Preparatory study on Smart Appliances

Task 5

VITO: Ana Virag, Helena Gerard, Daan Six

Project management: Sarah Bogaert

Study accomplished under the authority of the European Commission DG Energy
under framework contract ENER.C3.2012-418-lot 1
2014/TEM/R/

Version: 20 May 2016

VITO NV
Boeretang 200 - 2400 MOL - BELGIE
Tel. + 32 14 33 55 11 - Fax + 32 14 33 55 99
vito@vito.be - www.vito.be

BTW BE-0244.195.916 RPR (Turnhout)
Bank 375-1117354-90 ING
BE34 3751 1173 5490 - BBRUBEBB

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS

AC	Air Conditioning
ADSL	Asymmetric Digital Subscriber Line
BAT	Best Available Technology
BRP	Balancing Responsible Parties
CFL	compact fluorescent light
CHP	Combined Heat and Power
DHW	Domestic Hot Water
DOCSIS	Data Over Cable Service Interface Specification
DR	Demand response
DSO	Distribution System Operators
ETSI	European Telecommunications Standards Institute
EV	Electric vehicle
GLS	general lighting service 'incandescent'
GSM	Global System for Mobile Communications
GW	Gigawatt
HEG	Home Energy Gateway
HID	high intensity discharge lamp
HVAC	Heating, Ventilation and Air Conditioning
LED	light emitting diode
LFL	linear fluorescent lamp
LTE	3GPP Long Term Evolution (4G)
M2M	Machine to Machine
NRVU	Non-Residential Ventilation Units
PLC	power line communication
PV	Photovoltaic
RES	Renewable Energy Sources
RVU	Residential Ventilation Units
SAREF	Smart Appliances REFerence ontology
SOC	State Of Charge
TSO	Transmission System Operators
TWh	Terawatt hour
UMTS	Universal Mobile Telecommunications System
UPS	Uninterruptible power supply
VDSL	Very-high-bitrate Digital Subscriber Line
VRF	variable refrigerant flow

TASK 5 ENVIRONMENT & ECONOMICS– DEFINITION OF BASE CASES

Following the MEErP Methodology for Energy related products, Task 5 should describe the environmental impact of the base-case product life cycle, the product life cycle impacts of new products entering the market and the annual impacts of the existing products. These impacts are expressed in base-case environmental impact data (usually by means of the Bill-of-Materials at the level of the EcoReport Unit Indicators, annual resources consumption and direct emissions during product life and at end-of-life) and the accompanying life cycle cost data on EU level.

The individual products in the scope of this Lot 33 Preparatory Study are products that almost all are subject to vertical regulations; however this Preparatory Study specifically addresses the implications underlying the connectivity and demand side flexibility (DSF) functionality aspect of these products. These environmental and economic implications need to be considered on two different levels. On the one hand, the DSF functionality will have implications on the level of the individual product and the network in which the product functions (see Task 4). On the other hand, the aggregated DSF that potentially can be provided by a whole group of smart appliances gives rise to environmental and economic benefits which go beyond the product level and can be found at the level of the entire energy system. If we would limit the study to the usual MEErP base-case environmental and economic impact data, we would keep these system impacts out of consideration.

Smart appliances can provide balancing services by shifting operation, thereby adapting the consumption to short term positive or negative discrepancies between forecasted and real generation by intermittent energy sources. Such activities may not reduce electricity consumption in total; however the optimised use of renewable energy reduces the need of conventional energy peaking generation and provision of conventional balancing capacities being linked to inefficient part load operation of conventional plants. This therefore provides both monetary savings by less consumption of fuel as well as reduced CO2 emissions, which in the framework of the ETS not only has an environmental but also an economic value.

In Task 6 and 7 these benefits are evaluated, but before such an evaluation can be done, the approach needs to be defined how these impacts will be quantified and a reference needs to be set as a point of comparison. Therefore, the goal of Task 5 is to define the base cases which serve as a reference case for the evaluation of the future environmental and economic costs and benefits in case more flexibility of the energy demand is achieved under various scenarios. These base cases assume a situation in which no flexibility is available from smart appliances. This means that for the reference scenario we make abstraction of the limited ongoing Demand response (DR) practices in the scope of this Lot 33 Preparatory Study (residential and commercial segments as defined in Task 1) and which are described in Task 2.

In order to quantify the economic and environmental benefits of smart appliances from an energy system perspective, the following key performance indicators (KPIs) are considered relevant:

1. KPI1: Economic value in terms of total energy system costs. This KPI quantifies the avoided costs related to the more efficient use of the energy system following the achieved flexibility.
2. KPI2: Total amount of CO_2 emissions over the considered period. This KPI quantifies part of the environmental benefits of decreased utilization of the less efficient and more CO_2 emitting peaking power plants in the system.

3. KPI3: Energy efficiency of the utilized generation mix over the considered period. This KPI more specifically indicates the increased share of Renewable Energy Sources (RES) integrated in the generation mix, and decrease in utilization of low efficient, often peaking, generating units. Energy efficiency of the utilized generation mix as defined here is related to the primary energy savings in the electricity production. It is not related to e.g. decrease in total consumption due to more efficient energy utilization.

A generic optimisation tool and a model were developed for the purpose of this study to assess the value of flexibility from the smart appliances by means of these KPIs. To quantify the KPIs, the model is run over a time horizon of one year for each of the three chosen benchmark years: 2014, 2020, and 2030. Specifically for the use cases defined in Task 2 (day-ahead use case and imbalance use case), the results of the KPIs will be compared for a situation without flexibility provided by smart appliances (Task 5) and a situation in which a part of these appliances (ones with medium and high potential as identified in Task 3 and for which data are available from Task 2) become smart, thus providing flexibility to the energy system (Task 6 and 7).

The task 5 report is structured as follows: section 0 gives an overview of the developed model functionalities. Next, section 5.2 introduces the input data utilized in the model and gives an overview of all data sources. In section 5.3, the calculation of the KPIs is described in detail. All the modelling and data assumptions are summarized at the end of this section in 5.2.7. In Section 5.4, the respective results for the three benchmark years are presented.

Note that apart from the benefits related to the use of flexibility from an energy system perspective, other benefits and costs are relevant from an end-user perspective (e.g. potential higher price of products and/or remuneration for available flexibility, potential impact on energy consumption of products) and from an industry perspective (e.g. costs related to redesign of products, new business opportunities). These impacts have been described in previous reports (mainly Task 4) and as they relate to impacts in a situation with flexibility, will be summarised and discussed in Task 6 and 7.

5.1 Assessment model description

5.1.1. Definition of the model

A generic optimisation tool and a model were developed for the purposes of this study to assess the value of flexibility from the smart appliances. This section explains the model in more detail.

The utilized model is an extension of the unit commitment (UC) model described in [1]. The model is utilized to determine the optimal scheduling of a given set of power plants, for the specified input data, as presented in Figure 1 Overview of inputs and outputs of the utilized model. Optimality is defined in terms of minimizing the total costs over the considered time period.

The total costs are defined as the sum of fuels costs, variable operational and maintenance costs, ramping costs, start-up and shut-down costs for generator units, CO_2 emission costs, RES curtailment costs, and costs of loss of load.
The model takes into account the technical constraints of each type of generation technology, transmission system constraints, and also the energy balance constraints.

The modelled technical characteristics of generation units include maximal ramp up rate, ramp down rate, maximal power output, minimal power output, minimal down time, minimal up time, CO_2 emissions per produced MWh, etc.

Due to the technical constraints of generation technologies, such as minimum time down or up, unit commitment models belong to the class of mixed integer linear programs (MILP). For this class of problems, off-the-shelve solvers exist.

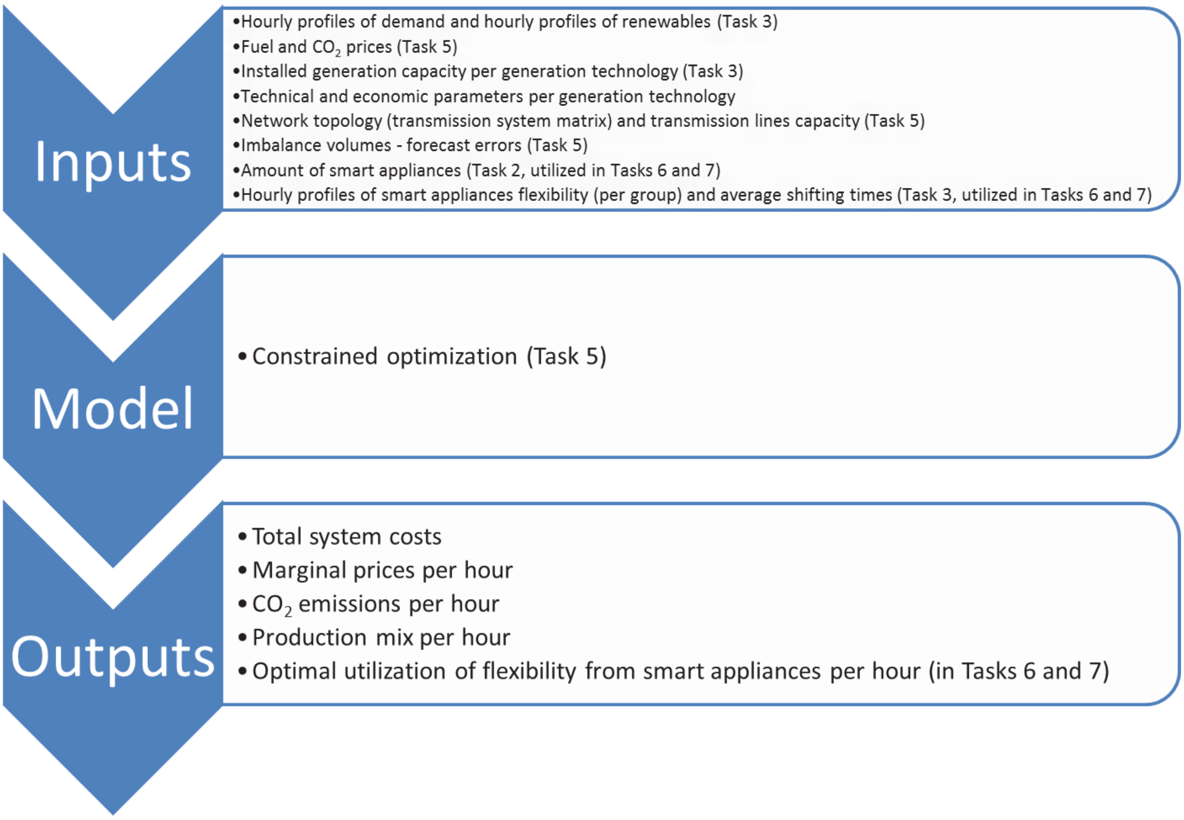

Figure 1 Overview of inputs and outputs of the utilized model.

The transmission system network within EU-28 area is modelled by means of the net transfer capacity (NTC) matrix[1]. The NTC values represent an estimation of the transmission capacities of the joint interconnections on a border between two neighbouring countries. The exchange of energy between two neighbouring countries cannot be larger than the NTC specified value.

The number of existing power plants in EU-28 mounts up to several hundreds. It is computationally demanding to solve MILP problems for a large number of variables and constraints, i.e., for a large number of power plants (generation units). Therefore, to reduce the modelling and computational effort, there is one representative generation unit modelled per generation type per member state. The generation unit has maximal capacity equivalent to the aggregated capacity of this technology type within EU-28 area. This results in a negligible error in the computed utilized power generation mix, total system costs, and CO_2 emissions. Other technical characteristics are typical for the given technology and taken from literature, [2].

[1] www.entsoe.eu/publications/market-reports/ntc-values/ntc-matrix/Pages/default.aspx

The model captures the European electricity system with an hourly time resolution. In total, 28 countries are included in the model.

The model utilizes as input the hourly data of the total demand per EU-28 member state, and profiles of renewable energy sources (wind and solar power production) per EU-28 member state. Next to this, in the imbalance use case, it is necessary to feed the hourly imbalance volumes, i.e., forecast errors in the model.
Next to this information, to run the model, it is necessary to define the fuel and CO_2 prices, installed generation capacity per generation technology per EU-28 member state, network topology and transmission lines capacity of the EU-28 interconnected power system, and lastly, technical and economic parameters per generation technology.

The model will result in several relevant indicators for assessment of benefits of smart appliances flexibility, such as: the total system costs, marginal electricity prices per hour, CO_2 emissions per hour, utilized production mix to serve demand (per hour), and eventually, if smart appliances are modelled, the optimal utilization of flexibility from smart appliances per hour (only in Task 6).

The EU targets on integrated energy markets and the expansion of international grid control cooperation (IGCC) mechanism implementation (see section 2.3.1 of Task 2 report), indicate that the European electricity network is developing towards a more integrated system. Therefore, a general assumption of the model is that there exists an integrated European Energy market, as explained in Task 2 report. As a result, the energy system of EU28 is modelled as one integrated market, still considering the limitations of the transmission network system.

Depending on the defined input assessment data, the model can represent the European electricity system in the benchmark years 2014, 2020 or 2030.

For the purposes of this study, the considered period for optimization is defined to be a period of 1 year (8760 hours). The utilized temporal resolution is 1 hour, which is also in line with the electricity market resolution.

The identified use cases from Task 2 are the day-ahead use case and imbalance use case. For the imbalance use case, the hourly forecast errors, which are the main imbalance driver, have to be modelled. We describe the developed approach in the following section.

5.1.2. MODELLING THE IMBALANCE VOLUMES

Imbalances in power systems are defined as the real-time differences in instantaneous power production and consumption. Imbalances are caused by the forecast errors of hourly demand profiles and intermittent RES production; see also section 2.3.1 for a more detailed discussion on the origin of imbalances in power systems. These forecast errors directly form the imbalance volumes.

To assess the value of smart appliances in the use case related to the imbalance settlement, the imbalance volumes, and hence, the hourly forecast errors for demand, wind and solar power are needed. It was shown in literature, [4], that the forecast errors of RES power profiles follow the Gaussian probability distribution. In [5], it was shown on the basis of historical data that day-ahead load forecast errors nearly follow the Gaussian normal distribution as well. Alternatively, these errors could be modelled by hyperbolic distribution. Moreover, in the same paper, it was shown that "the shape of day-ahead wind power forecasting errors is similar to those of day-ahead load forecasts". Therefore, all the forecast errors will be modelled as Gaussian processes.

To generate the imbalance volumes as a Gaussian processes, mean and standard deviation values are needed. From historical data for Belgium, obtained from webpages of the Belgian TSO[2], firstly normalized forecast error profiles were obtained. The normalized generation forecast errors are forecast errors divided by the monitored active wind or solar capacity at the corresponding time instances. The hourly load forecast errors are normalized by the observed peak load in the considered year. The mean and standard deviation values for Belgium for a period of one year are reported in Table 3.

From the devised mean and standard deviation values, and installed RES capacity and peak load for each EU-28 member state, hourly forecast errors are generated. The utilized values are reported in Table 2. The forecast errors are generated for solar production, wind production, and load curve, for each of the three considered reference years, and for each EU-28 member state, respectively. Finally on a yearly basis, the generated load, wind and solar forecast errors are summed for each of the EU-28 member states to obtain a single imbalance volume hourly profile per EU-28 state.

5.1.3. COMPUTATION OF THE BALANCING COSTS IN THE IMBALANCE USE CASE

The imbalance costs are computed as multiplication of the difference in hourly prices between the hourly prices obtained in the day-ahead market use case and in the imbalance use case by the generated hourly imbalance volumes.

5.2. ASSESSMENT DATA

5.2.1. TRANSMISSION NETWORK

The transmission network within EU-28 area is modelled by means of NTC matrix. NTC values can be adapted seasonally, and are in general computed ex-ante at several important moments before the real time: year ahead, month ahead, and day ahead. We utilized month-ahead data wherever possible, and where not possible, year-ahead computed NTC values were utilized. All the data can be downloaded from the ENTSO-E transparency portal[3], under the tab "Transmission". High voltage DC (HVDC) interconnector capacity was also taken into account.

For 2020 and 2030, the network capacity was extended according to expectations presented in the ENTSO-E Ten-Year Network Development Plan (TYNDP) from 2014[4].

5.2.2. FUEL COSTS

The fuel cost for the different technologies will largely determine which power plant will run and at which price. The utilized fuel costs were presented in Task 3, and are repeated here for convenience.

Fuel costs for nuclear power plants are taken from IEA, NEA & OECD: Projected Costs of Generating Electricity, 2015 Edition, [8][5], where the fuel costs are given under the following assumption "For nuclear power plants, fuel cycle costs include front-end costs as for all other generating technologies, but also back-end costs associated with waste management", see also [7] [6], 2010 edition of the

[2] ELIA, http://www.elia.be/ or http://www.elia.be/en/grid-data/data-download

[3] ENTSO-E transparency portal is at transparency.entsoe.eu

[4] All the documents related to the ENTSO-E Ten-Year Network Development Plan can be found here https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2014/Pages/default.aspx

[5] See page 49 of the reference.

[6] See Table 3.7 a of the reference.

report. Therefore, as the front-end and back-end costs are taken into account in the fuels price, it is necessary to set the power plant efficiency to 100% instead of normally utilized 32-34%, see [2].

In [8], nuclear fuel costs are disclosed for a few European countries, in particular, for Finland, France, Hungary, Belgium, Great Britain, and Slovakia. These costs vary 5.09$/MWh in Finland, to 9.33 in France to 9.6 in Hungary to 10.46 in Belgium to 11.31 in Great Britain to 12.43 in Slovakia. As the model works with a unique fuels price, we took an average of these prices, which is 9.7$/MWh. This price is converted to euros by assuming that $1\$_{2014} = 0.72$ $€_{2014}$. Under this assumption, the fuel price for nuclear is computed to be $6.98€_{2014}$.

For 2020 and 2030 nuclear fuel prices, the same value is assumed, as to the best of our knowledge, there was no good reference to forecast future price. This is supported by a very slight change in the price in the period from 2010 [7] to 2015 [8], of less then 5% (own calculation), which is comparable to the inflation rate.

Table 1 Utilized fuel costs per fuel type and reference year

Fuel	2014	2020	2030
Nuclear [€/MWh_{prim}]	6,98	6,98	6,98
Coal [€/MWh_{prim}]	9,20	11,93	11,97
Natural gas [€/MWh_{prim}]	18,75	31,66	32,71
Wood pellets [€/MWh_{prim}]	5,06	4,84	4,84[7]
Oil [€/MWh_{prim}]	48,48	53,54	57,42
CO_2 [€/t_{CO2}][8]	5,96	9,07	48,00

The fuel costs in the model (prices of oil, gas, coal and CO_2) for 2020 and 2030 are based on the growth assumptions as defined in the World Energy Outlook 2013. Prices for 2014 are based on current market prices. All the prices are presented in Table 1 Utilized fuel costs per fuel type and reference year. For CO_2, for the period 2014 and 2020, the forward prices for EUA as published by ICE Endex on 16/10 are used. The current forward value for 2020 is in line with a recent report from Platts (June 2014) and Moody's (July 2015) that also estimates CO_2-prices between 5 and 10€/ton. The value for 2030 is an estimate based on scenarios developed by Thomson Reuters (2014). For biomass, the fuel cost is based on the estimated costs for wood pellets (today most common source of biomass[9]). To note that currently, debates are ongoing with respect to the sustainability criteria of certain types of biomass. In the course of 2017 a new Renewable Energy Directive for the period beyond 2020 is expected, setting out amongst others a bioenergy sustainability policy[10]. This might

[7] XXX

[8] http://www.changepartnership.org/wp-content/uploads/2014/10/Point-Carbon-2014-11042014-MSR-Point-Carbon.pdf
http://carbon-pulse.com/higher-co2-price-would-help-eu-utilities-but-it-remains-a-pipe-dream-moodys/
http://www.changepartnership.org/wp-content/uploads/2014/10/Point-Carbon-2014-11042014-MSR-Point-Carbon.pdf

[9] http://www.europarl.europa.eu/RegData/etudes/BRIE/2015/568329/EPRS_BRI(2015)568329_EN.pdf

[10] http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52015DC0080

result in a shift of subsidies from one type of biomass to another type of biomass, dependent on the outcome of the sustainability assessment. Independent of which biomass technology will be subsidized, according to studies, it is clear that also after 2020 biomass will play an important role in the energy mix.

From the table, it can be noted that the prices are expected to remain relatively stable between 2014 and 2020. In 2030, the expectations are that mainly the price of CO_2 will have risen significantly, which will have impact on profitability of thermal plants and hence the system costs. It is expected that price for biomass will remain constant, although it is possible, see remark above, that based on new sustainability criteria, different types of biomass will be subsidized. Nevertheless, the assumption is made that subsidies would be adapted in order to reach the same level of competitiveness as today.

Next to the fuel costs, there are possible additional costs related to the load shedding and RES curtailment. The load shedding costs are defined as the multiplication of the total shed load by the value of the lost load. It is highly nontrivial to determine the value of lost load, and there are numerous studies with extensive discussion on the topic, [3], [10]. The value is highly dependent on, among other factors, the type of lost load, duration of supply interruption, advance notice, and time of the day of the supply interruption. For the purposes of this study, the price for lost load is chosen to be 20,000 €/MWh, which corresponds to the estimated value of lost load for Austria for combined residential and non-residential load for the duration of 1 hour in summer at 10 am, see Figure 19 on page 31 of [10][11].
In the model, RES curtailment is allowed, however RES curtailment is not free. There are also costs related to the curtailment of RES. These costs are set to be 2,900 €/MWh, so that they are lower from the load shedding costs.

5.2.3. DEMAND PROFILES AND INSTALLED CAPACITY

Both, demand and installed production capacity are based on realised 2014 data as published by ENTSO-E. Fuel prices are based on realised fuel prices of 2014. For the 2020 and 2030 scenarios, the PRIMES-model results for installed capacity per EU-28 member state, and price scenarios of the International Energy Agency (IEA) are utilized[12].

Demand hourly profiles are downloaded from the ENTSO-E[13]. So, published data of 2014 for EU 28 is utilized. No demand profile for Malta was found, so for Malta, a scaled demand profile from Cyprus was utilized.

Demand hourly profiles are corrected for import and export with countries not belonging to the EU-28 interconnected power system. Lastly, in order to determine the load in 2020 and 2030, a yearly demand growth factor is applied. The demand growth is assumed to be the same as assumed in the PRIMES scenario: 0.5% per year until 2020, and 1% per year after 2020.

[11] The value reported in the reference is 21,988 $\$_{2012}$/MWh
[12] http://ec.europa.eu/transport/media/publications/doc/trends-to-2050-update-2013.pdf.

[13] https://www.entsoe.eu/data/data-portal/Pages/default.aspx

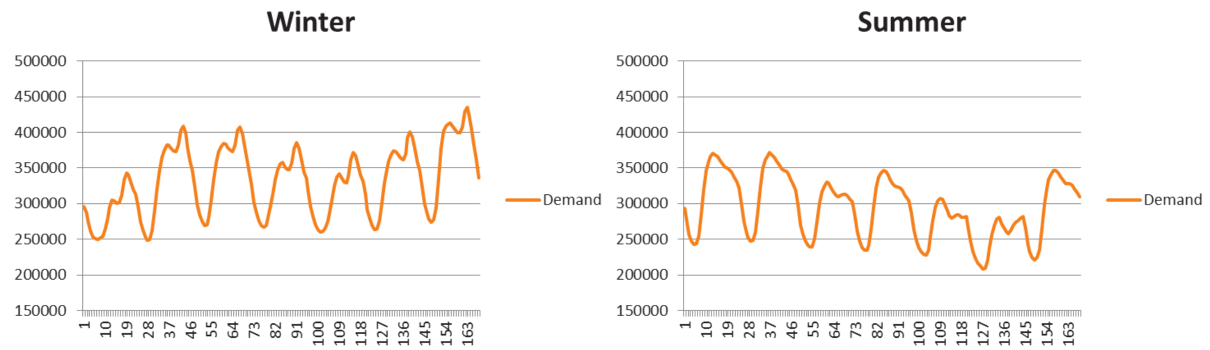

Figure 2 Total EU-28 demand hourly data for an arbitrarily selected week in winter and for an arbitrarily selected week in summer in 2014. Data source: ENTSO-E transparency database

Figure 2 shows a total EU-28 demand hourly data for an arbitrarily selected week in winter and for arbitrarily selected week in summer in 2014. Significant variations in the total demand, and also in the shape of demand curves, are observable.

The installed capacity of production units per country is based on the installed capacity of 2014 as published by the statistical database of ENTSO-E. For 2020 and 2030, the production mix per country is based on the PRIMES scenarios. The PRIMES model simulates the European energy system and markets on a country-by-country basis and across Europe for the entire energy system. The model produces projections over the period from 2015 to 2050 in 5-years intervals[14]. The installed capacity mix is obtained by the PRIMES model under the assumption of electricity demand growth rate of 0.5% per year up to 2020; and almost 1% per year thereafter.

Utilized values for the installed wind capacity, solar capacity and peak load are summarized in Table 2. For brevity, installed capacities of other EU-28 member states are not presented here.

From the utilized generation data, a large increase in renewable energy sources capacity can be observed. This growth of RES capacity is shown for wind and solar installed capacity in Figure 3. The wind installed capacity is expected to almost triple and solar installed capacity to double. This increase in intermittent RES capacity will increase the system's need for flexibility in both identified use cases.

[14] More information on the PRIMES model is listed on the website of E3Lab of the National Technical University of Athens - http://www.e3mlab.ntua.gr/e3mlab/index.php?option=com_content&view=category&id=35:primes&Itemid=80&layout=default&lang=en

Table 2 Installed RES capacity and peak load per EU-28 country per year (Source: ENTSO-E database for 2014 for all the countries besides Malta, PRIMES EU reference scenario outcomes for 2020 and 2030, and for Malta for 2014, and for peak load in Malta Enemalta[15])

	Installed solar capacity [MW]			Installed wind capacity [MW]			Peak load [MW]		
	2014	**2020**	**2030**	**2014**	**2020**	**2030**	**2014**	**2020**	**2030**
AT	400	787	1466	1529	3114	6051	12355	13430	15433
BE	1840	2429	4813	1966	4772	7068	13110	14251	16376
BG	1060	1116	1534	850	923	1515	8638	9390	10790
CY	79	194	658	145	249	329	871	947	1088
CZ	2011	2011	2068	277	307	387	10058	10933	12564
DE	35357	49089	53584	35600	48956	69949	81031	88081	101219
DK	282	360	762	4489	5960	7420	6163	6699	7699
EE	0	0	0	354	495	1056	1786	1941	2231
ES	7667	12655	16945	25028	25213	35707	39394	42821	49208
FI	7	50	60	411	1538	2556	13945	15158	17419
FR	4630	7470	13913	10238	25687	47354	84280	91612	105276
GB	1574	5985	8853	12140	38627	50721	50997	55434	63702
GR	3052	3286	3640	2195	3433	3745	8448	9183	10553
HR	16	27	182	394	640	713	3012	3274	3762
HU	3	93	712	413	903	1236	5712	6209	7135
IE	0	0	674	2088	11200	5992	4572	4970	5711
IT	16204	19553	28206	7371	222	22598	49523	53832	61861
LT	0	0	0	221	226	251	1408	1530	1758
LU	78	226	409	78	428	290	878	954	1097
LV	1	1	1	155	86	681	1172	1274	1464
MT	8	48	211	1	3561	191	290	316	363
NL	131	788	1037	4619	9624	12359	17850	19403	22297
PL	6	51	530	2472	6515	8843	23593	25645	29470
PT	1051	2212	5613	5398	5689	8324	8295	9017	10362
RO	214	679	1860	1566	1572	4043	8738	9499	10915
SE	13	182	248	3646	4447	5107	24295	26409	30348
SI	85	130	444	8	225	453	2074	2254	2591
SK	539	787	1009	48	113	455	4523	4917	5650

[15] Enemalta:http://www.transport.gov.mt/admin/uploads/media-library/files/DAirMaltaStudyVisit_The%20Energy%20Sector%20in%20Malta.pdf

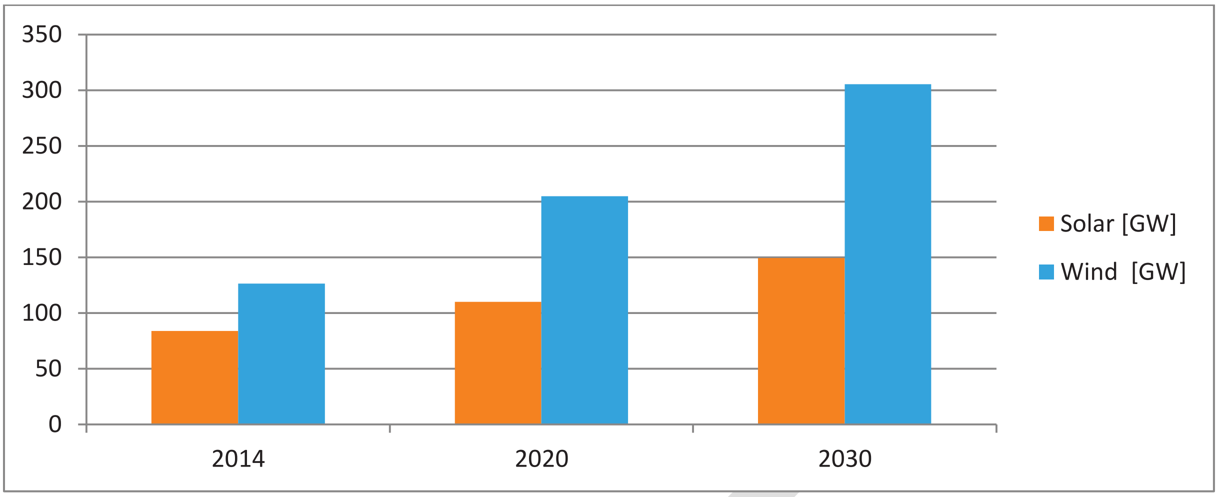

Figure 3 Installed RES capacity in [GW] for the whole EU-28 area in the reference years. Source: ENTSO-E database for 2014 for all the countries besides Malta, PRIMES scenario outcomes for 2020 and 2030, and for Malta for 2014, and for peak load in Malta Enemalta

5.2.4. WIND AND SOLAR HOURLY PROFILES

Hourly profiles of wind and solar power production are obtained from the TSO webpages of EU28 countries.

The TSOs of the following countries have publicly available wind hourly time series for 2014: Austria, Belgium, Czech Republic, Denmark, Estonia, Latvia, Lithuania, France, Germany, Ireland, Romania, and the United Kingdom. Hourly wind profiles for Finland, Spain were available only for 2013, and not 2014, so these profiles were utilized. For Italy, data from August 2013 until August 2014 was utilized.
For other countries, the hourly time series were estimated from the published profiles by rescaling the realised profiles of a comparable country, based on the difference in realised monthly production:

- Hourly wind profiles of Portugal were estimated from the Spanish profile;
- Cyprus and Greece were estimated from the Italian profile;
- Hourly wind profiles of Luxembourg and the Netherlands were estimated from the Belgian profile;
- Hourly wind profiles of Hungary were estimated from the German profile;
- Hourly wind profiles of Sweden were estimated from the Danish profile;
- Hourly wind profiles of Poland and Bulgaria were estimated from the Czech profile.

Slovenia, Slovakia and Malta have negligible installed wind capacities for 2014, and hence their hourly profiles are set to 0.

The TSOs of the following countries have publicly available solar photovoltaic hourly time series for 2014: Belgium, Czech Republic, France, Germany, Denmark, and Romania. For Spain hourly profiles for PV produced power hourly are available for 2013.
For other countries, the hourly time series were estimated from the published profiles (according to the same methodology as for the wind profiles):

- Hourly solar profiles of Portugal, Greece and Italy were estimated from the Spanish profile;
- Hourly solar profiles of Slovakia, Slovenia and Bulgaria were estimated from the Czech profile;

- Hourly solar profiles of Luxembourg and the Netherlands were estimated from the Belgian profile.

Other EU-28 countries have negligible amounts of installed PV capacities, and therefore their hourly profiles are set to 0.

An example of hourly intermittent RES time series for the whole EU-28 area is shown in Figure 4. On the left side, an arbitrarily selected winter week is shown, and on the right side, an arbitrarily selected summer week. Large differences in volatility and amplitude of produced power are obvious.

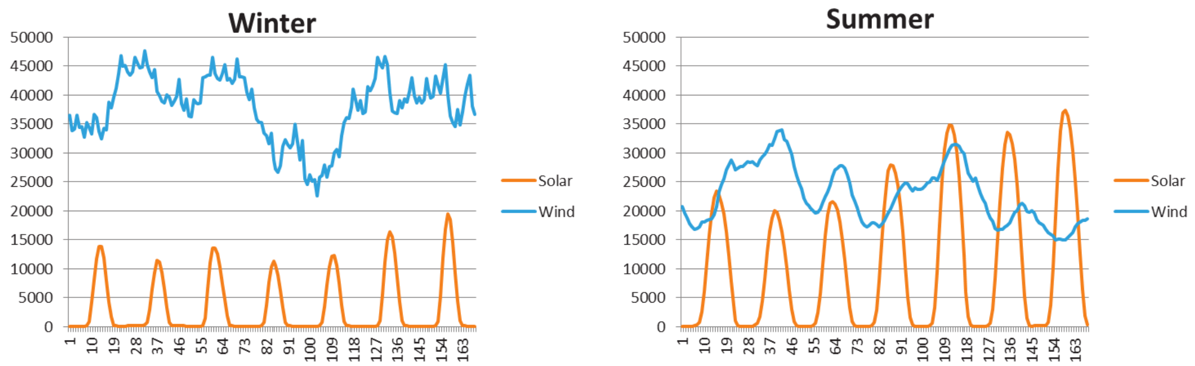

Figure 4 Intermittent RES hourly profiles for an arbitrarily selected week in winter, and for an arbitrarily selected week in summer.

For reference years 2020 and 2030, the hourly profiles are obtained from the profiles of 2014. The increase in the RES power production is assumed to be proportional to the increase of the installed capacity. In such a way, the same load factor is obtained for each RES technology nowadays and in the future. For countries were no realized profiles were published for 2014, the same methodology is used as for the construction of the 2014 profiles (see explanation before).

For the following countries, for 2020 and 2030, the solar profiles were estimated from the 2014 data: Cyprus, Estonia.

5.2.5. Forecast error hourly profiles

The statistical properties of the hourly load, wind and solar forecast errors are necessary for indication of net imbalance volumes. From historical data for Belgium, from webpages of Belgian TSO[16], the normalized forecast error profiles are obtained. The mean and standard deviation of these profiles are computed, and presented in Table 3. On basis of the computed standard deviation and mean value, the forecast errors, which are equivalent to the net imbalance size, are computed as explained above in Section 5.1.2 on page 8.

Figure 5 compares the realized and forecasted wind production over two days in 2014 in the overall EU-28 area. The difference of the two forms a part of total forecast error, and hence, imbalance volume.

[16] ELIA, http://www.elia.be/ or http://www.elia.be/en/grid-data/data-download

Table 3 Statistical data for normalized forecast errors on basis of historical data for Belgium in 2014 (Source: Elia.be)

	Mean [MW]	Standard deviation	Normalization factor
Hourly load forecast error	0,5615	0,6522	10353
Hourly wind forecast error	-0,0054	0,0775	[931, 1835]
Hourly solar forecast error	0,0059	0,0549	[2211, 2502]

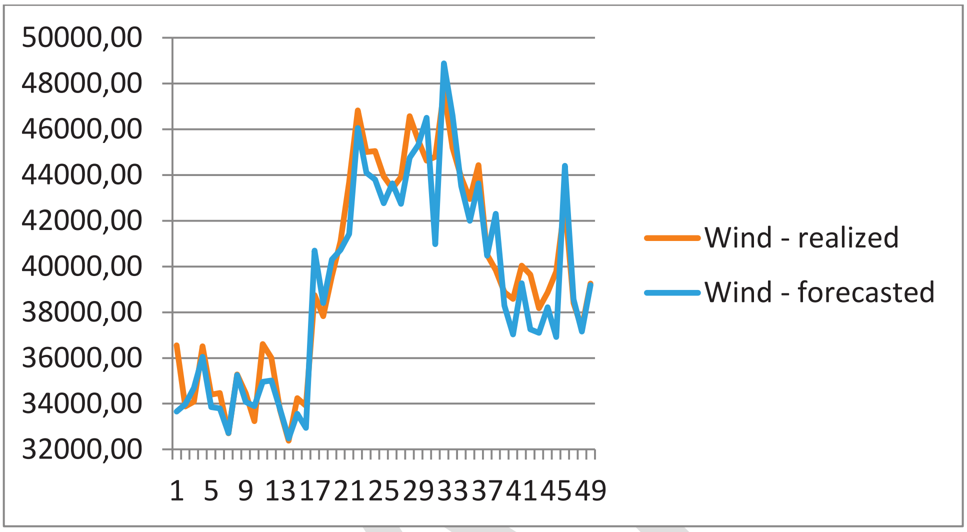

Figure 5 Comparison of the realized and forecasted wind production over two days in 2014 in the overall EU-28 area. The difference of the two forms a part of total forecast error, and hence, imbalance volume.

5.2.6. THE TECHNICAL PARAMETERS

Parameters for each technology (start-up time, minimum load, etc.) are based on the report of DIW (Prospective Costs of Electricity Generation until 2050 (2013) [2], in particular, see Tables 25-27, 29, 31, 33-35 in the reference. Parameter values that were not reported in this reference were taken from other literature. Namely, start-up costs of hydro units are taken from [11], ramp up/down rate of hydro and biomass units are taken from [12]. Variable operational and maintenance costs for hydro units are taken from [13], and for biomass units are taken from [14]. For biomass fired generation units, the values for minimum up time, minimum down time, start up costs, and ramping costs were not found in literature, and are assumed to be the same as for gas units.

5.2.7. OVERVIEW OF MODEL AND DATA ASSUMPTIONS

In summary, all the drawn assumptions are listed as follows:

1. All the input data for benchmark year 2014 is based on 2014 realized data.
2. The influence of the transmission system within EU-28 is modelled by means of net transfer capacity (NTC) matrix. Transmission constraints inside EU-28 member states are not considered.
3. The generation units are clustered per generation type, e.g., nuclear, hydro, coal fired power plants, etc. There is one equivalent unit for each generation type for each EU-28 country.
4. Hydro generators are assumed to be dispatchable, with the accordingly adapted yearly availability factor, which is set to approximately 0.4.

5. Undispatchable renewable generation, such as wind and solar power production, is represented in the model by the hourly generation profiles. Load factors of wind and solar power production is assumed to remain the same in 2020 and 2030 as it was in 2014.
6. Marginal price of wind power, and solar power is chosen to be 0. The efficiency of these units is set to 100%, as there is no input fuel directly utilized for these types of generation technologies.
7. Fuel prices are based on the realised fuel prices in 2014 and the assumptions for 2020 and 2030 as published by the World Energy Outlook 2013. For biomass, it is assumed that the price level will be the same, although different types of biomass might be subsidized.
8. For future scenarios, growth of demand is assumed to be 0.5% per year up to 2020; and almost 1% per year thereafter. Generation installed capacity and mix is assumed to grow as predicted by PRIMES scenarios, as specified earlier in Task 2.
9. Forecast errors are assumed to be normally distributed, and proportional to peak load, and installed intermittent RES capacity (installed wind and solar capacity).
10. In the lack of better references, forecast quality is assumed not to improve in the future, i.e., statistical properties of demand, load and wind forecast errors will remain the same in 2020 and 2030 as they are in 2015.
11. No generation unit is equipped by the carbon capture and storage (CCS) technology. No CO_2 emitted as a consequence of electricity production is captured and stored.

5.3. DEFINITION AND COMPUTATION OF KPIS

5.3.1. DEFINITION OF KPIS

The relevance of smart appliances is expressed in economical and environmental terms, and is measured by the three defined key performance indicators (KPIs). For each use case, three KPIs are defined to assess the impact of flexibility from smart appliances. These are:

4. KPI1: Economic value – total system costs [€/MWh].
5. KPI2: Total amount of CO_2 emissions over the considered period [Mt].
6. KPI3: Energy efficiency of the utilized generation mix over the considered period (defined as produced electrical energy divided by the total primary energy utilized to produce the electrical energy) [%].

Comparing KPIs over use cases without and with utilization of flexibility from smart appliances will give an indication on the economic and environmental impacts of smart appliances. This task is concerned only with the base cases, i.e., cases without utilization of flexibility from smart appliances; whereas in task 6, the cases with utilization of flexibility from smart appliances are presented.

The purpose of KPI1 is to provide a measure for economic benefits due to provision of flexibility to the system. This value is relevant for evaluation of costs and benefits of the smart appliances.
KPI2 and KPI3 define environmental benefits from smart appliances. They are defined to measure firstly, the potential of smart appliances to decrease utilization of the less efficient, and more CO_2 emitting peaking power plants (especially gas and coal fired units) in the system, and secondly, the impact of utilization of smart appliances' flexibility on the RES integration in the system.

5.3.2. CALCULATION OF KPIS

→ **Day-ahead use case**

KPI1, total system costs over the given time horizon of a year, is defined as the sum of the following costs:

- fuel costs of generator units,
- variable operational and maintenance costs of generator units,
- ramping costs of generator units,
- start-up costs of generator units
- shut-down costs of generator units,
- CO_2 emission costs of generator units,
- RES curtailment costs (if curtailment is allowed), and
- costs of loss of load (if load shedding is allowed).

KPI2 is simply defined as the sum of all CO_2 emissions from all the generation units over the considered time horizon. The CO_2 emission factors are defined for fossil fuel fired power plants per generation technology as given in the table below. The other technologies, such as nuclear power plants, hydro power plants, biomass power plants, or RES (wind and solar) are assumed to be CO_2 neutral, so emission factor for these technologies is set to 0. An overview of the utilized CO_2 intensity factors in [t_{CO2}/MWh_{prim}] for different generation categories is presented in Table 4 Utilized CO_2 intensity factors in [t_{CO2}/MWh_{prim}] for different generation categories. These factors are taken from [6].

Table 4 Utilized CO_2 intensity factors in [t_{CO2}/MWh_{prim}] for different generation categories

Category	CO_2 intensity [t_{CO2}/MWh_{prim}]
Coal fired	0,34
Gas fired	0,21
Oil fired	0,27

Note that KPI2 by no means represents total CO_2 emissions in the EU-28 area, it only gives an indication of the CO_2 emissions due to production of electricity[17]. These emissions are originating from fossil fuel fired electricity generation technologies. No emissions from other sectors, such as industrial or transport sector are taken into account.

KPI3 is the efficiency of the utilized generation mix that is utilized to satisfy the demand. It is defined as the quotient of the produced electrical energy and the total primary energy utilized to produce the electrical energy. It is computed from individual efficiency factors that are defined for each generation technology. The efficiencies are given in the table below, and are taken from [2]. For coal fired, gas fired, oil fired, and biomass plants, a plausible interval of efficiency factor is given in the reference. The chosen value is presented in Table 5. In the same reference, in table 35, for hydro power plants, more specifically, for run-of-river hydro power plants, efficiency of 90% is suggested.

Table 5 Output to input energy efficiency for different generation categories

[17] As in this study only the electricity energy system is modelled, and because the majority of CHP plants is gas fired, CHPs are here modelled as the gas fired units.

Category	Nuclear	Coal	Gas	Hydro	Oil	Biomass	Wind	Solar
Efficiency [%]	33[18]	45	50	90	39	45,5	100	100

→ **Imbalance use case**

In the imbalance use case, KPI1 is calculated as the sum of the total costs incurred by correcting the imbalance. It is computed as the multiplication of the imbalance volume and the marginal price of the marginal unit utilized to correct the imbalance.

To compute the KPI 2, i.e., the CO_2 emissions, in the imbalance use case, we define the average emissions factor of the generation park providing reserves under the assumption that the typical generating units providing reserves consist of the coal-fired, gas-fired, and oil-fired units. This factor is then defined as an average value of the individual emissions factors for the listed technologies, as presented in Table 4. The value of the average emission factor of generation mix providing reserves is 0.27.
To obtain KPI 2 value, this average emission factor is multiplied by the hourly imbalance volumes of each EU-28 member state.
Given this definition of KPI2, it can be interpreted as the additional CO_2 emissions that were emitted due to the balancing actions. In this sense, the emissions from the day-ahead use case are not taken into account in this KPI2 definition. Note that by definition, KPI2 can be negative. If it is negative, the total system CO_2 emissions after balancing actions are lower than the computed CO_2 emissions from the day-ahead market use case.

KPI 3 is calculated in the same was as in the day-ahead use case.

5.4. BASE CASE (BENCHMARK CASE)

In this section, firstly, the developed model and utilized data are validated by comparison of the model outcome to the available realized numbers from the electricity energy data. Next, the KPIs are presented for the benchmark case, i.e. for the case with no activation of smart appliances flexibility. The KPIs are given and explained for both use cases: day-ahead use case, and imbalance use case.

5.4.1. MODEL AND DATA VALIDATION

To validate the utilized model, and moreover to validate the utilized input data and parameters, in Figure 6 Comparison of the outcome of the model for input data defined for 2014, and the realized generation mix (electricity production source) in 2014 in EU-28 area., the outcome of the model in terms of committed generation mix is compared against the realized generation mix in EU-28 in 2014. The realized data is obtained from the provisional data for 2014 published in the Eurostat database and available on the Eurostat webpage[19]. The data is also presented and interpreted in the Eurostat report on Electricity and heat[20].

[18] As mentioned above, for the utilized nuclear fuel costs, the accompanying efficiency should be 100%. This efficiency factor of 33% is utilized only for the generation mix efficiency calculation.
[19] ec.europa.eu/Eurostat
[20] http://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_and_heat_statistics#Production_of_electricity

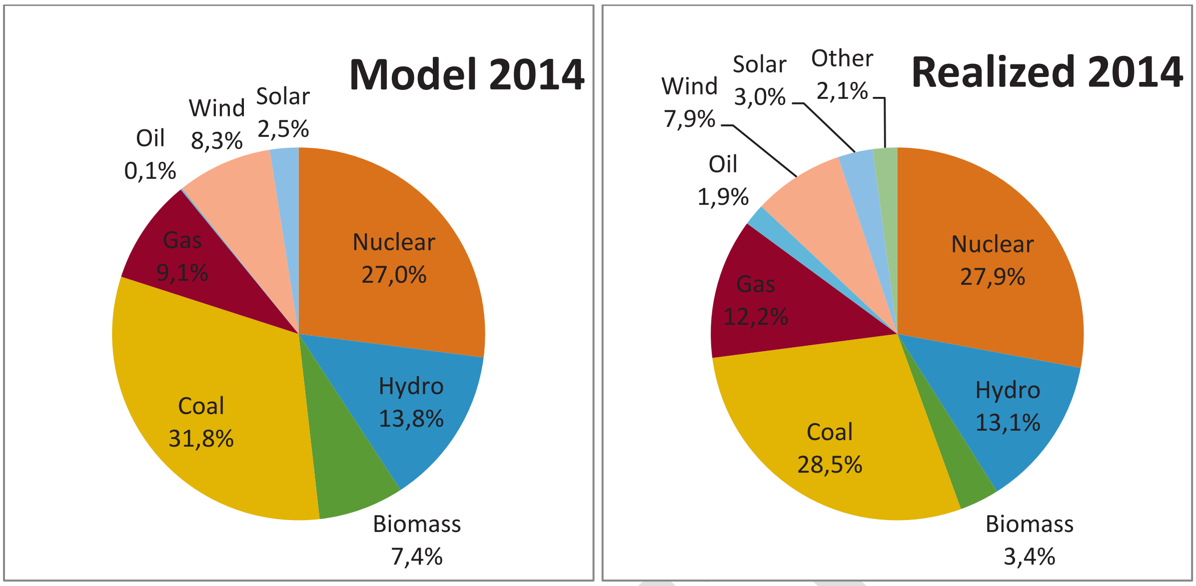

Figure 6 Comparison of the outcome of the model for input data defined for 2014, and the realized generation mix (electricity production source) in 2014 in EU-28 area.

As can be observed in Figure 6 Comparison of the outcome of the model for input data defined for 2014, and the realized generation mix (electricity production source) in 2014 in EU-28 area., the coincidence of the model results and realized numbers is very high. The model produced almost the same numbers as measured in reality for nuclear (27,5% against 27,9%), hydro (12,8% against 13,1%), and other intermittent RES (for wind 8,3% against 7,9%, and for solar 2,5% against 3%). Furthermore, if the total sum is considered for the fossil fuels fired power plants, very good overlap can be observed: gas and coal fired power plants produced 40,7% of total electricity in the year, whereas according to the model computation, it was 40,9%.

There is a minor mismatch in fuel fired generation (gas, oil, coal fired) if these technologies are considered individually. The mismatch in model-obtained and realized share of gas fired units and coal fired units is mostly due to the interchangeability of these technologies: both can be used as peaking units. Some of the mismatch can also be contributed to the limitations of the model, such as limiting the transmission network to the cross-border connections, and the fact that hydro power plants are modelled to be completely dispatchable. Lastly, the mismatch can be contributed to the choice of fuel prices and their variability over the year, which was not taken into account.

Lastly, there is a discrepancy in the electricity production by biomass and oil fired technologies. This is explained by a low price of wooden pellets utilized by the biomass power plants. The green certificates are already incorporated in the defined fuel price. The green certificates value varies significantly from country to country. Nevertheless, a single value had to be assigned to the wooden pellets price as the model takes a single price for each resource. As a result, a slight overestimation of the electricity production from the biomass power plants has occurred at the cost of lower electricity production by the oil-fired power plants.
In conclusion, the input data and model parameters are shown to be reliable and satisfactory for further purposes of the study.

5.4.1. DAY-AHEAD USE CASE

This section presents results for the day-ahead benchmark use case for the chosen benchmark years 2014, 2020 and 2030. Firstly, the outcome of the model in the form of a realized generation mix is presented in Table 6. As expected, the ratio of the electricity produced by the intermittent RES will increase over the years with the increase in the installed capacity, and according to the current load factor of these technologies.

Table 6 Total realized generation mix for EU-28 area per benchmark case, for 2014, 2020 and 2030.

Generation type	2014 [%]	2020 [%]	2030 [%]
Nuclear	27,0	23,5	21,1
Hydro	13,8	14,1	12,8
Biomass	7,4	8,7	9,0
Coal	31,8	27,5	19,9
Gas	9,1	9,8	15,5
Oil	0,1	<0,1	<0,1
Wind	8,3	12,9	17,3
Solar	2,5	3,6	4,6

The planned decrease in the installed nuclear power plant capacity is expectedly accompanied by the decrease in the share of electricity produced by nuclear generation units, and will drop from current 27,0% to around 21% in 2030.
Whereas the share of fossil fuels plants remains constant over the years, there is an expected restructuring in shares per technology within the group. From the table, it is obvious that the gas-fired technologies will have a higher share in 2030 than 2014. There are multiple reasons for this effect. Firstly, there is more installed capacity of gas fired technologies in 2030 than in 2014. At the same time, there is less coal fired technologies installed in 2030 than in 2014. This decrease in coal capacity, together with the decrease in nuclear capacity causes need for more baseload technologies. Gas fired units can take part in compensating it. Moreover, with more RES capacity, more flexibility is needed, and given the technical constraints of gas-fired units (such as fast ramping rates and low minimum down time and minimum up time), it is well known that they are suitable as a peaking technology. Lastly, the much higher general CO_2 emissions price, in combination with the lower CO_2 emissions factor (see Table 4) of gas fired units compared to coal fired units give the final argument for explanation of switch in the gas fired and coal fired power plants in 2030.

The share of biomass power plants is expected to increase over the coming years. This is largely a consequence of relatively low assumed fuel price for this technology, due to maintaining or increasing the green certificates and subsidies for such generation type. The share of biomass units in the generation mix is sensitive to variations in fuel prices for fossil fuels and subsidies.

The shares of electricity production per type, which are presented in Table 6, along with the emission factors given in Table 4, can later serve very well to explain the amounts obtained for KPI2, total CO_2 emissions from electricity production.

In Table 7, the share of total energy produced by RES that had to be curtailed is presented. In 2014 and 2020, no RES curtailment was necessary. Only in 2030, a small portion of produced intermittent RES energy had to be curtailed. Note that this is also due to the modelling assumptions, according to which only cross-border transmission network capacity is considered. In reality, RES curtailment could be a larger problem and lead to lower load factor of RES.

Table 7 Load shedding and RES curtailment for EU-28 area per benchmark case, for 2014, 2020 and 2030.

	2014 [%]	2020 [%]	2030 [%]
Load shedding	0	0	0,004
RES curtailment	0	0	0,008

Next to it, Table 7 shows the amount of load shedding as percentage of the total load in the whole EU-28 area. Load had to be shed only in 2030 benchmark scenario. Over the whole year, 0,004% of the total EU-28 demand, or 119 GWh had to be shed. The load was shed in 11 EU-28 countries, exclusively in winter months (between mid November and mid February). For most of these countries, the load was shed during less then 5 hours in the year.

The KPIs per benchmark year for day-ahead use case are presented in Table 8. These values are interesting on their own; however, their main purpose within the scope of the study is to serve as benchmark for the cases with utilized flexibility from smart appliances. Therefore, they are just briefly discussed in this task, and more elaborately in task 6 along with the KPIs from the use cases presented therein.

Table 8 KPIs for the day-ahead use case for each of the benchmark years

Day ahead use case	KPI1 (total system costs) [M€]	KPI2 (CO_2 emissions) [Mt]	KPI3 (efficiency of the utilized generation mix) [%]
2014	63.613,6	803,3	54,36
2020	75.079,2	736,2	58,11
2030	115.504,3	698,6	61,05

In the day-ahead use case, an increase in total costs for electricity production, i.e. KPI1, is observable over the years. All the costs are given in $€_{2014}$ value, so the most interesting outlier is for year 2030, in which the costs are significantly higher than in the other two benchmark years. The main reasons for this increase is in the increase of CO_2 emission price by factor 9 and 5 compared to 2014 and 2020, respectively, see also Table 1.

Development of the efficiency of the utilized generation mix (KPI3) over the benchmark years shows the slight increase in efficiency. Main reasons for this are firstly, the increased intermittent RES installed capacity, and secondly, the switch from electricity production by coal-fired power plants to the gas-fired power plants, see also Table 6, which are more efficient than the coal-fired ones: 50% compared to 45%, see Table 5.

5.4.2. IMBALANCE USE CASE

Add model tekort- gebrekken
The KPIs per benchmark year for imbalance use case are given in Table 9.

The same trends in KPI3 as observed in day-ahead use case are observable in the results for the benchmark imbalance use case, which is expected, as the generation mix that supplies energy in the day-ahead markets is not very different from the generation mix that supplies the day-ahead market needs and also provides reserves.
In KPI1, the same trends can be observed as in the Day-ahead use case: first a slight increase in total balancing costs can be observed from year 2014 to 2020, and after that in 2030, a significant increase in costs. This increase is, same as in day-ahead use case, caused by the load shedding, which put the market prices very high.

Table 9 KPIs for the imbalance use case for each of the benchmark years

Imbalance use case	KPI1 (total system costs) [M€]	KPI2 (CO_2 emissions) [Mt]	KPI3 (efficiency of the utilized generation mix) [%]
2014	7,79	1,56	54,36
2020	11,20	1,65	58,11
2030	143,66	1,78	61,05

The CO_2 emissions used by the generation mix to provide balancing services decreases over years. This can be explained by the methodology for generating imbalance volumes in the model. The imbalances are comprised from load forecast errors, and RES forecast errors. The load forecast error has a much larger mean value compared to the RES forecast errors. From Table 3 Statistical data for normalized forecast errors on basis of historical data for Belgium in 2014 (Source: Elia.be), it can be observed that the load prediction error has the tendency to be positive over long periods, whereas the RES prediction error is neutral (mean is almost zero). From 2014 to 2030, the RES installed capacity increased three times i.e. 300%, whereas the load grew around 15%. There is a decreasing portion of load prediction error compared to RES prediction error in the imbalance volumes. Hence, the total mean of the generated imbalance volumes will move towards zero in the period 2014 to 2030. The contribution of RES forecast error in the total forecast error increased over time, and moved the average more towards zero. This caused the emissions amount utilized to correct this imbalance to move towards zero as well.

5.5. Conclusions

This task introduced and validated the model and data utilized for the purposes of this study. Moreover, it set the ground for the evaluation of the potential impacts from smart appliances, which is continued in task 6. Therein, the results of the cases with smart appliances will be put in perspective with these benchmark results.

5.6. References

[1] K. Poncelet et al., “A Clustered Unit Commitment Problem Formulation for Integration in Investment Planning Models”, October 2014, available at www.mech.kuleuven.be/en/tme/research/energy_environment/Pdf/wp-luc.pdf

[2] Andreas Schröder, Friedrich Kunz, Jan Meiss, Roman Mendelevitch and Christian von Hirschhausen, "Current and Prospective Costs of Electricity Generation until 2050", 2013, available www.diw.de/documents/publikationen/73/diw_01.c.424566.de/diw_datadoc_2013-068.pdf

[3] "The Value of Lost Load (VoLL) for Electricity in Great Britain", Final report for OFGEM and DECC, report prepared by London Economics, Julyy 2013, see https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf

[4] M.H. Albadi, E.F. El-Saadany , "Overview of wind power intermittency impacts on power systems", 2010, Electric Power Systems Research, vol 80, pp. 627–632

[5] Bri-Mathias Hodge, Anthony Florita, Kirsten Orwig, Debra Lew, and Michael Milligan, "A Comparison of Wind Power and Load Forecasting Error Distributions ", 2012, NREL, available http://www.nrel.gov/docs/fy12osti/54384.pdf

[6] Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds): IPCC 2006, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Prepared by the National Greenhouse Gas Inventories Programme, Published: IGES, Japan, url: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2006gls_all_in.zip, and http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html

[7] IEA, NEA & OECD: Projected Costs of Generating Electricity. 2010 Edition, https://www.iea.org/publications/freepublications/publication/projected_costs.pdf

[8] IEA, NEA & OECD: Projected Costs of Generating Electricity. 2015 Edition, https://www.iea.org/Textbase/npsum/ElecCost2015SUM.pdf (only executive summary available online)

[10] "Estimating the Value of Lost Load", briefing paper preparedf or the Electric Reliability Council of Texas, Inc. (ERCOT) by London Economics, Boston, July 2013, available at https://www.hks.harvard.edu/hepg/Papers/2013/06%2018%2013%20ERCOT%20VOLL%20Literature%20Review%20and%20Macroeconomic%20Analysis_0613.pdf

[11] T. Bjorkvoll, and B.H. Bakken: "Calculating the start-up cost of hydropower generators, PSCC conference, June 2002, Seville, url: http://pscc.ee.ethz.ch/uploads/tx_ethpublications/s12p05.pdf,

[12] EURELECTRIC: Flexible generation: Backing up renewables, technical report, October 2011, url: http://www.eurelectric.org/media/61388/flexibility_report_final-2011-102-0003-01-e.pdf.

[13] IRENA working paper, Renewable energy technologies: cost analysis series - Hydropower, Volume 1: Power Sector, Issue 3/5, June 2012 , url: http://www.irena.org/documentdownloads/publications/re_technologies_cost_analysis-hydropower.pdf,

[14] IRENA: Renewable power generation costs in 2014, technical report, January 2015, url: http://www.irena.org/documentdownloads/publications/irena_re_power_costs_2014_report.pdf.