020	Estimated maximum installed capacity for 2050
	GWe	GWe
DE	14.81	20.73
DK	2.10	5.38
EE	0.70	0.90
ES	7.00	14.28
FI	2.10	4.00
FR	0.37	0.50
GR	0.00	5.00
HU	0.00	0.00
IE	0.75	1.11
IS	0.00	0.00
IT	0.00	0.00
LT	0.10	0.60
LU	0.00	0.00
LV	0.12	0.15
MT	0.00	0.00
NL	6.00	72.81
NO	1.89	7.30
PL	0.68	1.22
PT	1.00	3.38
RO	0.60	1.10
SE	5.50	11.00
SI	0.00	0.00
SK	0.00	0.00

COUNTRY	Wind offshore capacity potentials	
	Estimated maximum installed capacity for 2020	Estimated maximum installed capacity for 2050
	GWe	GWe
UK	7.82	9.82
AL	0.00	0.50
BA	0.00	0.00
HR	0.00	0.00
ME	0.00	0.00
MK	0.00	0.00

Table 21 - Geothermal maximum technical potential considered in JRC-EU-TIMES

Geothermal Potentials				
Region	Maximum total energy available (Hot Dry Rock & Dry Steam & Flash Power Plants) 2020	Maximum energy available (Hot Dry Rock & Dry Steam & Flash Power Plants) 2050	Maximum installed capacity 2020	Maximum installed capacity 2050
			Hot Dry Rock	Hot Dry Rock
	PJ	PJ	GW	GW
AT	0.00	0.00	0.000	0.000
BE	0.00	0.00	0.000	0.000
BG	2.52	2.52	0.000	0.000
CY	0.00	0.00	0.000	0.000
CZ	11.00	24.00	0.410	0.895
DE	10.91	20.52	0.000	0.000
DK	0.00	0.00	0.000	0.000

Geothermal Potentials				
Region	Maximum total energy available (Hot Dry Rock & Dry Steam & Flash Power Plants) 2020	Maximum energy available (Hot Dry Rock & Dry Steam & Flash Power Plants) 2050	Maximum installed capacity 2020	Maximum installed capacity 2050
			Hot Dry Rock	Hot Dry Rock
	PJ	PJ	GW	GW
EE	0.00	0.00	0.000	0.000
ES	20.84	34.78	0.800	1.400
FI	0.00	0.00	0.000	0.000
FR	0.00	0.00	0.000	0.000
GR	0.00	0.00	0.000	0.000
HU	2.16	2.16	0.075	0.075
IE	0.00	0.00	0.000	0.000
IT	26.17	26.17	0.000	0.000
LT	0.00	0.00	0.000	0.000
LU	0.00	0.00	0.000	0.000
LV	0.00	0.00	0.000	0.000
MT	0.00	0.00	0.000	0.000
NL	0.00	0.00	0.000	0.000
PL	8.63	12.60	0.322	0.463
PT	1.08	1.08	0.050	0.050
RO	0.00	0.00	0.000	0.000
SE	0.00	0.00	0.000	0.000
SI	0.00	0.00	0.000	0.000

Geothermal Potentials				
Region	Maximum total energy available (Hot Dry Rock & Dry Steam & Flash Power Plants) 2020	Maximum energy available (Hot Dry Rock & Dry Steam & Flash Power Plants) 2050	Maximum installed capacity 2020	Maximum installed capacity 2050
			Hot Dry Rock	Hot Dry Rock
	PJ	PJ	GW	GW
SK	0.17	0.21	0.007	0.008
UK	0.00	0.00	0.000	0.000
AL	0.00	0.00	0.000	0.000
BA	0.00	0.00	0.000	0.000
CH	0.00	0.00	0.000	0.000
HR	0.00	0.00	0.000	0.000
IS	5.4	5.4	/	/
ME	0.00	0.00	0.000	0.000
MK	2.52	2.52	0.000	0.000
NO	0.00	0.00	0.000	0.000
RS	2.52	2.52	0.000	0.000

Table 22 - Ocean maximum technical potential considered in JRC-EU-TIMES

Region	Ocean Energy Potentials	
	Maximum Wave & Tide Production 2020	Maximum Wave & Tide Production 2050
	PJ	PJ
AT	0.00	0.00
BE	0.54	0.54
BG	0.00	0.00
CY	0.86	0.86
CZ	0.00	0.00
DE	0.00	0.00
DK	9.29	9.29
EE	0.00	0.00
ES	47.63	47.63
FI	5.54	5.54
FR	47.38	55.88
GR	14.44	14.44
HU	0.00	0.00
IE	12.24	66.60
IT	11.59	11.59
LT	0.07	0.07
LU	0.00	0.00
LV	0.00	0.00
MT	0.22	0.22
NL	3.71	3.71
PL	14.04	23.40

Region	Ocean Energy Potentials	
	Maximum Wave & Tide Production 2020	Maximum Wave & Tide Production 2050
	PJ	PJ
PT	26.64	46.80
RO	0.00	0.18
SE	10.80	10.80
SI	0.00	0.00
SK	0.00	0.00
UK	212.04	309.60
AL	4.81	4.81
BA	0.00	0.00
CH	0.00	0.00
HR	4.81	4.81
IS	0.00	0.00
ME	0.00	0.00
MK	0.00	0.00
NO	75.60	79.20
RS	0.00	0.00

A different approach is taken to establish the maximum potential for Photovoltaic (PV) systems in the periods after 2020. For this technology, no upper bounds on electricity production are applied. Instead, a country-specific upper bound for 2050 is used for the photovoltaic peak power capacity, and the values between 2015 and 2050 are a linear interpolation. For 2015 JRC-EU-TIMES considers the expected investments based on on-going projects. The peak power capacity in 2050 is based on the assumption of a potential of 10 m^2 of PV panels per capita (for 2010 population). Independent of the country, we assume that a PV panel has a maximum production of electricity of 260 Wp/m^2 in 2050, based on clear sky conditions, 850 W/m^2 of solar radiation and a system efficiency of 30%. The JRC report “2011 Technology Map of the European Strategic Energy Technology Plan (SET-Plan)” (JRC-IET, 2011) underpins a strong increase of the PV module efficiency up to 40% in the long run. Although not a model input, the peak capacity can be transformed in an average annual electricity production as in Table 23. For reasons of comparison, the needed area is calculated as a percentage of the country's total land surface.

Table 23 – PV maximum technical potential considered in JRC-EU-TIMES

Region	Full load hours/Hours (comparable to AF data)	Peak PV power capacity		Average annual electricity production		% of total land surface
		2020	2050	2020	2050	2050
		GWe, Peak (derived from electricity production)	GWe, Peak	PJ	PJ (derived from peak power capacity)	
AT	979	7	21	23	75	0.10%
BE	983	2	28	8	98	0.36%
BG	1236	1	19	3	86	0.07%
CY	1480	0	2	0	11	0.09%
CZ	962	1	27	3	93	0.13%
DE	976	48	209	167	733	0.23%
DK	1023	0	14	2	52	0.13%
EE	935	0	3	0	12	0.03%
ES	1434	24	117	124	606	0.58%
FI	951	1	14	2	47	0.02%
FR	1161	5	160	21	670	0.11%
GR	1480	1	29	5	154	0.09%
HR	1123	0	11	0	44	0.08%
HU	1054	1	26	3	97	0.11%
IE	1048	0	11	1	43	0.06%
IT	1317	21	154	97	729	0.20%
LT	935	0	8	0	29	0.05%
LU	950	0	1	0	4	0.19%

Region	Full load hours/Hours (comparable to AF data)	Peak PV power capacity		Average annual electricity production		% of total land surface
		2020	2050	2020	2050	2050
		GWe, Peak (derived from electricity production)	GWe, Peak	PJ	PJ (derived from peak power capacity)	
LV	935	0	6	0	19	0.03%
MT	1480	0	1	0	6	1.31%
NL	1030	1	42	4	157	0.40%
PL	999	1	97	3	350	0.12%
PT	1517	11	27	59	148	0.12%
RO	1123	0	55	0	221	0.09%
SE	951	1	24	5	82	0.02%
SI	1060	0	5	0	20	0.10%
SK	953	0	14	1	47	0.11%
UK	1011	4	158	16	575	0.25%
CH	1032	0	20	0	74	0.19%
IS	951	0	1	0	3	0.00%
NO	951	3	12	9	42	0.01%

For the potentials for hydro-electricity in 2050, the capacities of the existing plants are multiplied with a country specific growth rate based on estimates on potentials from the World Hydro Atlas 2010 via Eurelectric (2011) (EURELECTRIC, 2011). The maximum capacities in the different periods are based on the potentials shown in Table 24.

Table 24 - Hydro technical potentials considered in JRC-EU-TIMES

Country	Eurostat 2005	Estimated potential for 2050
	GWe	GWe
AT	9.7	13.3
BE	0.1	0.1
BG	2	6.4
CY	0	0
CZ	1	1.4
DE	4.2	4.3
DK	0	0
EE	0	0
ES	12.8	34.2
FI	3	4.1
FR	18	28.1
GR	2.4	10
HR	1.8	2.2
HU	0.1	0.1
IE	0.2	0.4
IT	13.9	18.3
LT	0.1	0.2
LU	0	0.1
LV	1.5	1.8
MT	0	0
NL	0	0
PL	0.9	3.8
PT	4.5	12.4
RO	6.3	16.3

Country	Eurostat 2005	Estimated potential for 2050
	GWe	GWe
SE	16.3	32.5
SI	1	1.9
SK	1.6	2.5
UK	1.5	2
CH	11.7	12.8
IS	1.2	6.2
NO	27.2	45.4

It should be noted that concrete potential estimations might comprise a broad range of factors and depend substantially on the assumptions made on the driving factors. One example for a driving factor is the area availability for the construction of power plants or for the cultivation of biomass crops. Other limitations for the renewable energy potential including social acceptability of renewable power plants cannot easily be quantified.

6 Energy technologies

6.1 Primary energy supply and conversion

The mining of each primary energy resource is modelled using a supply curve with three cost steps. Biomass is modelled, but not in detail regarding the production processes. Refineries are modelled using a generic refinery structure.

6.2 Electricity generation

The electricity production sector is divided in accordance to producer types and generating plant types. Producers are classified according to the purpose of production. Main Activity Producers generate electricity and/or heat for sale to third parties, through the public grid, as their primary activity. Autoproducers generate electricity and/or heat, wholly or partly for their own use as an activity which supports their primary activity. Both types of producers may be privately or publicly owned. The types of plants are classified according to fuel input, technology group and whether the plant is electricity only or Combined Heat and Power (CHP). The categories of the plants follow closely the RES2020 (RES2020 Project Consortium, 2009) and Energy 2050 Roadmap nomenclature.

6.2.1 Techno-economic assumptions for existing electricity generation technologies

The model considers for the first time steps, i.e. the earlier modelled years, the current power plants in operation and under construction as well as plants to be decommissioned and built. For the information on installed capacity and on the main characteristics of the power units (e.g. year of commission, fuel type and type of power plant), the following sources were used: company homepages, energy regulator homepages, TSO homepages, EWEA and EPIA statistics. Each individual existing and planned nuclear power plant in Europe is modelled disaggregated at reactor level, considering its technological characteristics. In the JRC-EU-TIMES each electricity generation technology has a specific vintage. This means that the exact start date is considered in the model.

6.2.2 Techno-economic assumptions for electricity generation technologies

The techno economic details of the electricity generating technologies in JRC-EU-TIMES are detailed in Table 25. These values have been elaborated by technology experts from JRC-IET. They have been used for the 2011 SET-Plan Technology Map (JRC-IET, 2011) and the Commission Staff Working Document "Technology Assessment" (European Commission, 2013b) that accompanied the Communication "Energy Technology and Innovation" (European Commission, 2013a).

Besides these generic assumptions across the EU28+ region, the following country specific ones are made:

- Electricity generation from wind, marine, solar resources is not available in Iceland due to its geographical characteristics (sparse population and very high geothermal resources);
- Electricity generation from wind offshore is not available in countries without a coast;
- Electricity generation from high concentration PV is only possible in the following countries, where the assumed solar irradiance is considered high enough: BG, CY, ES, FR, GR, IT, MT, PT and HR.

Note that for comparison purposes an indication of the plant size was included in the following table. However, this is not used as such in the model, which considers continuous investment.

At the moment the model does not consider the possibility to use biomass in coal power plants.

Table 25 – Techno-economic characteristics of electricity generation technologies considered in JRC-EU-TIMES

Fuel	Technology	Size	Specific investments costs (overnight)				Fixed operating and maintenance costs				Electric net efficiency (condensing mode)				Tech. lifetime	Availability factor	CO_2 capture rate/ where applicable
		MWel	eur2010/kW				eur2010/kW				%					%	%
			2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
Electricity only plants																	
Hard coal	Subcritical	600	1365	1365	1365	1365	27	27	27	27	37	38	39	41	35	80	0
	Supercritical		1705	1700	1700	1700	34	34	34	33	45	46	49	49	35	80	0
	Fluidized bed		2507	2507	2507	2507	50	50	50	50	40	41	44	46	35	75	0
	IGCC		2758	2489	2247	1830	55	50	45	37	45	46	48	50	30	80	0
	Supercritical+post comb capture			2450	2209	2018		43	41	34	30	32	36	39	35	75	88
	Supercritical+oxy-fuelling capture			3028	2287	1876		38	37	31	28	31	36	40	35	75	90
	IGCC pre-comb capture			2689	2447	2030		47	40	38	31	33	39	44	30	75	89
Lignite	Subcritical	600	1552	1552	1552	1552	33	33	33	33	35	35	37	38	35	75	0
	Supercritical		1856	1856	1856	1856	39	39	43	45	43	45	47	49	35	75	0
	Fluidized bed		2758	2489	2247	1830	55	50	45	37	36	37	40	43	35	75	0
	IGCC		3009	2716	2451	1996	48	43	39	32	42	44	48	51	30	75	0

Fuel	Technology	Size	Specific investments costs (overnight)				Fixed operating and maintenance costs				Electric net efficiency (condensing mode)				Tech. lifetime	Availability factor	CO2 capture rate/ where applicable
		MWel	eur2010/kW				eur2010/kW				%					%	%
			2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
	Supercritical+post comb capture			2555	2479	2381		49	43	38	29	31	35	38	35	75	88
	Supercritical+oxy-fuelling capture			3330	2516	2063		45	41	35	27	30	35	39	35	75	90
	IGCC pre-comb capture			2953	2366	2006		71	64	58	30	32	38	42	30	75	89
Natural Gas	Steam turbine	550	750	750	750	750	19	19	19	19	42	42	42	43	35	45	0
	OCGT Peak device advanced		568	568	568	568	17	17	17	17	42	45	45	45	15	20	0
	Combined-cycle		855	855	855	855	26	21	20	20	58	60	62	64	25	60	0
	Combined-cycle+post comb capture			1244	1155	1093		44	41	39	42	44	49	53	25	55	88
	OCGT Peak device conventional		486	486	476	472	12	12	12	12	39	39	40	41	15	20	0
Nuclear	3rd generation LWR planned	1000	5000	5000	5000	5000	43	43	42	42	34	34	36	36	50	82	0
	3rd generation non-planned		5000	4625	4250	3500	*specific values for each reactor from IAEA*										
	4th generation Fast reactor					4400	91	85	80	69	34	34	36	40	50	82	0
Wind	Wind onshore 1 low (IES		1300	1200	1050	950	32	25	23	20	100	100	100	100	25	16	0

Fuel	Technology	Size	Specific investments costs (overnight)				Fixed operating and maintenance costs				Electric net efficiency (condensing mode)				Tech. lifetime	Availability factor	CO_2 capture rate/ where applicable
		MWel	eur2010/kW				eur2010/kW				%					%	%
			2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
onshore	class III)																
	Wind onshore 2 medium (IES class II)		1400	1270	1190	1110	34	27	24	21	100	100	100	100	25	21	0
	Wind onshore 3 high (IES class I)		1600	1380	1270	1190	36	29	27	25	100	100	100	100	25	30	0
	Wind onshore 4 very high (IES class S)		1700	1430	1320	1240	40	32	29	27	100	100	100	100	25	40	0
Wind offshore	Wind offshore 1 low		2500	2000	1800	1500	106	80	63	54	100	100	100	100	25	15	0
	Wind offshore 2 medium (IES class II)		3000	2600	2380	1950	106	80	63	54	100	100	100	100	25	32	0
	Wind offshore 3 high deeper waters (IES class I)		4300	3400	2700	2100	130	95	75	60	100	100	100	100	25	40	0
	Wind offshore 4 very high floating		6000	4200	3300	2700	170	120	90	70	100	100	100	100	25	51	0
Hydro	Lake very small expensive hydroelectricity <1 MW	<1	7300	7300	7300	7300	73	73	73	73	100	100	100	100	75	42	0
	Lake very small cheap hydroelectricity <1 MW	<1	1800	1800	1800	1800	18	18	18	18	100	100	100	100	75	42	0
	Lake medium scale	1-10	5500	5500	5500	5500	55	55	55	55	100	100	100	100	75	42	0

Fuel	Technology	Size	Specific investments costs (overnight)				Fixed operating and maintenance costs				Electric net efficiency (condensing mode)				Tech. lifetime	Availability factor	CO_2 capture rate/ where applicable
		MWel	eur2010/kW				eur2010/kW				%					%	%
			2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
	expensive hydroelectricity 1-10 MW																
	Lake medium scale cheap hydroelectricity 1-10 MW	1-10	1400	1400	1400	1400	14	14	14	14	100	100	100	100	75	42	0
	Lake large scale expensive hydroelectricity > 10 MW	>10-50	4600	4600	4600	4600	46	46	46	46	100	100	100	100	75	38	0
	Lake large scale cheap hydroelectricity > 10 MW	>10-50	1200	1200	1200	1200	12	12	12	12	100	100	100	100	75	38	0
	Run of River hydroelectricity		1454	1712	1575	1575	15	17	16	16	100	100	100	100	75	36	0
Solar	Solar PV utility scale fixed systems large > 10MW	> 10	3165	895	805	650	47	13	12	10	100	100	100	100	30	24	0
	Solar PV roof <0.1 MWp	< 0.1	3663	1420	1135	775	55	21	17	12	100	100	100	100	30	24	0
	Solar PV roof 0.1-10 MWp	0.1-10	3378	1065	850	675	51	16	13	10	100	100	100	100	30	24	0
	Solar PV high concentration		6959	2698	2157	1473	104	40	32	22	100	100	100	100	30	27	0
	Solar CSP	50	5200	2960	2400	1840	104	89	72	37	100	100	100	100	30	35	0
Biomass	Steam turbine biomass solid conventional		3069	2595	2306	2018	107	91	81	71	34	35	36	38	20	90	0

Fuel	Technology	Size	Specific investments costs (overnight)				Fixed operating and maintenance costs				Electric net efficiency (condensing mode)				Tech. lifetime	Availability factor	CO_2 capture rate/ where applicable
		MWel	eur2010/kW				eur2010/kW				%					%	%
			2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
	IGCC Biomass	100	3960	3574	3225	2627	139	125	113	92	37	37	43	48	20	90	0
	Biomass with carbon sequestration		4297	3373	2652	2321	150	118	93	81	33	34	35	36	20	61	85
	Anaerobic digestion biogas+ gas engine	3	3713	3639	3566	3426	130	127	125	120	36	38	40	45	25	80	0
Geothermal	Geothermal hydrothermal with flash power plants		2400	2200	2000	2000	84	77	70	70	100	100	100	100	30	90	0
	Enhanced geothermal systems		10000	8000	6000	6000	350	280	210	210	100	100	100	100	30	90	0
Ocean	Wave	5	5650	4070	3350	2200	86	76	67	47	100	100	100	100	30	22	0
	Tidal energy stream and range	10	4340	3285	2960	2200	66	62	59	47	100	100	100	100	30	22	0
CHP Plants																	
Wood	Steam Turbine	5	2623	2457	2158	2158	56	55	47	47	34	35	36	36	30	90	
	Steam Turbine2	30	2530	2271	1807	1807	51	45	36	36	33	34	34	34	30	90	
	Organic Ranking Cycle		3741	3734	3661	3661	75	75	73	73	19	20	20	20	25	90	
	Biomass gasification	100	5140	4584	4005	4005	77	77	77	77	34	34	34	34	25	70	

Fuel	Technology	Size	Specific investments costs (overnight)				Fixed operating and maintenance costs				Electric net efficiency (condensing mode)				Tech. lifetime	Availability factor	CO_2 capture rate/ where applicable
		MWel	eur2010/kW				eur2010/kW				%					%	%
			2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
Waste	Steam Turbine municipal waste		2530	2271	1807	1807	51	45	36	36	33	34	34	34	30	90	
	Anaerobic digestion sludges		3248	3416	3500	3500	157	138	127	127	32	34	34	34	25	70	
	Internal Combust Biogas		1745	1742	1708	1708	35	35	34	34	40	40	40	40	25	90	
Coal	Subcritical		1646	1645	1638	1638	33	33	33	33	37	38	40	40	25	90	
	Supercritical		2657	2441	2053	2053	52	48	41	41	40	42	46	46	30	90	
	Supercritical+post comb capture			3500	2827	2827		52	48	48	0	32	36	36	30	90	88
	Supercritical+oxy-fuelling capture			3648	2757	2757		47	45	45	0	31	36	36	30	90	90
	Int. gasification+post comb capture			3758	3087	3087		56	52	52	0	35	40	40	25	90	88
	Int. gasification+pre comb capture			3539	2827	2827		56	52	52	0	33	39	39	25	90	89
	Int. gasification+oxy-fuelling capture			3595	2822	2822		56	52	52	0	33	39	39	25	90	90
Lignite	Subcritical	250	1872	1872	1863	1863	40	40	40	40	35	35	37	37	25	90	

Fuel	Technology	Size	Specific investments costs (overnight)				Fixed operating and maintenance costs				Electric net efficiency (condensing mode)				Tech. lifetime	Availability factor	CO_2 capture rate/ where applicable
		MWel	eur2010/kW				eur2010/kW				%					%	%
			2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
	Supercritical		2810	2567	2130	2130	57	54	49	49	38	40	44	44	30	90	
	Supercritical+post comb capture			3883	3222	3222		59	56	56	0	29	33	33	30	90	88
	Supercritical+oxy-fuelling capture			2626	2460	2460		54	52	52	0	28	34	34	30	90	90
	Int. gasification+post comb capture			4135	3396	3396		86	77	77	0	32	37	37	25	90	88
	Int. gasification+pre comb capture			3893	3110	3110		86	77	77	0	31	37	37	25	90	89
	Int. gasification+oxy-fuelling capture			3955	3104	3104		85	77	77	0	31	37	37	25	90	90
Natural gas	Steam Turbine		1182	1180	1157	1157	21	21	21	21	38	38	39	39	25	90	
	Combined-cycle conventional	50	823	822	816	816	21	21	20	20	45	46	48	48	25	90	
	Combined-cycle advanced		1019	980	907	907	26	25	24	24	47	48	51	51	25	90	
	Combined-cycle +post comb capture			1637	1419	1419		35	32	32	0	44	46	46	25	90	88
	Combined-cycle + pre comb			1727	1328	1328		31	29	29	0	43	45	45	25	90	88

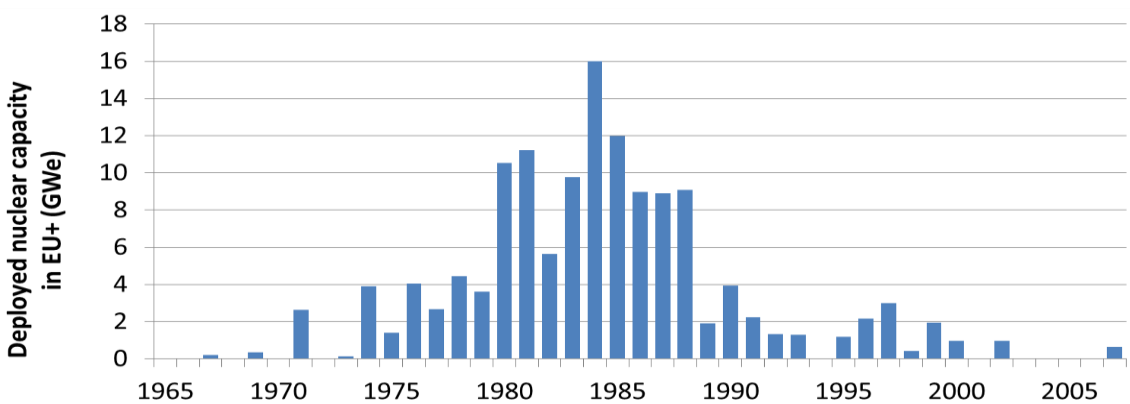
Fuel	Technology	Size	Specific investments costs (overnight)				Fixed operating and maintenance costs				Electric net efficiency (condensing mode)				Tech. lifetime	Availability factor	CO_2 capture rate/ where applicable
		MWel	eur2010/kW				eur2010/kW				%					%	%
			2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			
	capture																
	Combined-cycle + oxy fuelling capture			1827	1347	1347		32	30	30	0	41	43	43	25	90	88
	Internal Combustion Engine	2.68	606	604	593	593	18	18	18	18	38	39	40	40	25	90	88
District heating																	
Oil			129	129	129	129	3	3	3	3	88	88	88	88	25	20	
Coal			210	210	210	210	5.85	5.85	5.85	5.85	88	88	88	88	25	20	
Wood	Wood chips boiler		489	474	449	449	22	20	18	18	88	88	88	88	25	20	
Natural gas	Natural-gas boiler		140	140	140	140	3	3	3	3	90	90	90	90	25	20	

6.2.3 Specific assumptions regarding pace of deployment of energy technologies

For some of the energy technologies JRC-EU-TIMES considers, in addition to the technology costs described in Section 7.2.1, a technology cost curve which is dependent on the speed of deployment. This is the case for nuclear, solar (PV and CSP), fossil CCS, biomass (including CCS) and marine. Here we exemplify with more detail how this is implemented for nuclear. The principle is the same for the other technologies, although with different steps, described also in this section.

In order to capture to some extent the costs beyond[14] the conventional investment costs [(Stephens, Wilson, & Peterson, 2007), (OECD/IEA, 2012)], that substantially affect the pace of deployment of nuclear reactors and which are considered more relevant for nuclear than for other electricity generation technologies[15] [(Mez, 2012), (Kessides, 2010)], a mark-up factor is used to determine the total cost of nuclear energy. The principle behind these assumptions is translated into the model as follows:

- Step 1 - up to an annual deployment for the whole of EU28+ of 1.7 GW per year of nuclear, the technology costs is as estimated in the reference case and summarised in Table 20. From Figure 11, depicting the historical deployment of nuclear plants across EU+, it possible to estimate that since 1967, on average for the whole of EU28+, 3.36 GW were installed per year;
- Step 2 - for an annual average deployment of nuclear above 1.7 GW/year and up to 3.4 GW/year, the investment costs increase by 25% from the ones in Step 1;
- Step 3 - for faster annual deployment rates beyond 3.4 GW/year, the investment costs increase 50% from the ones in Step 1.



Reference: WNA (2013). Nuclear database of the World Nuclear Association (WNA). Available at: [http://world-nuclear.org/nucleardatabase/Default.aspx?id=27232]. Accessed 11 July 2013.

Figure 11 – Annual deployment of nuclear reactors in EU28+ in the period 1967-2007

[14] For example related with rising costs due to enhanced safety measures, difficulties in extending reactor life spans, and longer and more stringent processes for siting and licensing of new plants must be overcome (ETP, 2012).

[15] With perhaps the exception of CCS.

Note that for nuclear power plants in JRC-EU-TIMES, the period since initiating the financing decision on the investment for a new power plant and the first operation moment is considered to be five years (ILED TIMES attribute, for more explanations see (Loulou, et al., 2005b)).

The same type of user constraint is implemented for the following electricity generation technologies:

Table 26 - Specific assumptions regarding pace of deployment of electricity generation technologies considered in JRC-EU-TIMES

Technology	Steps for annual build rate (GW/year)					
	Step 1		Step 2		Step 3	
	GW/y	Cost increase	GW/y	Cost increase	GW/y	Cost increase
Nuclear	<1.7	None	1.7-3.4	25%	>3.4	50%
Biomass with CCS	<5	None	5-10	5%	n.a.	n.a.
CSP	<1	None	1-6	10%	>6	50%
Gas with CCS	<50	None	50-55	16%	n.a.	n.a.
Hydro	<20	None	20-40	5-14%	n.a.	n.a.
PV	<25	None	25-55	6%	n.a.	n.a.
Wind	<50	None	50-80	6-12%	n.a.	n.a.

[a] The costs are the same as in Table 25. n.a. – not applicable

For comparison purposes we include in the following table the annual deployment rate of electricity generation technologies in EU27 as available in EUROSTAT.

Table 27 – Historical annual deployment rates of some electricity generation technologies in EU27

Annual evolution in GW/year	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Electrical capacity, main activity producers - Combustible Fuels	13.6	0.5	2.7	1.8	7.8	7.9	2.9	14.1	10.5	18.7	0.1	1.2	10.6	12.2	4.5	12.6	4.2	6.4	4.6	15.1	9.3
Electrical capacity, main activity producers - Hydro	2.6	2.3	1.0	0.8	2.9	1.4	1.1	7.0	0.9	5.2	0.7	0.2	-0.5	0.9	0.9	0.8	1.9	0.7	1.3	1.5	1.6
Electrical capacity, main activity producers - Pumped Hydro	4.7	0.8	2.0	-0.8	0.6	0.7	0.0	1.9	0.1	-0.6	0.2	0.0	-0.3	-0.1	0.1	1.5	1.7	0.3	0.3	0.4	0.5
Net maximum capacity - Geothermal	0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electrical capacity, main activity producers - Wind	0.1	0.1	0.1	0.1	0.3	0.4	0.7	0.9	1.3	7.8	4.5	5.7	4.8	5.8	5.6	6.7	9.5	7.8	9.5	10.2	9.1
Electrical capacity, autoproducers - Wind	0.1	0.1	0.2	0.3	0.6	0.5	0.5	0.7	1.5	-4.1	0.0	0.2	0.3	0.2	0.6	0.5	-1.2	0.7	1.1	-0.6	0.4
Electrical capacity, main activity producers - Gas Turbine	0.5	1.3	-0.4	1.4	0.7	0.8	0.9	0.8	-2.4	0.3	0.2	-5.4	0.0	-0.9	0.2	-0.1	-0.4	1.0	-0.5	0.8	0.4
Electrical capacity, autoproducers - Gas Turbine	0.2	0.2	0.2	0.2	0.3	0.9	-0.4	0.4	-0.8	0.6	0.0	-1.2	-0.9	0.0	0.0	0.3	0.2	0.4	0.0	0.3	0.3
Electrical capacity, main activity producers - Combined Cycle	0.4	1.1	4.5	4.3	1.0	6.8	0.7	3.9	5.5	14.8	5.2	3.3	2.3	7.4	7.2	5.7	4.6	6.2	4.9	10.4	2.7
Electrical capacity, autoproducers - Combined Cycle	0.4	0.3	0.5	0.4	0.5	1.0	0.8	1.4	1.0	-3.5	0.3	-0.2	-1.2	1.4	-0.1	-0.1	0.1	0.9	0.8	0.0	0.2
Net maximum capacity - Solar Photovoltaic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.4	0.8	1.5	1.7	4.7	6.3	13.2	21.8
Net maximum capacity - Solar Thermal Electric	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.5	0.4
Net maximum capacity - Municipal Wastes	0.0	0.1	0.2	0.0	0.2	0.2	0.0	0.2	0.0	0.2	0.1	0.1	1.3	0.5	0.3	0.6	-0.2	0.2	0.7	0.4	0.0
Net maximum capacity - Wood/Wood Wastes/Other Solid Wastes	0.0	0.3	0.1	0.2	0.1	0.2	-0.1	0.0	0.5	0.6	0.5	0.3	1.0	0.9	1.7	0.8	0.6	1.2	1.9	1.3	1.6
Net maximum capacity - Tide, Wave, Ocean	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Reference: Eurostat. Infrastructure - electricity - annual data [nrg_113a]. Updated 26/06/2013.

6.2.4 Renewable technologies availability factors

In TIMES models the availability factor (AF) indicates the percentage of the year in which the technology is functional (i.e. without required maintenance stops and/or stopped due to low availability of variable renewable resources). This parameter is a model input obtained from literature and/or historical performance of existing plants. The AF introduced in the JRC-EU-TIMES (as in other TIMES models) is the maximum that the technologies can work and it can be directly compared with the estimated operation time from model outputs. The estimated operation time for each technology is computed using the model outputs of installed capacity and generated electricity in each scenario, and the "input" AF. Thus, it follows that the input AF is the maximum that a technology can operate and that it is not necessarily identical to its optimal deployment as identified by the model (Simoes, Seixas, Fortes, & Huppes, 2012).

For the wind, solar and hydro technologies the AF input into JRC-EU-TIMES are based on an estimate developed within IET-JRC as an input to the EUPowerDispatch model (Martínez-Anido et al., 2012). The availability factors were estimated from 2010 data by dividing the estimate of electricity generated from wind, hydro and solar per country with the installed capacity as in (Martínez-Anido, et al., 2012).

6.2.4.1 Wind

Based on (Martínez-Anido, et al., 2012), the electricity generation data was disaggregated for every hour of the year 2010 for every region in the JRC-EU-TIMES model. The installed capacity for 2010 used in (Martínez-Anido, et al., 2012) was obtained from ENTSO-E and Eurostat. Brancucci Martínez-Anidoa, 2012} also supplied similar wind electricity generation data for 2007, 2008 and 2009 but since the installed capacity for these years was not available, at this stage only 2010 data is used in JRC-EU-TIMES.[16] The disaggregated data from (Martínez-Anido, et al., 2012) was aggregated at national level per time slice in order to achieve coherence with the regions and time resolution in JRC-EU-TIMES as given in Table 28.

6.2.4.2 Solar

The solar AF in JRC-EU-TIMES also follows the approach of (Martínez-Anido, et al., 2012) based on solar radiation data from (Mueller, Matsoukas, Gratzki, Behr, & Hollmann, 2009). This data is then used to calculate PV energy production based on the PVGIS methodology (Huld, Müller, & Gambardella, 2012) and represents theoretical hourly energy output delivered to the grid (Wh/kWpeak installed) in each grid point which was then aggregated by (Martínez-Anido, et al., 2012) for every hour of the year 2010 for every country in JRC-EU-TIMES. As the AF gives an indication between the technology output and installed capacity for a certain period of time and

[16] The wind AF are based originally on wind speed data from (Kalnay et al., 1996) in the form of surface flux data and composed by two vector components at 10 m altitude, 4 times per day (0h, 6h, 12h, 18h), in a regularly spaced grid of 2.5 degrees latitude - longitude. Wind inputs are obtained assuming a linear relationship between the source data and that wind turbine height is 100 m. The methodology as in (Gipe, 2004) was used to estimate the wind speed calculation at the "real" height for every sub-country region considered in the EUPowerDispatch model.

since the PVGIS methodology considers a theoretical possible production, it is a direct function of the solar availability and as thus could be directly used as the AF into JRC-EU-TIMES (Table 29).

Table 28 - Availability factors per country and per time-slice for wind technologies considered in JRC-EU-TIMES

Time Slice /Country	WN	WD	WP	RN	RD	RP	SN	SD	SP	FN	FD	FP
AT	13%	13%	12%	9%	10%	9%	6%	7%	5%	8%	8%	7%
BE	18%	21%	19%	12%	17%	14%	6%	9%	7%	15%	16%	14%
BG	16%	15%	14%	7%	8%	5%	3%	3%	2%	11%	12%	10%
CZ	18%	17%	16%	11%	12%	10%	7%	8%	6%	13%	12%	11%
DE	18%	19%	18%	10%	14%	10%	6%	8%	6%	15%	15%	13%
DK	35%	35%	34%	23%	28%	24%	15%	18%	16%	31%	32%	30%
EE	10%	11%	10%	8%	8%	6%	7%	8%	5%	12%	12%	10%
ES	22%	23%	21%	12%	17%	14%	7%	13%	12%	12%	15%	13%
FI	9%	8%	8%	5%	5%	4%	6%	7%	5%	10%	10%	9%
FR	23%	25%	23%	15%	20%	17%	9%	13%	10%	16%	17%	15%
GR	25%	26%	24%	13%	15%	12%	8%	9%	8%	12%	13%	12%
HR	15%	16%	0%	9%	10%	8%	6%	8%	6%	11%	11%	9%
HU	13%	13%	11%	8%	8%	7%	4%	4%	3%	6%	6%	5%
IE	34%	35%	33%	28%	33%	30%	25%	32%	28%	42%	43%	43%
IT	49%	49%	47%	24%	26%	25%	16%	19%	19%	27%	29%	28%
LT	19%	19%	18%	13%	14%	13%	10%	11%	8%	21%	22%	19%
LU	17%	19%	17%	10%	15%	12%	6%	8%	6%	14%	14%	13%

Time Slice /Country	WN	WD	WP	RN	RD	RP	SN	SD	SP	FN	FD	FP
LV	19%	19%	18%	13%	14%	13%	10%	11%	8%	21%	22%	19%
NL	26%	27%	25%	17%	23%	18%	10%	16%	12%	27%	28%	26%
PL	12%	12%	11%	7%	9%	7%	5%	6%	4%	11%	11%	9%
PT	26%	27%	26%	16%	18%	17%	16%	24%	26%	13%	16%	16%
RO	16%	16%	15%	7%	9%	6%	4%	4%	3%	11%	11%	9%
SE	18%	18%	18%	11%	12%	10%	11%	12%	10%	18%	20%	18%
SI	13%	13%	12%	10%	11%	9%	6%	7%	5%	7%	8%	7%
SK	10%	11%	10%	8%	9%	8%	6%	7%	5%	9%	9%	7%
UK	32%	32%	31%	24%	28%	24%	18%	23%	19%	37%	38%	36%
AL	16%	16%	15%	7%	9%	6%	4%	4%	3%	11%	11%	9%
BA	16%	16%	15%	7%	9%	6%	4%	4%	3%	11%	11%	9%
CH	13%	15%	14%	8%	10%	9%	5%	8%	6%	8%	9%	9%
KS	16%	16%	15%	7%	9%	6%	4%	4%	3%	11%	11%	9%
ME	16%	16%	15%	7%	9%	6%	4%	4%	3%	11%	11%	9%
MK	16%	16%	15%	7%	9%	6%	4%	4%	3%	11%	11%	9%
NO	23%	23%	23%	17%	18%	16%	19%	21%	18%	23%	24%	22%
RS	16%	16%	15%	7%	9%	6%	4%	4%	3%	11%	11%	9%

Table 29 - Availability factors per country and per time-slice for solar based technologies considered in JRC-EU-TIMES

Time Slice/ Country	FD	FN	FP	RD	RN	RP	SD	SN	SP	WD	WN	WP
AT	22%	0%	3%	30%	1%	12%	33%	1%	16%	10%	0%	1%
BE	19%	0%	7%	32%	0%	21%	34%	1%	24%	9%	0%	2%
BG	27%	1%	1%	36%	2%	5%	38%	3%	8%	16%	0%	0%
CZ	21%	0%	2%	29%	1%	11%	33%	2%	16%	9%	0%	1%
DE	21%	0%	5%	31%	1%	16%	34%	1%	20%	8%	0%	1%
DK	22%	0%	4%	34%	1%	17%	36%	1%	22%	7%	0%	1%
EE	17%	1%	1%	31%	2%	7%	34%	3%	11%	6%	0%	0%
ES	34%	0%	22%	39%	0%	31%	42%	0%	36%	22%	0%	10%
FI	21%	0%	3%	31%	1%	13%	34%	2%	18%	7%	0%	1%
FR	26%	0%	11%	35%	0%	23%	37%	0%	28%	14%	0%	4%
GR	33%	2%	1%	43%	3%	7%	44%	3%	9%	22%	0%	0%
HR	23%	0%	3%	32%	1%	11%	37%	2%	15%	13%	0%	0%
HU	23%	0%	1%	31%	1%	8%	36%	2%	13%	11%	0%	0%
IE	19%	0%	14%	34%	0%	32%	33%	0%	33%	13%	0%	6%

Time Slice/ Country	FD	FN	FP	RD	RN	RP	SD	SN	SP	WD	WN	WP
IT	29%	0%	5%	37%	1%	15%	42%	1%	20%	19%	0%	2%
LT	18%	1%	1%	30%	2%	7%	34%	3%	11%	7%	0%	0%
LU	19%	0%	6%	31%	0%	18%	34%	1%	22%	8%	0%	2%
LV	17%	1%	1%	31%	2%	7%	34%	3%	11%	6%	0%	0%
NL	19%	0%	6%	36%	0%	23%	36%	1%	26%	9%	0%	2%
PL	22%	0%	2%	30%	2%	9%	35%	2%	13%	9%	0%	0%
PT	36%	0%	30%	40%	0%	38%	45%	0%	45%	21%	0%	16%
RO	24%	1%	1%	33%	2%	5%	36%	3%	8%	13%	0%	0%
SE	21%	0%	3%	31%	1%	13%	34%	2%	18%	7%	0%	1%
SI	21%	0%	3%	31%	1%	12%	36%	1%	16%	13%	0%	1%
SK	20%	0%	1%	28%	1%	8%	33%	2%	12%	10%	0%	0%
UK	20%	0%	11%	34%	0%	27%	32%	0%	29%	11%	0%	4%
AL	24%	1%	1%	33%	2%	5%	36%	3%	8%	13%	0%	0%
BA	24%	1%	1%	33%	2%	5%	36%	3%	8%	13%	0%	0%
CH	24%	0%	6%	30%	0%	16%	33%	1%	20%	12%	0%	2%
KS	24%	1%	1%	33%	2%	5%	36%	3%	8%	13%	0%	0%
ME	25%	1%	2%	30%	1%	8%	37%	2%	13%	13%	0%	0%

6. Energy technologies

Time Slice/ Country	FD	FN	FP	RD	RN	RP	SD	SN	SP	WD	WN	WP
MK	28%	1%	1%	35%	2%	7%	40%	2%	10%	18%	0%	0%
NO	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
RS	26%	1%	1%	32%	2%	7%	38%	2%	11%	13%	0%	0%

6.2.4.3 Hydro

The hydro power plants availability factors in JRC-EU-TIMES are seasonal (F, W, S, and R) and do not vary according to day, night and peak time-slices. Currently these AF are uniform across countries, as in Table 30.

Table 30 - Availability factors per season for hydro technologies considered in JRC-EU-TIMES

Hydro technology	Spring	Summer	Fall	Winter
Lake very small expensive hydroelectricity <1 MW	42.0%	42.0%	42.0%	42.0%
Lake very small cheap hydroelectricity <1 MW	42.0%	42.0%	42.0%	42.0%
Lake medium scale expensive hydroelectricity 1-10 MW	42.0%	42.0%	42.0%	42.0%
Lake medium scale cheap hydroelectricity 1-10 MW	42.0%	42.0%	42.0%	42.0%
Lake large scale expensive hydroelectricity > 10 MW	38.0%	38.0%	38.0%	38.0%
Lake large scale cheap hydroelectricity > 10 MW	38.0%	38.0%	38.0%	38.0%
Run of River hydroelectricity	35.9%	35.9%	35.9%	35.9%

6.2.5 Peaking equation

The JRC-EU-TIMES model includes for each region a constraint that requires the total dispatchable capacity (GW_e) of electricity generating technologies to be higher than the electricity demand in the Winter Peak. Hydropower plants contribute for 50% of their average capacity in spring and summer time slices and all fossil and nuclear plants fully contribute. In this version of the model, we assume that wind and PV technologies do not contribute to the peaking equation. This approach ensures sufficient capacity to be available in the event of a combined high electricity demand and a low available wind and solar electricity. By doing so we deviate on purpose from the average electricity production during a winter peak form wind and PV technologies. In the other 5 time slices, wind and PV technologies contribute according to their average availabilities. No reserve factor is assumed. The shadow price of this constraint can be interpreted as an additional premium to the electricity price for consumption during winter peak to cover the capacity related costs (e.g., investment costs).

6.2.6 Variable generation of electricity

This section describes how we improved the representation of variable energy sources in a model with limited number of time slices. The highest level of detail is the DAYNITE level. As an example, the SD time slice represents an average of all 88 summer days in a certain year. This level is sufficient for representing technologies that are not sensitive to variability. An example is thermal energy storage: by creating ice at night when electricity is usually less costly, and then using the ice to cool the air in buildings during the hotter daytime periods. However, when the number of time slices is low, the model does not fully grasp the physics behind the relations when these show a pattern different from "constant". After all, in the JRC-EU-TIMES model, every variable is constant within a time slice. By using additional constraints, we move away from this "averaging out". The table down summarises the improvements made in JRC-EU-TIMES.

Table 31 – Overview of improvements to deal with variable generation of electricity.

Situation	Solution
In reality, availability can be close to zero so some technologies are not available for generating electricity when demand is high.	Peaking constraint for the peaking demand time slice (see previous section) + constraint (1) where we require the model to rely on capacity coming from all electricity producing systems except wind, variable solar, CHP and hydro pump storage.
In reality, availability during SN of 0.4 can for example represent a mixed pattern of hours with full power and hours with very little power, like in the case of variable energy sources	Equation (2) forces the excess PV electricity production to be charged or stored.
In reality, full power of renewable energy has to be absorbed at any time.	Constraint (3) on capacities so that the sum of all "absorbing capacities" (demand + storage + curtailment) is higher than the peaking supply power.

Constraint (1) is included to mimic conditions with low wind and solar activity. In these situations, we require the model to rely on capacity coming from all electricity producing systems except wind, variable solar, CHP and hydro pump storage.

$$CAP(NUC, GAS, COA, CSP, GEO, HYD, STOR) \geq \ CAP(TotalConsumption) \tag{1}$$

Characteristics*:*

- *Level: Electricity Capacity*
- *This constraint is built for each region and year*
- *CAP(TotalConsumption) is the highest peak demand of the combined end-use sectors.*
- *Excluding pumped storage and CHP*
- *CSP: concentrated solar power*

In reality, the distribution of available electricity from variable sources is far from constant. When high capacities enter the model solution, it could lead to situations with excess electricity production. Constraint (2) forces excess electricity from PV to be charged or stored. The choice for PV is not arbitrary: it is the technology with the highest difference between peak and average power. In addition, the projection for installation costs for PV systems show a strong reduction and being competitive, large capacities are installed.

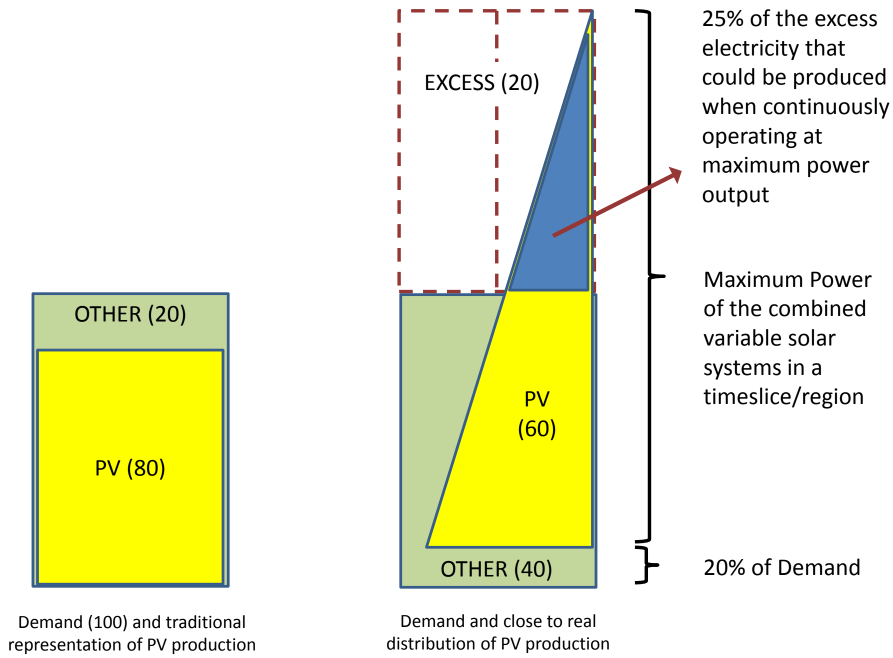


Figure 12 – Representation of variable Solar electricity in the traditional approach (left) and close to real cumulative distribution of PV production in a time slice (right). In this arbitrary example, electricity production from non-PV is doubled from 20% to 40%.

The flow based constraint (2) forces part of the PV production to be charged or stored. The amount is assumed to be 25% of the excess electricity that theoretically could be produced by PV when continuously operating at maximum power output for the region. A minimum of 20% alternative production (non-PV) is assumed to estimate this excess electricity. The calculation of the excess electricity is based on following parameters: the peak production (PeakF, see further), the average production (ACT), the capacity factor (CF) and the average demand.

$$FLO(Storage + Curt.) \geq \frac{\frac{PeakF}{CF} x\ ACT(SOL) - 0.8\ x\ ACT(TotalConsumption)}{4} \qquad (2)$$

Characteristics:

- *Level: electricity Flow (FlowIN for Storage and Curtailment , Activity for Solar and Total Consumption)*
- *This constraint is built for each region,timeslice and year*

- *Storage: these are additional storage systems, so excluding the existing hydropower.*
- *SOL: only variable solar*
- *PeakF: Peak Factor. Maximum power of the combined variable Solar systems in a time slice/region, as a factor compared to total installed peaking capacity. For Germany, this Maximum Solar Power is for example 80% in the Summer Day time slice and 40% in the Winter Day time slice.*
- *CF: Capacity Factor of the variable Solar systems in each time slice*

This method assumes a linear cumulative distribution for the production of electricity. Data from (TenneT) in Germany for 2012 shows that this approximation seems reasonable.

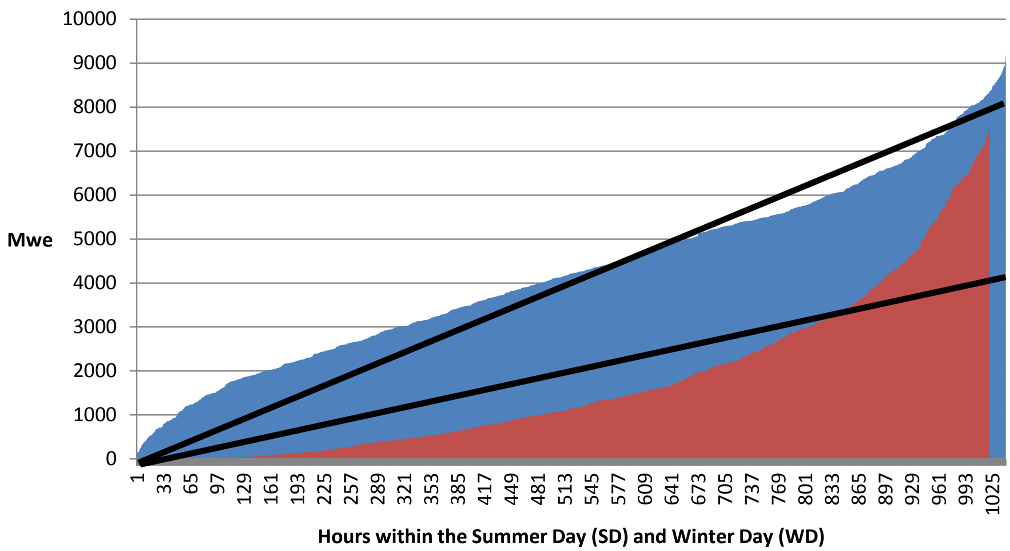


Figure 13 – Cumulative distribution of electricity production from PV for both Summer Day (blue) and Winter Day (red) (data from Tennet, 2012) and approximation (black lines).

The excess of electricity is quadratic to the capacity of PV. The figure down shows the small error we make by linearizing this surface with the blue triangle (25% of the rectangle).

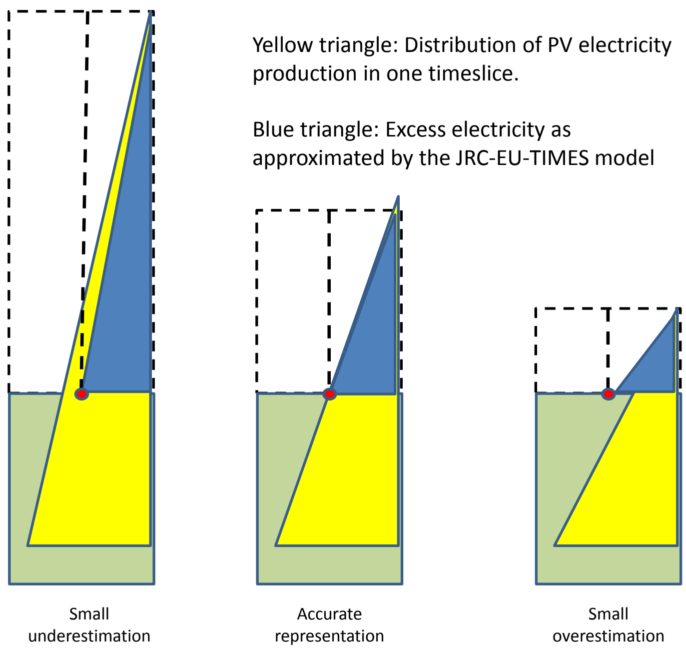


Figure 14 – Linearization method to represent the excess electricity in JRC-EU-TIMES.

The constraint is flow based to model excess energy in the situation with high variable solar power capacity. Since this equation is implemented at time slice level, it reflects the average power. An additional constraint (3) is necessary to model the actual power in each time slice.

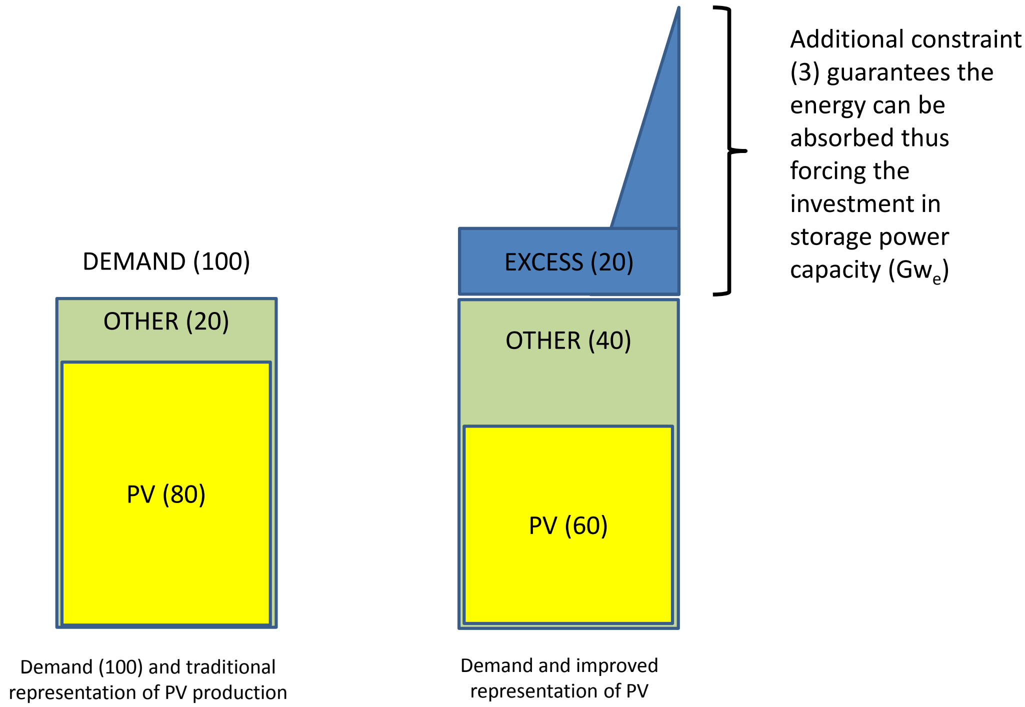


Figure 15 – Representation of variable Solar electricity in the standard (left) and approved approach (right). JRC-EU-TIMES averages out the excess electricity so there is a need for an additional constraint.

$$CAP(Storage) \geq \frac{\frac{PeakF}{CF} x\ ACT(SOL) - 0.8\ x\ ACT(TotalConsumption) - FLO(Curt.)}{CAPACT} \quad (3)$$

Characteristics:

- *Level: a mix of Electricity Capacity and Flow Level*
- *This constraint is built for each region, time slice and year*
- *CAPACT is the ratio between activity and capacity (maximum electricity production in a time slice, assuming full availability)*

6.3 Combined heat and power

In line with Eurostat methodology, in JRC-EU-TIMES CHP and electricity generation processes are considered separately in different groups, depending on the facilities' activity scope and the processes developed (Figure 16).

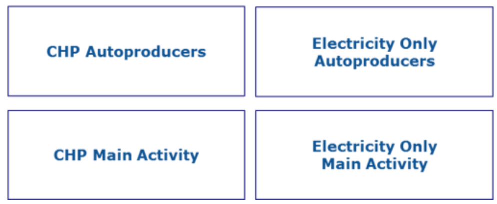


Figure 16 – Electricuty generation technologies in JRC-EU-TIMES including CHP

6.3.1 Centralised CHP technologies

The centralised CHP technologies (CHP main activity) considered in JRC-EU-TIMES are presented in Table 25, page 83. The characterisation of these technologies considers an adaptation of an electricity only power plant (in the same table), with adaptations in costs and efficiencies, as follows:

- For steam and gas turbines the investment and fixed operation and maintenance costs will increase by 10% in order to consider investment on pipes, valves and heat exchangers, following expert information, such as the Danish District Heating Association;
- For internal combustion engines the investment and fixed operation and maintenance costs will increase by 20% in order to consider investment on pipes, valves and heat exchangers, following expert information, such as the Danish District Heating Association.

Table 32 presents an overview of the efficiency assumptions.

Table 32 – Overview of efficiency assumptions comparing electricity only plants and equivalent CHP for 2020

Technology type	Fuel	Net Electricity Efficiency (no possibility for CHP)	HEAT to POWER Ratio	Net Electricity Efficiency (CHP - no heat output)	Net Electricity Efficiency (CHP - Max heat output)	Electricity Loss per Heat Gained (z)
Steam Turbine	biomass	0.346	2.568	0.346	0.280	0.026
Steam Turbine	Biomass & MSW	0.307	2.589	0.337	0.279	0.023
Internal Combustion	biomass	0.484	1.064	0.484	0.484	0.000

Technology type	Fuel	Net Electricity Efficiency (no possibility for CHP)	HEAT to POWER Ratio	Net Electricity Efficiency (CHP - no heat output)	Net Electricity Efficiency (CHP - Max heat output)	Electricity Loss per Heat Gained (z)
ORC	biomass	0.1946	4.140	0.1946	0.1946	0.0000
Steam Turbine	coal	0.377	1.832	0.377	0.283	0.051
Steam Turbine Super Critical	coal	0.421	1.531	0.421	0.316	0.069
Steam Turbine	lignite	0.354	2.011	0.354	0.266	0.044
Steam Turbine Super Critical	lignite	0.402	1.651	0.402	0.302	0.061
Steam Turbine	Gas	0.420	2.206	0.420	0.312	0.049
Gas Turbine CC	Gas	0.541	1.006	0.541	0.498	0.043
Gas Turbine CC advanced	Gas	0.560	0.990	0.560	0.502	0.058
Internal Combustion	Gas	0.486	1.056	0.486	0.486	0.000

6.3.2 CHP autoproducers technologies

Besides centralised CHP, JRC-EU-TIMES also considers CHP Autoproducers, following the Eurostat definition. Since the Eurostat data for these activities is limited it was necessary to develop a methodology to properly consider them in the base-year, which also considers their interactions with the different industrial subsectors and includes Electricity Only Autoproducers. This methodology is described in detail in Annex 16.8.

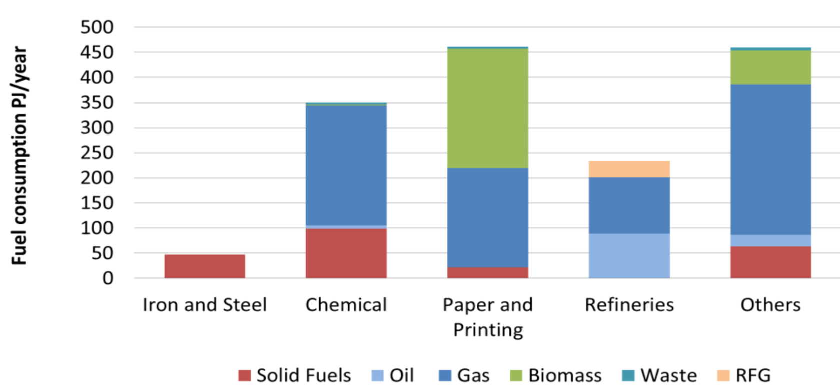


Figure 17 - Fuel Allocation by Sector for CHP Autoproducers

6.4 District heating

The new district heating technologies considered in JRC-EU-TIMES are summarised in Table 25, page 83. It should be mentioned that the model considers the existing district heating networks in several countries in Europe. Regarding the availability factor of 20% this reflects the number of hours in the year where there is a need for heating. The values used for the moment are preliminary as these AF should vary per country depending on the heating degree days.

6.5 Carbon Storage

The cumulative CO_2 storage capacity data in Europe is presented in Table 33 and is from the GEOCAPACITY EU research project[17]. The data assumes the usage of legacy wells. These technical potentials do not consider policy decisions of some Member States on restrictions to their use, such as only storing in offshore sites, or not at all.

The CO_2 transport costs per country and in between countries considered in JRC-EU-TIMES (Table 34) were obtained from the InfraCCS model (Morbee, Serpa, & Tzimas, 2012).

In JRC-EU-TIMES, CO_2 can be captured from power generation plants (Table 25) and from the following industrial processes: advanced aluminium production using as fuels natural gas and electricity, cement kilns (dry process) consuming either coal or gas, blast furnaces (that can consume coal, coke, electricity and/or heavy fuel oil), glass and pulp production, and from iron direct reduction processes based on electricity and natural gas. Biofuel production with CCS is also included. The model has the possibility to gasify biomass (tree salix, etc.) to methane (BWOOGAS110). As emissions from biomass are assumed to be zero, biomass with CCS leads to negative emissions.

[17] http://www.geology.cz/geocapacity

Table 33 - Maximum CO_2 storage potential in Mt in JRC-EU-TIMES

Country	Enhanced Coalbed Methane recovery <1000 m	Enhanced Coalbed Methane recovery >1000 m	Depleted gas fields (offshore)	Depleted gas fields (onshore)	Depleted oil fields (offshore)	Depleted oil fields (onshore)	Deep saline aquifers (offshore)	Deep saline aquifers (onshore)	Enhanced Oil Recovery	Depleted oil & gas fields (onshore)	Depleted oil & gas fields (offshore)	Enhanced Coalbed Methane recovery	Total per country
AT	0	0	0	0	0	0	0	0	0	488	0	0	488
BE	0	0	0	640	0	0	0	199	0	0	0	0	839
BG	0	17	3	0	0	0	0	2100	0	0	0	0	2120
CY	0	0	0	0	0	0	0	0	0	0	0	0	0
CZ	0	110	0	33	0	0	0	766	0	0	0	0	909
DE	22	0	0	1492	15	41	6336	20000	0	0	0	0	27905
DK	0	0	516	0	294	0	14718	1954	0	0	0	0	17482
EE	0	0	0	0	0	0	0	0	0	0	0	0	0
ES	145	0	0	0	34	1	0	23	0	0	0	0	203
FI	0	0	0	0	0	0	0	0	0	0	0	0	0
FR	0	0	0	0	0	11	7922	0	0	1007	0	0	8941
GR	0	0	5	2	63	0	1864	255	0	0	0	0	2189
HR	0	0	0	0	0	0	0	2710	0	189	0	0	2899
HU	0	87	0	0	0	0	0	140	0	389	0	0	616
IE	0	0	0	0	0	0	92277	0	0	0	1505	0	93782

Country	Enhanced Coalbed Methane recovery <1000 m	Enhanced Coalbed Methane recovery >1000 m	Depleted gas fields (offshore)	Depleted gas fields (onshore)	Depleted oil fields (offshore)	Depleted oil fields (onshore)	Deep saline aquifers (offshore)	Deep saline aquifers (onshore)	Enhanced Oil Recovery	Depleted oil & gas fields (onshore)	Depleted oil & gas fields (offshore)	Enhanced Coalbed Methane recovery	Total per country
IT	0	0	0	1600	0	210	2709	1963	0	0	0	71	6553
LT	0	0	0	0	0	6	0	42	5	0	0	0	52
LU	0	0	0	0	0	0	0	0	0	0	0	0	0
LV	0	0	0	0	0	0	0	404	0	0	0	0	404
MT	0	0	0	0	0	0	0	0	0	0	0	0	0
NL	0	0	1160	8864	15	20	170	170	0	0	0	0	10399
PL	0	115	0	0	0	682	0	3523	0	82	0	0	4402
PT	0	0	0	0	0	0	0	7700	0	0	0	0	7700
RO	0	0	0	240	0	235	0	7500	0	16	0	0	7991
SE	0	0	0	0	0	0	2250	0	0	0	0	0	2250
SI	0	0	0	6	0	0	0	92	0	0	0	0	98
SK	0	0	0	0	0	0	0	1716	0	0	0	0	1716
UK	0	0	6391	0	3553	0	14933	0	0	0	0	0	24877
AB	0	0	0	0	0	0	0	20	0	111	0	0	131
BH	0	0	0	0	0	0	0	296	0	0	0	0	296
CH	0	0	0	0	0	0	0	0	0	0	0	0	0

Country	Enhanced Coalbed Methane recovery <1000 m	Enhanced Coalbed Methane recovery >1000 m	Depleted gas fields (offshore)	Depleted gas fields (onshore)	Depleted oil fields (offshore)	Depleted oil fields (onshore)	Deep saline aquifers (offshore)	Deep saline aquifers (onshore)	Enhanced Oil Recovery	Depleted oil & gas fields (onshore)	Depleted oil & gas fields (offshore)	Enhanced Coalbed Methane recovery	Total per country
IS	0	0	0	0	0	0	0	0	0	0	0	0	0
MK	0	0	0	0	0	0	0	1050	0	0	0	0	1050
NO	0	0	0	0	0	0	26031	0	0	0	3157	0	29188
Total	167	329	8074	12876	3975	1206	169210	52623	5	2282	4662	71	255479

Reference: JRC-IET on GEOCAPACITY

Table 34 – CO_2 transport costs across EU28+ considered in JRC-EU-TIMES

Country	Domestic transport investment from InfraCCS (Million euros)	Domestic transport (Mt/y)	Domestic transport cost [15%] (euros/t)	Comparable country (for missing data)	Final domestic transport cost	
					euros/t	euros/kg
AT	0	0	0.0	Poland	0.0	0.000000
BE	0	0	0.0	Netherlands	0.0	0.000000
BG	0	0	0.0	Romania	0.0	0.000000
CY	0	0	0.0	Denmark	0.0	0.000000
CZ	0	0	0.0	Poland	0.0	0.000000
DE	981	111	1.3		1.3	0.001324

Country	Domestic transport investment from InfraCCS (Million euros)	Domestic transport (Mt/y)	Domestic transport cost [15%] (euros/t)	Comparable country (for missing data)	Final domestic transport cost	
					euros/t	euros/kg
DK	586	14	6.4		6.4	0.006434
EE	0	0	0.0	Denmark	0.0	0.000000
ES	1069	80	2.0		2.0	0.002014
FI	0	0	0.0	Denmark	0.0	0.000000
FR	514	17	4.6		4.6	0.004574
GR	0	0	0.0	Netherlands	0.0	0.000000
HU	56	9	1.0		1.0	0.000991
IE	0	0	0.0	UK	0.0	0.000000
IT	594	61	1.4		1.4	0.001450
LT	0	0	0.0	Denmark	0.0	0.000000
LU	0	0	0.0	Germany	0.0	0.000000
LV	0	0	0.0	Denmark	0.0	0.000000
MT	0	0	0.0	Denmark	0.0	0.000000
NL	453	40	1.7		1.7	0.001681
PL	289	17	2.6		2.6	0.002615
PT	0	0	0.0	Spain	0.0	0.000000

Country	Domestic transport investment from InfraCCS (Million euros)	Domestic transport (Mt/y)	Domestic transport cost [15%] (euros/t)	Comparable country (for missing data)	Final domestic transport cost	
					euros/t	euros/kg
RO	280	43	1.0		1.0	0.000972
SE	0	0	0.0	Denmark	0.0	0.000000
SI	0	0	0.0	Poland	0.0	0.000000
SK	0	0	0.0	Poland	0.0	0.000000
UK	1618	173	1.4		1.4	0.001401

Reference: (Morbee, et al., 2012)

6.6 Industry

The industrial sector is analysed in detail following an initial description that distinguishes between energy intensive industries and other industries. The energy intensive industries (see Figure 1) are: iron and steel, non-ferrous metals (aluminium, copper), chemical (ammonia, chlorine), non-metallic minerals (cement, lime, glass) and pulp, paper and printing. For each one of these industrial branches a detailed description of the production processes is being used in the model (Table 36).

Other industries include: other non-ferrous metals, other chemical and petrochemical, other non-metallic minerals, food, beverages and tobacco, textile and leather, transport equipment, machinery, mining and quarrying and other non-energy-intensive industries. These sub-sectors are not modelled in detail on a process basis. However, they are represented using the same generic structure as the energy intensive industries with the energy uses of steam, process heat, machine drive, electrochemical processes and other processes.

For each industry, a series of base-year technologies produce different industrial materials themselves used in the process chain. They are modelled using expert assumptions on input and output values, starting from typical literature values (mainly ECN - The Western European MATTER database), for the default inputs and outputs of energy intensive technologies. The stocks of these technologies are derived from the total production and the technology shares provided for the base-year using Eurostat and national data, mainly reports from several industry associations and also national experts inputs. In order to meet the Eurostat energy balance data, a single process with various fuel inputs is added between the material produced and the demand. This single process covers all possible finishing processes and aggregates their energy consumption.

Autoproducer CHP technologies are defined for each input fuel and for each industrial sector. Currently similar sets of parameters are set for each sector. Table 35 summarizes the parameters for the main technology groups included in the model.

It should be noted that trade of materials is not included in JRC-EU-TIMES.

Table 35 - Autoproducer CHP technologies

Technology	Fuel	Avail-ability Factor	Ratio of Heat/Electricity Produced					Total cost of investment in new capacity					Annual Fixed O&M cost					Tech. Lifetime
			%					eur2010/kW					eur2010/kW					
Process\Year		2005	2005	2010	2015	2025	2035	2005	2010	2015	2025	2035	2005	2010	2015	2025	2035	2005
Comb CYC backpressure	GAS L	0.6	0.98	0.97	0.96	0.96	0.94	619.2	619.2	562.9	562.9	562.9	31.0	28.1	28.1	28.1	28.1	35
Comb CYC backpressure	GAS S	0.6	0.98	0.96	0.94	0.91	0.88	703.7	658.6	658.6	658.6	658.6	36.6	33.8	33.8	33.8	33.8	35
Comb CYC condensing	GAS CCS	0.6	0.00	0.00	1.03	0.98	0.93	0.0	0.0	1421.2	1333.4	1245.7	0.0	0.0	67.6	67.6	67.6	35
Comb CYC condensing	GAS L	0.6	0.98	0.98	0.98	0.93	0.89	965.2	965.2	965.2	877.4	789.7	33.8	33.8	31.0	31.0	31.0	35
Comb CYC condensing	GAS M	0.6	1.10	1.10	1.10	1.05	1.00	1013.4	1013.4	1013.4	921.3	829.2	45.0	45.0	42.2	42.2	42.2	35
Comb CYC condensing	GAS S	0.6	1.35	1.35	1.35	1.29	1.23	1064.1	1064.1	1064.1	967.4	870.6	56.3	56.3	53.5	53.5	53.5	35
Comb CYC condensing	Heavy Fuel Oil	0.6	1.35	1.35	1.35	1.29	1.23	895.1	895.1	895.1	895.1	895.1	56.3	56.3	53.5	53.5	53.5	35
IGCC CO_2Seq.COH	Hard Coal	0.6	0.00	0.00	1.57	1.48	1.41	0.0	0.0	2071.8	1978.7	1978.7	0.0	0.0	52.4	52.4	52.4	30
Steam Turb backpressure	Hard Coal	0.6	1.43	1.42	1.42	1.38	1.34	1351.0	1351.0	1345.4	1345.4	1345.4	63.0	61.4	61.4	61.4	61.4	35
Steam Turb condensing	Hard Coal	0.6	1.51	1.51	1.51	1.44	1.38	1292.5	1292.5	1219.3	1213.2	1213.2	53.5	53.5	52.4	52.4	52.4	35

Technology	Fuel	Avail-ability Factor	Ratio of Heat/Electricity Produced %					Total cost of investment in new capacity eur2010/kW					Annual Fixed O&M cost eur2010/kW					Tech. Lifetime
Process\Year		2005	2005	2010	2015	2025	2035	2005	2010	2015	2025	2035	2005	2010	2015	2025	2035	2005
Steam Turb condensing	Hard Coal	0.6	1.67	1.67	1.67	1.59	1.51	1360.5	1360.5	1283.5	1277.1	1277.1	59.1	59.1	58.0	58.0	58.0	35
Steam Turb condensing	Coal	0.6	1.51	1.51	1.51	1.44	1.38	1550.9	1550.9	1463.2	1455.8	1455.8	53.5	53.5	52.4	52.4	52.4	35
Steam Turb condensing	Sludge	0.6	2.00	2.00	2.00	2.00	2.00	1711.3	1711.3	1711.3	1711.3	1711.3	82.9	82.9	82.9	82.9	82.9	20
Steam Turb condensing	Straw	0.6	3.05	3.05	3.05	3.05	3.05	2927.2	2814.6	2589.5	2476.9	2476.9	120.0	120.0	120.0	120.0	120.0	25
Steam Turb condensing	Wood	0.6	1.74	1.74	1.74	1.74	1.74	1970.2	1970.2	1801.4	1801.4	1801.4	80.8	80.8	80.8	80.8	80.8	25
Wood gasification	Wood	0.6	1.00	1.00	0.97	0.95	0.90	2420.6	2251.7	2139.1	2139.1	2026.5	181.5	168.9	160.4	139.0	101.3	25
Fuel Cell MCFC	Biogas	0.6	0.00	0.83	0.79	0.79	0.76	0.0	5629.2	3659.0	1125.8	1125.8	0.0	309.6	201.2	61.9	61.9	7
Fuel Cell MCFC	Gas	0.6	0.70	0.70	0.71	0.72	0.76	9006.8	5066.3	3377.5	1125.8	1125.8	495.4	278.6	185.8	61.9	61.9	7
Fuel Cell SOFC	Biogas	0.6	0.00	0.86	0.65	0.58	0.58	0.0	6755.1	2814.6	1238.4	900.7	0.0	371.5	154.8	68.1	49.5	7
Fuel Cell SOFC	Gas	0.6	0.86	0.86	0.64	0.57	0.59	12384.3	6755.1	2533.2	1125.8	844.4	681.1	371.5	139.3	61.9	46.4	7
Fuel Cell SOFC	Hydrogen	0.6	0.00	0.86	0.64	0.57	0.59	0.0	6755.1	2533.2	1125.8	844.4	0.0	371.5	139.3	61.9	46.4	7

Technology	Fuel	Avail-ability Factor	Ratio of Heat/Electricity Produced					Total cost of investment in new capacity					Annual Fixed O&M cost					Tech. Lifetime
			%					eur2010/kW					eur2010/kW					
Process\Year		2005	2005	2010	2015	2025	2035	2005	2010	2015	2025	2035	2005	2010	2015	2025	2035	2005
IGCC CO_2Seq	Hard Coal	0.6	0.00	0.00	1.57	1.48	1.41	0.0	0.0	2071.8	1978.7	1978.7	0.0	0.0	52.4	52.4	52.4	30
Int Combust	Black Liquor	0.6	1.07	1.07	1.07	1.07	1.07	844.4	844.4	844.4	844.4	844.4	39.4	39.4	39.4	39.4	39.4	15
Int Combust	Black Liquor	0.6	1.21	1.21	1.21	1.21	1.21	957.0	957.0	957.0	957.0	957.0	73.2	73.2	73.2	73.2	73.2	15
Int Combust	BioGas	0.6	1.28	1.28	1.28	1.28	1.28	2645.7	2645.7	2645.7	2645.7	2645.7	129.5	129.5	129.5	129.5	129.5	15
Int Combust	BioGas	0.6	1.62	1.62	1.62	1.62	1.62	4503.4	4503.4	4503.4	4503.4	4503.4	129.5	129.5	129.5	129.5	129.5	15
Int Combust	Gas	0.6	1.28	1.28	1.28	1.28	1.28	844.4	844.4	844.4	844.4	844.4	39.4	39.4	39.4	39.4	39.4	18
Int Combust	Gas	0.6	1.50	1.50	1.50	1.50	1.50	1182.1	1182.1	1182.1	1182.1	1182.1	50.7	50.7	50.7	50.7	50.7	15
Int Combust	Gas	0.6	1.83	1.83	1.83	1.83	1.83	2814.6	2814.6	2814.6	2814.6	2814.6	73.2	73.2	73.2	73.2	73.2	15
Int Combust	Light Fuel Oil	0.6	1.14	1.14	1.14	1.14	1.14	844.4	844.4	844.4	844.4	844.4	39.4	39.4	39.4	39.4	39.4	18
Int Combust	Light Fuel Oil	0.6	1.50	1.50	1.50	1.50	1.50	957.0	957.0	957.0	957.0	957.0	50.7	50.7	50.7	50.7	50.7	15
Int Combust	Light Fuel Oil	0.6	1.93	1.93	1.93	1.93	1.93	1182.1	1182.1	1182.1	1182.1	1182.1	73.2	73.2	73.2	73.2	73.2	18

Table 36 – Overview of industry sub-sectors structure in JRC-EU-TIMES including materials

Industry subsector	Code used in JRC-EU-TIMES	Main processes considered in the model	Materials (modelled as Mt)
Energy intensive sectors			
Iron and steel	IIS	Iron Blast Furnace (charcoal or equivalent, direct coal injection), COREX, with and without CCS, Cyclone Convertor Furnace CCF, Argon Oxygen Furnace AOD. Regular, Blast Oxygen Furnace BOF, with and without CCS; Blast Oxygen Furnace with top gas recirculation, with and without CCS. Regular, Blast Oxygen Furnace BOF Scrap, EAF for DRI, with and without CCS, EAF for DRI with hydrogen, Electric Arc Furnace, Cast Iron Cupola and Blast furnace with CO_2 capture	Steel plus the following intermediate materials: Ore, Pellet, Sinter, Raw Iron, DRI Iron, Scrap Iron, Oxygen, Quick Lime, Ferrochrome, Crude Steel
Aluminium	IAL	Hall Heroult. Hall Heroult Point Feeders, Inert Anodes and Recycled Production New possible processes that could be included in the model: Heroult Low Temperature Prebake with 5% energy efficiency gains from 2010, and 50% from 2030, via Prebake Reduced Temperature Electrode Technology (PBRTE)(Luo & Soria, 2007); (Overgaag, Harmsen, & Schmitz, 2009) Heroult Inert Anodes with 15% energy efficiency gains from 2020 and up to 34% from 2030 via Prebake Anode technology (PBANOD)(Luo & Soria, 2007); (Overgaag, et al., 2009)	Aluminium plus the following intermediate materials: Bauxite, Scrap, Crude Aluminium
Copper	ICU	Standard process and process with recycling	Copper plus the following intermediate materials: Ore, Scrap, Melted Copper
Ammonia	IAM	Steam reforming process with the following possibilities: standard, advanced with 12% energy efficiency gains from 2010 and advanced with CO_2 capture with 11% energy efficiency gains from 2030(Overgaag, et al., 2009).	Ammonia
Chlorine	ICL	Standard Mercury, Standard Diaphragm, Standard Membrane, and Advanced Membrane	Chlorine
Cement	ICM	Dry clinker kiln, wet clinker kiln, advanced dry kiln regular and advanced kiln with CO_2 capture.	Besides cement, the following intermediate materials: Clinker and Blast Furnace Slag
Lime	ILM	Quick lime production standard, advanced lime production	Lime

Industry subsector	Code used in JRC-EU-TIMES	Main processes considered in the model	Materials (modelled as Mt)
Glass (hollow and flat)	IGH and IGF	Hollow glass and flat glasses kilns with increasing share of natural gas and improved furnaces possibility from 2020 with 19% energy efficiency gains for hollow glass and 27% for flat glass (Overgaag, et al., 2009). Both technologies can be coupled with CCS from 2020. Glass recycling with improved melting, with and without CCS.	Hollow and flat glass and as an intermediate material cullet (from recycling)
Pulp, paper and printing	IPP (pulp), IPH (graphic paper) and IPL (other paper)	Chemical Pulp, Mechanical Pulp (with and without CCS), Recycling Pulp and two paper production technologies: High Quality Paper and Low quality Paper (including advanced drives with CCS)	Besides graphic and other paper, the following intermediate materials: Pulp, Wood, Recycled, Oxygen, Kaolin and Gypsum
Other industries			
Other chemical industry	ICH	Generic steam boilers, furnaces and kilns for process heat, machine drive, electrochemical processes and other processes	None
Other non-Ferrous metals	INF		None
Other Non-metallic minerals	INM		None
Other industry	IOI		None

6.6.1 Specific assumptions regarding pace of deployment of energy technologies in industry

In order to replicate the inertia in major changes in production processes in the energy intensive industry the following assumptions are considered in the industry sector:

- Raw iron and crude steel - the relative importance of the different raw iron production alternative routes as in 2005 per country for each country total steel production (e.g. COREX, Blast furnace and cyclone furnaces or BOX, DRI, etc.) will be maintained until 2010 and can be gradually reduced until 2025 (in that year each process can reduce its relative importance for total national steel production to 40% of the 2005 values) and 2050 (each process can reduce its relative importance for total national steel production to 20% of 2005 values). This means for example for Belgium, which in 2005 produced 99% of its raw iron via blast furnace, it will in 2025 still produce at least 40% via blast furnace and in 2050 at least 20%. This allows for adopting more efficient processes within each technology (e.g. more efficient blast furnace) but not to completely change the production process;

- Aluminium and copper – the assumptions are similar to the ones adopted for the steel production but assuming that in 2025 each process (Heroult, anode and recycling routes for aluminium and recycling for copper) can reduce its relative importance for production by 8% from 2005 values. In 2050 is assumed that each process can reduce its relative importance by 15% from 2005 values. Thus it is assumed that this subsector has more inertia than the steel sub-sector;
- Cement – assumed the same values as for steel for dry clinker kilns;
- Pulp production - the assumptions are similar to the ones adopted for the steel production but in 2025 each process (mechanical and chemical pulp) can reduce its relative importance for production to 85% from 2005 values. In 2050 is assumed that each process can reduce its relative importance to 60% from 2005 values;
- For industrial heat it is assumed a maximum share of heat production from biomass and district heat similar to what happened in 2005, up to 2030. Similarly, a minimum lower share is assumed for heavy fuel oil, electricity and natural gas.

6.7 Hydrogen energy system

The hydrogen energy system in JRC-EU-TIMES includes hydrogen production, hydrogen delivery (encompassing hydrogen conditioning) and end-use technologies for transportation and stationary applications (Figure 18). The data for techno-economic descriptions of each stage of the chain was obtained from several references as follows: (Krewitt & Schmid, 2005), (Yang & Ogden, 2007), (National Renewable Energy Laboratory, 2006), (Gül, Kypreos, Turton, & Barreto, 2009), (Committee on Alternatives and Strategies for Future Hydrogen Production and Use, National Research Council, & National Academy of Engineering, 2004) and working papers of UKSHEC on MARKAL Modelling of Hydrogen Energy Systems for UK (Hawkins & Joffe, 2005), (Joffe & Strachan, 2007) (Joffe, Strachan, & Balta-Ozkan, 2007) (Balta-Ozkan, Kannan, & Strachan, 2007).

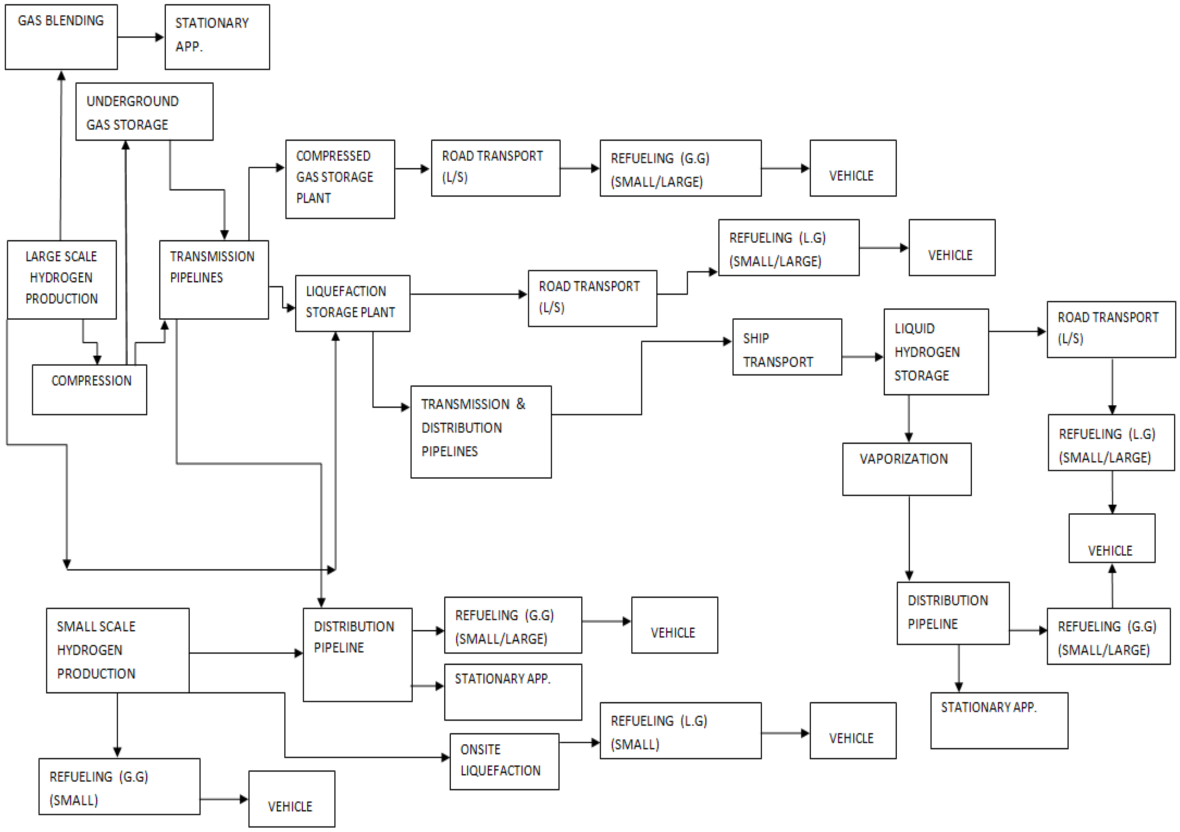


Figure 18 - Overview of the hydrogen supply chain considered in JRC-EU-TIMES

Hydrogen production technologies are modelled as large-scale (centralized) production and small-scale (decentralized) production. Small-scale hydrogen production includes electrolysis, steam methane reforming (SMR) and ethanol based SMR. Large-scale hydrogen production is possible with the following technologies:

- Steam Methane Reforming with/without Carbon Capturing and Sequestration (CCS);
- Coal Gasification with/without CCS;
- Biomass Gasification and Pyrolysis with/without CCS;
- Partial Oxidation;
- Kvaerner Process.

Reforming, gasification and pyrolysis can also have associated carbon capture sequestration (CCS) ((Hawkins & Joffe, 2005); NREL, 2011).

In the JRC-EU-TIMES model, hydrogen delivery begins with hydrogen conditioning and is completed with delivering hydrogen to end users. Hydrogen delivery is modelled in a simplified form by creating aggregated processes coupling several hydrogen delivery sub processes. Consequently, an aggregated delivery process is formed by summing all processes of a probable pathway of hydrogen from conditioning to immediately before end-use application. Accordingly, sub processes include underground gas storage, liquefaction, compression, storage in tubes, pipeline distribution, and road and sea transportation and refuelling depending on the selected pathway of hydrogen delivery. The probable combinations of processes that are designed to obtain hydrogen delivery pathways are based on the following options:

- Delivery of hydrogen by road (short/long) in liquefied/compressed gas form ended with a refuelling process liquid to liquid, liquid to gas and gas to gas in small/large scales;
- Delivery of hydrogen by ship of liquefied hydrogen, which can also be delivered to end use with pipelines and road transport;
- Delivery of gaseous hydrogen by pipeline system;
- Blending hydrogen with natural gas within the current natural gas infrastructure.

In JRC-EU-TIMES assumptions were made regarding cost and transport distance, spatial distribution of demand density and size of refuelling sites. For refuelling stations, capacities of 300kg/day and 1200 kg/day have been considered as small capacity and large capacity stations respectively.

Regarding end use applications of hydrogen, JRC-EU-TIMES considers hydrogen use in the transport, residential, commercial and industrial sectors, as follows:

- End-use technologies of hydrogen for transportation include fuel cell vehicles and internal combustion engines. Hydrogen gas as a transport commodity can be consumed in fuel cell intercity buses, fuel cell cars and fuel cell heavy trucks. Liquefied hydrogen gas is used as a fuel commodity for internal combustion engine cars.
- In residential, commercial and industrial stationary applications, hydrogen gas and hydrogen-natural gas blending are also possible.

For the blending with natural gas JRC-EU-TIMES considers a relatively low concentration of hydrogen, i.e. a maximum of 15% by volume. The exact quantities of hydrogen blended with natural gas are endogenous to the model, depending on its cost-effectiveness. It is assumed that with this relatively low concentration it is not necessary to invest in extensive modifications of pipelines and end-use devices, following existing literature (NaturalHY Consortium Project, 2010). As hydrogen can be blended in the natural gas pipelines it can also be traded across regions via this route. More details are available on the section trade in JRC-EU-TIMES (Section 8.2).

6.8 Transport

6.8.1 Passenger cars technologies

The JRC-EU-TIMES model differentiates the following passenger car propulsion technologies in the base year: diesel, gasoline, LPG internal combustion engine, and electric.

For estimates on investment costs for the modelled years we assumed investment cost data for the vehicle glider (i.e. the vehicle without powertrain components, e.g. engine, transmission, tank, battery etc.) for 2010-2050, derived from (Thiel, Perujo, & Mercier, 2010) for all vehicles except hydrogen (both ICE and fuel cells), which were not considered in that study[18]. For the estimation of total 2010-2050 investment cost per vehicle/powertrain combination of the values of additional costs over the vehicle glider estimated by (Pasaoglu, et al., 2012) were added to the vehicle glider cost. (Pasaoglu, et al., 2012) estimated a cost evolution based on three scenarios for deployment with a learning rate of 0.90 for battery electric, plug-in hybrid electric vehicles and hybrid components, and a learning rate of 0.95 for new internal combustion engine related components both up to 2050. In JRC-EU-TIMES we have considered the cost evolution of Pasaoglu's medium scenario.

The following adaptations of the cost data in the literature were necessary:

i) since (Pasaoglu, et al., 2012) did not disaggregate cost evolution for diesel hybrids (both conventional and plug-in) we assumed the same cost differential as for 2010 total costs of gasoline and diesel hybrids as in (Thiel, et al., 2010);

ii) since (Pasaoglu, et al., 2012) and (Thiel, et al., 2010) did not consider H_2 ICE vehicles, we assumed here the cost of the gasoline ICE plus the difference for an H_2 ICE as in (Edwards, et al., 2011). This difference was kept constant over time;

iii) since the cost data for BEV in (Edwards, et al., 2011) and (Thiel, et al., 2010) was for a BEV with a 24 kWh battery and in the TIMES model batteries of 15, 30 and 60 kWh are considered, the cost for the BEVs was scaled up and down accordingly, using an average cost of the battery of 600 euros/kWh in 2010 and of 230 euros/kWh by 2050. Up to 2030 we assume that consumers, which buy an electric car, set money aside to buy a new battery pack after 7 years, while selling the old mobile battery for stationary applications at a transaction price of 150 euros/kWh. After 2030 this rule does not apply as we assume that mobile batteries will then have a cycle and calendar life that is equivalent to the car life.

These costs were validated with the IEA Energy Technology System Analysis Programme (ETSAP-IEA, 2010), with the exception of H_2 vehicles for which there is no such information from (OECD/IEA, 2012).

For the fixed O&M costs we assumed 3% of the investment costs for all vehicles except for the BEV for which we assumed 1% of investment costs, based on (Pasaoglu, Honselaar, & Thiel, 2011).

[18] The vehicle glider cost from (Thiel, et al., 2010) in turn originate from the study of JRC, EUCAR and CONCAWE 2008 and update of 2011 (Edwards, Larivé, & Beziat, 2011).

Because in the TIMES model these costs apply to new vehicles entering the market they do not include the assumption used in other models that O&M costs increase as vehicles get older (as considered for example in (Kampman, Braat, Essen, & Gopalakrishnan, 2011). Table 37 shows the resulting investment costs per time step, as they are employed in the JRC-EU-TIMES model.

Table 37 – Investment assumptions for passenger car technologies

Year/ Fuel €'2010	Gasoline ICE[19]	Diesel ICE	Hybrid Conventional		Plug In Hybrid		Gaseous H2		Liq H2	EV 15kwh	EV 30kwh	EV 60kwh
			Gasoline	Diesel	Gasoline	Diesel	ICE	Fuel Cell	ICE			
2010	19735	21435	22670	24670	30745	32155	24527	35098	24527	32320	43985	67315
2015	19735	21435	22670	24670	30745	32155	24527	35098	24527	30854	41054	61452
2020	19452	21155	21329	23182	28067	29479	24176	33205	24176	27302	35389	51561
2025	19430	21132	20886	22738	26410	27831	24148	30501	24148	25440	31188	42577
2030	19415	21118	20626	22478	25536	26962	24130	29122	24130	24655	29695	39633
2035	19403	21108	20446	22300	24845	26277	24115	28056	24115	24028	28537	37385
2040	19393	21100	20316	22171	24273	25709	24103	27159	24103	23261	27753	36581
2045	19385	21093	20212	22069	23803	25244	24092	26395	24092	22637	27114	35927
2050	19378	21088	20136	21995	23420	24864	24083	25727	24083	22128	26594	35394

For energy consumption in 2010 for all vehicles except BEV and PHEV we used the data for 2010+ vehicles from (Edwards, et al., 2011). For PHEV and BEV we used the data from (Thiel, et al., 2010), since these vehicles were not included in the study (Edwards, et al., 2011). As the energy consumption values of all these studies reflect only type approval values per the New European Drive Cycle (NEDC), we adjusted these values using a factor of 1.2 to reflect the difference between energy consumption in the drive cycle versus real life (Fontaras & Dilara, 2012). For the evolution of the vehicle efficiency from 2010-2020 we have used the same assumption as in (Pasaoglu, et al., 2011), i.e. no annual improvement for BEV, H2 and PHEV, an annual improvement of 1.3% for gasoline and diesel ICE and an annual improvement of 1.1% for hybrids. For the period of 2020-2050 we assumed an annual improvement of 0.5% for all variants (as in (Pasaoglu, et al., 2011)). These assumptions of efficiency evolution for the period 2010-2020 are substantially more modest than the ones adopted on the iTREN study (Schade, Purwanto, Merkourakis, Dallinger,

[19] CNG passenger car investment assumption is 23700 Euro for the whole modelling horizon, while for LPG variants it is 21000 Euro from 2010 to 2030 and 20700 Euro after 2030.

& Luo, 2008) but on the other hand are slightly more ambitious for the 2020-2050 period. Nonetheless, they seem to be in line with estimates made by (McKinsey & Company, 2010) for gasoline and diesel ICE vehicles which should improve 30% from 2010-2050 and with (European Commission, 2008) for 2005-2020. For the less mature technologies as BEV, PHEV, hybrid and H_2 we assume they will have a larger scope for improvement and we perform a sensitivity analysis for a different efficiencies evolution.

The data from literature was assumed to correspond to average consumption during long distance travel. The average consumption for short distance travel was assumed as being 21% higher than long distance for gasoline ICE and hybrids, H_2 ICE and H_2 FC; 14% higher for diesel ICE and hybrids; 12-23% lower in PHEV and 15-20% lower in BEV.

Table 38 shows the resulting specific energy consumption per time step, as they are employed in the JRC-EU-TIMES model.

Table 38 – Energy consumption for passenger cars considered in JRC-EU-TIMES

Energy consumption (MJ/100 km) - GENERAL, assumed long distance (see short distance below)											
unit	MJ/100 km										
Long distance	Gasoline ICE[20]	Diesel ICE	Hybrid Conv.		Plug In Hybrid		Gas. H_2		Liq H_2	EV 15kwh	EV 30kwh	EV 60kwh
			Gasol.	Diesel	Gasol.	Diesel	ICE	Fuel Cell	ICE			
2010	207	187	167	150	110	117	162	102	154	64	77	110
2015	193	174	157	141	110	117	162	102	154	64	77	110
2020	181	163	149	134	110	117	162	102	154	64	77	110
2025	176	159	141	127	104	111	154	97	146	62	75	107
2030	172	155	134	121	99	106	146	92	139	61	73	104
2035	168	151	128	114	94	101	139	88	132	59	72	102
2040	163	147	121	109	90	96	132	83	125	58	70	99
2045	159	144	115	103	85	91	125	79	119	56	68	97
2050	155	140	109	98	81	86	119	75	113	55	66	94

[20] CNG and LPG variants are assumed to have the same energy consumption as gasoline ICE variants.

Energy consumption (MJ/100 km) - Short distance												
unit	MJ/100 km											
Short distance	Gasol. ICE	Diesel ICE	Hybrid Conventional		Plug In Hybrid		Gaseous H_2		Liq H2	EV 15kwh	EV 30kwh	EV 60kwh
			Gasol.	Diesel	Gasol.	Diesel	ICE	Fuel Cell	ICE			
2010	251	213	202	170	97	91	196	124	187	51	62	82
2015	235	199	191	161	99	92	196	124	187	51	62	82
2020	220	186	181	152	101	94	196	124	187	51	62	82
2025	214	181	172	145	98	91	187	118	178	50	60	80
2030	209	177	163	137	95	88	177	112	169	48	59	78
2035	204	172	155	130	92	85	168	107	160	47	57	76
2040	199	168	147	124	89	82	160	101	152	46	56	74
2045	194	164	140	118	86	79	152	96	145	45	54	72
2050	189	160	133	112	84	76	144	91	137	44	53	71

6.8.2 Buses and other passenger road transport options

In the base-year motorbikes are fuelled with gasoline, whereas buses can be fuelled with either gasoline or diesel. Beyond that the JRC-EU-TIMES model considers additionally the following technologies for buses: CNG and hydrogen fuel cells. Buses can also be fuelled with blended gasoline /diesel with biofuels. For motorbikes, electric traction is the only additional future option in the JRC-EU-TIMES model.

6.8.3 Road freight

Light duty trucks are gasoline or diesel driven and heavy duty trucks are diesel only in the base year. For light duty trucks, the future powertrain options are the same as for passenger cars and the modelling assumptions are equivalent to the ones described for passenger cars.

For heavy duty trucks the JRC-EU-TIMES model considers in the modelled years additionally the following technologies: gasoline and diesel hybrid, ethanol, CNG and hydrogen fuel cell.

The model assumes the specific energy consumption values and investment costs as given in Table 39. The investment costs remain the same over the whole modelling horizon for all variants, except for the hydrogen fuel cell trucks that decrease their costs slightly to 197 kEuro in 2050. Annual fixed operation and maintenance costs are assumed to be 2% of the investment costs.

Table 39 - Specific energy consumption values and investment costs

MJ/VKm	Specific Energy consumption [MJ/Vkm]			Investment [kEuro]
	2010	2030	2050	2015
(Bio)diesel	10.8	10.3	9.8	141
(Bio)diesel hybrid	9.7	9.2	8.8	169
Gasoline, ethanol	11.9	11.3	10.7	141
Gasoline, hybrid	9.5	8.5	7.7	169
Gas	13.0	12.4	11.8	169
Hydrogen fuel cell	6.5	6.1	5.8	219

In JRC-EU-TIMES, the gasoline and diesel fuelled powertrain variants for all road transport modes can flexibly be fuelled with variable biofuel blends, endogenously determined in the model. This is described in more detail in Section 5.2.

6.8.4 Trains

Modelling rail based transport in JRC-EU-TIMES requires the following data for the base-year:

1. Demand values for Passenger/Tonne Kilometers (million).
2. The Stock of Vehicles (thousand).
3. The Kilometers per Vehicle per annum.
4. The Passenger/Tonne per Vehicle to compute the load, which is equal to: Demand /Total vehicle-kilometers.

The main source for this was the TREMOVE model (TREMOVE).

Three rail transport modes are considered in JRC-EU-TIMES: passenger trains, freight trains and light trains (metros). For each of these three modes, a different number of technologies are in competition to meet the demand: four types of passenger and freight trains (electric railcars, diesel railcars, electric locomotives and Diesel locomotives) and one type of light trains (electric). The efficiency and cost values for trains remain the same over the whole modelling horizon.

6.8.5 Aviation and navigation

The aviation and navigation are split into domestic and international, without further analysis of alternative technologies.

6.9 Energy storage

The JRC-EU-TIMES model considers storage solutions that can store energy produced in one time slice and available in another time slice in form of either electricity or heat, in particular: compressed air energy storage (CAES), pumped hydro, hydrogen conversion and batteries. For thermal storage the model includes water tanks (LWT) and underground storage (UTES). Energy storage processes have been implemented in the following sectors (Table 40):

- **Bulk Storage**: storage technologies that make electricity available to the high voltage grid (ELCHIG) produced from centralized power plants. Hydrogen Storage from intermittent electricity was also included.
- **Residential, Commercial and Transport Batteries**: batteries store low voltage electricity (ELCLOW) at demand level. Solar PVs with storage were also created.
- **Thermal Storage**: Heat from district heating *(HETHTH)* can be stored at SEASONAL level.
- **Cooling Storage**: Cooling from district cooling *(COOFRE)* can be stored at SEASONAL level.

Table 40 – List of storage technologies included in JRC-EU-TIMES

Category	Technology	Description	Type of Storage	Operation Level
Bulk Storage	D-CAES	Diabatic Compressed Air Energy Storage	TSS-STG/STS	2015-2035: DN from 2035: DN+S
	A-CAES	Adiabatic Compressed Air Energy Storage	TSS-STG	DN
	H2 Storage	Hydrogen storage (only Tank)	TSS-STG	S
	H2I Storage	Hydrogen storage (only Tank) - Intermittent ELC	TSS-STG	S
	PHS	Pump and Hydro Storage	TSS-STG/STS	2015-2035: DN from 2035: DN+S
	Lead-acid	Lead-acid batteries	TSS-STG/STS	2015-2035: DN from 2035: DN+S
	Li-ion	Lithium-ion batteries	TSS-STG/STS	2015-2035: DN from 2035: DN+S

Category	Technology	Description	Type of Storage	Operation Level
	NaS	Sodium-sulphur batteries	TSS-STG	DN
RSD Batteries	Lead-acid	Lead-acid batteries	TSS-STG	DN
	Li-ion	Lithium-ion batteries	TSS-STG	DN
	NaNiCl ZEBRA	ZEBRA batteries	TSS-STG	DN
COM Batteries	Lead-acid	Lead-acid batteries	TSS-STG	DN
	Li-ion	Lithium-ion batteries	TSS-STG	DN
	NaNiCl ZEBRA	ZEBRA batteries	TSS-STG	DN
TRA Batteries	TRABAT	Transport Batteries (already embedded within the Electric/Hybrid vehicles)	TSS-STG	DN
Thermal Storage	LWT	Large Water Tanks	TSS-STG	S
	UTES	Underground Thermal Energy Storage	TSS-STG	S
Cooling Storage	LWT	Large Water Tanks	TSS-STG	S
	UTES	Underground Thermal Energy Storage	TSS-STG	S

Reference: JRC-IET internal report. Note: S – seasonal; DN - DAYNITE

Depending on the storage typology, distinct operational levels were defined, varying between DAYNITE (DN), SEASON (S) and a mix of both (DN+S). More specific modelling details used for storage processes in JRC-EU-TIMES can be found in Annex 16.3.

Table 41 – Technological parameters of energy storage technologies included in JRC-EU-TIMES

Technology	Start year	Efficiency	Life	Discharge time (hr)	Power Cost 2015	Power Cost 2050	Energy Cost 2015	Energy Cost 2020	Energy Cost 2050	Power FIXOM	Energy FIXOM	Power VAROM	Energy VAROM	Input (elc)	Ref.
					(€/kW)	(€/kW)	(€/GJ)	(€/GJ)	(€/GJ)	(€/kW)	(€/GJ)	(€/GJ)	(€/GJ)		
Diabatic-CAES	2015	152%	30	4	461	461	3843	-	3843	8.1	12.8			0.66	(f)(h)
Adiabatic-CAES	2015	70%	30	4	489	489	12631	-	12631	7.4	12.8			1.43	(f)(h)
H2 Storage	2015	100%	20	4	-	-	4344	2858	579		108.6				(o)(v)(t)
H2I Storage	2015	100%	20	4	-	-	4344	2858	579		108.6				(o)(v)(t)
PHS	2015	75%	80	8	1146	1146	27281		27281	3.4					(j)(m)
Lead-acid batteries	2015	80%	8	4	0	0	93705		28112	20.2					(g)(m)
Li-ion batteries	2015	90%	10	1	0	0	281116		93705	16.9					(m)(h)(g)
NaS batteries	2015	85%	15	4	0	0	46853		23426	10.1					(m)(g)(l)
Lead-acid	2015	80%	8	4	0	0	93705		28112	20.2					(g)(m)
Li-ion	2015	90%	10	1	0	0	281116		93705	16.9					(g)(h)(m)
NaNiCl ZEBRA	2015	90%	10	4	0	0	43584		18994	10.1					(m)(l)(g)

Technology	Start year	Efficiency	Life	Discharge time (hr)	Power Cost 2015	Power Cost 2050	Energy Cost 2015	Energy Cost 2020	Energy Cost 2050	Power FIXOM	Energy FIXOM	Power VAROM	Energy VAROM	Input (elc)	Ref.
					(€/kW)	(€/kW)	(€/GJ)	(€/GJ)	(€/GJ)	(€/kW)	(€/GJ)	(€/GJ)	(€/GJ)		
Lead-acid	2015	80%	8	4	0	0	93705		28112	20.2					(g)(m)
Li-ion	2015	90%	10	1	0	0	281116		93705	16.9					(g)(r)
NaNiCl ZEBRA	2015	90%	10	4	0	0	43584		18994	10.1					(m)(l)(g)
Passenger car batteries	2006	90%	10	-	-	-	-	-	-	-	-	-	-	-	
LWT	2015	70%	30				769		128	15.4					(x)
UTES	2015	70%	20				2562			51.2					(x)
LWT	2015	70%	30				769		128	15.4					(x)
UTES	2015	70%	20				2562			51.2					(x)

Reference: JRC-IET internal report.

References codes: (f) Fraunhofer. Possible developments of Market Conditions determining the Economics of Large Scale CAES. 2009; (g) EC, JRC-IET, 2011 Technology Map of the European Strategic Energy Technology Plan (SET-Plan) - Technology Descriptions, JRC Scientific and Technical Reports.; (h) IEA-ETSAP and IRENA - Technology Policy Brief E18, Electricity Storage, 2012; (j) EPRI, Compressed Air Energy Storage (CAES): Executive Summary, Robert B. Schainker, August 2010; (l) IEA, Prospects for Large-Scale Energy Storage in Decarbonised Power Grids, International Energy Agency, Paris, 2009; (m) IRENA, Electricity Storage and Renewables for Island Power, 2012; (o) UCC, Study of Electricity Storage Technologies and their Potential to address wind energy intermittency in Ireland. 2004; (r) Haisheng Chen, Thang Ngoc Cong, Wei Yang, Chunqing Tan, Yongliang Li, Yulong Ding, Progress in electrical energy storage system: A critical review, Progress in Natural Science, Volume 19, Issue 3, 10 March 2009, Pages 291-312, ISSN 1002-0071, 10.1016/j.pnsc.2008.07.014; (t) Øystein Ulleberg, Torgeir Nakken, Arnaud Eté, The wind/hydrogen demonstration system at Utsira in Norway: Evaluation of system performance using operational data and updated hydrogen energy system modelling tools, International Journal of Hydrogen Energy, Volume 35, Issue 5, March 2010, Pages 1841-1852, ISSN 0360-3199, 10.1016/j.ijhydene.2009.10.077; (v) IFE, HSAPS Market Analysis Project; (x) IEA-ETSAP and IRENA - Technology Policy Brief E17, Thermal Energy Storage, 2012

JRC-EU-TIMES also considers both the existing and under costruction capacity stocks for the relevant storage technologies (namely PHS and CAES). PHS capacities are based on 2012 Eurostat. For CAES, only one plant is currently in operation within EU (Huntorf Power Plant, Germany), while the first adiabatic CAES is currently under extended engineering phase (Adele Project, Germany) and expected in operation for the year 2016. Both of these plants have been included within the JRC-EU-TIMES model.

To minimize the running time of JRC-EU-TIMES not all storage technologies are modelled with the same units, which are summarised in Table 42.

Future improvements to the way energy storage is modelled include the soft linking of the JRC-EU-TIMES model with transmission grid and dispatching models with higher spatial and temporal resolution.

For large scale electricity storage technologies JRC-EU-TIMES considers different energy and power costs, where applicable. The energy storage technologies characteristics are presented in Table 41.

Table 42 – Units used for cost and activity the energy storage technologies in JRC-EU-TIMES

Technology	Installed capacity		Activity	Investment costs		Fixed O&M costs		Variable O&M costs	
	Energy	Power		Energy	Power	Energy	Power	Energy	Power
CAES	GWh	GW	PJ	€/kWh	€/kW	€/kWh	€/kW	€/GJ	€/GJ
Pumped Hydro	GWh	GW	PJ	€/kWh	€/kW	€/kWh	€/kW	€/GJ	€/GJ
H_2	PJ	-	PJ	€/GJ	-	€/GJ	-	€/GJ	-
Large batteries	GWh	GW	PJ	€/kWh	-	€/GJ	€/kW	€/GJ	€/GJ
Small batteries	GWh	GW	PJ	€/kWh	-	€/GJ	€/kW	€/GJ	€/GJ
PV roof with storage	GWh	-	PJ	€/kWh	-	€/GJ	-	€/GJ	-
Thermal storage	PJ	-	PJ	M€/PJ	-	€/GJ		€/GJ	-

Reference: JRC-IET internal report.

6.10 Residential and commercial buildings

6.10.1 Assumptions for allocating energy consumption into residential buildings

JRC-EU-TIMES requires as a model input a very detailed characterisation of the energy services demand per type of residential building, in order to allocate the final energy consumption from Eurostat to the several modelled energy services. To do so it is necessary to assume fractional share numbers to split fuel consumption by end-use and by building type. Since the main data source (Eurostat) gives information at the sector level only (e.g. residential, commercial and agriculture), other sources or share assumptions were used. For the breakdown by end-use (fractional shares), in which the fuel consumption is split between end-use (space heating, space cooling, lighting, etc.) and for the breakdown by building type (fractional shares), in which the fuel consumption is split in three end-uses (space heating, space cooling and water heating) by three building types (rural houses, urban houses, apartments) the following sources were used:

- Heating and cooling demand and market perspective, (Pardo, et al., 2012) JRC Report;
- Odyssee European Energy Efficient Database. Intelligent Energy Europe, Enerdata and Association of European Energy Efficiency Agency. (ENERDATA);
- Energy Efficient Improvements in the European Household and Service sector - Data Inventory to the Gains model –Appendix C. IVL, Swedish Environmental Research Institute. (Astrom, Lindblad, Sarnholm, & Soderblom, 2010).

The final brake out of by end use and by building type for each member country in the Base Year can be consulted in the Annex 16.10.

6.10.2 Techno-economic assumptions for building technologies

The details of the heating and cooling energy technologies in JRC-EU-TIMES for buildings are based on the report by (Pardo, et al., 2012). The following assumptions were used to derive the heating and cooling technologies costs:

- The fixed operation and maintenance costs of the oil based technologies have been assumed to be 5% of the investment costs, similarly to the gas based technologies and wood-pellet boiler;
- A scaling factor of 0.7573 was used to adapt technology costs for residential buildings into the equivalent technologies in commercial buildings scale. This is based on the work done for the report by (Pardo, et al., 2012);
- FC generating hot water was assumed to have the same costs in residential and commercial buildings;
- No insulation technologies are modelled at the moment in JRC-EU-TIMES, as their effect is implicitly considered when generating the heating and cooling energy services demand (Section 4).

The techno-economic assumptions considered in JRC-EU-TIMES are summarised in Table 43 and in Table 44.

Table 43 – Techno economic parameters for new technologies for residential buildings considered in JRC-EU-TIMES

Residential		Fixom	Investment Cost	Efficiency	Efficiency Hot Water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010	2010		2020	2020				
Space Heating													
BIO101	Wood Fireplace		185.77	0.55						15	2006		
BIO201	Biomass stove		103.58	0.61						15	2006		
BDL101	Biodiesel Boiler. *Heat & Hot Water*	9.63	192.52	0.91	0.418					20	2006		
ELC101	Electric radiators	2.56	233.00	1						15	2006		1
ELCHP201	Air heat pump with electric boiler	64.00	1280.00	1			0.70			15	2006	3.3	share AHT
ELCHP202	Air heat pump with electric boiler. *Heat & Cool*	70.40	1408.00	1		1.000	0.70			15	2006	3.3	share AHT
ELCHP301	Adv Air heat pump with electric boiler	76.45	1529.00	1			0.79			15	2006	4.8	share AHT
ELCHP302	Adv Air heat	84.05	1681.00	1		1.000	0.83			15	2006	5.8	share

Residential		Fixom	Investment Cost	Efficiency	Efficiency Hot Water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010	2010		2020	2020				
	pump with electric boiler. *Heat & Cool*												AHT
ELCHP401	Ground heat pump with electric boiler	99.00	1980.00	1			0.80			20	2006	5	share GHT
ELCHP402	Ground heat pump with electric boiler. *Heat & Cool*	108.90	2178.00	1		1.000	0.80			20	2006	5	share GHT
GAS101	Natural gas stove	2.25	39.40	0.84						15	2006		
GAS201	Natural gas boiler	10.72	214.32	0.9						20	2006		
GAS301	Natural gas boiler. *Heat & Hot Water*	11.84	236.88	0.905	0.663					20	2006		
GAS401	Natural gas boiler condensing	18.80	376.00	1.025						20	2006		
GAS501	Natural gas boiler condensing.	20.89	417.78	1.07	0.561					20	2006		

Residential		Fixom	Investment Cost	Efficiency	Efficiency Hot Water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010	2010		2020	2020				
	Heat & Hot Water												
GASHP201	Air heat pump with natural gas boiler	62.00	1240.00	1			0.43			15	2006	1.75	share AHT
GASHP202	Air heat pump with natural gas boiler. Heat & Cool	62.00	1240.00	1		1.000	0.43			15	2006	1.75	share AHT
HYD110	Hydrogen burner	104.41	1827.25	0.86				-0.1	per10year	20	2010		
LPG101	LPG stove	2.25	39.40	0.84						15	2006		
LPG201	LPG boiler	8.27	165.50	0.88						20	2006		
LPG301	LPG boiler. *Heat & Hot Water*	9.10	182.05	0.91	0.659					20	2006		
LPGHP201	Air heat pump with LPG boiler	28.65	573.06	1			0.43			15	2006	1.75	share AHT
LPGHP202	Air heat pump with LPG boiler.	28.65	573.06	1		1.000	0.43			15	2006	1.75	share AHT

Residential		Fixom	Investment Cost	Efficiency	Efficiency Hot Water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010	2010		2020	2020				
	Heat & Cool												
LTH101	District heat exchanger. *Heat & Hot Water*	9.01	237.55	0.95	0.819					20	2006		
OIL101	Oil stove	8.43	147.49	0.65						15	2006		
OIL201	Oil boiler	9.50	190.00	0.92						20	2006		
OIL301	Oil boiler. *Heat & Hot Water*	10.45	209	0.91	0.418					20	2006		
OIL401	Oil boiler condensing. *Heat & Hot Water*	15.71	314.11	1	0.380					20	2006		
SOLE101	Solar collector with electric backup. *Heat & Hot Water*	46.05	2302.68	1	0.880		0.68			20	2010		
SOLD601	Solar collector with diesel backup. *Heat & Hot*	47.64	2382.00	1	0.568		0.71			20	2010		

Residential		Fixom	Investment Cost	Efficiency	Efficiency Hot Water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010	2010		2020	2020				
	Water												
SOLG201	Solar collector with gas backup. *Heat & Hot Water*	47.64	2382.00	1	0.568		0.68			20	2010		
WOO101	Wood-pellets boiler. *Heat & Hot Water*	24.35	487.00	0.85	0.418					20	2006		
Water Heating													
WOO101	Wood pellets boiler water heater	9.23	184.64	0.5						20	2006		
ELC101	Electric boiler water heater resistance	1.49	135.00	1						15	2006		
ELCHP201	Electric heat pump water heater	101.70	2034.00	1			0.57	1493		15	2006	2.34	share AHT
GAS101	Natural gas boiler water heater	7.65	153.00	0.76						15	2006		

Residential		Fixom	Investment Cost	Efficiency	Efficiency Hot Water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010	2010		2020	2020				
GEO101	Geo Heat Exchanger water heater	20.27	1031.28	1				733		20	2006		
LPG101	LPG boiler water heater	3.04	60.80	0.73						15	2006		
OIL101	Oil boiler water heater	8.50	170.00	0.70						15	2006		
SOLE101	Solar water heater with electricity backup	41.26	2063.00	1			0.5	1358		15	2010		
SOLD101	Solar water heater with diesel backup	41.62	2081.00	1			0.5	733		15	2010		
SOLG101	Solar water heater with gas backup	41.62	2081.00	1			0.5	834		15	2010		
FCW110	FC output to Hot Water demand	240.00	12000.00	1						15	2010		
Cooling													
ELC101	Room air-	24.05	481.00	2.025						10	2006		

Residential		Fixom	Investment Cost	Efficiency	Efficiency Hot Water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010	2010		2020	2020				
	conditioner												
ELC201	Air fans	7.60	151.99	0.4						10	2006		
ELC301	Roof-top central electric cooler	4.56	91.19	3.1						10	2006		
ELC401	Centralized electrical air conditioner	16.65	333.00	2.93						15	2006		
ELCHP101	Non-reversible electricity heat pump	13.62	272.46	3.306						15	2006		
GAS201	Centralized gas air conditioner	97.05	1940.96	4.41						15	2006		
GASHP101	Non reversible gas heat pump	69.13	1382.54	1.035						15	2006		
SOL110	Centralized solar air conditioner	76.56	3827.89	0.65				2500	1.25	15	2010		share SOL
Others													

Residential		Fixom	Investment Cost	Efficiency	Efficiency Hot Water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010	2010		2020	2020				
CDRELC101	Cloth drying high efficiency (AB)	0.00	0.51	1						15	2006		
CDRELC201	Cloth drying medium efficiency	0.00	0.70	1.25						15	2006		
COKELC101	Cooking electric stove	0.02	0.90	1						15	2006		
COKGAS101	Cooking gas stove	0.01	0.34	1						15	2006		
COKLPG101	Cooking LPG stove	0.00	0.23	0.6						15	2006		
CWAELC101	Electric Washing Machine	0.01	0.68	1						15	2006		
CWAELC201	Electric Washing Machine High Efficiency (AB)	0.01	1.01	1.54						15	2006		
CWAELC301	Electric Comb Washing/Drying Medium	0.01	0.62	1		0.67				15	2006		

Residential		Fixom	Investment Cost	Efficiency	Efficiency Hot Water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010	2010		2020	2020				
	Efficiency												
CWAELC401	Electric Comb Washing/Drying Mach High Efficiency	0.01	1.21	1.41		0.33				15	2006		
DWAELC101	Dish Washer medium efficiency (D)	0.01	0.17	1						15	2006		
DWAELC201	Dish Washer high efficiency (A+,A++)	0.00	0.36	2						15	2006		
LIGELC201	Incandescent IMP lighting system		0.00	1.5						2	2006		
LIGELC301	Halogens lighting system		0.01	2.8						5	2006		
LIGELC401	Fluorescent lighting system		0.01	5.71						8	2006		
OELELC101	Other Electricity Other	0.01	0.84	1						15	2006		

Residential		Fixom	Investment Cost	Efficiency	Efficiency Hot Water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010	2010		2020	2020				
	Appliances.												
REFELC501	Refrigerator/ Freezer baseline 510 lts (Class.AB)	0.01	0.84	1.56						15	2006		
REFELC601	Refrigerator/ Freezer max eff 510 lts (Class.A++)	0.03		2.92						15	2006		

Table 44 – Techno economic parameters for new technologies for commercial buildings considered in JRC-EU-TIMES

Commercial		Fixom	Investment Cost	Efficiency	Efficiency Hot water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010		2006	2020	2020				
Space heating													
ELC101	Electric radiators	0.26	233.00	1						15	2006		
ELC201	Electric boiler	0.14	123.84	1						20	2006		
ELCHP201	Air heat pump with electric boiler	56.55	1131.01	1			0.697			15	2006	3.3	share AHT
ELCHP202	Air heat pump with electric boiler. *Heat & Cool*	62.21	1244.11	1		1	0.697			15	2006	3.3	share AHT
ELCHP301	Adv Air heat pump with electric boiler	67.55	1351.02	1			0.792			15	2006	4.8	share AHT
ELCHP302	Adv Air heat pump with electric boiler. *Heat & Cool*	74.27	1485.33	1		1	0.828			15	2006	5.8	share AHT
ELCHP401	Ground heat pump with electric boiler	87.48	1749.53	1			0.800			20	2006	5	share GHT

Commercial		Fixom	Investment Cost	Efficiency	Efficiency Hot water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010		2006	2020	2020				
ELCHP402	Ground heat pump with electric boiler. *Heat & Cool*	96.22	1924.48	1		1	0.800			20	2006	5	share GHT
GAS101	Natural gas stove	0.56	33.78	0.95						15	2006		
GAS201	Natural gas boiler	11.36	162.30	0.9						20	2006		
GAS301	Natural gas boiler. *Heat & Hot Water*	12.56	179.39	0.95	0.663					20	2006		
GAS401	Natural gas boiler condensing	19.93	284.74	0.96						20	2006		
GAS501	Natural gas boiler condensing. *Heat & Hot Water*	22.15	316.38	1.07	0.561					20	2006		
GASHP201	Air heat pump with natural gas boiler	54.78	1095.66	1			0.429			15	2006	1.8	share AHT

Commercial		Fixom	Investment Cost	Efficiency	Efficiency Hot water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	**Description**	**eur00/kW**	**eur00/kW**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**eur00/kW**	**n.a.**	**years**	**year**	**n.a.**	**carrier**
Code			**2010**	**2010**	**2010**		**2006**	**2020**	**2020**				
GASHP202	Air heat pump with natural gas boiler. *Heat & Cool*	54.78	1095.66	1		1	0.429			15	2006	1.8	share AHT
LPG201	LPG boiler	8.27	165.50	0.85						20	2006		
LPG301	LPG boiler. *Heat & Hot Water*	9.10	182.05	0.734	0.817					20	2006		
LPGHP202	Air heat pump with LPG boiler. *Heat & Cool*	33.78	675.51	1		1	0.500			15	2006	2	share AHT
LTH101	District heat exchanger. *Heat & Hot Water*	3.94	78.81	0.95	1.000					20	2006		
OIL201	Oil boiler	3.52	70.31	0.73						20	2006		
OIL301	Oil boiler. *Heat & Hot Water*	3.87	77.34	0.85	0.418					20	2006		
OIL401	Oil boiler condensing. *Heat & Hot*	15.71	314.11	1	0.380					20	2006		

Commercial		Fixom	Investment Cost	Efficiency	Efficiency Hot water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010		2006	2020	2020				
	Water												
SOLE101	Solar collector with electric backup. *Heat & Hot Water*	34.23	1711.67	1	1.073		0.680			20	2006		share sol
SOLD601	Solar collector with diesel backup. *Heat & Hot Water*	34.53	1726.61	1	0.659		0.710			20	2006		share sol
SOLG201	Solar collector with gas backup. *Heat & Hot Water*	34.53	1726.61	1	0.659		0.680			20	2006		share sol
WOO101	Wood-pellets boiler. *Heat & Hot Water*	16.89	337.75	0.85	0.418					20	2006		
FCH110	FC output to Heat demand			1						20	2010		
Water Heating													

Commercial		Fixom	Investment Cost	Efficiency	Efficiency Hot water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010		2006	2020	2020				
WOO101	Wood pellets boiler water heater	9.23	184.64	0.5						20	2006		
ELC101	Electric boiler water heater resistance	0.83	75.00	1						15	2006		
ELCHP201	Electric heat pump water heater	89.86	1797.24	1			0.573			15	2006	2.3	share AHT
GAS101	Natural gas boiler water heater	5.79	115.87	0.76						15	2006		
GEO101	Geo Heat Exchanger water heater	20.27	1031.28	1						20	2006		
LPG101	LPG boiler water heater	3.04	60.80	0.73						15	2006		
OIL101	Oil boiler water heater	4.17	83.31	0.58						15	2006		
SOLE101	Solar water heater with electricity backup	34.23	1711.67	1			0.200	1358		15	2006		share sol

Commercial		Fixom	Investment Cost	Efficiency	Efficiency Hot water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010		2006	2020	2020				
SOLD101	Solar water heater with diesel backup	34.53	1726.61	1			0.200	733		15	2006		share sol
SOLG101	Solar water heater with gas backup	34.53	1726.61	1			0.200	834		15	2006		share sol
FCW110	FC output to Hot Water demand	240.00	12000.00	1						15	2010		
Cooling													
ELC101	Room air-conditioner	24.05	481.00	3						10	2006		
ELC201	Air fans	7.60	151.99	0.4						10	2006		
ELC301	Roof-top central electric cooler	0.73	91.19	3.1						10	2006		
ELC401	Centralized electrical air conditioner	2.66	333.00	2.93						15	2006		
ELCHP101	Non-reversible electricity heat pump	2.18	272.46	2.75						15	2006		
GAS201	Centralized gas	97.05	1940.96	4.41						15	2006		

Commercial		Fixom	Investment Cost	Efficiency	Efficiency Hot water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	**Description**	**eur00/kW**	**eur00/kW**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**eur00/kW**	**n.a.**	**years**	**year**	**n.a.**	**carrier**
Code			**2010**	**2010**	**2010**		**2006**	**2020**	**2020**				
	air conditioner												
GASHP101	Non reversible gas heat pump	69.13	1382.54	1.035						15	2006		
Others													
COKELC101	cooking electric stove	0.02	0.90	1						15	2006		
COKGAS101	cooking gas stove	0.01	0.34	1						15	2006		
COKLPG101	cooking LPG stove	0.00	0.23	0.6						15	2006		
LIGELC101	Incandescent STAD lighting system		0.00	1						1	2006		
LIGELC201	Incandescent IMP lighting system		0.01	2.8						2	2006		
LIGELC301	Halogens lighting system		0.00	2.8						5	2006		
LIGELC401	Fluorescent lighting system		0.00	5						8	2006		
OELELC101	Other Electricity Other	0.01	0.84	1						15	2006		

Commercial		Fixom	Investment Cost	Efficiency	Efficiency Hot water	Efficiency Cooling	Share AHT/GHT/SOL	Investment Cost	Efficiency Heating	Life	Start	Efficiency of heat pumps	
Units	Description	eur00/kW	eur00/kW	n.a.	n.a.	n.a.	n.a.	eur00/kW	n.a.	years	year	n.a.	carrier
Code			2010	2010	2010		2006	2020	2020				
	Appliances.												
PLIELC101	Public lighting	0.00	0.11	1						15	2006		
REFELC101	Refrigerators (energy class B,A)	0.02	0.43	1.54						15	2006		
REFELC201	Refrigerators (A+, A++)	0.01	0.65	2.86	1.857					15	2006		
REFELC301	Freezers (B,A)	0.01	0.43	1.62						15	2006		
REFELC401	Freezers (A+,A++)	0.01	0.60	3.01	1.858					15	2006		

6.10.3 Specific assumptions regarding pace of deployment of energy technologies in buildings

In order to replicate the inertia in major changes in appliances in buildings the following assumptions are considered (Table 45):

Table 45 – Assumption on energy technologies in buildings

Concept	Residential Buildings	Commercial Buildings
Share of heating	In 2015 the relative share of heating delivered by district heating in residential buildings has to be at most only 10% lower than the one in 2005. In 2050 this minimum share has to be at most 20% lower than the share in 2005	In 2050 the relative share of heating delivered by district heating in commercial buildings has to be at most 20% lower than the one in 2005
	In 2050 the maximum relative share of heating delivered by district heating in residential buildings can only increase by a maximum of 10% with respect to the share in 2005	In 2050 the maximum relative share of heating delivered by district heating in commercial buildings can only increase by a maximum of 5% with respect to the share in 2005
	In 2050 the maximum relative share of heating delivered by biomass in apartment residential buildings can be only up to 10% higher with respect to the same share in 2005. For urban single houses this upper bound is a maximum of 5% higher than the one in 2005	The maximum relative share of heating delivered by gas in commercial buildings is of 90% and the relative share of heating delivered by the combination of both natural gas and LPG can be at maximum 40% of total heating
	In 2015 the relative share of heating delivered by LPG in residential buildings can only decrease by 50% below the share in 2005. In 2050 this minimum share can decrease to 1% of the share in 2005	

Concept	Residential Buildings	Commercial Buildings
Space heating and water heating	In 2015 the relative share of space heating and water heating delivered by electric appliances in residential buildings has to be at least identical to the one in 2005 to account for houses not used all year round or when the energy service is only necessary for a very short period. In 2050 this minimum share has to be at most 10% lower than the share in 2005	In 2015 the relative share of space heating and water heating delivered by electric appliances in commercial buildings has to be at most 5% lower than the one in 2005. In 2050 this minimum share has to be at most 10% lower than the share in 2005
	In 2015 the maximum relative share of space heating and water heating delivered by the combination of gas and LPG in residential buildings can only increase up to 10% more than the one in 2005. In 2050 this maximum share can only increase up to 25% more than in 2005	In 2015 the minimum share of water heating delivered by electric appliances in commercial buildings has to be at most 5% lower than the share in 2005 and in 2050 only 10-20% lower than the share in 2005, respectively for small and large commercial buildings
Use of coal		There is no coal used for heating in commercial buildings
Lighting	The maximum lighting delivered by efficient lamps can be only 80% of all lighting	The maximum lighting delivered by efficient lamps can be only 80% of all lighting in commercial buildings
Cooking	In 2050 the relative share of electricity use for cooking in residential buildings has to be at most 15% lower than the one in 2005	In 2050 the relative share of electricity use for cooking in commercial buildings has to be at most 10% lower than the one in 2005
Heat pumps	Until 2030 heat pumps can deliver a maximum of 20% of total space heating in apartments, 25% of total space heating in urban family houses and up to 50% of total space heating in rural family houses	Until 2030 heat pumps can deliver a maximum of 5% of total space heating in large commercial buildings and up to 15% of total space heating in small commercial buildings

Concept	Residential Buildings	Commercial Buildings
Geothermal heat exchangers	Until 2030 geothermal heat exchangers can only deliver a maximum of 20% of total space heating in apartments, 25% of total space heating in urban single family houses and up to 50% of total space heating in rural single family houses. In 2050 these maximum values can be of 30%, 38% and 75% respectively for apartments, urban family houses and rural family houses	Until 2030 geothermal heat exchangers can only deliver a maximum of 5% of total space heating in large commercial buildings and up to 15% of total space heating in small commercial buildings. In 2050 these maximum values can be up to 8% and 23% for large and small commercial buildings

7 Grid representation and energy trade

In JRC-EU-TIMES, as in most multi-region TIMES models, the energy commodities such as natural gas, electricity, crude oil and the refined products chain can be consumed in each region from domestic production or from exogenous import (within Europe and from the rest of the world). Within each region the commodity can be delivered to all the end-use demand sectors, be subjected to transformation in order to obtain secondary commodities, or be used to generate electricity and/or heat. The modelling of grid and energy trade in JRC-EU-TIMES closely follows the approach of REALISEGRID (2009).

7.1 Energy trade within EU28

In JRC-EU-TIMES it is possible to trade the following commodities among EU28 regions, as well as the other regions modelled: electricity, liquid fuels, gaseous hydrogen (assumed to be using the same pipelines as for natural gas and starting only from 2025), CO_2 (for storage, starting only from 2025), nuclear fuel for electricity generation and natural gas. With the exception of the last two, which are unilateral, all other trade flows are represented as bilateral processes.

The energy trade among European countries is modelled via a trade matrix that defines the existing and expected links from one region to the other. The grids and consequently energy trade between countries are modelled in a simplified form with one single node per country.

The EU trade matrixes for electricity (see Annex 16.9) are characterised with European average information from ENTSO-E regarding technical parameters and constraints (bounds or investment constraints). Each link between two regions can be either bilateral or unilateral. The high, medium and low voltage grids are included in the model, with different types of technologies able to produce at different voltage, thus modelling distributed generation.

For the period of 2005 until 2025 JRC-EU-TIMES considers the electricity transmission capacity between countries as in ENTSO-E data. After 2025 it is possible to invest in transmission expansion, but only between the regions for which trade possibilities already exist. These values are presented in the following tables. Similarly, for natural gas trade the existing and planned capacities are considered, with maximum expected additional investment in pipelines imposed in the model until 2015. After that it is possible to invest in additional capacity with a generic cost of 50 euros/GJ. This means that the costs of the commodities being traded are endogenous to the model.

7.2 Energy trade with other regions

7.2.1 Electricity

For the non-European countries with which there is a possibility for electricity trade, JRC-EU-TIMES considers both import/export processes regarding the existing infrastructures (capacity and flows) from Rest of World (Table 46) to Bulgaria, Cyprus, Estonia, Finland, Greece, Hungary, Italy, Latvia, Lithuania, Slovakia, Slovenia, Poland, Spain, Romania and to Norway.

Table 46 – Possibilities for imports and exports of electricity from outside the geographical scope of JRC-EU-TIMES

Type of flow	Technology name	Description
Import	IMPELC-RU	Electricity import from Russia
	IMPELC-BY	Electricity import from Belarus
	IMPELC-UA	Electricity import from Ukraine
	IMPELC-MD	Electricity import from Moldova
	IMPELC-TR	Electricity import from Turkey
	IMPELC-TN	Electricity import from Tunisia
	IMPELC-AG	Electricity import from Algeria
Export	EXPELC-RU	Electricity export to Russia
	EXPELC-BY	Electricity export to Belarus
	EXPELC-UA	Electricity export to Ukraine
	EXPELC-MA	Electricity export to Morocco

Table 47 – Assumptions on maximum for imports and exports of electricity from outside the regions considered in JRC-EU-TIMES in GWh

From	To	2005	2010	2015	2020	2025	2030
Russia	NO	215	220	220	220	220	220
	EE	62	2000	2000	900	900	900
	LV	-173	800	800	400	400	400
	FI	11312	10000	9600	9600	11400	12600
	LT	-3045	-1000	1800	6000	3000	3000

From	To	2005	2010	2015	2020	2025	2030
	PL	0	0	0	0	3000	3000
Belarus	LT	800	3000	2000	-1000	-2000	-2000
	PL	875	500	500	500	3000	6000
	LV	0	0	0	0	0	0
Ukraine	PL	984	490	730	1940	3880	8100
	SK	-1718	-1000	-1000	-1000	-3150	-3150
	HU	4814	2300	3800	4750	7750	7750
	RO	653	1000	1500	2000	3000	3000
Moldova	RO	14	1200	3500	4000	7500	7500
Turkey	BG	0	0	2190	3066	3066	3066
	GR	0	0	2190	3066	4906	4906
	RO	0	0	0	3680	3680	3680
	CY	0	0	0	0	0	0
Tunisia	IT	0	0	0	6570	6570	6570
Algeria	IT	0	0	0	0	0	0
	ES	0	0	0	0	6570	6570
Morocco	ES	-787	-4200	-5520	-5520	-8585	-8585

Reference: REALISEGRID (2009). Note that the negative numbers in the table represent maximum export flows from Europe to its neighbours.

Additional investment in transmission capacity outside the EU28+ regions is possible at a cost of 100 Euros_{2000}/kW.

The following assumptions are made on electricity trade outside EU. Unless otherwise specified electricity import costs from outside the modelled regions are of 10 Euros_{2000}/GJ; for exports are of 5 Euros_{2000}/GJ.

Table 48 – Additional assumptions on maximum electricity trade considered (PJ)

Country / (PJ)	BG	ES	FI	GR	HU	LT	LV	NO	PL	SI	SK
Maximum import electricity from outside EU			40.7	2.9	17.4	10.6	1.9	0.8	3.5	0.0	
Maximum export electricity to outside EU	1.2	2.9		4.1	30.3	7.8	1.1				6.20

7.2.2 Trade of other energy commodities

Besides electricity imports and exports with regions outside of the model the following possibilities are considered:

Table 49 – Possibilities for imports and exports of non-electricity commodities from outside the geographical scope of JRC-EU-TIMES

Type of flow	Description
Import into EU28+	Import Hard Coal
	Import Coke
	Import Lignite
	Import Brown Coal
	Import Crude Oil
	Import Feedstock
	Import Refinery Gas
	Import Liquefied Petroleum Gas
	Import Motor Spirit
	Import Kerosene - Jet Fuels
	Import Naphtha
	Import Diesel
	Import Residual Fuel Oil
	Import Non Energy
	Import Other Petroleum Products
	Import Wood Products

Type of flow	Description
Exports outside EU28+	Export Hard Coal
	Export Coke
	Export Lignite
	Export Brown Coal
	Export Crude Oil
	Export Feedstock
	Export Refinery Gas
	Export Liquefied Petroleum Gas
	Export Motor Spirit
	Export Kerosene - Jet Fuels
	Export Naphtha
	Export Diesel
	Export Residual Fuel Oil
	Export Non Energy
	Export Other Petroleum Products
	Export Natural Gas
	Export Wood Products
	Export Biofuels

In particular for the case of natural gas the following possibilities are considered in JRC-EU-TIMES: import of natural gas from Russia, from Russia via Belarus, from Russia via Ukraine and from North Africa. In addition, it is also possible to import liquefied natural gas using the following routes into EU28+: BE, FR, IT, GR, PT, ES, UK, DE, PL, HU and CY. Finally it is also possible to invest in additional capacity for liquefied natural gas imports at a cost of 50 Euros $_{2000}$/GJ.

7.3 National electricity grids

The following table summarises the assumptions regarding losses in converting electricity within the grid as modelled in JRC-EU-TIMES, based on country-specific information supplied by national experts within the NEEDS and RES2020 projects and updated with Eurostat data in 2013.

Table 50 – Losses in conversion within the electricity grid considered in JRC-EU-TIMES

Country	Very High to High Voltage	High to medium voltage	Medium to low voltage
AT	2%	2%	2%
BE	2%	3%	3%
BG	2%	3%	3%
CY	2%	3%	3%
CZ	3%	6%	3%
DE	2%	3%	3%
DK	2%	3%	3%
EE	2%	3%	3%
ES	2%	3%	9%
FI	2%	3%	3%
FR	2%	3%	7%
GR	2%	4%	4%
HR	3%	4%	9%
HU	3%	6%	3%
IE	1%	1%	6%
IT	2%	3%	4%
LT	2%	3%	3%
LU	2%	2%	2%
LV	2%	3%	3%
MT	2%	3%	3%

Country	Very High to High Voltage	High to medium voltage	Medium to low voltage
NL	2%	3%	3%
PL	3%	6%	3%
PT	2%	3%	3%
RO	2%	3%	3%
SE	2%	2%	2%
SI	2%	2%	2%
SK	3%	6%	3%
UK	2%	3%	3%
AL	6%	8%	12%
BA	3%	6%	12%
CH	2%	2%	2%
IS	2%	3%	3%
KS	2%	5%	9%
ME	3%	6%	10%
MK	2%	6%	12%
NO	2%	2%	2%
RS	3%	6%	10%

Distribution grids are modelled in a simplified format via the EV-Trans processes in the model (convert electricity between different voltage levels) which have an associated cost in euros/kW based on the electricity transport tariff for 2011 for each country from Eurostat (except for BE, DE, and ES as they include feed-in tariffs in their network costs later than 2005, for which 2005 data is then used). There is a possibility to invest in further distribution with these costs. The goal is simply to reflect the cost of the grid on the basis of capacity rather than on electricity production.

7.4 Transnational electricity grids

Regarding the connection among JRC-EU-TIMES countries, the following cases exist:

1. Asynchronous connections.
2. Radial connections (synchronous but with unique corridor)
3. Synchronous connections.
4. No connections, e.g. Cyprus.

Figure 19 shows the network that was used in the JRC-EU-TIMES model. The blue lines correspond to asynchronous connections, which are simulated like a trade process in TIMES. The green lines are radial connections in the synchronous network, which behave like the trade processes in TIMES. The brown lines are the synchronous connections that are modelled using the DC Load Flow algorithm in TIMES. Finally the interconnections in the Western Balkans are painted light grey. These connections are modelled like trade processes in JRC-EU-TIMES at the moment, but could be included in the synchronous algorithm once data about the reactance can be calculated using real flow data.

Finally, the planned DC line interconnections are plotted in light blue and are included in the JRC-EU-TIMES as trade processes while the new synchronous connections are plotted in pink and are included in the JRC-EU-TIMES as trade processes.

In TIMES there are two approaches to the electricity trade between regions:

1) Electricity exchanges using the “transport model approach" and cost optimisation of investments on the new capacity of the interconnections between the countries (the characteristics of the grid lines are not important in this approach). The "transport model approach" uses the network as optimal as possible. Circular flows can be part of the solution when it is more cost optimal than investing in new grids.
2) Electricity exchanges (network use) based on DC load flow calculations and cost optimisation of grid investments, where the line characteristics are important. The DC load flow approach represents the physical flows depending on the grid characteristics. Only one solution of the electricity flow exists, investments in new lines are triggered by physical limitations and circular flows are part of the solution. The added value of DC load flow is that it models the physical flow of electricity and therefore the new investments in grid lines that are necessary, based on this physical flow. This usually leads to higher investments in grid lines than in the “transport model” approach.

In the JRC-EU-TIMES model, the asynchronous connections (DC lines) are modelled like normal “transport model” trade processes, since the flow through them does not depend on the line reactance, but is controlled by the operator. The same approach is used for the “radial connections” which are synchronous connections in which there is a unique corridor for the electricity flow. Therefore, the flow is determined only by the generation and consumption and not by the line reactance.

Long-term Energy consumption and Electrical Generation planning studies need to account at least approximately for the electricity exchange limitations imposed by the transmission network and the incurred transmission expansion cost, if this network is to be reinforced in order to accommodate increased transfers that are economically, environmentally, or otherwise deemed necessary.

A simplified continental transmission system model is used that may serve the above purpose under the following assumptions and conditions:

1) Transmission capacity limits are known and are the same in both directions of flow between any two adjustment nodes.
2) The transmission capacities correspond (at least approximately) to the actual total transfer capabilities of the respective corridors.
3) The cost of transmission reinforcement corresponds (at least approximately) to the actual cost of transmission expansion in €/MW of added capability.

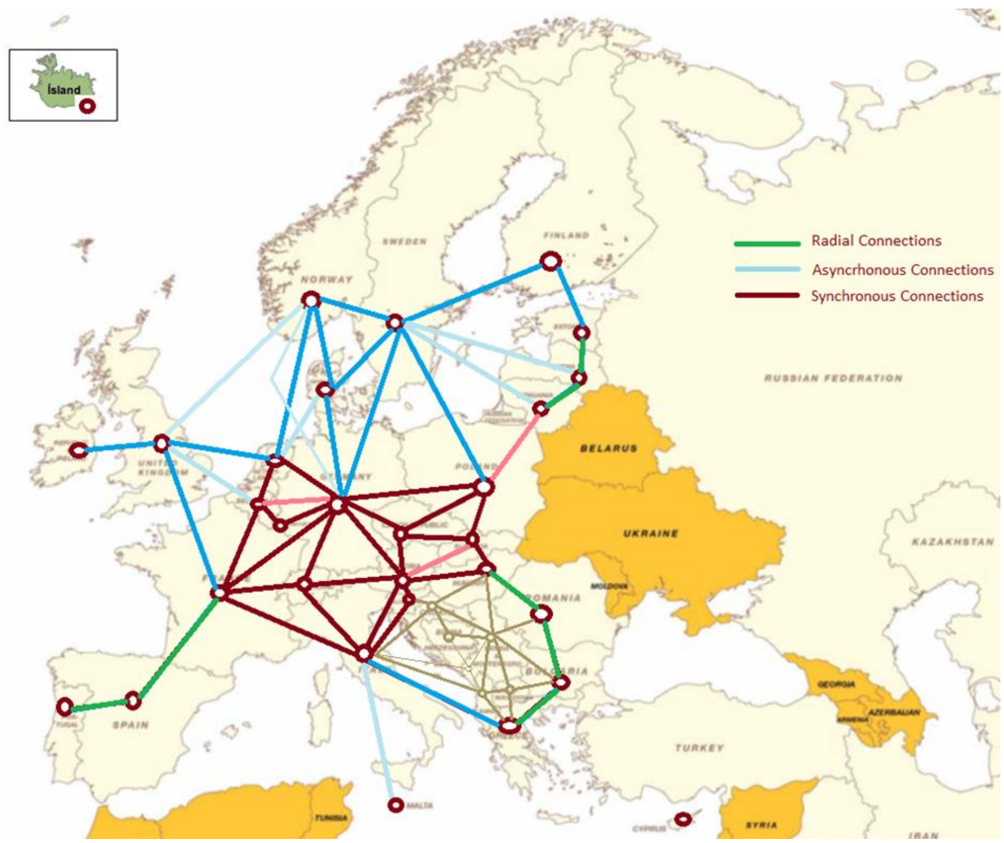


Figure 19 – Grid model in the JRC-EU-TIMES model

For the **synchronous connections**, a simplified DC Load Flow transmission model is used. In particular, the synchronous connections of the former UCTE 1st synchronous zone of the West and Central Europe are approximated by a 13 node network.

The simplified network is based on the least-square estimation of admittances (succeptances) of corridors connecting adjacent nodes. The admittances are estimated so as to minimize the sum of squared errors of calculated vs. assumed cross border flows for a number of instances (time-slices or snapshots).

The network proposed in this report is based on one actual reported measurement of European power flows reported in (Qiong & Bialek, 2005) and two estimated exchanges between European countries based on pre-existing JRC-EU-TIMES results. Reported or calculated cross-border flows, such as reported by ENTSO-E (ENTSOE), can be used to provide input to the admittance estimation process and thus extend/modify/replace the proposed network described here. However, the following sources of error should be carefully considered when applying this methodology:

1) The simplified network is not equivalent to the actual transmission network, as the equivalent will include branches between all pairs of nodes (i.e. for the 13 nodes 78 equivalent branches result).
2) Flows calculated with AC load flow cannot be always captured with a DC power flow model.
3) Special controls may exist (e.g. phase shifting transformers) that may affect the flows of certain instances.
4) The transmission network may change from instance to instance due to topology changes, lines on maintenance, periodic switching (e.g. between day and night) as well as network reinforcements.

Thus, even though the least-square estimation will provide the best possible match to the given data, this fit may still be not good enough, i.e. there may be large to very large estimation errors for certain corridors and instances, that should be carefully checked. It should be made clear therefore that further research (e.g., network reduction algorithm (HyungSeon, 2012)) is still necessary before establishing a reliable and efficient method that can yield an acceptably simplified network for any set of cross-border flow data in the context of an energy system model such as JRC-EU-TIMES.

The simplified transmission model has the following characteristics:

- $NN = 13$ number of nodes. In fact, each node represents a country of the former UCTE 1st synchronous zone of the West and Central Europe. These nodes are numbered successively from 1 to 13. Node 1 is the reference node.
- $NL = 23$ corridors, i.e., 23 synchronous connections.
- $NTS = 3$ time slices.

Following parameters are computed for each corridor:

1. The relative impedance (b_{ij} in p.u).
2. The branch type (1 or 2).
3. The number of circuits.
4. The line length (in km).

Table 51 shows the correspondence between nodes and countries.

Table 51. Computed values of corridor parameters.

Corridor	FROM	TO	Corridor Capacity (GW)	bij (p.u.)	Branch type	Number of circuits	Length (km)
1	AT	CZ	1.70	60.25	2	2	19
2	AT	HU	0.70	0.50	1	2	576
3	AT	IT	0.25	0.50	1	1	129
4	CH	AT	1.20	39.09	2	2	29
5	CH	DE	3.40	174.51	2	3	10
6	CH	IT	3.20	122.73	2	3	14
7	DE	AT	2.10	126.35	2	2	9
8	DE	CZ	2.00	60.97	2	2	19
9	DE	PL	1.20	0.50	1	2	605
10	FR	BE	3.40	172.33	2	3	10
11	FR	CH	3.20	161.08	2	3	11
12	FR	DE	4.20	141.64	2	4	16
13	FR	IT	2.40	75.12	2	3	23
14	NL	BE	2.40	116.32	2	3	15
15	NL	DE	3.40	161.46	2	3	11
16	PL	CZ	1.70	122.71	2	2	9
17	SI	AT	0.90	11.74	2	1	49
18	SI	IT	0.75	50.90	2	1	11
19	SK	CZ	1.70	82.34	2	2	14
20	SK	HU	1.40	91.56	2	2	13
21	BE	LU	0.30	60.87	2	1	9
22	DE	LU	1.00	38.73	2	2	30
23	PL	SK	0.75	16.63	2	1	34

8 Base-year calibration

The JRC-EU-TIMES model is currently calibrated to 2005 Eurostat data from its 2013 edition. In the following table we show the percentage difference between Eurostat Final Energy Consumption and JRC-EU-TIMES model results for 2005. With some exceptions (highlighted in orange) the difference is smaller than 20% and in most cases smaller than 10%. The main cause for these differences is the difficulty to obtain the very detailed bottom-up data used in JRC-EU-TIMES (e.g. stock and production of heat for CHP plants in industry that do not sell the heat and thus are not reported to Eurostat or passenger car stock and average travelled km). For some countries this data is not available and for some other countries even when the data is available from national sources it is not always coherent with final energy consumption. An example is the case of the transport sector for which in some countries a relevant share of passenger cars fill the tanks in neighbouring countries (tank tourism) and thus are not captured in national Final Energy Consumption.

Table 52. Relative difference between Final Energy Consumption results from JRC-EU-TIMES for 2005 and Eurostat (Supply, transformation, consumption - all products - annual data [nrg_100a], extracted 11 March 2013)

FEC % diff from Eurostat	Commercial	Industry	Residential	Transport	National Total
AT	2%	-16%	4%	-2%	-4%
BE	1%	33%	0%	-2%	10%
BG	8%	-19%	1%	-9%	-9%
CY	10%	57%	-33%	-12%	-2%
CZ	9%	2%	0%	0%	1%
DE	24%	1%	6%	-1%	-1%
DK	2%	6%	0%	-4%	0%
EE	-16%	2%	0%	-1%	-2%
ES	1%	0%	0%	-12%	-5%
FI	3%	1%	-2%	-2%	-5%
FR	-3%	5%	-1%	-1%	-4%
GR	0%	-1%	0%	-8%	-3%

FEC % diff from Eurostat	Commercial	Industry	Residential	Transport	National Total
HR	1%	-1%	-1%	-2%	-2%
HU	0%	12%	-1%	-2%	2%
IE	0%	-18%	0%	-17%	-10%
IT	-1%	11%	3%	-3%	2%
LT	4%	15%	-9%	-4%	0%
LU	-69%	-41%	19%	-3%	-12%
LV	9%	-45%	9%	0%	-3%
Mt	29%	14%	17%	33%	19%
NL	-12%	-5%	0%	-2%	-2%
PL	2%	6%	0%	-3%	1%
PT	0%	-5%	-1%	0%	-2%
RO	41%	-15%	0%	-3%	-7%
SE	0%	3%	-1%	-2%	1%
SI	-1%	-8%	-2%	-1%	-4%
SK	-6%	23%	-5%	-24%	1%
UK	9%	15%	-2%	-2%	2%
EU28	5%	4%	1%	-3%	-1%

Note: orange cells depict differences higher than 20%.

9 Policy assumptions

9.1 Consideration of current and planned energy policies in JRC-EU-TIMES

The EU 2050 roadmap policies as considered in PRIMES were used as a benchmark to decide on the policies included in the JRC-EU-TIMES model (Annex 16.4). A further assessment of specific policies developments per country has also been made for a set of key countries defined in conjunction with JRC-IET and based on their relevance in terms of energy consumption (ES, IT, FR, DE and UK). On the basis of their relevance in terms of energy consumption, EU and Member State energy policies to 2020 and goals up to 2050 were reviewed and, whenever considered important, included in the model.

At this moment JRC-EU-TIMES does not consider demand side measures, in the sense that the demand for energy services and materials is an exogenous input allocated across time-slices. There is no possibility to change endogenously this demand from one time-slice to the other.

9.2 Support to RES: Feed-in Tariffs and green certificates

In JRC-EU-TIMES it is possible to model green certificates and/or feed in tariffs using the same approach as in RES2020 (RES2020 Project Consortium, 2009) and updated in 2011. However, at the moment these incentives are not modelled in any of the scenarios presented in this report (see Section 11.1).

Although the two instruments have a different mechanism (green certificates represent a quantitative-based support policy while feed-in tariffs constitute a price-based policy instrument), in JRC-EU-TIMES, as in RES2020 (RES2020 Project Consortium, 2009), the green certificates can be modelled in a simplified format in terms of a price-based approach. Both policy instruments represent a price premium per unit of electricity (euro per GJ) and once the renewable technology is in operation, it receives the respective fixed tariff for every GJ produced. More information on the approach that can be used in JRC-EU-TIMES is detailed in Annex 16.5.

9.3 Renewable targets in final energy consumption

The European Union Directive 2009/28/EC establishes binding renewable energy targets for each Member State for 2020 that collectively achieve the overall EU 20% renewable energy penetration goal. The JRC-EU-TIMES model embeds this target in all scenarios (see Section 11.1). The target of single country trajectory is based on Annex 1 of Directive 2009/28/EC and is presented in Table 53. In the JRC-EU-TIMES model, the targets are extended up to 2030, but not beyond.

In the case of transport energy, at least 10% of (road and rail) transport energy must come from renewable sources in each Member State. This target is included in the reference scenario, and is assumed to continue up to 2050. No such targets are curently considered for Norway, Switzerland and Iceland.

Table 53 – RES share at EU MS level (%) based on Directive 2009/28/EC considered in JRC-EU-TIMES

Country	2005	2012	2014	2016	2018	2020
	Reference	Indicative trajectory				
Austria	23.3	25.4	26.5	28.1	30.3	34
Belgium	2.2	4.4	5.4	7.1	9.2	13
Bulgaria	9.4	10.7	11.4	12.4	13.7	16
Cyprus	2.9	4.9	5.9	7.4	9.5	13
Czech Republic	6.1	7.5	8.2	9.2	10.6	13
Denmark	17	19.6	20.9	22.9	25.5	30
Estonia	18	19.4	20.1	21.2	22.6	25
Finland	28.5	30.4	31.4	32.8	34.7	38
France	10.3	12.8	14.1	16	18.6	23
Germany	5.8	8.2	9.5	11.3	13.7	18
Greece	6.9	9.1	10.2	11.9	14.1	18
Hungary	4.3	6	6.9	8.2	10	13
Ireland	3.1	5.7	7	8.9	11.5	16
Italy	5.2	7.6	8.7	10.5	12.9	17
Latvia	32.6	34.1	34.8	35.9	37.4	40
Lithuania	15	16.6	17.4	18.6	20.2	23
Luxembourg	0.9	2.9	3.9	5.4	7.5	11
Malta	0	2	3	4.5	6.5	10
Netherlands	2.4	4.7	5.9	7.6	9.9	14
Poland	7.2	8.8	9.5	10.7	12.3	15
Portugal	20.5	22.6	23.7	25.2	27.3	31
Romania	17.8	19	19.7	20.6	21.8	24

Country	2005	2012	2014	2016	2018	2020
	Reference	Indicative trajectory				
Slovakia	6.7	8.2	8.9	10	11.4	14
Slovenia	16	17.8	18.7	20.1	21.9	25
Spain	8.7	11	12.1	13.8	16	20
Sweden	39.8	41.6	42.6	43.9	45.8	49
United Kingdom	1.3	4	5.4	7.5	10.2	15

The biofuels target for the whole of EU is implemented from 2005 until 2050. In 2005 a minimum 5.8% of biofuels has to be blended in gasoline and diesel for transport. In 2015 a minimum of 7.9% and from 2020 a minimum of 10%.

9.4 CO_2 targets

9.4.1 EU ETS

The European Emissions Trading System (ETS) as considered in JRC-EU TIMES (Table 54) only includes CO_2 emissions from electricity and heat producers as well as industries, as explained below. Therefore, while the current ETS includes also emissions from aviation, this is not considered in the JRC-EU-TIMES model. The following sources are considered as taking part in the EU ETS scheme:

- Central electricity, CHP and heat producers
- Industrial autoproducers (electricity and CHP)
- Large industries: Steel, Cement, Glass, Pulp and Paper
- Process emissions from all industries

As required by the current EU regulation, the reduction of emissions in the JRC-TIMES-EU ETS sectors is of 21% in 2020 based on 2005 CO_2 emissions levels (including aviation). Beyond 2020, the overall EU-ETS target evolves to 41% reductions from 1990 levels.

Table 54 – EU ETS target as considered in JRC-EU-TIMES

ETS target/Year	2010	2015	2020	2025	2030	2035	2040	2050
% reduction from 2005	11	16	21	26	31	34	38	41
kt CO_2	1,962,735	1,847,603	1,732,470	1,622,820	1,513,170	1,440,070	1,366,970	1,293,870

EU ETS is modelled in a simplified format as there are no possibilities for banking and offset. Moreover, at this moment there is no separation between sizes of the installations considered as part of EU-ETS. This means that for simplification, all cement or all CHP plants are considered to be within the scope of the Directive.

9.4.2 Long term EU wide CO_2 target

In JRC-EU-TIMES we model an EU wide long term CO_2 target for 2050 of 85% reductions from 1990 in all decarbonised scenarios, in the spirit of the EU Roadmap for moving to a Low Carbon Economy (EC, 2011). The reduction pathway considered in JRC-EU-TIMES is not exactly as mentioned in the Roadmap for a Low Carbon economy (Table 55), which mentions reductions of 40% and 60% below 1990 emissions, respectively for 2030 and 2040. Because JRC-EU-TIMES is an optimisation model we have a more gradual reduction pathway adopted to provide the model more flexibility for the optimization.

Table 55 –Long term CO_2 target considered in decarbonised scenarios in JRC-EU-TIMES

Year	1990	2015	2020	2025	2030	2035	2040	2050
EU28+ CO_2 emissions kt CO_2	4,136,831	3,516,306	3,309,465	2,895,782	2,482,099	1,861,574	1,241,049	640,917
% reduction from 1990	not applicable	15	20	30	40	55	70	85

At this moment aviation and navigation emissions are considered within this CO_2 target, as well as emissions from Norway, Switzerland, Iceland and Croatia.

10 Highlights of long term energy system trends for EU

10.1 Modelled scenarios

For the assessment of the JRC-EU-TIMES performance and analysis of the role of the SET Plan technologies in the context of the long-term energy trends, eight exemplary scenarios are studied from 2005 until 2050. In the scenarios' design we adopted a similar structure to the scenarios used in the Energy Roadmap 2050, but it is important to note that the design is not identical. Therefore, a direct comparison of the results with the Energy Roadmap 2050 has limited interest, as details in the assumptions and input data used in PRIMES and in JRC-EU-TIMES, as well as the modelling approach, differs.

The long-term scenarios considered in this report are summarised in the following table (Table 56).

Table 56 – Overview of the scenarios modelled in JRC-EU-TIMES

Scenario name	20-20-20 targets[21]	Long-term CO_2 cap	Other assumptions	Exemplary question to be addressed
Current Policies (CPI)	Yes, ETS till 2050	No	Until 2025 the only new nuclear power plants to be deployed in EU28 are the ones currently being built in FI and FR and also under discussion in BG, CZ, SK, RO and UK[22]. After 2025 all plants currently under discussion in EU28 (Annex VII) can be deployed but no other plants.	Used as reference scenario for comparison purposes
Current Policies with CAP (CAP85)	Yes, ETS till 2050	85% less CO_2 emissions in 2050 than 1990 levels	As CPI	Explores the technology and energy options to mitigate CO_2 emissions by 85%
Delayed CCS (DCCS)	Yes, ETS till 2050	85% less CO_2 emissions in 2050 than 1990 levels	As CPI & CCS is only commercially available in 2040 instead of 2020 and with 40% higher costs	Explores the impacts of delayed penetration of CCS options on technology and energy options and on total

[21] The EU ETS target is assumed to continue until 2050, as detailed in Section 10.4.1. The national RES targets are implemented for 2020 and 2030 (the target for 2030 is the same as in 2020). There are no such targets after 2030. The minimum share of biofuels in transport is implemented from 2020 and maintained constant until 2050.

[22] This corresponded to the following plants: in Bulgaria (BELENE-1, BELENE-2); Czech Republic (TEMELIN-3, TEMELIN-4), Finland (OLKILUOTO-3), France (FLAMANVILLE-3, PENLY-3), Hungary (PAKS-5, PAKS-6), Romania (CERNAVODA-3, CERNAVODA-4), Slovakia (MOCHOVCE-3, MOCHOVCE-4) and UK (HINKLEYPOINT-C1, HINKLEYPOINT-C2, SIZEWELL-C1, SIZEWELL-C2).

Scenario name	20-20-20 targets[21]	Long-term CO_2 cap	Other assumptions	Exemplary question to be addressed
				system costs
High Renewables (HRES)	Yes, ETS till 2050	85% less CO_2 emissions in 2050 than 1990 levels	As CPI & 30% higher RES potentials, plus maximum of 90% electricity that can be generated from solar and wind	Explores the impacts of higher social acceptance and facilitated permitting of RES plants options on technology and energy options and on total system costs
High Nuclear (HNuc)	Yes, ETS till 2050	85% less CO_2 emissions in 2050 than 1990 levels	None	Explores the impacts of higher social acceptance of nuclear plants options on technology and energy options and on total system costs
Low Energy (LEN)	Yes, ETS till 2050	85% less CO_2 emissions in 2050 than 1990 levels	As CPI & 30% less final energy consumption than in the CAP85 scenario from 2035 till 2050	Explores the impacts of stricter and more effective end-use energy efficiency requirements options on technology and energy options and on total system costs
Low Biomass (LBIO)	Yes, ETS till 2050	85% less CO_2 emissions in 2050 than 1990 levels	As CPI & 30% less biomass available	Explores the impacts of lower biomass availability for the energy system options on technology and energy options and on total system costs
Low Solar & Wind (LSW)	Yes, ETS till 2050	85% less CO_2 emissions in 2050 than 1990 levels	As CPI & maximum of 25% electricity that can be generated from variable solar and wind in 2050	Explores the impacts of higher concerns related to the reliability of transmission and distribution, reducing the share of variable solar and wind electricity on technology and energy options and on total system costs

The list of the "planned" nuclear power plants to be deployed and under discussion here mentioned are included in Annex 16.11 – Annex XI – List of nuclear power plants considered under discussion.

Except if otherwise mentioned, all the modelled scenarios have in common the following assumptions:

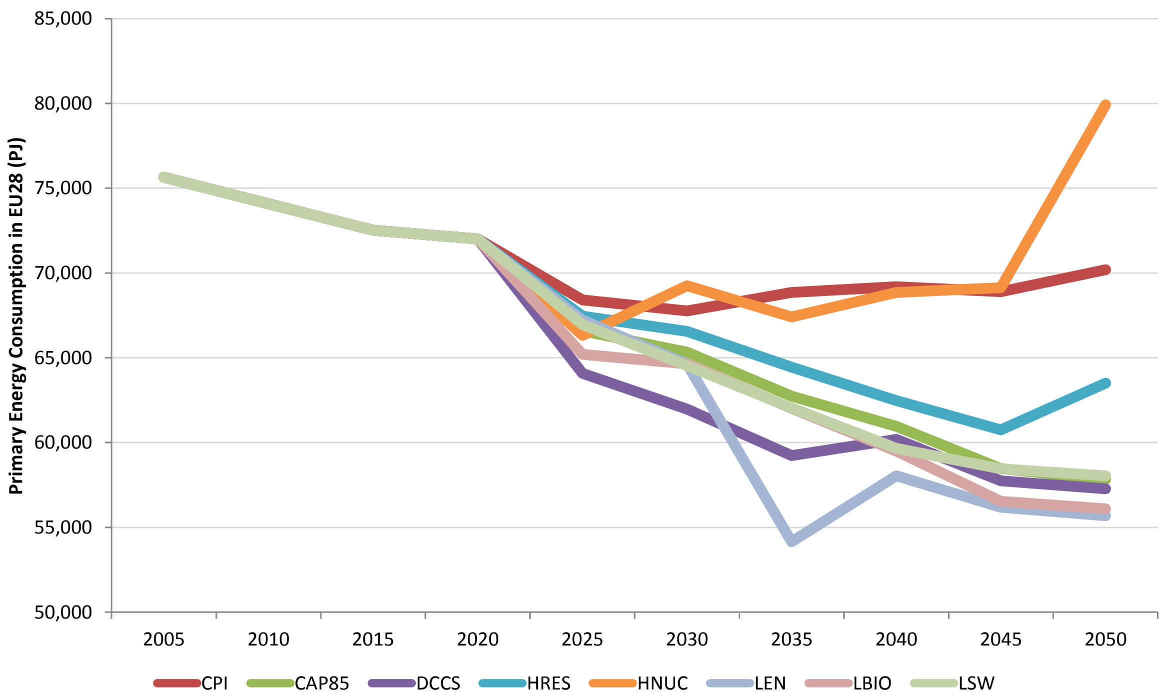
- No consideration of any of the specific policy incentives to RES (e.g. feed-in tariffs, green certificates, etc.) in all the studied scenarios, as for this analysis the objective is to assess the long term technology deployment based solely on cost-effectiveness (before 2030 the national RES targets could affect technology choices).

- A maximum of 50% electricity can be generated from variable solar and wind to account for concerns related to system adequacy and variable RES (except in the HRES scenario, where it is 90% and LSW where it is 25%). For the same reason, wind and solar PV technologies cannot operate during the winter peak time slice.
- Countries that for the time being do not have nuclear power plants (NPPs) will not have NPPs in the future. This is the case for: Austria, Portugal, Greece, Cyprus, Malta, Italy, Denmark and Croatia.
- Nuclear power plants in Germany are not operating after 2020 (although the planned date is from 2022, this intermediate year is not modelled in JRC-EU-TIMES). Belgium nuclear power plants are not operating after 2025.
- Primary energy import prices for oil, coal and gas are the same for the CPI and all the decarbonisation scenarios, and are as indicated in Section 3.2.1.
- No possibility to import biofuels from outside EU28+ as detailed in Section 3.2.

All the statements and figures in Sections 11 to 14 are based on the model outputs of the JRC-EU-TIMES when run with the above described scenarios. Hence, it is understood that all forward looking statements in this Section and beyond refer only to the model outputs and our interpretation thereof. For better readability we don't repeat this qualifying message in the next Sections.

10.2 Primary energy consumption

Primary energy consumption (PEC) evolution in EU28 for the 8 scenarios modelled in JRC-EU-TIMES is presented in Figure 20. Despite the high growth in the demand for energy services and materials, in 2050 in practically all the scenarios, there is a reduction of 7% to 26% less than in 2005. These values are in line with other studies for Europe and reflect both the effect of replacing existing technologies with more efficient ones, inherent to optimisation models, and also, for the decarbonised scenarios, the effect of the CO_2 cap. The exception to this trend in the HNUC scenario which has in 2050 a PEC 6% above 2005 values, due to substantially higher uranium imports. For the other scenarios, CPI has the lowest PEC reduction (7% less than in 2005), followed by HRES (16% less). Not surprisingly, LEN has the highest PEC reduction, although very similar to LBIO. The HRES scenario assumes 30% more renewables available in EU (both biomass and areas suitable for installing electricity generation technologies). Since biomass is a cheaper low carbon energy carrier than for example electricity, in the HRES scenario it is possible to meet the CO_2 cap with lower deployment of more efficient electricity-based energy technologies.



Reference: JRC-EU-TIMES

Figure 20 – Evolution of primary energy consumption in EU28 from JRC-EU-TIMES for the studied scenarios (values up to 2005 are taken from Eurostat)

The evolution of PEC from 2005 onwards in the various scenarios depicts the assumptions underlying their design. This is for instance the case of the steep decrease in 2035 for the LEN scenario since this is the year from which the constraint is implemented. Likewise, the start date for CCS technologies is set at 2040 in the DCCS scenario, and from 2030 in the HNUC scenario "unplanned" NPP can be deployed.

In the long term, the reduction in PEC is mostly due to the reduction of imports of coal, gas (especially for the CPI scenario, without a long term CO_2 cap) and uranium into the EU28. Even in the CPI scenario in 2050 oil imports are no longer prominent. These are only to a very limited extent refined products (gasoline and diesel), and instead smaller imports of heavy fuel oil mostly for the chemical industry and for navigation.

Primary production (oil and gas extraction, coal mining and harvesting of renewable resources) is reduced, mostly in the CPI scenario without a long term CO_2 cap (roughly 12% reduction from 2005 values), in HNUC (4% reduction), in LBIO, LEN and LSW (respectively less 5%, 7% and 9%). In the other scenarios (CAP85, DCCS and HRES), primary production increases due to higher harvesting of renewable energy within the EU28 (biomass, wind, solar and to a smaller extent ocean and geothermal). In 2050 in the decarbonised scenarios, there is practically no mining of lignite. In all scenarios, regardless of the CO_2 cap there is also practically no oil extraction in EU in 2050. These trends are also reflected in the PEC intensity (Table 57).

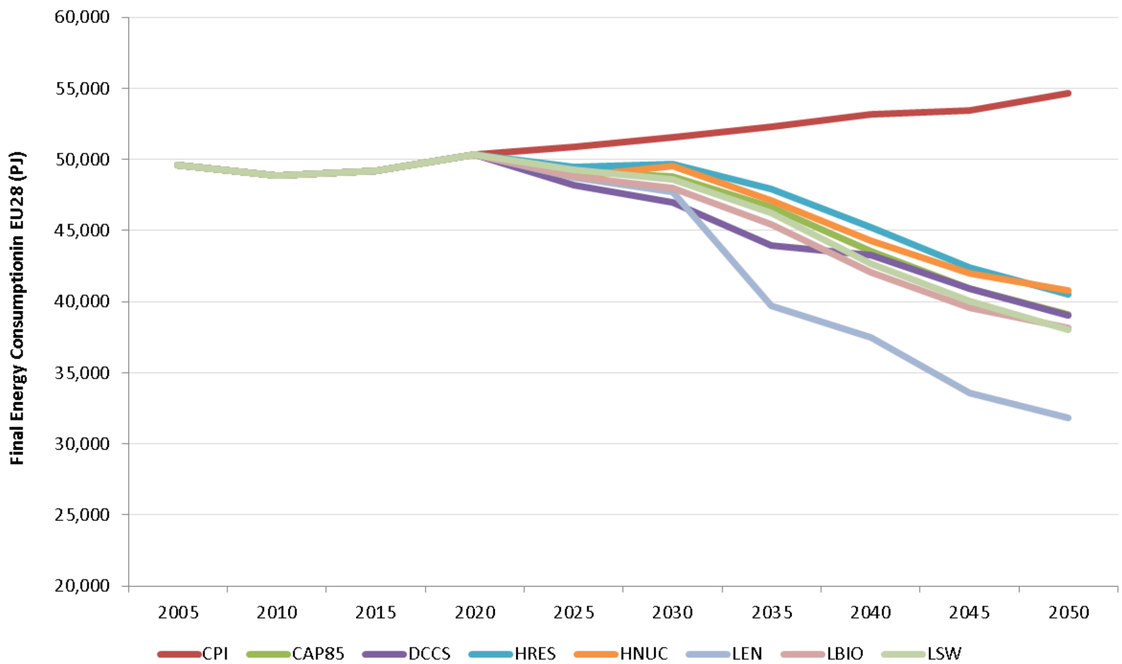
Table 57 – PEC intensity for EU28 (PJ/GDP in Meuros$_{2005}$)

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
CPI	6.84	6.40	5.64	5.08	4.41	4.02	3.78	3.52	3.26	3.09
CAP85	6.84	6.40	5.64	5.08	4.29	3.87	3.45	3.10	2.76	2.55
DCCS	6.84	6.40	5.64	5.08	4.13	3.67	3.25	3.06	2.73	2.52
HRES	6.84	6.40	5.64	5.08	4.35	3.95	3.54	3.18	2.87	2.80
HNUC	6.84	6.40	5.64	5.08	4.27	4.11	3.70	3.51	3.27	3.52
LEN	6.84	6.40	5.64	5.08	4.33	3.83	2.97	2.96	2.66	2.45
LBIO	6.84	6.40	5.64	5.08	4.20	3.83	3.41	3.03	2.67	2.47
LSW	6.84	6.40	5.64	5.08	4.31	3.83	3.41	3.04	2.76	2.56

10.3 Final energy consumption

The final energy consumption (FEC) has an increase from 2005 till 2050 of 10% for the CPI scenario. For the scenarios with a CO_2 cap there is a decrease in FEC of 18-36%. The HRES and HNUC scenarios have the lowest reduction in FEC since they can comply with the CO_2 cap by either using more nuclear power or more biomass and renewable electricity due to the assumed higher RES potentials. Likewise, the LEN scenario has the highest reduction in FEC.

The various end-use sectors contribute differently to the reduction in total FEC reflecting the different costs of adopting new, more efficient energy end-use technologies, as well as the exogenous techno-economic assumptions on new technologies for each sector. When comparing the energy intensity in 2050 to 2005 values (assuming as an indicator that 2005 = 100), in the decarbonised scenarios, the sector with the highest reduction in energy intensity is transport (mostly road transport) moving from 100 in 2005 to 26-28, followed by industry (from 100 to 34-49), the commercial sector (from 100 to 32-47) and finally the residential sector (from 100 to 51-63). It should be mentioned that in the buildings sector there is a substantial increase due to ambient air for heat pumps, which is not accounted in 2005. Clearly the LEN scenario has a very different evolution compared to the other decarbonised scenarios. On a sector level, the relative sector role regarding overall FEC reduction varies with the scenario, although the differences are small, particularly for transport. In general the LBIO and LSW scenarios have lower FEC intensity (although higher than in LEN) because there is less biomass available for FEC, due to the way the scenario is designed in the former and due to the fact that biomass is more cost-effective for electricity generation in the latter.



Reference: JRC-EU-TIMES

Figure 21 – Evolution of final energy consumption in EU28 from JRC-EU-TIMES for the studied scenarios (values for 2005 are taken from Eurostat)

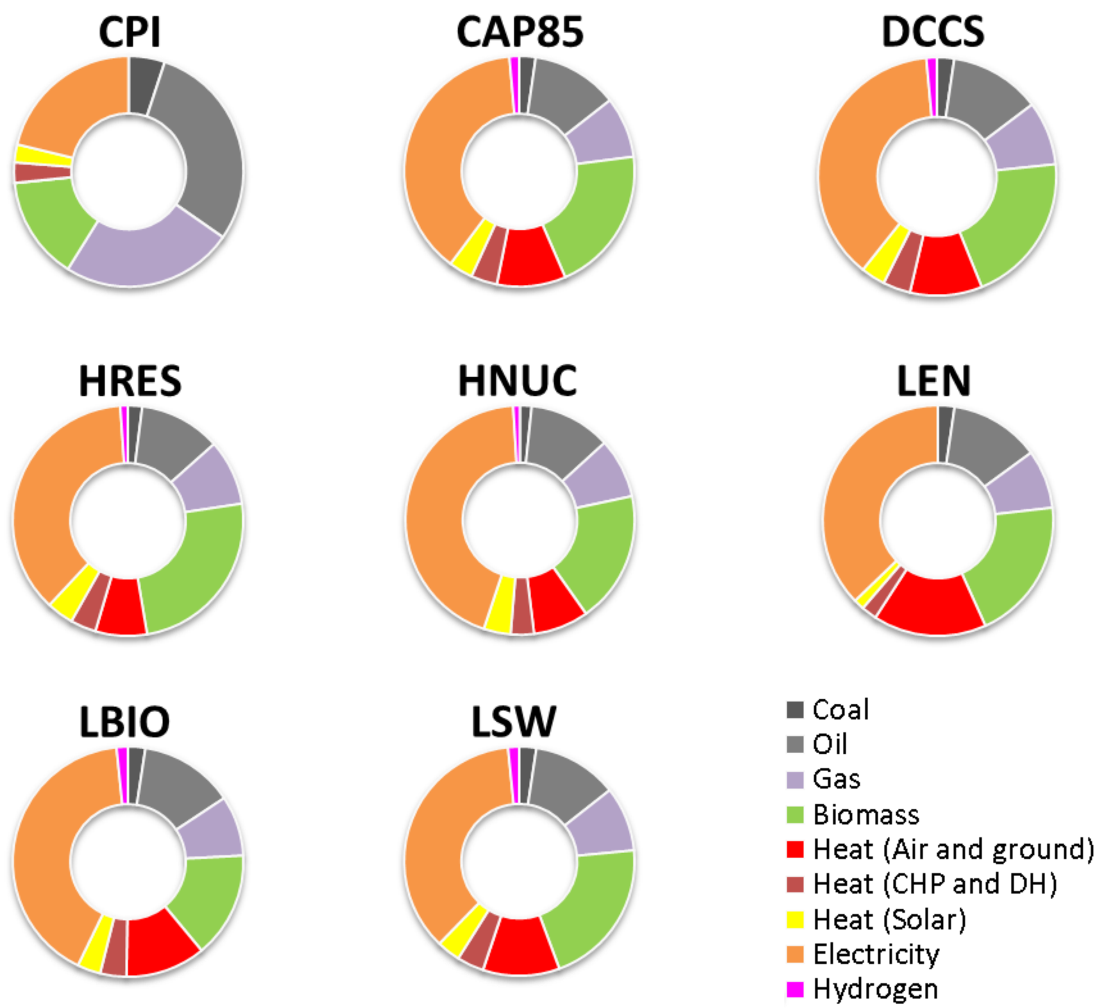
Table 58 – Energy intensity indicators for FEC in EU28 per sector relative to the year 2005 (2005=100)

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Industry (Energy on GDP)										
CPI	100	93	85	80	74	70	66	63	59	57
CAP85	100	93	85	80	72	67	60	54	49	44
DCCS	100	93	85	80	69	63	54	54	50	44
HRES	100	93	85	80	72	69	62	56	52	46
HNUC	100	93	85	80	71	69	60	55	51	47
LEN	100	93	85	80	70	64	42	40	35	32
LBIO	100	93	85	80	71	66	57	51	47	42
LSW	100	93	85	80	72	67	58	53	48	42
Residential (Energy on Population)										
CPI	100	96	94	90	87	85	83	80	78	76
Cap85	100	96	94	90	85	81	76	69	65	61
DCCS	100	96	94	90	83	79	73	69	65	60
HRES	100	96	94	90	85	82	77	71	68	62
HNUC	100	96	94	90	84	83	77	71	67	63
LEN	100	96	94	90	84	78	62	57	53	51
LBIO	100	96	94	90	84	80	75	67	63	60
LSW	100	96	94	90	85	81	76	68	64	59
Commercial (Energy on GDP)										
CPI	100	97	94	97	89	85	81	78	75	73
CAP85	100	97	94	97	84	80	75	69	64	60
DCCS	100	97	94	97	82	78	72	68	63	59
HRES	100	97	94	97	85	82	76	71	67	62
HNUC	100	97	94	97	83	81	76	71	67	62
LEN	100	97	94	97	83	77	59	56	51	49

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
LBIO	100	97	94	97	83	79	72	65	62	58
LSW	100	97	94	97	84	80	75	67	63	58
Transport (Energy on GDP)										
CPI	100	92	82	74	70	65	62	59	55	52
CAP85	100	92	82	74	68	61	52	42	31	27
DCCS	100	92	82	74	68	60	51	41	32	27
HRES	100	92	82	74	68	62	54	43	32	28
HNUC	100	92	82	74	68	63	57	45	33	26
LEN	100	92	82	74	68	63	57	45	33	26
LBIO	100	92	82	74	68	60	51	41	31	27
LSW	100	92	82	74	68	61	52	41	31	27

Reference: JRC-EU-TIMES

Regarding the relative composition of the different fuels in FEC in 2050 (Figure 22), there are also relatively small variations among the decarbonised scenarios. Electricity plays a major role in all decarbonised scenarios with a share between 37-44% of total FEC. Among the decarbonised scenarios HRES and LEN have the smallest electricity share of the decarbonised scenarios. In the CPI scenario electricity is only 21% of FEC, natural gas is 24% and oil is 30%. In the decarbonised scenarios biomass is the second most important energy carrier (15-25% of FEC), followed by oil (12-13% of FEC), and gas (8-9% of FEC) which has some blended H_2 (9% for transport). Solar and district heat have a relatively small contribution due to the conservative assumptions on their deployment as previously mentioned.



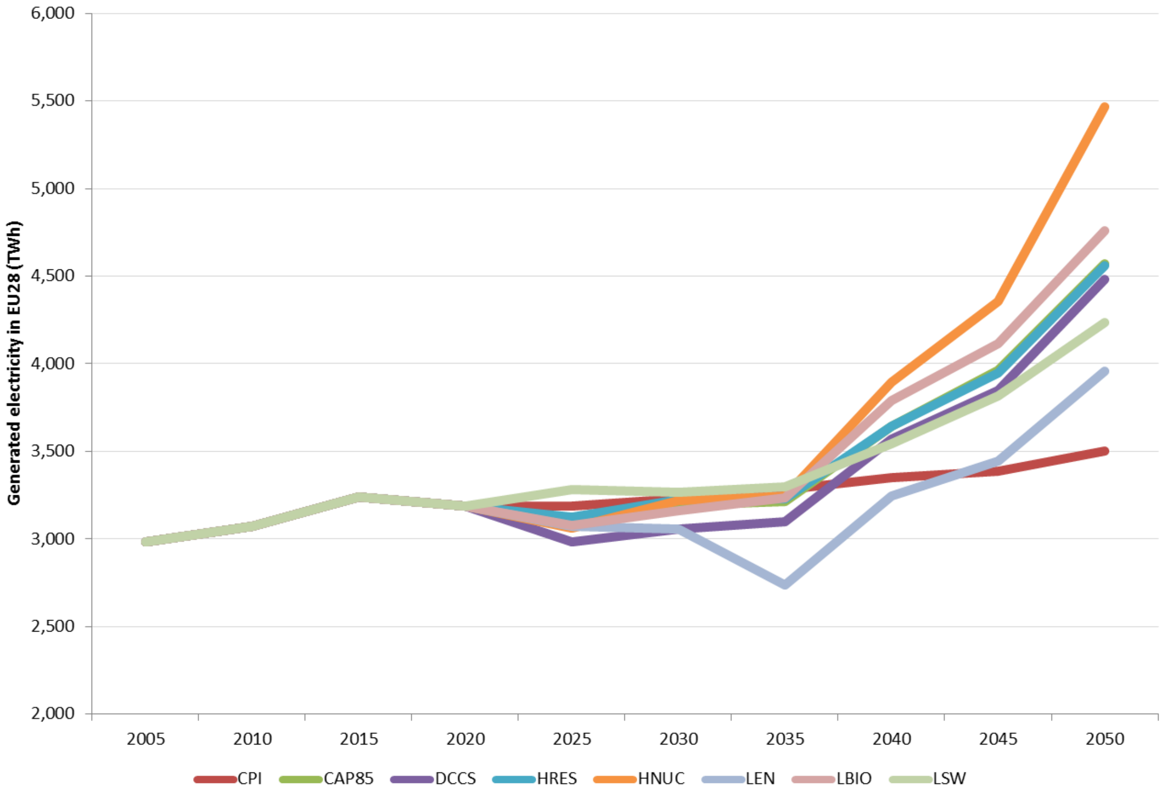
Reference: JRC-EU-TIMES

Figure 22 – Share of different energy carriers in FEC in EU28 from JRC-EU-TIMES in 2050

10.4 Electricity generation

10.4.1 Overall electricity generation trends

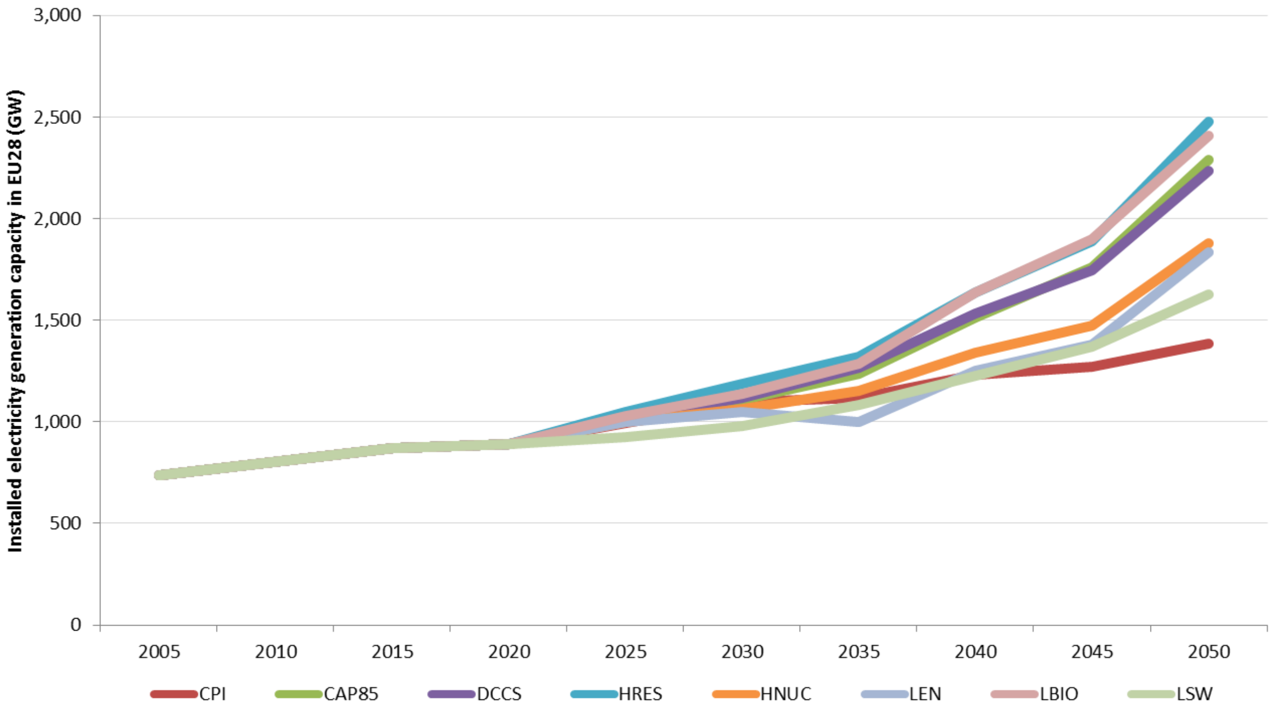
Total electricity generation and installed capacity are presented in Figure 23 and in Figure 24. The decarbonised scenarios show a substantially higher electricity generation than CPI, and as compared to 2005. Generated electricity increases by 33-83% from 2005 levels in the decarbonised scenarios. Besides the specific constraints from each scenarios' definition, the annual growth rates of generated electricity are influenced by the shutdown of nuclear power plants in Germany after 2020 (roughly less 100 TWh between 2020 and 2025) and by the CO_2 cap effect which starts to be binding from 2030 onwards. These trends are also observed in the installed capacity evolution (Figure 24).



Reference: JRC-EU-TIMES

Figure 23 – Evolution of electricity generation in EU28 from JRC-EU-TIMES for the studied scenarios

In the period of 2030-2040 a substantial part of the plants installed prior to 2005 are decommissioned as they reach the end of their life. This is particularly relevant for wind onshore (in 2040 all installed capacity prior to 2005 is decommissioned in our model), for PV (in 2040 only half of the capacity installed prior to 2005 remains), gas CCGT and for some of the coal and lignite plants (for which roughly one third of the capacity installed prior to 2005 remains operational in 2040). As a consequence a rapid investment in new power plants is made in the same period (2030-2040) and then slowed down in 2045. The rate of investment in new capacity is thus not constant over time, reflecting the retirement profile of the existent plants, the increasing stringency of the CO_2 target and the other policy assumptions such as nuclear shutdown or time of implementation of lower final energy bound. Furthermore, it should be noted that the investment pace is significantly affected by the evolution of demand for energy services, which is also not constant over time. In particular, the demand for useful energy for the other industry sub-sector accelerates significantly in the period 2045-2050.

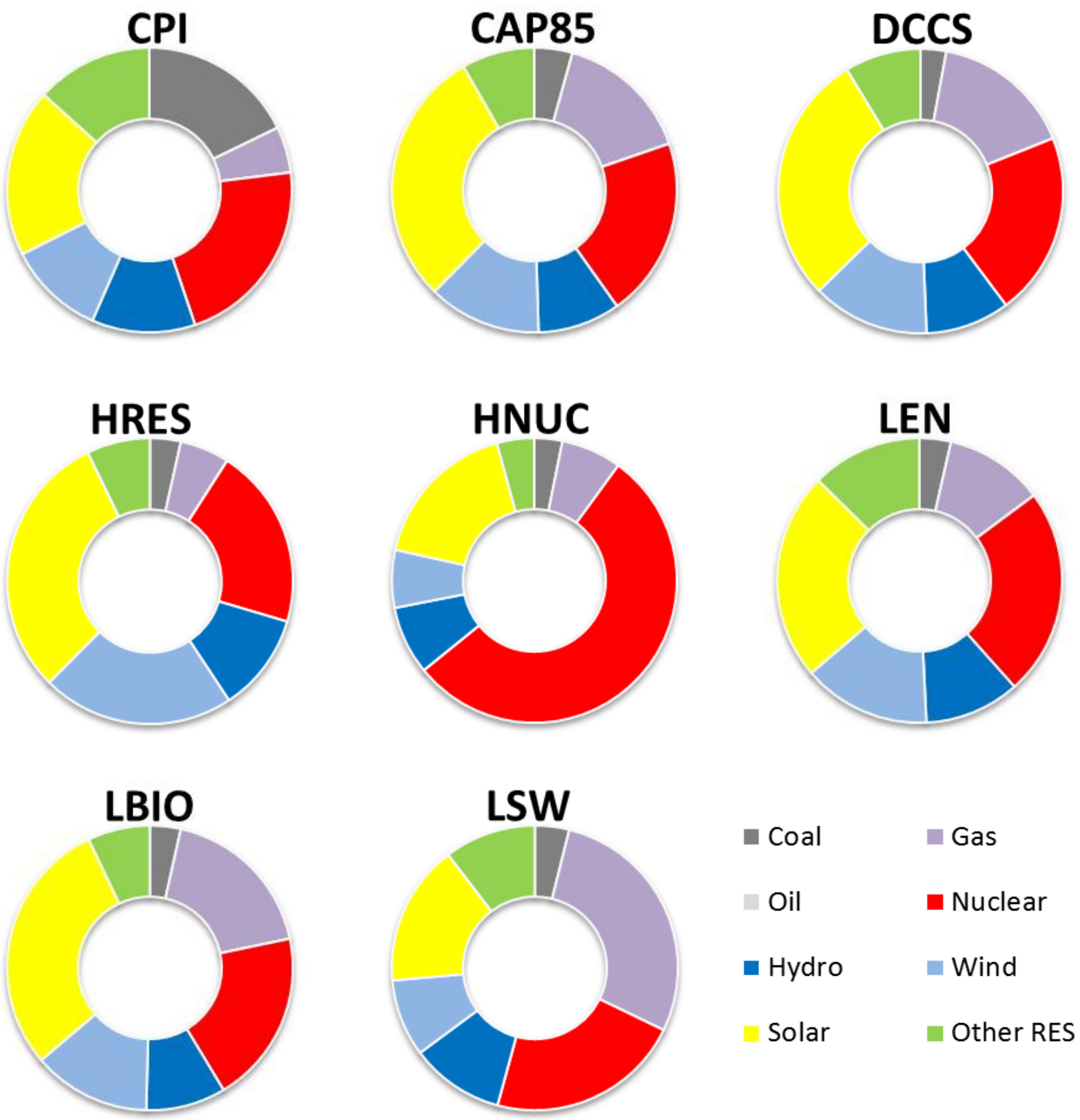


Reference: JRC-EU-TIMES

Figure 24 – Evolution of installed capacity for electricity generation in EU28 from JRC-EU-TIMES for the studied scenarios

Regarding the relative share of generated electricity from the different energy carriers in 2050, in practically all decarbonised scenarios, except HNUC and LSW, hydro, wind and solar (PV) generated electricity play a major role (49-63% of generated electricity, with only 32% and 35%, respectively in the HNUC and LSW scenarios). The share of variable wind and PV is in all scenario's lower than the imposed 50%, with the exception of the HRES scenario. The LSW scenario has naturally the lowest share of wind and PV (the imposed 25%). These technologies are backed up by gas, with 7-28% of total generated electricity, nuclear with 20-54% of total generated electricity, and other RES (4-13% generated electricity). It should be mentioned that in these scenarios storage systems play an important role which is discussed in Section 11.12. Even in the CPI scenario, without a long term CO_2 cap, coal and gas play a relatively small role in 2050 (23% generated electricity) as these fuels have high costs compared to the nuclear and renewable options, whose investment costs decrease until 2050.

Table 59 and Table 60 detail the generated electricity and installed capacity per technology. The percentage of electricity generated from RES increases from 18% in 2005 to 36-70% in 2050. The share of RES electricity is not so dependent on the CO_2 cap (in CPI scenario RES electricity is 55% of total generated electricity), but more on the assumptions on RES potentials and on nuclear deployment (HNUC has 36% RES electricity in 2050, while HRES has 70%).



Reference: JRC-EU-TIMES

Figure 25 – Share of generated electricity in EU28 from JRC-EU-TIMES in 2050

In the decarbonised scenarios the contribution of the various RES energy carriers to total RES electricity is as follows: the most important one is solar (35-50% total RES electricity in 2050), followed by wind (19-31% of RES electricity) and hydro (15-23% of RES electricity). In the LSW scenario biomass, ocean and geothermal generated electricity have a relative share of 23% of total RES electricity in 2050, whereas in the other decarbonized scenarios this is of 10-20%. There are no substantial differences among scenarios regarding the ranking of the different RES electricity technologies.

Regarding the full load hours per year, in 2050, in the CPI scenario coal plants operate on average 6000 hours and gas plants on average 1500 hours. In the CAP85 scenario CCS coal plants operate on average 6500 hours until 2040 (when there is a 60% CO_2 reduction target) and 3500 hours in 2050. CCS gas plants operate on average 5000 hours; coal plants without CCS operate on average 1000 hours; gas plants without CCS operate on average 250 hours per year. In other words: mainly gas without CCS and electricity storage provide in the decarbonisation scenario in 2050 for the flexibility needs of the power system.

Table 59 – Generated electricity per type of energy carrier

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Total generated electricity (TWh)										
CPI	2,982	3,073	3,240	3,190	3,186	3,227	3,282	3,350	3,384	3,502
CAP85	2,982	3,073	3,240	3,190	3,104	3,193	3,214	3,641	3,961	4,571
DCCS	2,982	3,073	3,240	3,190	2,985	3,058	3,097	3,570	3,850	4,483
HRES	2,982	3,073	3,240	3,190	3,125	3,225	3,227	3,642	3,948	4,558
HNUC	2,982	3,073	3,240	3,190	3,060	3,218	3,246	3,894	4,355	5,468
LEN	2,982	3,073	3,240	3,190	3,072	3,058	2,735	3,245	3,445	3,958
LBIO	2,982	3,073	3,240	3,190	3,076	3,163	3,235	3,790	4,116	4,758
LSW	2,982	3,073	3,240	3,190	3,283	3,266	3,299	3,542	3,814	4,234
Nuclear generated electricity (TWh)										
CPI	870	875	866	788	541	548	494	700	721	762
CAP85	870	875	866	788	541	660	773	937	964	934
DCCS	870	875	866	788	541	685	877	957	958	934
HRES	870	875	866	788	541	643	724	904	933	934
HNUC	870	875	866	788	541	1,107	1,274	1,891	2,219	2,959
LEN	870	875	866	788	541	656	623	841	896	934
LBIO	870	875	866	788	541	688	845	986	961	934
LSW	870	875	866	788	541	629	802	937	965	934
Thermal fossil (TWh)										
CPI	353	419	384	392	396	427	419	374	360	339
CAP85	353	419	384	392	371	372	327	329	341	420
DCCS	353	419	384	392	358	352	300	330	340	397
HRES	353	419	384	392	361	369	342	314	320	380
HNUC	353	419	384	392	364	330	292	262	249	295

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
LEN	353	419	384	392	376	370	322	306	296	310
LBIO	353	419	384	392	377	386	344	356	376	474
LSW	353	419	384	392	403	410	387	379	385	456
Renewable generated electricity (TWh)										
CPI	526	731	912	1,058	1,348	1,471	1,490	1,708	1,780	1,933
CAP85	526	731	912	1,058	1,438	1,605	1,770	1,984	2,217	2,735
DCCS	526	731	912	1,058	1,497	1,681	1,877	2,039	2,229	2,699
HRES	526	731	912	1,058	1,567	1,848	2,078	2,386	2,637	3,210
HNUC	526	731	912	1,058	1,414	1,458	1,524	1,558	1,650	1,961
LEN	526	731	912	1,058	1,430	1,581	1,568	1,855	1,967	2,438
LBIO	526	731	912	1,058	1,363	1,474	1,627	1,984	2,298	2,790
LSW	526	731	912	1,058	1,304	1,404	1,507	1,553	1,692	1,938
Hydro generated electricity (TWh)										
CPI	412	430	437	393	396	398	399	408	410	412
CAP85	412	430	437	393	409	414	417	421	425	428
DCCS	412	430	437	393	409	414	417	421	425	428
HRES	412	430	437	393	428	448	463	478	493	507
HNUC	412	430	437	393	407	411	415	418	421	425
LEN	412	430	437	393	407	411	412	416	420	428
LBIO	412	430	437	393	409	414	417	421	425	431
LSW	412	430	437	393	407	414	417	421	425	450
Wind generated electricity (TWh)										
CPI	56	143	203	240	264	277	277	315	336	386
CAP85	56	143	203	240	284	320	351	462	522	587
DCCS	56	143	203	240	310	354	398	476	527	598
HRES	56	143	203	240	323	395	482	650	760	993

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
HNUC	56	143	203	240	278	278	291	316	342	359
LEN	56	143	203	240	281	291	292	418	500	574
LBIO	56	143	203	240	297	340	379	475	549	637
LSW	56	143	203	240	269	279	279	331	342	370
Solar generated electricity (TWh)										
CPI	2	16	64	84	229	311	388	525	574	670
CAP85	2	16	64	84	246	326	530	763	974	1,341
DCCS	2	16	64	84	248	325	533	749	929	1,284
HRES	2	16	64	84	289	387	550	855	1,079	1,383
HNUC	2	16	64	84	251	282	434	586	690	946
LEN	2	16	64	84	234	278	308	546	653	937
LBIO	2	16	64	84	256	333	549	853	1,061	1,385
LSW	2	16	64	84	118	150	300	416	535	678
Geothermal generated electricity (TWh)										
CPI	0.0	9.0	14.3	16.1	18.1	19.4	19.4	19.4	19.4	19.4
CAP85	0.0	9.0	14.3	16.1	18.1	19.4	19.4	19.4	19.4	19.4
DCCS	0.0	9.0	14.3	16.1	18.1	19.4	19.4	19.4	19.4	19.4
HRES	0.0	9.0	14.3	16.1	20.1	23.4	23.5	23.5	23.6	23.6
HNUC	0.0	9.0	14.3	16.1	18.1	19.4	19.4	19.4	19.4	19.4
LEN	0.0	9.0	14.3	16.1	18.1	19.4	19.4	19.4	19.4	19.4
LBIO	0.0	9.0	14.3	16.1	18.1	19.4	19.4	19.4	19.4	19.4
LSW	0.0	9.0	14.3	16.1	18.1	19.4	19.4	19.4	19.4	19.4
Ocean generated electricity (TWh)										
CPI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAP85	0.0	0.0	0.0	0.0	0.0	0.0	0.2	26.1	49.6	154.5
DCCS	0.0	0.0	0.0	0.0	0.0	0.2	20.2	45.3	79.8	154.5
HRES	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	83.9
HNUC	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	1.4	45.0

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
LEN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	153.1
LBIO	0.0	0.0	0.0	0.0	0.0	0.0	0.4	34.9	87.9	154.5
LSW	0.0	0.0	0.0	0.0	0.0	0.0	0.2	29.8	86.2	170.0
Bioenergy generated electricity (TWh)										
CPI	56	133	194	326	440	466	406	440	440	446
CAP85	56	133	194	326	481	526	452	292	227	205
DCCS	56	133	194	326	511	568	489	329	249	215
HRES	56	133	194	326	507	594	558	380	282	220
HNUC	56	133	194	326	461	467	365	218	176	167
LEN	56	133	194	326	489	581	536	455	375	326
LBIO	56	133	194	326	384	368	262	180	156	163
LSW	56	133	194	326	492	542	491	336	285	251

Reference: JRC-EU-TIMES

Table 60 – Installed capacity for electricity generation per type of carrier/technology

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Total Generation Capacity in GW										
CPI	735	887	869	892	992	1,096	1,118	1,231	1,273	1,383
CAP85	735	887	869	892	1,008	1,106	1,238	1,513	1,758	2,289
DCCS	735	887	869	892	1,017	1,115	1,267	1,535	1,748	2,237
HRES	735	887	869	892	1,050	1,186	1,319	1,639	1,889	2,476
HNUC	735	887	869	892	1,001	1,062	1,154	1,341	1,472	1,881
LEN	735	887	869	892	999	1,048	998	1,249	1,381	1,834
LBIO	735	887	869	892	1,027	1,135	1,286	1,637	1,900	2,406
LSW	735	887	869	892	927	977	1,081	1,226	1,371	1,625
Nuclear energy generation capacity in GW										
CPI	127	127	125	113	76	74	66	93	96	100
CAP85	127	127	125	113	76	89	103	124	128	123

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
DCCS	127	127	125	113	76	92	116	127	127	123
HRES	127	127	125	113	76	86	96	120	124	123
HNUC	127	127	125	113	76	147	167	247	289	385
LEN	127	127	125	113	76	88	83	112	119	123
LBIO	127	127	125	113	76	92	112	130	127	123
LSW	127	127	125	113	76	85	106	124	128	123
Renewable energy										
Hydro (includes pumped hydro in GW)										
CPI	134	137	138	139	139	140	140	143	143	144
CAP85	134	137	138	139	144	146	147	148	149	150
DCCS	134	137	138	139	144	146	147	148	149	150
HRES	134	137	138	139	148	153	155	158	161	163
HNUC	134	137	138	139	143	145	146	147	148	149
LEN	134	137	138	139	143	145	145	146	147	150
LBIO	134	137	138	139	144	146	147	148	149	152
LSW	134	137	138	139	144	146	147	148	149	160
Wind										
CPI	40	86	123	137	145	138	121	122	127	139
CAP85	40	86	123	137	159	159	151	189	224	256
DCCS	40	86	123	137	176	180	177	201	234	269
HRES	40	86	123	137	179	196	207	275	321	452
HNUC	40	86	123	137	156	145	131	139	154	161
LEN	40	86	123	137	158	149	133	164	211	246
LBIO	40	86	123	137	168	170	165	199	243	285
LSW	40	86	123	137	152	143	126	145	149	156
Solar										
CPI	2	22	52	66	187	259	324	447	495	609
CAP85	2	22	52	66	206	277	455	657	844	1,206

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
DCCS	2	22	52	66	208	279	458	649	805	1,162
HRES	2	22	52	66	233	316	459	718	914	1,259
HNUC	2	22	52	66	210	237	367	501	592	830
LEN	2	22	52	66	195	235	260	470	563	868
LBIO	2	22	52	66	213	284	471	738	916	1,243
LSW	2	22	52	66	102	132	262	361	467	596
Other renewables in GWe (ocean, bioenergy, geothermal, etc.)										
CPI	20	37	42	44	49	54	45	50	50	52
CAP85	20	37	42	44	52	59	52	49	44	45
DCCS	20	37	42	44	54	62	55	54	49	47
HRES	20	37	42	44	53	62	56	51	47	48
HNUC	20	37	42	44	51	55	47	43	39	38
LEN	20	37	42	44	51	56	52	49	44	50
LBIO	20	37	42	44	48	51	43	44	40	40
LSW	20	37	42	44	50	56	49	50	46	44
Thermal power in GWe (gas, coal, oil, biomass, biogas)										
CPI	432	514	429	436	443	483	465	424	410	389
CAP85	432	514	429	436	421	433	379	378	384	469
DCCS	432	514	429	436	411	416	356	308	294	306
HRES	432	514	429	436	412	432	398	365	366	432
HNUC	432	514	429	436	413	387	340	305	286	330
LEN	432	514	429	436	425	429	375	355	338	363
LBIO	432	514	429	436	423	440	388	400	416	519
LSW	432	514	429	436	451	468	437	429	430	498
of which cogeneration units in GWe										
CPI	102	118	135	147	147	181	169	173	166	162
CAP85	102	118	135	147	143	173	166	175	186	231
DCCS	102	118	135	147	145	176	162	175	183	234

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
HRES	102	118	135	147	144	177	172	180	185	241
HNUC	102	118	135	147	139	168	151	152	150	187
LEN	102	118	135	147	140	168	153	145	135	155
LBIO	102	118	135	147	140	167	160	187	205	262
LSW	102	118	135	147	137	168	154	154	150	171
of which CCS units in GWe										
CPI	0	0	0	0	0	0	1	1	1	1
CAP85	0	0	0	0	46	68	91	124	139	205
DCCS	0	0	0	0	0	0	0	97	123	171
HRES	0	0	0	0	25	38	50	61	70	93
HNUC	0	0	0	0	28	34	57	77	84	118
LEN	0	0	0	0	40	64	73	104	112	134
LBIO	0	0	0	0	59	91	108	145	161	239
LSW	0	0	0	0	98	120	142	188	220	310
Solids fired in GWe (coal and biomass)										
CPI	210	241	222	223	221	235	227	203	189	166
CAP85	210	241	222	223	204	206	162	150	133	109
DCCS	210	241	222	223	181	172	138	114	105	80
HRES	210	241	222	223	197	202	168	131	116	91
HNUC	210	241	222	223	198	189	155	132	117	88
LEN	210	241	222	223	200	196	159	133	116	91
LBIO	210	241	222	223	203	207	166	149	135	108
LSW	210	241	222	223	212	220	191	162	147	118
Gas fired in GWe (natural gas and biogas)										
CPI	163	214	203	211	222	243	235	219	219	222

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
CAP85	163	214	203	211	217	223	214	226	250	354
DCCS	163	214	203	211	229	239	214	191	187	220
HRES	163	214	203	211	214	225	227	231	249	335
HNUC	163	214	203	211	214	194	182	171	168	242
LEN	163	214	203	211	225	228	212	220	221	266
LBIO	163	214	203	211	219	228	218	249	279	403
LSW	163	214	203	211	238	244	243	265	281	380
Oil fired										
CPI	59	59	5	2	1	5	4	3	2	1
CAP85	59	59	5	2	0	5	4	3	1	6
DCCS	59	59	5	2	0	5	4	3	1	6
HRES	59	59	5	2	1	5	4	3	2	6
HNUC	59	59	5	2	0	5	4	2	1	0
LEN	59	59	5	2	0	5	3	2	1	6
LBIO	59	59	5	2	1	5	4	3	2	7
LSW	59	59	5	2	0	5	4	2	1	0
Biomass-waste fired in GWe										
CPI	20	36	40	41	46	51	43	48	47	49
CAP85	20	36	40	41	50	56	49	47	41	43
DCCS	20	36	40	41	52	59	53	52	47	45
HRES	20	36	40	41	51	59	53	48	44	45
HNUC	20	36	40	41	48	53	45	41	36	35
LEN	20	36	40	41	48	54	49	47	41	48
LBIO	20	36	40	41	46	49	41	41	38	38
LSW	20	36	40	41	47	53	47	48	44	42
Geothermal heat										

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
CPI	0.0	1.1	1.8	2.0	2.3	2.5	2.5	2.5	2.5	2.5
CAP85	0.0	1.1	1.8	2.0	2.3	2.5	2.5	2.5	2.5	2.5
DCCS	0.0	1.1	1.8	2.0	2.3	2.5	2.5	2.5	2.5	2.5
HRES	0.0	1.1	1.8	2.0	2.6	3.0	3.0	3.0	3.0	3.0
HNUC	0.0	1.1	1.8	2.0	2.3	2.5	2.5	2.5	2.5	2.5
LEN	0.0	1.1	1.8	2.0	2.3	2.5	2.5	2.5	2.5	2.5
LBIO	0.0	1.1	1.8	2.0	2.3	2.5	2.5	2.5	2.5	2.5
LSW	0.0	1.1	1.8	2.0	2.3	2.5	2.5	2.5	2.5	2.5

Reference: JRC-EU-TIMES

The percentage of electricity generated from CHP (Table 61) decreases from 2005 values due to: 1) the exogenous assumptions described in the previous sections regarding the pace of deployment of centralised heat in buildings; 2) the strict CO_2 emission caps especially from 2030 onwards associated with the relatively limited CHP options with low carbon emissions (mostly biomass) and simultaneously low fuel costs, and 3) the very high share of electricity generated from solar (or nuclear for the HNUC scenario) in 2050.

Table 61 – Indicators for electricity generation

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
CHP indicator (% of electricity from CHP)										
CPI	12	12	13	14	14	14	11	12	11	11
CAP85	12	12	13	14	14	13	11	8	7	7
DCCS	12	12	13	14	15	14	12	9	9	8
HRES	12	12	13	14	14	13	11	8	7	6
HNUC	12	12	13	14	14	12	10	6	6	4
LEN	12	12	13	14	14	13	9	7	7	6
LBIO	12	12	13	14	14	12	10	8	7	7
LSW	12	12	13	14	13	13	11	10	9	9
CCS indicator (% of electricity from CCS)										
CPI	0	0	0	0	0	0	0	0	0	0

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
CAP85	0	0	0	0	10	13	16	18	18	18
DCCS	0	0	0	0	0	0	0	14	16	18
HRES	0	0	0	0	5	7	9	8	8	8
HNUC	0	0	0	0	6	6	10	10	10	9
LEN	0	0	0	0	8	12	15	16	16	14
LBIO	0	0	0	0	12	17	19	20	19	21
LSW	0	0	0	0	18	21	24	28	29	31
Nuclear indicator (% electricity generated from nuclear)										
CPI	29	28	27	25	17	17	15	21	21	22
CAP85	29	28	27	25	17	21	24	26	24	20
DCCS	29	28	27	25	18	22	28	27	25	21
HRES	29	28	27	25	17	20	22	25	24	20
HNUC	29	28	27	25	18	34	39	49	51	54
LEN	29	28	27	25	18	21	23	26	26	24
LBIO	29	28	27	25	18	22	26	26	23	20
LSW	29	28	27	25	16	19	24	26	25	22
Renewable energy forms and industrial waste indicator (% electricity generated from renewables)										
CPI	18	24	28	33	42	46	45	51	53	55
CAP85	18	24	28	33	46	50	55	54	56	60
DCCS	18	24	28	33	50	55	61	57	58	60
HRES	18	24	28	33	50	57	64	66	67	70
HNUC	18	24	28	33	46	45	47	40	38	36
LEN	18	24	28	33	47	52	57	57	57	62
LBIO	18	24	28	33	44	47	50	52	56	59
LSW	18	24	28	33	40	43	46	44	44	46

Reference: JRC-EU-TIMES

The contribution of electricity generation technologies with CCS varies in the range 9-31% total generated electricity in 2050 and it is especially relevant in the LSW scenario. CCS technologies have high fuel costs compared to renewable and nuclear options and are also penalised for the remaining carbon emissions. Not all the CO_2 storage potential available in EU28 is used in all decarbonised scenarios, as only roughly a maximum of 965 Mt CO_2 is stored in 2050 in the LSW scenario. Of these approximately 41-63% corresponds to electricity generation captured emissions, 23-59% to industry emissions, and the rest to coal gasifications to produce hydrogen to be used in the transport sector.

10.4.2 Electricity prices

The electricity price is a typical output of a TIMES model. It covers production, transportation and distribution costs as well as possible price mark-ups or subsidies when implemented. Unlike more simplified modelling approaches, the TIMES model produces a price for each time slice in each country and follows the paradigm of long term marginal pricing.

Thus the electricity price (exclusive taxes) is an indicator that reflects many interactions in the energy system model. The price covers the costs for investments in power plants, grids and storage plants as well as the variable and fixed operational costs. The CO_2 price as well as scarcity mark-ups for the limited availability of resources are included in the electricity price. Figure 26 shows the weighted average of the electricity prices in all EU28 countries. Differences in electricity prices between countries mainly come from differences in the costs for the network and the differences in resources, even if parts of these differences are smoothed out by trade.

In the CPI scenario, there is already a 35% increase in the electricity price in the period 2020-2050. The decarbonised scenarios have a price for residential users that goes from 250 Euro/MWh (HNUC scenario) to around 350 Euro/MWh such as in the LBIO scenario.

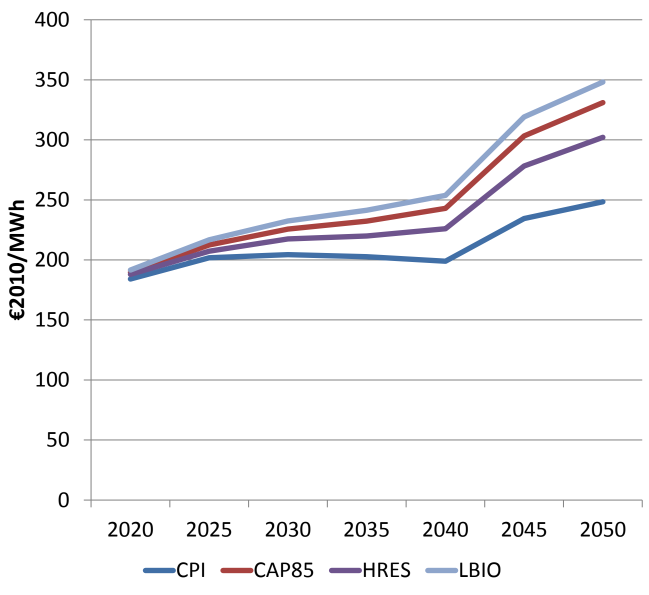


Figure 26 – Electricity prices for the CPI, CAP85, HRES and LBIO scenarios (excl. taxes, weighted average for EU-28, three period moving average)

We conclude that the efforts between 2040 and 2050 to meet the CAP85 target in EU28 are high. There is a visible increase in required investments for meeting the target. The model results seem to underline the role of the SET-Plan in decreasing the costs and efficiency of low-carbon technologies and consequently accelerating their deployment.

The most important components of the electricity price, apart from the typical investment, fuel and O&M costs are the CO_2 price, the system flexibility constraints and the costs for additional network.

The high CO_2 price in the decarbonized scenarios impacts the choices in the electricity sector. However the impact of the carbon price on the electricity price is tempered because of two reasons, as follows: i) the CPI scenario shows already an increase in electricity price of 35%, and ii) the CCS technology brings down the remaining emissions from fossil fuel burning to 12% of the produced emissions. The impact per unit of electricity is therefore 8 times lower than a non-CCS plant. We conclude that the capturing rate is a crucial characteristic. In the case of CCS with natural gas, the CO_2 price amounts to a level similar to the gas cost per unit of electricity produced. A general conclusion is that capital costs are a rather limited share of the total cost in the case of fossil fuel based plants.

There is a price effect caused by the system flexibility requirement that originates from the assumptions that a maximum of 50% electricity can be generated from variable solar and wind to account for concerns related to system adequacy. This amounts to 33 euro/MWh and it is a transfer from the variable to the flexible power plants. In the LSW scenario where variable plants only can produce 25% of the electricity, the flexible plants receive 42 euro/MWh but the variable plants contribute 126 euro/MWh (as in the LSW scenario the variable plants produce 1 unit for each 3 units produced by the flexible plants). This result can be interpreted as showing that the variable plants (solar and wind) are cost efficient even with this "additional" variability cost.

In the HRES scenario, this system safety requirement is relaxed to 90% under the assumption that JRC-EU-TIMES already considers the flexibility via the different model options. In this scenario, this constraint is not binding.

The additional equations to integrate the non-constant distribution of PV in one time slice (see Section 7.2.6) are another example of extended system flexibility. These encompass the different system options to deal with variability such as reducing the demand, increased use of storage or curtailment. The equation that guarantees that energy can be absorbed and forces investment in storage capacity is the most important. As a matter of fact, during the summer peak, the PV roof panels contribute to the installation costs of electricity storage at a cost of more than 2000 Euro per kWpeak. The conclusion is that installing PV roof panels comes along with an additional investment that is even higher than the investment of the PV panels itself.

All costs related to extension of the network are allocated to the winter peak time slice as wind and solar PV technologies cannot operate during this time slice. Grid costs for transporting and distributing are significant in both CPI and decarbonized scenarios.

10.4.3 Electricity Trade

The JRC-EU-TIMES model has trade within the 31 countries of the model and with limited countries outside the regional scope. The net imported electricity from outside Europe increases gradually in all scenarios from some 20 PJ to 200 PJ in 2030. Until 2030, most of the trades are fixed to a level in line with results from the REACCESS project. After 2030, upper bounds are implemented in the JRC-EU-TIMES and imports are observed from the outside up to these limits. The biggest imports are from Russia and Ukraine. The cost aspect of exogenous electricity trade will be refined in the future as the trade seems to be too advantageous.

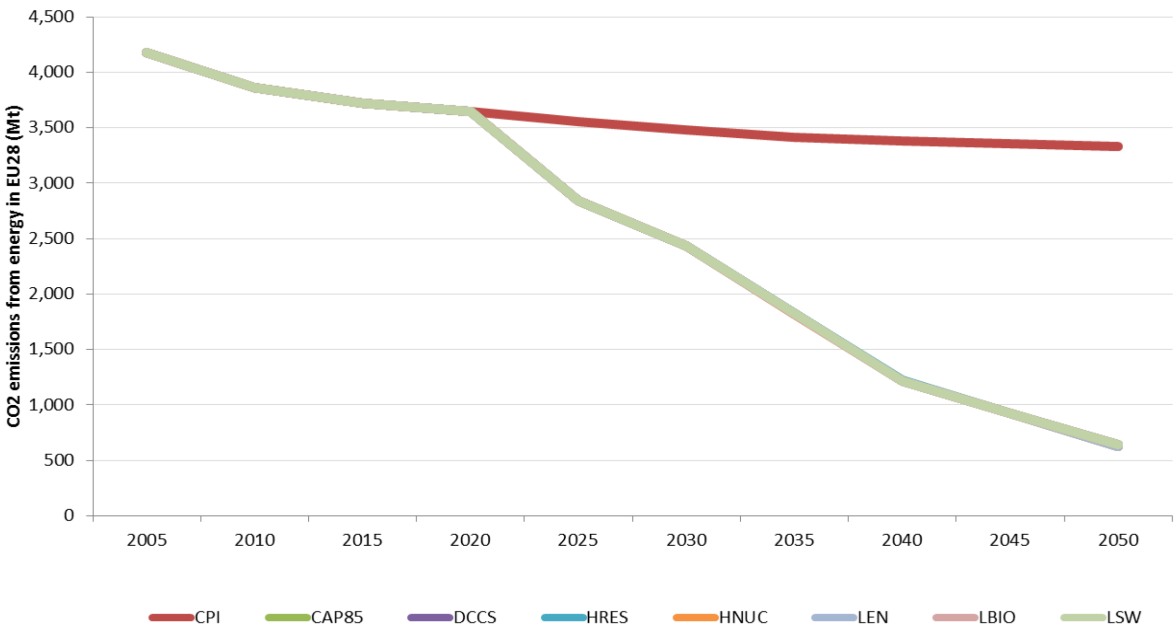
Regarding the trade within the 31 countries, we see clear patterns that are dependent on the timeframe and the chosen scenario. The underlying reason for a country to import or export is the availability of cheaper electricity in another country. This is why we for example see imports from Norway and Austria (further development of hydro). Summing up all trade within the 31 countries, there is a remaining net electricity import that is in line with the trade from regions outside the model (supra) and a smaller part of transmission losses in the trade processes.

In terms of the grid infrastructure within the 31 modelled countries, the total installed trans boundary capacity increases from roughly 122 GW in 2005 to 193-195 GW in 2025 (a growth of approximately 57-60% from 2005) and up to 202-205 GW in 2050 (a growth of approximately 4-6% from 2025). Until 2025 the new grid infrastructure is following the ENTSO-E forecasts (as in Section 7). After this period the model decides on additional capacity based on cost-effectiveness criteria. We conclude that until 2025 the expected increases in the grid are almost sufficient to ensure cost-effective electricity trade until 2050. However, it should be considered that JRC-EU-TIMES has a limited number of time slices and currently does not encompass regional differences in RES activity. The differences between scenarios are lower than 4%.

10.5 Energy system wide CO2 mitigation

10.5.1 Overall energy system wide CO_2 mitigation

The evolution of energy related CO_2 emissions (process and combustion) is presented in Figure 27 and Table 61 reflecting the CO_2 emission caps as imposed into JRC-EU-TIMES. This represents an evolution of CO_2 emissions per capita from 8.5 $ktCO_2$/inhabitant to 1.2-1.3 $ktCO_2$/inhabitant in 2050 in the decarbonised scenarios and from 8.5 to 6.5 $ktCO_2$/inhabitant for the CPI scenario.



Reference: JRC-EU-TIMES

Figure 27 – Evolution of CO_2 emissions in EU28 from JRC-EU-TIMES for the studied scenarios

Table 62 – Evolution of CO_2 indicators for EU28 (CO_2 emissions per capita $ktCO_2$/inhabitant)

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
CPI	8.5	7.7	7.3	7.1	6.9	6.7	7.2	6.6	6.5	6.5
CAP85	8.5	7.7	7.3	7.1	5.5	4.7	3.5	2.4	1.8	1.3
DCCS	8.5	7.7	7.3	7.1	5.5	4.7	3.5	2.4	1.8	1.2
HRES	8.5	7.7	7.3	7.1	5.5	4.7	3.5	2.4	1.8	1.2
HNUC	8.5	7.7	7.3	7.1	5.5	4.7	3.5	2.4	1.8	1.2
LEN	8.5	7.7	7.3	7.1	5.5	4.7	3.5	2.4	1.8	1.2
LBIO	8.5	7.7	7.3	7.1	5.5	4.7	3.5	2.4	1.8	1.3
LSW	8.5	7.7	7.3	7.1	5.5	4.7	3.5	2.4	1.8	1.3

Regarding the different contribution of the several sectors for CO_2 mitigation (Table 63), in the decarbonized scenarios clearly the electricity generation sector plays a major role in all the studied scenarios (less 92-95% CO_2 emissions in 2050 than in 2005), followed by industry (less 87-95% CO_2 emissions in 2050 than in 2005), transport (less 69-77% CO_2 emissions in 2050 than in 2005), and finally buildings (less 85-92 % CO_2 emissions in 2050 than in 2005). The primary energy conversion sector which is mainly composed by refineries and other fuel processing technologies, has very limited options to mitigate CO_2 as refineries are not modelled in detail in JRC-EU-TIMES, as previously explained. The mitigation options adopted in each sector are explained in more detail in the following sections.

Table 63 – Evolution of sector CO_2 emissions for EU28

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
CO_2 emissions power sector (Mt)										
CPI	1,367	1,352	1,300	1,185	1,072	946	1,105	764	726	670
CAP85	1,367	1,352	1,300	1,185	572	349	137	106	106	90
DCCS	1,367	1,352	1,300	1,185	627	413	228	84	87	83
HRES	1,367	1,352	1,300	1,185	596	342	114	79	79	67
HNUC	1,367	1,352	1,300	1,185	612	296	112	84	84	72
LEN	1,367	1,352	1,300	1,185	585	293	120	59	56	53

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
LBIO	1,367	1,352	1,300	1,185	542	322	140	108	107	92
LSW	1,367	1,352	1,300	1,185	592	369	168	121	121	105
CO_2 emissions industry (Mt)										
CPI	905	722	689	715	741	772	803	792	783	802
CAP85	905	722	689	715	586	503	344	129	107	58
DCCS	905	722	689	715	556	510	357	139	110	58
HRES	905	722	689	715	567	503	335	140	132	64
HNUC	905	722	689	715	554	526	340	142	121	65
LEN	905	722	689	715	581	543	391	193	185	113
LBIO	905	722	689	715	605	527	340	131	108	48
LSW	905	722	689	715	577	507	334	129	106	62
CO_2 emissions residential (Mt)										
CPI	492	477	458	437	412	391	366	344	324	311
CAP85	492	477	458	437	398	357	276	175	128	74
DCCS	492	477	458	437	389	343	259	187	131	74
HRES	492	477	458	437	397	364	289	206	160	108
HNUC	492	477	458	437	393	367	280	189	143	84
LEN	492	477	458	437	392	343	205	133	115	31
LBIO	492	477	458	437	395	351	270	158	116	57
LSW	492	477	458	437	395	353	273	172	125	66
CO_2 emissions commercial (Mt)										
CPI	183	166	169	179	189	203	212	223	231	243
CAP85	183	166	169	179	176	170	130	75	58	24
DCCS	183	166	169	179	172	162	122	85	72	26
HRES	183	166	169	179	176	169	127	69	64	32
HNUC	183	166	169	179	176	174	133	73	60	24
LEN	183	166	169	179	176	173	87	53	38	21
LBIO	183	166	169	179	179	174	137	77	52	20

Scenario	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
LSW	183	166	169	179	176	169	130	78	55	22
CO_2 emissions transport (Mt)										
CPI	1,021	935	898	924	939	952	978	1,009	1,014	1,026
CAP85	1,021	935	898	924	915	864	753	607	397	274
DCCS	1,021	935	898	924	908	827	730	596	397	278
HRES	1,021	935	898	924	911	865	770	599	363	232
HNUC	1,021	935	898	924	915	878	770	602	391	256
LEN	1,021	935	898	924	913	894	841	645	393	274
LBIO	1,021	935	898	924	927	869	772	615	413	315
LSW	1,021	935	898	924	908	847	737	593	390	275
CO_2 emissions energy branch - refineries and other primary energy conversion (Mt)										
CPI	134	132	132	132	132	153	191	191	209	208
CAP85	134	132	132	132	131	129	129	128	128	127
DCCS	134	132	132	132	130	128	127	128	127	127
HRES	134	132	132	132	130	129	128	128	128	127
HNUC	134	132	132	132	130	129	129	128	128	127
LEN	134	132	132	132	131	129	128	127	126	125
LBIO	134	132	132	132	131	130	129	128	128	127
LSW	134	132	132	132	131	130	129	128	128	127

Reference: JRC-EU-TIMES

Apart from the DCCS scenario, already in 2030 all decarbonised scenarios are building up the use of CCS with between 375 (HRES) and 675 Mt (LSW) of CO_2 stored yearly. This is between 13% (HRES) and 22% (LSW) of the total produced CO_2. For most of the decarbonised scenarios, the total CO_2 stored is at least half of the produced CO_2 in 2050 (except LEN). This illustrates the important role of CCS as there is yearly between 500 (LEN) and 965 Mt (LSW) of CO_2 stored.

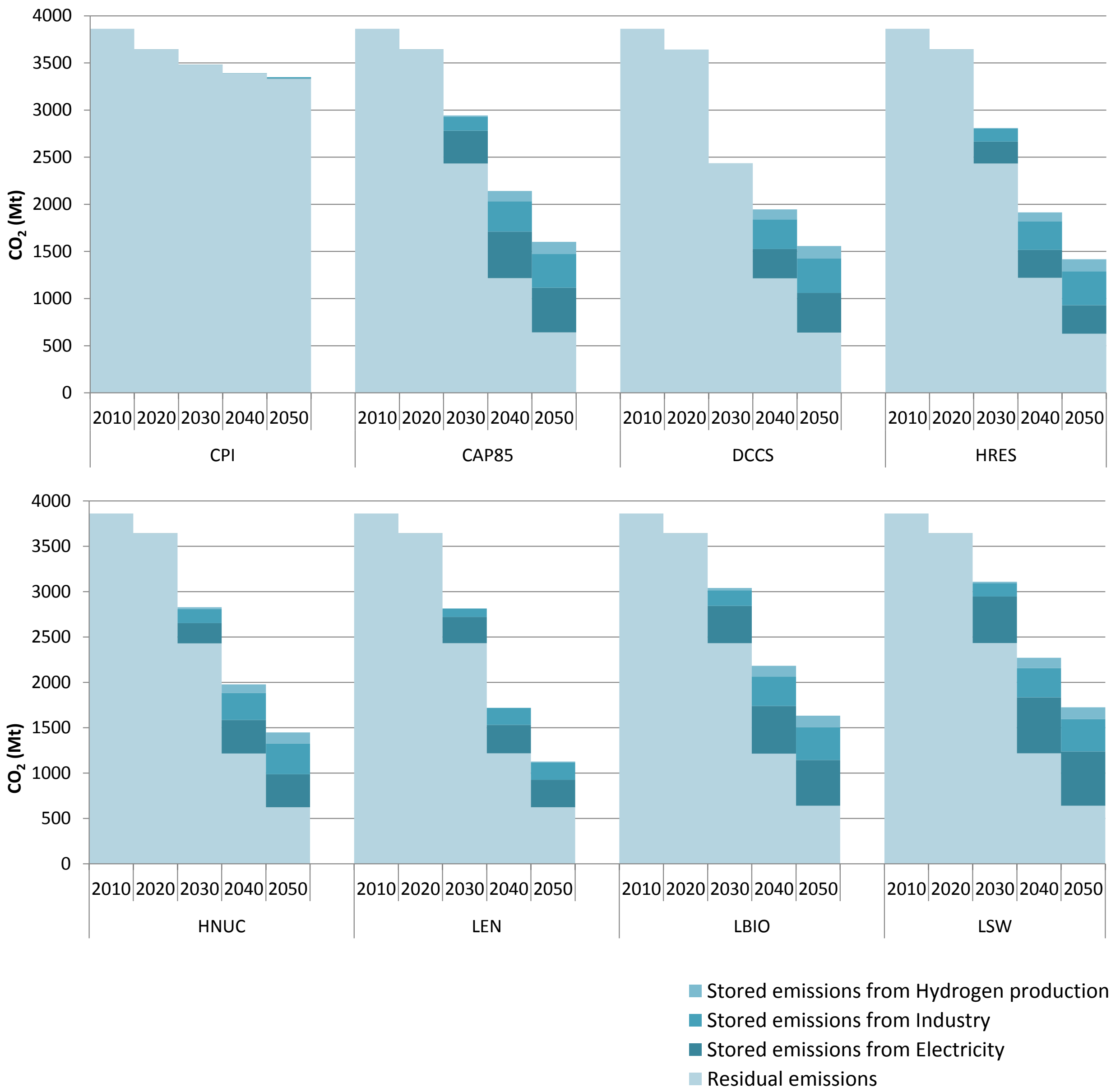


Figure 28 – Stored and residual emissions as computed by JRC-EU-TIMES for all scenarios

10.5.2 Insights on marginal abatement of CO_2

The impact of the carbon constraint applies to all sectors equally, though weighted by their relative residual emissions. However, the main driving force behind the magnitude of the carbon constraint is to be found in the breadth of technological options available in the model.

The CO_2 price estimated by the model as a consequence of the CO_2 constraint reflects the transition to an energy system that has marginally lower CO_2 emissions attained at rather high costs. Exploring the changes in system cost by technology in 2050, when the CO_2 emission constraint is tightened marginally in that year (i.e., it is 1Mt lower than in the CAP85), provides some insights into these critical driving forces of the JRC-EU-TIMES model. For instance, in the commercial and residential sectors, the tightening of the constraint is accompanied by a larger investment in heat pumps with electric boiler for both heating and cooling, as opposed to heating only. This comes at an additional net cost, but allows a less carbon intensive heating and cooling of buildings. In the transport sector, gas is substituted by bioethanol. As all available technological options to reduce emissions are exploited to their potential in the CAP85 scenario, the demand of cement and other industrial products needs to be further reduced, contributing to increasing the total costs, as a reduced demand generates consumer losses. These examples show that, in an energy system model, the CO_2 price cannot be attributed to the switch of only one set of technologies, but rather to a system-wide adjustment.

10.6 Costs of the energy system

The energy system cost represents the total of all energy expenses in an energy system. It can be decomposed into investment costs, fixed O&M costs, mining and imports costs and other variable O&M costs (for simplicity referred to as "fixed" and "variable costs"). For most of the indicators, we show results for the CPI, CAP85, HRES and LBIO scenarios. This selection of scenarios covers the full range of costs with the HRES being the cheapest scenario and LBIO being the most expensive. In terms of energy system costs DCCS, HNUC and LSW are close to the CPI scenario. The LEN scenario with a cap for energy use is more conceptual.

Figure 29 shows the energy system costs for the CPI, CAP85, HRES and LBIO scenarios in the years 2020, 2030, 2040 and 2050. The energy system costs in JRC-EU-TIMES do include all costs involved in providing an energy service. They include typical energy technologies such as power plants, but also include the costs for cars, trucks and the construction of steel production facilities. All costs related to heating systems in buildings are included; however the costs of the buildings are excluded.The increase of the energy system cost in the CPI is lower than the decrease of the final energy use (as explained in the previous sections) because of decreasing energy intensities. When adding a cap for the total CO_2 emissions, the annual costs increase in the year 2050 by approximately 185 to 310 BEuro for respectively the HRES scenario and the LBIO scenario. These costs represent a 5 to 10% increase with respect to the cost of 3389 BEuro in the CPI scenario.

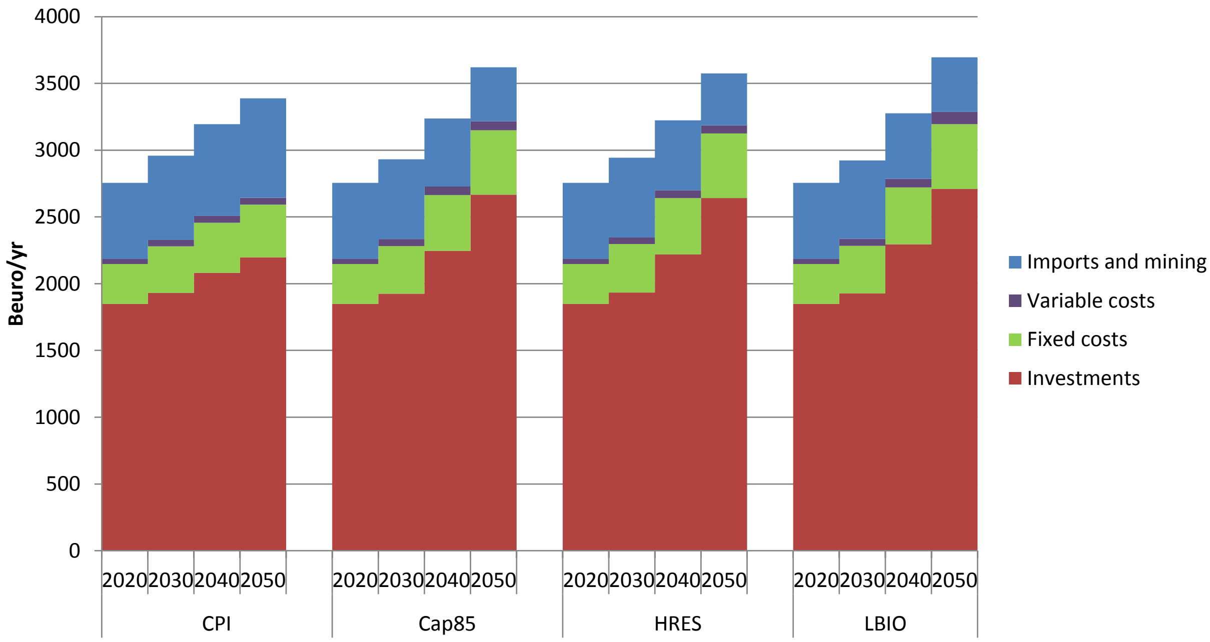


Figure 29 – Total energy system costs as computed by JRC-EU-TIMES for the CPI, CAP85, HNUC and LBIO scenarios

The TIMES modelling approach used in the JRC-EU-TIMES model allows giving detailed insights in these different components. The preferred approach is to analyse cost differences to some reference. In this section we take the CPI scenario as a reference. The following tables and figures show the additional energy system costs relative to the CPI scenario in the years 2030, 2040 and 2050. Up to 2040, the increased investment, fixed and variable costs are (over)compensated by lowered costs for importing and mining.

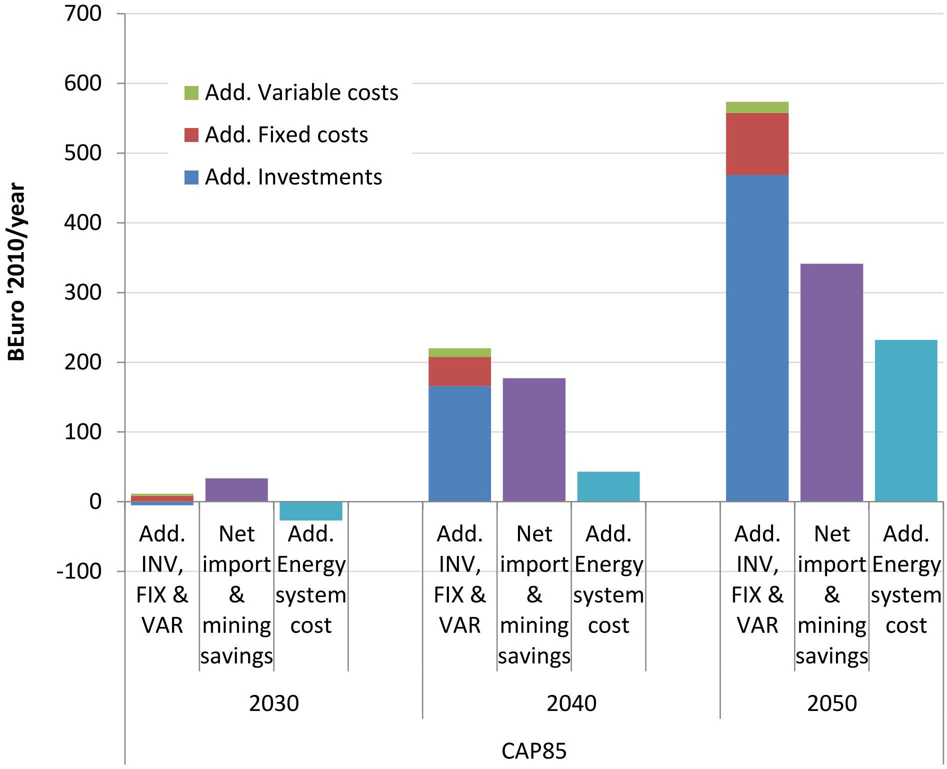


Figure 30 – Comparison of energy system costs between CPI and CAP85 scenarios

In the standard CAP85 scenario, additional investments in 2040 and 2050 amount to about 165 and 470 BEuro, respectively. The technologies in the low carbon scenarios show higher fixed and variable costs adding another 55 and 105 BEuro per year. Net import and mining savings amount to 175 and 340 BEuro per year. We calculated that the increase of the energy system cost -230 BEuro annual- can be compared to 1% of the European GDP in 2050 (GDP2050), assuming that the GDP increases from the current 13000 B€ to 23000 B€ in 2050 (in line with our macroeconomic assumptions).

For the CAP85 scenario in 2050, the 1% additional energy system cost can be decomposed into additional investment and fixed costs of around 2.5% of GDP2050 and reduced variable costs of around 1.5% of GDP2050. Assuming 500 Million habitants in EU28, this would be a per capita effort of 1100 Euro per year and savings of around 650 Euro per year.

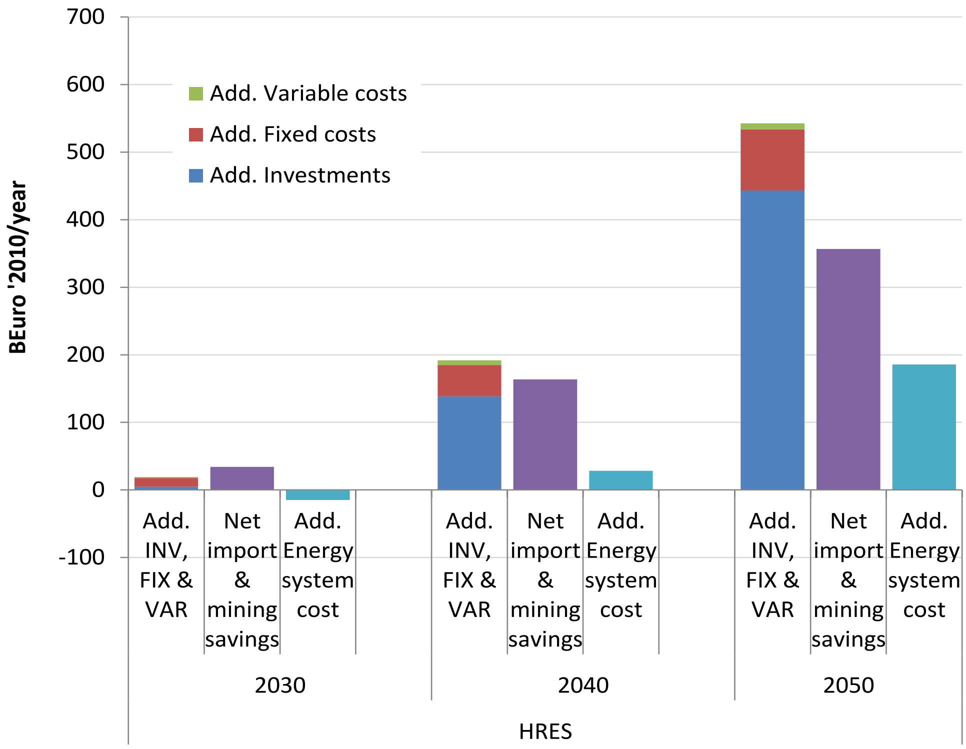


Figure 31 – Comparison of energy system costs between CPI and HRES scenarios

The smallest difference of energy system costs vis-à-vis the CPI scenario are observed in the HRES scenario with similar savings from net imports and mining, but with much lower additional investment, fixed and variable costs. The main driver for these reductions is the increased potential of solar and wind availability and biomass imports. It is important to recall that the higher renewable potential was not taken into account in the CPI scenario.

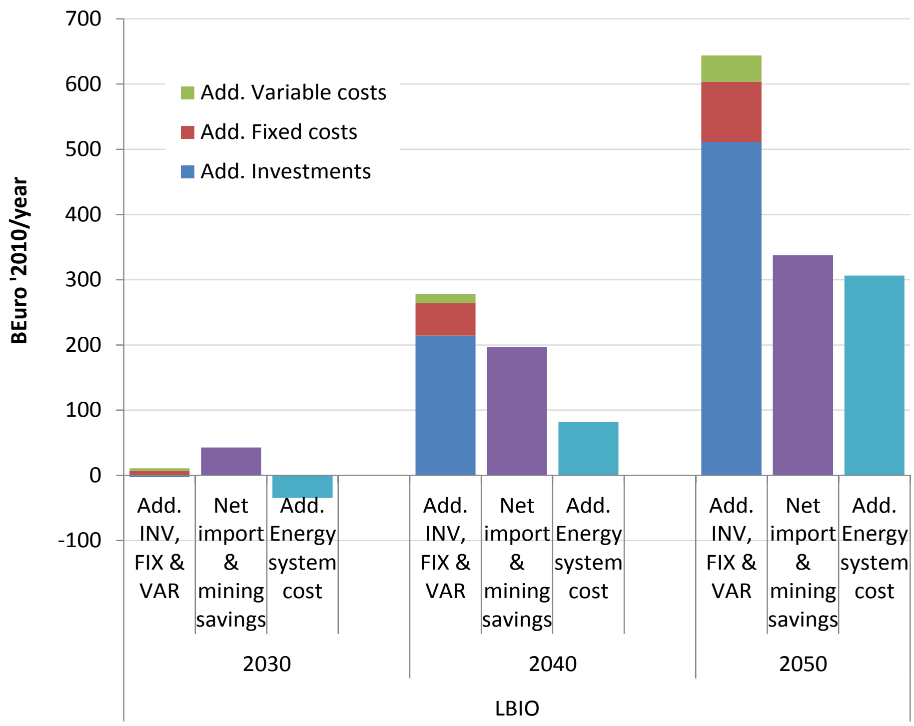


Figure 32 – Comparison of energy system costs between CPI and LBIO scenarios

In the LBIO scenario, the importance of biomass availability becomes clear. The additional costs for investment, variable and fixed costs amount to 645 BEuro per year compared to the CPI scenario. This difference is 70 BEuro higher than when comparing CAP85 with the CPI scenario. The savings are rather similar than the other scenarios. For completeness, Table 64 summarises the results for all scenarios. The impact of much higher availabilities of nuclear power plants comes along with a slightly higher energy system cost. However, the development of nuclear plants allows the level of energy services to be higher (less endogenous demand reduction caused by the demand elasticity).

Table 64 –Difference in costs relative to CPI (BEuros'2010) for 2020, 2035 and 2050.

Type of Cost/Scenario	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
2030							
Add. Investments	-5	-22	0	0	0	0	0
Add. Fixed costs	8	-1	13	10	7	7	7
Add. Variable costs	3	3	2	7	1	4	7
Net import and mining savings	34	46	34	41	20	43	23
Energy system cost	**-27**	**-66**	**-19**	**-24**	**-11**	**-32**	**-9**
2040							
Add. Investments	166	177	67	88	29	89	80
Add. Fixed costs	42	43	46	45	61	50	40
Add. Variable costs	12	12	7	21	-1	14	17
Net import and mining savings	177	171	164	190	189	196	163
Energy system cost	**43**	**61**	**-44**	**-35**	**-100**	**-43**	**-26**
2050							
Add. Investments	469	467	443	498	385	511	424
Add. Fixed costs	89	86	90	90	118	92	82
Add. Variable costs	16	16	9	33	0	40	21
Net import and mining savings	341	332	357	374	399	338	295
Energy system cost	**232**	**236**	**186**	**247**	**103**	**306**	**233**

The negative impact of greenhouse gas emissions is becoming a factor that influences investment decisions ("internalised in the market") via trading or tax mechanisms. However, damage from climate change is still the most important externality of fossil energy use today. The analysis so far does not include damage from CO_2 emissions. The CO_2 price used in the scenario runs (up to 51 €/ton) only reflects the climate policy and not the climate damage. However we calculated the total yearly avoided greenhouse gas to be 2 700 Mt in the period 2040-2050. With an additional energy system cost in the same period of around 200 BEuro, the average energy system cost of CO_2 reduction is around 75 €/ton.

Considering that all decarbonisation scenarios include the CAP85, shows the incremental cost effects referred to this CAP85 baseline. When it comes to energy system cost, HRES and LEN show relevant increased savings. In HRES the relaxed constraints on energy potentials and variable energy share contribute to lower the system cost, while lower demand at LEN shows the expected effect with less required investment to cope with the supply. On the other hand, DDCS will imply an increase of 4 BEuros, and HNUC will imply an increase of 15 BEuros, as explained before. Naturally, lower availability of cheap biomass, shows up as higher energy system cost in LBIO.

Table 65 –Difference in costs relative to CAP85 (BEuros'2010) for 2050

Type of Cost/Scenario	DCCS	HRES	HNUC	LEN	LBIO	LSW
	2050					
Add. Investments	-2	-26	29	-84	42	-45
Add. Fixed costs	-3	1	1	29	3	-7
Add. Variable costs	0	-7	17	-16	24	5
Net import and mining savings	-9	16	33	58	-3	-46
Energy system cost	4	-46	15	-129	74	1

Table 66 gives an overview of how energy system costs are translated into a single discounted cost in the base year or into an annuity or average cost for the period 2020-2050. For the total model horizon and using a 5% discount rate we have an additional discounted investment and fixed cost of around 2000 BEuro and a reduction of 1300 BEuro for the variable costs, including net import and mining costs. As most of the additional energy system costs come in the later periods, the additional discounted cost is only a factor of 2 to 3 higher than the additional energy system costs in 2050.

Table 66 – Overview of the energy system costs for the studied scenarios

Type of cost/scenario	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
Additional discounted energy system costs for total modelling horizon (Beur)	623	491	466	624	6	836	719
Additional fixed costs	370	326	388	362	462	387	344
Additional investment costs	1597	1531	1431	1624	1089	1820	1464
Additional variable costs	-1343	-1366	-1353	-1362	-1545	-1371	-1089
Annuity (5% rate) of total discounted additional energy system costs, period 2020-2050 (BEur/year)	39	30	29	39	0	52	45
Average of annual additional energy system costs, period 2020-2050 (BEur/year)	79	75	58	81	11	107	86

The energy system cost can also be calculated from the average cost of energy services and the amount of services used. In general, the average cost of energy services increases by around 25% in 2050 in comparison to the CPI scenario. The demand for energy services decreases on average from 15% up to 20% (for more detail see 10.6) with a higher reduction in fuel intensive demands and a lower reduction for transportation. The combined effect of both changes, a cost increase per unit of energy service and a reduced use of energy services, is an increase of the energy system costs by 5% to 10% in 2050.

10.7 Impact of key policy and technology related assumptions

In the JRC-EU-TIMES model, some policy and technology assumptions reduce the number of choices in the optimisation process. These assumptions are necessary to reflect certain limitations in the energy system. Based on the feedback from the model validators we describe in this section the impact of the most important constraints that are implemented in the exemplary scenario runs

We developed a framework to analyse the relevance of constraints in the JRC-EU-TIMES model. To analyse the impact of a constraint, we use the dual solution of a TIMES model that provides additional information in terms of marginal or opportunity costs (Remme, Blesl, & Tober, 2011). For example, the dual solution of the CO_2 limitation in JRC-EU-TIMES describes the marginal value (or shadow value) when an additional ton of CO_2 would be mitigated. The marginal value of the different constraints enhances the understanding of the model solution. We replicated this approach to all user constraints in the model for the CAP85 scenario by developing a measure of the relevance of each constraint in the total of the model. We calculated an indicator by multiplying the marginal shadow value of the constraint with the relevant quantities involved (t of CO_2, installed capacity, generated electricity, consumed biomass, etc...) which is then measured as a percentage of the total energy system cost of the CPI scenario in 2050 (3389 BEuro). This indicator should primarily be used for comparison of different user constraint's relevance, although it could also give indications of market size, such as the value of a CO_2-market across the modelled regions.

Using the described approach, the following main conclusions can be given for the CAP85 scenario. The CO_2 cap constraint is one of the most relevant in the JRC-EU-TIMES model with a gradually increasing marginal value over the modelled horizon. This marginal value penalizes the use of fossil fuels even if their associated emissions occur in small quantities such as the remaining emissions when CCS is applied. An equally important constraint is the amount of available biomass. Agriculture and forestry products and residues are all binding in 2050 in most of the countries.

Some of the constraints' impact is better assessed over the total modelled horizon because of their design, which does not have annual specific values. Whereas RES potentials or the CO_2 cap have different values for different modelled years, fossil fuel reserves and CO_2 storage capacities are cumulative from 2005 till the end of the modelled horizon. The speed of deployment is then endogenously estimated by the model and not via exogenous yearly assumptions. Therefore, the indicator on the constraint relevance for such fossil and CO_2 storage constraints cannot be directly compared with the other indicators. However, by looking into the marginal shadow value, we conclude that the impact is rather limited.

Regarding constraints directly imposed on specific technologies, we conclude that the two most important ones are the limitation of variable electricity from solar and wind to 50% of total electricity production and the increased cost for higher speed of deployment of nuclear power plants.

In addition, we calculated the impact of assumptions regarding the pace of deployment of technologies in the industrial and buildings sectors. A general conclusion is that the impact of such constraints is highly variable across countries and specific technologies considered. For example, for cement, aluminium and steel, the constraints have little relevance, whereas the marginal value of "slowing down" the replacement of existing technologies for chemical pulp production or of electric radiators in residential buildings is almost as relevant as some of the constraints for RES potentials (e.g. onshore wind).

Per definition, a constraint with a zero marginal or marginal value can be removed from the model without changing the result. However, the results should only be interpreted in the context in which they were produced. The marginal prices of the constraints are only valid *ceteris paribus*. A minor change in the definition of the scenarios, of the technologies or of the constraints can make the results deviate because of interdependencies between these constraints. Some constraints in the JRC-EU-TIMES model can have a very low or zero marginal value although they are important. Indeed, constraints can have overlap when they are applied, directly or indirectly, to similar technologies or technology groups. The clearest example is when several policy targets have an overlapping effect. When a carbon target is in place, the marginal value of a renewable target can be small or even non-existing. In the JRC-EU-TIMES model, on the decarbonisation scenarios after 2020 the renewable target is overshadowed by the CO_2 constraint in place. One can conclude that this target becomes irrelevant under the assumed high carbon price but another interpretation is that more renewable energy (more than the target in place) will be required to fulfil the CO_2 constraint. These insights can be very fruitful in the discussion of overlapping policies: overall CO_2 penalisation versus bottom-up support for low-carbon technologies.

10.8 Impact on demand reduction via demand elasticities

As explained previously, the JRC-EU-TIMES model can be run considering demand elasticities. In the seven decarbonised scenarios this option was employed, using as a reference the CPI scenario. The values are quite significant in 2050, in particular for the LEN scenario. In terms of the different demand responses clearly the non-specified "other uses" in buildings, agriculture, aviation and navigation reduce demand more, reflecting the fact that these are energy uses with a high carbon footprint and or with little low-carbon alternatives in the model. Regarding the sectors and uses modelled in detail the most relevant demand reduction compared to CPI occur in industry (lime production, cement, ammonia and other chemicals), in space heating for commercial buildings and water heating for residential buildings. Naturally the percent demand reductions have different relevance in terms of total energy consumed (e.g. lime production consumes very little of total energy in industry). These results reflect the exogenous elasticities of the demand which means that these are playing a significant role in model response. They can be interpreted as the result of a deployment of additional efficiency measures, a reduction in useful energy demand, or a combination of both.

Table 67 – % variation of the energy services and materials in the decarbonised scenario in 2050 compared to the CPI scenario

Energy service or material\Scenario	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
Agriculture	-23%	-23%	-19%	-19%	-40%	-24%	-24%
Commercial							
Cooling (large buildings)	-6%	-7%	-3%	-1%	-24%	-7%	-13%
Cooking	-19%	-19%	-15%	-14%	-27%	-19%	-20%
Cooling (small buildings)	-5%	-5%	-2%	-2%	-20%	-7%	-10%
Heating (large)	-28%	-28%	-28%	-28%	-34%	-29%	-28%
Heating (small)	-28%	-28%	-27%	-27%	-34%	-28%	-28%
Lighting	-10%	-11%	-7%	-4%	-26%	-11%	-12%
Other electric	-9%	-9%	-6%	-2%	-24%	-10%	-11%
Other	-30%	-30%	-29%	23%	-44%	-30%	-35%
Public lighting	-9%	-10%	-6%	-5%	-23%	-11%	-13%
Refrigeration	-8%	-10%	-5%	-2%	-25%	-11%	-12%
Water heating (large)	-10%	-10%	-10%	-8%	-34%	-11%	-11%
Water Heating (small)	-12%	-12%	-8%	-8%	-35%	-14%	-15%
Industry							
Aluminium	-16%	-17%	-15%	-15%	-29%	-18%	-19%
Ammonia	-27%	-27%	-22%	-22%	-43%	-28%	-28%
Other chemicals	-30%	-30%	-28%	-26%	-45%	-32%	-33%
Chlor alkali	-8%	-8%	-6%	-4%	-18%	-8%	-9%
Cement	-32%	-32%	-29%	-29%	-41%	-34%	-34%
Copper	-14%	-16%	-14%	-14%	-24%	-18%	-16%
Flat glass	-15%	-15%	-10%	-11%	-29%	-18%	-19%

Energy service or material\Scenario	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
Hollow glass	-21%	-22%	-20%	-18%	-34%	-22%	-24%
Iron and steel	-4%	-4%	-3%	-2%	-23%	-5%	-2%
Lime	-44%	-44%	-40%	-40%	-45%	-45%	-45%
Other non ferrous	-28%	-29%	-24%	-22%	-43%	-30%	-31%
Non-metallic	-32%	-32%	-29%	-27%	-46%	-34%	-35%
Other industry	-27%	-27%	-25%	-21%	-43%	-30%	-31%
High quality paper	-9%	-10%	-7%	-4%	-18%	-11%	-11%
Low quality paper	-11%	-12%	-11%	-8%	-21%	-13%	-14%
Residential							
Clothes drying	-9%	-9%	-6%	-2%	-23%	-11%	-12%
Cooling (existing apartments)	-6%	-6%	-3%	-2%	-23%	-7%	-12%
Cooling (new apartments)	-5%	-5%	-3%	-2%	-22%	-6%	-10%
Cooking	-7%	-7%	-7%	-7%	-11%	-8%	-8%
Cooling (existing rural houses)	-7%	-7%	-3%	-2%	-23%	-8%	-12%
Cooling (new rural houses)	-4%	-5%	-2%	-2%	-22%	-5%	-9%
Cooling (existing urban houses)	-6%	-6%	-2%	-2%	-21%	-6%	-11%
Cooling (new urban houses)	-5%	-4%	-2%	-2%	-22%	-5%	-10%
Clothes Washing	-10%	-10%	-6%	-3%	-24%	-12%	-13%
Dishwashing	-9%	-9%	-6%	-2%	-25%	-12%	-13%
Heating (existing apartments)	-28%	-28%	-26%	-26%	-35%	-28%	-29%
Heating (new apartments)	-27%	-27%	-23%	-25%	-34%	-27%	-27%
Heating (existing rural houses)	-24%	-24%	-22%	-21%	-32%	-26%	-25%

Energy service or material\Scenario	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
Heating (new rural houses)	-25%	-26%	-24%	-23%	-30%	-25%	-26%
Heating (existing urban houses)	-30%	-30%	-28%	-28%	-32%	-30%	-30%
Heating (new rural houses)	-27%	-27%	-26%	-26%	-32%	-28%	-27%
Lighting	-8%	-8%	-5%	-3%	-22%	-10%	-11%
Other electric	-10%	-10%	-7%	-2%	-23%	-11%	-12%
Other	-41%	-41%	-41%	-41%	-48%	-45%	-44%
Refrigeration	-5%	-5%	-2%	-1%	-13%	-6%	-6%
Water heating (existing apartments)	-13%	-16%	-13%	-13%	-37%	-16%	-16%
Water heating (new apartments)	-15%	-15%	-15%	-12%	-36%	-17%	-18%
Water heating (existing rural houses)	-18%	-19%	-17%	-15%	-38%	-18%	-19%
Water heating (new rural houses)	-17%	-16%	-15%	-13%	-37%	-17%	-16%
Water heating (existing urban houses)	-19%	-19%	-18%	-20%	-41%	-20%	-20%
Water heating (new urban houses)	-11%	-12%	-11%	-8%	-39%	-13%	-11%
Transport							
Aviation international	-40%	-40%	-35%	-37%	-35%	-40%	-40%
Aviation	-39%	-39%	-35%	-35%	-35%	-40%	-40%
Bus	-9%	-9%	-7%	-6%	-9%	-9%	-9%
Cars long distance	-3%	-3%	-1%	0%	-5%	-4%	-4%
Cars short distance	-1%	-1%	0%	0%	-1%	-1%	-1%
Heavy freight	0%	0%	0%	0%	0%	0%	0%

Energy service or material\Scenario	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
Light duty freight	0%	0%	0%	0%	0%	0%	0%
Motos	-9%	-10%	-8%	-6%	-21%	-11%	-12%
Navigation	-12%	-12%	-10%	-12%	-13%	-12%	-12%
Trains freight	-5%	-5%	-3%	-2%	-10%	-6%	-5%
Metro and trams	-1%	-1%	0%	0%	-7%	-1%	-2%
Passenger trains	-4%	-7%	-2%	-3%	-11%	-7%	-7%

11 Highlights on the long-term role of SET Plan strategic energy technologies

This section presents an overview of the long term role of SET Plan strategic energy technologies. For each of these, we discuss the evolution of generated energy and capacities in the different modelled scenarios in order to highlight the most relevant drivers for their deployment. We discuss results at national level although these should be treated with care since although parts of the model inputs are country specific (e.g. renewable potentials), some other are not (e.g. land availability for fossil deployment). At the end of each section, we add a brief comparison with current expectations on deployment for the whole of EU.

11.1 Wind Power Generation

11.1.1 Wind offshore

As shown in Figure 33, wind offshore generation deployment will start mainly from 2020 onwards in all scenarios. From then until 2050, it may reach a range of 118 TWh to 476 TWh depending on the considered scenario (from the HNUC to HRES). This means a range of 2 % to 10% of the generated electricity and from 6% to 15% of the total generated RES based electricity. In our model, when compared with onshore wind technologies, wind offshore will yield slightly higher generated electricity than onshore by 2050. This highlights that, according to our model, by 2050 offshore wind higher availability factors will be able to compensate its higher installation and maintenance cost.

Clear differences among the scenarios can be perceived mainly from 2030 onwards. Figure 33 shows also how the CAP85 scenario will trigger almost double the generated electricity coming from offshore wind in 2050: compared with the CPI, the CAP85 scenario will increase wind offshore generation from 193 TWh to 271 TWh. LEN shows that, compared with the CAP85, reduced FEC will only slightly influence offshore deployment, showing almost the same output as CAP85 in 2050. Delayed availability of CCS technology will allow higher generation of offshore wind only in a small window up to 2035. Finally, a lower availability of bioenergy resources (LBIO) will slightly increase the offshore generated energy in 2050 up to 298 TWh.

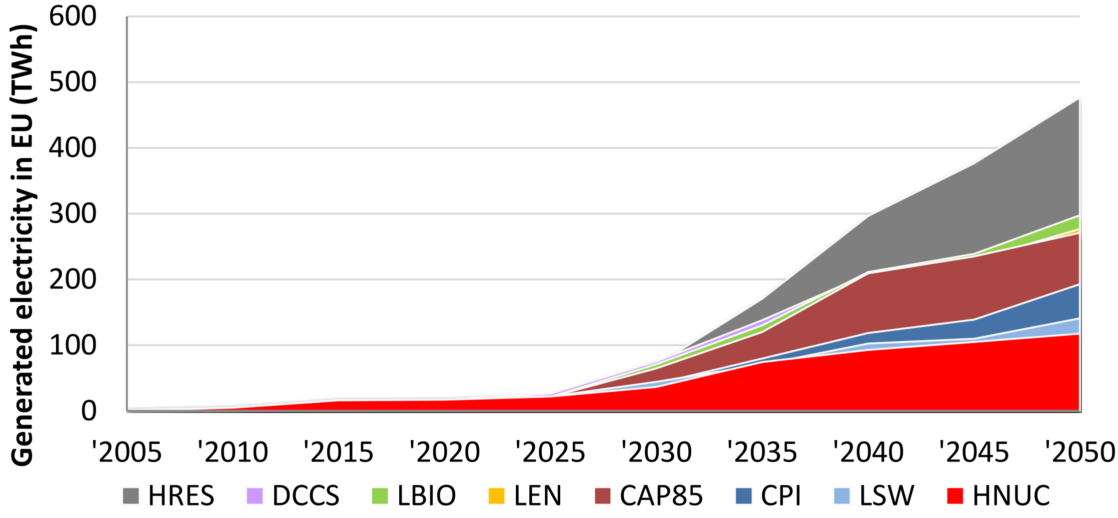


Figure 33 – Evolution of generated electricity in TWh – wind offshore

If the energy generated offshore is analysed by regions, starting with the CPI scenario, (without subsidies and without CO_2 cap), UK will be the leading producer by 2020 with over 10 TWh followed by DK and DE. In 2050, NL and DE will generate more than 40 TWh, followed by ES, UK and SE. By 2050, the HRES scenario, with CO_2 cap and increased RES potentials, will display NL generating more than 180 TWh, followed by DE, ES, SE, and UK.

When it comes to the installed capacity, Figure 34 clearly points out that the 2030-2040 decade displays the steepest offshore development in any scenario, even for the LSW. After those years, wind offshore will reduce slightly its build-rate as other alternatives, such as solar PV or nuclear, deploy faster and because there is a general investment cycle for the total electricity capacity (see Section 10.4). The annual average deployment will range from the 2.0 GW/yr in the CPI to 5.0 GW/yr in the HRES scenario. Only in the HNUC scenario the total capacity installed shows a beginning saturation around 2050. Mainly all the scenarios are characterized by a second installation peak in after the one around 2050, evidencing possible growth periods after the initial 2030-2040 take-off phase.

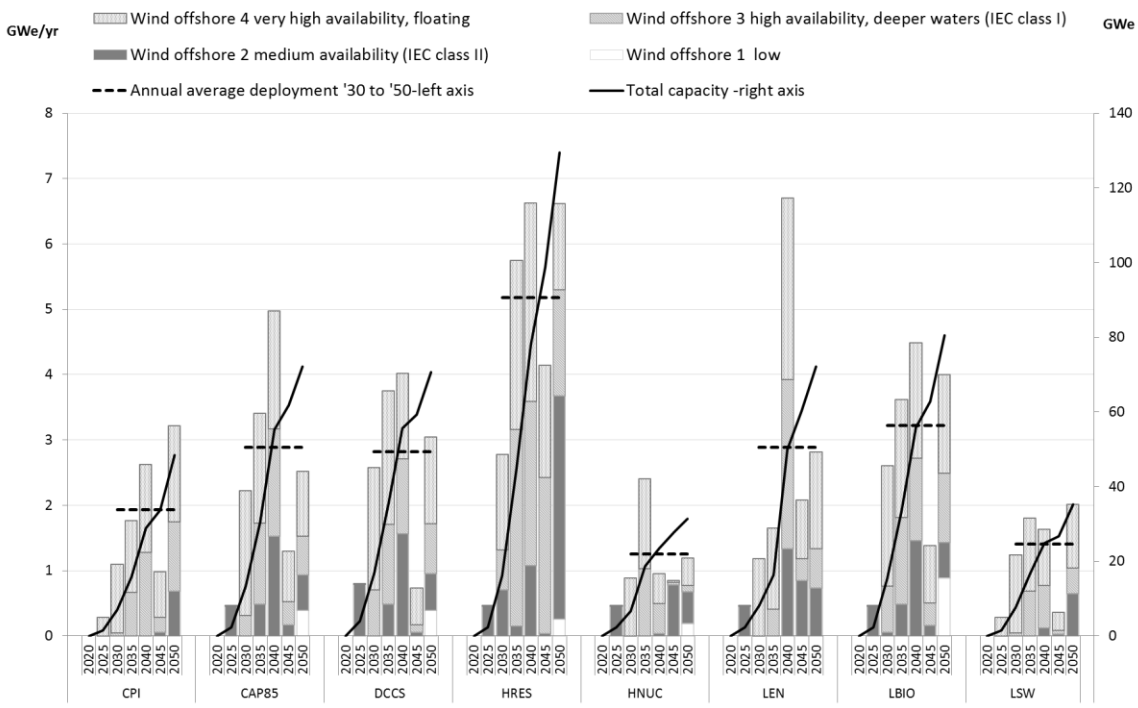


Figure 34 – – Technology deployment: annual investment in new capacity (GW/yr – left) and total capacity (GW - right) – Wind offshore

Among the different offshore technologies (from IEC class I to IV), wind offshore I (lowest availability factor) is less cost effective. In almost all scenarios, the high availability floating option will lead the installed capacity rate. Medium availability technologies will be less installed than the high ones. Only under the HRES scenario - with increased resource potential and an increased allowed share of intermittent generation - the deeper water technology displays higher growth rates than the floating systems.

In none of the scenarios, without any specific technology incentives, the total installed offshore capacity even comes close to the 150 GW offshore capacity that EWEA projects for 2030. (European Wind Energy Association, 2009)

11.1.2 Wind onshore

Wind onshore is a key technology to meet the EU renewable energy targets in the mid-term. All the scenarios display a large deployment of this technology starting in 2005 until 2020. In 2020 wind onshore will generate around 7% of the total electricity in Europe in all scenarios, representing almost 21% of the renewable electricity produced. According to the model, by 2050 the generated onshore wind electricity will reach a maximum share of 11% of the total electricity, equal to 16% of the renewable electricity.

By 2050, in the CAP85 scenario, the onshore wind generated electricity increases from 193TWh registered for the CPI scenario to 315 TWh. The DCCS scenario further increases the generated onshore wind electricity in the last decades, though marginally, peaking at 332 TWh in 2050. Under the HRES scenario, onshore wind electricity will reach its maximum at 516 TWh. The

HNUC scenario displays reduced 2050 generation -241 TWh- from the figures in the CAP85 scenario. And while the LEN will only show differences with CPI starting in 2040, the LBIO shows consistently higher generated onshore wind electricity when compared with CAP85. Finally, the LSW scenario will displays a reduced onshore wind electricity output versus CAP85 of 87TWh less by 2050.

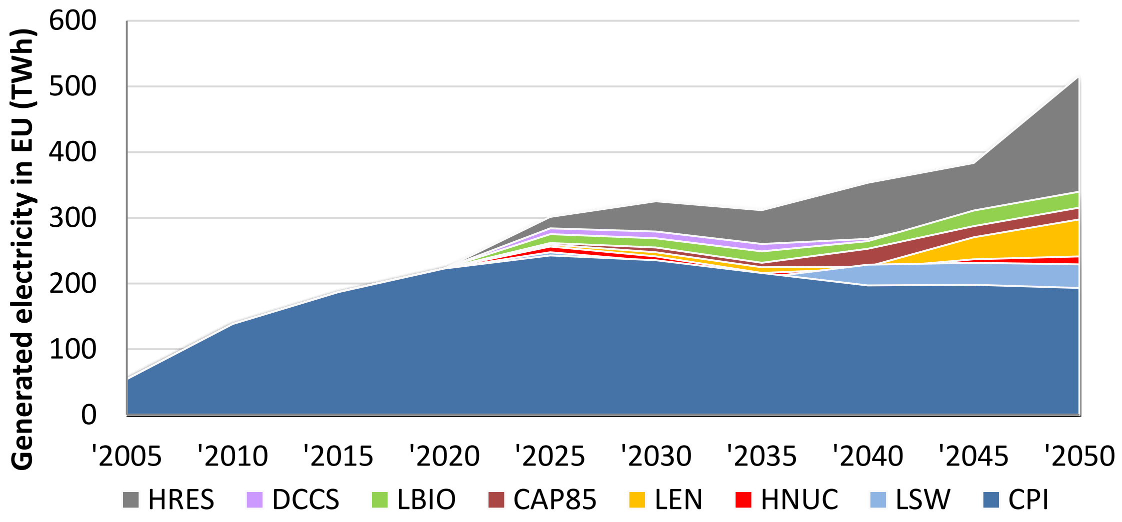


Figure 35 – Evolution of generated electricity in TWh – wind onshore

At a region level the CPI scenario will show IT, UK, DE and ES to be the leading generators in 2020. Still in CPI, in 2050, IT and UK will the clear leading wind generating countries with over 40 TWh, led by FR and ES. In the other hand, in the HRES scenario, evolution from a similar 2020 distribution will show in 2050, FI, DE, IT, UK and ES clearly leading the wind onshore generated electricity with over 60 TWh.

Total installed capacity increases for wind onshore in all the decarbonised scenarios for the whole period considered -except for the 2045-2050 period in the LSW. Among these decarbonised scenarios, during the 30-50s years, the annual average deployment will range from 12.2 GWe/yr in the HRES scenario to 4.46 GWe/yr found in the LSW scenario. New installed capacity for all the decarbonized scenarios (except LSW) shows main trend of steady increasing new installed capacity during 2030-2050. HRES shows a remarkable growth; over 30 GW/yr installed in the period 2035-2050 which are reduced to 6.4 GW/yr in the HNUC.

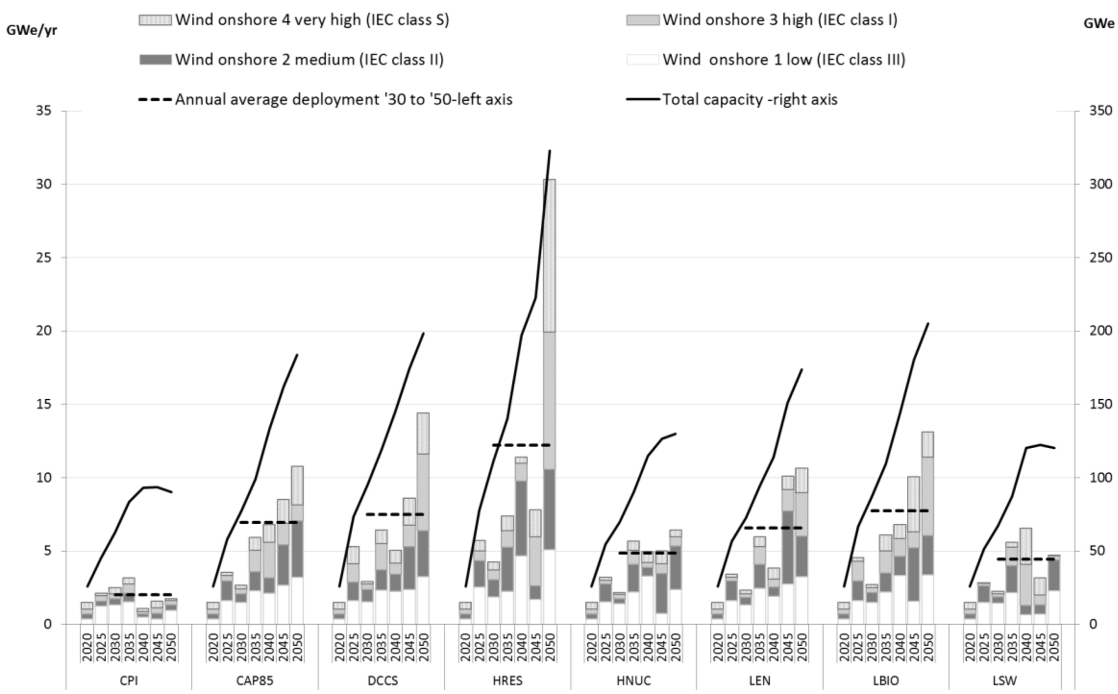


Figure 36 – Technology deployment: annual investment (GW/yr – left) and total capacity (GW - right) – wind onshore

For the different technologies, the Wind onshore 1 (IES class III) and Wind inshore 2 (IES class II) will be the dominant in the CPI, HNUC, LEN and LSW scenarios. Greater market share is foreseen for categories IEC I and IEC S in the other decarbonised scenarios, becoming the leading installed technologies in the HRES in 2050.

In none of the scenarios, without any specific technology incentives, the total installed onshore capacity even comes close to the 250 GW onshore capacity that EWEA projects for 2030. (European Wind Energy Association, 2009)

11.2 Solar Photovoltaic Electricity and Concentrated Solar Power Generation

Solar photovoltaic technologies have the potential to become one of the key technologies for electricity generation in the decarbonised scenarios. In 2050 PV generates in all scenarios 16-30% of the total electricity mix, accounting for between 33% and 49% of the renewable electricity generated across all scenarios.

With the considered costs and availability factors it is only in 2030 that PV has a higher growth in the decarbonised scenarios, with between 9% and 12% of total generated electricity, as opposed to around 3% in 2020. In the case of LSW scenario, in 2040 PV's share in total electricity generated is only 4%.

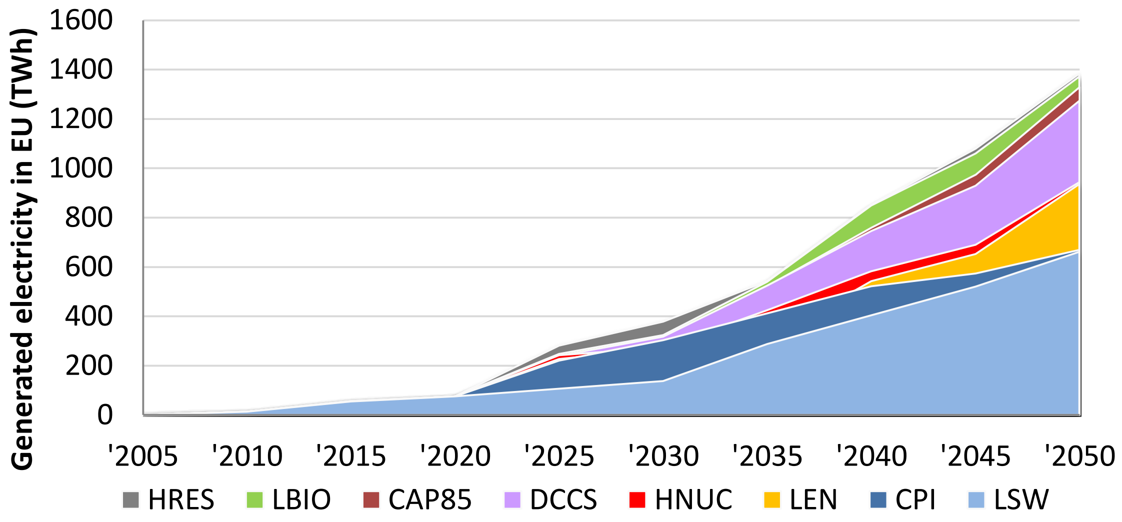


Figure 37 – Evolution of generated electricity in TWh – solar PV

However, it is in the last periods of the modelled horizon where PV shows the stronger growth, from 2030 and soaring beyond 2040, with installation rates of 40GW per year on average in the 2030-2050 period. This is compared to 10GW/year in the CPI over the same period. The decarbonised scenarios with the highest and lowest average overall yearly installed capacity are, in line with expectations, the HRES and LSW scenarios, with 39GW/year and 22GW/year respectively.

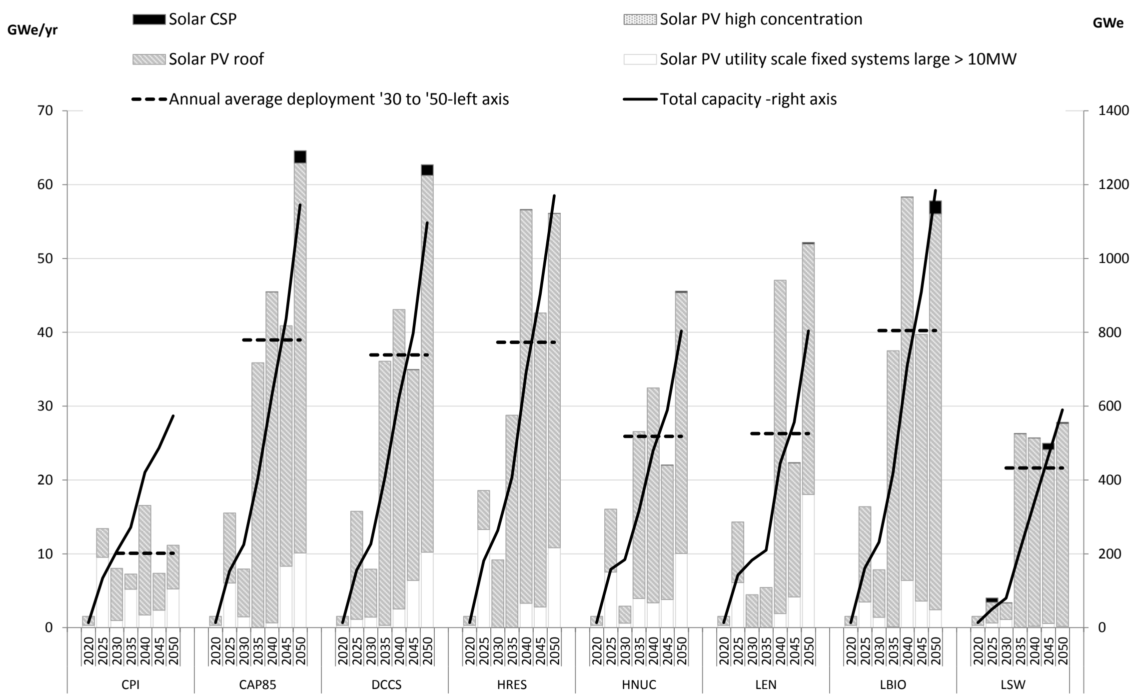


Figure 38 – Technology deployment: annual investment in new capacity (GW/yr – left) and total capacity (GW - right) – Solar PV and CSP

The main factors affecting PV deployment are clearly the CO_2 cap, and the relative contribution of biomass and nuclear based electricity, with an inverse relationship. Similarly, the limited availability for solar energy clearly negatively impacts the deployment of the technology.

The most relevant PV deployment in absolute terms occurs in DE, IT, ES, FR and the UK. Countries such as RO, PL, PT, HU and CZ will also have a high PV deployment but PV varies across scenarios. The maximum PV potential is achieved only in 2050 in most countries, though a few already reach their full potential in 2030. This occurs in all decarbonized scenarios for AT, FI and LU. In LT, LV, D, F, HU, UK and IT.

In terms of deployed technologies, in the medium to long term, medium sized roof PV plays the major role, followed by plant size PV, in all scenarios. In addition, existing PV electricity plants continue to play a role up to 2040 in all scenarios. The roof sized PV, although marginally more expensive than plant size, delivers low voltage electricity thus avoiding conversion losses and becoming more cost-effective in overall system terms. Similarly to other electricity generation technologies it is clear that installation accelerates after 2030 and especially 2040, and then slows down in 2045. This is to compensate for decommissioning of roughly half of the PV plants installed prior to 2005 which occurs in 2020-2040.

It should be mentioned that the very high PV deployment is accompanied by electricity storage (see Section 11.12) due to the way variable intermittent electricity technologies are modelled. Not only that, but PV is curtailed to some extent in the model.

CSP has a substantially more modest contribution to overall electricity generation (below 1% of total generated electricity over time in all scenarios). In fact until 2050 (2025 in the LSW scenario) there is practically no significant additional installed capacity.

CSP currently installed and expected in ES till 2015 are maintained and gradually decommissioned in most scenarios from 2035. CSP becomes cost effective in the decarbonised scenarios only for CY and GR in earlier periods. In 2050, CSP is cost-effective in PT and ES, but only for the DCCS and LBIO scenarios. Only in the LSW scenario, where the deployment of PV and wind is limited, CSP becomes cost-effective in additional countries (IT, ES and PT) and in earlier periods, albeit in marginal levels (producing a maximum of 16 TWh of electricity in 2050).

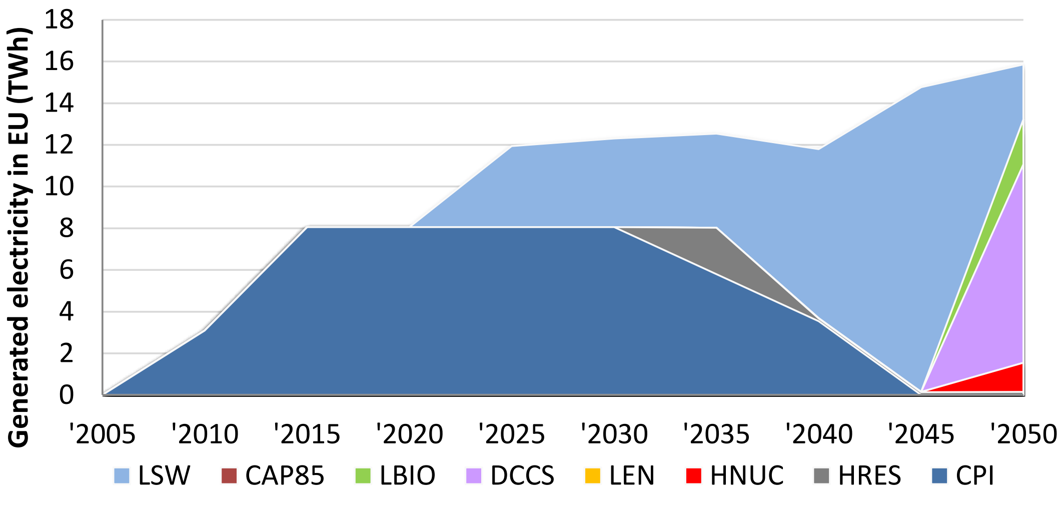


Figure 39 – Evolution of generated electricity in TWh – Concentrated Solar Power (CSP)

The forecast of the solar industry (Solar Europe Industry Initiative, 2013) points to 333 GW of installed PV in 2030, 12% of electricity generated by PV by 2020 and 30 GW of CSP installed capacity by 2020 (European Solar Thermal Electricity Association, 2010). These indicative figures seem to be too optimistic when compared with the model results, considering that only by 2030 4-13% of electricity is generated from PV. However, it should be noted that we do not consider in our model any long-term feed-in tariffs or other incentives.

11.3 Bioenergy – Power and Heat Generation

Biomass (solids and gas) provides, in the various scenarios, 8-17% of final electricity generation in 2035. In 2050, its relative importance declines to 3-8% in the decarbonised scenarios, with lowest and highest contribution in the LBIO and LEN scenarios respectively. In the CPI, biomass-based electricity generated accounts for 13% of total electricity in 2050. Both solid and gaseous biomass based technologies are deployed throughout the EU28 for electricity generation.

Electricity produced from solid biomass is generated via CHP technologies, both centralized (steam turbine, organic rankine cycle, biomass gasification) and in the industrial sector (steam turbine condensing, IGCC and recovery boilers). Section 11.11 provides more details on CHP technologies. Other centralized technologies (conventional steam turbine, IGCC, anaerobic digestion) play a decreasingly important role, contributing in 2050 in the CPI only 4% of total electricity produced with solid biomass as opposed to 10% in 2020. In addition, the production of FT diesel and ethanol from lignocellulosic biomass generates a significant amount of electricity as a by-product, becoming the main source of electricity generated with solid biomass already in 2035. In 2050, electricity generated via CHP technologies in the CPI is 145TWh, but only an average of 51TWh in the decarbonised scenarios. This indicates a significant shift in the use of solid biomass for electricity production. On the contrary, electricity generated via second generation biofuels production processes is in the CPI in 2050 217TWh and, in the decarbonised scenarios, an average of 85TWh. However, the relative contribution of these processes is very similar across the scenarios: 60% in the CPI and 63% on average in the decarbonised scenarios.

Solid biomass plays an important role in the electricity generation mix in the mid-term, providing 6-17% of total electricity generated in 2035 in all scenarios, including the CPI (196-461TWh). Its relative contribution however declines in the longer term in the decarbonized scenarios, dropping to between 2% and 6% of total electricity in the HNUC/LBIO and LEN scenarios respectively (98-228TWh). In CPI the contribution of biomass-based electricity generation levels off at around 10.5% until 2050, equivalent to 362TWh in 2050. The limited role of solid biomass in long-term electricity production in the decarbonised scenarios is an indication of its critical role as a cost-effective technology for the decarbonisation of transport (via second generation biofuels) and industry, where the low carbon fuel options are more limited than in the electricity sector.

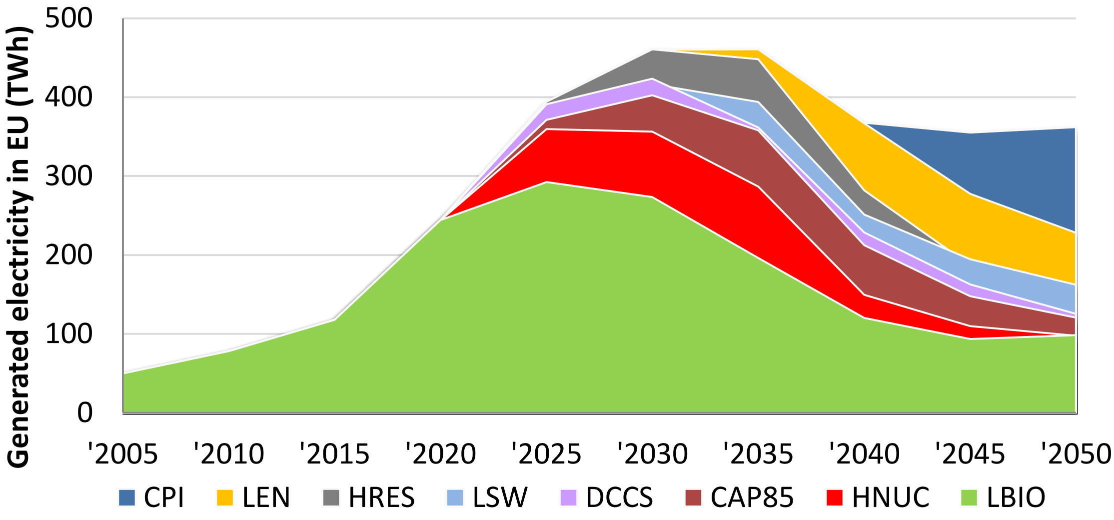


Figure 40 – Evolution of generated electricity in TWh – bioenergy (solid biomass, CHP, and 2nd generation biofuel production processes)

The high generation of electricity from solid biomass translates into its importance in the RES mix, reaching in 2050 a maximum of 18% of total electricity generated via RES in the CPI. In the decarbonised scenarios, the share of solid biomass in total RES-generated electricity varies between 4% in the LBIO and HRES scenarios, and 9% in the LEN scenario, with an average of 5% in 2050 in the other scenarios. In line with the significant increase in mid-term electricity generation, solid biomass has a more important role in RES generated electricity in the medium-term – in 2035, it constitutes between 12% and 29% of RES electricity in the LBIO and LEN scenarios respectively – while, in the CPI, its share is 22%.

The availability of biomass is, not surprisingly, the factor that most influences the deployment of solid biomass for electricity generation. This reinforces the conclusion that solid biomass is most cost effective as an abatement technology for the industrial and transport sector, hence increasing (decreasing) its availability relaxes (tightens) competition with electricity generation.

A similar pattern is observed in the electricity generated with biogas, which peaks in 2030, at between 94-144TWh in the LBIO and DCCS scenarios respectively. After 2030, electricity generated via biogas declines in all scenarios, though in the CPI, HRES and LBIO it shows a (marginal) come back after 2045. Total electricity generated in 2050 is on average across all scenarios 85TWh (65TWh and 103TWh in the LBIO and HRES scenarios respectively). Overall, biogas electricity generation is not a significant share of total electricity produced, reaching a maximum of 9% in 2030 in the LSW scenario. By 2050, however, biogas-based electricity generation accounts for only 2-5% of total electricity, contributing the maximum share in the LSW scenarios.

While the generation path for biogas is very similar across all decarbonised scenarios, availability of biomass appears to significantly influence its use for electricity generation: with low biomass availability, in line with what is seen in the use of solid biomass, the use of biogas for electricity generation is significantly lower.

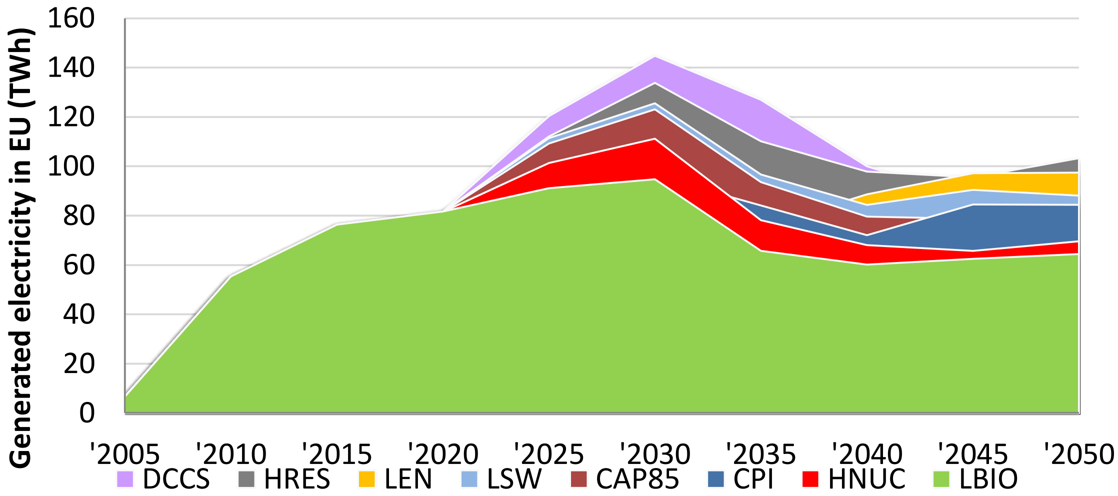


Figure 41 – Evolution of generated electricity in TWh –biogas

While there is no significant new deployment of non-CHP solid biomass based electricity generation plants, the annual deployment of new biomass-based CHP decentralised capacities reflects the above described trends, with an average additional capacity between 2030 and 2050 of between 0.7-0.9GW/year in the decarbonised scenarios, and 1Gw/year in the CPI scenario (Section 11.11). Installed capacity of solid biomass-based decentralised CHP is also aligned with the overall pattern observed in Figure 40, with a marked decline between 2030 and 2040.

Besides the processes in the figure there is also new capacity in second generation biofuel processes that deliver electricity as a co-product. New capacity increases significantly starting in 2035, and continues to increase in all decarbonised scenarios, except LEN. In the CPI, investments in new capacity also decline starting in 2045.

11.4 Fuel Cells and Hydrogen

Fuel cells hardly play a role in the JRC-EU-TIMES model with the current technology data. Natural gas fuelled fuel cells are not economic in competition with mainly direct combustion or electricity use. The fixed annual costs in the model are high. A strong decrease of these costs would drastically increase the cost efficiency.

Hydrogen is mainly used in sectors where the alternatives of direct use of electricity or fuel are limited. In all decarbonized scenarios, hydrogen plays a role in steel production and transportation (trucks and cars). In the steel sector, hydrogen can be largely used in competition with biomass based steel production. Part of the hydrogen is blended in the gas network to be used in buildings. In the runs until now, hydrogen is not used as a storage medium, probably because other storage options are cheaper. The two most important drivers for hydrogen are the limitation on CO_2 and the availability of biomass. The decarbonised scenario with the highest hydrogen use is the LBIO scenario where it mainly replaces the role of biomass in the transport sector. Hydrogen is mainly produced from coal gasification with CCS (some 500 PJ hydrogen). To a much lower extent, and with the exception of the HRES scenario, hydrogen is also produced from electricity with electrolysers (some 50 PJ).

11.5 Nuclear

The deployment of nuclear follows closely the assumptions included in the modelled scenarios. In all scenarios, except HNUC, until 2025 the only new nuclear power plants to be deployed in EU28 are the ones currently being built in FI and FR and also under discussion in BG, CZ, SK, RO and UK[23]. After 2025, all plants currently under discussion in EU28 (Annex 16.11) but no other plants can be deployed. In the HNUC scenario it is possible to deploy generic "unplanned" new nuclear power plants but only from 2030. The underlying assumption in HNUC is that if a plant is not currently under discussion it will take roughly 15 years until it can start to deliver electricity to the grid.

In all the scenarios (including HNUC) conservative assumptions were made on the lifetime of the plants following the information in the IAEA PRIS database as of July 2013. This means that a significant fraction of the current capacity in FR is decommissioned between 2020-2025. This does not reflect cost-effectiveness criteria but simply the current status of expected permitted lifetime of the plants.

Under these assumptions nuclear plants maintain a relevant contribution to the total electricity generated in the EU by 2050 (20-24% of total generated electricity in all scenarios and 54% in the HNUC scenario). In all scenarios except HNUC the total nuclear installed capacity in 2050 is roughly the same as in 2005. In the HNUC scenario in 2050 the installed capacity is three times higher than in 2005, which could be considered as too optimistic or even unrealistic. The annual deployment rate in this scenario reaches 14 GW/yr in the period of 2030-2050. These results of the HNUC scenario serve to emphasize the point that with the costs considered in the model, nuclear plays a major role in decarbonising the energy system.

Besides the constraints on nuclear deployment across countries, the other main factor affecting deployment of nuclear is clearly the CO_2 cap, as all decarbonized scenarios have a higher share of nuclear electricity than CPI.

[23] This corresponded to the following plants: in Bulgaria (BELENE-1, BELENE-2); Czech Republic (TEMELIN-3, TEMELIN-4), Finland (OLKILUOTO-3), France (FLAMANVILLE-3, PENLY-3), Hungary (PAKS-5, PAKS-6), Romania (CERNAVODA-3, CERNAVODA-4), Slovakia (MOCHOVCE-3, MOCHOVCE-4) and UK (HINKLEYPOINT-C1, HINKLEYPOINT-C2, SIZEWELL-C1, SIZEWELL-C2).

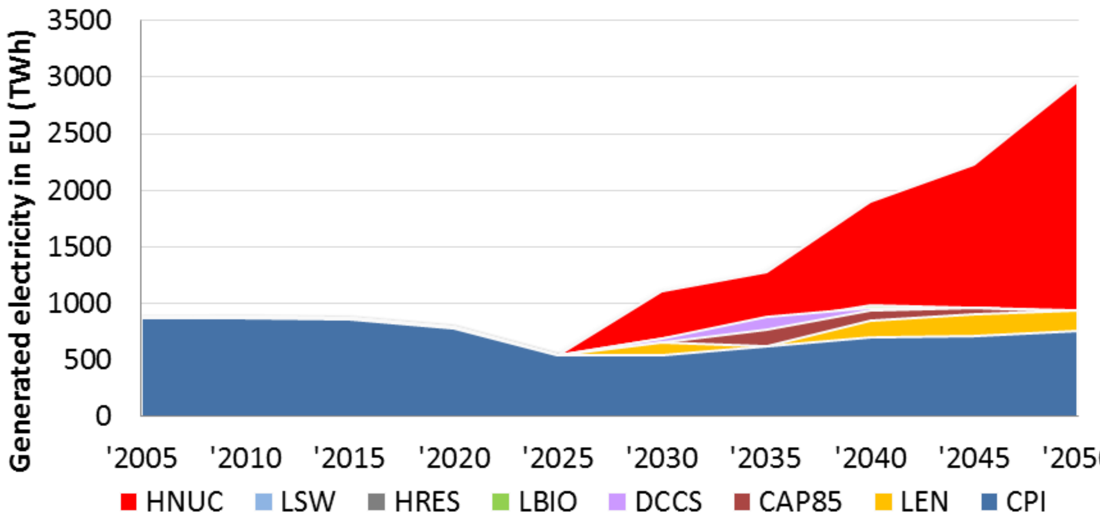


Figure 42 – Evolution of generated electricity in TWh - nuclear

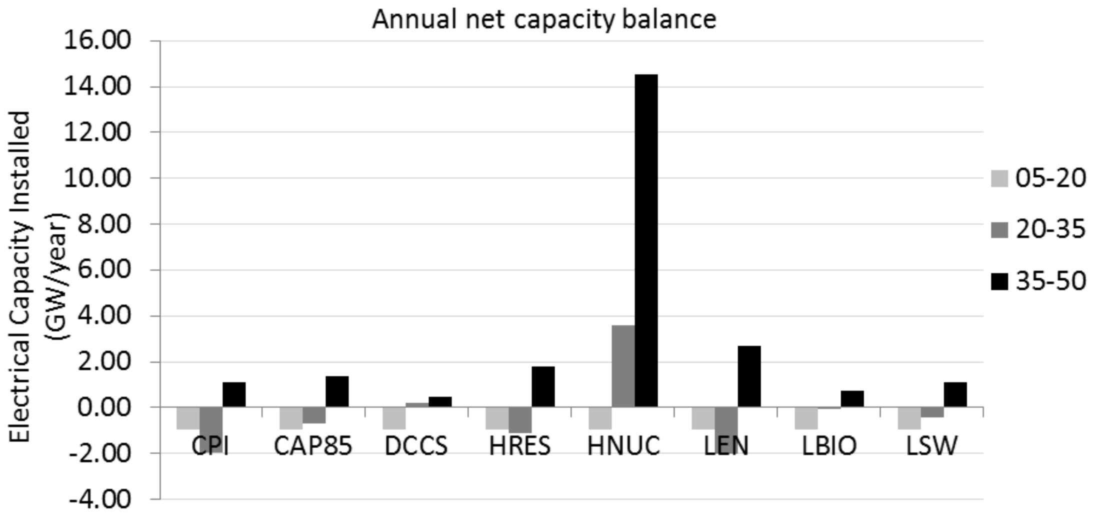


Figure 43 – Evolution of aggregated technology deployment in installed GW/year per decade – nuclear

In terms of country level results, FR, UK, ES and FI are still the countries with the highest nuclear electricity generation, followed by BG, CZ, HU, SI and LT. In SE the existing plants are decommissioned following a cost-effective approach.

In all but the HNUC scenarios, the long term share of nuclear electricity generation is below 30%, while the Sustainable Nuclear Energy Technology Platform aims at maintaining the role of nuclear electricity generation at least at a level of 30% in the long term (SNETP, 2013).

11.6 Carbon Capture and Storage in Power Generation

CCS plays a major role in all decarbonized scenarios, except HNUC and HRES, reaching 14-31% of the total electricity produced in EU28 in 2050 (only 8% for HRES and 9% for HNUC). The highest value of this range is for the LSW scenario. In the period of 2020-2030, most CO_2 capture is done in the power sector but in 2050 24-36% is captured in industry and 3-20% in coal gasification generating H_2.

The CO_2 is stored mostly in onshore saline aquifers, onshore depleted gas and oil fields across EU but mostly in DE and UK. This is because we do not implement in the model the latest policy decisions regarding stopping (totally or partially) CO_2 storage in some of the EU28 countries.

It is important to highlight that these results need to be interpreted with care. In these model runs, CCS technologies are assumed to enter the market already in 2020, which may be unrealistic unless very specific policy incentives are implemented. Moreover, the penetration rate of CCS technologies is unconstrained, implying sometimes, and in particular in the early period, significant rapid increases in installed capacity, both for electricity generation, and in industry. From 2020 to 2025, this is an extremely rapid annual deployment. This will only be feasible in reality if very special policy incentives or conditions are in place, similarly to what has happened in the last decade to solar and wind technologies, natural gas CCGT or nuclear in the seventies (see Section 6.2.3).

Finally, in these runs retrofitting of existing plants with CCS technologies is not modelled.

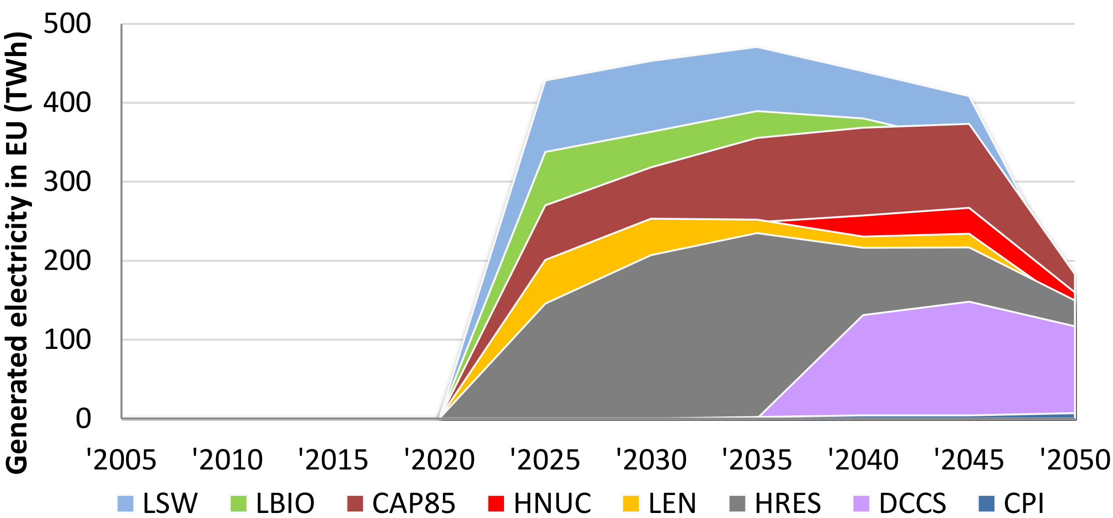


Figure 44 – Evolution of generated electricity in TWh – coal and lignite with CCS

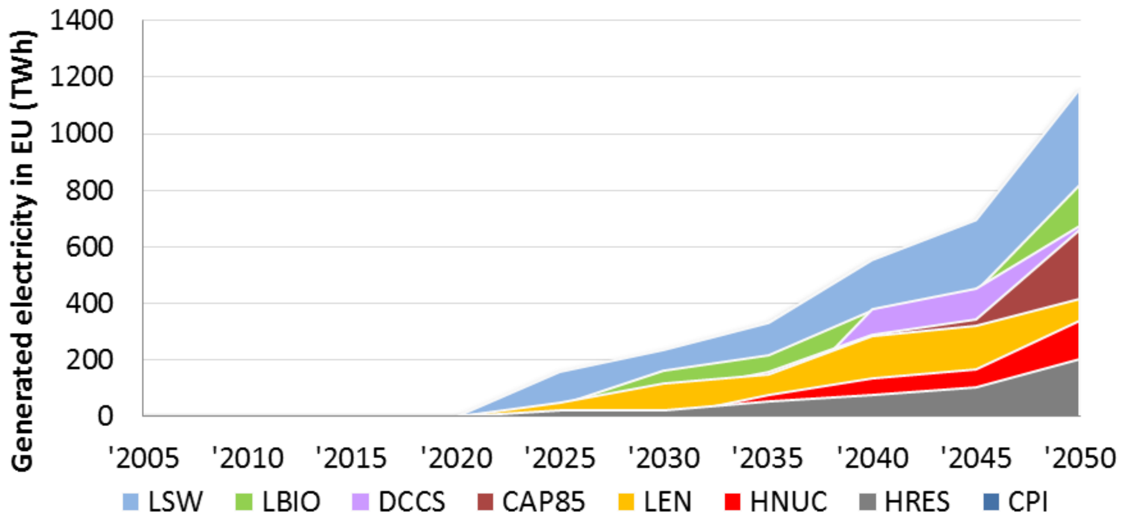


Figure 45 – Evolution of generated electricity in TWh – gas with CCS

The European Technology Platform for Zero Emissions Fossil Fuel Power Plants states that CCS may contribute to reduce CO_2 emissions in the European Union by 400 MtCO_2 per year by 2030 (Zero Emission Fossil Fuel Power Plants, 2008). According to JRC-EU-TIMES results, all decarbonised scenarios are building up CCS capacity resulting in yearly CO_2 stored in the range of 500 (LEN) to 965 Mt (LSW)

11.7 Advanced Fossil Fuel Power Generation, including CHP

This section describes the fossil fuelled power generation without CCS, including CHP. However, for clarification purposes we discuss further the CHP technologies in a separate section. In the CPI scenario, the coal based generated electricity decreases by 11 percentage points between 2020 and 2050, reaching an 18% share of the total electricity generated by 2050.

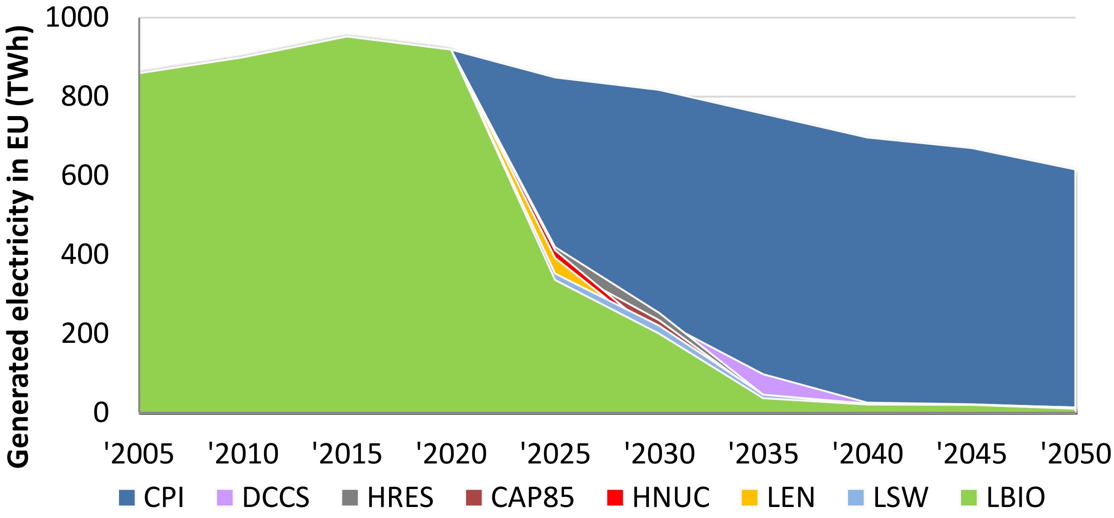


Figure 46 – Evolution of generated electricity in TWh (left) – coal without CCS

Coal based generation of electricity only plays a role in the CPI scenario. Even with a CO_2 price in place that gradually increases up to 51 Euro/t, coal is competitive to produce large amounts of electricity with rather limited fuel costs. The top-5 countries with coal based electricity generation in this scenario are DE, PL, RO, UK and NL accounting for 80% of the total.

As from 2035 in the decarbonised scenarios, coal based electricity without CCS declines dramatically and, in 2050, a maximum of 14TWh are generated via these technologies. This is equivalent to approximately 0.2% of total electricity generated, down from over 10% in 2025 in the same scenarios. This is also reflected in the annual net capacity balance where the net balance of generation capacity is negative in all scenarios. In the decarbonised scenarios, the capacity of coal without CCS goes down on average with 3.5 up to 5 GW_e per year.

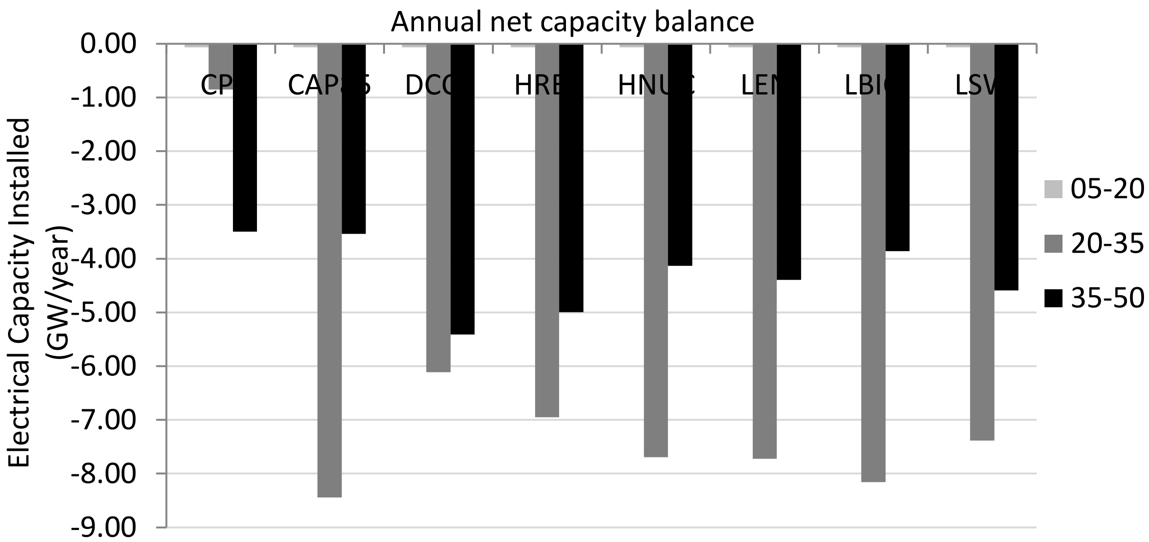


Figure 47 – Evolution of net technology deployment in installed GW/year per decade – coal without CCS

In all decarbonised scenarios, no new investment in coal-based electricity production without CCS is made after 2030, as shown in Figure 48.

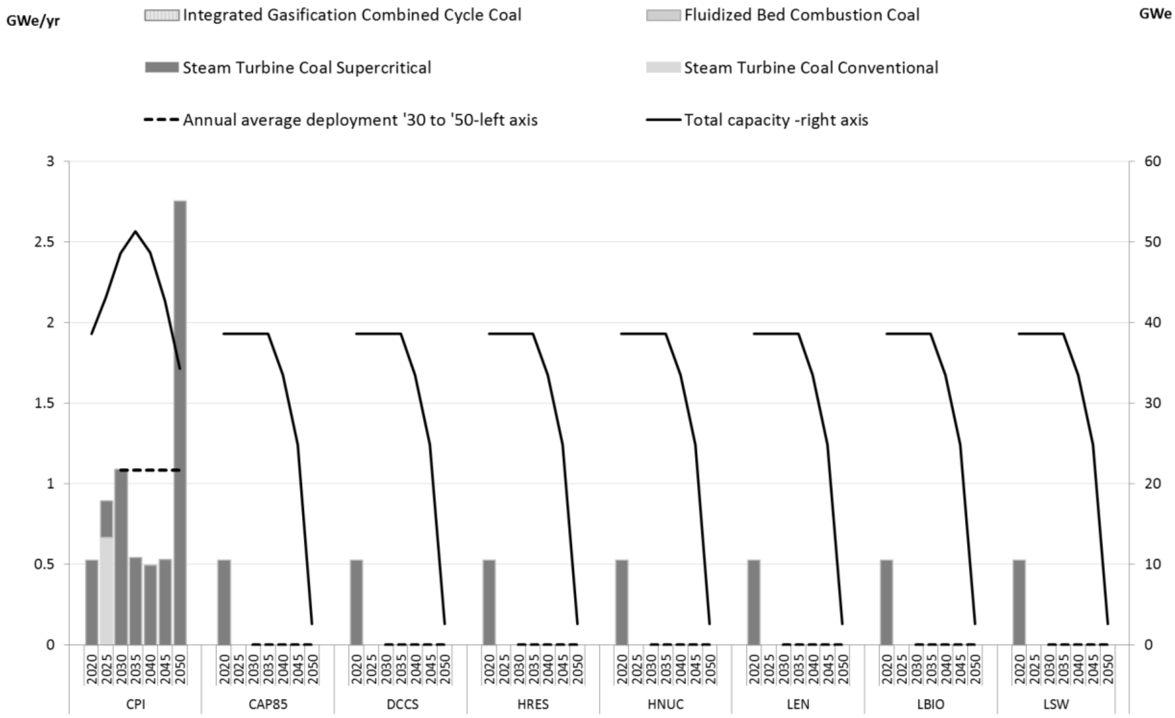


Figure 48 – Technology deployment – annual investment in new capacity (GW/yr – left) and total capacity (GW – right) – coal without CCS

In the context of a low carbon future, oil based generated electricity in the EU decreases dramatically in all scenarios, including the CPI. In all contexts of scenarios the contribution of oil to the total electricity mix in EU represents less than 1% of total generated electricity and electrical capacity in EU by 2020. By 2050, in all scenarios the contribution to the total generated electricity in the EU countries almost disappears.

Aiming at achieving the targets set for a low carbon future, the gas based generated electricity without CCS in the EU decreases also significantly. In the majority of the decarbonised scenarios, the contribution of gas to the electricity mix produced in the EU28 decreases to around 1% in 2040, from approximately 15% in 2025. As the renewable share in the production mix increases, cheaper low-carbon technology options become available, and higher investments are directed to CCS. In 2050, the share of non-CCS gas based electricity produced remains around 1% - and it is the lowest (0.7%) in the HRES scenario.

In the CPI, "sure bet" countries for a continued contribution of gas without CCS in the electricity mix in 2030 are IT, NL, HR and DE. In 2050, IT and HR continue to show a relatively larger contribution of gas without CCS to electricity production, in absolute terms, while the use of gas in the other countries declines significantly. In the decarbonised scenarios, countries where gas continues to play a role are DE, with an average of 35.6Twh in 2030 and 9TWh in 2050; IT (avg. 52.5TWh and 2.9TWh in 2030 and 2050 respectively); the UK (avg. 15.2TWh and 3.5TWh in 2030 and 2050); NL (74.2TWh and 2.6TWh in 2030 and 2050); and RO (22.7TWh and 1.8TWh in 2030 and 2050).

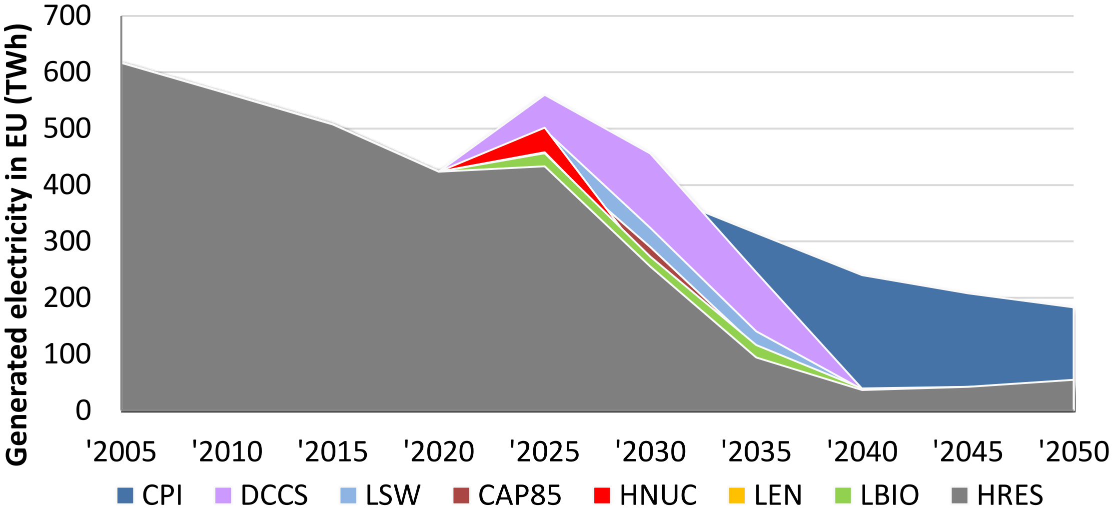


Figure 49 – Evolution of generated electricity in TWh – gas without CCS – including CHP

However, the electricity generation is not the only value of the gas based plants. Via different mechanisms, the JRC-EU-TIMES model takes into account the value of reserve capacity. This is now reflected in the figure representing the net generation capacity.

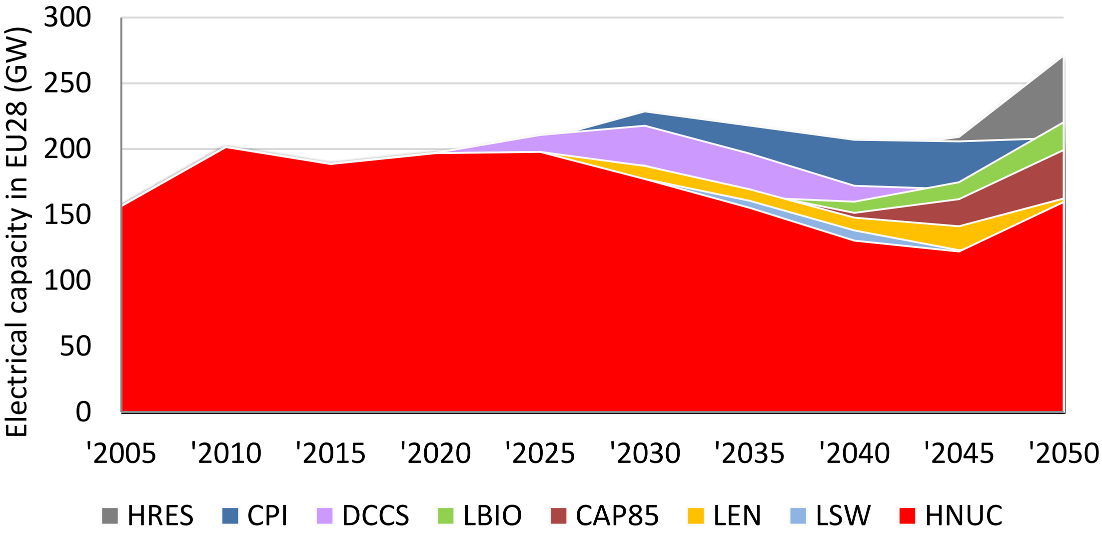


Figure 50 – Evolution of net generation capacity GWe – gas without CCS – including CHP

In all scenarios, though investment shifts towards gas combined cycle with CCS (see also Section 12.6), new gas plants without CCS are also built, as these are cost efficient. However, the average operating hours are between 180h and 300h in the various decarbonised scenarios, as opposed to around 1000h in the CPI. The most important factor affecting EU wide installation in the long run is concerns regarding intermittent variable electricity (with an installed capacity in the HRES and LBIO higher than in the CPI scenario).

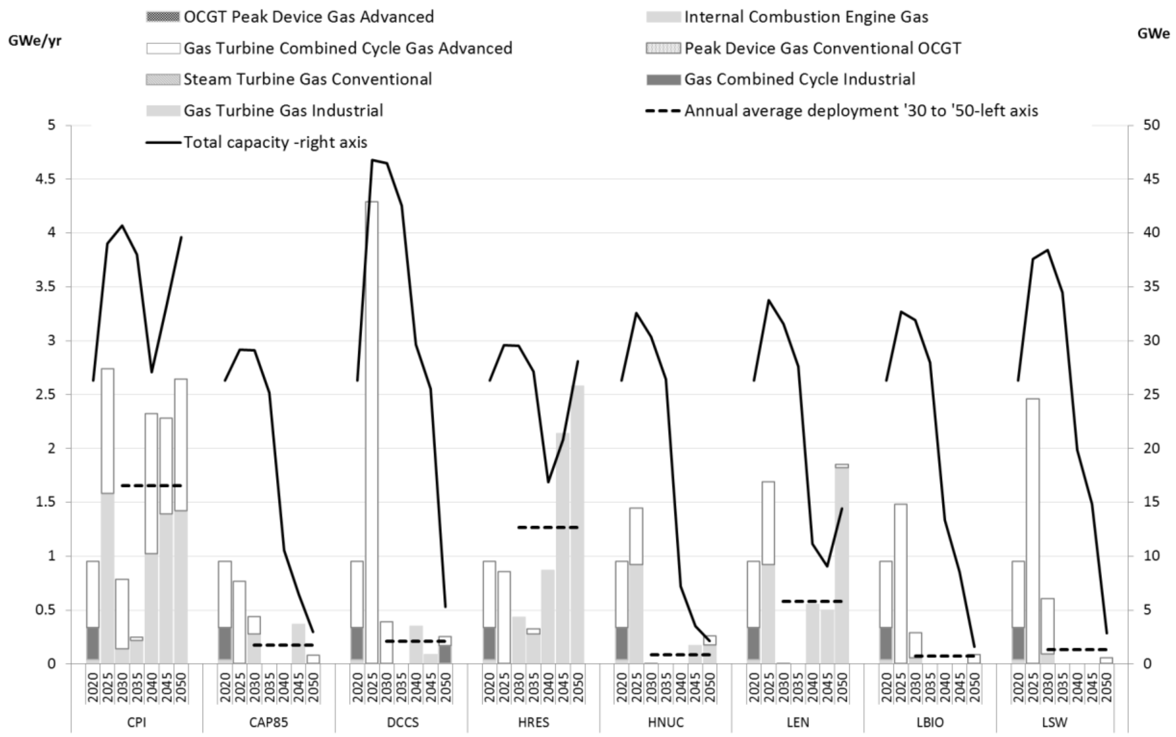


Figure 51 – Technology deployment – annual investment in new capacity (GW/yr – left) and total capacity (GW – right) – gas without CCS, excluding CHP

11.8 Hydropower

Hydropower continues to play an important role for electricity generation across all the time horizons and scenarios, with 9-12% relative share of generated electricity in 2050. It is the second most important RES energy carrier in the total RES electricity (15-23% in 2050).

Hydro is especially relevant in the earlier periods. When other RES technologies become cheaper (as is the case of PV and wind offshore, and, to a lesser extent, marine in the decarbonised scenarios) the role of hydro is slightly reduced with respect to 2005. In all scenarios in 2015-2020 the existing plants' activity decreases slightly due to wind onshore deployment.

After 2020 in the CPI scenario new run-of-river capacity is deployed mainly DE, ES, PT, IT and HR. New lake capacity is also deployed in a few countries (mostly FI and DE), starting in 2025. In the decarbonised scenarios, similar patterns are observed – but many more countries invest in new lake capacity, with IT and ES showing the highest new investments.

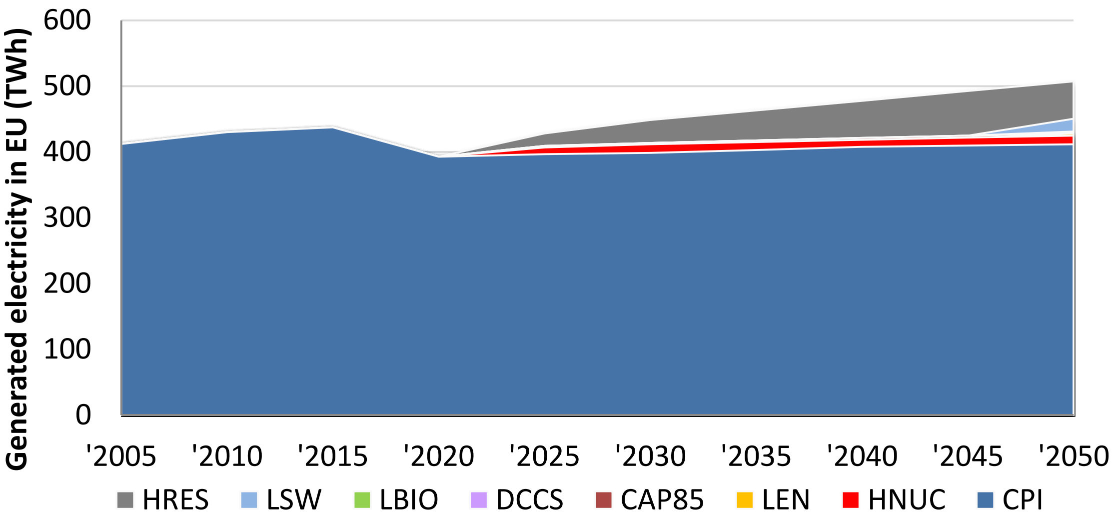


Figure 52 – Evolution of generated electricity in TWh – hydropower

As expected the highest overall increase in generated electricity from hydropower occurs in the HRES scenario of around 4 TWh/year in the period from 2020 to 2050, as compared to 0.6TWh/year in the CPI, and 1.1-1.9TWh/year range in the other decarbonised scenarios. This growth is accompanied by an average overall annual capacity increase from 0.2 GW/year (2010-2020) to 0.8 GW/year (2020-2050) in the HRES scenario. Hydropower reaches its full technical potential in most of the countries. Yearly average deployments between 2030 and 2050 range from 0.09GW/yr in the CPI, and 0.35GW/year in the HRES.

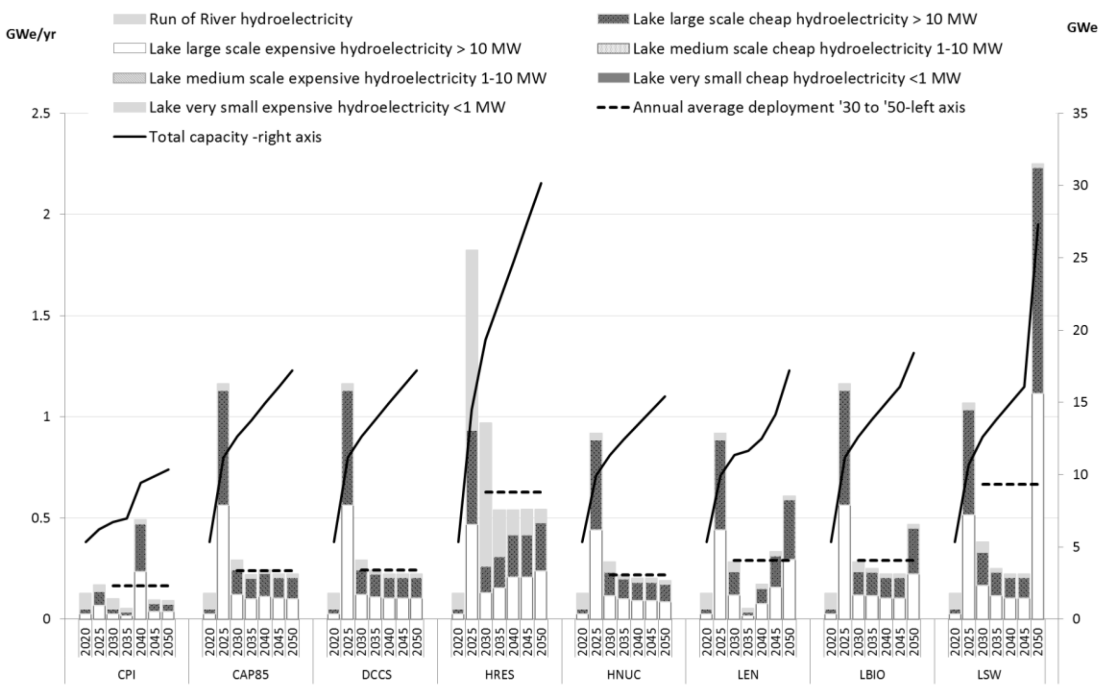


Figure 53 – Technology deployment: annual investment in new capacity (GW/yr – left) and total capacity (GW - right) –Hydro

11.9 Geothermal Energy

Geothermal energy will have an insignificant growth in terms of its share in total electricity generation up to 2050, constituting approximately 1% in total electricity mix and a maximum of 1% among RES energy carriers. It needs to be pointed out that in our model the potentials for geothermal energy are rather conservative. Indeed, in all scenarios geothermal energy potentials are exploited to the full already starting in 2030 in most. The HRES scenario sees the highest growth in electricity generation from geothermal energy from 2010 till 2050, with the higher annual deployment of 0.07 GW/year in the mid-term up to 2030 (for the other decarbonised scenarios is slightly lower, 0.06 GW/year). There are no substantial differences among the other decarbonized scenarios.

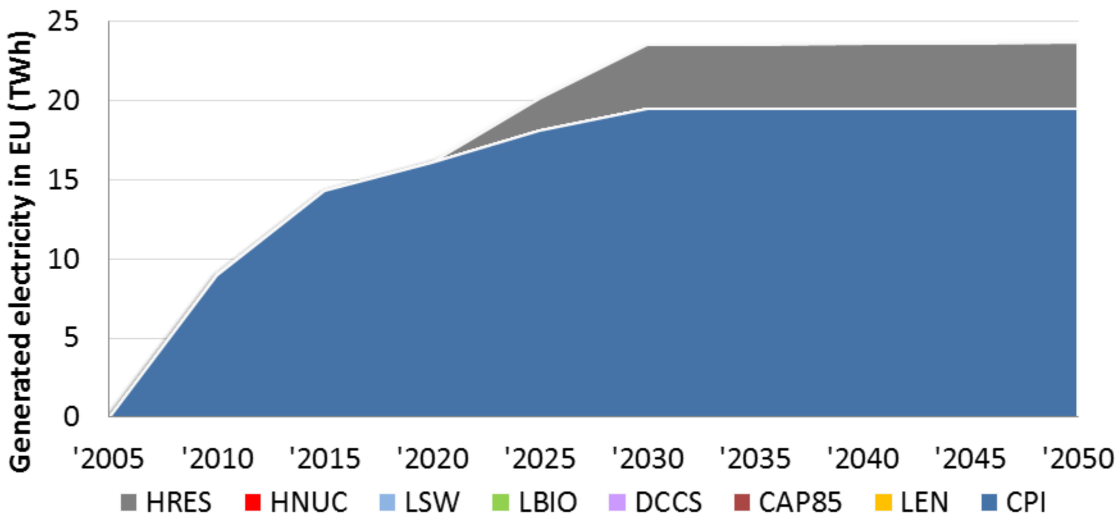


Figure 54 – Evolution of generated electricity in TWh - geothermal

Germany and Italy have an increase in growth in their electricity generation from geothermal energy in 2030, while the rest of the EU28 countries will have close to no geothermal energy under most of the scenarios. Only in the HRES scenario, in addition to IT and DE, BG (and marginally, PT) show some growth in electricity generation from geothermal in 2030. This however changes in 2050, where almost none of the EU28 countries would demonstrate any further increase in their geothermal electricity generation under the different scenarios. In terms of technology deployment only geothermal hydrothermal with flash power plants is cost-effective with the considered costs.

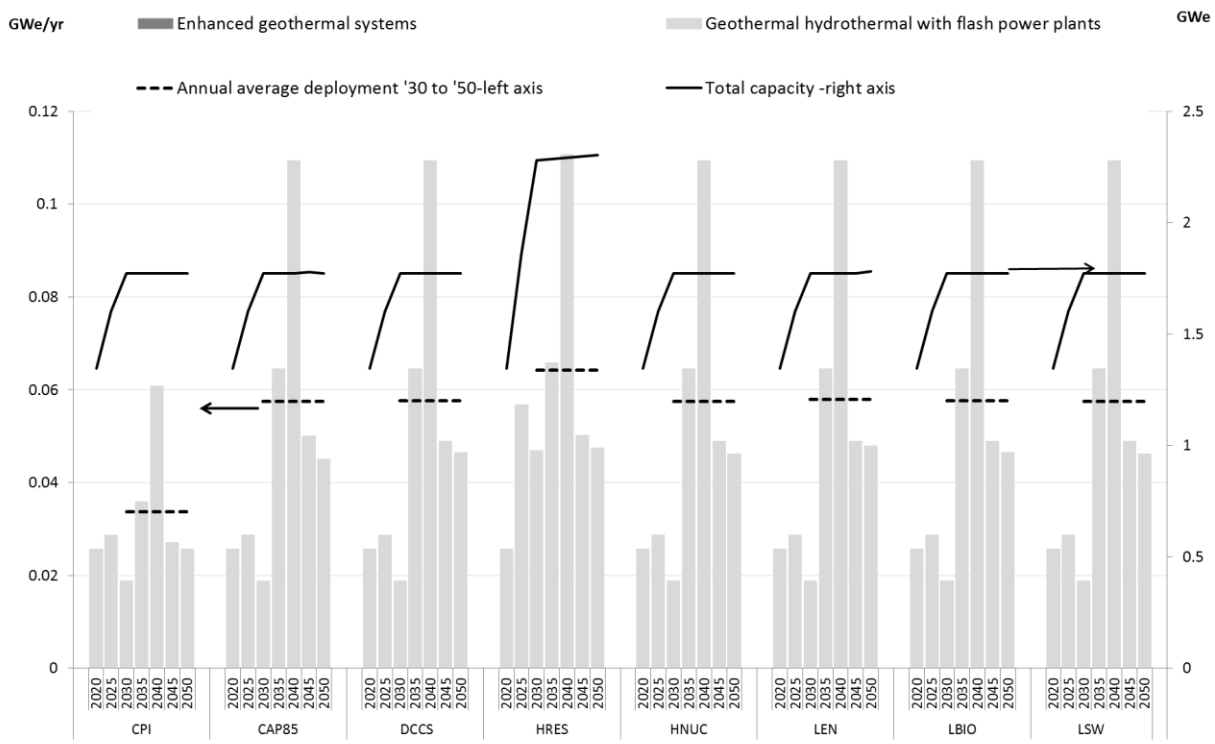


Figure 55 – Technology deployment: annual investment in new capacity (GW/yr – left) and total capacity (GW - right) –Geothermal

11.10 Marine Energy

Marine energy encompasses a group of technologies that could play a significant role in the long term energy system in Europe. However, the currently observed trend in the development of the sector is below the initial expectations.

The results of the model are in line with this observation. In the CPI scenario, marine energy does not play any role, while in the decarbonised scenarios it becomes economically viable starting in 2035. The only exception is the LEN scenario, where the deployment of marine energy technologies is delayed to 2040.

Only relatively cheaper tidal energy stream and range technologies are deployed, while wave technologies do not become a viable option for electricity generation between now and 2050 in our modelled scenarios. Moreover, the pattern of deployment is skewed towards the end of the horizon, with a very slow deployment between 2035 and 2045, and a significant increase in efforts in 2050 in all the scenarios (Figure 56). The deployment path is smoother in the scenarios with limited potential for other RES (LBIO and LSW), where electricity produced via tidal energy technologies is higher already in the early periods. DCCS also leads to an increase in electricity produced in the early periods, when compared to the other decarbonised scenarios.

New annual installed capacity between 2035 and 2050 is the highest in the LSW scenario (about 3.5Gw/year), while the slowest is observed in the HNUC scenario (0.9Gw/year). For the other scenarios, new annual installed capacity grows between 1.8 and 3.3 GW/year.

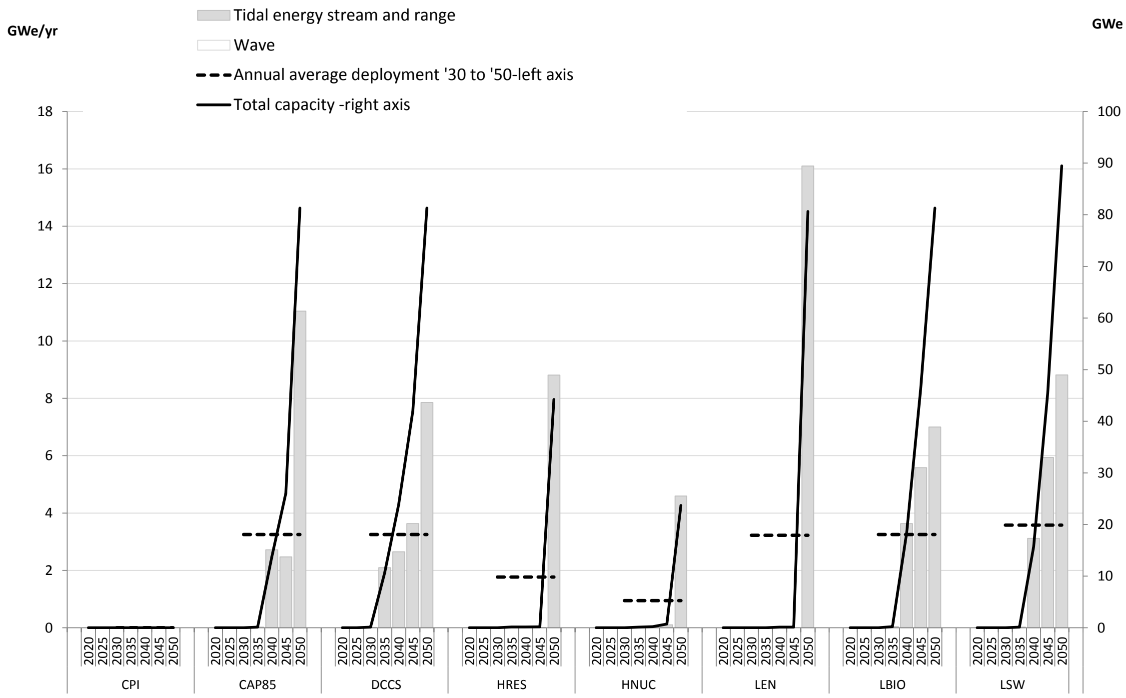


Figure 56 – Technology deployment: annual investment in new capacity (GW/yr – left) and total capacity (GW - right) – tidal energy

Installed capacity reaches between 24-89 GW in 2050 in the decarbonised scenarios, with HNUC and LSW on the lowest and highest extremes of the range respectively. It is also interesting to note that, in the HRES scenario, installed capacity only reaches 44GW in 2050 – a significant increase from 0.2GW in 2045. This would seem to indicate that other RES technologies are more competitive at least until 2045.

Despite the significant increase in deployment and generated electricity towards the end of the horizon, the importance of tidal energy in the electricity generation mix remains marginal, reaching in 2050 a maximum of 4% in the LSW decarbonised scenario. In all other decarbonised scenarios, the contribution of tidal energy to electricity generated ranges from 0.8% in the HNUC scenario to 3.9% in DCCS and CAP85, with an average of 2.8% across all the scenarios.

In terms of generated electricity, tidal energy can generate between 45-170 TWh of electricity in the decarbonised scenarios (HNUC and LSW respectively), with an average of 131TWh across the decarbonised scenarios. The HRES scenario also shows a limited use of tidal energy for electricity generation in 2050 (84TWh in 2050), an indication of competition with more established, cheaper renewable energy technologies.

Despite the relatively low contribution to electricity generation, tidal energy can be an important technology to ensure the decarbonisation of electricity production, accounting for up to 10% of total RES electricity in 2050 in the scenario where its deployment is highest (LSW). In the other scenarios, the share of marine into RES electricity generated is between 2% and 7% (in the HNUC and LEN scenarios respectively), with an average of 6%.

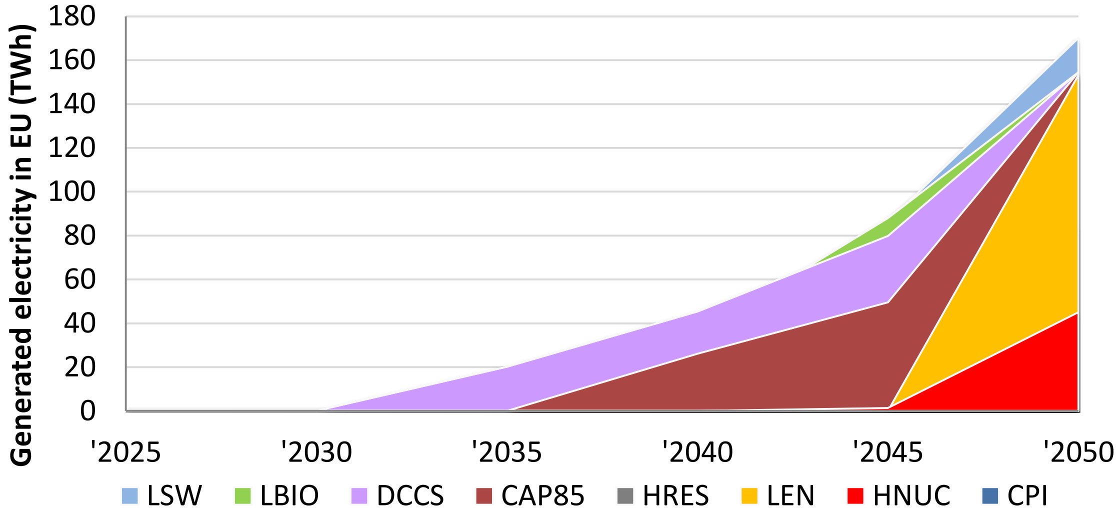


Figure 57 – Evolution of generated electricity in TWh – tidal energy

From a comparison of the pattern of deployment of tidal energy across the scenarios, it appears clear that the factors that influence its commercial viability are the availability of other, better established, low carbon electricity generation technologies, such as nuclear and other RES. Solar and wind in particular are in direct competition with tidal energy and, to a lesser extent, biomass. The DCCS scenario provides additional incentives for marine energy, whose electricity generation in this scenario picks up at a quicker pace already in 2045.

In the HRES scenario, only 26% of the total tidal energy potential at the European level is used in 2050. This is in contrast with the LSW, when 100% of the potential of tidal energy is exploited. In the other scenarios, the exploitation of tidal energy potential is around 90%, with the exception of the HRES scenario where by 2050 49% of the European tidal energy potential is exploited.

Zooming in at the situation at the country level, IE, NL, DK, CY and BE are the first countries to generate electricity via tidal energy in 2035. Other countries that start producing electricity with tidal energy are ES, PT and GR. The situation is however different in the HRES, HNUC and LEN scenarios, where the only countries producing tidal electricity before 2050 are CY and BE. It is also interesting to note that, under the HRES scenario, some countries that would deploy tidal energy do not do so – e.g. ES, GR, IT, PT, NL and DK. This result confirms the competitive link between tidal energy and other, better established, renewables, which are cheaper and can be deployed more in the HRES scenario. In the JRC-EU-TIMES model, tidal energy only becomes competitive in the UK in 2050, when it is rolled out and the UK becomes the leading country in the generation of tidal electricity (56-86TWh). In FR, on the other hand, tidal energy does not become competitive over the time horizon, with the exception of the LSW scenario, where it reaches its maximum electricity generation capacity in 2050. Indeed, by 2050, all countries that do produce electricity via tidal energy reach their full potential.

According to the European Ocean Energy Association (European Ocean Energy Association, 2010), 3.6GW of installed capacity could be realised by 2020, and close to 188GW by 2050. Our model displays a much smaller marine energy capacity. Tidal energy only becomes cost-effective only in the decarbonised scenarios, and only from 2035 in the DCCS scenario (2040 in the other decarbonised scenarios). According to our modelling exercise, a maximum installed capacity of 90GW is achieved, in the LSW scenario, in 2050 – half of the industry's expectation.

11.11 Cogeneration or Combined Heat and Power

In total terms the share of electricity generated from CHP decreases from 2005 values in all scenarios (from 12% in 2005 to 11% in CPI in 2050 and 6-9% in the decarbonized scenarios). This is due to a combination of the following:

- there are relatively limited CHP options for low carbon electricity generation, one of which is biomass based. In the decarbonized scenarios, as previously discussed, biomass is more cost-effective to be used in the transport sector;
- there are conservative assumptions on the deployment of centralized heat (that can be originated from CHP besides district heating options) in buildings.

Regarding the share of the different energy carriers for CHP, clearly gas based CHP play the most important role in all scenarios. Gas is followed by biomass and lignite (with CCS) CHP. The rate of deployment varies substantially across carriers: new biomass CHP plants are installed at a faster pace in 2020 and then again in 2050, whereas gas CHP plants (with CCS) are more relevant in the later periods. This is again due to the fact that biomass is more cost-effective for transport in the later periods with the more stringent cap. In CAP85 and LEN biomass based CHP is replaced by coal CCS CHP but only in the intermediate years (2035).

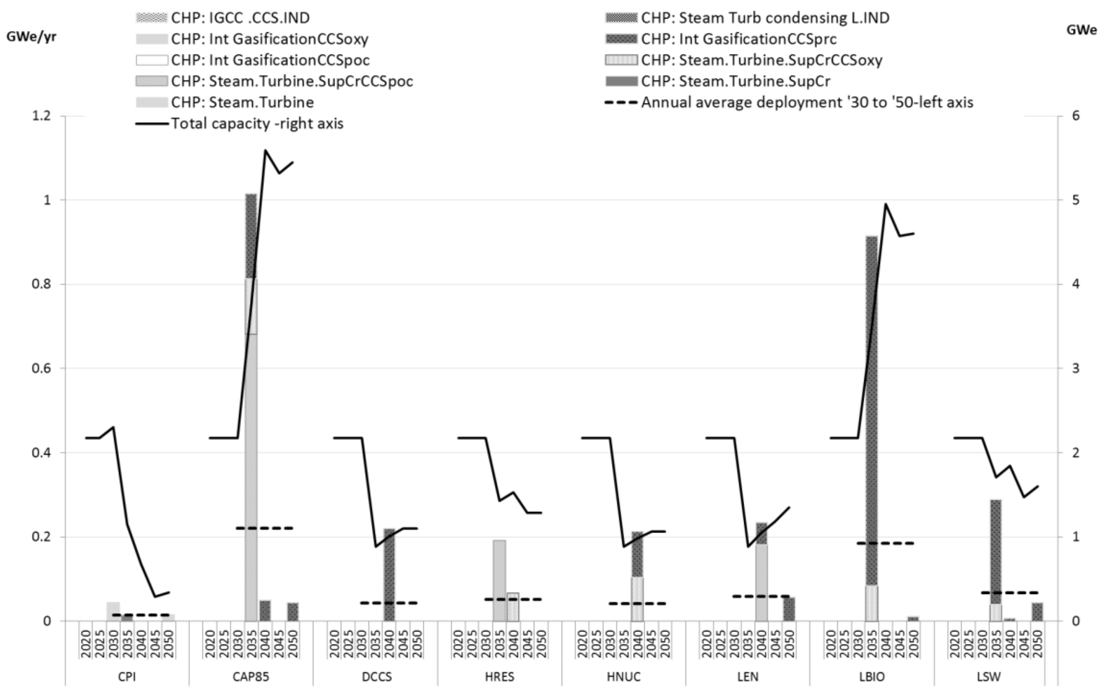


Figure 58 – Technology deployment: annual investment in new capacity (GW/yr – left) and total capacity (GW - right) – coal CHP

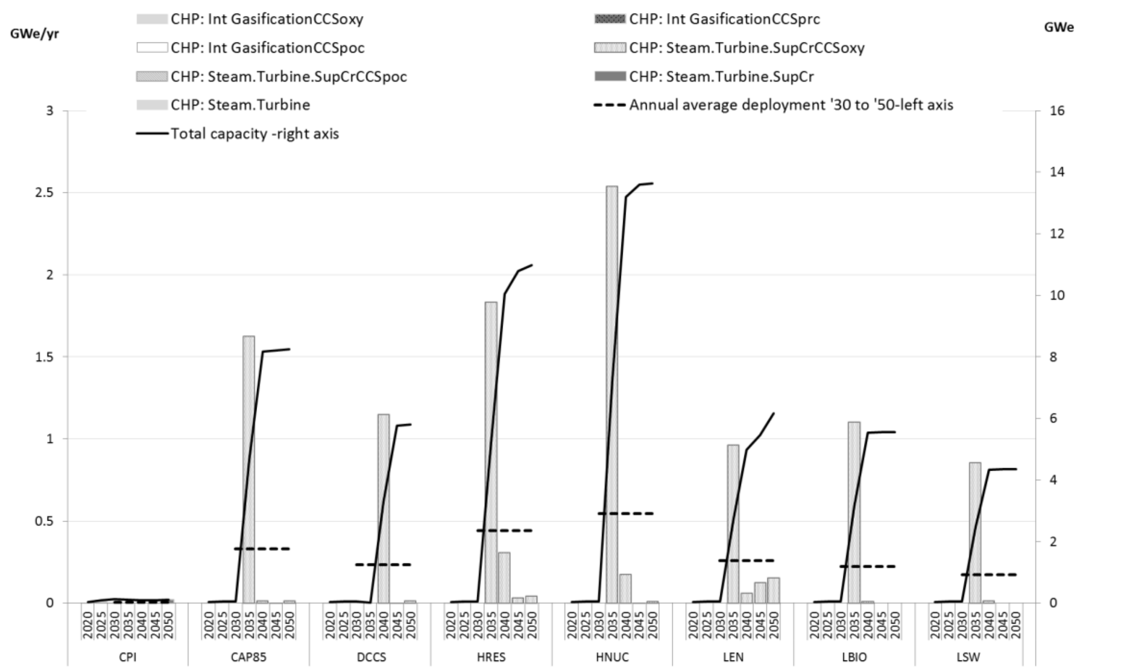


Figure 59 – Technology deployment: annual investment in new capacity (GW/yr – left) and total capacity (GW - right) – lignite CHP

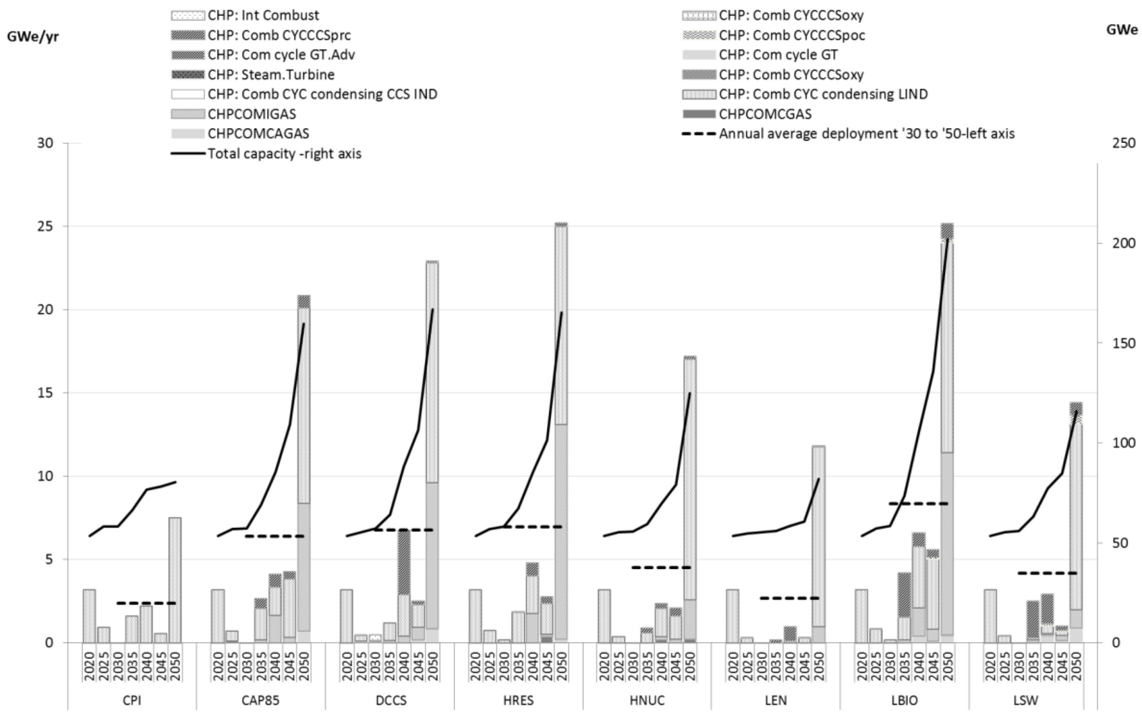


Figure 60 – Technology deployment: annual investment in new capacity (GW/yr – left) and total capacity (GW - right) – gas CHP

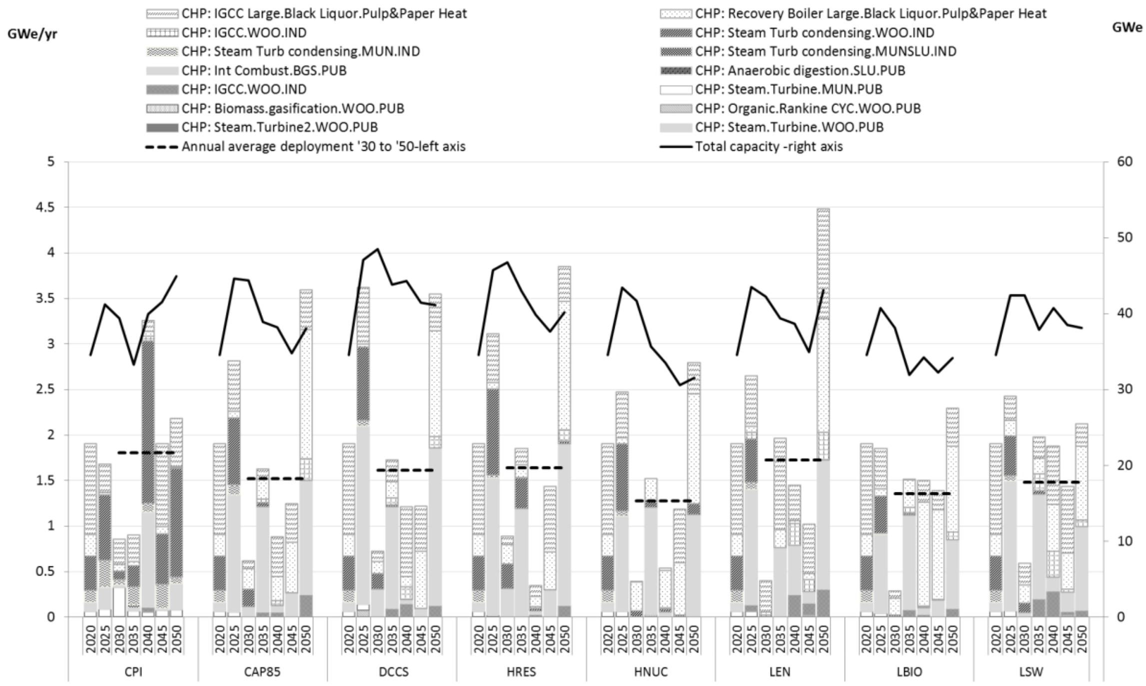


Figure 61 – Technology deployment: annual investment in new capacity (GW/yr – left) and total capacity (GW - right) – biomass CHP

Whereas the biomass based CHP are mainly delivering heat and electricity directly to the industry sector, the other CHP plants deliver heat and electricity to the distribution grid. In 2050 the most relevant CHP technologies are for combined cycle natural gas condensing plants in industry, black liquors plants associated to the pulp and paper industry; IGCC lignite supercritical steam turbines with oxyfuel with CCS and for integrated coal gasification with post combustion with CCS. Biomass based CHP is deployed roughly throughout all countries in EU28 but gas and coal/lignite CHP with CCS are mostly deployed in AT, CZ, DE, DK, HR, HU, IT, NL, PL and SK.

According to a press release by the industry association COGEN Europe (COGEN Europe, 2013), the total potential for CHP's contribution to the European power market is around 225GWe. In our model's results, the average co-generation installed capacity in 2050 is 205GWe. In most of the decarbonised scenarios (CAP85, DCCS, HRES, and LBIO), the full potential is reached (and slightly overshot) in 2050.

11.12 Energy Storage

This part of the report discusses energy storage in the JRC-EU-TIMES model. Figure 62 presents the available capacities of electricity storage technologies in EU28 from 2010 until 2050, expressed as charging power. Solar curtailment is included, although it is not a storage technology. For solar curtailment, the total maximum curtailed power is plotted in Figure 62 occurring in the summer peak time slice.

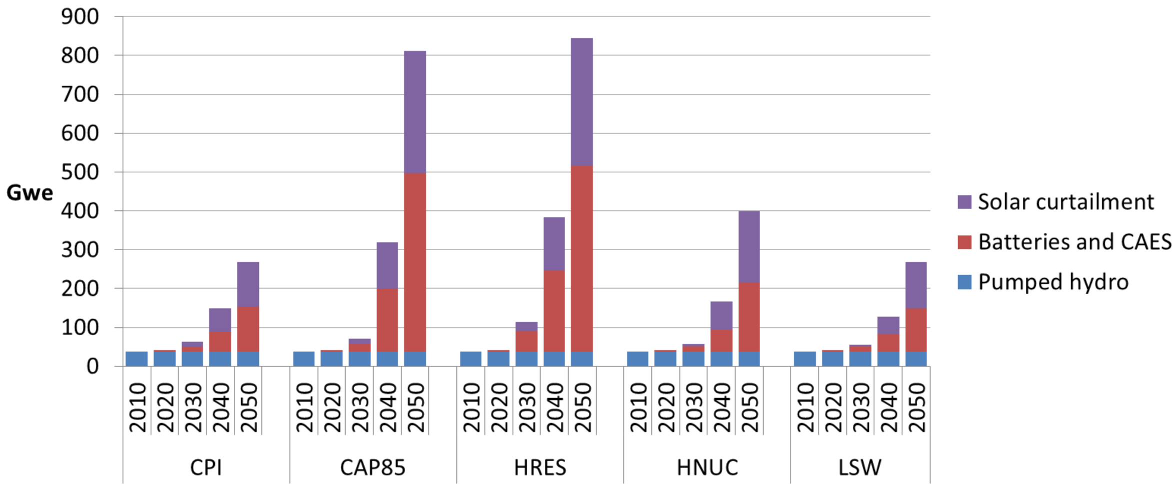


Figure 62 – Evolution of power capacities (charging power), including solar curtailment

As expected, the pumped hydro storage technologies that are already installed in 2005 continue their activity until 2050 in all the studied scenarios. Investment in new storage technologies only becomes cost-effective from 2030 onwards but scale up fast. There is the tendency to move to batteries and CAES rather than new pumped hydro. H_2 storage does not become cost-effective in this exercise. The next graph shows the total annual electricity that is used to charge storage systems as well as the total electricity being curtailed. Only a share of the stored electricity is recovered in other time slices and used for consumption.

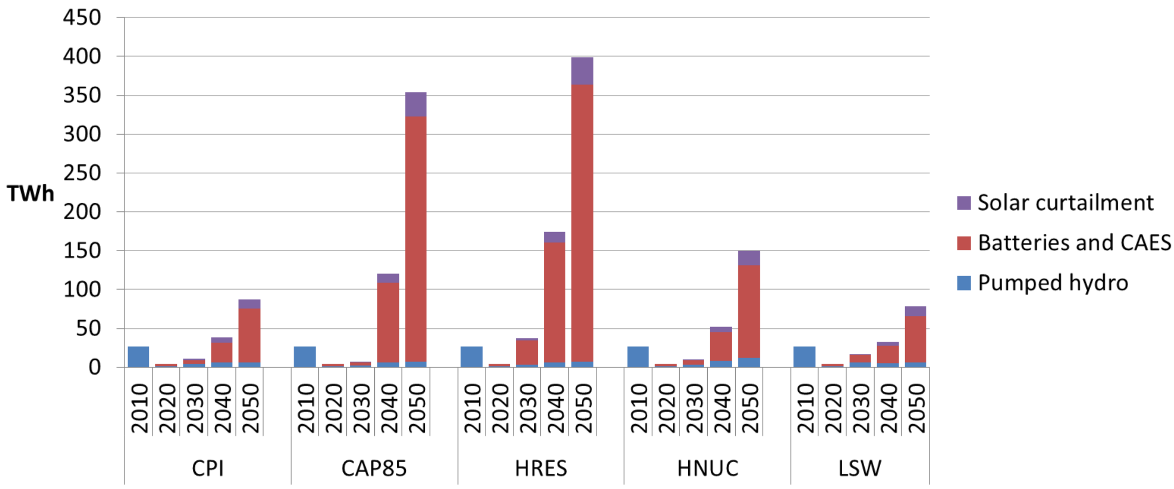


Figure 63 – Evolution of storage capacities (expressed as total annual inflow), including solar curtailment

Regarding the contribution of the different storage technologies, in 2050, batteries and CAES play a relevant role in all modelled scenarios. The introduction of a CO_2 cap leads to a significantly higher deployment of storage. The deployment of renewables in the electricity production has a direct impact on the use of storage technologies, as expected. The increased use of nuclear electricity reduces both the storage activity and the storage capacity.

Heat storage is cost effective from 2015 onwards when large underground water tanks are used. It contributes to a small share of the heat consumption. The role doubles in the LEN scenario. Heat storage has lower importance in the LSW scenario.

11.13 Energy Efficiency and CO_2 Emission Reduction in Industry

Industrial final energy consumption accounts for just over one third of overall energy consumption in 2050 in the CPI scenario. It is thus important to understand the dynamics of changes in patterns of energy consumption and CO_2 emissions in the sector.

While final energy demand by the industrial sector continues to increase over time in the CPI scenario, reaching 18724 PJ in 2050 (an increase of 16% with respect to 2020), in all the decarbonised scenarios industrial energy demand in 2050 is below the demand levels of 2010, ranging from 13714 PJ in the LSW scenario to 15362 in the HNUC scenario. In the LEN scenario the decrease of industrial energy consumption in 2050 is much sharper (industrial energy demand drops to 10452 PJ, a 35% decrease with respect to energy demand in 2020 in the same scenario).

Beyond the LEN scenario, the LSW and LBIO scenarios show the sharpest decline in industrial energy demand over time, with a 15% decrease between 2020 and 2050. This is compared to an average decrease of 9% between 2020 and 2050 in the other decarbonised scenarios. With respect to the CPI scenario, industrial energy consumption drops by 27% in the LSW and LBIO scenarios, more than the average decrease of 21% in the other decarbonised scenarios.

This highlights the importance of biomass (including municipal and industrial waste) for the sector when a CO_2 cap is implemented: biomass in the industrial energy mix in 2050 significantly increases, constituting in the decarbonised scenarios 24%-36% of the total energy demand in industry. Only in the LBIO and HNUC scenario the share of biomass is below the levels of the CPI (27%), at 24% and 25% respectively. This is not surprising, as a more stringent constraint on biomass limits the extent to which it can be used and, in the case of HNUC, electricity is more competitive as a source of energy. There is also an increase in the importance of biomass for industry over time: in 2020, the contribution of biomass to energy in the industrial sector is less than 20%, but in 2050 the average contribution in the decarbonised world is 32%.

Biomass mostly substitutes coal inputs – with the relative contribution of coal to the total energy mix of the industrial sector in 2050 dropping from 13% in the CPI to 4-7% in the decarbonised scenarios though, in absolute terms, coal plays a much reduced role as compared to the CPI because of the lower demand for final energy services.

Electrification is also an important decarbonisation avenue for the industrial sector, with electricity providing 34-51% of total energy consumed in 2050 in the decarbonised scenarios, compared to only 22% in the CPI scenario.

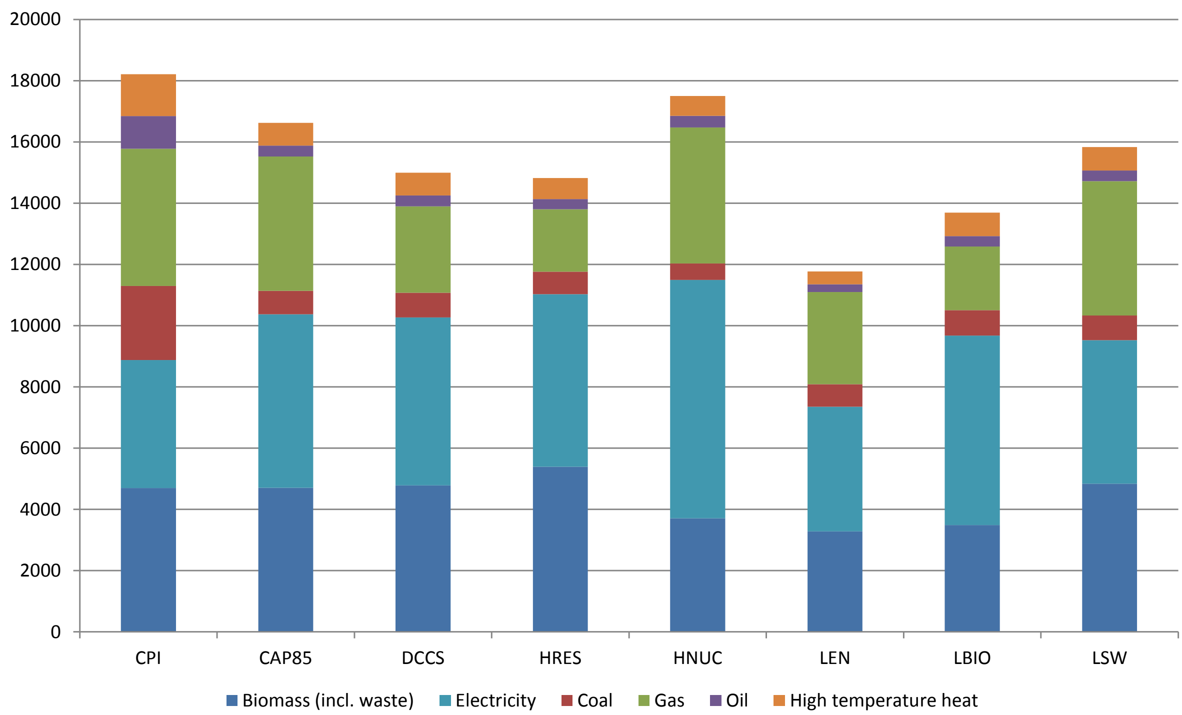


Figure 64 – Final energy consumption in industry by carrier (PJ) in 2050

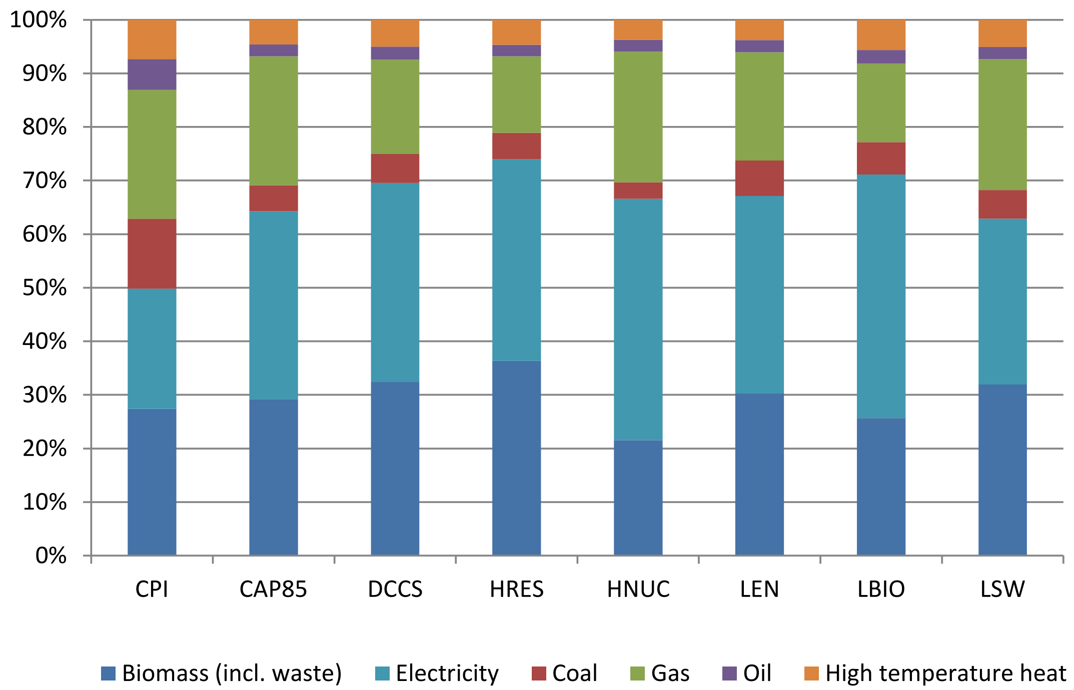


Figure 65 – Final energy consumption in industry by carrier (% of total) in 2050

Industrial CO_2 emissions in the CPI scenario increase over time (by about 18% in 2050 with respect to 1990 levels). The picture changes drastically in the decarbonised scenarios: in 2050 the industrial sector has to reduce its emissions by 83-93% with respect to 1990 levels. It needs to be pointed out at the outset, however, that this only accounts for direct emissions from the sector, whereas the emissions from electricity and other energy carriers that are input to production processes are not accounted for here.

Not only does industry reduce its emissions over time, it also reduces its contribution to total system CO_2 emissions in the long term: contributing 24% of total emissions in 2050 in the CPI scenario, the share of industrial emissions reaches 7-10% in all the decarbonised scenarios, with the exception of the LEN scenario, where industry continues to contribute around 18% of total CO_2 emissions in 2050. In the remainder of this section, we will focus on the decarbonised scenarios other than LEN, as compared to the CPI scenario.

Emission reductions of this magnitude require indeed a significant change in the energy mix used by the sector, as seen in the figures above. However, also the demand elasticity displays a strong effect in industry: demand for industrial products is 23-30% lower in the decarbonised scenarios than in the CPI scenario in 2050 (except the LEN scenario, where demand is 43% lower).

Despite the stringent cap, the energy intensity of production in the industrial sector does not improve significantly over time in the decarbonised scenarios, though the emission intensity of energy use does improve. This shows an increasing decoupling between industrial emissions and energy use over time in all the decarbonised scenarios.

The decoupling has three main drivers: increased electrification and biomass use, but also a significantly higher deployment of CCS technologies, with stored CCS in the industrial sector increasing from 14Mt in 2050 in the CPI to 216-233Mt in the decarbonised scenarios. The relative importance of industrial CCS capture in the overall capture, however, is lower in the decarbonised scenario than in the CPI: while in the CPI most of the capture is observed in the industrial sector (74%), the share decreases to an average of 29% in the decarbonised scenarios.

Deployment of CCS technologies in the CPI is limited to cement dry advanced production with CO_2 capture, while in addition to cement, in the decarbonised scenarios production technologies with CCS become competitive in the chemical industry (ammonia), as well as iron and steel, pulp and paper and glass recycling sub-sectors. Dry kilns with CCS in the cement sub-sector in particular constitute the largest share of CO_2 captured in industry in all the decarbonised scenarios, alongside CCS capture technologies for the production of ammonia.

Iron and Steel Industry

The main change observed in the steel and iron subsector is a progressive move towards biomass use, reaching around 90% of energy in the sub-sector in 2050. The only scenario where biomass is not substantially deployed in 2050, besides the CPI, is the LEN scenario. Coal, gas and oil progressively lose their importance in all decarbonised scenarios, while electrification, though increasing over time, does not play a major role in the iron and steel sub-sector.

Production technologies with CCS become competitive staring in 2025 in all decarbonised scenarios, with the exception of the DCCS scenario where, by design, CCS technologies can only be deployed starting in 2040. However, the level of production with CCS technology quickly reaches the same level as in the other decarbonised scenarios.

Emissions from the iron and steel sub-sector decline over time in all scenarios, including the CPI, where emissions are around 40% lower in 2050 than in 2020. The decarbonised scenarios, though, require a significant shift away from emission-intensive production technologies: indeed, the carbon intensity of demand for iron and steel declines significantly over time and with respect to the CPI (from 0.69 in the CPI to 0.02 tCO_2/Mt of iron and steel in the decarbonised scenarios), with emissions dropping by close to 100% in all decarbonised scenarios. This is brought about by a massive deployment of biomass, as seen in the previous paragraphs.

Cement Industry

Cement production increasingly uses biomass and electricity, while the use of oil and gas considerably declines in all decarbonised scenarios with respect to the CPI scenario. In 2050, biomass constitutes approximately 14% of energy input in the CPI, while in the decarbonised scenarios its contribution varies between 17% and 28% in the low biomass and high renewable potential scenarios respectively. Electricity, on the other hand, moves from approximately 12% to 24%-37%. The highest contribution of electricity is seen in the HNUC scenario.

In all scenarios, production technologies with CCS become competitive starting in 2025, except in the DCCS scenario where they can only be deployed starting in 2040. The production of cement via dry production with CCS in this scenario, however, quickly picks up and, in 2050, it reaches the same level as in the other decarbonised scenarios. Captured CO_2 ranges from 166Mt to 183Mt in the decarbonised scenarios, compared to 17Mt in the CPI. This allows the sub-sector to continue using coal, though to a smaller extent than in the CPI.

While in the CPI CO_2 emissions from cement production continue to increase, all the decarbonised scenarios show a sharp decrease in emissions over time and with respect to the CPI – in 2050, the emission reduction from the sub-sector with respect to the CPI is around 90% in the decarbonised scenarios. We also see a significant decarbonisation of production in the sector, with the emission intensity declining significantly with respect to the CPI in 2050: in 2050, CO_2/production is 0.63 in the CPI, while in the decarbonised scenarios it ranges only from 0.08 to 0.11 tCO_2/Mt.

Pulp and Paper Industry

In the paper and pulp industry, biomass (biogas and black liquors) cogeneration is significant already in the CPI scenario, with coal-based cogeneration stabilising at around 7% over time. In the decarbonised scenarios, this situation changes significantly, with coal declining almost to zero per cent. Bioenergy provides in 2050 between 37% and 56% of total energy needs in the decarbonised scenarios.

Electricity also plays a role in decarbonising the paper and pulp production, increasing its contribution to the sub-sector energy requirement from 23% in 2050 in the CPI to 40%-57% in the decarbonised scenarios, with the highest contribution observed in the HNUC scenario.

In 2040, high quality paper production processes with CCS become competitive in all decarbonised scenarios. In the LBIO and LSW scenarios, where there is more limited possibility to decarbonise, production technologies with CCS are already competitive in 2035. Their deployment is slower in the DCCS scenario, whereas it is not competitive in the CPI.

The pulp and paper industry also shows an important decarbonisation of production, with CO_2/production declining to around 0.07 in the decarbonised scenarios compared to 0.23 tCO_2/Mt in the CPI.

11.14 Energy Performance of Buildings

We focus this section on the most relevant energy use in buildings, i.e. heating and cooling (including for sanitary water). The very stringent CO_2 target leads, in the decarbonised scenarios, to a major change in energy carriers, mainly phasing out of fossil fuels (gas and oil) accompanied by increased RES deployment (mainly solar and biomass) and heat pumps. The RES share in total final energy consumption for heating and cooling in 2050 varies from 27% (in CPI) to a 75-89% range for the decarbonised scenarios. This is mostly due to the increase of renewable electricity followed closely by biomass. Besides biomass electricity, ambient air as an input into heat pumps and geothermal devices plays a very relevant role.

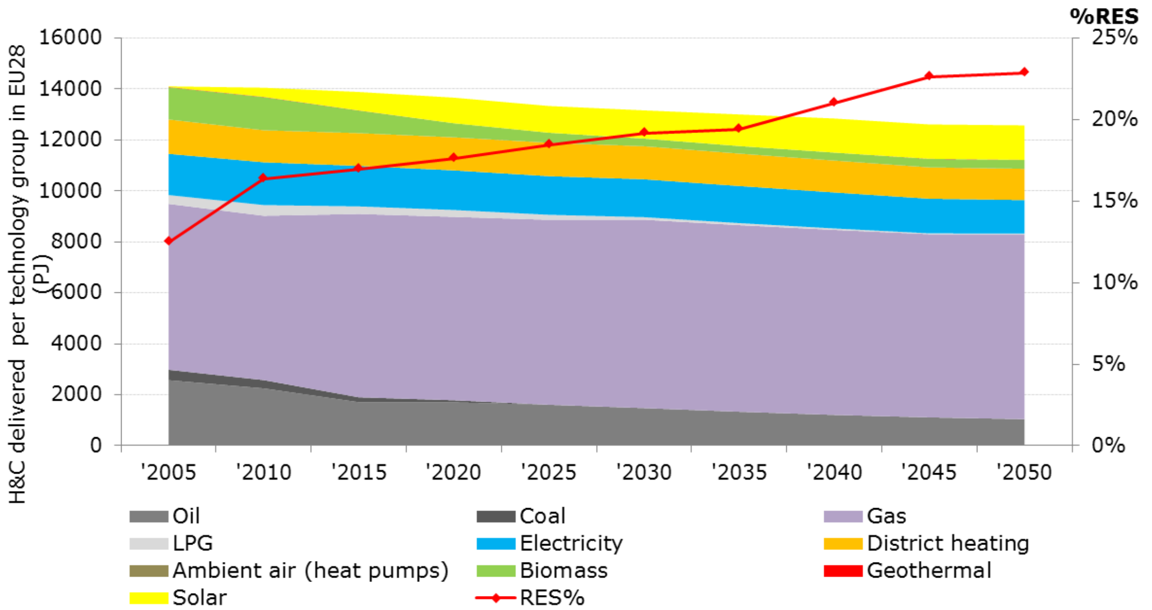


Figure 66 – Evolution of final energy consumption for heating, cooling and sanitary water – CPI

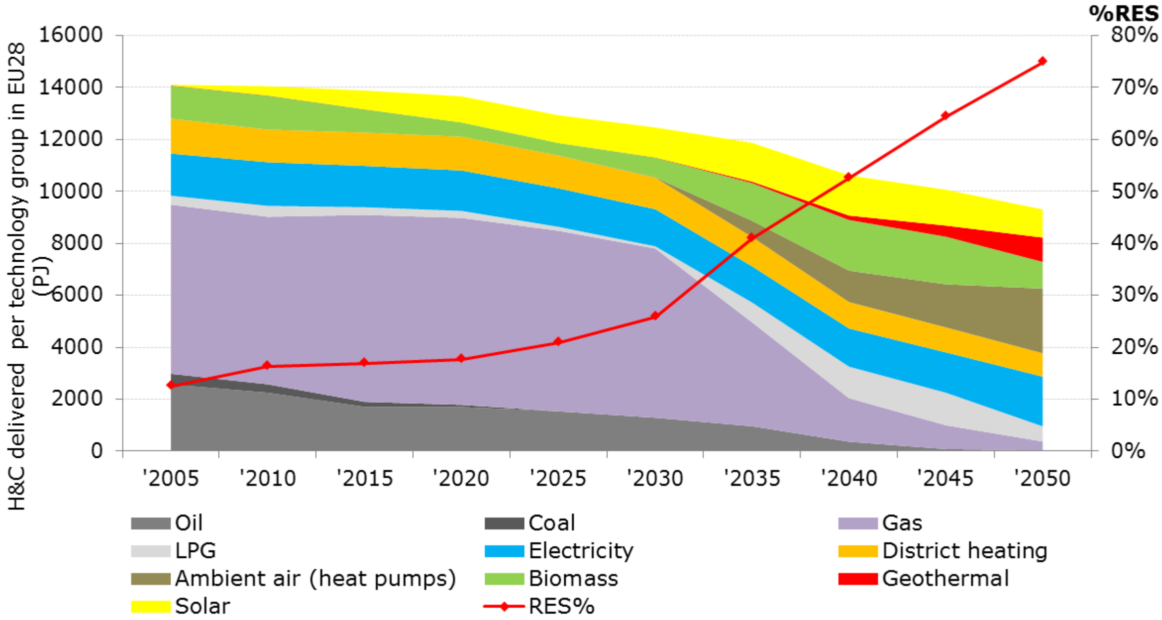


Figure 67 – Evolution of final energy consumption for heating, cooling and sanitary water – CAP85

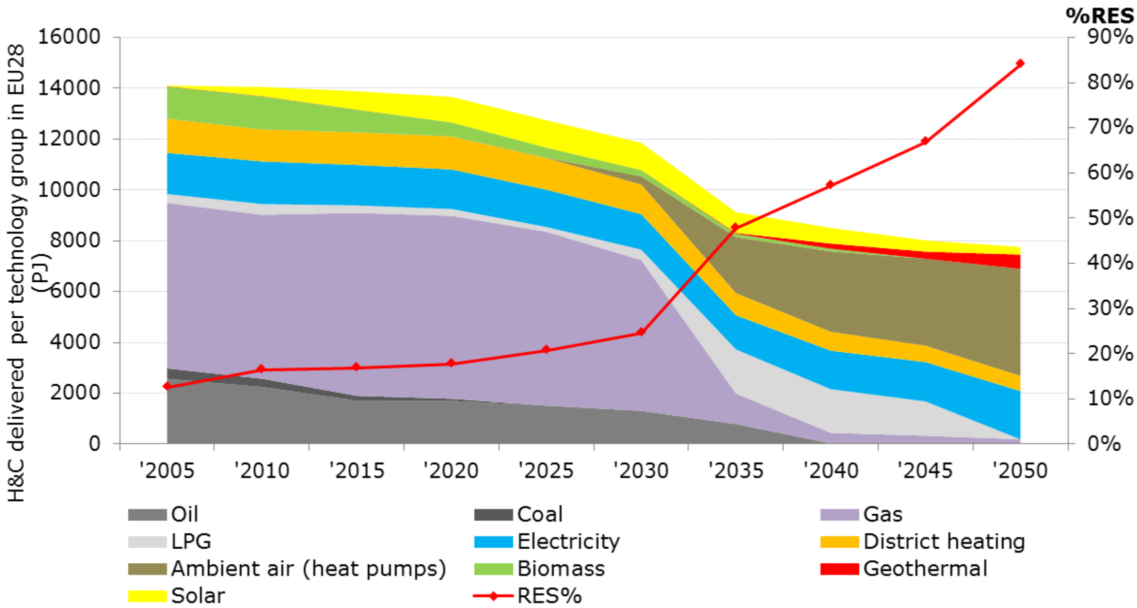


Figure 68 – Evolution of final energy consumption for heating, cooling and sanitary water – LEN

Not surprisingly, most of the decarbonised scenarios do not show substantial differences in the share of energy carriers for heating and cooling since they were mainly designed to study the electricity sector. The exceptions are the LEN scenario in which heat pumps play a more important role as higher energy efficiency is required, replacing solar and biomass based heating which has lower efficiency. It should be mentioned that these results reflect the relatively conservative assumptions on solar and DH deployment and show that the deployment of heat pumps competes with solar based heating.

Although the values are so small (max 7 PJ) that are not included in the figures in this section, district cooling technologies (absorption and compression heat pumps) in the residential sector are cost-effective from 2030 onwards.

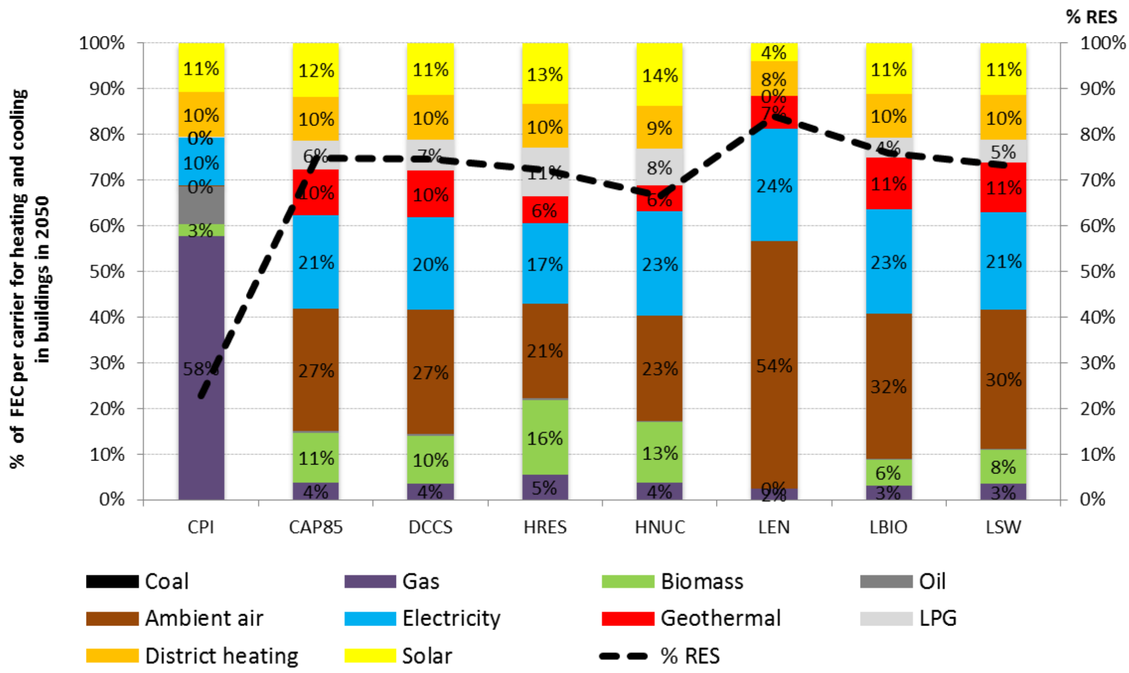


Figure 69 – Shares of final energy consumption for heating, cooling and sanitary water in 2050 (left axis) and % of RES in heating and cooling including RES electricity and RES district heating (right axis)

The RES share in the centralised heating (includes both district heating and heat from CHP) final energy consumption for heating and cooling in 2050 varies from 36% (without any CO_2 cap) to 29-37% for the decarbonised scenarios, with the exception of the LEN scenario where it is 47%. This again because in the decarbonised scenarios biomass is not available for buildings as it is mostly used in transport.

Finally, it should be mentioned that the CO_2 cap can only be met in association to an endogenous reduction in the demand for heating and cooling in buildings. This is due to the consideration in the JRC-EU-TIMES model of long term price elasticities of demand for the different materials and energy end-uses.

11.15 Transport including biofuels

We show the most interesting scenarios for the transport sector, the CPI, CAP85, HRES, LBIO, and LSW scenarios. As all other decarbonised scenarios focus very much on the power sector, they show for transport a similar impact as the CAP85 scenario.

Figure 70 shows the fuel use broken down by fuel. It displays the limited potential to displace kerosene in aviation. In the CPI scenario Gasoline and Diesel from crude oil continue to play a big role even through 2050. The decarbonised scenarios see more electrification of the transport sector, mainly in road transport, which also sees some deployment of hydrogen fuel cell vehicles, displacing large shares of Gasoline from crude oil. The HRES scenario increases to a certain extent the fuel use of bio-based jet-fuel.

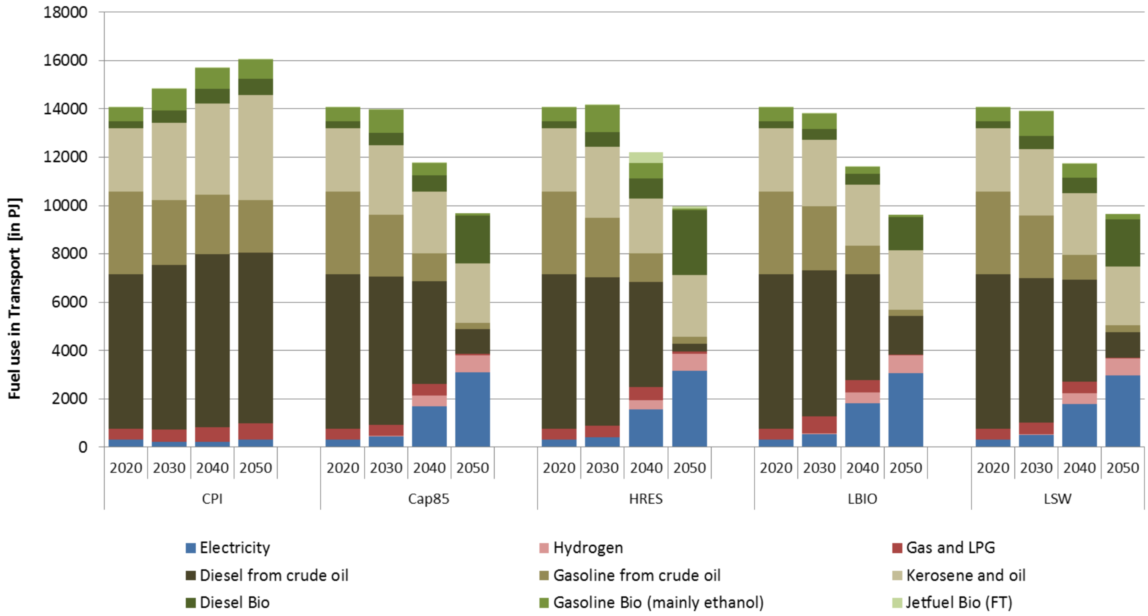


Figure 70 – Evolution of fuel consumption in the transport sector – breakout per fuel

The 3 scenarios CPI, CAP85, and HRES display a big impact on the passenger car technologies that the model chooses to satisfy the passenger transport demand. The following figures show the passenger car technologies and their share to satisfy the pkm demand fulfilled by passenger cars. Under the CPI scenario (Bio)-Diesel fuelled ICE (internal combustion engine) propelled cars will play a more important role until 2040, in line with the past observed market share growth of Diesel cars. Their increasing role is only curbed after 2040 when the model chooses to deploy electrified cars and also hybrid vehicles. The (Bio)-Gasoline fuelled ICE cars show a decreasing role, but remain also in 2050 the second most important technology option (Figure 71).

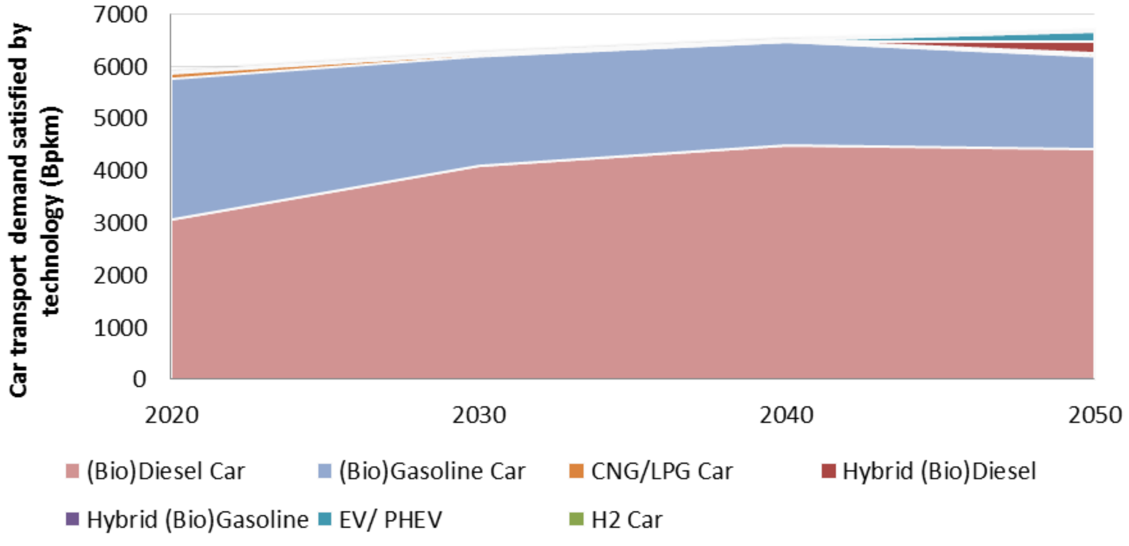


Figure 71 – Evolution of technology shares in passenger cars in the CPI scenario

In the CAP85 scenario nearly all passenger car transport demand in 2050 is satisfied by EV and PHEV. The massive deployment of these technologies starts in 2030. A small share of hydrogen cars is deployed from 2040 onwards but is invisible in the figure below. It needs to be noted that the electrification of the passenger car in our decarbonised scenarios does not necessarily imply a total displacement of gasoline, as the PHEV variants represent the lion's share in this scenario. Figure 72 also reveals that the pkm demand fulfilled by cars is slightly reduced in the CAP85 scenario versus the CPI and HRES scenarios due to the price elasticity employed in the model.

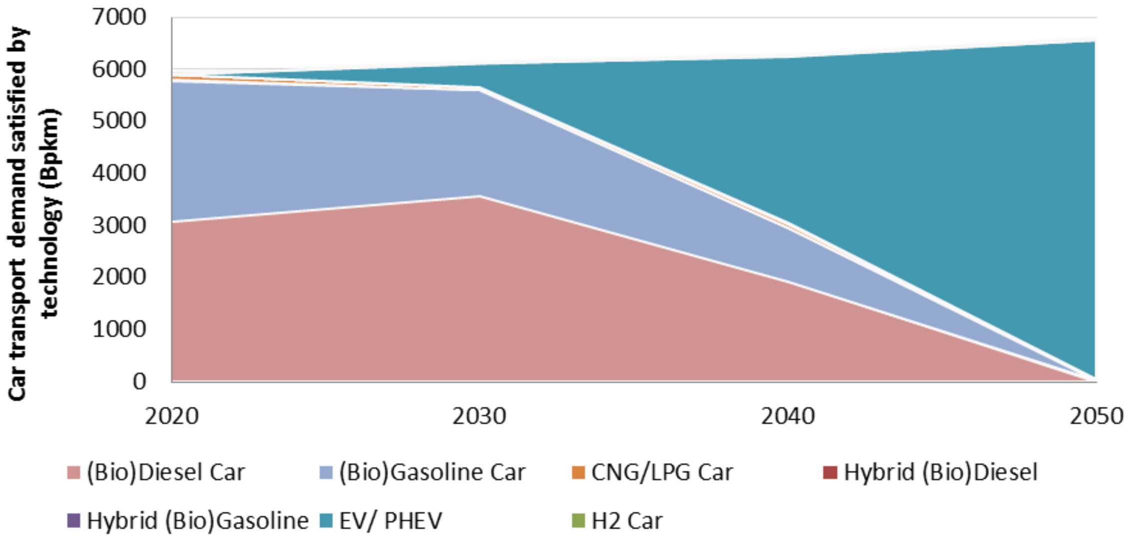


Figure 72 – Evolution of technology shares in passenger cars in CAP85 scenario

Figure 73 displays the results of the HRES scenario. As the CAP85 scenario this scenario is dominated by EVs and PHEVs. A small portion of non-plug-in hybrid vehicles appears intermediately in the market. The deployment of H_2 cars in this scenario is even lower than in the CAP85 scenario.

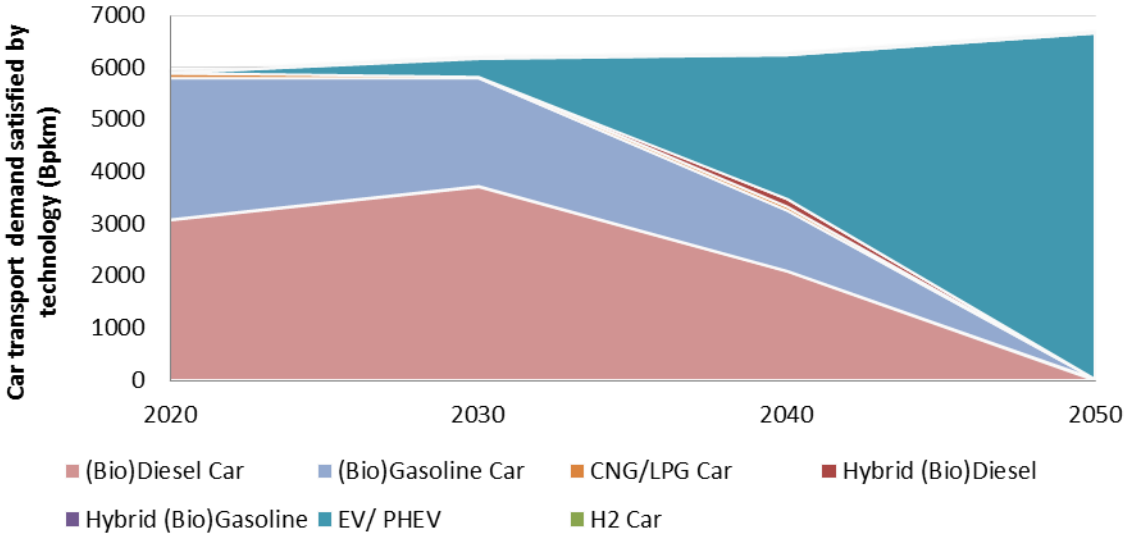


Figure 73 – Evolution of technology shares in passenger cars in HRES scenario

When looking at the technologies that the model selects to satisfy the freight transport demand fulfilled by heavy duty trucks, it can be observed that under the CPI scenario trucks driven by (Bio)-Diesel fuelled ICE remain the dominant technology option throughout the whole modelling horizon. There is also a small deployment of hybridised, CNG, and (Bio)-Gasoline trucks.

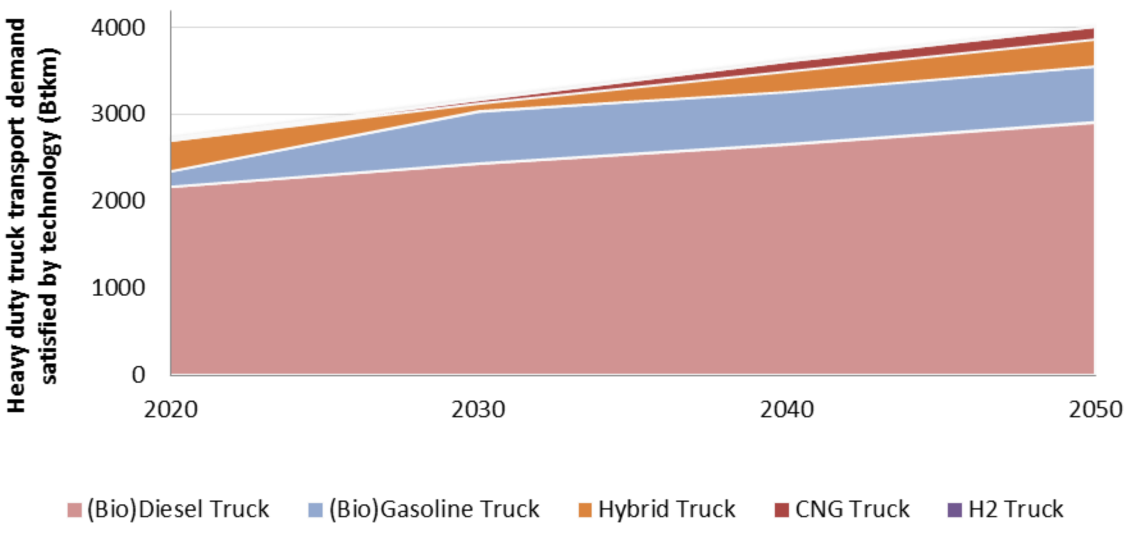


Figure 74 – Evolution of technology shares in freight trucks in CPI scenario

In the CAP85 scenario there is a massive deployment of hybridised heavy duty trucks and from 2030 onwards even hydrogen fuelled trucks.

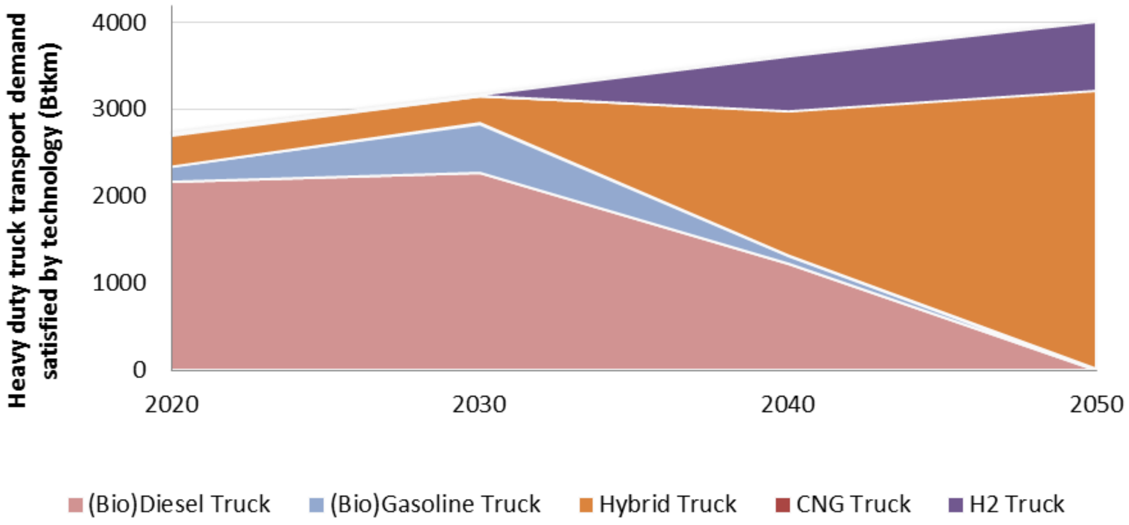


Figure 75 – Evolution of technology shares in freight trucks in CAP85 scenario

The HRES scenario has a similar impact on the technology uptake for freight transport as the CAP85 scenario. Hence, in this scenario the increased availability of biomass is directed towards aviation in the transport sector and other sectors, such as industry.

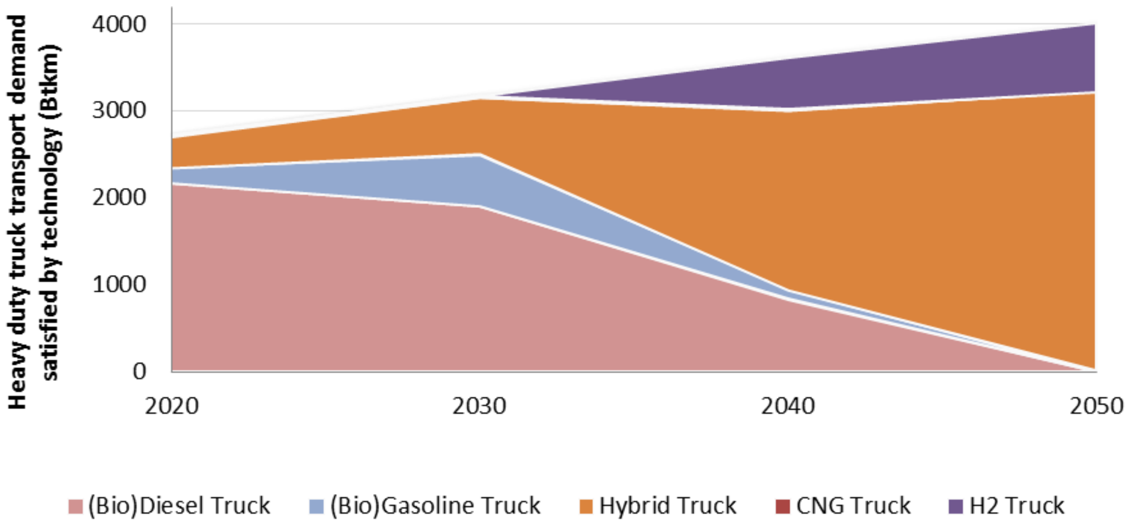


Figure 76 – Evolution of technology shares in freight trucks in HRES scenario

12 Sensitivity analysis

In order to enhance our understanding of the model and confidence in its results, a sensitivity analysis was performed on key input parameters, namely: prices of oil, gas and coal – both imported and domestically produced; technology-specific discount rates; biomass potential; and final energy demand. To enable direct comparison of the results and the assessment of the *relative* importance of individual drivers, we vary each parameter in turn by +/- 20% with respect to its value in the reference scenario (CPI). In order to ensure comparison of the sensitivity runs to the reference scenario, we fix all parameter values to the same as CPI for the first two periods (2005-2010). We allow demand to adjust to the changes in prices in all the sensitivity runs. We then explore the impacts on the model results in terms of final energy demand, final electricity consumption, relative importance of RES in final energy and final electricity, total system costs, and CO_2 emissions. We also discuss the impact of the changes on other elements of the energy system, where relevant.

12.1 Price of oil, gas and coal

In this set of sensitivity runs, the prices of domestic and imported oil, gas and coal is increased/decreased by 20% with respect to the CPI. In general the model's results do not show a high sensitivity to changes in the prices of primary commodities, as shown by the magnitude of the variations. The model is particularly insensitive to changes in coal price in the order of +/-20%, as coal remains a relatively cheap energy carrier even in its higher price range. This is also reflected in the long term own price elasticity of demand: while the response of the quantity consumed to changes in prices is asymmetric for all commodities (i.e. the response to an increase in price is not equivalent to the response to a decrease in price), demand for coal is the least elastic (with a price elasticity of demand ranging between -0.01 and -0.1), while gas demand is the most elastic (-2.8 to -2.2). Price elasticity of demand for oil is somewhere in between (-0.4 to -0.5[24]). It is important to point out that, in our model, the price elasticity of demand crucially depends on substitution possibilities: while coal and oil cannot easily be replaced in some sectors (e.g. transport and industry), gas can more easily be substituted for, in particular because of its more relevant role in electricity production.

[24] Empirical estimates of price elasticity of demand for oil, coal and gas vary considerably, depending on the time period analysed, as well as on the grouping of countries. For oil, for instance, estimates for the EU are around 0.1 (see for instance (Fournier, Koske, Wanner, & Zipperer, 2013), (Haas & Schipper, 1998), (Dées, Karadeloglou, Kaufmann, & Sánchez, 2007) , and (IEA, 2006). For gas, Bilgili (Bilgili, 2014) estimates a price elasticity of natural gas ranging from – 0.345 to -1.292 for OECD countries.

Table 68 – Summary results on sensitivity runs on prices of coal, gas and oil

Parameter	Model Change	Final energy demand	% REN in FEC	Gen. Elec	% REN in gen EL	Total System Cost (disc.)	Annual cost in 2050	CO_2 emissions	CO_2 captured
		(% change wrt CPI)							
Oil price	-20%	0.29	-6.8	-0.3	-2.1	-2.5	-2.1	2.5	-21
	+20%	-0.62	3.2	0.7	0.4	2.1	1.9	-2	1
Gas price	-20%	0.26	-11.1	0.1	-3.4	-1.2	-0.8	2.6	-100
	+20%	-0.39	5.2	-0.1	0.7	0.7	0.2	-1.3	104
Coal price	-20%	0.14	0.1	-0.2	0.7	-0.3	-0.3	-0.1	20
	+20%	0.05	0.7	0	-0.03	0.3	0.1	0.2	-21

The results are, generally, aligned with expectations: lower (higher) prices lead to higher (lower) final energy demand, and to a shift away from (towards) renewable sources of energy. As mentioned, changes in the price of carbon on either ends do not impact significantly the composition of energy carriers – and therefore final energy demand. CO_2 emissions also move in the expected direction, with higher emissions linked to lower prices through the increase in consumption of oil and gas. In the case of coal, however, CO_2 emissions increase with higher coal prices and decrease with lower coal prices– this is linked to a wider deployment of coal with CCS in the case of higher coal prices.

The total discounted system costs are also affected by changes in the price of these primary commodities – with lower costs lowering the total costs to the system. A similar pattern is observed in the difference in annual system cost in 2050, though the effects are somewhat muted.

Lower prices of oil, gas and coal lead to a higher final energy demand, while at the same time to a lower share of renewables in final energy consumption, as the energy generated with oil and gas respectively increases. The reverse is true for higher prices for these commodities, indicating that fossil fuel prices can contribute to enhanced deployment of RES.

Table 69 – Portfolio of energy carriers in final energy consumption in the EU28 in 2050

% FEC in 2050	CPI	Low oil	High oil	Low gas	High gas	Low coal	High coal
Coal	5%	5%	5%	5%	5%	5%	5%
Oil	30%	35%	30%	29%	31%	30%	30%
Gas	25%	22%	25%	28%	22%	25%	25%
Biomass	14%	13%	14%	13%	15%	14%	14%
Heat (Air and ground)	0%	0%	0%	0%	0%	0%	0%
Heat (CHP and DH)	3%	3%	3%	3%	3%	3%	3%
Heat (Solar)	2%	2%	2%	2%	3%	2%	2%
Electricity	21%	21%	21%	21%	21%	21%	21%
Hydrogen	0%	0%	0%	0%	0%	0%	0%

The effect of changes in coal price can be considered negligible: as shown in Table 69, the share of coal in final energy consumption is hardly affected by changes in coal prices, and the portfolio of energy carriers remains substantially unchanged. This is driven by two forces: on the one hand, coal remains a relatively cheap energy carrier even in the high price scenario; on the other hand, the use of coal cannot be expanded much further, as even in the CPI there is an emission limit that affects energy choices in the longer term. In absolute terms, coal use in final energy consumption increases (decreases) with respect to the CPI in the case of lower (higher) prices, by 2% (-4%). This change is much less significant than the equivalent for oil and gas, i.e. +16% (-11%) and +14% (-11%) respectively.

It is interesting to note that the use of gas in energy consumption decreases with low prices of oil– indicating that these commodities can easily substitute for one another.

While the percentage contribution to total electricity production moves in line with expectations (lower prices leading to an increase in the contribution to electricity production), the effect on overall generated electricity is negligible, with the direction of the change depending on the relative importance of the fuel in the production of electricity.

Table 70 – Share of different fuels in generated electricity in EU28 in 2050

% share fuels	CPI	Low oil	High oil	Low gas	High gas	Low coal	High coal
Coal	18%	18%	17%	18%	17%	17%	18%
Gas	6%	6%	6%	7%	5%	5%	6%
Oil	0%	0%	0%	0%	0%	0%	0%
Nuclear	22%	23%	22%	22%	23%	22%	22%
Hydro	12%	12%	12%	12%	12%	12%	12%
Wind	10%	10%	10%	10%	11%	10%	10%
Solar	19%	19%	19%	18%	20%	19%	19%
Other RES	14%	13%	14%	14%	13%	14%	14%

Lower oil prices lead to a lower penetration of electricity and gas in transport (-13% and -46% with respect to the CPI in 2050 respectively). Gas, on the other hand, is deployed more for electricity production when its price is 20% lower – thus significantly displacing the penetration of renewable energy technologies (electricity produced via gas is 22.2% higher than in the CPI in 2050).

The interplay between coal, gas and oil is the main driver behind the results related to CCS – which in turn also affect total emissions of CO_2. In the industrial sector, carbon capture and storage technologies are deployed in the production of cement, where an increase in the prices of oil or a decrease in the prices of coal lead to a higher use of coal in the production process. In the primary energy supply sector, high gas prices and low coal prices lead to an increase in the deployment of IGC with CCS, thus further increasing the quantity of CO_2 captured and stored in the energy system. It is also important to note that the absolute magnitude of the difference in captured CO_2 is relatively small: +/-16Mt of CO_2 in the case of the sharpest percentage change related to the gas prices scenarios.

Gas prices have historically been linked with oil prices through long-term contracts, as both commodities were being produced largely by the same countries and were often used in the same industries. Even though, in the last few years, there has been an increasing disconnect between the two markets, it is interesting to explore the reaction of the model to an increase/decrease in the price of both commodities at the same time. We also run two scenarios in which the prices of oil, coal and gas vary in the same direction – though the prices of coal have historically been lower and more stable. The results are summarised in Table 71.

Table 71 – Summary results on sensitivity runs on joint price changes

Parameter	Model Change	Final energy demand	% REN in FEC	Gen. Elec	% REN in gen EL	Total System Cost (disc.)	Annual cost in 2050	CO_2 emissions	CO_2 captured
		(% change wrt CPI)							
PEC prices	-20%	0.31	-12.3	-0.5	-3.2	-3.2	-2.5	3.2	-100
	+20%	-1.55	8.8	0.2	2	3.1	1.8	-3.8	144
Oil and Gas prices	-20%	0.3	-11.9	-0.3	-3.1	-.3	-2.3	3.3	-100
	+20%	-1.28	8.4	0.3	1.7	2.7	1.8	-3.8	97

While the impacts on the model's results are more pronounced, the direction of change remains the same, and in line with expectations. Higher (lower) prices of oil and gas, as well as oil, gas and coal, lead to lower (higher) final energy demand and higher (lower) electricity generation, confirming that higher primary commodity prices can induce electrification of the energy system. The deployment of renewable energy technologies is also enhanced by higher prices of primary commodities (Table 72).

Table 72 – Portfolio of energy carriers in final energy consumption in the EU28 in 2050

% FEC in 2050	CPI	High PC prices	Low PC Prices	High Oil and Gas prices	Low Oil and Gas prices
Coal	5%	5%	5%	5%	5%
Oil	30%	28%	31%	28%	31%
Gas	25%	24%	26%	25%	26%
Biomass	14%	16%	12%	16%	12%
Heat (Air and ground)	0%	0%	0%	0%	0%
Heat (CHP and DH)	3%	3%	3%	3%	3%
Heat (Solar)	2%	3%	2%	3%	2%
Electricity	21%	21%	21%	21%	21%
Hydrogen	0%	0%	0%	0%	0%

In electricity production, the most evident change is a higher deployment of solar and wind technologies (Table 73). Moreover, an interesting difference needs to be highlighted, notably tidal energy becoming competitive in 2050 in the high oil, coal and gas prices scenario. The total electricity generated from tidal technologies remains however negligible – 0.24TWh, as compared to 370 TWh from wind-based electricity in this sensitivity runs.

Table 73 – Share of different fuels in generated electricity in EU28 in 2050

% fuels	CPI	High PC prices	Low PC Prices	High Oil and Gas prices	Low Oil and Gas prices
Coal	18%	16%	18%	17%	18%
Gas	6%	5%	6%	5%	7%
Oil	0%	0%	0%	0%	0%
Nuclear	22%	22%	22%	22%	23%
Hydro	12%	12%	12%	12%	12%
Wind	10%	11%	10%	11%	10%
Solar	19%	20%	18%	20%	19%
Other RES	14%	14%	14%	14%	13%

Total system costs, as well as annual costs in 2050, move in the expected direction – thus confirming that the price of primary commodities is an important determinant of total system cost.

Captured CO_2 increases with higher prices of primary commodities: while the absolute and percentage consumption of coal, oil and gas decreases in these scenarios, as expected, in particular in the industrial sector biogas substitutes the inputs with higher prices, thus driving the deployment of advanced cement production technologies with CCS using mostly biogas as input. The effect is indeed more pronounced when the price of coal is increased, together with the prices of oil and gas.

Finally, it is also interesting to note that the *additional* impact of changing coal prices along-side oil and gas prices is limited, as shown in Table 71.

12.2 Biomass potential

Biomass, according to our model, plays an important role in the EU energy mix, constituting in 2050 around 14% of final energy consumption in the CPI. Indeed the biomass potential is a factor limiting its deployment, in particular in a decarbonized world (see Section 3.2.2). Varying by ±20% the biomass potential has a discernible impact on the energy technology mix, though the impact on overall energy demand , electricity consumption and total system cost is small.

Table 74 – Summary results on sensitivity runs on biomass potential

Parameter	Change	Final energy demand	% REN in FEC	Gen. Elec	% REN in gen EL	Total System Cost (disc.)	Annual cost in 2050	CO_2 emissions	CO_2 captured
		(% change wrt CPI)							
Biomass pot.	-20%	0.01	-9.3	0.2	-1.7	0.1	0.2	1.4	-6
	+20%	0	7.3	0	1.6	-0.1	-0.2	-1.1	-2

With a lower biomass potential, the share of renewables in final energy consumption and the share of renewable electricity production decline. The share of biomass (excluding biogas) in final energy consumption is 13% lower than in the CPI with a lower biomass potential (11% higher with a higher biomass potential). As expected, the share of biomass in electricity production is also lower in the case of limited biomass potential (-14% with respect to the CPI). At the same time, however, the use of biomass shows an *increase*, albeit small (+0.1%) in the transport sector, in particular due to the higher use of blended fuels.

The portfolio of electricity generating technologies is affected by changes in the biomass potential, in particular other RES are displaced when a higher biomass potential is available: in this scenario, the share of electricity generated by wind and solar in 2050 declines by -1.5% and -1.2% respectively with respect to the CPI, and biomass becomes the dominant form of renewable energy (27% of total RES-based electricity produced in 2050 vs. 25% in the CPI and 22% in the low biomass potential scenario).

Interestingly, the deployment of CCS technologies is lower in both scenarios – though the change is less pronounced in the case of higher biomass potential. The result is driven by the substitution of biomass for coal and gas in the industrial sector and for electricity production: in order to meet the emission reduction targets, additional coal and gas can only be used if coupled with capture technologies.

12.3 Technology specific discount rate

As discussed in Section 3.3, different discount rates are used for different types of technologies, reflecting the variations in the cost of capital of the investment. Variations in technology specific discount rates are expected to lead to changes in the mix of technologies deployed, as the capital intensity of technologies will determine their relative attractiveness.

As in the case for the other parameters, though, aggregated indicators of energy demand are not significantly sensitive to changes in technology specific discount rates. When looking at the direction of the changes, both total energy system costs and annual costs in 2050 increase with higher discount rates, reflecting a higher cost for capital investments. Indeed it is changes in the annual investment component of total system cost in 2050 that drive the observed higher (lower) annual system costs in 2050. Annual investment costs increase by 7.5% with a

20% increase in the technology specific discount rates (the equivalent decrease for 20% lower discount rates is -10.8%). The changes in the other component of total system cost (e.g. operation and maintenance) or of much lower magnitude.

Table 75 – Summary results on technology-specific discount rates

Parameter	Change	Final energy demand	% REN in FEC	Gen. Elec	% REN in gen EL	Total System Cost (disc.)	Annual cost in 2050	CO_2 emissions	CO_2 captured
		(% change wrt CPI)							
Tech specific discount rate	-20%	-0.12	0.6	+0.6	0.4	-6.7	-7.6	-0.7	-1
	+20%	-1.1	-2	-3	0.6	6.8	7.5	0.2	4

In the case of changes in the discount rate of specific technologies, it is of interest to assess the impact on the portfolio of electricity generation. The contribution of different energy carriers to total electricity production in 2050 is summarized in Table 76. There is interplay between gas and coal on the one hand, and renewables, in particular wind and nuclear, on the other. With lower discount rates, wind in particular expands. Moreover, tidal technologies become competitive in 2050 – though their deployment remains low (producing 0.24TWh of electricity in 2050, compared to over 600TWh from solar and almost 380TWh from wind, in these sensitivity runs). This result is driven by the relative costs of these technologies, with wind and ocean in particular having a higher capital cost and fixed operation cost, but lower variable costs. Overall, however, the share of renewable in total electricity produced does not change, as biomass is substituted away. This interplay also drives the results related to CCS deployment.

Table 76 – Share of different fuels in generated electricity in EU28 in 2050 under different discount rates

% fuel	CPI	Low tech discount rate	High tech discount rate
Coal	17.6%	16.9%	18.1%
Gas	5.5%	4.8%	5.7%
Oil	0.0%	0.0%	0.0%
Nuclear	21.9%	23.2%	20.9%
Hydro	11.9%	12.1%	12.0%
Wind	9.9%	10.9%	9.5%
Solar	19.0%	19.1%	18.6%
Biomass	13.6%	12.5%	14.5%
Ocean	0.0%	0.01%	0.0%
Geothermal	0.6%	0.6%	0.6%

12.4 Energy services demand

The demand for energy services is a key determinant of the energy system and its related costs, as well of the level of GHG emissions. The evolution of energy services demand for the industrial, commercial, residential, transport and agricultural sectors in the reference scenario is determined exogenously, based on projected changes in the underlying demand drivers (see Section 4 for the full description). As shown in the summary table, changes in energy services demand have a more significant impact on the overall parameters of the energy system. An increase/decrease in the demand leads to higher energy system costs, as well as to higher emissions of CO_2. These are led by higher energy and electricity demand.

Table 77 – Summary results on sensitivity runs on energy services demand

Parameter	Change	Final energy demand	% REN in FEC	Gen. Elec	% REN in gen EL	Total System Cost (disc.)	Annual cost in 2050	CO_2 emissions	CO_2 captured
		(% change wrt CPI)							
Energy services demand	-20%	-20.3	4.9	-20.2	-7.6	-15.3	-21.4	-15	14
	+20%	18.2	-8.8	18.4	4.8	15	21.9	14.6	28

At the same time, the change in energy service demand leads to a relative change in the importance of renewables in total energy and electricity consumption, leading to relative changes in the technology portfolios.

Table 78 – Portfolio of energy carriers in final energy consumption in the EU28 in 2050

% FEC in 2050	CPI	High Energy Demand	Low Energy Demand
Coal	5.0%	4.7%	5.8%
Oil	29.9%	31.2%	28.7%
Gas	24.7%	25.6%	24.1%
Biomass	14.0%	12.5%	15.2%
Heat (Air and ground)	0.0%	0.0%	0.0%
Heat (CHP and DH)	2.9%	2.7%	2.8%
Heat (Solar)	2.5%	2.5%	2.4%
Electricity	21.0%	20.8%	21.0%

With a higher demand for energy services, the relative importance of oil and gas increases, displacing other renewables. The situation is however different in the electricity sector, where an increasing share of electricity is produced through RES technologies, in particular solar and wind. It is also interesting to note that tidal energy becomes competitive in 2050 in the high energy demand scenario. This pattern is driven by the use of fossil fuels that is more competitive in sectors other than electricity production, when it comes to meeting higher energy demand.

Table 79 – Share of different fuels in generated electricity in EU28 in 2050

	CPI	High Energy Demand	Low Energy Demand
Coal	18.7%	14.11%	23.79%
Gas	5.9%	6.72%	5.24%
Oil	0.0%	0.01%	0.01%
Nuclear	23.1%	24.32%	22.63%
Hydro	12.5%	10.57%	15.44%
Wind	4.7%	6.44%	3.78%
Solar	20.1%	22.73%	15.12%
Biomass	14.4%	14.60%	13.22%
Ocean	0.0%	0.01%	0.00%
Geothermal	0.6%	0.50%	0.75%

The higher consumption of fossil fuels in the industrial sector in particular drives the significantly higher deployment of CCS technologies in the high energy demand scenario. In the low energy demand scenario, on the other hand, it is mostly deployment of CCS technologies in the electricity production sector that account for the higher storage with respect to the CPI, as more coal is used for electricity production as a cheaper alternative "freed" by lower industrial demand.

Total system costs change in the expected direction – with higher demand leading to higher costs, both over the whole time horizon and in 2050 (not discounted). The higher impact observed on undiscounted costs in 2050 is driven by the fact that most of the system cost differences are seen in the longer term as the system adjusts and, therefore, have a lower weight in the discounted total system cost.

Interestingly, increasing or decreasing the energy services demand has very similar impacts on the key system parameters, though in opposing direction.

13 Discussion and further work

The JRC-EU-TIMES model displays the capability to analyse the role of energy technologies and their innovation for meeting Europe's energy and climate change related policy objectives. It can model technologies uptake and deployment and their interaction with the energy infrastructure including storage options in an energy systems perspective. It can be used as a relevant tool to support impact assessment studies in the energy policy field that require quantitative modelling at an energy system level with a high technology detail.

Section 15.1 will briefly discuss some key highlights of the exemplary scenario runs that were performed during the JRC-EU-TIMES model validation.

Any energy system model due to its size and complexity has to be continuously improved, both regarding data inputs and regarding modelling aspects. The current major areas for improvements within JRC-EU-TIMES are detailed in the following sections and are divided in improvements in the model mechanisms (requiring changing the current model structure) and in exogenous data and assumptions

The external experts, together with the JRC-EU-TIMES modelling team, identified possible improvements for the model. These are listed in Sections 13.2 to 13.4. During the model validation workshop the experts replied to a catalogue of questions on the JRC-EU-TIMES model. The agreed answers are documented in Annex 16.13.

13.1 Discussion

The main objective of this report is to provide an overview on the major data inputs and assumptions of the JRC-EU-TIMES model, in order to facilitate future information exchange with other modelling teams and stakeholders. For the same reason the report also describes a number of model outputs from exemplary runs. These results do not represent a quantified view of the European Commission on the future EU energy mix. They are thus not meant to inform policy decisions but simply to test the JRC-EU-TIMES model response.

Having this in mind, the results show that indeed the model responds well to the different decarbonisation pathways defined in the six decarbonised scenarios complementary to the CAP85 scenario: smaller contribution of CCS (DCCS); higher social acceptance and facilitated permitting of RES plants (HRES); higher social acceptance of nuclear plants (HNUC); stricter end-use energy efficiency requirements and more effective enforcement (LEN); lower biomass availability for the energy system for example due to competition between land-use for food production or stricter sustainability criteria for bioenergy production (LBIO); and higher concerns with ensuring the reliability of transmission and distribution, reducing the share of variable solar and wind electricity (LSW).

In all the decarbonised pathways and according to our scenario runs, electricity plays a major role in the EU28 energy system (from 20% of FEC in 2020 to 38-45% in 2050). In 2050, under a 85% CO_2 emission reduction cap from 1990 levels, electricity is essential in buildings and transport for ensuring low carbon passenger mobility and delivering space heating via heat pumps. Biomass is the other energy carrier that plays a major role in a decarbonised EU28 mostly in freight transport and for production of heat in industry. Considering the very important role of biomass under the studied decarbonised scenarios and the variations of the modelled sensitivity analysis we find that biomass technologies are always very cost-effective. Thus, it is important to ensure that the RES potentials for biomass production in EU28 and the import possibilities are reviewed and if necessary updated in the model. With the current results we also believe that there is room for enlarging the variety of technological options other than biomass and electricity based in the end use sectors. Examples are solar heating in industry, waste based district heating in buildings or electric drive light duty vehicles. The further improvement options for the model are discussed in more detail in the next sections.

Regarding the supply side of the energy system, the power sector moves towards renewable electricity (in 2050 36-70% of total generated electricity). This is caused not only by the CO_2 cap, but also by the cost-effectiveness of certain RES electricity technologies in JRC-EU-TIMES (RES electricity is 55% of total electricity in 2050 in the CPI scenario, which has no long-term overall CO_2 cap). The high cost-effectiveness of RES electricity is influenced by the fact that JRC-EU-TIMES, as most energy system models, has limited time resolution and thus, concerns with integration of variable RES are dealt with in a simplified manner. We have found that the portfolio of renewable electricity technologies in JRC-EU-TIMES is very much dependant on the considered RES potentials for EU28, which are somewhat conservative, especially for wind. These will be reviewed during the coming year. In particular, the very high share of solar PV electricity is only possible if cheap and highly flexible small scale storage solutions are available. Modelling variability and flexibility of the power system merits further work, as detailed in the next section.

Another factor that affects RES electricity deployment is the role of nuclear power plants. In these runs optimistic cost assumptions were used for new "unplanned" nuclear power plants which significantly affect the very high cost-effectiveness of these options in JRC-EU-TIMES, especially in the HNUC scenario. The costs and lifetime of nuclear power plants are being reviewed during the coming year.

CCS plants also play an important role in total electricity generation (8-31% of generated electricity in 2050) but this is mostly coal (until 2030) and gas plants (later periods), as biomass is such a limited resource in the model that it is not the most cost-effective carrier for electricity generation. In a decarbonised scenario the factors affecting the deployment of CCS are the deployment of other competing generation technologies and proximity to the CO_2 storage sites. We have analysed the annual deployment rates of the several electricity generation technologies and conclude that for some (notably CCS plants) there is an extremely rapid annual deployment, which will only be feasible in reality if very special policy incentives or conditions are in place, similarly to what has happened in the last decade to solar and wind technologies, natural gas CCGT or nuclear in the seventies.

We have found that in overall terms the most critical key assumptions and data inputs affecting the current JRC-EU-TIMES results are the RES potentials and the costs for solar PV and nuclear power plants. In terms of exogenous model assumptions, clearly the overall CO_2 cap plays a major role, followed by RES potentials and restriction on variable RES electricity produced from solar and wind.

13.2 Further work in model mechanisms

The major improvements on the model mechanisms are grouped in two main areas: (i) penetration of some energy technologies, mainly in the power sector, and (ii) modelling of variable RES and flexibility (including grid).

On the first of these areas it was suggested to introduce bounds[25] in the model to align the pace of deployment considering historical average annual trends. A maximum annual growth in technology capacity of 40% seems reasonable, bearing in mind the deployment rates in the last decade of solar and wind technologies, of natural gas CCGT, or nuclear in the seventies.

Finally, it was suggested to improve the modelling of O&M costs as a function of age of the technology, which currently is implemented for coal and gas plants.

Regarding the modelling of variable RES and flexibility it was suggested to add 30% of the availability of pumped hydro to the peaking equation. Likewise, specific situations as the fact that certain Austrian pumped hydro plants are dispatched from Germany should also be reflected in the peaking equation.

Another major area for further work would be linking the JRC-EU-TIMES model with dispatch models introducing a constraint on the trade-off between storage and interconnectivity (derived from the dispatch model). Another option, which still requires elaboration of the concrete modelling approach, could be to add a flexibility target, similar to the peaking equation. This would establish the right merit order in the technology mix.

Regarding the modelling of storage technologies it was suggested that all three storage technology components (charging, discharging and storage process plus an additional commodity representing the stored commodity) could be modelled explicitly, as this would be closer to the actual storage technology, and in some cases reflect how the storage works, e.g. H_2 storage.

Finally, regarding grids it was suggested to improve synchronization of the peak time-slices across regions and to review the interconnectors data.

13.3 Further work in exogenous data and assumptions

Regarding the improvements in currently used data and assumptions, the most relevant improvements can be grouped as follows: demand for energy services and materials, energy transformation, electricity and heat generation technologies, end-use sectors and policy assumptions.

[25] This type of constraints can also be applied for residential district heating, but for these technologies all assumptions on the minimum heating from different technologies should be in absolute numbers (and not on share). This is because dwellings with district heating are less likely to replace this technology and also less likely to adopt energy efficiency measures compared with dwellings without district heating. When applying such a constraint with a share of total heat delivered via district heating, all dwellings are assumed to undertake energy efficiency measures in the same manner.

13.3.1 Demand for energy services and materials and energy transformation sector

- Ensure that the interrelation of the underlying GDP and population assumptions and the way they are used to generate the exogenous demand for energy services and materials are explained in more detail;
- Review the material demand, in particular the cement demand as the current long-term projections are rather high;
- Review the assumptions on share of long and short distance travelled km per country regarding passenger cars when more data is available;
- Review exogenous data assumptions on buildings stock and types, as well as heat requirements for new dwellings when compared to old;
- Refine the energy services demand projections for cooling in buildings considering that GDP may be a driver to include GDP per capita differences across of Europe (cooling is considered to follow a S-curve function of household incomes), and improving the maximum saturation years assumption considering Cooling Degree Days;

13.3.2 Energy transformation sector

- Review costs for additional pipeline capacity and LNG import capacity;
- Review delivery costs for all energy commodities and consider including energy taxes;
- Review assumptions on AC vs. DC interconnection, as there is no choice for some connections;
- Include CCS options upstream (gas sweetening – cfr Sleipner);
- Include CCS options for refineries;
- Include "centralized" natural gas CHP fuel cells, which could be relevant for future subsidized gas prices;
- Consider differentiated import prices per time-slice for oil and gas trade outside EU;
- Review H_2 production possibilities from fossil fuels including more CCS possibilities;
- Current lignite in Scandinavia is in fact peat. The difference is due to an aggregation done in EUROSTAT data, thus consider separating these;

13.3.3 Electricity and heat generation

- Update RES potential and RES techno-economic values, especially for biomass;
- Review assumptions on biomass imports into EU28+;
- Make the availability (or capacity) factor for RES technologies time dependent;
- Review assumptions for CCS technologies, including: delay/start date from current 2020 to 2030 at least, capture rate for oxyfuel plants that should be higher than 90%, CO_2 storage potential data especially for Ireland that seems overestimated;
- Include possibility to model explicitly retrofit of fossil fuel plants for CCS and/or its lifetime extension;
- Include biomass input in coal power plants;
- Review assumptions on cost of "unplanned" nuclear power plants as they seem too cheap when compared to "planned" plants;
- Consider making the availability (or capacity) factor of nuclear power plants seasonal accounting for maintenance in summer, which is especially relevant for France;

- Review investment costs for large-scale storage technologies, in particular pumped hydro *versus* CAES. Consider disaggregating pumped hydro technologies in three ranges of prices;
- Review seasonal variations of district heating plants and verify that all capacity is being used comparing with Eurostat;
- Review the availability (or capacity factors) for CHP plants;
- Include district heating options from sewage via heat pumps;
- Include blending of biogas and other gases besides H_2 in natural gas pipelines;
- Include the following technologies: biogas CHP, geothermal CHP, district heat pump based on sewage, solar district heating, oil gas turbine (CC) for delivering electricity for refineries;

13.3.4 End-use sectors

- Review and refine technologies for light duty trucks;
- Review costs for electric vehicles with more recent studies as the current data seems too high;
- Include derived gases based CHP plants in industry;
- Review the commercial buildings assumptions and include more detailed bottom-up data in the energy services demand projections, e.g. taking into account floor area, number of employees;
- Review assumptions on district and solar heating deployment for buildings and include hot water as an output of heat pumps;
- Include assumptions for non-electricity potentials as for solar thermal;
- Include heat pumps and solar heaters for other industry;
- Add hot water sanitary storage technologies in the residential sector;
- Model buildings insulation explicitly;
- Introduce a maximum boundary on gas for cooking in countries with no or with limited gas for heating (e.g. Scandinavia);

13.3.5 Policy assumptions

The JRC-EU-TIMES model as it stands allows studying a very broad range of policy assumptions, objectives and instruments. Therefore, the validators only mentioned the following improvements:

- Review the industry CHP assumptions considered for the RES 2020 targets to use specific sub sector values instead of one average value for the whole of the industry sector;
- Consider excluding international aviation and navigation from the cap target.

13.4 Possible areas for model expansion and possible future model applications

- Perform a systematic identification of the relevance of the modelled sectors currently without specific abatement options and focus on these for improvement. A possible starting point would be aviation and navigation, and followed by assessing the need to expand the technology detail for refineries, agriculture and/or more industry sub-sectors;

- Include endogenous modelling of land competition between sectors (e.g. agriculture and energy) and among energy technologies (biomass, wind,…);
- Include modelling of water uses for energy technologies;
- Assess the added value of changing the base-year to 2010 and/or to perform a detailed validation for the period 2005-2015 for all the end-use sectors;
- Include non-CO_2 emissions (also process related), both for other GHG and for air pollutants;
- Endogenously model substitution among energy service and materials demands (e.g. higher aluminium use due to weight advantage) and other demand related mechanisms such as: consumer effects due to monetary savings from less demand, price effects, consideration of cross price elasticities, and modal shifts;
- Endogenously model the use of materials (including critical materials) for energy technologies, including the linkages to the whole production chain (e.g. use of steel for wind turbines);
- Assess the trade-off associated to expanding the number of time-slices, i.e. data availability limitations and increased running time *versus* improved representation of demand and flexibility of the power sector;
- Run without activated elastic demand for energy services and materials in order to assess the impact of elasticities;
- Perform exploratory analysis on the impact of exogenous assumptions regarding the lifetime of existing nuclear power plants (especially for France) testing effects of expanding the life time to both 2040 and 2060;
- Expand the sensitivity analysis running with wider variations than the 20% range and assessing also the effect of varying technology costs. Expand the approaches to deal with uncertainty.

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16 Annexes

16.1 Annex I – Exogenous energy services demands

Table 80 - Energy services demand in the residential sector in the EU28– Heating and cooling (PJ)

	Space heating (rural)	Space heating (existing urban)	Space heating (multi)	Water heating (rural)	Water heating (urban)	Water heating (multi)	Cooling (rural)	Cooling (urban)	Cooling (multi)
2005	1684.8	2623.8	2837.8	262.2	501.7	523.0	16.01	27.22	32.31
2010	1643.4	2595.8	2754.1	271.7	526.2	545.0	21.61	34.95	41.20
2015	1580.5	2498.7	2676.4	281.3	552.0	579.0	25.41	40.74	48.27
2020	1497.0	2379.2	2560.2	281.7	562.2	592.2	27.94	44.65	52.93
2025	1407.3	2243.6	2425.5	280.7	567.1	600.0	30.26	48.19	57.19
2030	1326.7	2126.9	2310.9	278.8	571.6	607.0	32.56	51.88	61.69
2035	1245.0	2016.0	2197.5	275.1	573.9	612.4	34.25	55.08	65.80
2040	1172.2	1908.9	2086.3	271.2	572.6	614.4	36.06	58.23	69.70
2045	1102.9	1796.7	1969.9	265.7	564.1	610.8	37.62	60.83	73.09
2050	1051.6	1717.6	1883.9	262.9	563.1	612.4	39.63	64.25	77.25

Table 81 - Energy services demand in the residential sector in the EU28– Other uses (PJ)

	Lighting	Cooking	Refrigeration	Cloth washing	Cloth drying	Dish washing	Other electric	Other energy
2005	618.4	597.7	178.9	165.1	72.8	64.2	951.8	0.7
2010	687.7	606.5	178.6	165.6	74.1	65.3	1108.6	0.7
2015	718.4	618.1	180.7	167.2	74.7	66.1	1403.9	0.7
2020	724.3	623.6	181.2	167.6	75.6	66.8	1526.4	0.7
2025	726.5	628.2	180.4	167.0	76.0	67.0	1651.5	0.7
2030	730.5	632.6	180.1	166.7	76.7	67.5	1746.7	0.7
2035	730.4	633.2	178.9	165.4	76.7	67.1	1765.4	0.7
2040	728.3	633.6	177.0	163.6	76.1	66.5	1802.7	0.7
2045	720.7	632.4	173.7	160.7	74.8	65.4	1813.1	0.7
2050	721.8	633.2	172.3	159.7	74.4	65.0	1838.9	0.7

Table 82 - Energy services demand in the commercial sector in the EU28 – PJ

	Space heating	Water heating	Cooling	Lighting	Cooking	Refrigeration	Public lighting	Other electricity	Other energy
2005	2359.7	533.5	673.9	2070.9	323.7	240.0	220.1	531.0	110.1
2010	2511.4	552.4	719.7	2234.6	338.3	252.3	230.7	607.4	113.2
2015	2630.6	583.0	759.6	2346.6	351.7	265.0	236.9	706.1	120.4
2020	2739.6	612.1	803.5	2467.5	366.9	279.5	244.0	798.9	127.5
2025	2818.6	633.8	839.7	2566.4	379.2	291.3	248.3	893.3	132.4
2030	2927.8	659.3	889.1	2688.3	393.0	307.8	255.4	1008.5	137.4
2035	3042.7	687.9	938.1	2819.9	407.4	324.0	262.6	1091.0	142.7
2040	3160.5	717.7	983.1	2951.3	421.6	339.2	269.7	1172.0	150.6
2045	3248.1	739.6	1018.9	3058.0	432.2	351.3	275.2	1245.7	155.9
2050	3387.3	775.1	1067.7	3215.8	447.7	368.7	282.6	1323.2	165.3

Table 83 - Demand for transport services in the EU28 – passenger transport (Billion pkm)

	Road car - Short	Road car - Long	Road - Moto	Bus - Urban	Bus - Intercity	Rail - Heavy	Rail - Light
2005	2268.4	2891.4	133.4	580.2	276.5	363.5	63.9
2010	2328.3	3040.3	136.3	592.3	281.5	370.6	65.4
2015	2369.4	3291.8	142.3	599.1	284.1	375.0	66.3
2020	2403.8	3475.0	146.2	604.1	285.9	378.7	67.1
2025	2432.1	3633.1	150.0	607.4	286.9	381.3	67.7
2030	2454.3	3792.3	153.9	609.0	287.1	383.0	68.0
2035	2469.9	3924.5	156.5	609.0	286.6	383.6	68.2
2040	2480.3	4027.8	158.5	607.9	285.7	383.6	68.2
2045	2486.2	4091.6	159.0	605.9	284.4	382.9	68.2
2050	2487.6	4192.0	161.2	603.0	282.6	381.7	68.1

Table 84 - Demand for transport services in the EU28 – freight transport, aviation and navigation

	Road freight – Light (Billion tkm)	Road freight – Heavy (Billion tkm)	Rail freight (Billion tkm)	Aviation – Generic (PJ)	Aviation – International (PJ)	Navigation – Generic (PJ)	Navigation – International (PJ)
2005	88.3	2043.7	398.7	396.8	1547.0	234.9	1883.2
2010	92.8	2171.2	424.0	417.7	1607.9	244.8	1966.7
2015	104.3	2443.1	480.2	472.4	1799.4	265.4	2129.3
2020	116.5	2727.4	539.1	534.7	2042.5	296.9	2390.7
2025	125.9	2935.9	582.9	581.9	2252.7	320.9	2568.8
2030	137.5	3178.1	629.7	644.7	2498.0	355.4	2842.5
2035	149.4	3420.1	679.5	707.6	2732.0	385.9	3118.4
2040	158.5	3621.4	720.6	765.6	2935.0	415.5	3390.4
2045	167.5	3796.8	760.8	815.3	3124.2	437.9	3624.0
2050	178.3	4012.3	807.9	875.6	3364.5	465.2	3917.5

Table 85 - Industrial demand in the EU28

	Cement (Mt)	Iron and Steel (Mt)	Aluminium and copper (Mt)	Paper (High and low quality) (Mt)	Ammonia (Mt)	Chlorine (Mt)	Lime (Mt)	Glass (Hallow and Flat) (Mt)	Chemicals – Other (PJ)	Other - Non ferrous (PJ)	Other non-metallic (PJ)	Other industries (PJ)
2005	236	196	8.8	100	12	11	32	31	2006	190	495	4268
2010	251	185	8.3	101	12	12	34	33	2091	186	502	4106
2015	269	195	9.1	104	13	14	37	36	2215	194	518	4447
2020	298	197	9.4	111	14	16	41	41	2483	201	554	4744
2025	340	194	9.4	125	15	16	46	47	2613	196	612	4765
2030	363	186	9.0	134	16	16	50	52	2683	195	624	4836
2035	389	186	9.2	142	16	16	55	57	2670	187	637	4826
2040	417	187	9.1	153	17	17	60	62	2820	201	663	4818
2045	437	183	8.8	160	18	18	64	68	2912	203	671	4718
2050	475	173	8.2	170	20	20	70	75	3117	215	716	4875

16.2 Annex II – Additional information for considering price elasticities

This section follows closely the approach described by (Kanudia & Regemorter, 2006) .At an aggregate level, energy demand is equal to the energy service demand times the energy efficiency of the process used to satisfy the demand. Depending on the substitution possibilities between inputs and processes, the relation between the two price elasticities will be different.

Energy demand

$$ED = ES * UE$$

where:

ED: energy demand

ES: energy service demand

UE: energy demand per unit of energy service demand, function of capital and energy

Assuming a fixed relation between capital and energy in the production function of energy services (Leontief structure), then the price elasticity of energy demand is a function of the price elasticity of energy demand and the share of energy in the total cost:

$$pelas_{ED} = pelas_{ES} * share\,of\ E\,in\,PES$$

where PES: cost of the energy service

pelasED: price elasticity of energy demand

pelasES: price elasticity of energy service demand

Assuming substitution possibilities between capital and energy in the production function (e.g. a CES production function, then the price elasticity of energy demand will also depend on the substitution elasticity:

$$pelas_{ED} = pelas_{ES} * share\,of\ E\,in\,PES - \sigma(1 - share\,of\ E\,in\,PES)$$

where σ: elasticity of substitution in the CES function.

The greater the shares of energy in the total cost, the closer are the two elasticities while the greater the substitution possibilities the greater the distance between the two elasticities.

16.3 Annex III – Modelling details for storage processes considered in JRC-EU-TIMES

In order to fully represent the dual character of electricity storage technologies regarding both: 1) “storage” (or “energy”), representing the amount of energy that can be stored, and 2) “power" representing the speed with which energy can be delivered we have implemented modelling of storage as follows. Because the current TIMES code cannot model both approaches in parallel in the same technology, a new modelling approach has been used introducing a dummy technology associated to the storage process. Storage processes were setup to represent the “energy” character, while a dummy input process (standard process) was designed to represent separately the “power” character, namely the discharging power (e.g. the turbine power for PHS). This is represented in the following figures where the red boxes represent the storage processes in JRC-EU-TIMES and the blue boxes represent the mentioned "dummy" technologies.

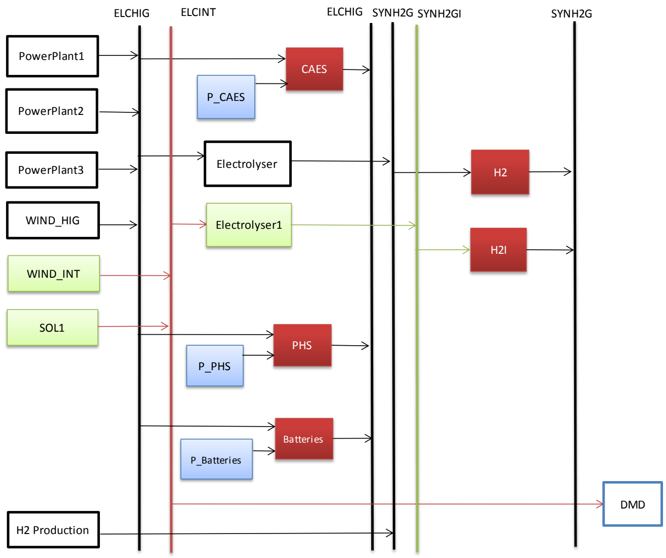


Figure 77 – Reference energy system for large scale electricity storage in JRC-EU-TIMES

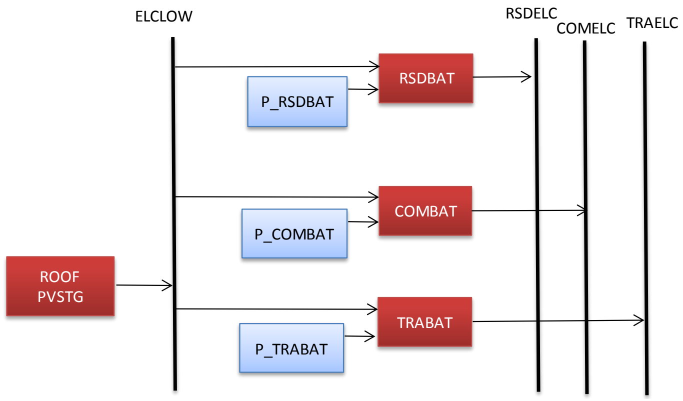


Figure 78 – Reference energy system for small scale electricity storage (Residential, Commercial and transport batteries) in JRC-EU-TIMES

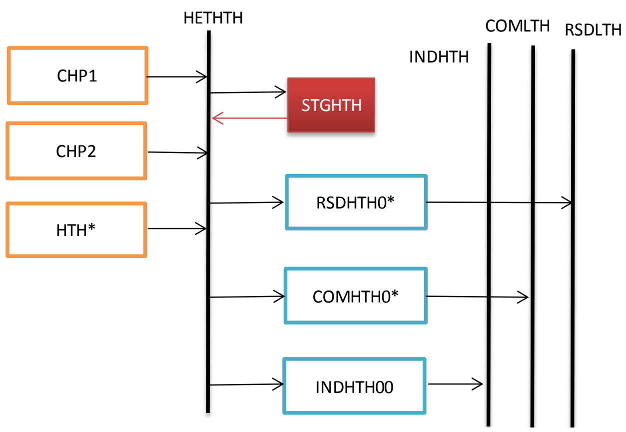


Figure 79 – Reference energy system for heat storage in JRC-EU-TIMES

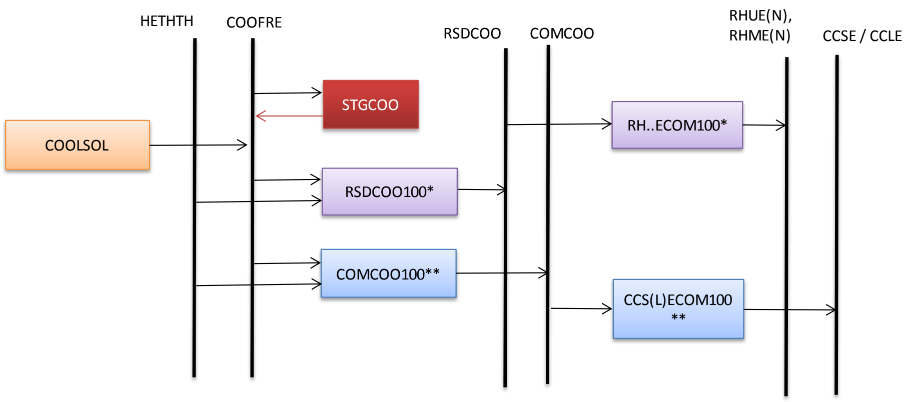


Figure 80 – reference energy system for cooling energy storage in JRC-EU-TIMES

16.4 Annex IV - Policy measures mentioned in the EU Energy Roadmap 2050 and consideration in JRC-EU-TIMES

16.4.1 Policy measures as in the *reference* scenario *of the EU Energy Roadmap 2050*

Table 86 - Policy measures included in the EU-TIMES CPI scenario (together with Table 87)

<table>
<tr><th colspan="3">Measure</th><th>How the measure is reflected in JRC-EU-TIMES</th></tr>
<tr><td colspan="4">Regulatory measures</td></tr>
<tr><td colspan="4">Energy Efficiency</td></tr>
<tr><td>1</td><td>Ecodesign Framework Directive</td><td>Directive 2005/32/EC</td><td rowspan="10">Currently not reflected but it can be by adapting the modelling parameters for different products for Ecodesign and decrease of costs and increase of efficiency.</td></tr>
<tr><td>2</td><td>Stand-by regulation</td><td>Regulation No 1275/2008</td></tr>
<tr><td>3</td><td>Simple Set-to boxes regulation</td><td>Regulation No 107/2009</td></tr>
<tr><td>4</td><td>Office/street lighting regulation</td><td>Regulation No 245/2009</td></tr>
<tr><td>5</td><td>Household lighting regulation</td><td>Regulation No 244/2009</td></tr>
<tr><td>6</td><td>External power supplies regulation</td><td>Regulation No 278/2009</td></tr>
<tr><td>7</td><td>TVs regulation (+labelling)</td><td>Regulation No 642/2009</td></tr>
<tr><td>8</td><td>Electric motors regulation</td><td>Regulation No 640/2009</td></tr>
<tr><td>9</td><td>Circulators regulation</td><td>Regulation No 641/2009</td></tr>
<tr><td>10</td><td>Freezers/refrigerators regulation (+labelling)</td><td>Regulation No 643/2009</td></tr>
<tr><td>11</td><td>Labelling Directive</td><td>Directive 2003/66/EC</td><td>The model considers different types of appliances with different energy efficiency performance and costs reflecting the different labels and energy performance levels. These are deployed or not based on its cost-effectiveness. In this sense the spirit of this Directive is considered in the model but not its specificities.</td></tr>
</table>

Measure			How the measure is reflected in JRC-EU-TIMES
12	Labelling for tyres	Regulation No 1222/2009	The modelling parameters have been adapted by decreasing technology costs and increasing efficiency. As generic TIMES modelling approach the car technologies have an exogenous autonomous evolution performance regarding energy consumption, which implicitly considers technology learning and technology improvements not directly motivated by energy efficiency concerns. In that sense, the spirit of this directive is considered but not in a quantitative manner, as the specific improvements in energy consumption solely due to tyre improvement are not quantified.
13	Energy Star Program (voluntary labelling program)		The model considers different types of appliances with different energy efficiency performance and costs reflecting the different labels and energy performance levels. These are deployed or not based on their cost-effectiveness. In this sense the spirit of this Program is considered in the model but not its specificities.
14	Directive on end-use energy efficiency and energy services	Directive 2006/32/EC	National implementation measures are reflected (NEEAP targets).
15-16	Buildings Directive and Recast of the EPBD	Directive 2010/31/EU (recasts Directive 2002/91/EC)	National measures e.g. on strengthening of building codes and integration of RES are reflected in an exogenous assumption on increased existing and new building efficiency by period. This is modelled by assuming an exogenous improvement in buildings varying between 0.5% to 2% per year depending on the country. No explicit assumptions are made for new buildings.
17	Cogeneration Directive	Directive 2004/8/EC	Repealed by Directive 2012/27/EU.
Energy markets			
18	Completion of the internal energy market (including provisions of the 3rd package)	http://ec.europa.eu/energy/gas_electricity/third_legislative_package_en.htm	The model reflects the electricity and gas trade between Member States. It simulates the electricity and gas market with optimal use of interconnectors. In this sense the spirit of this Directive is considered in the model but not its specificities.
19	EU ETS directive	Directive 2003/87/EC as amended by Directive 2008/101/EC and Directive 2009/29/EC	The ETS cap is modelled and the CO_2 price is endogenously generated by the model. The ETS cap is assumed to continue declining beyond 2020 as stipulated in legislation. At this moment the model does not include specific sector targets but this can be included.

Measure			How the measure is reflected in JRC-EU-TIMES
20	RES directive	Directive 2009/28/EC	Legally binding national targets for RES share in gross final energy consumption are achieved in 2020; 10% target for RES in transport is achieved for EU27 as biofuels can be traded among Member States; sustainability criteria for biomass and biofuels can be respected by ensuring that only compliant amounts and energy carriers are available. RES subsidies decline after 2020 starting with the phasing out of operational aid to new onshore wind by 2025; other RES aids decline to zero by 2050 at different rates according to technology.
21	GHG Effort Sharing Decision	Decision 406/2009/EC	A global target for EU27 for all sectors is achieved in 2020, taking full account of the flexibility provisions such as transfers between Member States. The all sectors cap is assumed to continue declining beyond 2020 based on the 1990 emissions with the following road map: 2035 (50%) and 2050 (60%). The improvement possibilities are the following: The National targets for non-ETS sectors could be implemented and achieved in 2020, taking full account of the flexibility provisions such as transfers between Member States. After 2020, stability of the provided policy impulse but no strengthening of targets could be assumed.
22	Energy Taxation Directive	Directive 2003/96/EC	The Directive is not implemented. Tax rates (EU minimal rates or higher national ones) could be implemented and kept constant in real term
23	Large Combustion Plant directive	Directive 2001/80/EC	Requirements of this Directive are currently not implemented in the model but this can be done with the current level of technological detail by including the emission factors for acidifying gases and corresponding emission reduction technologies, complemented with emission caps as in the Directive.
24	IPPC Directive	Directive 2008/1/EC	The costs of filters and other devices necessary for compliance with non GHG emissions are for the moment not reflected in the parameters of the model but can be included.
25	Directive on the geological storage of CO_2	Directive 2009/31/EC	The Directive is not explicitly implemented in the model. The CCS potential and penetration is implemented in the model.
26	Directive on national emissions' ceilings for certain pollutants	Directive 2001/81/EC	The requirements of this Directive are currently not implemented in the model but this can be done with the current level of technological detail by including the emission factors for acidifying gases and corresponding emission reduction technologies, complemented with emission caps as in the Directive.

Measure			How the measure is reflected in JRC-EU-TIMES
27	Water Framework Directive	Directive 2000/60/EC	Hydro power plants in JRC-EU-TIMES respect the European framework for the protection of all water bodies as defined by the Directive, which limits the potential deployment of hydropower and might impact generation costs.
28	Landfill Directive	Directive 99/31/EC	The possibility to perform energy recovery from waste is included in the model but no other specific Directive requirements
		Transport	
29	Regulation on CO_2 from cars	Regulation No 443/2009	Limits on emissions from new cars are implemented, adapting cars efficiencies and costs.
30	Regulation EURO 5 and 6	Regulation No 715/2007	Emissions limits introduced for new cars and light commercial vehicles
31	Fuel Quality Directive	Directive 2009/30/EC	Not implemented in the model. This directive could be implemented in the model changing some model parameters and taking into account the uncertainty related to the scope of the Directive addressing also parts of the energy chain outside the area of the JRC-EU-TIMES model (e.g. oil production outside EU).
32	Biofuels directive	Directive 2003/30/EC	Support to biofuels such as tax exemptions and obligation to blend fuels is reflected in the model. The requirement of 5.75% of all transportation fuels to be replaced with biofuels by 2010 has been imposed as target. After 2010 the target increases to 10% in 2020 and then is assumed constant until 2050. The biofuel blend is generated on the supply side using bio-refineries.
33	Implementation of MARPOL Convention ANNEX VI	2008 amendments - revised Annex VI	Not implemented but can be done by changing the refineries output to reflect the modified sulphur content
34	Regulation Euro VI for heavy duty vehicles	Regulation (EC) No 595/2009	Emissions limits are introduced for new heavy duty vehicles.
35	Regulation on emission performance standards for new light commercial vehicles to reduce CO 2 emissions from light-duty vehicles	Regulation EU 510/2011	Limits on emissions from new light duty vehicles are implemented, adapting vehicles efficiencies and costs.
36	TEN-E guidelines	Decision No 1364/2006/EC	The model takes into account all TEN-E realised infrastructure projects

Measure			How the measure is reflected in JRC-EU-TIMES
37	EEPR (European Energy Programme for Recovery) and NER 300 (New entrance reserve) funding programme	For EEPR: Regulation No 663/2009; For NER300: EU Emissions Trading Directive 2009/29/EC Article 10a(8), further developed through Commission Decision 2010/670/EU	Not implemented in the model. In the model the demonstrations plants for CCS for commissioning in 2020 could be added: Germany 950 MW (450MW coal post-combustion, 200MW lignite post-combustion and 300MW lignite oxy-fuel), Italy 660 MW (coal post-combustion), Netherlands 1460 MW (800MW coal post-combustion, 660MW coal integrated gasification pre-combustion), Spain 500 MW (coal oxy-fuel), UK 3400 MW (1600MW coal post-combustion, 1800MW coal integrated gasification pre-combustion), Poland 896 MW (306MW coal post-combustion, 590MW lignite post-combustion).
38	RTD support (7th framework programme- theme 6) + SET-Plan	Energy research under FP7, IEE	The R,D &D support for innovative technologies such as CCS, RES, nuclear and energy efficiency is currently simulated in the model by exogenous technology learning and economies of scale assumptions leading to cost reductions of these technologies
39	State aid Guidelines for Environmental Protection and 2008 Block Exemption Regulation	Community guidelines on state aid for environmental protection	Financial support to R&D for innovative technologies such as CCS, RES, nuclear and energy efficiency is reflected implicitly by the exogenous assumptions on technology learning and economies of scale leading to cost reductions of these technologies as exogenous model inputs
40	Cohesion Policy – ERDF, ESF and Cohesion Fund		This is not explicitly included in the model
41	Rural development policy – EAFRD	Council Regulation (EC) No. 1698/2005	Not implemented. The structure of the model does not include farmers and other actors in the rural areas.
42	Strong national RES policies		National policies on e.g. feed-in tariffs, quota systems, green certificates, subsidies and other cost incentives are explicitly included as an option in the model and were updated in 2011.
43	Nuclear		The TIMES-EU model describes each individual existing nuclear power plants and all the plants under constructions or planned in all the Member States. On the supply side the nuclear chain to provide the availability of the nuclear fuel is implemented. Nuclear, including the replacement of plants due for retirement, is modelled on its economic merit and in competition with other energy sources for power generation except for MS with legislative provisions on nuclear phase out. Several constraints are put on the model such as decisions of MS not to use nuclear at all (Austria, Cyprus, Denmark, Estonia, Greece, Ireland, Latvia, Luxembourg, Malta and Portugal) and closure of

Measure			How the measure is reflected in JRC-EU-TIMES
			existing plants in some MS according to agreed schedules (e.g. Germany). Nuclear investments are possible in all the other countries.

16.4.2 *Policy measures as in the Current Policy Initiatives scenario of the EU Energy Roadmap 2050*

In addition to previous measures, the Current Policy Initiatives Scenario includes the following policies and measures:

Table 88 - Policy measures included in the EU-TIMES Current Policy Initiatives scenario

Area	Measure	How the measure is reflected in JRC-EU-TIMES
Internal market		
1	Effective transposition and implementation of third package, including the development of pan-European rules for the operation of systems and management of networks in the long run	The model reflects the electricity and gas trade between Member States. It simulates the electricity and gas market with optimal use of interconnectors.
2	Regulation on security of gas supply (N-1 rule, necessity for diversification)	This is implemented in a simplified format.
3	Regulation on Energy market integrity and transparency (REMIT)	The model considers a perfect market by default.
Infrastructure		
4	Facilitation policies (faster permitting; one stop shop)	Not implemented but can be done adapting model parameters and reducing infrastructure construction time.
5	Infrastructure instrument	Not implemented but can be done adding constraints on the maximum amount that can be spent for infrastructure in the model.
6	Updated investments plans based on ENTSO-e Ten Year Network Development Plan	Interconnection capacity reflects projects in the TYNDP by 2020.
7	Smartening of grids and metering	Not implemented explicitly but can be done updating the demand commodity fraction allocation. A new commodity fraction allocation will give flexibility to locate grids in the model.
Energy	Directive 2012/27/EU	

Area	Measure	How the measure is reflected in JRC-EU-TIMES
efficiency		
8	Obligation for public authorities to procure energy efficient goods and services	Not implemented explicitly.
9	Planned Ecodesign measures (boilers, water heaters, air-conditioning, etc.)	Not implemented but can be done by adapting the modelling parameters for different product goods.
10	High renovation rates for existing buildings due to better/more financing and planned obligations for public buildings	The exogenous assumption on rate of energy efficiency improvement of the building stock can be adapted to consider higher renovation rates than in the Reference scenario.
11	Passive houses standards after 2020	The exogenous assumption on rate of energy efficiency improvement of the building stock can be adapted to consider the penetration of passive houses.
12	Greater role of Energy Service Companies	Not implemented as ESCOs are not explicitly modelled in the JRC-EU-TIMES model.
13	Obligation of utilities to achieve energy savings in their customers' energy use of 1.5% per year (until 2020)	Not implemented in the model. This could be implemented reducing exogenously the energy service demand in residential and tertiary.
14	Mandatory energy audits for companies	Not implemented in the model but can be done exogenously adapting efficiency parameter in the model based on the mandatory audits.
15	Obligation that, where there is a sufficient demand authorisation for new thermal power generation is granted on condition that the new capacity is provided with CHP; Obligation for electricity DSOs to provide priority access for electricity from CHP; Reinforcing obligations on TSOs concerning access and dispatching of electricity from CHP	Model does not consider dispatch but CHP are already penetrating in the solution.
16	Obligation that all new energy generation capacity reflects the efficiency ratio of the best available technology (BAT), as defined in the Industrial Emissions Directive	High energy efficiency to a large extent already reflected in the Reference scenario 2050 as a response to the carbon prices; energy efficiency improves furthermore in power generation along with new investment from more efficient vintages.
17	Other measures (better information for consumers, public awareness, training, SMEs targeted actions)	Not implemented but can be done exogenously adapting model parameters based on the other measures leading to faster energy efficiency improvements.

Area	Measure	How the measure is reflected in JRC-EU-TIMES
Nuclear		
19	Nuclear Safety Directive	Not implemented because the safety dimension is not considered in the model. A possibility for its integration would be increases investment and operation costs for these plants.
20	Waste Management Directive	This cost is included in the generation cost of the nuclear power plant.
21	Consequences of Japan nuclear accident	Stress tests and other safety measures reflected through higher costs for retrofitting (up to 20% higher generation costs after lifetime extension compared with Reference scenario) and introduction of risk premium for new nuclear power plants. Nuclear determined on economic grounds, subject to non-nuclear countries (except for Poland) remaining non-nuclear.
CCS		
22	Slower progress on demonstration plants	Downward revision of planning for some CCS demonstration plants compared to the Reference case; some plants might be commissioned later depending on carbon prices. Change regarding potential storage sites in BE and NL.
Oil and gas		
23	Offshore oil and gas platform safety standards	Not implemented but can be done slightly increasing production costs for oil and gas in the EU due to the standards.
Taxation		
24	Energy taxation Directive (revision 2011)	Not implemented in the model but could be included. If included changes to minimum tax rates for heating and transport sectors will reflect the switch from volume-based to energy content-based taxation and the inclusion of a CO_2 tax component. Where Member States tax above the minimum level, the current rates are assumed to be kept unchanged. For motor fuels, the relationships between minimum rates could be assumed to be mirrored at national level even if the existing rates are higher than the minimum rates.
Transport		
25	A revised test cycle to measure CO_2 emission under real-world driving conditions (to be proposed at the latest by 2013)	Not implemented but can be done updating model parameters and implementing CO_2 standards for passenger cars by 2020. Starting with 2020 - assuming autonomous efficiency improvements.
Energy import prices	This parameter is up to date and can be always updated.	
Technology	Higher penetration of EVs	Not implemented but can be done assuming specific

Area	Measure	How the measure is reflected in JRC-EU-TIMES
assumptions	reflecting developments in 2009-2010 national support measures and the intensification of previous action programmes and incentives, such as funding research and technology demonstration (RTD) projects to promote alternative fuels.	battery costs per unit kWh in the long run: 390-420 €/kWh for plug-in hybrids and 315-370 €/kWh for electric vehicles, depending on range and size, and other assumptions on critical technological components.

16.5 Annex V – Details on model approach to include financial incentives to RES in JRC-EU-TIMES

The JRC-EU-TIMES model can integrate the following possibilities of finantial incentives to RES: Feed-in-Tariffs (FiT) and green certificates from renewable electricity generation (also including CHP) and from consumption of renewables in final energy (including biofuels in transport). For the latter, each GJ of RES commodity consumed in the model generates a corresponding green certificate, also modelled as energy. The certificates have a price and can be traded across regions in EU28.

For FiT, Table 89 summarizes the current level (2012) of feed-in tariffs in the different member states. Though these are currently not considered in any of the scenarios presented in this report (see Section 11.1), the FiT mechanisms can easily be included in the JRC-EU-TIMES. The model includes a scenario file which has the FiT summarised as in Table 89 up to 2020 and extented to 2030. For periods beyond 2030 a gradual phase out of the present FiT support schemes is assumed, given the economic situation of several EU-Countries and the increasing concerns about extending FiT mechanisms.

Table 89 – Feed-in tariffs for EU MS (€2000/kWh)

Country	Wind On-shore	Wind Off-shore	Solar PV	Biomass	Hydro
Austria	0.073	0.073	0.29 - 0.46	0.06 -0.16	n/a
Belgium	n/a	n/a	n/a	n/a	n/a
Bulgaria	0.07 - 0.09	0.07 - 0.09	0.34 - 0.38	0.08 - 0.10	0.045
Cyprus	0.166	0.166	0.34	0.135	n/a
Czech Republic	0.108	0.108	0.455	0.077 - 0.103	0.081
Denmark	0.035	n/a	n/a	0.039	n/a
Estonia	0.051	0.051	0.051	0.051	0.051
Finland[26]	n/a	n/a	n/a	n/a	n/a
France	0.082	0.31 - 0.58	n/a	0.125	0.06
Germany	0.05 - 0.09	0.13 - 0.15	0.29 - 0.55	0.08 - 0.12	0.04 - 0.13
Greece	0.07 - 0.09	0.07 - 0.09	0.55	0.07 - 0.08	0.07 - 0.08
Hungary	n/a	n/a	0.097	n/a	0.029 - 0.052
Ireland	0.059	0.059	n/a	0.072	0.072
Italy	0.3	0.3	0.36 - 0.44	0.2 - 0.3	0.22

[26] National market intervention based on Taxation policies

Country	Wind On-shore	Wind Off-shore	Solar PV	Biomass	Hydro
Latvia	0.11	0.11	n/a	n/a	n/a
Lithuania	0.1	0.1	n/a	0.08	0.07
Luxembourg	0.08 - 0.10	0.08 - 0.10	0.28 - 0.56	0.103 - 0.128	0.079 - 0.103
Malta	n/a	n/a	n/a	n/a	n/a
Netherlands	0.118	0.186	0.459 - 0.583	0.115 - 0.177	0.073 - 0.125
Poland[27]	n/a	n/a	n/a	0.038	n/a
Portugal	0.074	0.074	0.31 - 0.45	0.1 - 0.11	0.075
Romania[28]	n/a	n/a	n/a	n/a	n/a
Slovakia	0.05- 0.09	0.05- 0.09	0.27	0.072 - 0.10	0.066 - 0.10
Slovenia	0.087 - 0.094	0.087 - 0.095	0.267 - 0.414	0.074 - 0.224	0.077 - 0.105
Spain	0.073	0.073	0.32 - 0.34	0.107 - 0.158	0.077
Sweden[29]	n/a	n/a	n/a	n/a	n/a
United Kingdom	0.31	n/a	0.42	0.12	0.23

The amount of money spent by a country on promoting renewable energy sources has to be capped in JRC-EU-TIMES model basically because of its optimising nature. If the total support budget for renewable energy technologies is not capped then the model tends to overinvest in these technologies since their long run marginal costs are being reduced by the support policy. Moreover, a maximum total support budget should be introduced for each renewable technology or by category of renewable technologies in order to avoid an overinvestment in one technology having a larger potential (*e.g.* photovoltaic systems).

In order to establish a maximum total support budget by renewable technology or by category of renewable technologies, the following hypothesis was made. In their National Renewable Energy Action Plans (NREAPs), submitted in 2009, member states identified 2020 targets for renewable energy production by technology or category of technologies. These targets were multiplied by the current support level in order to obtain the support budget in 2020 per country and per technology or category of technologies. Furthermore, actual support budgets are linearly extrapolated to reach the estimated 2020 levels. Finally, 2030 budget levels are set to be equal to 2020 budget levels since support levels are generally decreasing over time because of the improved cost-competitiveness of the supported versus other technologies.

[27] National market intervention based on Quota obligation
[28] National market intervention based on Quota obligation
[29] National market intervention based on Taxation policies and Quota obligation

16.6 Annex VI – Fossil Fuel Reserves

The following Fossil Fuel Reserves have been considered in JRC-EU-TIMES. The main data sources are national expert modellers within the NEEDS and RES2020 EU projects, updated within the REACCESS research project.

Table 90 – Fossil Fuel Reserves implemented in the JRC-EU-TIMES

COUNTRY	TECHNOLOGY DESCRIPTION	TOTAL ESTIMATED RESERVES	EXTRACTION COST 2005	EXTRACTION COST 2050	MAXIMUN EXTRACTION 2005	MAXIMUM EXTRACTION 2050
		PJ	Euro/GJ	Euro/GJ	PJ	PJ
AT						
	Crude Oil - Located reserves - Step 1	379.4	3.00	3.00	52.1	52.1
	Natural gas - Located reserves - Step 1	562.0	1.80	1.85	61.0	61.0
	Lignite - Located reserves - Step 1	300.0	0.99	1.20		
	Crude Oil - Reserves growth - Step 1	333.7	3.00	3.00		
	Natural gas - Reserves growth - Step 1	67.2	2.60	2.60		
	Natural gas - New discovery - Step 1	865.0	2.60	2.60		
BG						
	Crude Oil - Located reserves - Step 1	91.8	1.67	1.94	7.5	7.5
	Natural gas - Located reserves - Step 1	222.6	1.80	1.85		
	Hard Coal - Located reserves - Step 1	3000.0	1.40	2.30	2.5	10.0
	Lignite - Located reserves - Step 1	12917.6	1.10	1.50	178.0	178.0
	Crude Oil - Reserves growth - Step 1	80.9	3.00	3.00		
	Natural gas - Reserves growth - Step 1	27.1	2.60	2.60		
	Lignite - Reserves growth - Step 1	24857.0				
	Crude Oil - New discovery - Step 1	65.8	3.30	3.30		
CZ						
	Crude Oil - Located reserves - Step 1	91.8	3.00	3.00	40.3	40.3
	Natural gas - Located reserves - Step 1	148.4	1.80	1.85	7.5	7.5
	Hard Coal - Located reserves - Step 1	2677.5	1.20	1.60	450.0	400.0
	Lignite - Located reserves - Step 1	5060.3	0.99	1.20	480.7	550.0
	Crude Oil - Reserves growth - Step 1	80.9	3.00	3.00		
	Natural gas - Reserves growth - Step 1	18.0	2.60	2.60		
	Hard Coal - Reserves growth - Step 1	319792.5	1.40	2.30	50.0	50.0
	Lignite - Reserves growth - Step 1	47970.0	1.10	1.34	100.0	100.0
	Crude Oil - New discovery - Step 1	105.3	3.30	3.30		
	Natural gas - New discovery - Step 1	653.6	2.60	2.60		
DE						

COUNTRY	TECHNOLOGY DESCRIPTION	TOTAL ESTIMATED RESERVES	EXTRACTION COST 2005	EXTRACTION COST 2050	MAXIMUN EXTRACTION 2005	MAXIMUM EXTRACTION 2050
		PJ	Euro/GJ	Euro/GJ	PJ	PJ
	Crude Oil - Located reserves - Step 1	2410.9	3.00	3.00	316.5	316.5
	Natural gas - Located reserves - Step 1	7151.0	1.80	1.85	595.5	595.5
	Hard Coal - Located reserves - Step 1	630200.0	1.40	2.30	1500.0	
	Lignite - Located reserves - Step 1	318240.0	1.10	1.34	1609.9	1565.0
	Crude Oil - Reserves growth - Step 1	2126.0	3.00	3.00		
	Natural gas - Reserves growth - Step 1	869.3	2.60	2.60		
	Hard Coal - Reserves growth - Step 1	6302000.0	2.65	2.65		
	Lignite - Reserves growth - Step 1	606840.0	1.50	1.50		
	Crude Oil - New discovery - Step 1	1494.1	3.30	3.30		
	Natural gas - New discovery - Step 1	15903.3	2.60	2.60		
DK						
	Crude Oil - Located reserves - Step 1	8120.8	1.67	1.94	842.0	842.0
	Natural gas - Located reserves - Step 1	4942.1	0.91	1.19	392.8	392.8
	Crude Oil - Reserves growth - Step 1	7161.3	3.00	3.00		
	Natural gas - Reserves growth - Step 1	600.8	1.80	1.85		
	Crude Oil - New discovery - Step 1	888.6	3.00	3.00		
	Natural gas - New discovery - Step 1	951.0	1.80	1.85		
EE						
	Lignite - Located reserves - Step 1	5500.0	0.99	1.20	500.0	500.0
	Lignite - Reserves growth - Step 1	500.0	1.10	1.34	0.0	
	Lignite - New discovery - Step 1	1000.0	1.10	1.34	0.0	75.0
ES						
	Crude Oil - Located reserves - Step 1	966.8	3.00	3.00	65.6	65.6
	Natural gas - Located reserves - Step 1	95.4	1.80	1.85	13.0	13.0
	Hard Coal - Located reserves - Step 1	21035.7	1.40	2.30	274.0	274.0
	Lignite - Located reserves - Step 1	4157.0	1.50	1.50	96.3	96.3
	Crude Oil - Reserves growth - Step 1	852.6	4.50	4.50	57.8	57.8
	Natural gas - Reserves growth - Step 1	11.4	2.60	2.60		
	Hard Coal - Reserves growth - Step 1	82232.2	2.10	3.45		
	Lignite - Reserves growth - Step 1	4157.0	2.25	2.25		
	Crude Oil - New discovery - Step 1	5680.4	5.25	5.25	385.1	385.1
	Natural gas - New discovery - Step 1	21780.8	2.60	2.60		
	Hard Coal - New discovery - Step 1	0.0	2.65	2.65	274.0	
	Lignite - New discovery - Step 1	0.0	1.50	1.50	50.0	
FI						

COUNTRY	TECHNOLOGY DESCRIPTION	TOTAL ESTIMATED RESERVES	EXTRACTION COST 2005	EXTRACTION COST 2050	MAXIMUN EXTRACTION 2005	MAXIMUM EXTRACTION 2050
		PJ	Euro/GJ	Euro/GJ	PJ	PJ
	Lignite - Located reserves - Step 1		0.99	0.99	89.1	89.1
	Lignite - Reserves growth - Step 1		0.99	0.99	25.0	25.0
	Lignite - New discovery - Step 1		1.10	1.34	25.0	25.0
FR						
	Crude Oil - Located reserves - Step 1	893.4	3.00	3.00	163.4	163.4
	Natural gas - Located reserves - Step 1	478.1	1.80	1.85	43.0	
	Hard Coal - Located reserves - Step 1	598.0	2.65	2.65		
	Crude Oil - Reserves growth - Step 1	785.9	3.30	3.30		
	Natural gas - Reserves growth - Step 1	57.2	2.60	2.60		
	Crude Oil - New discovery - Step 1	8148.7	3.30	3.30		
	Natural gas - New discovery - Step 1	25492.0	2.60	2.60		
GR						
	Crude Oil - Located reserves - Step 1	42.8	3.00	3.00	12.7	12.7
	Natural gas - Located reserves - Step 1	37.1	2.60	2.60	0.8	0.8
	Lignite - Located reserves - Step 1	12441.0	1.50	1.50	357.5	
	Crude Oil - Reserves growth - Step 1	37.7	3.30	3.30		
	Natural gas - Reserves growth - Step 1	4.4	2.60	2.60		
	Lignite - Reserves growth - Step 1	25636.0	1.50	1.50	30.0	200.0
	Crude Oil - New discovery - Step 1	0.0				
	Natural gas - New discovery - Step 1	0.0				
	Lignite - New discovery - Step 1	0.0				
HR						
	Crude Oil - Located reserves - Step 1	376.8	3.00	3.00	43.4	65.1
	Natural gas - Located reserves - Step 1	1050.0	1.80	1.85	78.1	117.1
HU						
	Crude Oil - Located reserves - Step 1	624.1	3.00	3.00	94.2	94.2
	Natural gas - Located reserves - Step 1	1282.8	1.80	1.85	97.6	97.6
	Hard Coal - Located reserves - Step 1	5968.3	2.65			
	Lignite - Located reserves - Step 1	20982.0	1.20		73.2	219.6
	Crude Oil - Reserves growth - Step 1	549.1	3.30	3.30		
	Natural gas - Reserves growth - Step 1	153.4	2.60	2.60		
	Lignite - Reserves growth - Step 1	58363.5				
	Crude Oil - New discovery - Step 1	1474.4	3.30	3.30		
	Natural gas - New discovery - Step 1	3069.8	2.60	2.60		
IE						

COUNTRY	TECHNOLOGY DESCRIPTION	TOTAL ESTIMATED RESERVES	EXTRACTION COST 2005	EXTRACTION COST 2050	MAXIMUN EXTRACTION 2005	MAXIMUM EXTRACTION 2050
		PJ	Euro/GJ	Euro/GJ	PJ	PJ
	Natural gas - Located reserves - Step 1	742.1	0.91	1.19	21.3	21.3
	Peat - Located reserves - Step 1	1960.0	0.99	1.20	39.0	39.0
	Natural gas - Reserves growth - Step 1	88.7	1.80	1.94		
	Peat - Reserves growth - Step 1	2400.0	0.99	1.20	0.0	0.0
IS						
	Hard Coal - Located reserves - Step 1		1.20	1.20	5.0	5.0
IT						
	Crude Oil - Located reserves - Step 1	4901.2			283.5	283.5
	Natural gas - Located reserves - Step 1	4680.0			414.3	414.3
	Hard Coal - Located reserves - Step 1	1686.0	1.40	2.30	2.5	2.5
	Lignite - Located reserves - Step 1	140.7	1.10	1.34	0.0	0.0
	Crude Oil - Reserves growth - Step 1	4311.6			255.1	113.5
	Natural gas - Reserves growth - Step 1	559.6			372.9	93.1
	Hard Coal - Reserves growth - Step 1	7868.0	2.65	2.65	0.0	0.0
	Lignite - Reserves growth - Step 1	442.2	1.50	1.50	0.0	0.0
	Crude Oil - New discovery - Step 1	6154.3			229.6	102.1
	Natural gas - New discovery - Step 1	33380.6			335.6	83.8
	Hard Coal - New discovery - Step 1	0.0	2.65	2.65	0.0	0.0
	Lignite - New discovery - Step 1	402.0	1.50	1.50	0.0	0.0
LT						
	Crude Oil - Located reserves - Step 1	73.0	3.00	3.00	18.0	
	Crude Oil - Located reserves - Step 2	65.0	3.00	3.00	18.0	
	Crude Oil - Located reserves - Step 3	0.0			0.0	
	Natural gas - Located reserves - Step 1	0.0			0.0	
	Natural gas - Located reserves - Step 2	0.0			0.0	
	Natural gas - Located reserves - Step 3	0.0			0.0	
	Hard Coal - Located reserves - Step 1	0.0			0.0	
	Lignite - Located reserves - Step 1	49.0	0.99	1.20	5.0	
	Crude Oil - Reserves growth - Step 1	0.0			0.0	
	Crude Oil - Reserves growth - Step 2	0.0			0.0	
	Crude Oil - Reserves growth - Step 3	0.0			0.0	
	Natural gas - Reserves growth - Step 1	0.0			0.0	
	Natural gas - Reserves growth - Step 2	0.0			0.0	
	Natural gas - Reserves growth - Step 3	0.0			0.0	
	Hard Coal - Reserves growth - Step 1	0.0			0.0	

COUNTRY	TECHNOLOGY DESCRIPTION	TOTAL ESTIMATED RESERVES	EXTRACTION COST 2005	EXTRACTION COST 2050	MAXIMUN EXTRACTION 2005	MAXIMUM EXTRACTION 2050
		PJ	Euro/GJ	Euro/GJ	PJ	PJ
	Lignite - Reserves growth - Step 1	0.0			0.0	
	Crude Oil - New discovery - Step 1	0.0			0.0	
	Crude Oil - New discovery - Step 2	0.0			0.0	
	Crude Oil - New discovery - Step 3	0.0			0.0	
	Natural gas - New discovery - Step 1	0.0			0.0	
	Natural gas - New discovery - Step 2	0.0			0.0	
	Natural gas - New discovery - Step 3	0.0			0.0	
	Hard Coal - New discovery - Step 1	0.0			0.0	
	Lignite - New discovery - Step 1	0.0			0.0	
LV						
	Lignite - Located reserves - Step 1	100.0	0.99	1.20		
	Lignite - Reserves growth - Step 1	0.0	0.00			
	Lignite - New discovery - Step 1	0.0	0.00			
NL						
	Crude Oil - Located reserves - Step 1	1525.0	1.67	1.94	105.3	105.3
	Natural gas - Located reserves - Step 1	58855.7	0.91	1.19	2355.7	2355.7
	Crude Oil - Reserves growth - Step 1	1341.5	2.50	2.92	92.6	92.6
	Natural gas - Reserves growth - Step 1	7038.0	0.91	1.19		
	Crude Oil - New discovery - Step 1	58337.5	2.92	3.40	4028.4	4028.4
	Natural gas - New discovery - Step 1	189.7	1.80	1.85		
NO						
	Crude Oil - Located reserves - Step 1	59488.6	1.67	1.94	6631.1	6631.1
	Natural gas - Located reserves - Step 1	118273.0	0.91	1.19	3193.7	3193.7
	Crude Oil - Reserves growth - Step 1	52332.4	2.50	2.92	6631.1	6631.1
	Natural gas - Reserves growth - Step 1	14143.2	0.91	1.19	3193.7	3193.7
	Hard Coal - Reserves growth - Step 1	99999.0	1.20	1.60	25.0	25.0
	Crude Oil - New discovery - Step 1	149638.5	2.92	3.40	6631.1	6631.1
	Natural gas - New discovery - Step 1	224033.7	0.91	1.19	3193.7	3193.7
PL						
	Crude Oil - Located reserves - Step 1	587.4	3.00	3.00	73.3	73.3
	Natural gas - Located reserves - Step 1	4081.0	1.80	1.85	162.6	162.6
	Hard Coal - Located reserves - Step 1	261168.4	1.20	1.60	2478.0	2500.0
	Lignite - Located reserves - Step 1	16598.2	0.99	1.20	533.2	450.0
	Crude Oil - Reserves growth - Step 1	516.8	3.00	3.00		

COUNTRY	TECHNOLOGY DESCRIPTION	TOTAL ESTIMATED RESERVES	EXTRACTION COST 2005	EXTRACTION COST 2050	MAXIMUN EXTRACTION 2005	MAXIMUM EXTRACTION 2050
		PJ	Euro/GJ	Euro/GJ	PJ	PJ
	Natural gas - Reserves growth - Step 1	488.0	2.60	2.60		
	Hard Coal - Reserves growth - Step 1	2436393.0	1.40	2.30		
	Lignite - Reserves growth - Step 1	229400.0	1.10	1.34	100.0	100.0
	Crude Oil - New discovery - Step 1	1757.4	3.00	3.00		
	Natural gas - New discovery - Step 1	3454.1	2.60	2.60		
	Hard Coal - New discovery - Step 1	0.0				
PT						
	Natural gas - Located reserves - Step 1	9.0	1.80	1.85		
	Natural gas - Reserves growth - Step 1	0.9	1.80	1.85		
RO						
	Crude Oil - Located reserves - Step 1	2864.9	3.00	3.00	253.8	253.8
	Natural gas - Located reserves - Step 1	11044.8	1.80	1.85	464.3	464.3
	Hard Coal - Located reserves - Step 1	11383.8	1.20	1.60	100.0	100.0
	Lignite - Located reserves - Step 1	9548.0	0.99	1.20	300.0	
	Crude Oil - Reserves growth - Step 1	2520.3	4.50	4.50	223.2	223.2
	Natural gas - Reserves growth - Step 1	1320.8	2.60	2.60		
	Hard Coal - Reserves growth - Step 1	13316.6	1.20	1.60	50.0	50.0
	Lignite - Reserves growth - Step 1	24766.0	1.10	1.34	100.0	100.0
	Crude Oil - New discovery - Step 1	7905.2	5.25	5.25	700.2	700.2
	Natural gas - New discovery - Step 1	6629.1	2.60	2.60		
	Hard Coal - New discovery - Step 1	0.0	1.40	2.30	50.0	50.0
	Lignite - New discovery - Step 1	0.0	1.10	1.34	100.0	100.0
SE						
	Natural gas - Located reserves - Step 1	5.2	1.80	1.85		
	Lignite - Located reserves - Step 1	14400.0	1.10	1.34	43.0	65.0
	Natural gas - Reserves growth - Step 1	0.5	1.80	1.85		
SI						
	Hard Coal - Located reserves - Step 1	1124.0	1.40	2.30	33.7	0.0
	Lignite - Located reserves - Step 1	1243.0	1.10	1.34	53.1	
	Hard Coal - Reserves growth - Step 1	1601.7	2.65	2.65	48.1	50.5
	Lignite - Reserves growth - Step 1	6960.8	1.50	1.50	53.1	55.8
	Natural gas - New discovery - Step 1	12.2	1.80	1.85		
SK						
	Crude Oil - Located reserves - Step 1	55.1	3.00	3.00	28.7	28.7
	Natural gas - Located reserves - Step 1	28.7	1.80	1.85	5.5	5.5

COUNTRY	TECHNOLOGY DESCRIPTION	TOTAL ESTIMATED RESERVES	EXTRACTION COST 2005	EXTRACTION COST 2050	MAXIMUN EXTRACTION 2005	MAXIMUM EXTRACTION 2050
		PJ	Euro/GJ	Euro/GJ	PJ	PJ
	Lignite - Located reserves - Step 1	1243.0	1.10	1.34	26.7	26.7
	Crude Oil - Reserves growth - Step 1	48.4	3.00	3.00		
	Natural gas - Reserves growth - Step 1	12.4	2.60	2.60		
	Lignite - Reserves growth - Step 1	6960.8				
	Crude Oil - New discovery - Step 1	105.3	3.30	3.30		
	Natural gas - New discovery - Step 1	0.0				
	Hard Coal - New discovery - Step 1	0.0				
UK						
	Crude Oil - Located reserves - Step 1	24460.7	1.67	1.94	4040.7	4040.7
	Natural gas - Located reserves - Step 1	30925.4	0.91	1.19	3324.2	6648.4
	Hard Coal - Located reserves - Step 1	4950.0	1.30	1.43	800.0	1600.0
	Crude Oil - Reserves growth - Step 1	21518.2	2.50	2.92		
	Natural gas - Reserves growth - Step 1	3698.1	1.80	1.85		
	Hard Coal - Reserves growth - Step 1	45000.0	1.20	1.60	387.9	775.8
	Crude Oil - New discovery - Step 1	46917.5	2.92	3.40		
	Natural gas - New discovery - Step 1	28.6	1.80	1.85		

16.7 Annex VII – CO_2 emissions Factors

The following tables outline the emission factors for CO_2 considered for each sector and region in the model

Table 91 – Electricity generation. Static emission factors (ktCO2/PJ)

Region	Hard Coal	Coke	Lignite	Brown Coal	Crude Oil	Refinery Gas	[Liquefied Petroleum Gas	Naphtha	Diesel	Residual Fuel Oil	Other Petroleum Products	Natural Gas	Coke-Oven Gas	Coke-Oven Gas	Gasworks Gas	Wood Products	Biogas	Municipal Waste	Industrial Waste-Sludge	Biofuels
AT	95	105	110.6	110.6	80	60	65	73.3	74	78	80	56	108.2	108.2	46.5	0	0	45	45	0
BE	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
BG	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
CH	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
CY	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
CZ	95	105	110.6	110.6	80	60	65	73.3	74	78	80	56	108.2	108.2	46.5	0	0	45	45	0
DE	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
DK	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
EE	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
ES	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
FI	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0

Region	Hard Coal	Coke	Lignite	Brown Coal	Crude Oil	Refinery Gas	[Liquefied Petroleum Gas	Naphtha	Diesel	Residual Fuel Oil	Other Petroleum Products	Natural Gas	Coke-Oven Gas	Coke-Oven Gas	Gasworks Gas	Wood Products	Biogas	Municipal Waste	Industrial Waste-Sludge	Biofuels
FR	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
GR	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
HR	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
HU	95	105	110.6	110.6	80	60	65	73.3	74	78	80	56	108.2	108.2	46.5	0	0	45	45	0
IE	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
IS	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
IT	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
LT	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
LU	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
LV	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
MT	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
NL	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
NO	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
PL	95	105	110.6	110.6	80	60	65	73.3	74	78	80	56	108.2	108.2	46.5	0	0	45	45	0
PT	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
RO	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0

Region	Hard Coal	Coke	Lignite	Brown Coal	Crude Oil	Refinery Gas	[Liquefied Petroleum Gas	Naphtha	Diesel	Residual Fuel Oil	Other Petroleum Products	Natural Gas	Coke-Oven Gas	Coke-Oven Gas	Gasworks Gas	Wood Products	Biogas	Municipal Waste	Industrial Waste-Sludge	Biofuels
SE	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
SI	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0
SK	95	105	110.6	110.6	80	60	65	73.3	74	78	80	56	108.2	108.2	46.5	0	0	45	45	0
UK	98.3	94.6	101.2	101.2	73.3	56.1	63.1	73.3	74.1	77.4	73.3	56.1	108.2	108.2	56.1	0	0	85.85	85.85	0

Table 92 – Electricity generation. Dynamic emission factors (ktCO2/PJ)

Region	Hard Coal	Lignite	Oil	Refinery Gas	Diesel	Heavy Fuel Oil	Natural Gas	Derived Gas	Wood Products	Biogas	Municipal Waste	Industrial Waste
AT	95.0	110.6	77.9	60.0	74.0	78.0	56.0	108.2	0.0	0.0	45.0	45.0
BE	98.3	101.2	77.1	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
BG	98.3	101.2	77.4	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
CH	98.3	101.2	74.1	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
CY	98.3	101.2	77.4	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
CZ	95.0	110.6	77.4	60.0	79.7	78.0	56.0	108.2	0.0	0.0	45.0	45.0
DE	98.3	101.2	75.7	56.1	73.7	77.4	56.1	108.2	0.0	0.0	85.9	85.9
DK	98.3	101.2	77.1	56.1	73.9	77.4	56.1	108.2	0.0	0.0	85.9	85.9
EE	98.3	101.2	77.4	56.1	73.3	77.4	56.1	108.2	0.0	0.0	85.9	85.9
ES	98.3	101.2	77.4	56.1	73.3	77.4	56.1	108.2	0.0	0.0	85.9	85.9
FI	98.3	101.2	77.1	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
FR	98.3	101.2	77.2	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
GR	98.3	101.2	76.7	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
HR	98.3	101.2	77.3	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
HU	95.0	110.6	77.7	60.0	74.0	78.0	56.0	108.2	0.0	0.0	45.0	45.0
IE	98.3	101.2	77.1	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
IS	98.3	101.2	74.1	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
IT	98.3	101.2	77.1	56.1	73.7	77.4	56.1	108.2	0.0	0.0	85.9	85.9

Region	Hard Coal	Lignite	Oil	Refinery Gas	Diesel	Heavy Fuel Oil	Natural Gas	Derived Gas	Wood Products	Biogas	Municipal Waste	Industrial Waste
LT	98.3	101.2	77.2	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
LU	98.3	101.2	77.4	56.1	73.3	77.4	56.1	108.2	0.0	0.0	85.9	85.9
LV	98.3	101.2	77.3	56.1	73.7	77.4	56.1	108.2	0.0	0.0	85.9	85.9
MT	98.3	101.2	77.0	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
NL	98.3	101.2	58.8	56.1	73.8	77.4	56.1	108.2	0.0	0.0	85.9	85.9
NO	98.3	101.2	73.3	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
PL	95.0	110.6	77.4	60.0	74.0	78.0	56.0	108.2	0.0	0.0	45.0	45.0
PT	98.3	101.2	89.0	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
RO	98.3	101.2	77.0	56.1	74.0	77.4	56.1	108.2	0.0	0.0	85.9	85.9
SE	98.3	101.2	76.0	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
SI	98.3	101.2	75.4	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9
SK	95.0	110.6	78.0	60.0	2.4	78.0	56.0	108.2	0.0	0.0	45.0	45.0
UK	98.3	101.2	77.2	56.1	74.1	77.4	56.1	108.2	0.0	0.0	85.9	85.9

Table 93 – Industry. Static Emission Factors (ktCO2/PJ)

Region	Hard Coal	Lignite	Brown Coal	Coke	Refinery Gas	Liquefied Petroleum Gas	Light Fuel Oil	Light Fuel Oil	Heavy Fuel Oil	Non Energy	Natural Gas	Coke Oven Gas	Blast Furnace Gas	Biomass Wood	Municipal Waste	Industrial Waste-Sludge
AT	95.0	105.0	110.6	110.6	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2
BE	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
BG	95.0	105.0	110.6	110.6	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2
CH	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
CY	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
CZ	95.0	105.0	110.6	110.6	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2
DE	95.0	105.0	110.6	110.6	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2
DK	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
EE	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
ES	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
FI	92.7	105.8	104.5	99.2	55.5	62.5	68.6	71.2	72.6	73.4	76.6	0.0	72.6	55.8	107.7	107.7
FR	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
GR	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
HR	95.0	105.0	110.6	110.6	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2
HU	95.0	105.0	110.6	110.6	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2

Region	Hard Coal	Lignite	Brown Coal	Coke	Refinery Gas	Liquefied Petroleum Gas	Light Fuel Oil	Light Fuel Oil	Heavy Fuel Oil	Non Energy	Natural Gas	Coke Oven Gas	Blast Furnace Gas	Biomass Wood	Municipal Waste	Industrial Waste-Sludge
IE	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
IS	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
IT	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
LT	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
LU	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
LV	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
MT	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
NL	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2
NO	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0	56.1	108.2	108.2	0	85.85	85.85
PL	95	105	110.6	110.6	60	65	73.9	73.3	78	0	64.35	108.2	108.2	0	45	45
PT	98.3	94.6	101.2	101.2	56.1	63.1	74.0	73.3	77.4	0	67.6	108.2	108.2	0	85.85	85.85
RO	98.3	94.6	101.2	101.2	56.1	63.1	73.4	73.3	77.4	0	56.3	108.2	108.2	0	85.85	85.85
SE	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0	57.6	108.2	108.2	0	85.85	85.85
SI	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0	66.6	108.2	108.2	0	85.85	85.85
SK	95.0	105	110.6	110.6	60	65	74	73.3	78	0	60.1	108.2	108.2	0	45	45
UK	98.3	94.6	101.2	101.2	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2

Table 94 – Industry. Dynamic emission factors (ktCO2/PJ)

Region	Hard Coal	Lignite	Brown Coal	Coke	Refinery Gas	Liquefied Petroleum Gas	Light Fuel Oil	Naphtha	Heavy Fuel Oil	Non Energy	Natural Gas	Coke Oven Gas	Blast Furnace Gas	Biomass Wood	Municipal Waste	Industrial Waste-Sludge
AT	95.0	105.0	110.6	110.6	60.0	65.0	74.0	73.3	78.0	0.0	73.5	108.2	108.2	0.0	45.0	45.0
BE	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	57.3	108.2	108.2	0.0	85.9	85.9
BG	95.0	105.0	110.6	110.6	60.0	65.0	74.0	73.3	78.0	0.0	63.9	108.2	108.2	0.0	45.0	45.0
CH	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	133.1	108.2	108.2	0.0	85.9	85.9
CY	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	56.1	108.2	108.2	0.0	85.9	85.9
CZ	95.0	105.0	110.6	110.6	60.0	65.0	74.0	73.3	78.0	0.0	55.2	108.2	108.2	0.0	45.0	45.0
DE	95.0	105.0	110.6	110.6	60.0	65.0	74.0	73.3	78.0	0.0	63.3	108.2	108.2	0.0	45.0	45.0
DK	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	68.3	108.2	108.2	0.0	85.9	85.9
EE	98.3	94.6	101.2	101.2	56.1	63.1	74.0	73.3	77.4	0.0	68.4	108.2	108.2	0.0	85.9	85.9
ES	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	75.8	108.2	108.2	0.0	85.9	85.9
FI	92.7	105.8	104.5	99.2	55.5	62.5	73.4	72.6	76.6	0.0	131.6	107.7	107.7	0.0	31.5	74.3
FR	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	66.9	108.2	108.2	0.0	85.9	85.9
GR	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	100.0	108.2	108.2	0.0	85.9	85.9
HR	95.0	105.0	110.6	110.6	60.0	65.0	73.9	73.3	78.0	0.0	56.0	108.2	108.2	0.0	45.0	45.0
HU	95.0	105.0	110.6	110.6	60.0	65.0	74.0	73.3	78.0	0.0	61.5	108.2	108.2	0.0	45.0	45.0
IE	98.3	94.6	101.2	101.2	56.1	63.1	73.2	73.3	77.4	0.0	67.9	108.2	108.2	0.0	85.9	85.9
IS	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	56.1	108.2	108.2	0.0	85.9	85.9
IT	98.3	94.6	101.2	101.2	56.1	63.1	72.7	73.3	75.8	0.0	56.6	108.2	108.2	0.0	85.9	85.9
LT	98.3	94.6	101.2	101.2	56.1	63.1	73.7	73.3	77.4	0.0	157.7	108.2	108.2	0.0	85.9	85.9
LU	98.3	94.6	101.2	101.2	56.1	63.1	74.0	73.3	77.4	0.0	56.1	108.2	108.2	0.0	85.9	85.9
LV	98.3	94.6	101.2	101.2	56.1	63.1	73.8	73.3	77.4	0.0	61.1	108.2	108.2	0.0	85.9	85.9
MT	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	56.1	108.2	108.2	0.0	85.9	85.9
NL	98.3	94.6	101.2	101.2	56.1	63.1	74.0	73.3	77.4	0.0	79.0	108.2	108.2	0.0	85.9	85.9
NO	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	56.1	108.2	108.2	0.0	85.9	85.9

Region	Hard Coal	Lignite	Brown Coal	Coke	Refinery Gas	Liquefied Petroleum Gas	Light Fuel Oil	Naphtha	Heavy Fuel Oil	Non Energy	Natural Gas	Coke Oven Gas	Blast Furnace Gas	Biomass Wood	Municipal Waste	Industrial Waste-Sludge
PL	95.0	105.0	110.6	110.6	60.0	65.0	74.0	73.3	78.0	0.0	64.4	108.2	108.2	0.0	45.0	45.0
PT	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	67.6	108.2	108.2	0.0	85.9	85.9
RO	98.3	94.6	101.2	101.2	56.1	63.1	73.5	73.3	77.4	0.0	56.4	108.2	108.2	0.0	85.9	85.9
SE	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	57.7	108.2	108.2	0.0	85.9	85.9
SI	98.3	94.6	101.2	101.2	56.1	63.1	74.1	73.3	77.4	0.0	66.6	108.2	108.2	0.0	85.9	85.9
SK	95.0	105.0	110.6	110.6	60.0	65.0	74.0	73.3	78.0	0.0	60.2	108.2	108.2	0.0	45.0	45.0
UK	98.3	94.6	101.2	101.2	56.1	63.1	73.4	73.3	77.4	0.0	65.5	108.2	108.2	0.0	85.9	85.9

Table 95 – Residential, commercial and agriculture. Static emission factors (ktCO2/PJ)

Region	Hard Coal	Coke	Lignite	Brown Coal	Liquefied Petroleum Gas	Motor Spirit	Kerosene - Jet Fuels	Diesel	Residual Fuel Oil	Other Petroleum Products	Natural Gas	Gasworks Gas	Wood Products	Biogas	Municipal Waste	Industrial Waste-Sludge
AT	95.0	105.0	110.6	110.6	65.0	72.0	74.0	74.0	78.0	80.0	56.0	46.5	0.0	0.0	45.0	45.0
BE	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
BG	95.0	105.0	110.6	110.6	65.0	72.0	74.0	74.0	78.0	80.0	56.0	46.5	0.0	0.0	45.0	45.0
CH	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
CY	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
CZ	95.0	105.0	110.6	110.6	65.0	72.0	74.0	74.0	78.0	80.0	56.0	46.5	0.0	0.0	45.0	45.0
DE	95.0	105.0	110.6	110.6	65.0	72.0	74.0	74.0	78.0	80.0	56.0	46.5	0.0	0.0	45.0	45.0
DK	95.0	105.0	110.6	110.6	65.0	72.0	74.0	74.0	78.0	80.0	56.0	46.5	0.0	0.0	45.0	45.0

Region	Hard Coal	Coke	Lignite	Brown Coal	Liquefied Petroleum Gas	Motor Spirit	Kerosene - Jet Fuels	Diesel	Residual Fuel Oil	Other Petroleum Products	Natural Gas	Gasworks Gas	Wood Products	Biogas	Municipal Waste	Industrial Waste-Sludge
EE	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
ES	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
FI	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
FR	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
GR	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
HR	95.0	105.0	110.6	110.6	65.0	72.0	74.0	74.0	78.0	80.0	56.0	46.5	0.0	0.0	45.0	45.0
HU	95.0	105.0	110.6	110.6	65.0	72.0	74.0	74.0	78.0	80.0	56.0	46.5	0.0	0.0	45.0	45.0
IE	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
IS	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
IT	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
LT	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
LU	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
LV	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
MT	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
NL	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
NO	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
PL	95.0	105.0	110.6	110.6	65.0	72.0	74.0	74.0	78.0	80.0	56.0	46.5	0.0	0.0	45.0	45.0

Region	Hard Coal	Coke	Lignite	Brown Coal	Liquefied Petroleum Gas	Motor Spirit	Kerosene - Jet Fuels	Diesel	Residual Fuel Oil	Other Petroleum Products	Natural Gas	Gasworks Gas	Wood Products	Biogas	Municipal Waste	Industrial Waste-Sludge
PT	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
RO	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
SE	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
SI	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9
SK	95.0	105.0	110.6	110.6	65.0	72.0	74.0	74.0	78.0	80.0	56.0	46.5	0.0	0.0	45.0	45.0
UK	98.3	94.6	101.2	101.2	63.1	69.3	71.9	74.1	77.4	73.3	56.1	56.1	0.0	0.0	85.9	85.9

Table 96 – Residential, commercial and agriculture. Dynamic emission factors (ktCO2/PJ)

Region	Coal	Liquefied Petroleum Gas	Oil	Natural Gas	Biomass
AT	102.8	65.0	74.3	56.0	0.0
BE	98.3	63.1	74.1	55.9	0.0
BG	102.8	65.0	74.0	56.0	0.0
CH	100.1	63.1	74.1	56.1	0.0
CY	98.3	63.1	71.9	56.1	0.0
CZ	107.6	65.0	74.0	56.0	0.0
DE	105.6	65.0	74.0	56.0	0.0
DK	95.0	65.0	73.9	55.9	0.0
EE	98.9	63.1	74.1	56.1	0.0
ES	98.3	63.1	74.2	56.1	0.0
FI	101.0	63.1	74.1	56.1	0.0
FR	98.2	63.1	74.3	56.1	0.0
GR	101.2	63.1	74.1	56.1	0.0
HR	110.6	65.0	74.2	55.9	0.0
HU	97.7	65.0	74.0	56.0	0.0
IE	100.0	63.1	72.5	56.1	0.0
IS	98.3	63.1	74.1	56.1	0.0

Region	Coal	Liquefied Petroleum Gas	Oil	Natural Gas	Biomass
IT	98.3	63.1	74.3	56.1	0.0
LT	99.1	63.1	74.1	56.1	68.7
LU	98.3	63.1	74.1	56.1	0.0
LV	98.3	63.1	71.1	56.1	0.0
MT	98.3	63.1	71.9	56.1	0.0
NL	98.3	63.1	73.5	56.1	0.0
NO	94.6	63.1	72.7	56.1	0.0
PL	95.3	65.0	74.0	56.0	0.0
PT	98.3	63.1	74.1	56.1	0.0
RO	101.2	63.1	76.8	56.1	0.0
SE	98.3	63.1	74.1	56.1	0.0
SI	98.3	63.1	74.1	56.1	0.0
SK	109.9	65.0	74.0	56.0	0.0
UK	98.2	63.1	72.0	56.1	5.7

Table 97 – Energy transformation. Static emission factors (ktCO2/PJ)

Region	Hard Coal	Coke	Lignite	Brown Coal	Crude Oil	Feedstock	Refinery Gas	Liquefied Petroleum Gas	Motor Spirit	Kerosene - Jet Fuel	Naphtha	Diesel	Residual Fuel Oil	Non Energy	Other Petroleum Products	Natural Gas	Coke-Oven Gas	Blast-Furnace Gas	Gasworks Gas	Wood Products	Biogas	Municipal Waste	Industrial Waste-Sludge	Biofuels
AT	95.0	105.0	110.6	110.6	80.0	80.0	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2	46.5	0.0	0.0	45.0	45.0	0.0
BE	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
BG	95.0	105.0	110.6	110.6	80.0	80.0	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2	46.5	0.0	0.0	45.0	45.0	0.0
CH	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
CY	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
CZ	95.0	105.0	110.6	110.6	80.0	80.0	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2	46.5	0.0	0.0	45.0	45.0	0.0
DE	95.0	105.0	110.6	110.6	80.0	80.0	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2	46.5	0.0	0.0	45.0	45.0	0.0
DK	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
EE	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
ES	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
FI	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
FR	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
GR	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
HR	95.0	105.0	110.6	110.6	80.0	80.0	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2	46.5	0.0	0.0	45.0	45.0	0.0
HU	95.0	105.0	110.6	110.6	80.0	80.0	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2	46.5	0.0	0.0	45.0	45.0	0.0
IE	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0

Region	Hard Coal	Coke	Lignite	Brown Coal	Crude Oil	Feedstock	Refinery Gas	Liquefied Petroleum Gas	Motor Spirit	Kerosene - Jet Fuel	Naphtha	Diesel	Residual Fuel Oil	Non Energy	Other Petroleum Products	Natural Gas	Coke-Oven Gas	Blast-Furnace Gas	Gasworks Gas	Wood Products	Biogas	Municipal Waste	Industrial Waste-Sludge	Biofuels
IS	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
IT	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
LT	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
LU	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
LV	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
MT	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
NL	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
NO	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
PL	95.0	105.0	110.6	110.6	80.0	80.0	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2	46.5	0.0	0.0	45.0	45.0	0.0
PT	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
RO	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
SE	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
SI	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0
SK	95.0	105.0	110.6	110.6	80.0	80.0	60.0	65.0	72.0	74.0	73.3	74.0	78.0	0.0	80.0	56.0	108.2	108.2	46.5	0.0	0.0	45.0	45.0	0.0
UK	98.3	94.6	101.2	101.2	73.3	73.3	56.1	63.1	69.3	71.9	73.3	74.1	77.4	0.0	73.3	56.1	108.2	108.2	56.1	0.0	0.0	85.9	85.9	0.0

Table 98 – Energy transformation. Dynamic emission factors (ktCO2/PJ)

	Coal	Crude Oil	Refinery Gas and LPG	Refined Petroleum Products	Natural Gas	Biomass
AT	108.2	80.0	60.6	85.1	0.0	0.0
BE	98.3	73.3	56.4	89.6	0.0	
BG	108.3	80.0	65.1	78.0	0.0	0.0
CH	98.3	73.3	71.0	111.1	0.0	0.0
CY	98.3	73.3	56.1	77.4	0.0	0.0
CZ	108.3	80.0	60.0	119.4	3.5	0.0
DE	108.7	80.0	60.5	88.4	0.0	0.0
DK	98.3	73.3	57.5	105.5	0.0	0.0
EE	101.2	73.3	56.1	74.5	0.0	0.0
ES	107.0	73.3	56.1	76.2	0.0	0.0
FI	98.3	73.3	56.1	273.6	0.0	0.0
FR	107.5	73.3	56.5	80.5	0.0	0.0
GR	98.3	73.3	56.8	94.6	0.0	0.0
HR	95.0	80.0	60.2	78.3	0.0	0.0

	Coal	Crude Oil	Refinery Gas and LPG	Refined Petroleum Products	Natural Gas	Biomass
HU	108.3	80.0	60.0	85.6	0.0	0.0
IE	101.2	73.3	56.6	76.8	0.0	0.0
IS	98.3	73.3	56.1	77.4	0.0	0.0
IT	98.7	73.3	56.8	78.0	0.0	0.0
LT	98.3	73.3	56.1	118.8	0.0	0.0
LU	98.3	73.3	56.1	77.4	0.0	0.0
LV	98.3	73.3	56.1	77.4	0.0	0.0
MT	98.3	73.3	56.1	77.4	0.0	0.0
NL	108.2	73.3	69.4	102.7	0.0	0.0
NO	98.3	73.3	56.3	74.1	0.0	0.0
PL	104.7	80.0	60.0	197.8	0.0	45.0
PT	98.3	73.3	63.1	75.5	0.0	0.0
RO	107.9	73.3	56.3	76.8	0.0	85.9
SE	108.2	73.3	56.1	173.8	37.4	0.0
SI	98.3	73.3	56.1	77.4	0.0	0.0
UK	108.1	73.3	56.2	80.3	0.0	0.0
SK	108.2	80.0	61.1	241.4	0.0	0.0

Table 99 – Transport. Static emission factors (ktCO2/PJ)

Region	Liquefied Petroleum Gas	Motor Spirit	Kerosene - Jet Fuels	Diesel	Residual Fuel Oil	Non Energy	Natural Gas	Biofuels
AT	65.0	72.0	74.0	74.0	78.0	0.0	56.0	0.0
BE	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
BG	65.0	72.0	74.0	74.0	78.0	0.0	56.0	0.0
CH	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
CY	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
CZ	65.0	72.0	74.0	74.0	78.0	0.0	56.0	0.0
DE	65.0	72.0	74.0	74.0	78.0	0.0	56.0	0.0
DK	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
EE	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
ES	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
FI	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
FR	64.0	72.8	72.8	75.4	78.0	0.0	56.1	0.0
GR	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
HR	65.0	72.0	74.0	74.0	78.0	0.0	56.0	0.0
HU	65.0	72.0	74.0	74.0	78.0	0.0	56.0	0.0
IE	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0

Region	Liquefied Petroleum Gas	Motor Spirit	Kerosene - Jet Fuels	Diesel	Residual Fuel Oil	Non Energy	Natural Gas	Biofuels
IS	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
IT	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
LT	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
LU	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
LV	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
MT	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
NL	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
NO	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
PL	65.0	72.0	74.0	74.0	78.0	0.0	56.0	0.0
PT	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
RO	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
SE	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
SI	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0
SK	65.0	72.0	74.0	74.0	78.0	0.0	56.0	0.0
UK	63.1	69.3	71.9	74.1	77.4	0.0	56.1	0.0

Table 100 – Transport. Dynamic emission factors (ktCO2/PJ)

Region	Liquefied Petroleum Gas	Gasoline	Kerosene - Jet Fuels	Blending diesel + EMHV + FT + HVO	Heavy Fuel Oil	Natural Gas	Biodiesel
AT	65	72	74	74	78	56	0
BE	63.1	69.3	71.9	74.1	77.4	56.1	0
BG	65	72	74	74	78	56	0
CH	63.1	69.3	71.9	74.1	77.4	56.1	0
CY	63.1	69.3	71.9	74.1	77.4	56.1	0
CZ	65	72	74	74	78	56	0
DE	65	72	74	74	78	56	0
DK	63.1	69.3	71.9	74.1	77.4	56.1	0
EE	63.1	69.3	71.9	74.1	77.4	56.1	0
ES	63.1	69.3	71.9	74.1	77.4	56.1	0
FI	63.1	69.3	71.9	74.1	77.4	56.1	0
FR	63.9	72.7	72.7	75.3	78.0	56.1	0
GR	63.1	69.3	71.9	74.1	77.4	56.1	0
HR	65	72	74	74	78	56	0
HU	65	72	74	74	78	56	0
IE	63.1	69.3	71.9	74.1	77.4	56.1	0
IS	63.1	69.3	71.9	74.1	77.4	56.1	0
IT	63.1	69.3	71.9	74.1	77.4	56.1	0

Region	Liquefied Petroleum Gas	Gasoline	Kerosene - Jet Fuels	Blending diesel + EMHV + FT + HVO	Heavy Fuel Oil	Natural Gas	Biodiesel
LT	63.1	69.3	71.9	74.1	77.4	56.1	0
LU	63.1	69.3	71.9	74.1	77.4	56.1	0
LV	63.1	69.3	71.9	74.1	77.4	56.1	0
MT	63.1	69.3	71.9	74.1	77.4	56.1	0
NL	63.1	69.3	71.9	74.1	77.4	56.1	0
NO	63.1	69.3	71.9	74.1	77.4	56.1	0
PL	65	72	74	74	78	56	0
PT	63.1	69.3	71.9	74.1	77.4	56.1	0
RO	63.1	69.3	71.9	74.1	77.4	56.1	0
SE	63.1	69.3	71.9	74.1	77.4	56.1	0
SI	63.1	69.3	71.9	74.1	77.4	56.1	0
SK	65	72	74	74	78	56	0
UK	63.1	69.3	71.9	74.1	77.4	56.1	0

16.8 Annex VIII - Calibration of the CHP autoproduction

Information related to the different autoproducers technologies was provided for the year 2005 such as the electrical capacity, overall efficiency, electrical efficiency and the availability. For the calibration of the autoproducers the Eurostat Main Tables data were used for year 2005 and Eurostat data for 2002 (Danko & Lösönen, 2006) as follows:

- Supply, transformation, consumption - all products - annual data (nrg_100a)
- Supply, transformation, consumption - solid fuels - annual data (nrg_101a)
- Supply, transformation, consumption - oil - annual data (nrg_102a)
- Supply, transformation, consumption - gas - annual data (nrg_103a)
- Supply, transformation, consumption - electricity - annual data (nrg_105a)
- Supply, transformation, consumption - heat - annual data (nrg_106a)
- Supply, transformation, consumption - renewables and wastes (total, solar heat, biomass, geothermal, wastes) - annual data (nrg_1071a)
- Infrastructure - electricity - annual data (nrg_113a)

Information for the EU-27 in the year 2005 was extracted from the energy database of Eurostat.

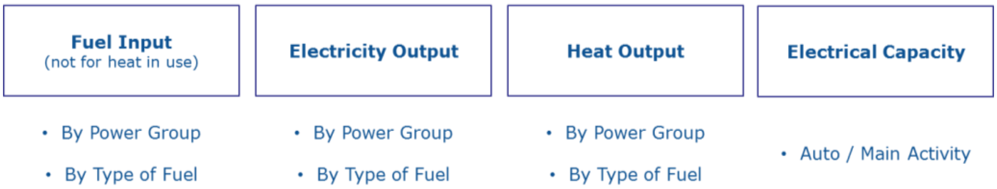


Figure 81 – Eurostat database information scope

The available information from Eurostat, allows to calculate the energy balance for the autoproducers. However, Eurostat does not provide information related to the capacity of the separate groups autoproducers CHP and electricity only. It only provides aggregated information of electrical capacity for the total of Autoproducers and the Main Activity Sector.

To fill this missing gap, we use capacity data from Eurostat for 2002 (Danko & Lösönen, 2006) shown in the "CHP2002By cycle" worksheet. 2002 data was adjusted to 2005, and used for providing the description of each of the technologies.

The main steps for the calibration, information use and associated assumptions are explained below.

1) Energy balance CHP Autoproducers

The energy balance for each of the power groups was made mainly using the information from Eurostat. Nevertheless, Eurostat for the CHP Auotoproducer category, provides a number for the fuel input that excludes the fuel used for the production of the "heat in use". For this reason, data from Loesoenen 2002 was used in order to calculate the total fuel input.

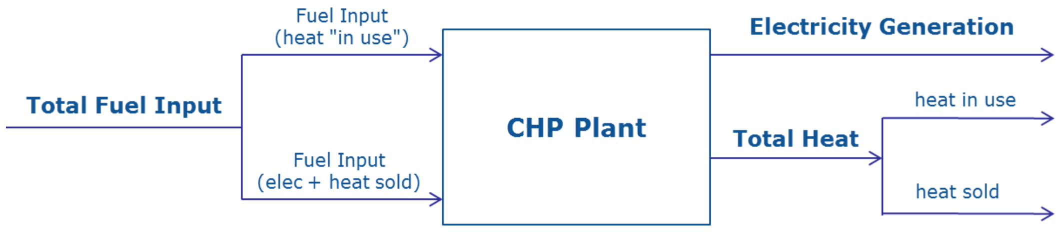


Figure 82 – CHP plant input/output

The Fuel consumption of CHP autoproducers in Eurostat is split in FUELtrans and FUELfinal: a part seen by Eurostat as "Fuel as input for Transformation" and "Fuel as part of Final energy consumption in Industries". The share of FUELtrans in the total Fuel input of the CHP is based on the share of the production of electricity and heat sold in the total energy production. As a consequence, the share of FUELfinal in the total Fuel input is the share of heat used on site in the total energy production. Eurostat does not provide heat used on site as derived heat is only the heat sold. Therefore, the approach used was to subtract FUELfinal from the final energy consumption and to add the heat used on site. The first is done to prevent double counting. The second step is done because this heat is truly consumed by Industrial processes but missing in Eurostat. For exemplification, at European level, we have the following data:

FUELtrans= 1695 PJ , fuel used for Electricity production (661 PJ) and production of heat sold (687 PJ)

FUELfinal = 1638 PJ, fuel used for production of heat used on site (1174 PJ)

Different methods exist to calibrate data coming from two mentioned sources. The table gives the basis of how the calibration was done using 3 different methods. The table is a collection of the data references and calculations that we used. The shaded cells indicate which part of the data is not in line with the Eurostat 2005 data tables. Whatever method is used, there will always remain some ambiguity when comparisons are made with the Eurostat energy balances.

Table 101 –Methods to calibrate CHP autoproducers

	Abbrev.	Method 1 (not used)	Method 2 (not used)	Method 3
Fuel input	Ftot	(2006)	(2006)	(2006)
Fuel input (elec + heat sold)	Ftrans	Can be calculated as = Ftot x (E + HS)/(E + H)	Eurostat Tables	Eurostat Tables
Fuel Input (heat "in use")	Ffinal	= Ftot – Eurostat Tables Ftrans	= Ftot – Ftrans	= Ftot – Ftrans
Generation of Electricity	E	Eurostat Tables	Eurostat Tables	Eurostat Tables
Generation of Heat	H	(2006)	= HS + HU	(2006)
Generation of Heat sold	HS	Eurostat Tables	Eurostat Tables	= Ftrans/Ftot x (E + H) – E
Generation of Heat used	HU	= H – HS	= (E + HS) x Ffin/Ftrans	= H – HS

In general, the fuel split is based on the equation Ftrans/Final = (E+HS)/HU. This condition is not met in the **first method** in which we try to be in line with Eurostat for electricity production and heat production, including heat sold. We presume that the heat sold is not an accurate number in Eurostat and for this reason, the equation is not fulfilled (the numbers in Eursotat for E+HS are not consistent with the numbers in Eurostat for Ftrans). The most clear example is Germany where E = 85 PJ and HS = 297 PJ and HU = 0PJ. From these numbers, the Ftrans can be estimated to be 476 PJ that is much higher than the number we see in Eurostat being 315 PJ. In the **second method**, the equation is used to calculate HU. However, the total heat production of CHPs is not in line with (Danko & Lösönen, 2006). In the **third method that we use**, both heat and fuel consumption are consistent with Loesoenen 2002 (extrapolated for 2005). The only disadvantage is that the Heat sold is not in line with Eurostat. More important is that the fuel consumption is fully in line with Eurostat and that the distinction between heat sold and heat used on site does not exist in JRC-EU-TIMES.

2) Capacities Calculation

Once the energy balance has been calculated, it is possible to determine the electrical capacities for each of the power groups. Bearing in mind the fact that Eurostat data is not disaggregating the electrical capacities sufficiently for our modelling framework (as it is shown in sheet EL Cap ALL Autoprod) some assumption should be made to obtain the capacities of CHP and Electricity only groups.

An iteration calculation method is used for calculating the Autoproducers capacities, the calculation method is described in Figure 83. Starting point of the calculation is the date from (Danko & Lösönen, 2006) , which provide the CHP capacities for 2002. If this capacity is not larger than the maximum assumed for CHP then it is considered, otherwise the maximum derrived from our calculations is introduced. Afterwards capacities are increased if necessary to achieve a maximum availability factor of 0.9.

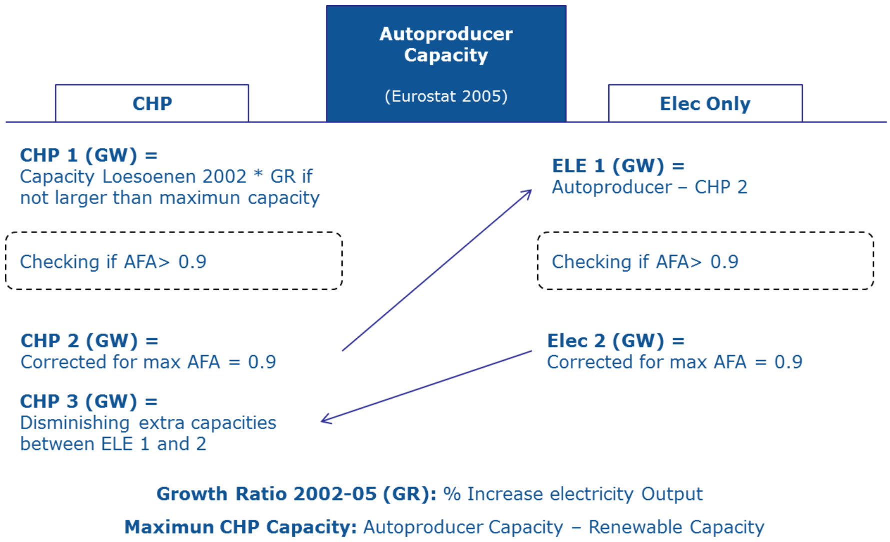


Figure 83 – Autoproducers calculation method

Once a preliminary capacity for CHP has been calculated, the capacity for the Electricity Only group can be obtained by substracting this amount from the total capacity for Autoproducers. After this calculation, the availability factor is used again for checking, obtaining the final capacities for this group.

3) Fuel Consumption Allocation by Sector

The last group of calculations are those related to the allocation of fuels consumption in the Autoproducers Power plants disaggregated by industrial sector activity. For this purpose, two kind of data are used: on the one hand the total fuel input to CHP Autoproducers and on the other hand the total energy input to each of the industrial sectors. Combining these two sources of information, the allocation of the fuels within the sectors is developed in the sheet: "Autoproducers calculations".

Figure 84 – Priority sectors for fuel allocation

The methodology followed in the calibration of Switzerland differed from the one previously explained, as this country was not contained in (Danko & Lösönen, 2006) 's scope. Calculations were made using the available information from Eurostat 2005 and the following assumptions:

Heat Generation: Eurostat is providing the heat sold for CHP Autoproducers, but not total heat production. An assumption is made, considering for CH the same ratio of total heat/heat sold than the one from the whole EU-27 industry.

Heat Capacity: Once the heat production is calculated, the heat capacity can be estimated by using the EU-27 ratio between Heat Production and Heat Capacity.

Electrical Capacity: With the data of CHP Autoproducer electricity generation, the capacity is estimated by assuming an AFA=0.9. This is in line with the assumptions made for other countries, and also in line with the maximum capacity expected from Autoproducers CHP from Eurostat.

Fuels Input: An inconsistency was found in the fuels input data from Eurostat for the sector, as the total fuel input was not meeting the by-fuel disaggregation. In the case of CH, numbers where corrected maintaining the overall consumption, and increasing the disaggregated consumption by fuel so the total was reached, but the shares of each fuel where not changed.

The fuels are distributed following a list of priority sectors. Each fuel presents a dominant sector which will consume the maximum possible of that type of fuel according to the total input of that sector. If there remains fuel from the CHP fuels input, those are allocated to the following dominant sector as did before. The process continues until there is no more fuel from CHP to allocate.

16.9 Annex IX – Energy Trade Matrices

Table 102 – Trade matrix for electricity within the regions considered in JRC-EU-TIMES including assumption on maximum considered transmission capacity in GW implemented for 2025

ELCHIG	AT	BE	BG	CH	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HU	IE	IS	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK	UK	AL	BA	HR	ME	MK	RS	XK
AT				1.40		2.18	6.88							1.50			2.20											1.20	1.50								
BE							1.00					3.70							0.60			2.40								1.00							
BG													1.50													0.95									0.45	1.00	
CH	1.40						4.40					3.50					6.54																				
CY																																					
CZ	2.18						3.80																	2.00					2.00								
DE	6.88	1.00		4.40		3.80		3.15				5.60							0.98			5.35	2.40	3.10			0.60										
DK							3.15															0.60	1.60				2.44										
EE											1.00									1.40																	
ES												4.00													3.00												
FI									1.00														1.00				2.80										
FR		3.70		3.50			5.60			4.00					1.00		4.20		0.30											3.00							
GR			1.50														0.50														0.30				0.60		
HU	1.50																									1.40		0.90	3.00				3.00			0.60	
IE												1.00																		1.85							
IS																																					
IT	2.20			6.54								4.20	0.50								0.20							2.15			2.00		1.00	1.00			
LT																				2.10				1.00			1.00										
LU		0.60					0.98					0.30																									
LV									1.40									2.00									0.70										
MT																	0.20																				
NL		2.40					5.35	0.60															0.70							1.32							
NO							2.40	1.60			1.00											0.70					5.45			1.40							
PL						2.00	3.10											1.00									0.60		1.50								
PT										3.00																											
RO			0.95											1.40																						1.30	
SE							0.60	2.44			2.80							1.00		0.70			5.45	0.60													
SI	1.20													0.90			2.15																1.90				
SK	1.50					2.00								3.00										1.50													
UK		1.00										3.00			1.85							1.32	1.40														
AL													0.30				2.00																	0.50	0.50	0.75	
BA																																	1.60	1.00		0.75	
HR														3.00			1.00											1.90				1.60				0.68	
ME																	1.00														0.50	1.00				0.70	
MK			0.45										0.60																		0.50					1.10	
RS			1.00											0.60												1.30					0.70	0.70	0.60	0.65	0.85		
KS																																					

Reference: ENTSO-E via (Lavagno & Auer, 2009)

Table 103 – Investment costs considered for additional transmission capacity for electricity trade within the regions considered in JRC-EU-TIMES in euros 2000/kW

ELCHIG	AT	BE	BG	CH	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HU	IE	IS	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK	UK	AL	BA	HR	ME	MK	RS	KS
AT				57.5		57.5	57.5							57.5			57.5											57.5	57.5								
BE							414					57.5							57.5			57.5								414							
BG													57.5													57.5									57.5	57.5	
CH	57.5						57.5					57.5					57.5																				
CY																																					
CZ	57.5						57.5																	57.5					57.5								
DE	57.5	414		57.5		57.5		414				57.5							57.5			57.5	414	57.5			414			414							
DK							414															414	414				414										
EE											414									57.5																	
ES												57.5													57.5												
FI									414														57.5				57.5										
FR		57.5		57.5			57.5			57.5					414		57.5		57.5											414							
GR			57.5														414														57.5				57.5		
HU	57.5																									57.5		57.5	57.5				57.5			57.5	
IE												414																		414							
IS																							414							414							
IT	57.5			57.5								57.5	414								287.5							57.5			414		414	414			
LT																				57.5				57.5			414										
LU		57.5					57.5					57.5																									
LV									57.5									57.5									414										
MT																	287.5																				
NL		57.5					57.5	414															414							414							
NO							414	414			57.5											414					57.5			828							
PL						57.5	57.5											57.5									414		57.5								
PT										57.5																											
RO			57.5											57.5																						57.5	
SE							414	414			57.5							414		414			57.5	414													
SI	57.5													57.5			57.5																57.5				
SK	57.5					57.5								57.5										57.5													
UK		414					414					414			414							414	828														
AL													57.5				414																	57.5	57.5	57.5	
BA																																	57.5	57.5		57.5	
HR														57.5			414											57.5				57.5				57.5	
ME																	414														57.5	57.5				57.5	
MK			57.5										57.5																		57.5					57.5	
RS			57.5											57.5												57.5					57.5	57.5	57.5	57.5	57.5		
kS																																					

Reference: (Lavagno & Auer, 2009)

Table 104 – Fixed O&M costs considered for additional transmission capacity for electricity trade within the regions considered in JRC-EU-TIMES in euros 2000/GJ

ELCHIG	AT	BE	BG	CH	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HU	IE	IS	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK	UK	AL	BA	HR	ME	MK	RS	KS
AT				2.5		2.5	2.5							2.5			2.5											2.5	2.5								
BE							18					2.5							2.5			2.5								18							
BG													2.5													2.5									2.5	2.5	
CH	2.5						2.5					2.5					2.5																				
CY																																					
CZ	2.5						2.5																	2.5					2.5								
DE	2.5	18		2.5		2.5		18				2.5							2.5			2.5	18	2.5			18			18							
DK							18															18	18				18										
EE											18									2.5																	
ES												2.5													2.5												
FI									18														2.5				2.5										
FR		2.5		2.5			2.5			2.5					18		2.5		2.5											18							
GR			2.5														18														2.5				2.5		
HU	2.5																									2.5		2.5	2.5				2.5			2.5	
IE												18																		18							
IS																							18							18							
IT	2.5			2.5								2.5	18								12.5							2.5			18		18	18			
LT																				2.5				2.5			18										
LU		2.5					2.5					2.5																									
LV									2.5									2.5									18										
MT																	12.5																				
NL		2.5					2.5	18															18							18							
NO							18	18			2.5											18					2.5			36							
PL						2.5	2.5											2.5									18		2.5								
PT										2.5																											
RO			2.5											2.5																						2.5	
SE							18	18			2.5							18		18			2.5	18													
SI	2.5													2.5			2.5																2.5				
SK	2.5					2.5								2.5										2.5													
UK		18					18					18			18							18	36														
AL													2.5				18																	2.5	2.5	2.5	
BA																																	2.5	2.5		2.5	
HR														2.5			18											2.5				2.5				2.5	
ME																	18														2.5	2.5				2.5	
MK			2.5										2.5																		2.5					2.5	
RS			2.5											2.5												2.5					2.5	2.5	2.5	2.5	2.5		
KS																																					

Reference: (Lavagno & Auer, 2009)

Table 105 – Trade matrix for CO_2 within the regions considered in JRC-EU-TIMES

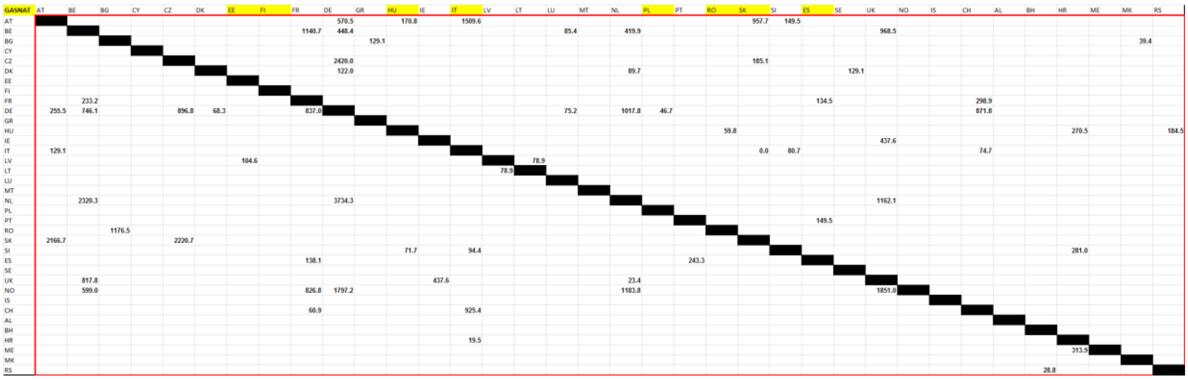
SNKCO2N	AT	BE	BG	CH	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HU	IE	IS	IT	LT	LU	LV	MT	NL	NO	PL	PT	RO	SE	SI	SK	UK	AL	BA	HR	ME	MK	RS	KS
AT						1	1							1														1	1								
BE							1					1							1			1								1							
BG													1													1											
CH																																					
CY													1																								
CZ	1						1																	1					1								
DE	1	1				1		1											1			1		1													
DK							1															1	1	1			1			1							
EE											1									1																	
ES												1													1												
FI									1														1				1										
FR		1								1							1		1											1							
GR			1		1												1																				
HU	1																									1		1	1								
IE																														1							
IS																																					
IT												1	1								1							1									
LT																				1				1													
LU		1					1					1																									
LV									1									1									1										
MT																	1																				
NL		1					1	1																						1							
NO								1			1																1			1							
PL						1	1	1										1											1								
PT										1																											
RO			1											1																							
SE								1			1									1			1														
SI	1													1			1																				
SK	1					1								1										1													
UK		1						1				1			1							1	1														
AL																																					
BA																																					
HR																																					
ME																																					
MK																																					
RS																																					
KS																																					

Reference: (Morbee, et al., 2012)

Table 106 – Trade matrix for hydrogen within the regions considered in JRC-EU-TIMES

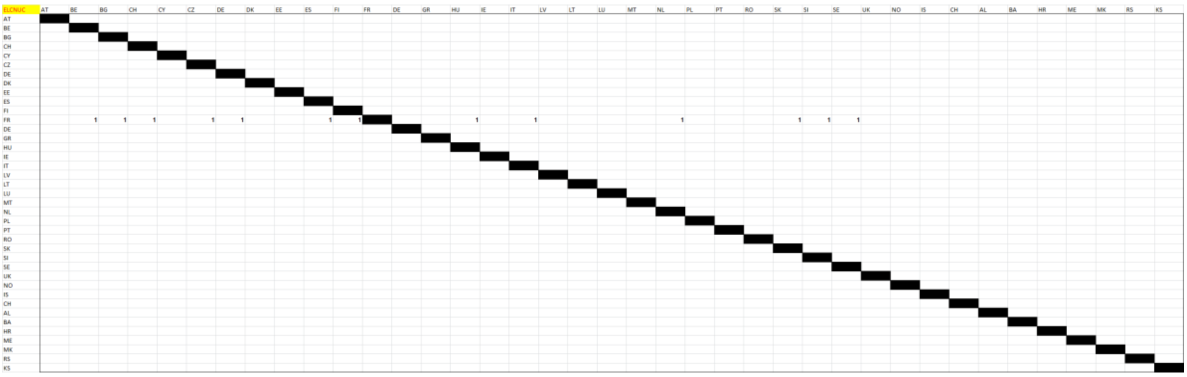
Reference: Assumed as the same as for natural gas

Table 107 – Trade matrix for natural gas within the regions considered in JRC-EU-TIMES assumption on maximum considered pipeline capacity in GJ of natural gas implemented for 2015



Reference: (Lavagno & Auer, 2009)updated with REACCESS project (n.d.)

Table 108 – Trade matrix for nuclear fuel within the regions considered in JRC-EU-TIMES



Reference: (Lavagno & Auer, 2009)

16.10 Annex X - Allocation of energy services to final energy carriers in the residential sector for the base-year (2005) considered in JRC-EU-TIMES

This Annex covers the end-use break out for Residential Buildings for each region included in the JRC-EU-TIMES. The following colour code has been used to specify the adjustment applied for the data sources outlined in section 6.10.1

Colour	Meaning
Green	minor manual adjustment with decimal points difference
Grey	Data from Odyssee (ENERDATA: www.enerdata.net)
Light blue	Data from national modelling teams within NEEDS and RES2020 EU projects old templates; since no data from Odyssee or because Odyssee data not coherent
Yellow	Data adjusted manually since Odyssee data not coherent

AL

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	1.00	0.60	0.50		0.70			0.31	0.85	
Space Cooling								0.001		
Water Heating		0.15	0.15		0.15			0.15	0.15	
Lighting								0.194		
Cooking		0.25	0.35		0.15			0.12		
Refrigeration								0.180		
Cloth Washing								0.0470		
Cloth Drying								0.0022		
Dish Washing										
Other Electric										
Other Energy										

Breakout by building type (Fractional Shares)

End-use description	Building Type	RSDCOA	RSDLPG	RSDOIL	RSDGAS	RSDBIO	RSDSOL	RSDGEO	RSDELC	RSDLTH	RSDHTH
Space Heating	Single House-Rural	1.00				1.00			0.75		
Space Heating	Single House-Urban		0.08	0.08					0.08		
Space Heating	Multi Apartment-All		0.92	0.92					0.17	1.00	
Space Cooling	Single House-Rural										
Space Cooling	Single House-Urban								1.00		
Space Cooling	Multi Apartment-All										
Water Heating	Single House-Rural					0.95			0.7		
Water Heating	Single House-Urban		0.05	0.05		0.05			0.1		
Water Heating	Multi Apartment-All		0.95	0.95					0.2	1.0	

AT

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.87	0.92	0.91	0.84	0.91	0.10	0.74	0.11	0.85	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.13	0.08	0.09	0.15	0.08	0.90	0.26	0.11	0.15	0.00
Lighting								0.09		
Cooking	0.00	0.00	0.00	0.01	0.01	0.00		0.07		
Refrigeration								0.07		
Cloth Washing								0.20		
Cloth Drying								0.01		
Dish Washing								0.01		
Other Electric								0.32		
Other Energy								0.00		

Breakout by building type (Fractional Shares)

End-use description	Building Type	RSDCOA	RSDLPG	RSDOIL	RSDGAS	RSDBIO	RSDSOL	RSDGEO	RSDELC	RSDLTH	RSDHTH
Space Heating	Single House-Rural	0.35	0.44	0.50	0.30	0.55	0.44	0.45	0.30	0.00	0.06
Space Heating	Single House-Urban	0.46	0.44	0.33	0.28	0.40	0.44	0.45	0.32	0.22	0.06
Space Heating	Multi Apartment-All	0.194	0.12	0.172	0.418	0.05	0.12	0.10	0.377	0.779	0.88
Space Cooling	Single House-Rural								0.44		
Space Cooling	Single House-Urban								0.36		
Space Cooling	Multi Apartment-All								0.20		
Water Heating	Single House-Rural	0.40	0.44	0.50	0.28	0.50	0.45	0.50	0.30	0.10	0.06
Water Heating	Single House-Urban	0.40	0.44	0.40	0.30	0.42	0.45	0.45	0.30	0.20	0.06
Water Heating	Multi Apartment-All	0.20	0.12	0.10	0.43	0.08	0.10	0.05	0.40	0.70	0.88

BA

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.85		0.53	0.54	0.70			0.09	0.84	
Space Cooling								0.003		
Water Heating			0.47	0.27	0.15			0.26	0.16	
Lighting								0.16		
Cooking	0.15	1.00		0.20	0.15			0.22		
Refrigeration								0.19		
Cloth Washing								0.05		
Cloth Drying										
Dish Washing										
Other Electric								0.03		
Other Energy										

Breakout by building type (Fractional Shares)

End-use description	Building Type	RSDCOA	RSDLPG	RSDOIL	RSDGAS	RSDBIO	RSDSOL	RSDGEO	RSDELC	RSDLTH	RSDHTH
Space Heating	Single House-Rural	0.9				0.9					
Space Heating	Single House-Urban	0.1		0.1		0.1					
Space Heating	Multi Apartment-All			0.9	1.0				1.0	1.0	
Space Cooling	Single House-Rural										
Space Cooling	Single House-Urban								0.22		
Space Cooling	Multi Apartment-All								0.78		
Water Heating	Single House-Rural			0.6		1.0			0.76		
Water Heating	Single House-Urban			0.1	0.1				0.07		
Water Heating	Multi Apartment-All			0.3	0.9				0.17	1.0	

BE

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.99	0.73	0.89	0.85	0.98	0.00	0.00	0.11	1.00	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.01	0.14	0.11	0.11	0.02	1.00	0.00	0.17	0.00	0.00
Lighting								0.14		
Cooking	0.00	0.13	0.00	0.04	0.00	0.00		0.08		
Refrigeration								0.07		
Cloth Washing								0.08		
Cloth Drying								0.06		
Dish Washing								0.01		
Other Electric								0.27		
Other Energy								0.00		

Breakout by building type (Fractional Shares)

End-use description	Building Type	RSDCOA	RSDLPG	RSDOIL	RSDGAS	RSDBIO	RSDSOL	RSDGEO	RSDELC	RSDLTH	RSDHTH
Space Heating	Single House-Rural	0.7	0.6	0.5	0.2	1.0			0.5	0.0	
Space Heating	Single House-Urban	0.3	0.4	0.4	0.5	0.0			0.3		
Space Heating	Multi Apartment-All	0.0	0.1	0.1	0.3	0.0			0.2	1.0	
Space Cooling	Single House-Rural								0.33		
Space Cooling	Single House-Urban								0.42		
Space Cooling	Multi Apartment-All								0.25		
									1.0		
Water Heating	Single House-Rural		0.3	0.3	0.3	1.0			0.3		
Water Heating	Single House-Urban		0.4	0.4	0.4	0.0			0.4		
Water Heating	Multi Apartment-All		0.3	0.3	0.3	0.0			0.3	1.0	

BG

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.96	0.86	0.89	0.82	0.91	0.04	0.20	0.20	0.94	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.01	0.14	0.11	0.08	0.02	0.96	0.80	0.09	0.06	0.00
Lighting								0.06		
Cooking	0.02	0.00	0.00	0.10	0.07	0.00		0.10		
Refrigeration								0.06		
Cloth Washing								0.10		
Cloth Drying								0.01		
Dish Washing								0.00		
Other Electric								0.37		
Other Energy								0.00		

Breakout by building type (Fractional Shares)

End-use description	Building Type	RSDCOA	RSDLPG	RSDOIL	RSDGAS	RSDBIO	RSDSOL	RSDGEO	RSDELC	RSDLTH	RSDHTH
Space Heating	Single House-Rural	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.0	0.8
Space Heating	Single House-Urban	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1
Space Heating	Multi Apartment-All	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.9	0.2
Space Cooling	Single House-Rural				0.6			0.6	0.5		
Space Cooling	Single House-Urban				0.1			0.1	0.1		
Space Cooling	Multi Apartment-All				0.3			0.3	0.4		
Water Heating	Single House-Rural	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Water Heating	Single House-Urban	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Water Heating	Multi Apartment-All	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3

CH

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	1.00	0.85	0.88	0.86	0.94	0.50	1.00	0.43	0.85	0.85
Space Cooling				0.00			0.00	0.01		
Water Heating	0.00	0.13	0.12	0.12	0.05	0.50	0.00	0.14	0.15	0.15
Lighting								0.08		
Cooking	0.00	0.02	0.00	0.02	0.01	0.00		0.05		
Refrigeration								0.05		
Cloth Washing								0.07		
Cloth Drying								0.02		
Dish Washing								0.02		
Other Electric								0.13		
Other Energy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		

Breakout by building type (Fractional Shares)

End-use description	Building Type	RSDCOA	RSDLPG	RSDOIL	RSDGAS	RSDBIO	RSDSOL	RSDGEO	RSDELC	RSDLTH	RSDHTH
Space Heating	Single House-Rural	0.285	0.285	0.285	0.285	0.285	0.285	0.285	0.285	0.0	0.285
Space Heating	Single House-Urban	0.185	0.185	0.185	0.185	0.185	0.185	0.185	0.185	0.18	0.185
Space Heating	Multi Apartment-All	0.530	0.530	0.530	0.530	0.530	0.530	0.530	0.530	0.8	0.530
Space Cooling	Single House-Rural								0.30		
Space Cooling	Single House-Urban								0.20		
Space Cooling	Multi Apartment-All								0.50		
Water Heating	Single House-Rural	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Water Heating	Single House-Urban	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Water Heating	Multi Apartment-All	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50

CY

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.00	0.05	0.91	0.00	0.06	0.00	0.00	0.03	0.00	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.00	0.05	0.09	0.00	0.88	1.00	0.00	0.05	0.00	0.00
Lighting								0.17		
Cooking	0.00	0.90	0.00	0.00	0.06	0.00		0.16		
Refrigeration								0.03		
Cloth Washing								0.06		
Cloth Drying								0.00		
Dish Washing								0.02		
Other Electric								0.47		
Other Energy								0.00		

Breakout by building type (Fractional Shares)

End-use description	Building Type	RSDCOA	RSDLPG	RSDOIL	RSDGAS	RSDBIO	RSDSOL	RSDGEO	RSDELC	RSDLTH	RSDHTH
Space Heating	Single House-Rural		0.3	0.2		1.0			0.2	0.0	
Space Heating	Single House-Urban		0.3	0.5					0.5		
Space Heating	Multi Apartment-All		0.4	0.3					0.3	1.0	
Space Cooling	Single House-Rural								0.2		
Space Cooling	Single House-Urban								0.5		
Space Cooling	Multi Apartment-All								0.3		
									1.0		
Water Heating	Single House-Rural		0.3	0.2			0.2		0.2		
Water Heating	Single House-Urban		0.3	0.5			0.5		0.5		
Water Heating	Multi Apartment-All		0.4	0.3			0.3		0.3		

CZ

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.93	0.81	0.81	0.82	0.95	0.10	0.81	0.10	0.65	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.04	0.19	0.19	0.09	0.02	0.90	0.19	0.20	0.35	0.00
Lighting								0.06		
Cooking	0.03	0.00	0.00	0.08	0.03	0.00		0.20		
Refrigeration								0.04		
Cloth Washing								0.04		
Cloth Drying								0.00		
Dish Washing								0.03		
Other Electric								0.32		
Other Energy								0.00		

Breakout by building type (Fractional Shares)

End-use description	Building Type	RSDCOA	RSDLPG	RSDOIL	RSDGAS	RSDBIO	RSDSOL	RSDGEO	RSDELC	RSDLTH	RSDHTH
Space Heating	Single House-Rural	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.00	0.00
Space Heating	Single House-Urban	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25		0.00
Space Heating	Multi Apartment-All	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	1.00	1.00
		1.0	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	
Space Cooling	Single House-Rural								0.3		
Space Cooling	Single House-Urban								0.2		
Space Cooling	Multi Apartment-All								0.5		
									1.0		
Water Heating	Single House-Rural	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5		0.0
Water Heating	Single House-Urban	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3		0.0
Water Heating	Multi Apartment-All	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	1.0	1.0

DE

Breakout by end-use (Fractional Shares)										
End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.93	0.86	0.91	0.84	0.94	0.04	0.20	0.13	0.87	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.07	0.14	0.09	0.14	0.04	0.96	0.80	0.17	0.13	0.00
Lighting								0.08		
Cooking	0.00	0.00	0.00	0.02	0.03	0.00		0.09		
Refrigeration								0.07		
Cloth Washing								0.02		
Cloth Drying								0.01		
Dish Washing								0.01		
Other Electric								0.41		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)											
End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.2	0.2	0.5	0.0	0.5	0.5	0.5	0.2	0.0	0.0
Space Heating	Single House-Urban	0.4	0.3	0.3	0.4	0.2	0.2	0.2	0.3	0.4	0.4
Space Heating	Multi Apartment-All	0.5	0.6	0.3	0.6	0.3	0.3	0.3	0.5	0.6	0.6
Space Cooling	Single House-Rural				0.0			0.0	0.15		
Space Cooling	Single House-Urban				0			0	0.39		
Space Cooling	Multi Apartment-All				0.0			0.0	0.46		
									1.0		
Water Heating	Single House-Rural	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Water Heating	Single House-Urban	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3
Water Heating	Multi Apartment-All	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.7	0.7

DK

Breakout by end-use (Fractional Shares)										
End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.75	0.38	0.94	0.74	0.75	0.00	0.75	0.14	0.75	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.25	0.13	0.06	0.25	0.25	1.00	0.25	0.18	0.25	0.00
Lighting								0.10		
Cooking	0.00	0.50	0.00	0.02	0.00	0.00		0.08		
Refrigeration								0.07		
Cloth Washing								0.15		
Cloth Drying								0.12		
Dish Washing								0.08		
Other Electric								0.08		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)											
End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	1.00	0.80	0.61	0.03	0.80	0.60	0.10	0.49	0.29	0.00
Space Heating	Single House-Urban		0.20	0.30	0.80	0.20	0.40	0.90	0.40	0.20	0.50
Space Heating	Multi Apartment-All	0.0		0.1	0.2				0.1	0.5	0.50
		1.0	1.0	1.0	1.0	1.0		1.0	1.0	1.0	
Space Cooling	Single House-Rural								0.25		
Space Cooling	Single House-Urban								0.35		
Space Cooling	Multi Apartment-All								0.40		
									1.0		
Water Heating	Single House-Rural	1.00	0.70	0.60		0.70	0.50	0.10	0.60		
Water Heating	Single House-Urban		0.30	0.40	0.80	0.30	0.50	0.90	0.40	0.30	0.50
Water Heating	Multi Apartment-All				0.20					0.70	0.50

EE

Breakout by end-use (Fractional Shares)										
End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.85		0.85	0.30	0.80			0.05	0.90	0.75
Space Cooling								0.00		
Water Heating	0.15		0.15	0.15	0.10			0.17	0.10	0.25
Lighting								0.21		
Cooking	0.00		0.00	0.55	0.10			0.04		
Refrigeration								0.09		
Cloth Washing								0.14		
Cloth Drying								0.07		
Dish Washing								0.07		
Other Electric								0.16		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)											
End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.8		0.5		0.6			0.0	0.0	0.0
Space Heating	Single House-Urban	0.2		0.2	0.1	0.3			0.0	0.0	0.1
Space Heating	Multi Apartment-All	0.0		0.3	1.0	0.2			1.0	1.00	0.9
		1.0		1.0	1.0	1.0			1.0	1.0	1.0
Space Cooling	Single House-Rural								0.2		
Space Cooling	Single House-Urban								0.1		
Space Cooling	Multi Apartment-All								0.7		
Water Heating	Single House-Rural	0.1		0.5		0.6			0.1	0.0	0.0
Water Heating	Single House-Urban	0.9		0.2	0.1	0.2			0.3	0.0	0.1
Water Heating	Multi Apartment-All	0.0		0.4	1.0	0.3			0.6	1.0	0.9

ES

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.79	0.82	0.86	0.49	0.95	0.10	1.00	0.30	0.00	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.21	0.10	0.14	0.40	0.05	0.90	0.00	0.07	0.00	0.00
Lighting								0.13		
Cooking	0.00	0.08	0.00	0.11	0.00	0.00		0.04		
Refrigeration								0.06		
Cloth Washing								0.07		
Cloth Drying								0.01		
Dish Washing								0.02		
Other Electric								0.29		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.8	0.2	0.3	0.1	0.5	0.0	0.6	0.3	0.0	1.0
Space Heating	Single House-Urban	0.2	0.2	0.2	0.2	0.3	0.8	0.4	0.2		
Space Heating	Multi Apartment-All	0.0	0.6	0.5	0.7	0.2	0.2	0.0	0.5	1.0	
		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0		
Space Cooling	Single House-Rural				0.2			0.0	0.2		
Space Cooling	Single House-Urban				0.2			0.0	0.2		
Space Cooling	Multi Apartment-All				0.5			0.0	0.5		
									1.0		
Water Heating	Single House-Rural	0.8	0.3	0.3	0.2	0.6	0.3	0.6	0.3		
Water Heating	Single House-Urban	0.2	0.2	0.2	0.1	0.3	0.2	0.3	0.2		
Water Heating	Multi Apartment-All	0.0	0.5	0.5	0.7	0.1	0.5	0.1	0.5		

FI

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.82	0.00	0.84	0.82	0.84	0.00	0.00	0.36	0.84	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.18	0.60	0.16	0.16	0.16	0.00	0.00	0.07	0.16	0.00
Lighting								0.17		
Cooking	0.00	0.40	0.00	0.03	0.00	0.00		0.04		
Refrigeration								0.06		
Cloth Washing								0.04		
Cloth Drying								0.01		
Dish Washing								0.02		
Other Electric								0.21		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.6		0.6	0.4	0.6			0.6	0.0	0.1
Space Heating	Single House-Urban	0.4		0.3	0.2	0.4			0.4	0.1	0.1
Space Heating	Multi Apartment-All	0.1		0.1	0.4	0.0			0.0	0.9	0.8
Space Cooling	Single House-Rural								0.4		
Space Cooling	Single House-Urban								0.2		
Space Cooling	Multi Apartment-All								0.4		
									1.0		
Water Heating	Single House-Rural		0.7	0.5		0.6			0.6	0.1	0.1
Water Heating	Single House-Urban		0.2	0.4		0.4			0.4	0.2	0.1
Water Heating	Multi Apartment-All		0.1	0.1		0.0			0.0	0.7	0.8

FR

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	1.00	0.44	0.90	0.85	0.99	0.00	1.00	0.29	0.95	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.00	0.11	0.10	0.08	0.01	1.00	0.00	0.13	0.05	0.00
Lighting								0.07		
Cooking	0.00	0.44	0.00	0.06	0.00	0.00		0.07		
Refrigeration								0.06		
Cloth Washing								0.05		
Cloth Drying								0.03		
Dish Washing								0.05		
Other Electric								0.23		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.42	0.45	0.40	0.20	0.47	0.00	0.30	0.15	0.00	
Space Heating	Single House-Urban	0.53	0.47	0.46	0.38	0.49	1.00	0.70	0.55	0.00	
Space Heating	Multi Apartment-All	0.05	0.08	0.14	0.42	0.04	0.00	0.00	0.30	1.00	1.00
Space Cooling	Single House-Rural								0.3		
Space Cooling	Single House-Urban								0.3		
Space Cooling	Multi Apartment-All								0.4		
Water Heating	Single House-Rural	0.25	0.25	0.25	0.25	0.25	0.40	0.40	0.30	0.00	
Water Heating	Single House-Urban	0.25	0.25	0.25	0.25	0.25	0.40	0.40	0.30	0.00	
Water Heating	Multi Apartment-All	0.50	0.50	0.50	0.50	0.50	0.20	0.20	0.40	1.00	1.0

GR

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.67	0.10	0.97	0.86	0.79	0.00	0.70	0.15	0.90	0.00
Space Cooling				0.00			0.30	0.01		
Water Heating	0.00	0.00	0.03	0.04	0.15	1.00	0.00	0.08	0.10	0.00
Lighting								0.34		
Cooking	0.33	0.90	0.00	0.10	0.06	0.00		0.14		
Refrigeration								0.05		
Cloth Washing								0.06		
Cloth Drying								0.00		
Dish Washing								0.02		
Other Electric								0.15		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.30	0.70	0.11	0.04	0.85	1.00	1.00	0.64	0.32	0.00
Space Heating	Single House-Urban	0.20	0.10	0.11	0.04	0.10		0.00	0.30		
Space Heating	Multi Apartment-All	0.50	0.20	0.78	0.92	0.05		0.00	0.1	0.7	1.00
Space Cooling	Single House-Rural				0.0			0.0	0.2		
Space Cooling	Single House-Urban				1.0			1.0	0.2		
Space Cooling	Multi Apartment-All				0.0			0.0	0.5		
								1.0	**1.0**		
Water Heating	Single House-Rural			0.1	0.0	0.8	0.2		0.1		
Water Heating	Single House-Urban			0.2	0.200	0.2	0.3		0.2		
Water Heating	Multi Apartment-All			0.7	0.800	0.0	0.5		0.7	1.0	1.0

HR

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating			0.650	0.670	0.900			0.250	0.750	
Space Cooling								0.008		
Water Heating			0.350	0.180				0.120	0.250	
Lighting								0.124		
Cooking		1.000		0.150	0.100			0.115		
Refrigeration								0.147		
Cloth Washing								0.112		
Cloth Drying								0.020		
Dish Washing								0.018		
Other Electric								0.086		
Other Energy										

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural			1.0	0.1	1.0			0.7		
Space Heating	Single House-Urban				0.2				0.2		
Space Heating	Multi Apartment-All				0.7				0.2	1.0	
Space Cooling	Single House-Rural										
Space Cooling	Single House-Urban								0.31		
Space Cooling	Multi Apartment-All								0.69		
Water Heating	Single House-Rural			1.0		1.0			0.8		
Water Heating	Single House-Urban			0.0	0.2				0.1		
Water Heating	Multi Apartment-All			0.0	0.8				0.1	1.0	

HU

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.91	0.86	0.00	0.70	0.94	0.10	0.86	0.13	0.78	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.09	0.14	0.00	0.22	0.06	0.90	0.14	0.22	0.22	0.00
Lighting								0.26		
Cooking	0.00	0.00	0.00	0.08	0.00	0.00		0.03		
Refrigeration								0.09		
Cloth Washing								0.04		
Cloth Drying								0.0045		
Dish Washing								0.02		
Other Electric								0.20		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.74	0.37	0.79	0.54	0.37	0.37	0.37	0.39	0.19	0.00
Space Heating	Single House-Urban	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21		0.00
Space Heating	Multi Apartment-All	0.05	0.42	0.0	0.2	0.42	0.42	0.42	0.4	0.8	1.00
		1.0	**1.0**		**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	
Space Cooling	Single House-Rural				0.3			0.3	0.3		
Space Cooling	Single House-Urban				0.18			0.18	0.2		
Space Cooling	Multi Apartment-All				0.5			0.5	0.5		
									1.0		
Water Heating	Single House-Rural	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4		0.0
Water Heating	Single House-Urban	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2		0.0
Water Heating	Multi Apartment-All	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.0	1.0

IE

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.93	0.71	0.85	0.77	1.00	0.00	0.75	0.14	1.00	0.00
Space Cooling				0.00			0.00	0.00		
Water Heating	0.07	0.12	0.15	0.19	0.00	1.00	0.25	0.22	0.00	0.00
Lighting								0.04		
Cooking	0.00	0.17	0.00	0.04	0.00	0.00		0.12		
Refrigeration								0.05		
Cloth Washing								0.04		
Cloth Drying								0.02		
Dish Washing								0.01		
Other Electric								0.37		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.614	0.562	0.562	0.035	0.624	0.9	0.9	0.222	0.0	0.0
Space Heating	Single House-Urban	0.362	0.411	0.412	0.910	0.353	0.1	0.1	0.592		0.5
Space Heating	Multi Apartment-All	0.024	0.027	0.027	0.055	0.024	0.0	0.0	0.185	1.0	0.5
		1.0	1.0	1.0	1.0	1.0		1.0	1.0	1.0	
Space Cooling	Single House-Rural								0.820		
Space Cooling	Single House-Urban								0.100		
Space Cooling	Multi Apartment-All								0.080		
Water Heating	Single House-Rural	0.995	0.560	0.560	0.034		0.9	0.9	0.549		0.0
Water Heating	Single House-Urban	0.000	0.414	0.413	0.911		0.1	0.1	0.401		0.5
Water Heating	Multi Apartment-All	0.005	0.027	0.027	0.055		0.0	0.0	0.050	1.0	1.0

IS

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating			1.00				0.80	0.10	0.70	
Space Cooling										
Water Heating							0.20		0.30	
Lighting								0.20		
Cooking		1.00						0.20		
Refrigeration								0.12		
Cloth Washing								0.12		
Cloth Drying								0.02		
Dish Washing								0.05		
Other Electric								0.19		
Other Energy										

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural									0.0	
Space Heating	Single House-Urban			1.0				0.9	0.9	0.8	
Space Heating	Multi Apartment-All							0.1	0.1	0.2	
				1.0				1.0	1.0	1.0	
Space Cooling	Single House-Rural										
Space Cooling	Single House-Urban										
Space Cooling	Multi Apartment-All										
Water Heating	Single House-Rural										
Water Heating	Single House-Urban							0.88		0.85	
Water Heating	Multi Apartment-All							0.12		0.15	

IT

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.40	0.85	0.81	0.82	0.95	0.00	0.85	0.01	0.75	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.40	0.08	0.12	0.11	0.05	1.00	0.15	0.11	0.25	0.00
Lighting								0.17		
Cooking	0.20	0.07	0.08	0.07	0.00	0.00		0.05		
Refrigeration								0.11		
Cloth Washing								0.08		
Cloth Drying								0.02		
Dish Washing								0.02		
Other Electric								0.42		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.8	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Space Heating	Single House-Urban	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2		0.0
Space Heating	Multi Apartment-All	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	1.0	1.0
		1.0	1.0	1.0	1.0	1.0		1.0	1.0	1.0	
Space Cooling	Single House-Rural				0.1				0.1		
Space Cooling	Single House-Urban				0.2				0.2		
Space Cooling	Multi Apartment-All				0.7				0.7		
									1.0		
Water Heating	Single House-Rural	0.8	0.1	0.1	0.1	0.1	0.1	0.1	0.1		0.0
Water Heating	Single House-Urban	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2		0.0
Water Heating	Multi Apartment-All	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.7	1.0	1.0

KS

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	1.00		0.35		0.30			0.4500	1.00	
Space Cooling										
Water Heating			0.25		0.25			0.1700		
Lighting								0.0800		
Cooking			0.40		0.45			0.1500		
Refrigeration								0.0850		
Cloth Washing								0.0350		
Cloth Drying										
Dish Washing										
Other Electric								0.0300		
Other Energy										

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	1.0		0.7		1.0			0.7		
Space Heating	Single House-Urban										
Space Heating	Multi Apartment-All			0.3					0.3	1.0	
		1.0		**1.0**		**1.0**			**1.0**	**1.0**	
Space Cooling	Single House-Rural										
Space Cooling	Single House-Urban										
Space Cooling	Multi Apartment-All										
Water Heating	Single House-Rural			0.7		1.0			0.6		
Water Heating	Single House-Urban										
Water Heating	Multi Apartment-All			0.3					0.4		

LT

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.70	0.20	0.70	0.45	0.85	1.00	0.70	0.01	0.89	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.25	0.40	0.25	0.11	0.04	0.00	0.30	0.03	0.11	0.00
Lighting								0.12		
Cooking	0.00	0.40	0.00	0.44	0.11	0.00		0.14		
Refrigeration								0.11		
Cloth Washing								0.02		
Cloth Drying								0.01		
Dish Washing								0.01		
Other Electric								0.54		
Other Energy	0.05		0.05					0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.8	0.8	0.2	0.3	0.8			0.1		0.0
Space Heating	Single House-Urban	0.2	0.2	0.8	0.3	0.2		0.3	0.8	0.2	0.1
Space Heating	Multi Apartment-All	0.0	0.0	0.0	0.5	0.0		0.7	0.1	0.9	0.9
		1.0	**1.0**	**1.0**							
Space Cooling	Single House-Rural								0.3		
Space Cooling	Single House-Urban								0.2		
Space Cooling	Multi Apartment-All								0.5		
Water Heating	Single House-Rural	0.2	0.5	0.2	0.3	0.8			0.2	0.0	0.0
Water Heating	Single House-Urban	0.8	0.5	0.8	0.3	0.2			0.4	0.1	0.1
Water Heating	Multi Apartment-All	0.0			0.5	0.0		1.0	0.4	0.9	0.9

LU

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	1.00	0.70	0.74	0.65	0.75		1.00	0.03	1.00	1.00
Space Cooling								0.00		
Water Heating		0.10	0.10	0.10	0.10	1.00		0.10		
Lighting								0.19		
Cooking		0.20	0.15	0.20	0.15			0.03		
Refrigeration								0.11		
Cloth Washing								0.14		
Cloth Drying								0.10		
Dish Washing								0.02		
Other Electric								0.28		
Other Energy			0.01	0.05				0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.5	0.5	0.5	0.2	0.6			0.4		
Space Heating	Single House-Urban	0.5	0.5	0.4	0.5	0.4			0.5		
Space Heating	Multi Apartment-All	0.0	0.1	0.1	0.4	0.0			0.2	1.0	
Space Cooling	Single House-Rural								0.3		
Space Cooling	Single House-Urban								0.4		
Space Cooling	Multi Apartment-All								0.3		
Water Heating	Single House-Rural		0.4	0.3	0.3	1.0	1.0		0.3		
Water Heating	Single House-Urban		0.4	0.4	0.4	0.0			0.4		
Water Heating	Multi Apartment-All		0.2	0.3	0.3	0.0			0.3	1.0	

LV

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.84	0.10	0.70	0.54	0.83	0.00	0.00	0.04	0.72	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.16	0.50	0.30	0.20	0.12	0.00	0.00	0.17	0.28	0.00
Lighting								0.18		
Cooking	0.00	0.30	0.00	0.26	0.05	0.00		0.08		
Refrigeration								0.09		
Cloth Washing								0.02		
Cloth Drying								0.01		
Dish Washing								0.01		
Other Electric								0.39		
Other Energy		0.10						0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.4	0.4	0.1	0.0	0.6			0.1	0.0	0.0
Space Heating	Single House-Urban	0.6	0.4	0.1	0.0	0.2			0.2	0.0	0.1
Space Heating	Multi Apartment-All	0.0	0.2	0.9	1.0	0.2			0.7	1.0	0.9
Space Cooling	Single House-Rural								0.2		
Space Cooling	Single House-Urban								0.2		
Space Cooling	Multi Apartment-All								0.6		
									1.0		
Water Heating	Single House-Rural	0.3	0.4	0.0	0.0	0.4			0.0	0.0	0.0
Water Heating	Single House-Urban	0.7	0.3	0.1	0.0	0.3			0.1	0.0	0.1
Water Heating	Multi Apartment-All	0.0	0.3	1.0	1.0	0.4			0.9	1.0	0.9

ME

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating			0.75		0.75			0.31		
Space Cooling								0.00		
Water Heating			0.15		0.15			0.25		
Lighting								0.07		
Cooking			0.10		0.10			0.23		
Refrigeration								0.08		
Cloth Washing								0.05		
Cloth Drying										
Dish Washing										
Other Electric								0.01		
Other Energy										

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural			0.6		1.0			0.6		
Space Heating	Single House-Urban			0.0		0.0			0.0		
Space Heating	Multi Apartment-All			0.4					0.4		
Space Cooling	Single House-Rural										
Space Cooling	Single House-Urban								0.10		
Space Cooling	Multi Apartment-All								0.90		
Water Heating	Single House-Rural			0.9		1.0			0.5		
Water Heating	Single House-Urban			0.0		0.1			0.0		
Water Heating	Multi Apartment-All			0.1					0.5		

MK

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	1.00		0.55		0.90			0.2500	0.75	
Space Cooling								0.0030		
Water Heating			0.45					0.3000	0.25	
Lighting								0.1220		
Cooking		1.00			0.10			0.2100		
Refrigeration								0.0670		
Cloth Washing								0.0200		
Cloth Drying										
Dish Washing										
Other Electric								0.0280		
Other Energy										

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	1.0				0.7			0.1		
Space Heating	Single House-Urban			0.2		0.2			0.1		
Space Heating	Multi Apartment-All			0.8		0.1			0.8	1.00	
Space Cooling	Single House-Rural										
Space Cooling	Single House-Urban										
Space Cooling	Multi Apartment-All								1.00		
Water Heating	Single House-Rural								0.4		
Water Heating	Single House-Urban			0.2					0.1		
Water Heating	Multi Apartment-All			0.8					0.4	1.0	

MT

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.00	0.40	0.80	0.00	0.00	0.00	0.00	0.04	0.00	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.00	0.30	0.20	0.00	1.00	0.00	0.00	0.19	0.00	0.00
Lighting								0.15		
Cooking	0.00	0.30	0.00	0.00	0.00	0.00		0.07		
Refrigeration								0.03		
Cloth Washing								0.06		
Cloth Drying								0.02		
Dish Washing								0.02		
Other Electric								0.42		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural		0.1	0.1					0.1	0.0	
Space Heating	Single House-Urban		0.5	0.5					0.5		
Space Heating	Multi Apartment-All		0.5	0.5					0.5	1.0	
Space Cooling	Single House-Rural								0.0		
Space Cooling	Single House-Urban								0.5		
Space Cooling	Multi Apartment-All								0.5		
									1.0		
Water Heating	Single House-Rural		0.1	0.1					0.1		
Water Heating	Single House-Urban		0.5	0.5					0.5		
Water Heating	Multi Apartment-All		0.5	0.5					0.5		

NL

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	1.00	0.50	0.85	0.81	1.00	0.00	0.90	0.07	0.95	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.00	0.00	0.08	0.17	0.00	1.00	0.10	0.09	0.05	0.00
Lighting								0.15		
Cooking	0.00	0.20	0.08	0.03	0.00	0.00		0.04		
Refrigeration								0.09		
Cloth Washing								0.08		
Cloth Drying								0.06		
Dish Washing								0.01		
Other Electric								0.41		
Other Energy		0.30						0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.4500	0.4500	0.4500	0.4500	0.4500	0.0	0.4500	0.4500	0.0	0.2
Space Heating	Single House-Urban	0.2750	0.2750	0.2750	0.2750	0.2750	0.0	0.2750	0.2750	0.5	0.5
Space Heating	Multi Apartment-All	0.2750	0.2750	0.2750	0.2750	0.2750	0.0	0.2750	0.2750	0.5	0.3
Space Cooling	Single House-Rural								0.4		
Space Cooling	Single House-Urban								0.3		
Space Cooling	Multi Apartment-All								0.3		
Water Heating	Single House-Rural	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.2	0.2
Water Heating	Single House-Urban	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.5	0.5
Water Heating	Multi Apartment-All	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.3	0.3

NO

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	1.00	0.83	0.85	0.83	1.00			0.50	0.85	
Space Cooling								0.01		
Water Heating	0.00	0.10	0.15	0.10				0.25	0.15	
Lighting								0.06		
Cooking	0.00	0.07		0.07				0.03		
Refrigeration								0.03		
Cloth Washing								0.02		
Cloth Drying								0.02		
Dish Washing								0.02		
Other Electric								0.06		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural		0.22	0.22	0.22	0.22			0.22		
Space Heating	Single House-Urban	1.0	0.30	0.30	0.30	0.30			0.30	0.10	
Space Heating	Multi Apartment-All		0.48	0.48	0.48	0.48			0.48	0.90	
Space Cooling	Single House-Rural								0.22		
Space Cooling	Single House-Urban								0.30		
Space Cooling	Multi Apartment-All								0.48		
									1.0		
Water Heating	Single House-Rural		0.22	0.22	0.22				0.22	0.22	
Water Heating	Single House-Urban		0.30	0.30	0.30				0.30	0.30	
Water Heating	Multi Apartment-All		0.48	0.48	0.48				0.48	0.48	

PL

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.95	0.85	0.85	0.75	0.85	0.10	0.85	0.08	0.85	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.05	0.15	0.15	0.10	0.15	0.90	0.15	0.09	0.15	0.00
Lighting								0.17		
Cooking	0.00	0.00	0.00	0.15	0.00	0.00		0.14		
Refrigeration								0.06		
Cloth Washing								0.07		
Cloth Drying								0.00		
Dish Washing								0.03		
Other Electric								0.35		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.5	0.5	0.4	0.4	0.5	0.9	0.5	0.2	0	0.0
Space Heating	Single House-Urban	0.5	0.5	0.5	0.5	0.5	0.1	0.5	0.2	0.2	0.0
Space Heating	Multi Apartment-All	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.6	0.8	1.0
Space Cooling	Single House-Rural								0.3		
Space Cooling	Single House-Urban								0.4		
Space Cooling	Multi Apartment-All								0.3		
									1.0		
Water Heating	Single House-Rural	0.5	0.5	0.4	0.5	0.5	0.5	0.5	0.4		0.0
Water Heating	Single House-Urban	0.5	0.5	0.4	0.5	0.5	0.5	0.5	0.4	0.5	0.0
Water Heating	Multi Apartment-All	0.0	0.0	0.2	0.1	0.0	0.0	0.0	0.2	0.5	1.0

PT

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.00	0.02	0.26	0.03	0.51	0.02	0.00	0.09	1.00	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.00	0.42	0.74	0.62	0.07	0.98	0.00	0.02	0.00	0.00
Lighting								0.09		
Cooking	0.00	0.57	0.00	0.35	0.41	0.00		0.41		
Refrigeration								0.06		
Cloth Washing								0.08		
Cloth Drying								0.02		
Dish Washing								0.03		
Other Electric								0.19		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural		0.3	0.4	0.1	0.7	0.3		0.1	0.0	0.0
Space Heating	Single House-Urban		0.2	0.3	0.2	0.1	0.5		0.4		0.0
Space Heating	Multi Apartment-All		0.5	0.3	0.7	0.2	0.2		0.5	1.0	1.0
Space Cooling	Single House-Rural				0.0				0.2		
Space Cooling	Single House-Urban				0				0.4		
Space Cooling	Multi Apartment-All				0.0				0.5		
									1.0		
Water Heating	Single House-Rural		0.5	0.4	0.1	0.8	0.3		0.2		
Water Heating	Single House-Urban		0.2	0.3	0.4	0.2	0.5		0.3		
Water Heating	Multi Apartment-All		0.3	0.3	0.5	0.0	0.2		0.5		

RO

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.81	0.10	0.28	0.30	0.65	0.10	1.00	0.05	0.78	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.19	0.30	0.28	0.12	0.10	0.90	0.00	0.01	0.22	0.00
Lighting								0.13		
Cooking	0.00	0.60	0.44	0.58	0.25	0.00		0.00		
Refrigeration								0.09		
Cloth Washing								0.15		
Cloth Drying								0.03		
Dish Washing								0.01		
Other Electric								0.50		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.8	0.0	0.0	0.8	0.8	0.5	0.1	0.0	0.0	0.0
Space Heating	Single House-Urban	0.3	0.4	0.4	0.1	0.2	0.5	0.1	0.4	0.1	0.1
Space Heating	Multi Apartment-All	0.0	0.7	0.7	0.2	0.0	0.0	0.8	0.6	0.9	0.9
Space Cooling	Single House-Rural				0.0				0.5		
Space Cooling	Single House-Urban				0				0.2		
Space Cooling	Multi Apartment-All				0.0				0.4		
									1.0		
Water Heating	Single House-Rural	0.8	0.0	0.0	0.8	0.8	0.5	0.1	0.0	0.0	0.0
Water Heating	Single House-Urban	0.3	0.4	0.4	0.1	0.2	0.5	0.1	0.4	0.1	0.1
Water Heating	Multi Apartment-All	0.0	0.7	0.7	0.2	0.0	0.0	0.8	0.6	0.9	0.9

RS

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.90		0.62	0.60	0.80			0.12	0.76	
Space Cooling								0.003		
Water Heating			0.18	0.20	0.10			0.19	0.24	
Lighting								0.108		
Cooking	0.10		0.20	0.20	0.10			0.19		
Refrigeration								0.133		
Cloth Washing								0.10		
Cloth Drying								0.025		
Dish Washing								0.011		
Other Electric								0.120		
Other Energy										

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	1.0				1.0			0.4		
Space Heating	Single House-Urban	0.1		0.1	0.1				0.1		
Space Heating	Multi Apartment-All			0.9	0.9				0.6	1.0	
Space Cooling	Single House-Rural										
Space Cooling	Single House-Urban								0.08		
Space Cooling	Multi Apartment-All								0.92		
Water Heating	Single House-Rural			0.8		1.0			0.80		
Water Heating	Single House-Urban			0.1	0.0	0.0			0.02		
Water Heating	Multi Apartment-All			0.2	1.0				0.18	1.0	

SE

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.00	0.00	0.72	0.48	0.88	0.00	0.00	0.29	0.82	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.00	0.00	0.29	0.40	0.12	0.00	0.00	0.03	0.18	0.00
Lighting								0.09		
Cooking	0.00	0.00	0.00	0.12	0.00	0.00		0.04		
Refrigeration								0.04		
Cloth Washing								0.04		
Cloth Drying								0.03		
Dish Washing								0.03		
Other Electric								0.39		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural			0.62	0.32	0.95		0.80	0.75	0.01	0.10
Space Heating	Single House-Urban			0.20	0.20	0.05		0.20	0.20	0.20	0.03
Space Heating	Multi Apartment-All	0.0		0.18	0.5	0.00		0.00	0.1	0.8	0.87
Space Cooling	Single House-Rural								0.3		
Space Cooling	Single House-Urban								0.1		
Space Cooling	Multi Apartment-All								0.5		
Water Heating	Single House-Rural			0.5	0.3	0.9	0.9		0.6		0.1
Water Heating	Single House-Urban			0.4	0.2	0.1	0.1		0.2	0.0	0.0
Water Heating	Multi Apartment-All			0.1	0.5	0.0			0.2	1.0	0.9

SI

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.50	0.45	0.84	0.75	0.83	0.00	0.85	0.03	0.78	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.47	0.45	0.17	0.20	0.15	1.00	0.15	0.20	0.22	0.00
Lighting								0.09		
Cooking	0.03	0.10	0.00	0.05	0.02	0.00		0.04		
Refrigeration								0.05		
Cloth Washing								0.08		
Cloth Drying								0.02		
Dish Washing								0.02		
Other Electric								0.46		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.700	0.400	0.500	0.000	0.800		0.000	0.500		0.00
Space Heating	Single House-Urban	0.200	0.100	0.200	0.400	0.200		0.000	0.400		0.00
Space Heating	Multi Apartment-All	0.100	0.500	0.300	0.600	0.000		1.000	0.100	1.0	1.00
Space Cooling	Single House-Rural							0.000	0.485		
Space Cooling	Single House-Urban							0.000	0.208		
Space Cooling	Multi Apartment-All							0.000	0.308		
Water Heating	Single House-Rural	0.600	0.600	0.600	0.000	0.650	0.700	0.000	0.550		0.00
Water Heating	Single House-Urban	0.100	0.100	0.100	0.400	0.350	0.200	0.100	0.250		0.00
Water Heating	Multi Apartment-All	0.300	0.300	0.300	0.600	0.000	0.100	0.900	0.200	1.0	1.00

UK

Breakout by end-use (Fractional Shares)

End-use description	Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	0.77	0.73	0.00	0.79	0.77	0.50	1.00	0.16	0.00	0.00
Space Cooling				0.00			0.00	0.01		
Water Heating	0.22	0.23	1.00	0.19	0.22	0.50	0.00	0.10	0.00	0.00
Lighting								0.14		
Cooking	0.00	0.04	0.00	0.02	0.00	0.00		0.06		
Refrigeration								0.05		
Cloth Washing								0.05		
Cloth Drying								0.05		
Dish Washing								0.01		
Other Electric								0.37		
Other Energy								0.00		

Breakout by end-use (Fractional Shares)

End-use description		Coal	LPG	Oil	Gas	Bio	Solar	Geo	Elec	LTH	HTH
Space Heating	Single House-Rural	0.70	0.18	0.40	0.02	0.50	0.33	0.00	0.30	0.00	
Space Heating	Single House-Urban	0.30	0.82	0.60	0.70	0.50	0.33	0.20	0.69		
Space Heating	Multi Apartment-All				0.28		0.33	0.80	0.01	1.00	1.00
		1.00	1.00		1.00	1.00	1.00	1.00	1.00		
Space Cooling	Single House-Rural								0.08		
Space Cooling	Single House-Urban								0.70		
Space Cooling	Multi Apartment-All								0.22		
									1.00		
Water Heating	Single House-Rural	0.16	0.18		0.08	0.40			0.10		
Water Heating	Single House-Urban	0.84	0.82	1.00	0.67	0.60		0.12	0.65		
Water Heating	Multi Apartment-All				0.25			0.88	0.25	1.00	1.00

16.11 Annex XI – List of nuclear power plants considered under discussion

ENBG_BELENE-1

ENBG_BELENE-2

ENBG_KOZLODUY-7

ENCZ_DUKOVANY-5

ENCZ_TEMELIN-3

ENCZ_TEMELIN-4

ENFI_OLKILUOTO-3

ENFI_OLKILUOTO-4

ENFI_PYHA-YOKI

ENFR_FLAMANVILLE-3

ENFR_PENLY-3

ENHU_PAKS-5

ENHU_PAKS-6

ENLT_IGNALINA-1

ENLT_IGNALINA-2

ENLT_VISAGINAS-1

ENNL_BORSSELE-2

ENPL_POLAND-1

ENPL_POLAND-2

ENRO_CERNAVODA-2

ENRO_CERNAVODA-3

ENRO_CERNAVODA-4

ENRO_CERNAVODA-5

ENSI_KRSKO-2

ENSK_BOHUNICE-NEWBLOCK

ENSK_KECEROVCE

ENSK_MOCHOVCE-3

ENSK_MOCHOVCE-4

ENUK_HINKLEYPOINT-C1

ENUK_HINKLEYPOINT-C2

ENUK_MOORSIDE

ENUK_OLDBURY-B

ENUK_SIZEWELL-C1

ENUK_SIZEWELL-C2

ENUK_WYLFA-B

16.12 Annex XII – Stringency of the RES potentials

Legend:

Green	Potential not fully exploited
Red	Potential fully exploited
	Not applicable

Maximum Conventional Hydro Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
AT	Red	Green	Green	Green	Green	Green	Green	Green	Red	Green	Green	Red	Green	Green	Green	Green
BE	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Green	Green	Red
BG	Green	Red	Red	Green	Red	Green	Red	Red	Green	Green	Green	Green	Green	Green	Green	Green
CH	Red	Green	Red	Green	Red	Red	Red	Red	Red	Red	Red	Green	Red	Red	Red	Red
CY	Red	Red	Red	Red	Red	Red	Red	Green	Red	Green	Green	Green	Green	Red	Green	Green
CZ	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Green	Red	Red	Red	Red
DE	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red
DK	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red
EE	Green	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red
ES	Red	Red	Red	Green	Red	Red	Red	Red	Red	Green	Red	Green	Green	Red	Red	Red

Maximum Conventional Hydro Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
FI																
FR																
GR																
HR																
HU																
IE																
IS																
IT																
LT																
LU																
LV																
MT																
NL																
NO																
PL																
PT																
RO																
SI																
SE																
SK																

Maximum Conventional Hydro Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
UK																

Hydro S + L

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
AT																
BE																
BG																
CH																
CY																
CZ																
DE																
DK																
EE																
ES																
FI																
FR																
GR																
HR																

Hydro S + L

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
HU																
IE																
IS																
IT																
LT																
LU																
LV																
MT																
NL																
NO																
PL																
PT																
RO																
SE																
SI																
SK																
UK																

Maximum Hydro run of river Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
AT																
BE																
BG																
CH																
CY																
CZ																
DE																
DK																
EE																
ES																
FI																
FR																
GR																
HR																
HU																
IE																
IS																
IT																
LT																
LU																

Maximum Hydro run of river Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
LV																
MT																
NL																
NO																
PL																
PT																
RO																
SE																
SI																
SK																
UK																

Maximum Wind Onshore Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
AT																
BE																
BG																
CH																

Maximum Wind Onshore Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
CY																
CZ																
DE																
DK																
EE																
ES																
FI																
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GR																
HR																
HU																
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IT																
LT																
LU																
LV																
MT																
NL																
NO																

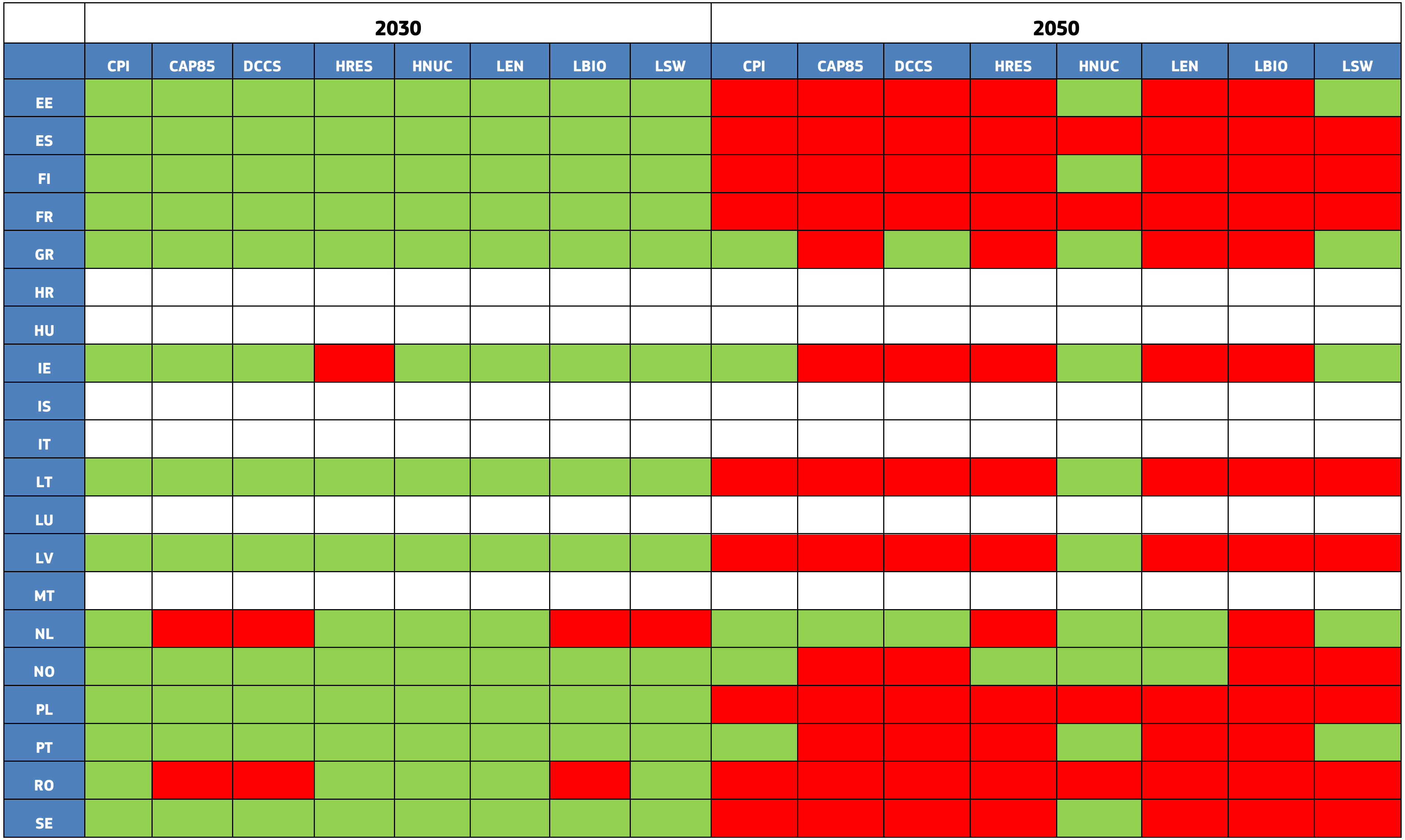
Maximum Wind Onshore Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
PL																
PT																
RO																
SE																
SI																
SK																
UK																

Maximum Wind Offshore Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
AT																
BE																
BG																
CH																
CY																
CZ																
DE																
DK																

Maximum Wind Offshore Capacity



Maximum Wind Offshore Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
SI																
SK																
UK																

Maximum solar PV Production

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
AT																
BE																
BG																
CH																
CY																
CZ																
DE																
DK																
EE																
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Maximum solar PV Production

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
GR																
HR																
HU																
IE																
IS																
IT																
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LU																
LV																
MT																
NL																
NO																
PL																
PT																
RO																
SE																
SI																
SK																
UK																

Maximum Solar Thermal Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
AT																
BE																
BG																
CH																
CY																
CZ																
DE																
DK																
EE																
ES																
FI																
FR																
GR																
HR																
HU																
IE																
IS																
IT																
LT																
LU																

Maximum Solar Thermal Capacity

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
LV																
MT																
NL																
NO																
PL																
PT																
RO																
SE																
SI																
SK																
UK																

Maximum Geothermal Total Production

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
AT																
BE																
BG																
CH																

Maximum Geothermal Total Production

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
CY																
CZ																
DE																
DK																
EE																
ES																
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HR																
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LU																
LV																
MT																
NL																
NO																

Maximum Geothermal Total Production

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
PL																
PT																
RO																
SE																
SI																
SK																
UK																

Maximum Wave & Tide Production

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
AT																
BE																
BG																
CH																
CY																
CZ																
DE																

Maximum Wave & Tide Production

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
DK																
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NO																
PL																
PT																
RO																

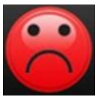
Maximum Wave & Tide Production

	2030								2050							
	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW	CPI	CAP85	DCCS	HRES	HNUC	LEN	LBIO	LSW
SE																
SI																
SK																
UK																

16.13 Annex XIII – Questions & answers regarding the JRC-EU-TIMES model adequacy filled during the model validation workshop

During the JRC-EU-TIMES model external validation workshop of November 2013 a series of questions were asked to the experts regarding both the model and data appropriateness, as it stood at the date of the workshop. In this annex these questions and replies are summarized in the following tables. The replies to the questions were qualitative following the colour code as in the next table.

Table 109 – Code used to reply the questions during the JRC-EU-TIMES model validation workshop

Statement	Code
Strongly disagree	
Disagree	
Neither agree or disagree	
Agree	
Strongly agree	

1. Modelling mechanisms: Are the JRC-EU-TIMES model status and mechanisms appropriate for assessing the role of energy technologies and their innovation for meeting Europe's energy and climate change related policy objectives?

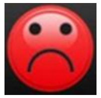
Table 110 – Questions & Answers on modelling mechanisms

Item	Model appropriate?	Qualitative statement
1. Primary and final energy demand		Evident from the model philosophy: flow based.
2. Calibration (data)		Base year Final Energy Consumption deviates less than 10% from EUROSTAT which is favourable when compared with other models (although still 2005 could be improved). The years following the base year should be improved. In future consider going to 2010 to gain time when running the model.
3. Energy investments and modelling dynamics		The model has an investment decision for each technology but additional effort is needed for realistic growth rates for some technologies (data)
4. Power and heat generation in the overall supply system; analysis of linkages between the electricity and heat markets		Interaction between power producing technologies, between power and heat as well as between sectors is covered.
5. Infrastructure and grid representation in modelling, interconnections and intra-EU trade		No geographical coverage except countries. Represents the physical flows depending on the grid characteristics and loads/injection patterns of the different countries in all time slices. Power market analysis, power system security via link with dispatch models would be good approach. Nonetheless the experts found the current model is good when compared with other energy system models.

Item	Model appropriate?	Qualitative statement
6. Long term price formation of energy services and recovery of costs with a focus on electricity		Both a market for electricity and capacity could be implemented. All costs are always recovered. The pricing mechanism is as if perfect real time pricing. There are limitations regarding time resolution and not all possible future market segments are represented (e.g. ancillary services). Security of supply is taken into account in the long term price.
7. Price reaction of consumers		Price elasticity of energy service has a strong theoretical basis. Data feed is a problem.
8. Perfect foresight versus myopic view		Model can cope with both.
9. Modelling variable electricity and storage. This is also related to modelling flexibility measures: larger balancing areas, demand side response and flexibility of the various electricity generation technologies.		The JRC-EU-TIMES is able to analyse storage options although in a simplified way at the moment. This is due to the rough time resolution and the no consideration of operational constraints. That is, the model does not take into account a flexibility target and flexibility of the various electricity technologies (ramp up, etc.). Can be changed via constraints. Load shape is currently not shifted, but it could be modelled. Good possibility to reflect investment decisions on whole system.
10. Technology learning		Endogenous learning possible (OFL), but not implemented now. Model is European but technologies can be in a global market. However the model is being linked with a global model.
11. Bio-energy (biofuels) modelling		Data for biomass import needs to be improved.

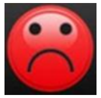
Item	Model appropriate?	Qualitative statement
12. Land use competition modelling		Competition with land-use is included in simplified format via supply curve. It is not endogenous at the moment which is very relevant for addressing competition with agriculture. This is feasible with TIMES models.
13. CCS: modelling of capture, transport and storage of energy and process emissions		Capture is appropriately represented. Transport infrastructure is not covered in detail due to low geographic representation.
14. Translation of policy measures into modelling parameters (energy efficiency, security of supply)		Modelling of energy efficiency policies could be improved, such as explicit modelling of insulation which needs to some extant to be exogenously calculated.
15. Modelling and role of hydrogen infrastructure	 	Hydrogen: OK. Hydrogen infrastructure: no detailed representation so far due to low geographic resolution.
16. Energy security		The model is adequate for EU level, energy security definition is crucial and has been done (see REACCESS EU research project). Having the gas grid represented in the model would enhance its capabilities to assess this topic.
17. Climate impacts on the energy system / adaptation focus		Not existing now. It can be implemented but requires substantial work (it has been done with global TIMES model, TIAM)
18. Uncertainties (technology, resource prices, macroeconomic influences, policy)		Sensitivities covered should be complemented with investment cost analysis. Model features, including running time, allow for several different approaches to treat uncertainties including Monte Carlo analysis and running in stochastic mode.

Item	Model appropriate?	Qualitative statement
19. Transport system (more specific energy demand of transport)		The model does not detail aviation and navigation. Decisions in the transport sector are not usually due to cost minimisation. Geographical resolution is low. No modal shifts. However, for technology it is appropriate.
19. Consideration of externalities other than GHG, air pollutants, and water use.		Could be included like it is for GHG; work to do on mitigation. Land use is more complicated but we see a strong link with the modelling of renewables (see specific question for this).
20. Consideration of externalities CO_2 emissions and other GHG gases.		The model has very good representation of GHG emissions.
21. Modelling of CHP in the public and industry sector		Difficulty for CHP is the small cost difference with dedicated production of heat and electricity. Different temperature levels within industry not considered.
22. Depiction (approximation) of spatial aspects/constraints for generation within a country		An example for Austria showed this is feasible. We are striving to include detailed cost supply curves for RES in the short term.
23. Sensitivity analysis (especially on characteristics of new technologies to illustrate technology improvements needed)		See previous
24. Long term CO_2 targets		The model is very suited for long term analysis of mitigation pathways.

Item	**Model appropriate?**	**Qualitative statement**
25. Short term ETS CO_2 emissions reductions targets & burden sharing ETS/non ETS		To be improved is the definition of smaller emitters in ETS and banking and offset within EU ETS. Whereas banking will be difficult to include, offset is feasible. This is especially relevant for short term analysis.
26. Behavioural aspects of consumers		Only via price elasticity and perceived discount rates.
27. Modelling approach for financial incentives especially for renewables		Very good at technology implementation level, but is not possible to link the incentive with effect in consumer price.

2. Modelling assumptions/data: Are the modelling assumptions plausible / do we use the best possible data ?

Table 111 – Questions & Answers on data and assumptions

Item	Data appropriate?	Qualitative statement
1. Assumptions on capital costs for present and future power generation, cost developments and learning rates		Good. For a few technologies data will be reviewed.
2. Decommissioning pathways and economics of lifetime extension		For electricity plants: advanced implementation of fixed costs being built up. Other technologies: lifetime often too close to assumed technical lifetime.
3. Sustainable bio-energy potential and way of sectoral allocation (linked to 1.9)		Need to improve transparency.
4. Transport systems and parameters used for electro-mobility (battery costs, recharging systems, etc.)		For a few technologies data will be reviewed.
5. Renewables potentials		Based on political rather than technical potential. Mainly wind, solar and geothermal potentials need to be revised.
6. Buildings data		Need to be updated. Example is the demolition rate.

Item	**Data appropriate?**	**Qualitative statement**
7. Electricity storage and grids		Link to dispatch model is important. Some data needs to be reviewed in stand-alone mode (only JRC-EU-TIMES). Grids (cost) could be improved as data is scarce.
8. Discount rates		Current values ok, can be changed very easily.
9. CO_2 storage potential – effective and theoretical and costs.		Some values could be improved (e.g. for Germany). Maybe could be important to have conservative (only onshore) and optimistic scenario (all options).
10. Assumptions on policy measures (like nuclear deployment, CCS, deployment of end-use technologies)		Very easy to change. Transparent.
11. District heat grids		Would be good to have peak equation for heat (model, not data). Assess if costs for grid could be made explicit (disaggregate?). Include cost curves if data is available.
12. Energy saving potentials/measures as well as their costs in the end-use sectors (related to how energy savings are modelled)		Implicitly in the model via two mechanisms: technology improvement and reduction of energy services demand.
13. Demand-side response potentials and costs		Cost of DSM campaigns can be included, as well as insulation. The same applies for endogenously shifting demand across time-slices.

Item	**Data appropriate?**	**Qualitative statement**
14. Electricity and (district) heat load curves (or ideally energy service load curves)		The more time slices the better.
15. Quantification of data uncertainties		Data is often subject to large uncertainty. This is intrinsic to all these type of models. To deal with this sensitivities are run. Variation of 20% used in the sensitivities is too little; a wider range of variations should be considered. Need to identify range of variation in critical technological parameters (e.g. low and high cost of energy technologies). Need to know which data is highly uncertain.
16. Macro-economic assumptions (international energy prices, GDP, useful energy demand forecast)		This is the best available at the moment considering need to ensure internal JRC coherence. These will be periodically reviewed. Could be improved with supply curve for primary energy import prices (carbon dependent), i.e. use two different sets of prices.

European Commission

EUR 26292 – Joint Research Centre – Institute for Energy and Transport

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Abstract

The JRC-EU-TIMES model is one of the models currently pursued in the JRC under the auspices of the JRC Modelling Taskforce. The model has been developed over the last years in a combined effort of two of the JRC Institutes, IPTS and IET. The JRC-EU-TIMES model is designed for analysing the role of energy technologies and their innovation for meeting Europe's energy and climate change related policy objectives. It models technologies uptake and deployment and their interaction with the energy infrastructure including storage options in an energy systems perspective. It is a relevant tool to support impact assessment studies in the energy policy field that require quantitative modelling at an energy system level with a high technology detail. This report aims at providing an overview on the JRC-EU-TIMES model main data inputs and major assumptions. Furthermore, it describes a number of model outputs from exemplary runs in order to display how the model reacts to different scenarios. The scenarios described in this report do not represent a quantified view of the European Commission on the future EU energy mix.

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