UNIVERSITEIT GENT

Prof. Dr. Johan Albrecht
Dr. Ruben Laleman

May, 2015

POLICY TRADE-OFFS for the BELGIAN ELECTRICITY SYSTEM

REVISION - 2015

ABSTRACT

The outlook of the Belgian electricity system is increasingly unpredictable and challenging. Belgium is confronted with a nuclear phase out in a liberalized European electricity market which is strongly impacted by climate and renewable energy policies. In the market context of today, incentive schemes focus on renewable energy sources which are sheltered from market dynamics. Load factors of conventional power plants have dropped markedly due to a stagnating demand and an increasing share of intermittent renewable electricity generation with low variable costs. As a consequence, the investment climate for controllable, non-intermittent assets is very problematic.

In this report we evaluate the expected changes in the Belgian electricity supply from 2014 until 2030. We also estimate cost implications of the nuclear phase out, combined with a decrease in old fossil capacity and an increase in renewable electricity generation. In a baseline scenario we find that, in the near future, Belgium strongly will have to rely on electricity imports to meet peak demand. This import dependency can eventually increase black out risks. We assume that this risk is unacceptable for policymakers and therefore assess several “secure supply” scenarios for the future of the Belgian electricity system. We assume that a reserve margin of at least 5% always needs to be maintained, and evaluate the implications of meeting this benchmark. Incentives for capacity growth, system flexibility and system reliability are compared. We consider investments in new assets, the prolonged use of old thermal assets and demand-side measures. For various scenarios we estimate subsidy costs, overall system costs and related outcomes such as surplus problems. In the sets of scenarios, we compare two options to deal with the variability of renewable generation technologies. The first option is similar to the current situation and assumes that renewables have grid priority as well as priority in the merit order due to their output related support (production subsidies). The second option assumes that renewables are obliged to participate in the market to a certain extent. Finally, we combine all scenarios to estimate the costs of a balanced approach.

Contact Information: Prof. Dr. Johan Albrecht, Universiteit Gent - Faculteit Economie & Bedrijfskunde

Tweekerkenstraat 2, B-9000 Gent

E-mail: Johan.Albrecht@ugent.be / Tel: ++ (0)9 264 35 10 / Fax: ++ (0)9 264 35 99

Executive Summary

The Belgian electricity mix based on nuclear and fossil fuels will evolve into a system with an increasing share of renewable energy technologies. The Belgian situation is very special because a large share of the existing capacity is planned to be phased out or closed in the next 15 years. This decline in old nuclear and fossil capacity can already in the very near future (2015-2017) results in shortages, especially at very cold winter evenings. Current policies trigger mainly investments in (intermittent) renewable capacity. Incentives for investments in system reliability or system flexibility are currently lacking. Hence we face the deployment of solar and wind technologies without new investments in controllable assets or 'firm capacity'.

This transition is challenging from a system perspective. In this report various scenarios are put forward to provide incentives for both renewable and controllable assets. More specifically, we foresee a support system for wind, PV and biomass to promote renewable energy technologies (and meet European targets). In addition, remunerations for the availability of capacity are introduced to support gas fired (OCGT, CCGT) and biomass combustion technologies. In a country like Belgium, biomass power plants provide the only large scale firm and renewable capacity. In theory, hydro power could also serve this purpose but Belgium has very limited potential to increase its hydro capacity. Other technologies (CCS, wave and tidal energy ...) which are not yet commercially viable are not considered in this study.

In total, 16 scenarios have been evaluated in this report. Half of these assume moderate growth of installed renewable capacities (business as usual or 'BAU RES' scenarios); the other 8 assume strong renewables policies ('High RES scenarios'). The scenarios vary in two other dimensions as well. One dimension is the degree of market participation that is expected from the renewable technologies. The other dimension is the support system to facilitate investments in firm capacity and to meet peak demand. For all scenarios a minimal reserve margin of 5% was set as a policy goal, in order to have a sufficiently secure electricity system. For all of these 16 scenarios we have calculated the cumulative additional subsidy costs - additional to the subsidies already in place today - and total annual as well as cumulative system costs for period 2014-2030. Also, an assessment of problematic volumes of electricity oversupply was added.

When comparing all the scenarios evaluated in this study, we found that the least cost option to meet the 5% reserve margin requirement is a scenario with a moderate growth of total renewable capacity combined with a modest degree of market participation by the renewable assets. This type of market participation mainly consists of flexible use of biomass plants and an option to curtail PV and wind at times of low demand combined with favourable weather conditions. The lowest cost scenario also assumes an increased use of demand response measures ('Demand Side Management') to postpone or replace the need for firm capacity (OCGT, CCGT or eventually biomass). An additional way to dampen costs is to keep old assets on line as back-up for cold winter peaks.

The estimated total cumulative (undiscounted) subsidy cost for this least cost generation scenario is € 21 Billion for the period 2014-2030. The latter subsidy cost only contains financial support for generation assets. In contrast, the total system cost also contains the costs of other generation assets (used without new subsidies) and the costs of transmission and distribution. With the lowest cost scenario, the cumulative system costs in the period 2014-2030 amount to about € 160 Billion. Total annual system costs will increase from € 6 Billion (assuming the use of amortised nuclear assets) in 2014 to roughly € 10 Billion in 2030. With this scenario, the share of renewable electricity in total domestic supply in 2030 will be about 27%. This is likely to be sufficient to meet European RES-targets for 2030 (still under debate).

The energy transition up to 2030 will not be a cheap transformation. Total cumulative subsidy costs (2014-2030) for the generation scenarios range from € 21 Billion to € 41 Billion and cumulative system cost are in the range of € 160 to € 180 Billion. **As a consequence, appropriate policy choices to minimize the cumulative cost of energy security can be € 20 Billion less expensive between 2014 and 2030 than the most expensive policy options.** Total annual system costs in 2030 range from € 9.9 Billion (low share of renewables, flexible electricity system) to € 11.6 Billion (high share of renewables, inflexible system). The most expensive scenario consists of a system with a high share of intermittent renewables, inflexible biomass plants, a lot of (new and efficient) gas-fired power plants with very low load factors and a limited contribution of demand response measures. The share of renewable generation will vary between 27% and 57% by 2030.

Incentives for renewable generation will need to change from a current “production based” perspective to a more system-wide perspective with system flexibility and reliability needs taken into account. A new incentive scheme for renewables is essential because production subsidies hamper the further expansion of new renewable capacity, due to risks for oversupply, grid instability as well as high system-based costs.

GLOSSARY

General	
RES	Renewable Energy Sources
ETS	Emissions Trading System
CCGT	Combined Cycle Gas Turbine
OCGT	Open Cycle Gas Turbine
CHP	Combined Heat and Power
PV	Photovoltaic (Panels) - Solar Panels
LF	Load Factor
DSM	Demand Side Management
CWE	Central West European (electricity trading region)
O&M	Operation and Maintenance
GHG	Greenhouse Gasses (CO2, CH4, …)
RM	Reserve Margin
LCOE	Levelized Cost of Electricity
RAC	Reliably Available Capacity
Scenarios	
BAU	Business as Usual (BAU RES scenario)
CFD	Contract For Differences scenario (p 19)
CFD-MP	CFD-Market Participation scenario (shedding of RES, p 20)
OT	Old Thermal (incentives for old fossil capacity, p 21)
New	Incentives for NEW fossil capacity (p 21)
DSM	DSM- Scenario: strong focus on DSM deployment (p 22)
MP-IR	Market Participation - Intermittent RES (p 34)
Companies, public and private organizations	
ENTSO-E	European Network of Transmission System Operators - Electricity
CREG	Commission for the Regulation of Electricity and Gas markets (Belgium)
DENA	Deutsche Energie-Agentur GmbH (German Energy Agency)
DG-Energy	Directorate-General for Energy (EU commission)
FOD-Economy	Federal Government Agency - Economy (Belgium)
NEA	Nuclear Energy Agency
IEA	International Energy Agency
OECD	Organization for Economic Co-operation and Development
UBS	UBS- AG Swiss Bank
US-PJM	United States Regional Transmission Organization (Pennsylvania, New Jersey, …)
EREC	European Renewable Energy Council
EPIA	European Photovoltaic Industry Association
EWEA	European Wind Energy Association
Units	
MW	Mega Watt (10^8 W)
TWh	Tera Watt hours (10^{12} Wh)
GWh	Giga Watt hours (10^9 Wh)

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1 Introduction

More than ever, electricity markets in Europe are facing rapid changes due to a combination of many unprecedented challenges. First, there are the European 20/20/20 targets that aim to increase the share of renewable energy sources (RES) in total energy consumption (up to 20%), decrease greenhouse gas emissions (by 20%) and improve the overall energy efficiency of the European economy by the year 2020. Meanwhile, new targets for 2030 are on their way, but are still heavily debated. Also, a long and persistent economic crisis is increasing uncertainty and many member states are urged to reduce their deficits. On top of this, the recent accident in Fukushima has resulted in the rapid phase out of nuclear power plants in Germany. In Belgium and the U.K., old nuclear power plants are planned to retire in the next decades. In addition to these phase out plans, many other old assets in Europe will be closed down in the next decade. Cheap coal and the strong expansion of subsidized renewables with very low marginal costs are putting pressure on wholesale prices and pushing new and efficient gas plants (CCGT's) out of the market. Very low ETS prices are further complicating the situation for gas fired plants in Europe. New investments in non-intermittent, controllable assets are virtually non-existent, resulting in an increased fear of electricity shortages in some regions. More interconnection can help solve some issues, but local opposition against large infrastructure projects and complex licensing procedures complicate rapid development.

In this complex world governments (local, federal and European) are urged to come up with measures to provide a more attractive and secure investment climate for energy (technology) companies. This report aims to pinpoint the problems occurring in the Belgian and the Central-West-European (CWE) electricity systems. We focus on the big impact of the Belgian nuclear phase out in combination with increasing (intermittent) renewable generation and the low profitability of traditional gas plants (CCGT's). Some future policy scenarios are presented and evaluated. We focus on Belgium, but keep the larger European landscape in mind.

2 The Belgian Situation

2.1 Current trends

The installed capacities of the various energy technologies in Belgium are presented in Figure 1 (Eurelectric, 2013). The share of renewables has increased markedly in the recent 5 years. However, nuclear capacity is still very dominant in the electricity production park with a share of about 30% in total capacity and about 40% of the *controllable* or *firm* capacity (total capacity without PV, hydro and wind). Despite the increase in total capacity, the sum of firm capacity has remained fairly constant at about 15.700 MW.

According to current government policies, the share of nuclear capacity will decrease drastically in the next 20 years. From 2025 onwards, nuclear capacity (currently +/- 5 900 MW) will be completely phased out. Meanwhile, several fossil fuelled plants will also be closed because of end of life or due to steep losses in profitability. The Belgian electricity landscape will therefore change dramatically.

Figure 1: Share of Technologies in Belgian Electricity Capacity (2010-2012) source: (Eurelectric, 2013)

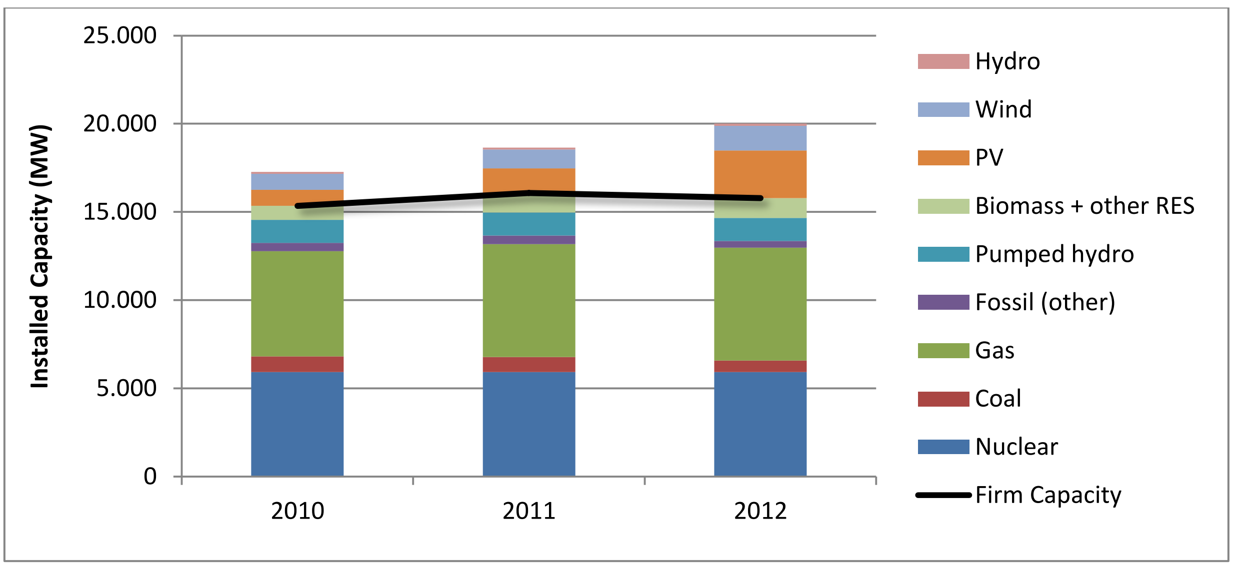


Table 1 shows some recent load factors for the various technologies in the Belgian production park. A remarkable fact is that the load factors of the gas plants (in bold) decreased significantly since the economic crisis, while the load factor of the coals plants increased. This is caused by the combination of low CO_2 and low coal prices, increasing gas prices and a rather flat or even decreasing electricity demand. The drop in the nuclear load factors is due to the safety issues at the Doel 3 and Tihange 2 reactors, which were shut down in 2012. Their start-up took place in June 2013. We can therefore assume that the LF of nuclear capacity at the end of 2013 did return to ‘normal’ values. Due to the large variation in load factors, the technologies’ share in electricity production is very different from the share in total capacity (Figure 2 vs. Figure 1). Renewable energy technologies may have a relatively high share in total capacity, their share in electricity generation is still quite modest. Nevertheless, the share of renewable electricity in domestic production is rising steadily - mainly because of PV growth - to attain 14% in 2012.

Table 1: Load factor of various technologies (2010-2012) (Eurelectric, 2013)

Load Factor (%)	2010	2011	2012
Nuclear	88%	88%	74%
Fossil (other)	14%	14%	11%
Coal	74%	70%	91%
Gas	**58%**	**41%**	**34%**
Biomass + other RES	76%	58%	62%
Hydro	29%	19%	37%
Wind	16%	25%	22%
PV	7%	10%	7%
Pumped Hydro	12%	11%	11%
Average	60%	52%	43%

Figure 2: Domestic electricity production (2010-2012), excluding import and export, source: (Eurelectric, 2013)

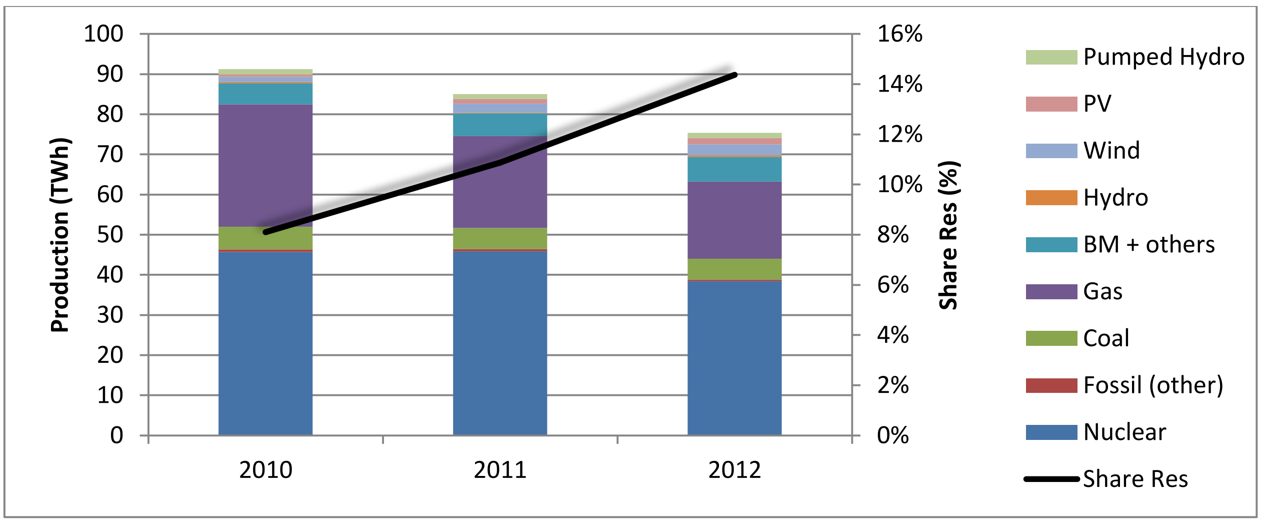


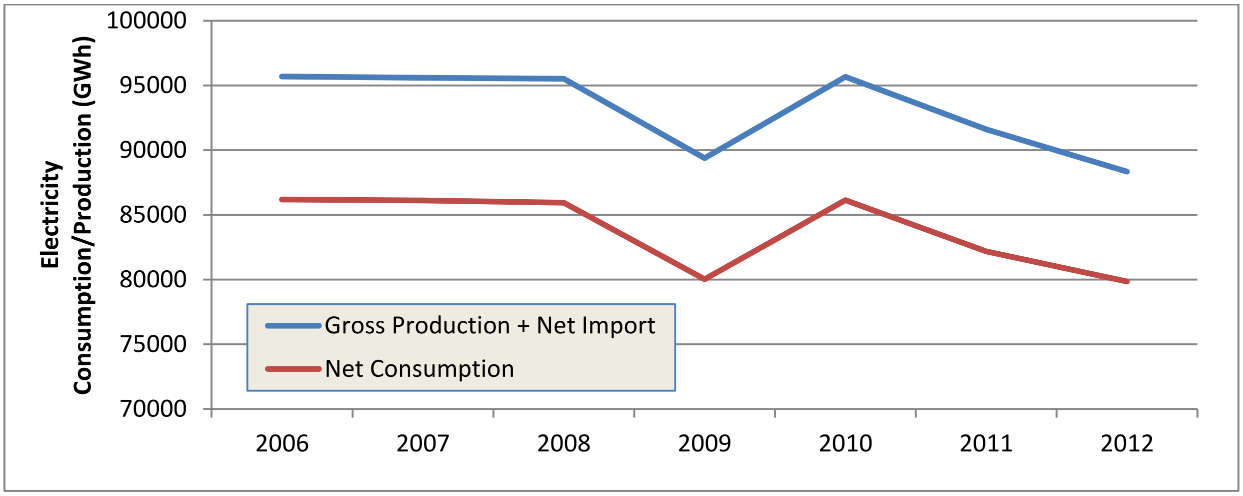
Figure 2 shows that domestic gross electricity production (TWh) has decreased steadily in recent years. This is largely due to a strong increase of imported electricity. It is therefore interesting to take a look at total gross and net consumption as well, to see how much electricity is imported and how much is actually consumed in Belgium. In order to obtain the annual net consumption of electricity we need to take import[1] and losses into account. We obtain gross production of electricity (blue line in Figure 3) by adding the total amount of electricity produced domestically (Figure 2) and the balance of imported and exported electricity. By subtracting losses and internal electricity consumption (electricity used by the power plant) from gross electricity production (+/- import/export) we obtain net electricity consumption (red line in Figure 3).

Figure 3 shows that since the financial and economic crisis - which started in 2008 - the average annual consumption of electricity in Belgium has dropped by about 7% (compared to 2006-2008). The drop in

[1] Electricity is imported and exported on a daily basis, depending on electricity prices. In recent years we have become net-importers. Over the whole year, more is imported then exported.

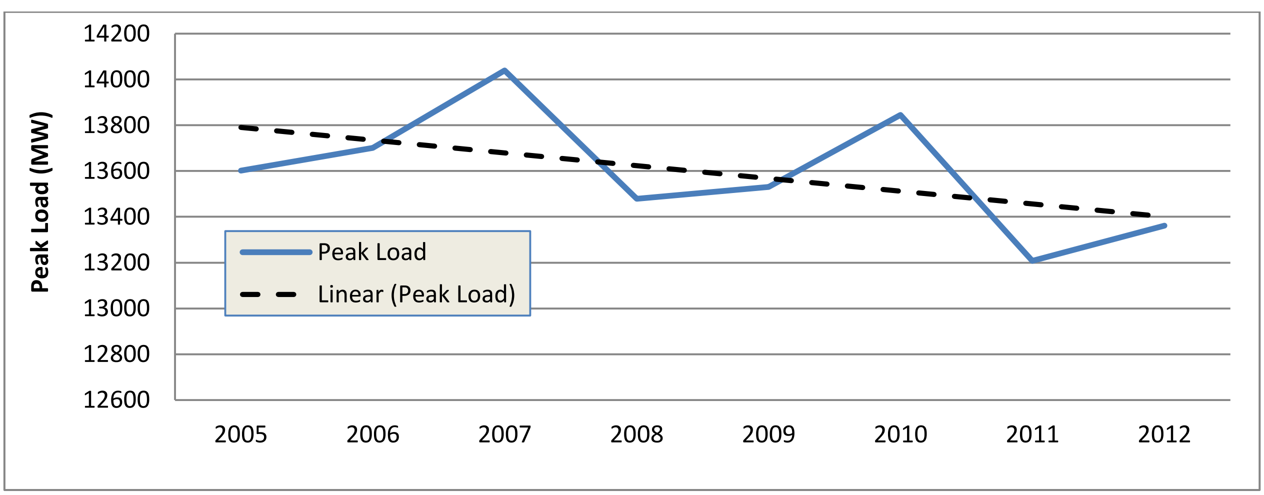
total demand does not necessarily result in a higher security of supply. It is the (instantaneous) peak demand that determines whether or not a country faces a high or low black out risk.

Figure 3: Annual gross electricity production (+ net import) and consumption (source: (IEA, 2013))



Data for overall peak *demand* are hard to find because of auto-production. Peak *load*, on the other hand, is measurable and precise figures are available. However, it is important to stress that peak *demand* (including auto-production) is higher than peak *load* (= electricity taken from the grid) so we are underestimating peak demand when analyzing peak load. Nevertheless, we observe that peak load did not decrease as dramatically as the total annual demand. Peak load reached a maximum of about 14 000 MW in 2007, to drop to around 13 400 MW in 2012 (Figure 4). Whether or not this evolution resulted in a lower black out risk depends on the evolution of available firm capacity. It is very unclear whether this decrease in peak load is a structural trend or whether the decline is due to the economic crisis. Another explanation relates to the widening of the gap between peak load and peak demand. Overall, there is no certainty that the peak load (or peak demand) will remain low in the coming years.

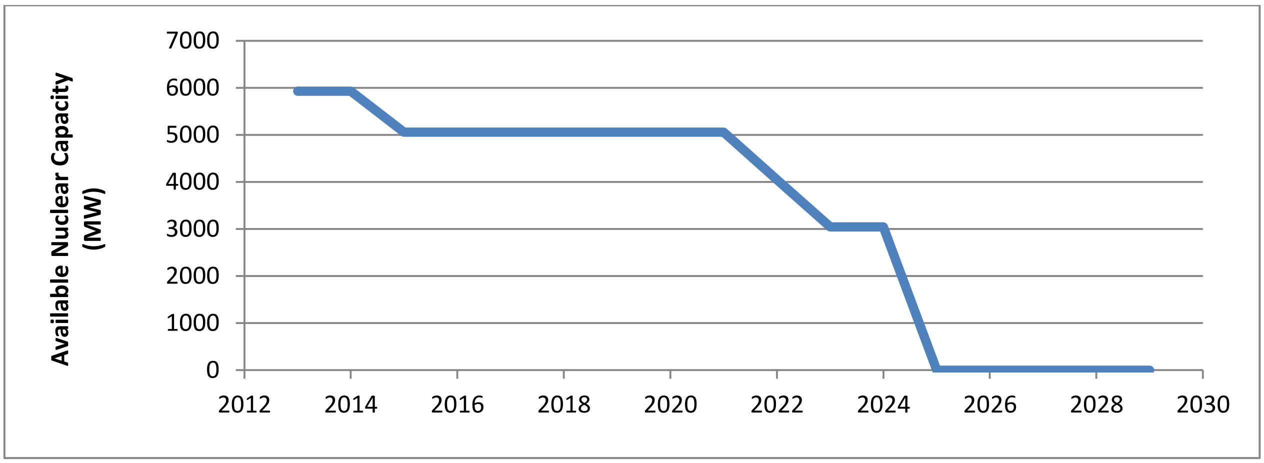
Figure 4: Peak Load (LOAD; source: (Elia, 2013) - remark: auto-production not included)



2.2 *Future of electricity production - Plan Wathelet*

In the summer of 2013 the Federal Minister for Energy, Environment, Mobility and State Reform, Mr. Wathelet, was able to get an approval for his plan on the future of the Belgian electricity system. The "Plan Wathelet" foresees in the phase out of the two oldest nuclear reactors in 2015 (Doel 1 and Doel 2). A reactor in Tihange (Tihange 1) - which was initially foreseen to be phased out in 2015 - will be refurbished and its lifetime will be extended with another ten years[2]. Thus, the short term decrease in nuclear capacity is not as radical as initially scheduled. However, the extension of Tihange 1 results in a stronger decrease in nuclear output in the period 2020-2025, when 5 000 MW of nuclear capacity is scheduled to be phased out (Figure 5). Whether this will happen is at the moment unclear[3].

Figure 5: Nuclear Phase out according to the "plan Wathelet"



Prolonging the lifetime of Tihange 1 should result in fewer concerns about security of supply in Belgium in the short run. However, the nuclear phase out is not the only issue when it comes to security of supply. Many fossil fired plants are facing closure due to their age (old coal plants) or due to the fact that they are no longer profitable (as illustrated by the recent "mothballing" of gas plants).

Increased capacities of wind and solar technologies come with a different kind of security of supply problem. Their variable nature is causing rapid oscillations of electricity injections into the grid. Intermittent RES are putting stress on the existing grid infrastructure, not well suited to cope with such events.

The Plan Wathelet also includes incentives for investments in new gas-fired capacity of 800 MW and incentives to increase demand side management (DSM) efforts equal to 400 MW by 2015 (on top of the existing DSM potential of 331 MW). The rapid execution of existing interconnection plans to connect Belgium with the U.K. and Germany is also part of the Plan Wathelet.

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[2] http://wathelet.belgium.be/nl/2013/07/05/beslissingen-van-het-kernkabinet-van-5-juli-2013-met-het-oog-op-het-waarborgen-van-de-bevoorradingszekerheid-van-elektriciteit-in-belgie/

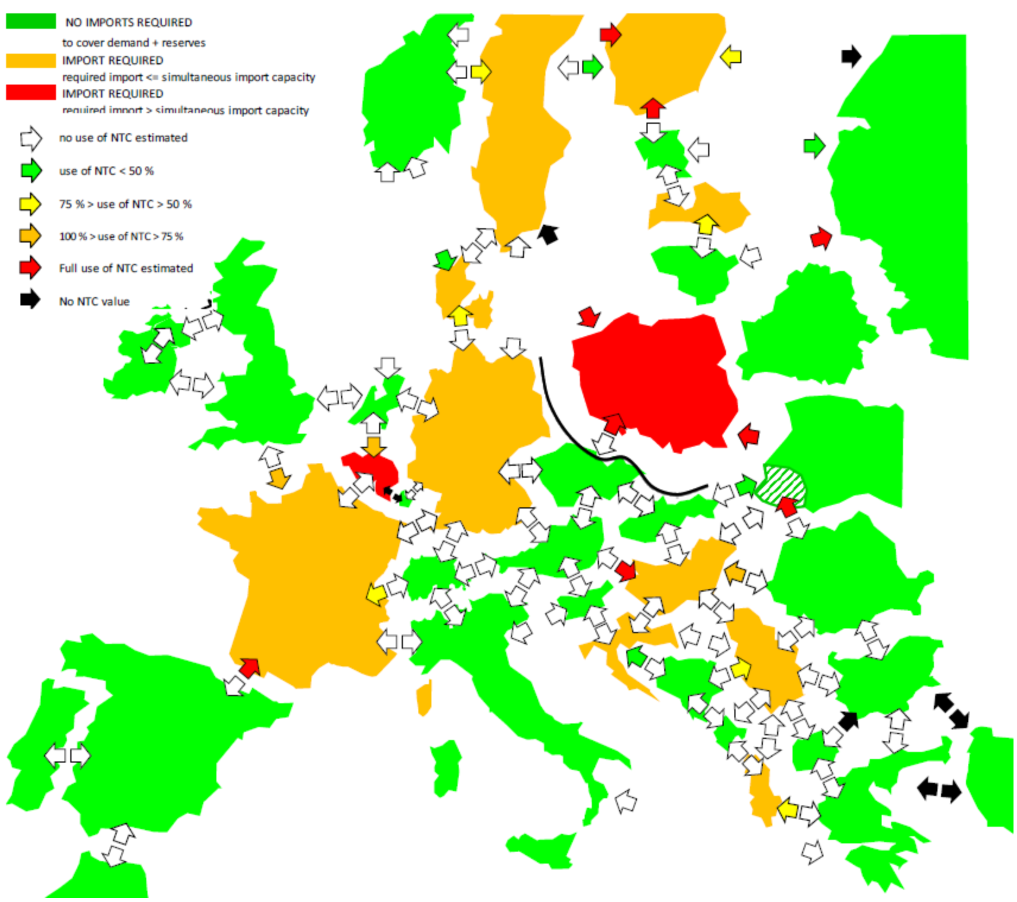
[3] There is a chance that one of the more recently built reactors' lifetime will be extended in case of security of supply concerns. Furthermore, since March 2014 the two old nuclear reactors that were restarted in June 2013 have been closed again because of security concerns.

In our future scenarios - see below - we take the phase out as in the “Plan Wathelet” as our starting point. We also assume that new policy incentives will facilitate investments in gas plants (along with support for biomass and other renewables). Additionally, demand side management and interconnection will be mentioned in our analysis. The main focus will be on how security of supply can be achieved and on the main trade offs in terms of the overall costs for society.

2.3 The Central West European electricity market

Belgium is a small country in the middle of Western Europe. By consequence, it is strongly influenced by the energy policies of its neighbouring countries. The interconnection capacity of Belgium is 3,5 GW, which is about 20% of peak demand. In other words, importing electricity can be a solution for a short term shortage. Unfortunately, France, Germany and Belgium have a limited production capacity to cope with very cold winters. The Winter Outlook report by ENTSO-E (2012) assigned code ‘red’ to Belgium and code ‘orange’ to France and Germany (Figure 6).

Figure 6: Winter Outlook 2012 (ENTSO-E, 2012)



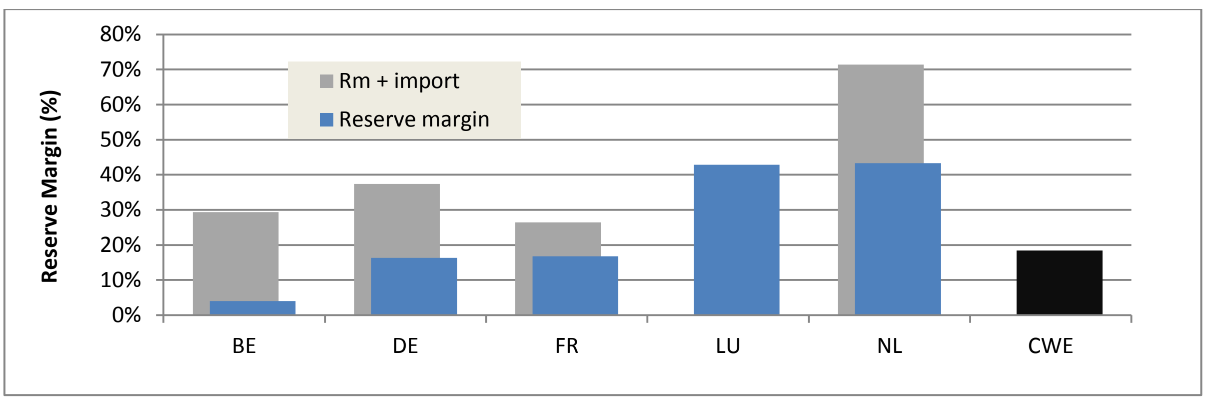
Here we use the 2012 report (and not the 2013 outlook) because the situation in the Belgian electricity market in that winter was similar to the situation we will face in 2015, after the phase out of the oldest reactors. In 2012 there was a temporary shutdown of 2 nuclear reactors, resulting in a drop of 2 GW in the firm capacity.

The "code red" in the ENTSO-E report indicates that peak demand in a strong winter would be higher than the total available capacity and total import capacity combined. In other words, a shortage in capacity can occur (resulting in blackouts). In Germany and France as well, some import would be needed under severe winter conditions, but the import capacity should be sufficient (in contrast to the Belgian case). The graph also shows that between Belgium and France, in case of a long and cold winter, there will no net-import or export, since they are both in the "danger zone". France would import mostly from Spain (Red arrow). Belgium would mainly import electricity from the Netherlands (orange arrow from the Netherland to Belgium).

A recent report from the CREG (CREG , 2013) presents historical data to support this, with strong import from the Netherlands in the winters of 2007-2008, 2009-2010 and 2011-2012. Import and export patterns between France and Belgium are much less seasonal. For example, there was a net-export situation from July 2009 until March 2010. In the winter of 2011-2012, there was net-export to France in October, November and January.

The reserve margin for the CWE-region as a whole is about 20% (Figure 7). Only the Netherlands and Luxemburg have a RM above 25 percent. Despite the low reserve margin in Belgium, average electricity prices remain very low in Belgium because of interconnection with countries with relative overcapacity, an increasing influx of low-marginal cost renewable electricity and a sluggish demand. Too low prices do not trigger new investments and hence lead to even lower reserve margins in the next years...

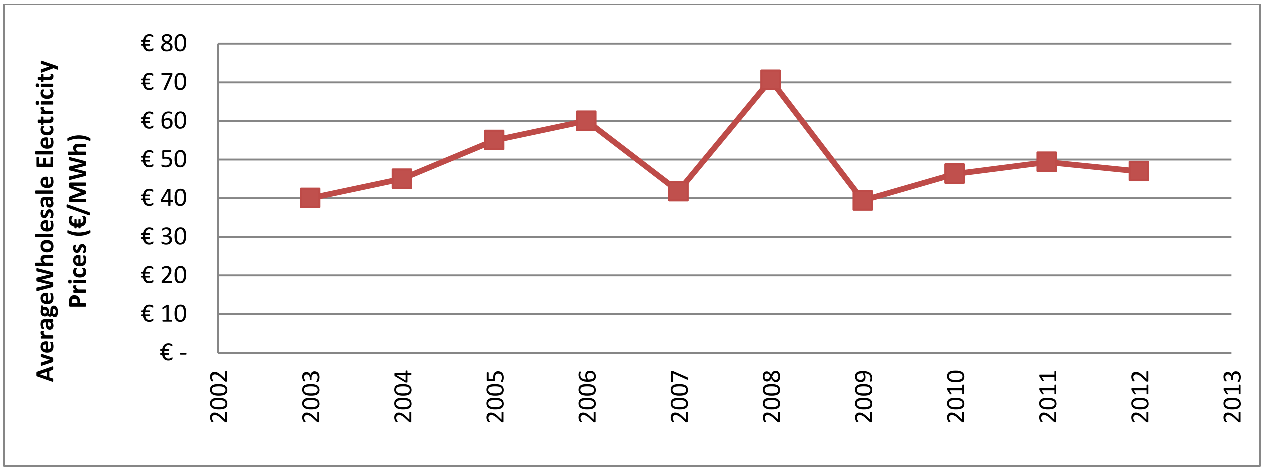
Figure 7: Reserve margins in CWE[4] (based on data from (ENTSO-E, 2012) (European Commission, 2013) (DENA, 2010))



The reserve margin only takes into account the *reliable* or firm capacity. *Total* capacity *did* increase in recent years, but this was mainly due to increases in (non-reliable) wind and PV capacity. Also, cheap coal fired power plants in Germany are now determining market prices, resulting in CWE-prices of about 40-50 €/MWh (Figure 8). A recent report from DG-Energy indicates that prices have dropped even further, to historically low levels of 30-35 €/MWh for the second quarter of 2013 (European Commission, 2013).

[4] On the peak demand in Germany, very diverging data can be found; appendix III in the Commission report mentions a peak load of 92 GW, while DENA mentions data in the range of 78-83 MW. A graph by IHS indicates a reserve margin of about 20% for Germany (IHS, 2013). We have opted for a peak demand of 83 MW in this study, since this seems to fit most of the literature estimates.

Figure 8: Average Wholesale prices in CWE (historic data based on (European Commission, 2004) (European Commission, 2006) (European Commission, 2008) (European Commission, 2012))



3 Future electricity supply scenarios for Belgium

3.1 Introduction

Until 2020, some evolutions are rather predictable because they are driven by legislation. Firstly, there is the phase out of the two oldest nuclear reactors in Belgium, and the extension of Tihange 1. Secondly, we can expect a general increase in renewable electricity production in order to reach Belgium's national target of 20% renewable electricity production by 2020 (13% renewable energy in the whole economy). Based on these evolutions, we briefly evaluate a "No Policy" scenario as a benchmark to illustrate what would happen if no new firm capacity would be added to the system. Then, in the next sections, we will evaluate several "security of supply" scenarios, to see which types of incentives are needed to guarantee a 5% reserve margin at all times in Belgium. Finally we evaluate the impact of the security of supply scenarios on the risk of oversupply and compare various renewable policy scenarios that can - or cannot - reduce the potential oversupply problem.

For the 'No Policy' scenario we combine the phase out plan with information about the decision to shut down or mothball existing capacity. By comparing generation capacity to the expected evolution of peak demand - we assume an increase by 0.5% per year - the overall risk of shortages in Belgium is assessed. It is important to stress that we consider Belgium as an island. This simplifies the analysis and is considered to be the safest scenario. We also estimate the effect of 10% capacity credit or *guaranteed contribution* of wind energy to the reserve margin (Figure 9). The potential for PV to contribute to the reserve margin is close to zero because Belgium is a country with a peak demand during winter evenings. However, in Southern countries or regions (e.g. Spain, Italy) the contribution of solar technologies in response to peak demand can be very significant (EPIA, 2012).

Figure 9: Reserve margin in the No Policy scenario

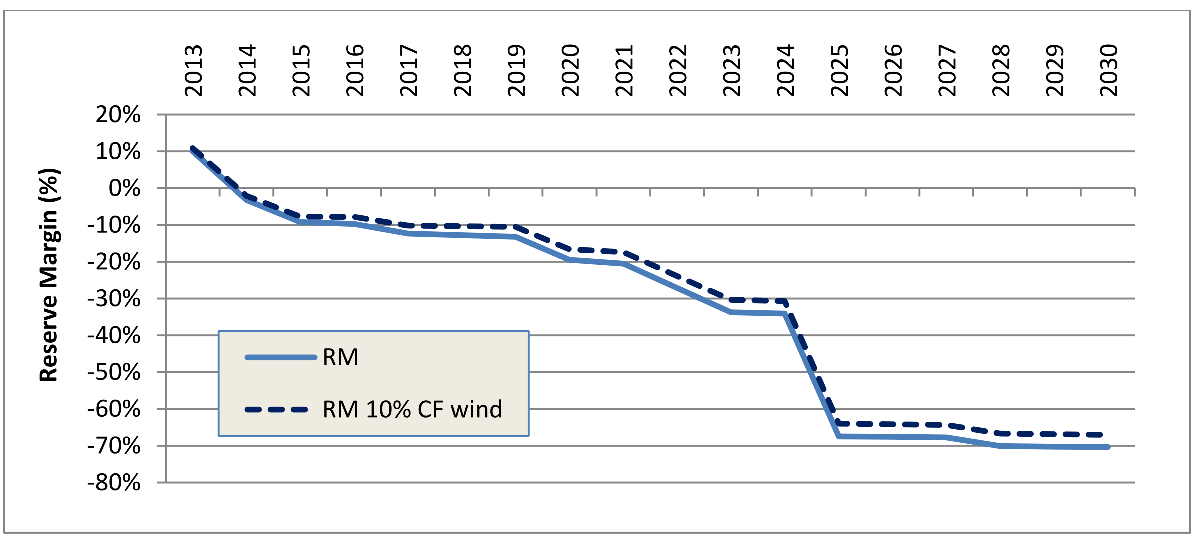


Figure 9 clearly shows that the phase out of Doel 1 and 2, combined with the closing or mothballing of fossil assets (coal, gas) will result in a negative reserve margin from 2015 onwards. The situation will be dramatic in 2024-2025 with extremely low reserve margins in our No Policy scenario (without new investments).

The above results clearly show that initiatives to increase the reserve margin are urgently needed. Therefore we will suggest "security of supply" alternatives in the following sections.

Based on our findings from the "No Policy" scenario, we assess different policy options such as new incentives for flexible capacity, renewable generation and increasing the potential for demand side management (DSM). The different scenarios and assumptions are listed in Table 2. We aim to estimate overall costs of various combinations of these options, as well as the impact on the stability of the electricity system (by quantifying the size and frequency of surpluses). The details of the policy options will be discussed below.

Table 2: Overview of policy options

Shortage issues	**Surplus issues**
DSM potential	*Renewables incentives*
No DSM increase 2100 MW additional DSM by 2030	Contract For Difference (CFD) system CFD system + Market Participation (MP)
Incentives for Flexible generation	
Support for new capacity only Support for New and Old Thermal capacity (OT)	

3.2 The Model

This section will elaborate on the methodology used to estimate the system and subsidy costs. First, we will estimate the capacity need, from which we can calculate the capacity shortage in a given year. Once the shortage in firm capacity is known, the model will fill this capacity gap with new reliable assets (firm capacity), which can be biomass, CCGT's and OCGT's. This is done until we meet the RM > 5% criteria.

When the required installed capacity is known, we add this to the existing capacity and the total installed capacity (a mix of various technologies) in a given year is obtained, and the cost of the electricity mix in a given year is calculated based on the LCOE methodology. The subsidy costs for the renewables are estimated by comparing the LCOE of the technologies with the market price. The subsidies for available capacity are calculated based on the amount of new capacity that is needed to keep the RM > 5%.The total subsidy cost is the sum of the renewables subsidies and the capacity subsidies. We will elaborate further on these calculations below. First, we need to estimate the capacity that needs to be added to the system each year, to compensate the decrease in reliable capacity.

3.2.1 Capacity Need

As an input, the assumed evolution of the installed firm capacity is given. This data presents the evolution of controllable assets (nuclear, gas, biomass, CHP, coal, hydro) from 2013 until 2030. As Figure 9 suggests, the firm capacity is going to decline rapidly, with a major drop in the period 2023-2026, when all nuclear assets will be phased out. This drop will result in serious problems for the Belgian electricity market. Therefore, we assume that policy makers will intervene. Accordingly, we assume that the reserve margin in Belgium should not be lower than 5% in order guarantee a secure supply of electricity at all times. The reserve margin is estimated as follows:

Reserve Margin = (capacity minus demand)/demand, where "capacity" is the expected maximum available supply and "demand" is expected peak demand[5]

However, it should be stressed that the expected maximum available supply is not equal to the total installed capacity of controllable assets (or firm capacity) in a country. Due to weather constraints (i.e. hydro can be impacted by very low temperatures as the water freezes) and other issues, it is possible that not all controllable capacity is reliably available at the moment of peak demand. Therefore, it is generally accepted to incorporate an availability factor which indicates the share of the firm capacity that is available. In this study we assume that 88% of the firm capacity is always available, this figure is based on data from the FOD economy report on the Belgian electricity supply (FOD Economy, 2012). The share of the capacity that is always available is referred to as the reliably available capacity:

RAC = part of national generation capacity that is actually available to cover the load at a reference point[6]

$= 0{,}88 \times FC$

With FC = Firm Capacity [MW]

The firm capacity can refer to the total capacity need or to the baseline firm capacity in the following paragraphs. The above definitions are generally applicable; in the next section we will apply these definitions to the Belgian case study, in which new capacity is needed to meet the > 5 % RM target.

Now that we have provided the definitions we calculate the capacity shortage which can occur in a given year:

$$\text{Shortage} = TCN - BFC$$

With	TCN	= Total Capacity Need (to meet 5% RM)	[MW]
	BFC	= Baseline Firm Capacity (in No Policy scenario)	[MW]

We can calculate the total capacity need (in a given year) from the peak demand (exogenous) and the reserve margin (assumed to be > 5% at all times).

$$\begin{aligned} \text{RM} \quad &= (RAC - PD)\,/\,PD \\ &= (TCN \times 0{,}88 - PD)\,/\,PD \\ &= 0{,}05 \end{aligned}$$

Thus

[5] EIA (2012) http://www.eia.gov/todayinenergy/detail.cfm?id=6510

[6] ENTSO-E (2014) https://www.entsoe.eu/Documents/Publications/SDC/141201_Winter_Outlook_2014-15_Summer_Review_2014.pdf

$$\text{TCN} = \frac{((RM \times PD) + PD)}{0{,}88} = PD \times (1 + RM) \times (1/0{,}88)$$

And

$$\text{Shortage} = PD \times (\frac{1 + RM}{0{,}88}) - BFC$$

With	RM	= Reserve Margin	[%]
	PD	= Peak Demand	[MW]
	BFC	= Baseline Firm Capacity	[MW]

When there is a shortage, new assets will be placed in the system automatically by the model, until the RM is above the 5% minimal value. The shortage is filled up with biomass, CCGT's (both with a 300 MW capacity) and OCGT's (with a 50 MW capacity). The share of biomass or CCGT's depends on the scenario (see section 3.4.1). OCGT's are assumed to replace 20% of the decrease in total capacity, since more OCGT's will be required in a future with a higher share of intermittent renewables. The calculations are as follows:

$$Shortage = a + b + c$$

With

$$a = 0{,}2 \times shortage$$
$$(b + c) = 0{,}8 \times shortage$$

The number of OCGT's is then calculated by dividing the capacity of an OCGT and rounding to the highest integer.

An example to clarify:

$$If\ a\ Shortage = 1268MW$$

$$1286 = a + b + c$$

$$a = 253\ and\ b + c = 1015$$

N° of OCGT plants = $int\left(\frac{253}{50}\right) + 1 = int(5{,}06) + 1 = 6$

So, 6 new 50 MW assets will be installed. The same method is applied to calculate the number of new CCGT's and biomass plants that need to be installed. This methodology will result in an overestimation of the amount of new capacity that is needed to reach exactly a 5% RM. However, this is not a big issue, as we assume that the 5% reserve margin is a minimal requirement. In all our scenarios, the RM is in the range of 6-10%.

3.2.2 Electricity production

When the first step in the model (estimating the required amount of controllable capacity) is finished, we have obtained the installed capacity of various assets in Belgium in a given year, in a given scenario. The capacity of intermittent renewables (PV and wind) is assumed to be policy driven and thus exogenous. Both the intermittent (exogenous) and controllable (endogenous) installed capacity will produce electricity to meet the demand in a given year. So for each year in the model, total electricity supply is equal to total electricity demand. Demand side management is thus implicitly assumed to displace electricity consumption, not reduce it. In order to estimate the amount of GWh produced, we multiply the installed capacity with the load factor of each technology. The load factor presents the % of time that a given technology is producing electricity. We apply the following calculations:

$$LF_{n,t} = \frac{Prod_{n,t}}{CAP_{n,t}} \times \frac{1}{24 \times 365} \qquad \text{[GWh/GW x 1/h]}$$

With	$LF_{n,t}$	= Load Factor in year (t) for technology (n)	[%]
	$Prod_{n,t}$	= electricity produced by a technology (n) in a given year (t)	[GWh]
	$CAP_{n,t}$	= installed capacity of technology (n) in year (t)	[GW]

Supply is equal to demand in a given year, and demand is given (exogenously). Demand is not influenced by price or other variables, we assume that policy intervention in energy efficiency (or a lack thereof) and electrification of transport and heating will be the major drivers of the demand. Since it is difficult or impossible to predict these policy measures, and the effectiveness of such measures, we assume a slow increase in demand (440 GWh/y or 0,5% of the demand in 2013). And supply in a given year (t) is equal to demand in that year:

$$D_t = D_{t-1} + 440\ GWh$$

$$S_t = D_t \quad \text{[GWh]}$$

with	t	= year (2014-2030)
	S	= Supply
	D	= Demand

Supply in a given year is equal to the sum of the electricity produced by the technologies

$$S_t = \sum_{n=1}^{k} Prod_{n,t}$$

With	k	= number of technologies that are in the system (10 technologies)
	$Prod_n$	= electricity produced by a technology (n) in a given year (i)

The amount of electricity produced in year (t) by a technology (n) is given by the load factor and the installed capacity:

$$Prod_{n,t} = LF_{n,t} \times CAP_{n,t} \times 24 \times 365 \qquad \text{[GWh/year]}$$

For all assets, except for the CCGT's, the LF is exogenously given. For the renewables, the LF depends on the chosen scenario (with or without market participation of renewables). The LF for the variable renewables depends on the weather and the introduction (or not) of market participation (shedding of PV and wind, see 3.5.2). The LF for biomass is high in the scenarios with no market participation of renewables (68%) and low in a scenario with market participation (35%). Since the cost of biomass electricity production is not competitive with market prices, the use of these assets will depend on policy choices, not economics. The LF of nuclear is high and constant due to the low marginal costs of this technology. The LF for OCGT's is assumed to be low (used only during price peaks). In other words, only the CCGT load factors are variable, the LF's of the other technologies are constant (in a given scenario). The CCGT's fill the "gap" between, on the one hand, the annual supply of the OCGT's, the renewables, CHP and nuclear assets and, and other hand, the total annual demand. Because of this, the load factors of the CCGT's decrease, for example, when the share of renewables increases, or increase when nuclear assets are phased out. An overview of the assumed load factors, based on a literature review, is presented in Table 3 (page 23).

3.2.3 Cost of electricity supply

To estimate the cost of electricity production we use the "Levelized Cost of Electricity" methodology. The cost to produce 1 MWh of electricity with a given technology is the sum of the annualized investment costs, the fuel costs, the O&M costs and the carbon costs (ETS price). In this way, the LCOE represents the average electricity price required over the lifetime of the asset, in order for the investor to have a reasonable return on his investment. This "reasonable return" is equal to the discount rate, used to discount the initial investment costs. In order words, an investor will invest if the average price of electricity of the lifetime of the technology is at least equal to the LCOE for a given technology.

$$LCOE = AIC + O\&M + FS + C \qquad [€/MWh]$$

With	AIC	= Annualized investment costs	[€/MWh]
	O&M	= Operation and Maintenance Costs	[€/MWh]
	FS	= Feedstock Cost	[€/MWh]
	C	= Carbon Cost	[€/MWh]

Variable renewable electricity sources have zero feedstock and carbon costs, thus the LCOE for such a technology is simply the sum of the annualized investment costs and the O&M costs.

Carbon costs are based on the ETS price and the emissions from the fossil assets:

$$C = ETS \times EF \qquad [€/MWh]$$

With	ETS	= ETS carbon price	[€/ton of GHG equivalent]
	EF	= Emission Factor	[ton of GHG_{eq}/MWh]

In order to calculate the annualized investment costs, the total upfront investment cost needs to be discounted.

$$AIC = INV / (FLEOH \times AF) \qquad [€/MWh]$$

With	INV	= Upfront Investment	[€/MW]
	FLEOH	= Full Load Equivalent Operating Hours	[h]
	AF	= Annuity Factor	

And

$$FLEOH = LF \times 365 \times 24 \qquad [h/year]$$

With LF = Load factor

The annuity factor can be calculated from the discount rate and the time that a certain investment lasts. Applied to energy technologies, this can be interpreted as the lifetime of the assets, since a certain energy technology will provide a revenue until it is no longer operational.

$$AF = [1 - (1 + DR)^{-\tau}] / DR$$

With	DR	= Discount Rate
	τ	= Lifetime

3.2.4 The impact of the learning rate

The initial investment cost of a given technology is likely to decrease in time. This concept is often presented by the "learning curve". According to the learning curve literature, the cost of a given technology decreases with increasing experience, the latter is assumed to be given by the accumulated production output. Figure 10 illustrates this concept. When plotted on logarithmic scales, we find a linear trend between unit cost and cumulative output. The investment cost at a given time for a technology is assumed to follow this learning curve; we calculate the investment cost at a given time:

$$INV_t = INV_{t0} \left(\frac{CAP_t}{CAP_{t0}}\right)^{-\alpha}$$

With	INV_t	= Investment cost in a given year
	INV_{t0}	= Investment cost at t0 (2013)
	CAP_t	= Installed Global Capacity in a given year
	CAP_{t0}	= Installed Global Capacity at t0 (2013)

With $\alpha = -\frac{\ln(PR)}{\ln(2)}$

And PR = Progress Rate = 1 - LR

This learning curve methodology is applied to the investment costs of the renewables, coal plants and CCGT's. However, as the global capacity of fossil assets is already very high the learning rate has a very limited impact on the investment costs of CCGT's and coal plants. The effect of learning on the investment costs of the renewables, gas (CCGT) and coal are illustrated in Figure 11. The learning for nuclear plants was assumed to be zero. For OCGT's and CHP, no data on learning rates were found in the literature, we assumed a linear decrease in the investment costs for these technologies of 6€/kW each year.

Figure 10: Illustration of the learning curve or experience curve

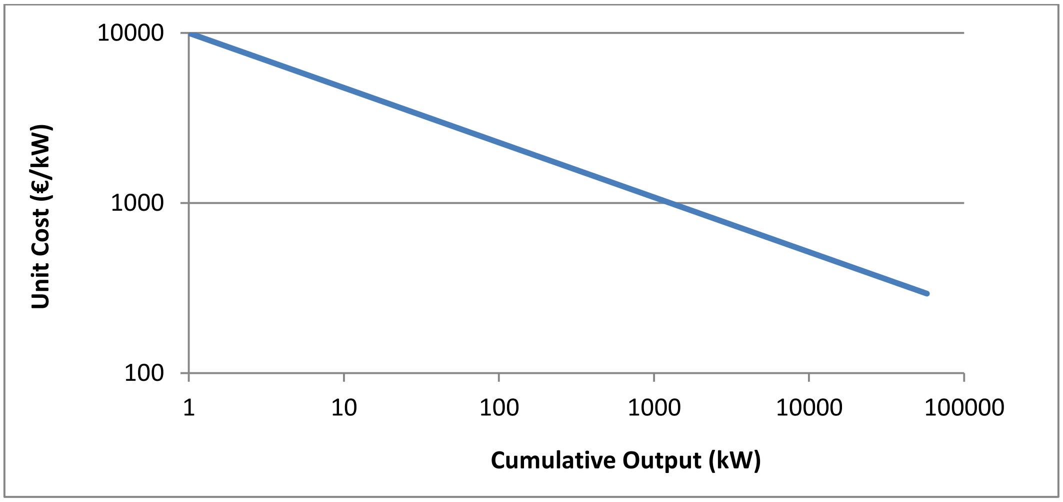
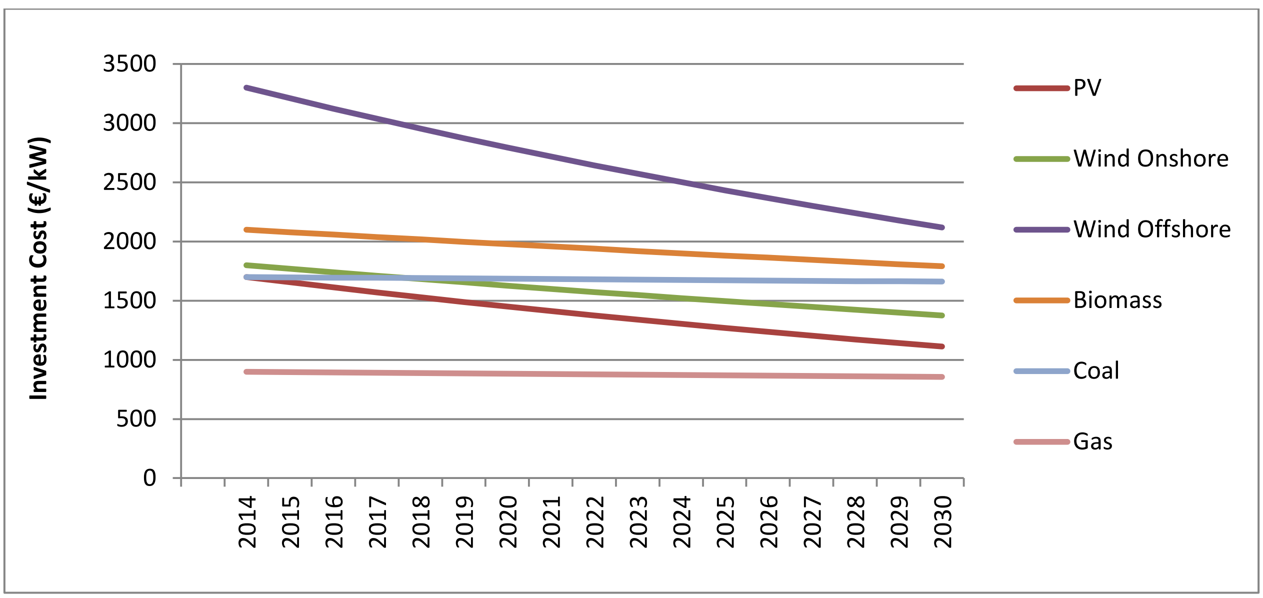


Figure 11: Evolution of the investment costs due to the learning effect



When we combine the LCOE methodology with the learning curve methodology, we find the following general formula to estimate the cost of electricity production with a given technology (n) at a time (t):

$$LCOE_{n,t} = \frac{INV_{n,t0}\left(\frac{CAP_{n,t}}{CAP_{n,t0}}\right)^{-\alpha}}{\left[FLEOH_{n,t} \times \left(\frac{1-(1+DR)^{-\tau n}}{DR}\right)\right]} + O\&M_n + FS_n + C_{n,t}$$

Combining all the equations, we can see that the cost of producing electricity in a year (t) with a given technology depends on:

- The investment costs in time t0 (INV_{t0})
- The globally installed capacity at t0 (CAP_{t0}) and time t
- The learning rate ($\alpha = -\frac{\ln(1-LR)}{\ln(2)}$)
- The discount rate (DR)
- The lifetime (τ) of a given technology (n)
- The Full Load Equivalent Operating Hours (FLEOH) in a given year
- The carbon cost in a given year (t) for a technology (n)
- The O&M costs (assumed to be constant in time)
- The fuel costs (assumed to be constant in time)

However, keep in mind that for most technologies, the formula can be simplified. For example, there are no carbon or feedstock costs for PV and wind. Also, there are no learning effects for nuclear, CHP and OCGT's. In addition, the FLEOH is assumed to be constant in a given scenario, except for the CCGT's. The CCGT FLEOH depends on the Load Factor, which is calculated based on the 'gap' between the supply and the demand, assumed to be filled by these flexible assets.

The total cost of electricity production in a given year is then given by:

$$LCOEsystem_t = \sum_{n=1}^{k} LCOE_{n,t} \times Prod_{n,t} \qquad [€/MWh \text{ x } MWh = €]$$

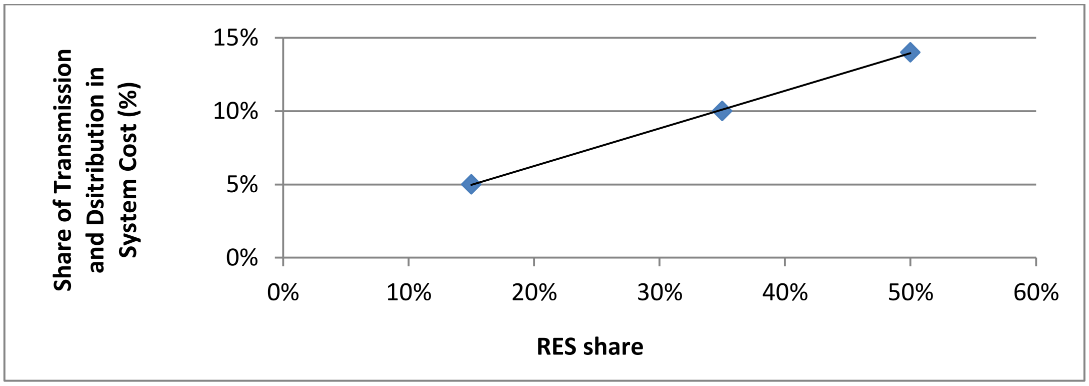
With	$LCOEsystem_t$	= Total system LCOE cost in a given year (t)
	$LCOE_{n,t}$	= LCOE of a technology (n) at time (t)
	$Prod_{n,t}$	= Electricity produced by technology (n) at time (t)
	k	= Number of technologies in the system

3.2.5 Endogenous distribution and transmission cost estimates

The cost of electricity supply is not limited to the sum of the costs of the generation assets. Costs in transmission and distribution should also be taken into account. The costs of connecting a 400 MW offshore wind park to the grid are significantly higher than the costs of adding a 400 MW CCGT plant. The OECD-NEA study of 2013 provides a relationship between the increase in RES and the increase in overall system costs.

Figure 12 is based on a German case study from the OECD-NEA report and shows the relationship between the share of renewables and the additional distribution and transmission costs. It indicates that the share of transmission and distribution in the overall system costs increases to 14% if renewables increase to a share of 50% in overall electricity supply.

Figure 12: RES share and transmission and distribution cost increase (based on data from (OECD - NEA, 2013))



It should be stressed that this linear relationship between the share of renewables and the share of transmission and distribution costs is a simplification of the reality. Firstly, this relationship does not take into account the differences between various technologies. The cost for connecting offshore wind turbines is higher than the cost of connecting onshore wind turbines. Also, the additional grid costs of adding more biomass to the system are lower than other renewable technologies. In short, the relationship between the share of renewables and the distribution and transmission costs is in reality more complex than what the above graph suggests. However, as the energy mix used in the German case study is similar to our scenarios for the Belgian energy mix, we feel that it is justified to apply the results of the German case study to Belgium. In both cases, the renewables mix consists of roughly 50% dispatchable (biomass + hydro) and 50% intermittent renewables (PV + wind). The total System costs in the Belgian case are then estimated (based on the German case study) to be given by the following empirical equation:

$$\text{System T\&D Cost Share (\%)} = 0{,}247 \text{ x Res Share (\%)} + 0{,}014$$

$$\text{Total System Costs} = \text{LCOEsystem x } (1 + \text{System T\&D Cost Share}) \qquad [€]$$

3.2.6 Subsidy Costs

In order to estimate the subsidy costs for RES with a support scheme responsive to market dynamics we assume a Contract-For-Difference approach (see 3.5.2). As this scheme responds to market prices, an estimate of the future wholesale electricity price is needed to assess the difference between the market price and the targeted support. It is obviously very difficult to extrapolate the price of electricity in the next 15 years. Our estimates are based on a combination of recent data by the EU commission (European Commission, 2013) and a report from OECD-NEA on the German electricity system with nuclear capacity and an increasing share of RES (OECD - NEA, 2013).

The report by NEA/OECD finds an endogenous relationship between the share of RES and the wholesale market prices. They present various load duration curves for a system with 21 GW of nuclear capacity - in a system with a total reliably available capacity of about 80 GW. The share of renewable electricity (a mix of PV, wind, biomass and hydro) in this system increases from 15% to 80% (keeping other things constant). The result is that the average wholesale prices decrease with a higher renewables share (blue dots in Figure 13). The prices mentioned here are yearly averages. This is very important since, in practice, there is a relatively strong variation in the day to day and hour to hour prices on wholesale electricity markets, depending on the availability of PV or wind assets and imports from neighbouring countries. The following formula for the German case study presents the relationship between the electricity price and the share of renewables:

$$P = -78{,}8x^2 + 1{,}41x + 73{,}7$$

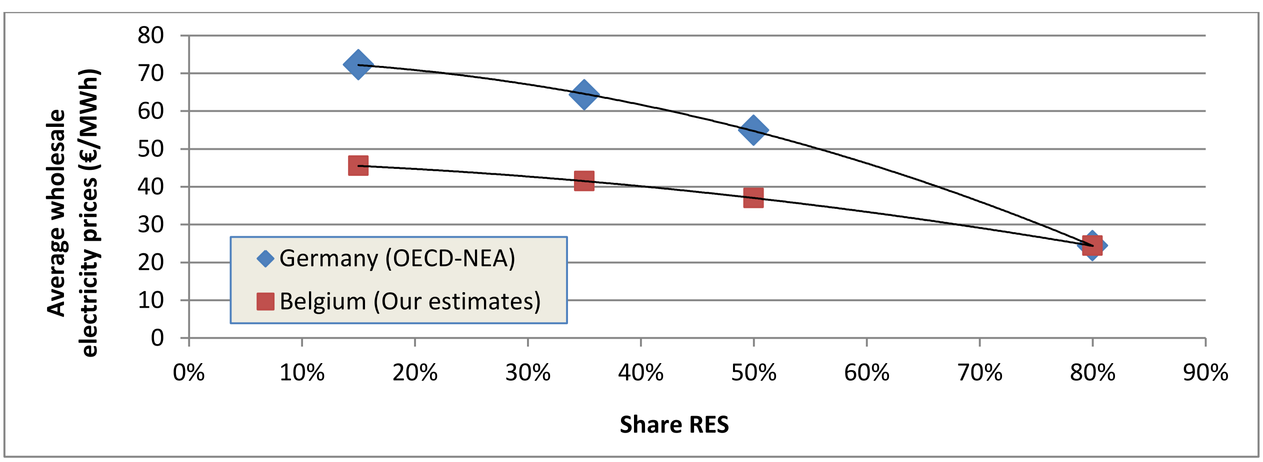
With P = wholesale price
X = the share of renewable electricity

However, recent wholesale prices in Belgium are not even close to the € 70 per MWh that was found in the German case (corresponding with a 15% share of renewables). Therefore, we adapted the above relationship in line with today's lower prices. Based on the average wholesale prices in Belgium in the period 2003-2012, we assumed that the average price would be 45,5 €/MWh in the 15% RES case. The price then also decreases with higher shares of renewables, and is equal to the price for the German case study in a 80% renewables scenario. The following relationship for the electricity price in Belgium is used:

$$P = -27{,}6x^2 - 6{,}32x + 47$$

With P = wholesale price
X = the share of renewable electricity

Figure 13: Relationship between average wholesale electricity prices and share of Renewables (blue data: (OECD - NEA, 2013))



An average wholesale price of 30 €/MWh for a given year, for example, does not entail that gas assets are not used at all in this year, however, the load factor is these gas assets is likely to be low in such a case. The number of hours that have sufficiently high prices to trigger these assets will be rather limited.

3.2.7 Renewable Subsidy Costs

The cost of the renewable energy subsidies in a given year (t) is the sum of the costs of the subsidies for each renewable technology (n). For a given renewable technology (n), the total subsidy cost in a given year (t) is calculated as follows:

$$RE_{n,t} = RE_{n,t-1} + \left(Prod_{n,t} - Prod_{n,t-1}\right) \times (LCOE_{n,t} - P_t)$$

With $RE_{n,t}$ = Renewable Electricity subsidy in year (t) for technology (n)
$Prod_{n,t}$ = Electricity produced in year (t) by technology (n)
$LCOE_{n,t}$ = Levelized Cost of Electricity in year (t) by technology (n)
P_t = Electricity Price

This formula shows the definition of the "contract for difference" approach. New investments in renewables capacity result in an increase in the production of renewable electricity compared to the previous years $\left(Prod_{n,t} - Prod_{n,t-1}\right)$. This additional production receives a subsidy which is equal to the difference between the levelized cost and the electricity price $(LCOE_{n,t} - P_t)$. This stream of revenue is guaranteed for the whole lifetime of these assets, which is at least 20 years, considerably longer than the timeframe of this study (2015-2030).

This approach is very intuitive for the calculation of subsidies for technologies that always have an increasing amount of electricity production. However, there is one exception to the rule that the electricity production of renewables always increases. In the market participation scenarios, the share of biomass decreases in the year 2014 compared to 2013. This results in a drop in production and consequently a drop in the subsidies. Consequently, $RE_{n,t}$ becomes negative, as the subsidies in 2014 are lower than the subsidies in 2013. In practice, a forced reduction of biomass output from one year to another is very unlikely. This would essentially be a breach of contract. Off course, this theoretical model is not designed to deal with such practical issues and problems.

3.2.8 Capacity Subsidy Costs

The subsidies for the availability of capacity for a given technology (n) at time (t) are calculated in the following way:

$$AV_{n,t} = INV_{n,t} \times \left(CAP_{n,t} - CAP_{n,t-1}\right)$$

With $AV_{n,t}$ = Availability Subsidy for technology (n) at time (t)
$INV_{n,t}$ = Investment cost for technology (n) at time (t)
$CAP_{n,t}$ = Installed capacity for technology (n) at time (t)

In words, the upfront investment cost of a technology is reimbursed when the installed capacity of this technology increases, in other words, when $\left(CAP_{n,t} - CAP_{n,t-1}\right)$ > 0. Keep in mind that the investment costs decrease in time (due to the learning effect).

The way this upfront cost is calculated is very different compared to the renewable subsidy costs. The most remarkable difference is that in the renewables subsidy scheme, the investment costs are spread out in time, using the LCOE-methodology. While the capacity subsidies are one-off payments. Consequently, the RE subsidy streams are very stable in time, while the AV costs can be zero in some years, and be very high in other years. In order to facilitate the comparison of the subsidy costs between the various scenarios we have opted to provide results on the cumulative subsidy costs, in addition to the annual subsidy costs, as the latter can fluctuate markedly from year to year.

For Biomass, we opted to have a 'hybrid' subsidy system: a capacity payment, and renewable electricity subsidy, since this technology provides both reliable capacity and renewable electricity. The capacity subsidy is equal to 50% of the upfront investment costs, and the renewables subsidy is based on the LCOE of biomass, taking into account that only 50% of the upfront investment needs to be compensated.

3.2.9 Total Subsidy Costs

The subsidy costs in a given year (t) are given by the sum of the capacity subsidies and the renewables subsidies:

$$SC_t = \sum_{n=1}^{k} RE_{n,t} + AV_{n,t}$$

With SC_t = Subsidy Costs in a given year (t)
$RE_{n,t}$ = Renewable subsidy
$AV_{n,t}$ = Availability Subsidy

Notice that for most renewables, there is no AV subsidy, only biomass assets receive RE and AV subsidies (see section 3.5).

3.3 Overview of assumptions

3.3.1 Evolution of peak demand

First of all, we need an assessment of the evolution of peak demand. Our assessment is based on peak load data from Elia (see Figure 4) and on the FOD Economy Report on the supply of electricity in Belgium in 2012-2017 (FOD Economy, 2012). In our study we assume a 0,5% increase in annual peak demand (starting at 13 500 MW in 2013) which results in a peak demand of 14 700 MW in 2030. However, demand side management could reduce this need (see Figure 17). The costs calculated in this report should be interpreted with these assumptions in mind. *If we can decrease peak demand - by reducing energy consumption in winter or by the widespread use of DSM - costs in any given scenario will be lower. However, if peak demand increases, the opposite will be the case and overall costs will be higher.*

$$PD_{t+1} = PD_t \times 1{,}005 \qquad [MW]$$

With t =year
PD = Peak Demand [MW]

3.3.2 Evolution of the carbon price

The price of carbon in the ETS is currently at a very low level. This level certainly does not represent the "real" environmental cost of a ton of GHG-emissions. Also, many stakeholders in the energy business and politicians agree that the current price is too low to trigger investments in low carbon technologies. We assume that the price of carbon will increase: from € 8/ton $CO_{2\text{-eq}}$ in 2014 to € 40/ton $CO_{2\text{-eq}}$ in 2030. The cost of 1 tonne of CO_2 increases with € 2 each year. The CO_2 price is assumed not to be impacted by the share of renewables in Belgium, because the impact of the Belgian electricity market on the EU ETS is considered to be very small. In other words, the ETS price is exogenous in this model and it is driven by European legislation. In ANNEX 1 we also add a sensitivity analysis with a CO_2 price that increases with only € 1 each year or € 3 each year.

3.3.3 Discount rate

For the calculations of the levelized cost of electricity, we use a discount rate of 8%. Lower discount rates will result in lower costs. Higher discount rates will result in higher costs, especially for assets with high upfront investment costs (wind, PV, hydro and nuclear). In ANNEX 2 we also add sensitivity analysis with lower (4%) and higher (12%) discount rates.

3.3.4 Cost calculations

All costs are calculated in real terms and do not include inflation. The subsidy costs of the current system are not included in our scenarios. Negative cost changes can in principle occur, indicating that implementing a given policy will reduce the current system costs (e.g. by lowering the subsidy cost of renewable generation technologies). For example, in some scenarios the biomass assets are incentivized to run in a more flexible way. This will reduce the costs of support for biomass plants compared to the support scheme already in place. At the moment there is no real incentive for the flexible use of biomass capacity.

3.3.5 Technology assumptions

For all evaluated technologies the assumptions on investment costs, load factor, learning rate and other parameters such as feedstock and operational and maintenance (O&M) costs can be found in Table 3.

These assumptions are the baseline assumptions for 2014. Carbon costs will increase with time (see section 3.3.2) and investment costs will decease according to learning rates. Feedstock (coal, gas, uranium, biomass pellets) and O&M costs are assumed to be constant in the period concerned. This was done to improve transparency of the results. The goal of this paper is to compare various policy scenarios, adding variable feedstock costs will make it harder to interpret the results of this study. Therefore, we choose to keep them constant. Predicting future feedstock costs is in any case highly speculative and very difficult.

The load factor is an important parameter, as it can have a big impact on the cost of electricity production, especially for assets with high investment costs. In reality the LF is driven by a variety of circumstances (import, export, weather). In this model we assume - for a given scenario - a constant LF for all technologies except OCGT's, which are expected to fill the gap between the supply from OCGT's, renewables, CHP, and nuclear and the demand. The LF of the renewables will also depend on the policy choices regarding the market participation of renewables in the system, see section 3.5.2.

Table 3: Technology Properties (sources: (OECD - NEA, 2013) (EPIA, 2012) (Department of Energy and Climate Change, 2012) (IEA, 2010) (IEA, 2010) (Laleman, Balduccio, & Albrecht, 2012)

Assumptions *2014 estimates*	**Life time**	**LF**	**LR**	**Invest. Cost**	**O&M Cost**	**Feedstock Cost**	**Carbon Cost**	**LCOE 2014**
	(years)	(%)	(%)	(€/kW)	(€/MWh)	(€/MWh)	(€/MWh)	(€/MWh)
PV	25	11-12	15	1700	10	0	0	175-192
Onshore Wind	25	24-28	8	1800	18	0	0	95-102
Offshore Wind	20	29-33	10	3300	30	0	0	158-167
Hydro	50	34	5	4000	20	0	0	144
BM (Large Scale)	25	35-68	7	2100	15	75	0	127-154
Coal	35	80	5	1700	7	30	8	66
CCGT	30	10-90	7	900	5	50	4	74-200
Nuclear	50	90	0	5700	13	8	0	84
CHP	35	68	0	1200	15	30	2	71
OCGT	40	11	0	700	20	65	6	158

3.4 Security of supply scenarios

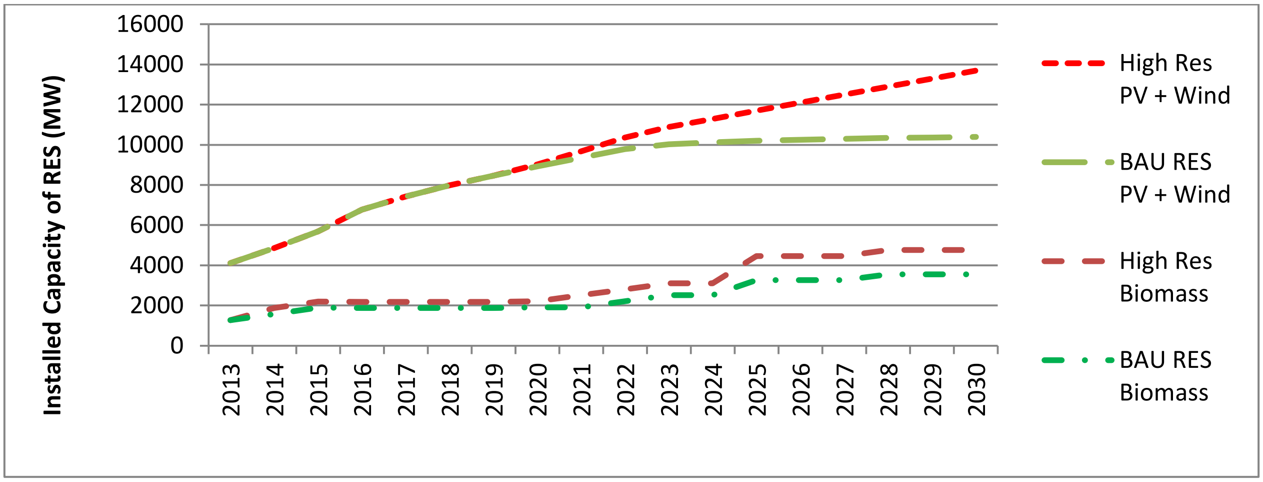
As mentioned before, the reserve margin (RM) is above 5% at all times, in our calculations. This is a relatively optimistic assumption, given the strong decline in capacity in 2024-2025. The 5% reserve margin can only be attained by adding new capacity. We focus on the costs of the incentives needed to motivate investors to install new capacity. To ensure a 5% RM at all times, our model autonomously triggers new investments once the RM is below 5% in a given year. We assume that every capacity shortage is filled with investments in CCGT, OCGT and biomass plants. We elaborate in section 3.4.1 on the share of each technology in the additional supply to secure the 5% RM. In alternative scenarios, we evaluate the impact of an increase in DSM potential as well as a combination of incentives for new gas plants and support policies for old gas plants. Finally, a policy that combines all three options is discussed.

3.4.1 'Business as usual (BAU)' and high renewable scenario (High RES)

For all policy options considered, we distinguish two possible evolutions of renewable capacity, namely a 'high renewable' future and a 'business as usual' renewable future. Both scenarios differ in the installed capacities of CCGT's, biomass, wind and PV that will be added to the system in the coming years. The evolution of biomass capacity on the one hand and PV and wind on the other hand is shown in Figure 14.

The difference between both renewable capacity scenarios is determined by policy choices regarding RES. Biomass is a special kind of RES, since it is not weather dependant. Additional biomass capacity contributes to a higher reserve margin. As a consequence, biomass can replace a share of the disappearing nuclear and fossil assets. This is why a jump in biomass capacity occurs in 2023-2025, since in that period, 3 000 MW of nuclear capacity is planned to be phased out. The added capacity of biomass plants is higher in the "High Res" case and a lower in the "BAU RES" case.

Figure 14: Evolution of renewables installed capacity (biomass, wind, PV) in BAU and high Res scenarios



For offshore wind, we assumed in both renewable scenarios that all the approved Belgian offshore parks will be operational by 2023 resulting in a final offshore capacity of 2 300 MW. PV and onshore wind are assumed to have a decreasing growth rate in the "BAU RES" scenario but a linear growth in the "High Res" scenario. For hydro we assume that no further growth is possible in Belgium, hence the installed capacity remains stable between today and 2030. The assumptions for the BAU and high renewables scenarios are summarized in Table 4.

Table 4: Summary of assumptions for the BAU and High renewables scenarios

In case of a shortage (RM < 5%), missing capacity is replaced with		
	BAU RES	**High Res**
CCGT	60%	50%
Biomass	20%	30%
OCGT	20%	20%
Final Capacity installed in 2030 (MW)	**BAU RES**	**High Res**
Wind Onshore	3333	4904
Wind Offshore	2300	2300
PV	4756	6488
Hydro	94	94
Biomass	3558	4758
TOTAL RES capacity	*14042*	*18544*
Total installed capacity	*27167*	*30169*

With respect to biomass, it is important to stress that additional capacity does not automatically result in more biomass electricity production. As will be explained later, biomass has the important advantage of being a controllable or "firm" generation technology that can be used in a flexible way in response to market signals. Depending on market circumstances, biomass can be used as a baseload plant with high load factors or as a flexible medium-load plant with much lower load factors. In short, the total amount of renewable electricity actually produced will strongly depend on the policies regarding biomass electricity production.

3.5 Incentive scenarios to guarantee security of supply

3.5.1 Introduction

Table 5 provides an overview of the possible policy scenarios. We combined two types of “Renewables Supply” policies (see next section) with three types of “Capacity Need” policies (the last “Capacity Need” scenario is a combination of the three previous ones), in this way we obtain eight different scenarios. The details will be explained below.

Table 5: Overview of Scenarios

RES Supply		*Capacity Need*	**NEW**	**DSM**	**Old Thermal**	**DSM + OT**
CFD	**contract for difference**		1	3	5	7
CFD-MP	**CFD-market participation**		2	4	6	8

In all scenarios, capacity payments are introduced to incentivize the build-up of controllable assets, i.e. we assume capacity payments for biomass plants, OCGTs and CCGTs. The capacity payments are part of the subsidy costs (see section 3.2.9). Table 6 shows our assumptions on capacity payments. For biomass we opted for subsidizing only 50% of the upfront investment costs. The investment costs of biomass plants far exceed the investment costs of gas-powered plants but biomass plants also receive financial support per MWh of renewable electricity produced. We thus provide a hybrid incentive system for biomass; a capacity payment equal to 50% of the investment cost since biomass investments add to the reliable capacity, and a CFD-contract as a renewable support subsidy (see 3.5.2) covering all other costs (the remaining 50% of investment and all the operational costs). The support per MWh under this CFD-contract depends on the load factor (LF) of the biomass plant; the lower the LF, the higher the CFD-support per MWh has to be to compensate higher capital costs per MWh produced.

Gas fired plants only receive a capacity payment, and no separate incentives for production. Marginal costs for CCGT’s are assumed to be sufficiently low to trigger start up of power plants in case of rising demand. OCGT’s have higher marginal costs but are assumed to only to produce electricity in times of scarcity. The latter situation is likely to occur more frequently in the coming decades as more intermittent renewables will be on line and more firm capacity is phased out.

Table 6: Assumptions on Capacity Payments

Technology	**Share of upfront investment covered**	**Cap Payment (€/ kW)**
Biomass	*50%*	1050
CCGT	100%	900
OCGT	100%	700

3.5.2 Renewable supply measures

Contract for Difference scenario (CFD)

A CFD policy provides a guaranteed revenue stream for the (renewable) power plant operator. In principle, the gap between the market price and the average electricity production costs is covered by the CFD-scheme. For wind and PV, the levelized cost of electricity is compared to the estimated average electricity price on the market. For biomass, the LCOE is calculated based on an estimated investment cost of € 1050/kW (50% of investment, since it also receives a capacity payment, see Table 6).

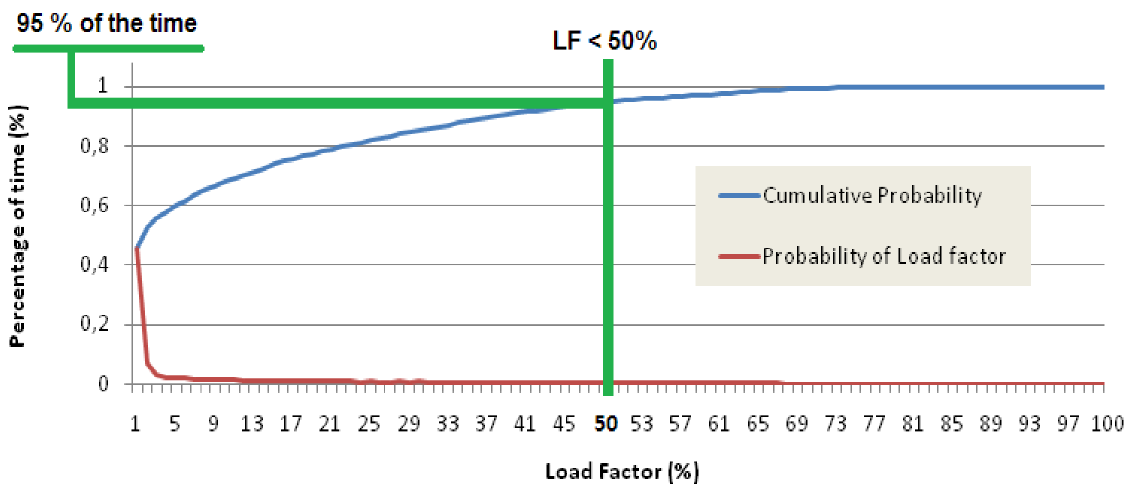
Market Participation (CFD-MP)

In the CFD scenario, renewables are not incentivized to reduce output in times of low demand with a potential risk for overproduction (e.g. on a sunny summer weekend with strong wind). *In the CFD-MP scenario we still assume a CFD-mechanism, but add some constraints on the feed-in of variable renewable electricity production* (wind and PV). Also, we assume that biomass will be operated in a flexible way. As a consequence, in the CFD-MP scenario, biomass plants run with a load factor of only 35% (about half the current load factor) while PV and wind can be curtailed under specific circumstances. We assume that PV and wind are only curtailed at times when they produce above 50% of their theoretical maximal output - from a country wide perspective. Beware, in practice, this does not entail that wind and PV will always have to be curtailed at times when their load factors exceed 50%. However, this 'rule' was introduced in the electricity model in this way. Put differently, this assumption simply implies that wind and PV will never be curtailed when they produce less than 50% of their theoretical maximal output[7]. Based on real production data from 2012-2013, we concluded that curtailments will be rather rare.

Figure 15 illustrates that the total output of all PV panels in Belgium rarely exceeds 50% of theoretical maximal capacity of all PV-systems installed in Belgium. This is actually not that surprising in a country with modest solar conditions. If we apply the "market participation" policy, this would result in a rather modest decline of the load factor of PV from 12% to 11%. From the graph we can see that only 5% of the time it would be necessary to actually top-off some PV-systems. In reality, curtailment of residential PV installations requires the roll-out of a smart grid with smart meters. We realize that there will not be such a comprehensive smart grid in Belgium in the next years. Nevertheless, a further increase of residential PV capacity without the technical ability to control and regulate PV output is not a consistent policy scenario. From 2030 onwards, a smart grid would be beneficial to facilitate the further expansion of residential PV capacity and other renewables.

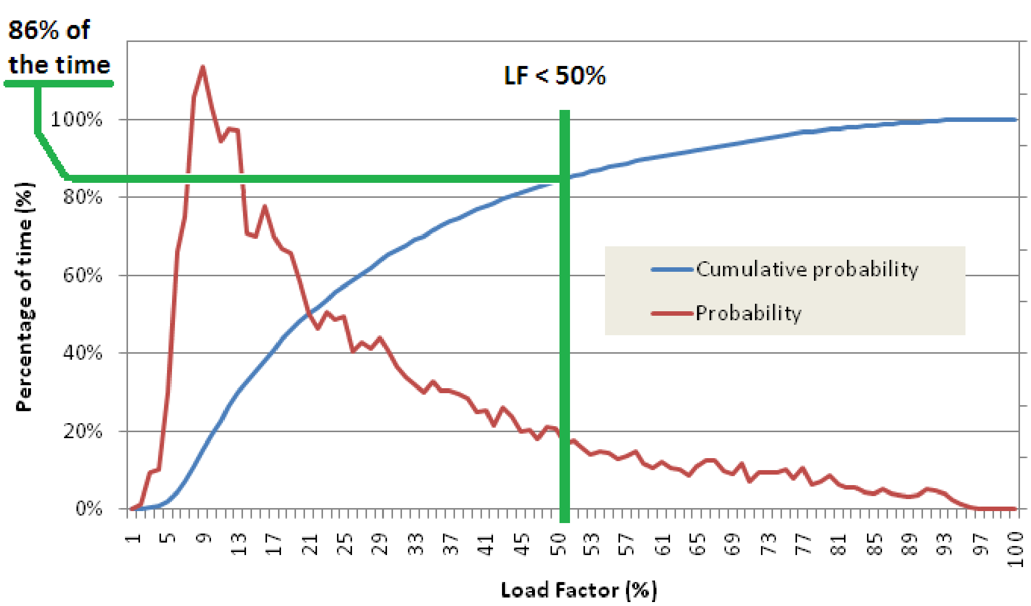
[7] Let's clarify this "curtailment option" with a numerical example. If, in a given year, the total capacity of PV-systems in Belgium is equal to 6000 MW, curtailment will be possible once the production of all the PV-systems combined exceed 3000 MW. The same goes for wind capacity.

Figure 15: Probability curves for the load factor of PV-production in Belgium (Elia, 2013)



A similar logic is applied to the curtailment of wind energy. However, the probability of the total wind output in Belgium going above 50% of nominal output is slightly higher (Figure 16). This is not really an issue since it would probably be easier to curtail wind production compared to PV production.

Figure 16: Probability curves for the load factor of onshore wind production in Belgium (Elia, 2013)



Capping the total wind production in Belgium at 50% of theoretical maximum output would result in a decrease of the LF from 28% to 24%. Actually, in practice there is already some load shedding of wind occurring in Belgium at times of low demand and high wind speeds. For offshore wind insufficient data is currently available. Therefore we assume a decrease in the LF for offshore wind from 33% to 29%.

Summary of Renewable supply policy options

In all scenarios, the CFD incentive scheme is applied to wind (onshore and offshore), PV and biomass. It is designed in such a way that whatever the design of the system -with or without market participation- the total returns for the investors will be equal to the LCOE of the technology. Because of this, the LCOE for the technologies will be slightly larger in the "CFD-Market Participation" scenario, since the lower load factors need to be compensated by increasing the CFD-payments. Biomass is a special case; the CFD cost is based on only a part of the overall costs, since biomass investments also receive a capacity payment (see Table 6). Also, the load factor for biomass assets decreases the most (from 68% to 35%) because biomass plants have the ability to follow the load and can be used in a flexible way.

3.5.3 Incentives for firm capacity

The *Plan Wathelet* specifically mentions some incentives to stimulate new capacity additions on top of the increase of demand side management and an extension of the strategic reserve as options for dealing with the supply concerns. Given the nuclear phase out and the current lack of market incentives for new capacity, this is a very legitimate policy concern. We will evaluate these options in this study.

The increase of strategic reserves is referred to as the "Old Thermal" option in our analysis (see further). In this scenario we consider the possibility of keeping old thermal assets (scheduled to stop in the period 2014-2025) online until 2025 to cope with possible shortages.

New Capacity

In the "New Capacity" scenario there is no additional DSM potential used and all existing capacity that was planned to be phased out is replaced with new assets (biomass, CCGT and OCGT). Obviously, the total cost of this scenario will be significant.

Old Thermal

In this scenario we assume that we can provide specific incentives for capacity scheduled to be closed in the next 10 years (roughly 1300 MW in 2014-2024) to remain online and provide backup in times of need. In 2012, the tertiary reserve contracted by Elia was only 400 MW. This capacity produced about 13,8 GWh of electricity in 2012 and was operational for about 1% of the time. In a world with increasing volatility and low reserve margins, these 'back-up' load factors are likely to be higher.

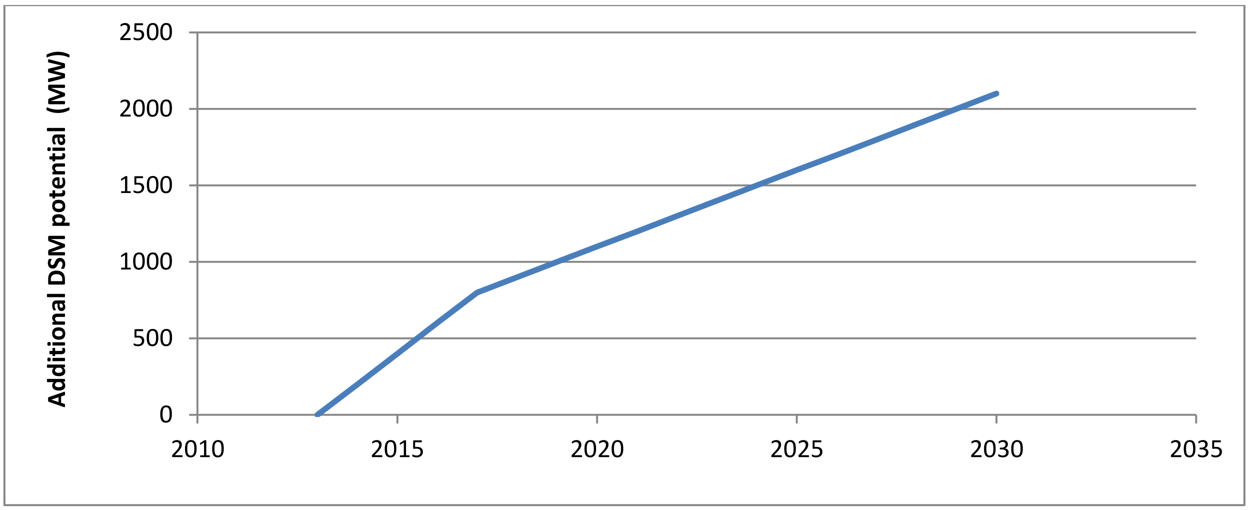
We assume here that they would have a load factor of 5%. The "Old Thermal" assets receive a 'back-up' subsidy equal to about 95€ per MWh produced. Overall, an annual subsidy of € 50-60 Mio would be required from 2014-2024 to keep them online. It is hard to estimate what the costs would be in reality; an auction would be best to reach truly accurate cost estimates.

Demand side management

The *Plan Wathelet* mentions the possibility to increase DSM with 400 MW by the end of 2015. Based on this ambition, we created a DSM scenario (Figure 17) with a period of faster DSM potential growth in the beginning (2014-2017) and a more modest growth from 2017 onwards. This scenario is based on the assumption that the "easy" DSM options will be spotted first and that further DSM development might be more complicated.

The costs of this DSM scenario - as an alternative or additional to capacity payments for new or old assets - were estimated based on a report by UBS (UBS Investment research, 2013). The report mentions auction clearing prices for a capacity auction in the 'US-PJM' capacity market of about $ 110-250/MW per day for any kind of capacity (e.g. DSM, conventional generation or other options). UBS also states that prices could be lower for Europe. Based on this information, we assumed a conservative clearing price of € 150/MW/Day.

Figure 17: Evolution of DSM potential in Belgium (own estimates, based on Plan Wathelet until 2015)



It is important to stress that the above graph only refers to downward DSM potential. This can be considered as a kind of strategic reserve, only to be used in cases where peak demand would be very high. Also, the increased amount of DSM does not result in lower annual electricity demand. The demand for electricity is "moved" to other hours, and not reduced. The increase of upward DSM is not considered here, as it serves other purposes in the electricity market.

Old Thermal and DSM combined

As a final scenario we chose to combine the DSM scenario and the "Old Thermal" scenario. In this case, new capacity is only added when DSM and the 1.300 MW of "old thermal" are not sufficient to keep the RM at a 5% level. After 2025, when the old power plants in the "old thermal" scenario are assumed to be phased out together with the remaining nuclear reactors, this scenario will evolve into the DSM scenario.

Summary

Various options to obtain a "secure supply" system with a reserve margin above 5% are considered in this study. New capacity can be installed, old capacity can be used longer as a strategic reserve, and the potential for downward DSM can be increased. We will first of all evaluate the impact of each scenario separately. After this assessment, some of the scenarios will be combined. We present total subsidy costs as well as the annual system costs and the cumulative (2014-2030) system costs for each of these policy choices.

3.6 *Discussion: PRIMES and TIMES*

Most studies that analyse the energy system use (models which are based on) PRIMES and TIMES modelling. These are economic partial equilibrium models which are able to model the entire energy system (electricity, transport, heating, ...). The PRIMES model is considered to be the most detailed and most “realistic” model, based on economic decision-making, but also takes more practical “engineering” restrictions into account, compared to other economic models. It is also used by the European Commission for energy system modelling[8].

Our model is similar to the PRIMES model, in the sense that we use the perspective of the economic agent (the investor). For example, we apply the LCOE-methodology to estimate the required electricity prices, to achieve a reasonable return on the energy investment. We also apply learning-by-doing for technologies. However, there are also many differences between our model and the PRIMES model. For example, the endogenous electricity price is modelled in a very different way in our model. Also, we focus only on the electricity sector; interactions with other energy sectors - and consequently the substitution between electricity and other energy sources - are not taken into account explicitly in the model. Other economic variables which are often important in the TIMES and PRIMES models, such as demographic data and GDP growth estimates are also not included in our model. Electricity demand in our model is exogenously given, in contrast to PRIMES, where demand and supply interact. The model in this study was specifically designed for the purpose of estimating the cost implications of a given policy choice in the current Belgian electricity market.

Some disadvantages of the PRIMES model - in relation to the research objectives of this study - are:

- Very complex (all energy sectors are modelled)
- Results are presented every 5 years, not annually
- Model owned by National Technical University of Athens: not open access
- More suitable for big countries or the EU as a whole, less for a small country

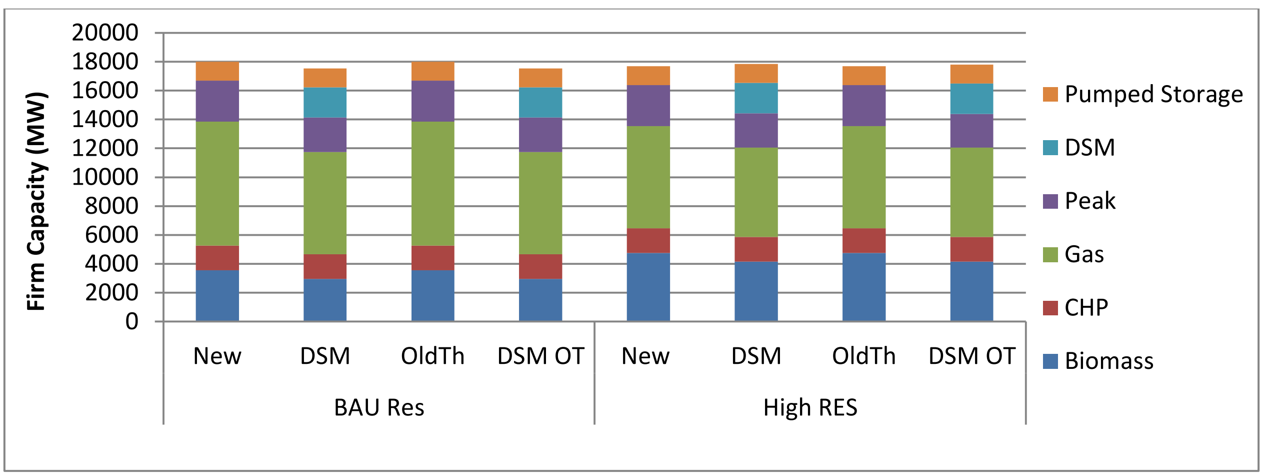
[8] http://ec.europa.eu/energy/sites/ener/files/documents/sec_2011_1569_2_prime_model_0.pdf

4 Results

4.1 Electricity Supply in 2030

As stated above, our model produces a "security of supply" portfolio with a RM above 5% at all times. This is an essential assumption in all the following scenarios. Figure 18 shows the resulting installed firm capacity in the different scenarios in 2030. In all cases the model foresees a total installed firm capacity of about 17,5-18 GW. Not all of this can be assumed to be available all the time (due to maintenance, accidents or other circumstances) hence an availability of 88% was assumed (based on FOD 2012 report). Given this correction we can assume that about 16 GW can be considered to be available all the time. Assuming a peak demand of 14,7 GW, we obtain a reserve margin (RM) of 8-9% in 2030. As assumed in the model, the lower limit of a 5% reserve margin (RM) is exceeded. Thus, peak demand in Belgium can in principle be met at all time with a safe margin. Notice that demand side management (2,1 GW in 2030) is also included in this graph, assuming it can contribute to a lower need for firm capacity. Figure 18 also illustrates that gas plants (CCGT) will have the biggest share in total installed firm capacity, followed by biomass plants. In the "BAU RES" scenario, biomass capacity will be about 3000-3500 MW, in the "High Res" it will be about 4000-4500 MW.

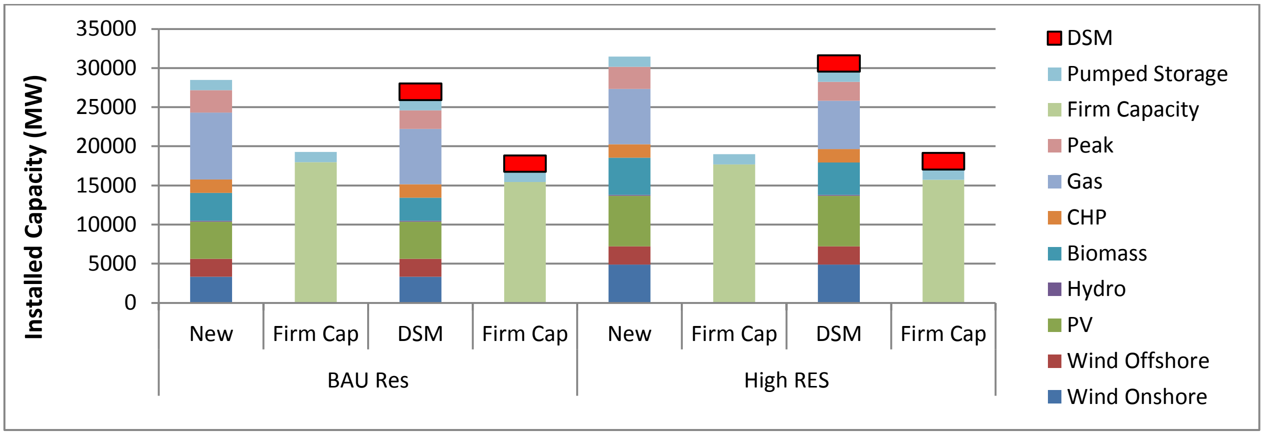
Figure 18: Firm Capacity in 2030 in 8 scenarios in Belgium (DSM= Demand Side Management, OT= Old Thermal)



The results in Figure 18 show that the shares of firm capacities are virtually the same in the "New" and in the "Old Thermal" scenarios. Old thermal support is assumed to stop in 2024, hence, from then on the "New" and "Old Thermal" scenarios are very similar when it comes to the total installed capacity, see 3.5.3.

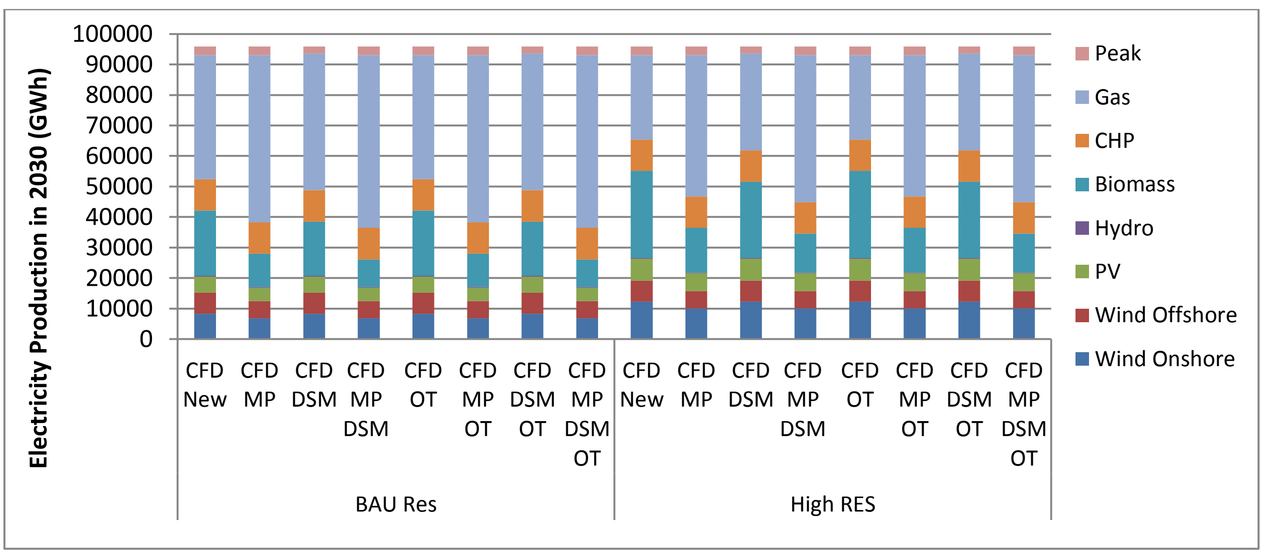
Figure 19 highlights that total installed capacity will be much larger than firm capacity. We do not mention the "Old Thermal" scenario in this graph since the results are almost identical to the "New" scenario in 2030. Depending on the scenario, the total installed capacity in Belgium will be about 25-30 GW in 2030. With a "firm" share of 18 GW, this means that roughly 30% (10-15 GW) of the capacity is not considered to contribute to the required 5% reserve margin. The most extreme case is the "High Res New" scenario, with a total capacity of 31 GW and an intermittent capacity of 14 GW - almost 50% of the total capacity is intermittent. When we compare this to the peak demand in 2030 (14,7 GW), we see that total installed capacity is more than twice the peak demand in the "High Res" scenario in 2030.

Figure 19: Total installed capacity in Belgium in 2030 (in 4 scenarios)



Notice that we do not mention the impact of "contract for difference" (CFD) and "CFD-market participation" (CFD-MP) scenarios in the above graph, since these policy options only affect electricity *supply* or the use of assets and not the installed *capacity*. The impact of the CFD-MP and CFD scenarios is however significant and will be illustrated in the following graph of the total electricity production in 2030 (Figure 20). DSM and storage do not appear in this graph since these are in principle not considered to be production assets.

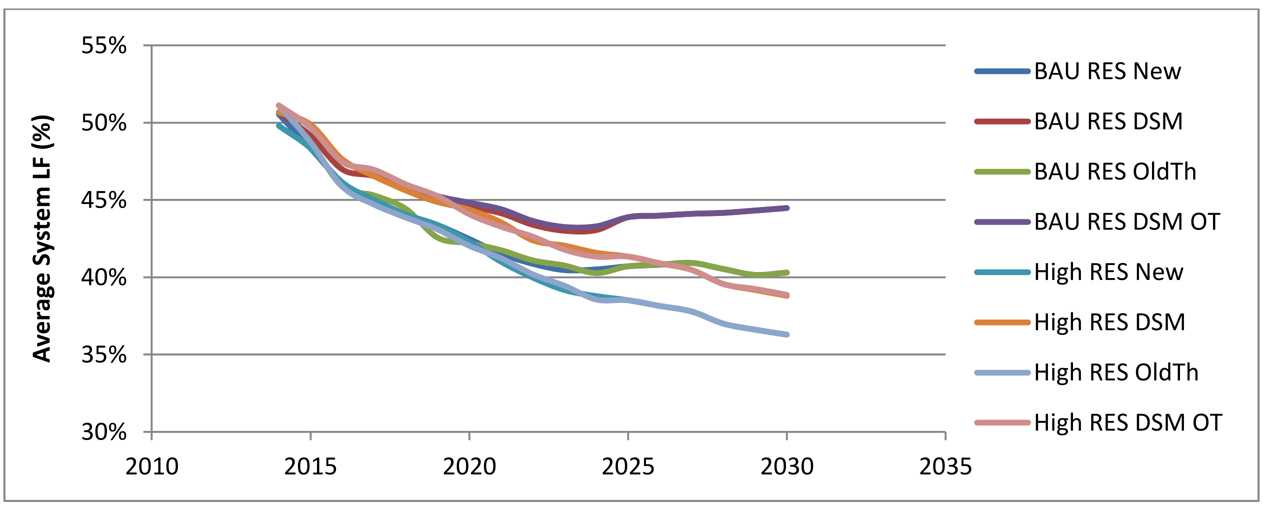
Figure 20: Electricity Production in Belgium in 2030, in 16 scenarios



The share of gas and biomass in total generation is very much influenced by the scenario of choice. Whereas "BAU vs High RES" determines the installed capacity of renewables, the CFD or CFD-MP scenarios determine the load factors. As explained above (section 3.5.2), in the CFD-MP scenarios, PV, wind offshore and wind onshore can be curtailed to a certain (limited) amount. This results in slightly lower load factors for these renewables. On top of this, biomass is used in a much more flexible way, reducing the load factors of biomass plants significantly (compared to current Grid-Priority policies). Mainly this latter aspect of the CFD-MP scenario will result in higher load factors for the remaining CCGTs. In the CFD approach (with no market participation) renewables are given no incentives to adopt and thus have higher load factors (especially biomass) and, by consequence, CCGTs only produce 40-50% of the electricity. The overall share of renewable electricity in total annual production varies from about 28% in the "BAU RES CFD" scenarios to almost 60% in the "High Res CFD" scenarios.

Installed total capacity in 2014 is about 20 GW (Figure 1). Given the assumptions and constraints of this model, this total capacity increases to about 30 GW in 2030, which is a staggering 50% increase. Annual domestic electricity demand, on the other hand, increases only by about 8%, from 89 TWh in 2014 (Figure 3) to 96 TWh in 2030 (Figure 20). This results in the inevitable decline of the overall load factor of the electricity system. Obviously, the higher the share of intermittent renewables, the lower the overall "generation portfolio" load factor. Figure 21 shows the decrease of the generation portfolio load factor[9]. Results for "CFD-MP" and "CFD" scenarios are the same, so they are not displayed separately in the graph. This is due to the fact that "CFD-MP" and "CFD" only influence the load factor of a given technology, in relation to another technology, not the total "generation portfolio" load factor. For example, in the "CFD-market participation" case, the load factor of renewables is lower, but the load factor of CCGTs is higher, the overall load factor of the portfolio as a whole remains the same - vice versa for the "Contract-For-Difference" scenario.

Figure 21: Total generation portfolio load factor



The impact of a different scenario on the decrease of the load factor is very significant. In the "BAU RES DSM" and "BAU RES DSM OT" scenario this effect is quite limited: the LF drops from 50% to 45%. In the "High Res New" and "High Res OT" scenarios, the LF decreases to almost 35%. Put differently, in the latter scenarios, on average about 65% of the installed capacity is not producing any electricity. Obviously, this will have a strong impact on the overall system costs of a given policy choice, as will be discussed in the following section.

[9] Generation portfolio load factor = Total electricity demand / (Total installed capacity x 365 x 24) = [MWh/MW/h]

Only one study was found that looks at the installed capacity in Belgium between now and 2030. The "Bureau Fédéral du Plan" recently published their view on the evolution of installed capacity in Belgium in a working paper (Bureau Fédéral du Plan, 2013). In Table 7 we compare our results with theirs. Their Nuc-1800 scenario corresponds to a BAU RES scenario and their EE/RES++ scenario corresponds to a High Res Scenario. The "Bureau Fédéral du Plan" used a PRIMES model to come to these results. The primary goal of this report was to determine the best way to obtain a balance between supply and demand, taking into account a number of constraints. The model calculates the necessary investments to respond to the demand. The evolution of the demand is presented as an input, through various scenarios, with or without increased efforts in demand side management and efficiency. Despite the use of a different model by the "Bureau Federal du Plan", the results they present are similar to the results found in this paper.

Table 7: Capacity in Belgium in 2030, results from this study and "Bureau Fédéral du Plan" (Bureau Fédéral du Plan, 2013)

			Installed Cap	**Reliable Cap**	**Intermittent Cap**
This Study	BAU RES		27 GW	18 GW	9 GW
Bureau FdP		Nuc-1800	27 GW	17 GW	10 GW
This Study	High Res + DSM		30 GW	16 GW	14 GW
Bureau FdP		EE/RES++	28 GW	13 GW	15 GW

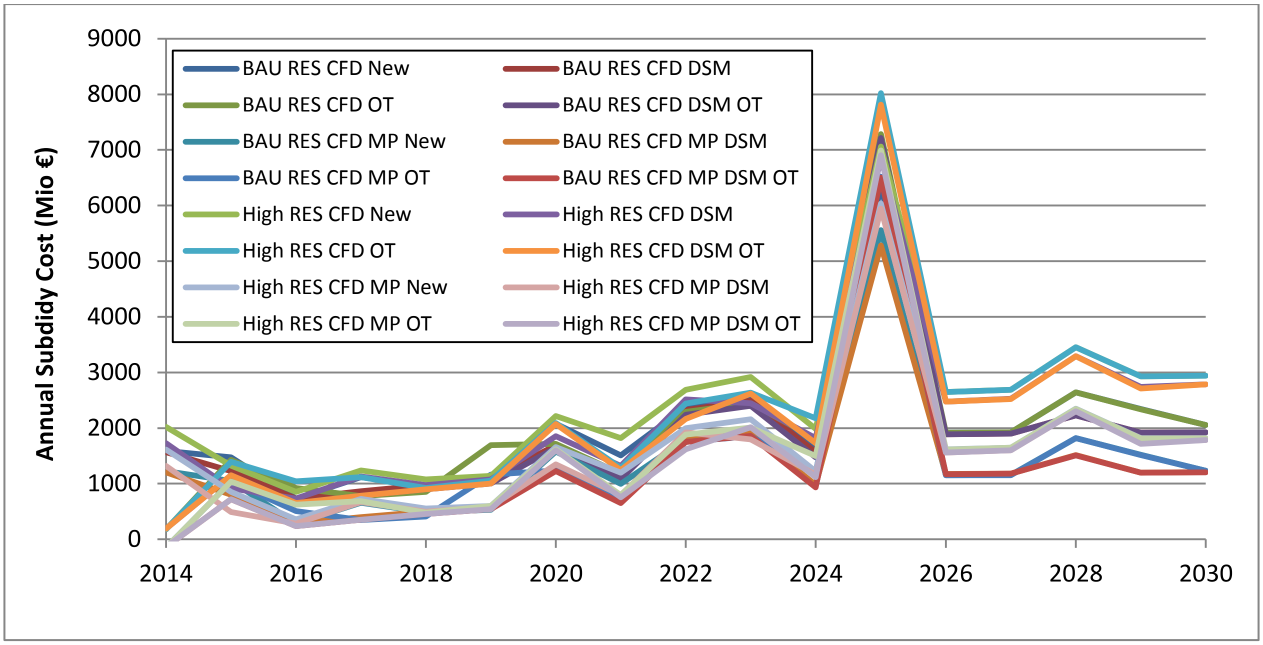
4.2 Annual and cumulative subsidy costs from 2014 to 2030

When interpreting the results, it is important to stress than the total annual subsidy costs – capacity remunerations plus production subsidies for renewable generation – of the different scenarios represent the *additional* cost of a specific option from 2014 onwards of a specific policy. The actual total annual subsidy costs are thus likely to be higher because of historical decisions such as guaranteed subsidies for renewable capacity installed in the recent years but with an impact up to 2030. For example, annual subsidy costs in Flanders were about 1,2 Billion € in 2012 (SERV, 2014). Most of these costs are due to the boom in solar PV in Flanders in 2008-2010, when subsidies were generous.

In contrast to energy policies of the past 5 years, we assumed that in the next couple of years some sort of capacity payment will be put in place (following the "Plan Wathelet"). Since these are modelled as one-off payments for investors in the year of installation, they result in high cost peaks in the years with new investments. In practice, these costs can be spread over time to reduce the impact of sudden expenditures, but for simplicity we assumed this not to be the case in the model. Given the huge phase out step in 2025 (see Figure 5) there is a high "capacity payment peak" in 2025 in all scenarios (Figure 22). The size of the peak varies from about € 5 Billion (in the "BAU RES MP DSM" scenario) to € 8 Billion (in the "High Res CFD OT" scenario). The reason for the highest peak in 2025 appearing in the Old Thermal (OT) scenarios is that all investments in new capacity are postponed until this date. This leads to a high cost in 2025, but lower costs in the period 2014-2024. More specifically, a gap between the OT scenarios and the other scenarios is very clear in the year 2014.

This gap is further exacerbated by the difference between the CFD and CFD-MP scenarios. In the CFD-MP scenarios, the costs of renewables incentives are much lower in the first year of implementation, mostly due to the big drop in biomass support. The biomass load factor falls from 68% in the CFD scenario to 35% in the CDF-MP scenario, this results in an obvious decline in annual biomass support costs, and thus overall subsidy costs.

Figure 22: Annual subsidy cost in 16 scenarios

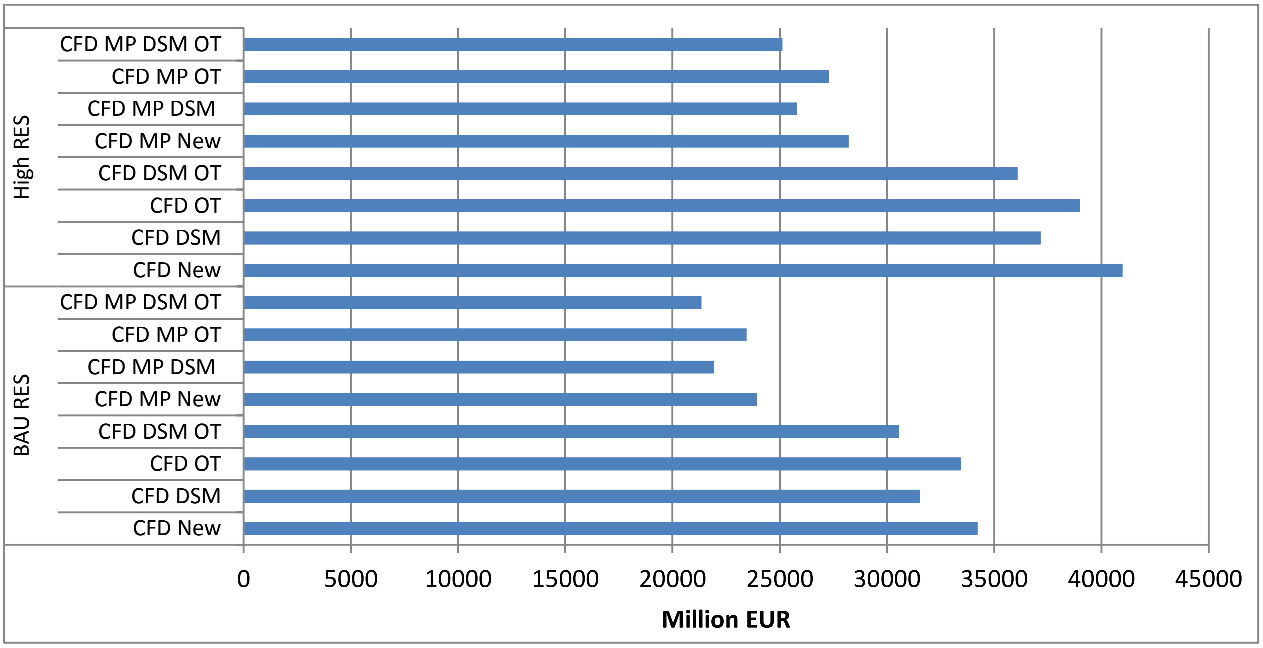


In the period before the peak (2014-2024) the annual subsidy costs for the different generation scenarios do not differ very much. They fluctuate around € 0,5-1 Billion per year in the period 2014-2019 and around €1,5-2,5 Billion per year in 2020-2024. After the peak however, the differences are much more pronounced. The cheapest scenario is around € 1,2 Billion/year (BAU RES CFD MP DSM OT), and the most expensive one is around € 3 Billion/year (High Res CFD New). This is due to the fact that, from 2025 onwards, almost all technologies in all of the scenarios receive some kind of support since almost none of the current capacity (available in 2014) will still be operational by 2030. A large portion of the firm capacity enjoys a capacity payment and all renewable assets get CFD-incentives. Biomass, being both controllable and renewable, receives a hybrid incentive scheme (see section 3.5). Obviously, in this case, a portfolio with a lot of renewables will also require a lot of subsidies.

As the annual subsidy costs can vary a lot from year to year and between scenarios (because of the capacity incentives) it can be hard to compare overall costs of the scenarios. To facilitate the interpretation we present the total cumulative subsidy cost between 2014 and 2030 (undiscounted, real prices) for all generation scenarios in Figure 23. The results for the cumulative subsidy costs clearly show that a different policy (thus a different scenario) will have a huge impact on the overall costs of the electricity system in the next 15 years.

The most expensive scenario "High Res CFD new" results in cumulative costs of roughly € 41 Billion, compared to € 21 Billion in the least expensive "BAU RES CFD MP DSM OT" scenario.

Figure 23: Total cumulative subsidy costs of 16 scenarios

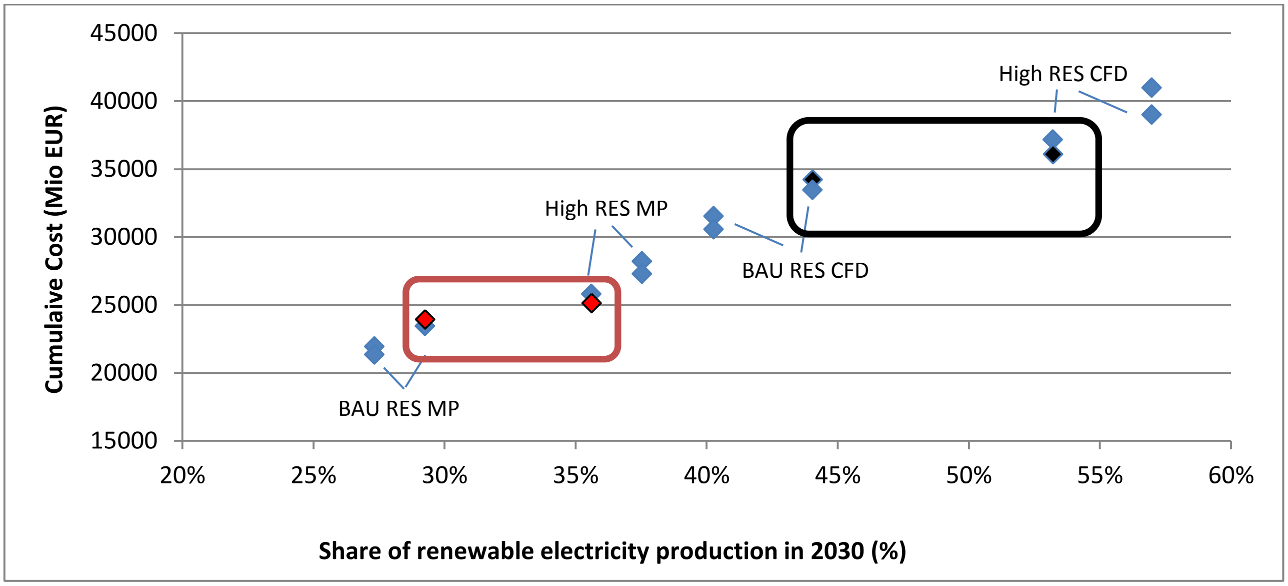


Another important observation is that demand side management scenarios are always significantly cheaper than their non-DSM counterpart. The effect of keeping old thermal capacity online is relatively small, since this policy option simply postpones the needed investments in new assets. This scenario can be seen as a way of "buying time" and possibly make better decisions in the future. However, the model does not put any value on time, whereas politicians may find this very attractive as this can make current policy less costly.

In Figure 24 we compare the share of renewable electricity production in 2030 and the cumulative costs. The graph shows two interesting gaps, where a strong increase in the share of renewables only results in a modest increase in total cumulative support costs (see red and black frames). In the red frame, we move from the "BAU RES MP New" scenario to the "High Res CFD MP DSM OT" scenario. Choosing the latter scenario over the former, results in slightly higher cumulative costs, of about € 2 Billion (over the whole 15 year period) while the share of renewables increases from about 30% to 35%. A similar situation can be found on the black frame where we move from "BAU RES CDF New" to "High Res CFD DSM OT". Total costs increase by a similar amount as in the red frame, but the share of renewable generation technologies increases from 44% to a staggering 53%. These two cases clearly show that the trade-off between more renewables and higher costs is not linear. With the right policies, a significant increase in the share of renewables can be achieved with only limited additional costs.

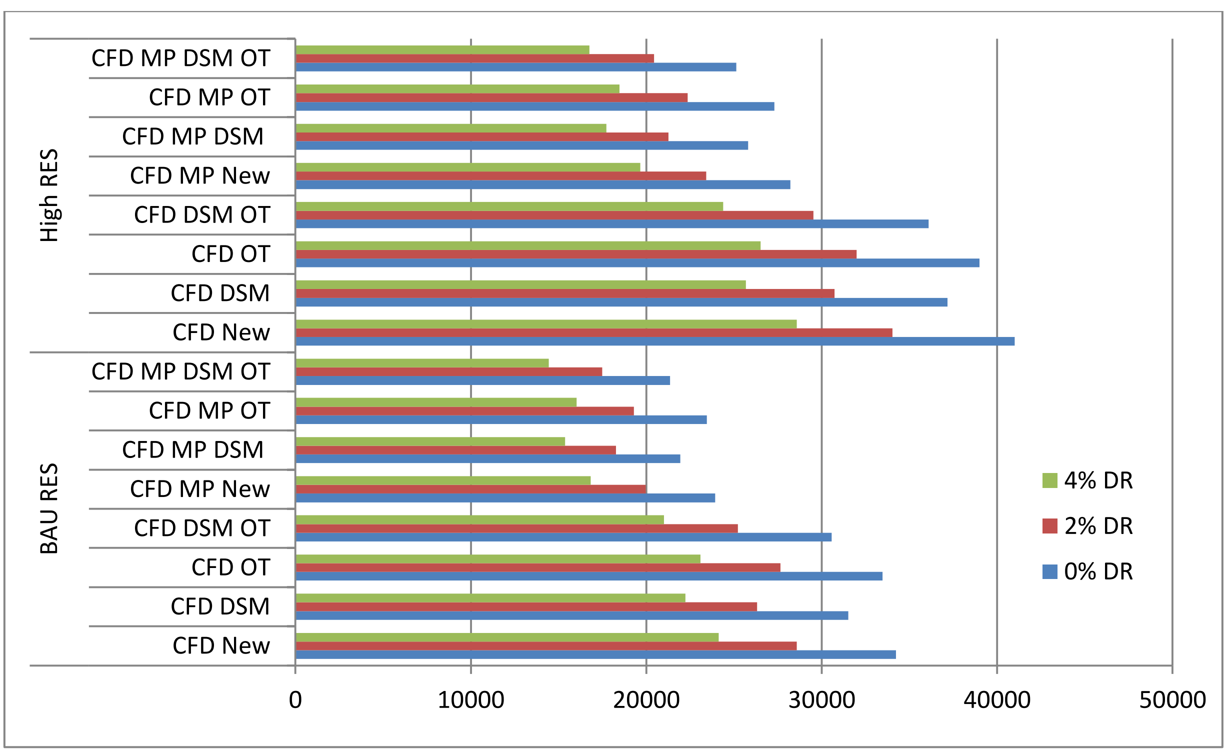
The total subsidy costs of the generation portfolios are very important from a policy maker's perspective. However, some factors are not included in this analysis. From the perspective of society as a whole, the total system cost is more relevant and this will be discussed in the next section (4.3). The total system costs include the extra costs for transmission and distribution that come with the integration of renewables and also the non-subsidised part of electricity production, such as the fuel and operational costs for CCGT's.

Figure 24: Renewables share in the electricity mix in 2030 versus cumulative cost (2014-2030)



We can assume that these future expenditures should be discounted to today, if the government puts a value on postponing costs. We opted to evaluate the impact of a 2% and 4% discount rate (Figure 25).The results show (as can be expected) that the overall costs decline. One interesting observation is that the difference between the most expensive scenario High RES CFD NEW) and the least expensive scenario (BAU RES CFD MP DSM OT) decreases from +/- € 20 billion to +/- € 14 billion if the DR increases from 0% to 4%.

Figure 25: Impact of discount rate on the subsidy cost results



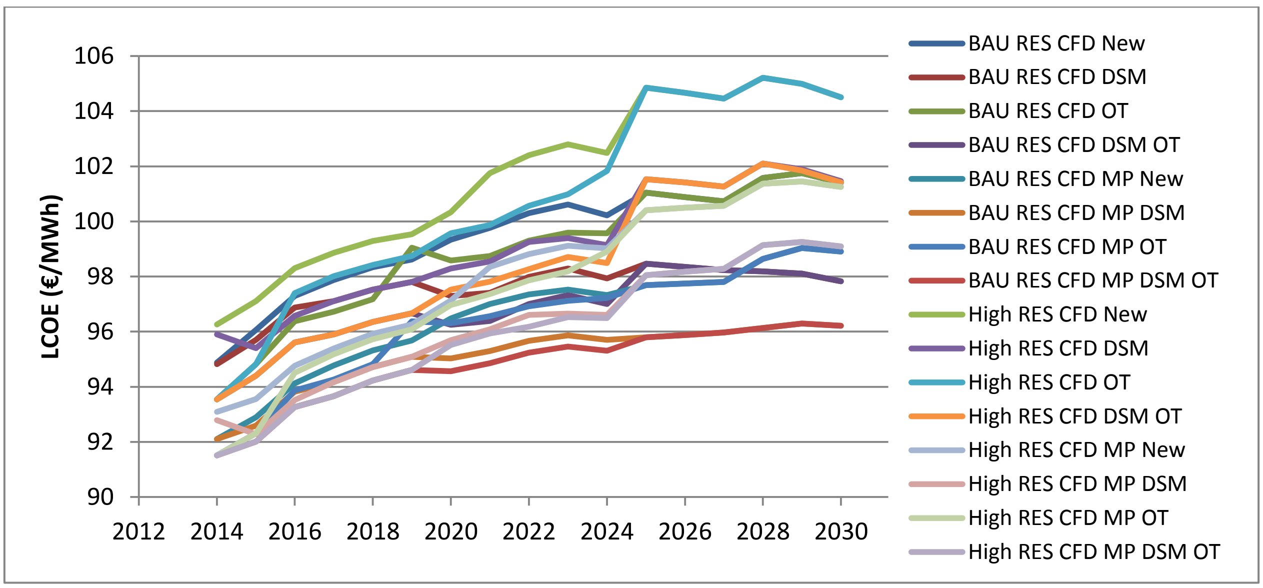
4.3 System costs from 2014 to 2030

We will look at the system costs from a theoretical and a practical perspective. In the theoretical perspective, the LCOE of the complete system is calculated based on the assumptions in Table 3. The implicit assumption of this methodology is that only new assets are used and that there are no depreciated assets present in the system. However, the nuclear reactors in the system are already depreciated, and so their effective operational cost includes only the marginal cost. The impact of this reality on the LCOE of the system will be evaluated under the practical perspective.

4.3.1 Theoretical perspective

Figure 26 shows the average levelized cost of electricity *generation* (no transport or balancing costs included) in Belgium in all scenarios from a theoretical perspective (ignoring the fact that some assets are depreciated). The average LCOE of the 2014 generation-mix is about € 94 /MWh. Note that the wholesale market price is only half this amount. In the least costly scenario, the "BAU RES CFD MP DSM OT" scenario, this cost steadily grows to € 96 /MWh in 2030, overall a fairly modest increase. In the highest cost scenario "High Res CFD New" this increases to about € 104-105 /MWh.

Figure 26: LCOE of the Belgian electricity generation mix in 16 scenarios, theoretical perspective



Total system costs are shown in Figure 27. To obtain the total system cost we multiply the average LCOE-cost (from Figure 26) with the total amount of electricity consumed [€/MWh x MWh]. On top of this we add the transmission and distribution costs. This is obtained by applying the results presented in Figure 12 (based on the data from the OECD-NEA study, see 3.2.5). The following formula is applied:

Additional System T&D Cost (%) = 0,247 x Res Share (%) + 0,014

This latter step takes into account that total system costs increase with an increasing share of renewables. For various reasons, renewables result in higher transmission and distribution costs per kWh produced, compared to - for example - a CCGT plant.

Figure 27: Total annual system cost of Belgian electricity production in 16 scenarios, theoretical perspective

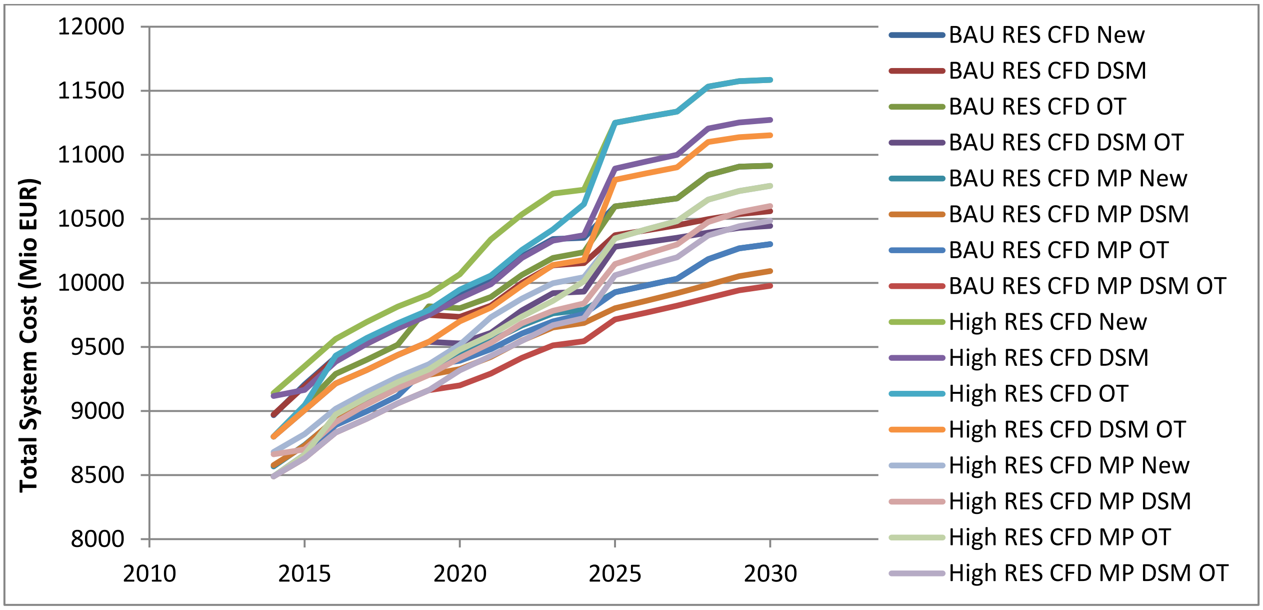


Figure 27 shows that including these extra system costs indeed widens the gap between the "High Res" and the "BAU RES" scenarios. The top 4 most expensive options are all "High Res" scenarios. Table 8 summarizes the overall system costs in the scenarios.

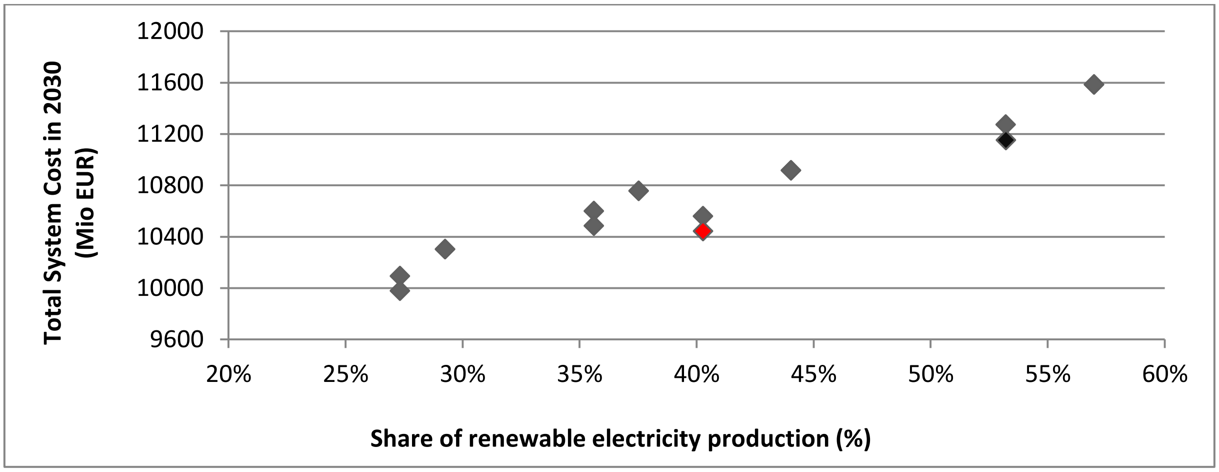
Table 8: Overview total annual system costs in 2030

	High Res CFD	High Res CFD MP	BAU RES CFD	BAU RES CFD MP
System Cost in 2030 (€ Billion)	11,2-11,6	10,5-10,8	10,4-10,9	9,9-10,3
Share of RES	53%-57%	36%-38%	40-44%	27-29%

We can reproduce the "System Cost vs RES" graph from the previous section, and thus obtain Figure 28. Again we find two points that seem to couple relatively large shares of renewable energy at relatively low costs (see red and black dots). The red dot refers to the "BAU RES CFD DSM OT" scenario and couples a share of 41% of renewables with a total system cost of € 10,44 Billion. The black dot refers to the "High Res CFD DSM OT" scenario and couples a 53% share of RES with a € 11,15 Billion system cost. Again, this shows that smart policies can bring the costs of a given renewables target to an acceptable level.

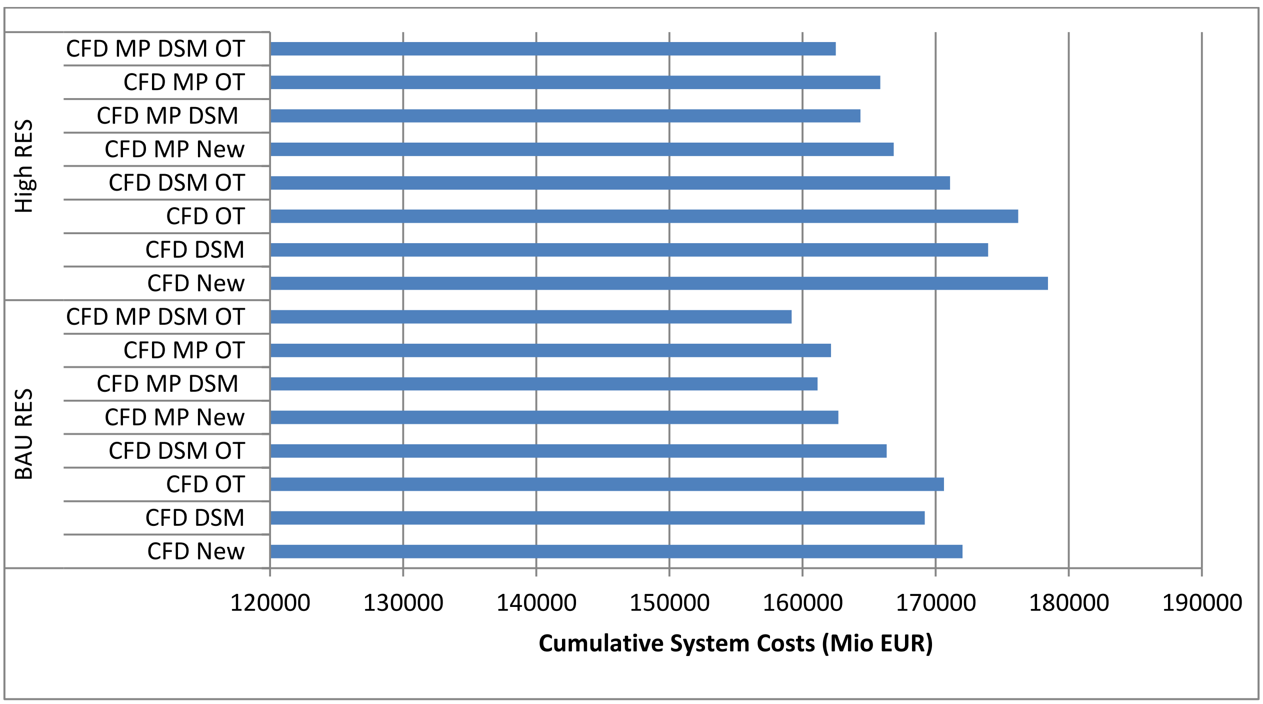
Note that there are many differences between the results from Figure 24 and Figure 28. Keep in mind that in Figure 28 we evaluate the system cost in the year 2030, where in Figure 24 we compare the total cumulative subsidy costs for a given generation scenario. These two different perspectives provide different insights. What could be the best cost/RES trade off in 2030 is not necessarily the best policy for the whole 2014-2030 period. This will be discussed further in section 4.4.

Figure 28: Total annual system cost in 2030 vs. share of renewables



The differences between the lowest system costs and the highest systems costs are relatively small, if we compare them on an annual basis. In Figure 29 we show the total cumulative system costs (2014-2030) for a given scenario to emphasize the different costs of the scenarios between 2014 and 2030.

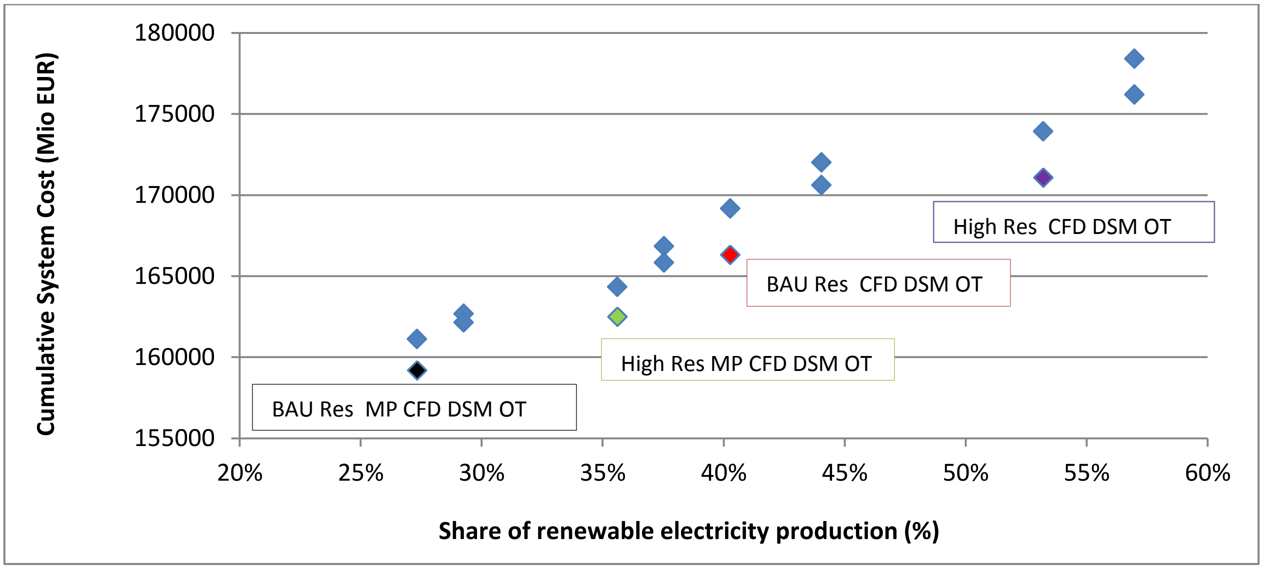
Figure 29: Cumulative Systems costs (2014-2030)



In relative terms, the differences between the scenarios are not that big. However, in absolute figures, the costs of the most expensive option (High RES CFD New - almost € 180 Billion) are about € 20 Billion higher that the least expensive scenario (BAU RES CFD MP DSM OT - almost € 160 Billion). The overall conclusion remains similar, the BAU RES scenarios are cheaper than the High RES scenarios, and the MP scenarios are cheaper than the “non MP” scenarios.

We can now also compare RES share versus total system cost, in a similar way as in Figure 28. We thus obtain the results as presented in Figure 30. The policy choices that result in relatively cheaper scenarios to obtain a certain RES target are highlighted. When looking at the scenarios from this perspective, it is more clearly visualised that the DSM OT scenarios are always the cheaper option.

Figure 30: Cumulative System Costs vs. share of renewables in 2030



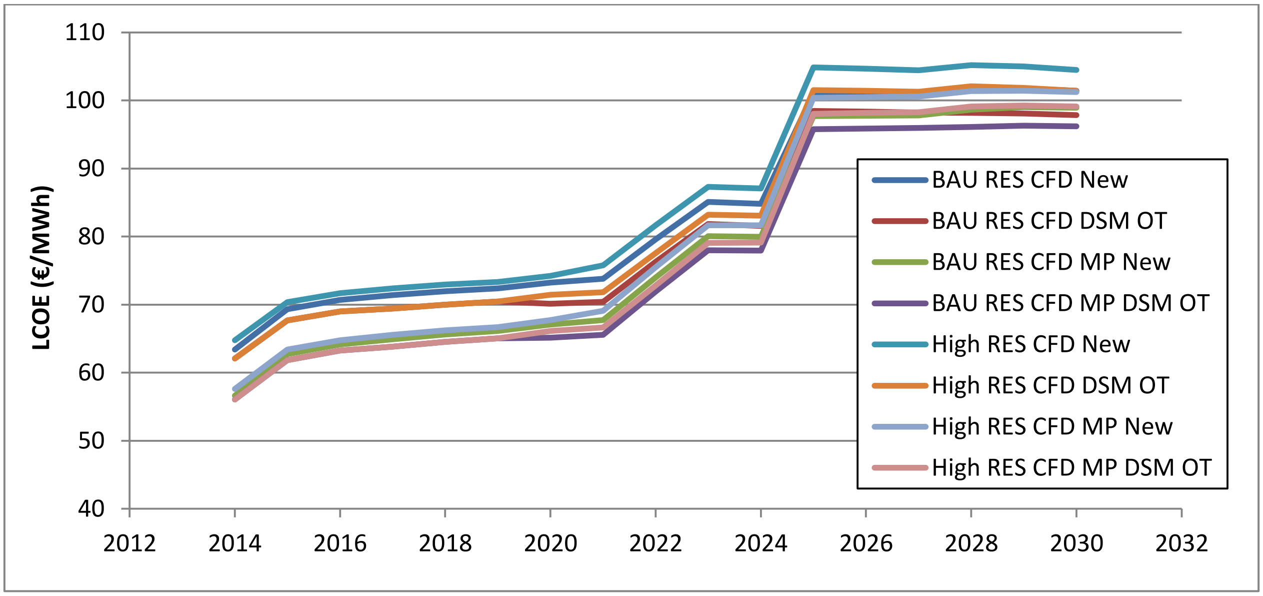
4.3.2 Practical perspective

As mentioned above, the nuclear assets in Belgium are depreciated, so including the investment costs of nuclear in the LCOE-estimates result in an overestimation of the average production cost of a MWh of electricity. Figure 31 shows that - taking this into account - we find a much steeper increase in the average LCOE between 2014 and 2030. In order to simplify the graph we only compare only the "New" and "OT DSM" scenarios.

In Figure 31, the effect of the phase-out on the annual system cost is very clear. The LCOE results for 2030 are the same compared to Figure 26, but the results for 2014-2025 are completely different. When applying this "practical" method, we find that that the "real" LCOE is going to increase from about € 55-65 /MWh to about € 95-105 /MWh. If we compare this with the electricity prices, we find that, today, the cost is € 15-20 /MWh higher than the electricity price, while in 2030, this is about € 50 above wholesale prices (if we assume a wholesale price of € 45 /MWh). This simple observation can help explain the increase in total subsidy costs found in section 4.2.

The total system cost (including extra transmission and distribution costs) obviously evolves in a very similar way as the average LCOE, rising from about €6 Billion in 2014 to €11 Billion in 2030. The results for 2030 in the "practical" perspective are the same as in the "theoretical" perspective, since all nuclear is phased out by 2025.

Figure 31: LCOE of the Belgian electricity mix in 8 scenarios, practical perspective



4.4 Discussion

It may be surprising, when comparing the 2030 results from the "Annual Subsidy Cost" and the "Annual System Cost" perspective, that the differences between the scenarios are much more pronounced in the former than the latter. In the System Cost perspective, the most expensive option is 20% higher than the least expensive one, leading to a € 10-12 Billion cost range. In the "Annual Subsidy" perspective, the most expensive option is about 140% higher than the cheapest, widening the cost range from € 1.2 Billion per year up to € 3 Billion per year. This is due to various reasons.

Firstly, "Total System Cost" is the sum of all the LCOE's in the generation mix and some additional transmission and distribution costs. In the LCOE methodology, all the investment costs are discounted over the lifetime of the asset. By consequence, a strong increase in investments does not automatically lead to an increase in the LCOE's of a given electricity system in the year of investment. In fact, if a new technology is installed which has a lower LCOE than the average LCOE of the system this would result in a decrease of the LCOE, and a decrease of the total system cost. For example, this would occur if a CCGT plant is added to a system with a high share of renewables.

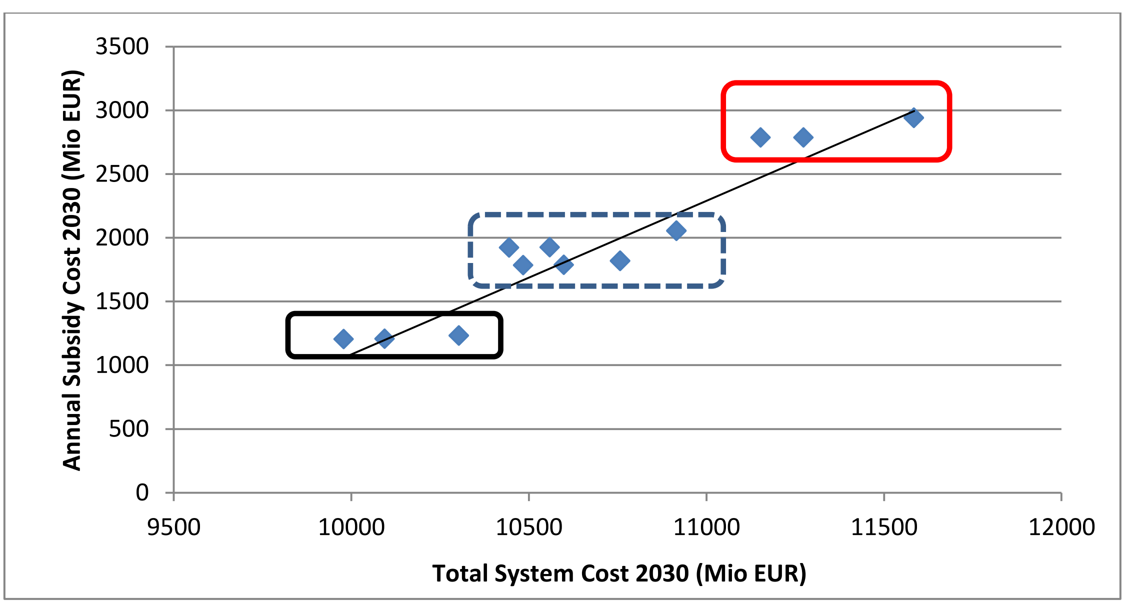
Another reason for the observation that annual subsidy costs are more divergent than annual total system costs can be attributed to the fact that only the *extra costs* (above market prices) are included in the subsidy cost analysis. This is in contrast to the *total system costs* analysis which covers *all* the costs to produce electricity. The Contract-For-Difference system almost literally refers to this difference between market prices and overall production costs. In the CFD-system, technologies that produce electricity above market prices receive a subsidy to make them competitive. If we would subtract market prices from the "total system cost" calculations, we obtain the "total subsidy costs" of a given electricity mix. A simple example can clarify this.

Example: assume that the highest cost scenario has a LCOE of € 104 /MWh and the lowest cost scenario a LCOE of € 96 /MWh. In relative terms the most expensive scenario is only 8% more costly. If we subtract a market price of, for example, € 40 /MWh from both these scenarios, we obtain the subsidy cost per MWh, namely € 64 /MWh and € 56 /MWh, the relative difference has now increased to about 14%.

A third and final reason why subsidy costs differ more widely than total system costs, relates to the amount of electricity that is still market driven. In the "High Res CFD" scenarios, the so-called *free market* has become completely obsolete. In these scenarios, all the renewable technologies receive subsidies equal to the LCOE, and the share of renewables is almost 60% of total production. The remaining 40% consists mainly of CCGT's and 's which have received capacity payments. As almost all electricity production is subsidized, total subsidy costs are high. In the "BAU RES CFD DSM scenario", on the other hand, a slightly larger share of electricity is still market-based (if not the capacity, at least the MWh produced). To put it differently, in a given system the subsidy costs will rise if the share of subsidized electricity increases, even if the total system cost remains constant.

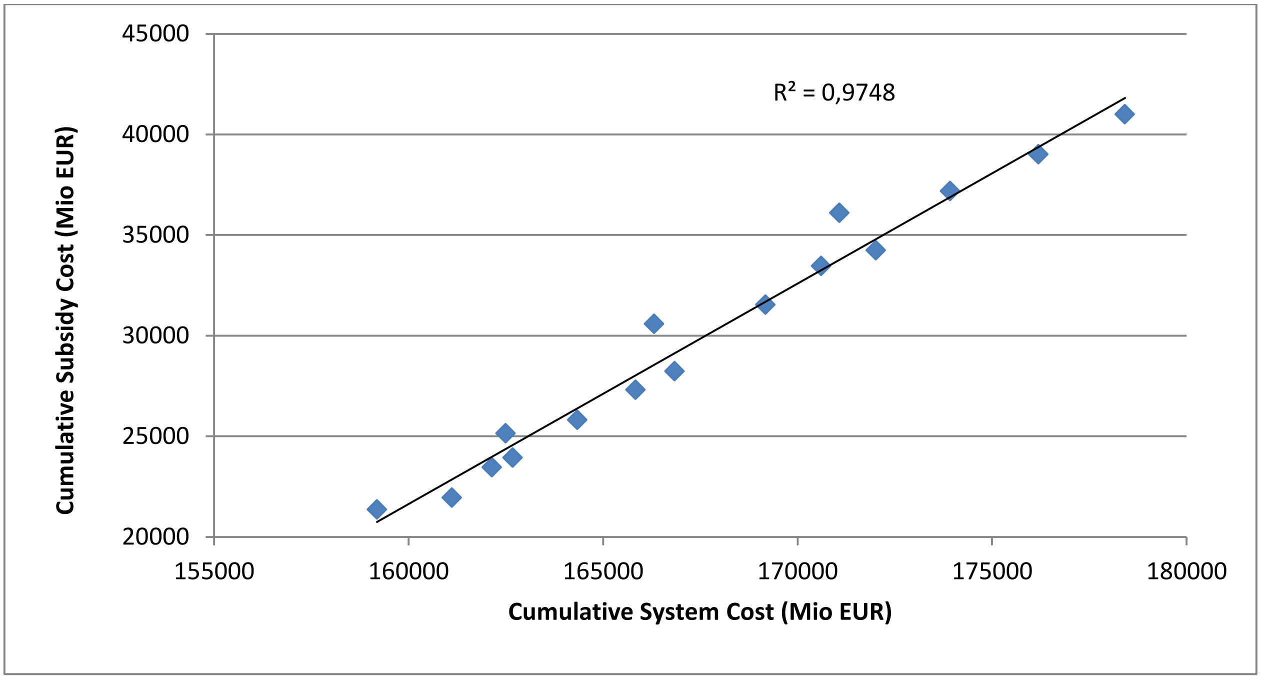
As an overview of all the results we can compare total system cost estimates with annual subsidy costs for the year 2030, and see how well these correlate. Figure 32 shows three distinct zones. The black zone contains policy options that result in annual costs of about € 1.3 Billion/year, the blue zone contains policies that cost around € 1.7 Billion/year and in the red zone costs are around € 2.7 Billion/year. Total system costs (TSC) however, do not show this trend. In effect, for a given subsidy cost, the total system cost can vary widely. In the black circle, the TSC varies from € 10 - € 10.4 Billion, in the blue circle from € 10.5 - € 11 Billion and in the red circle from € 11.1 - € 11.6 Billion. The data points at the right of the linear-trend curve (high system costs for a given annual subsidy cost) always belong to scenarios with relatively high shares of renewables, which are assumed to increase the transmission and distribution costs. This largely explains this observation.

Figure 32: Annual subsidy cost vs. total annual system cost in 2030



If we look at a more long term, overall perspective, we find a more linear trend between subsidy costs and system costs. Figure 33 compares cumulative system costs (2014-2030) with cumulative subsidy costs. The R^2 of 0,97 indicates an almost perfect linear trend. However, in relative terms, the cumulative subsidy costs are twice as high in the highest cost scenario, compared to the lowest cost scenario, whereas the total cumulative system costs are only about 13% higher in the most expensive scenario, compared to the cheapest scenario.

Figure 33: Cumulative subsidy cost vs. cumulative system cost (2014-2030)



It is interesting to see that the absolute cost difference between the cheapest and most expensive scenarios is almost identical when comparing cumulative system costs with cumulative subsidy costs (Table 9).

Table 9: Comparing lowest and highest cost scenario from subsidy and system cost perspective

Scenario	Cumulative Subsidy Cost	Cumulative System Cost
BAU RES CFD MP DSM OT	€ 21 351 Mio	€ 159 187 Mio
High RES CFD New	€ 40 996 Mio	€ 178 417 Mio
Difference in cost	€ 19 230 Mio	€ 19 645 Mio

In short, we can conclude that both perspectives (subsidy costs or system costs) result in similar outcomes when looking at the long term cumulative perspective. In both cases, the most expensive scenario is about € 20 Billion more costly compared to the least expensive scenario.

5 Surplus Risk

We have assumed a RM above 5% at all times in our study. However, this does not mean that all security of supply problems have been dealt with. In a world with a large share of intermittent renewables, security of supply can be compromised due to the uncontrolled influx of renewable electricity into the grid. Already today we observe low or even negative prices on sunny summer weekends, where demand is low and PV-production is high (CREG , 2013).

In this section on the surplus risk, only the “New Capacity” scenario is presented since the focus is more on the surplus issues, not on the shortage issues. Adding the other “security of supply” options does not contribute much to the insights.

It is important to stress that the DSM-potential mentioned in the previous chapters is assumed only to contribute to the shortage issue, not the supply issue. However, increasing “upward-DSM” (to reduce surpluses) would be beneficial regardless of any scenario, and is thus considered useful and important. We do not use the same DSM potential for capacity shortages and surplus issues since there may be important differences in the technologies. Some are able to provide predictable, long term “downward” load (in case of winter peaks) and others provide short and fast responses to a surplus of electricity by increasing their demand. There might be some kind of overlap (technologies that can be useful under both circumstances) but this is likely to be rare.

5.1 Method

To study the occurrence of surpluses, a Matlab model was designed. Data from PV and wind production from 2013 and load data from 2005-2012 were used as input for the model. Basically, load and production patterns are compared for 15 minute intervals and the frequency of surpluses - the number of 15 min intervals in a year for which production exceeds demand - and the height of the surplus (1000 MW, 2000 MW…) are presented as results. This methodology has already been presented at several academic conferences.

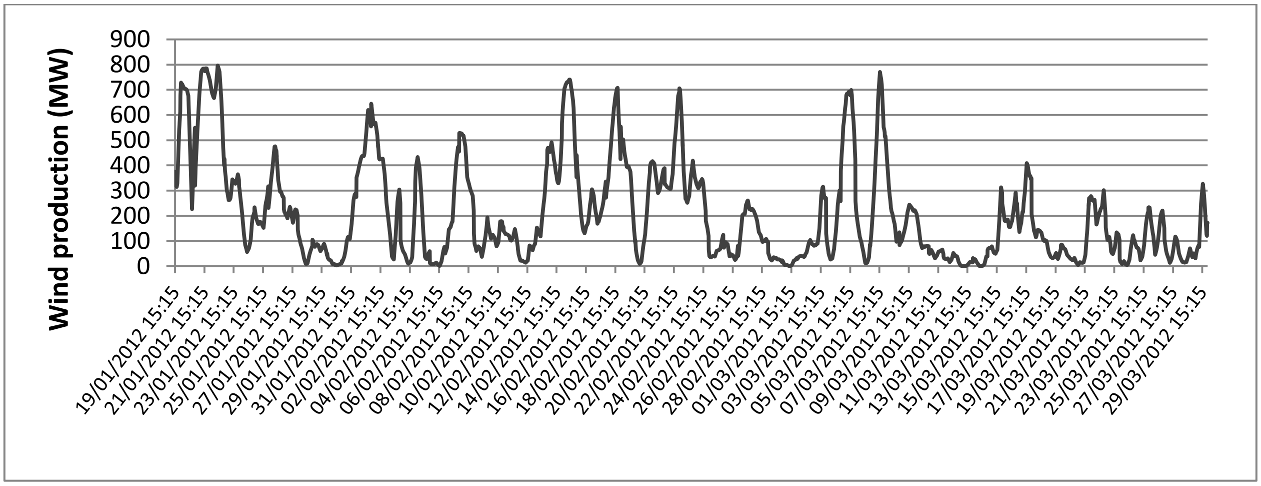
5.1.1 Wind production model

Wind data for Belgium was available for the period 02/2012 - 02/2013 and retrieved from the website of Elia. The wind data is provided in 15 minute intervals. Figure 34 shows the pattern of wind production for a monitored capacity of 930,65 MW during the first months of 2012 in Belgium. The graph clearly illustrates that the availability of wind is very variable and can occasionally have high peaks (800 MW in January). On the other hand, long periods of very low wind production are also possible (3rd week of March, where between 11/03/2012 and 15/03/2012 the capacity does not go above 100 MW).

Using only one year of data can have a major impact on the results. Therefore, a random wind generation pattern was created by at random selection of 5 days of wind from the data which were then put in a random order. This was repeated until a whole year of randomized wind patterns was obtained. In this way, we could create an almost infinite amount of yearly wind patterns. This step was repeated until 100 year-wind patterns were created.

Unfortunately, in this way the seasonal variation was lost. Luckily, seasonal variation in wind speeds in Belgium is rather limited, with average wind speeds of 3 m/s in summer and 3,7 m/s in winter (KMI, 2010). Also, keep in mind that wind electricity production is not linearly related to average wind speeds, the relation is much more complicated.

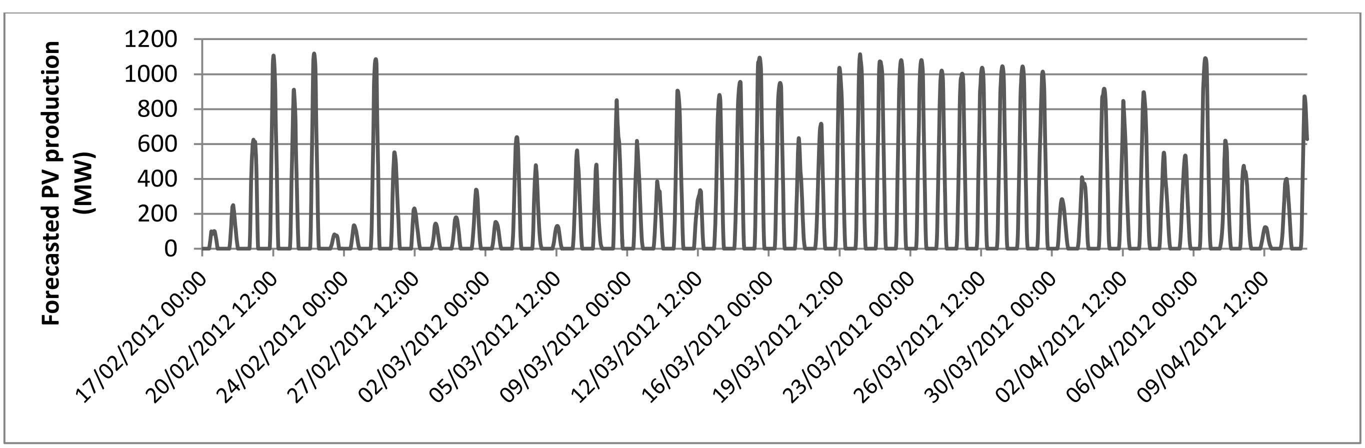
Figure 34: Wind production in Belgium from 19/01/2012 - 29/03/2012 (930,65 MW - Data from Elia, 2013)



5.1.2 PV production model

The pattern of PV-electricity production is obviously very different from that of a wind turbine. PV-electricity production varies in essence in two time dimensions, firstly, the day/night pattern which makes it fluctuate daily from zero to a peak and back again to zero, and secondly, the seasonal variation which makes PV more productive in summer compared to winter. Because of these special properties, the PV-production model is different from the wind model. Elia provides forecasted PV production data for a monitored capacity of 1600 MWp from 02/2012 until 02/2013. Figure 35 shows that even on a winter day the peak can be relatively high (> 1000 MW). Also, it can be cloudy during relatively long periods (27th of February - 3rd of March).

Figure 35: Forecasted PV production in Belgium from 17/02/2013 - 09/04/2013 (1600 MWp) (Data from Elia, 2013)



The random generation model for PV production was split up in months, in order to account for the seasonal variation. For a given day in a given month, the average monthly production curve was multiplied with a correction factor to create a fluctuating daily pattern.

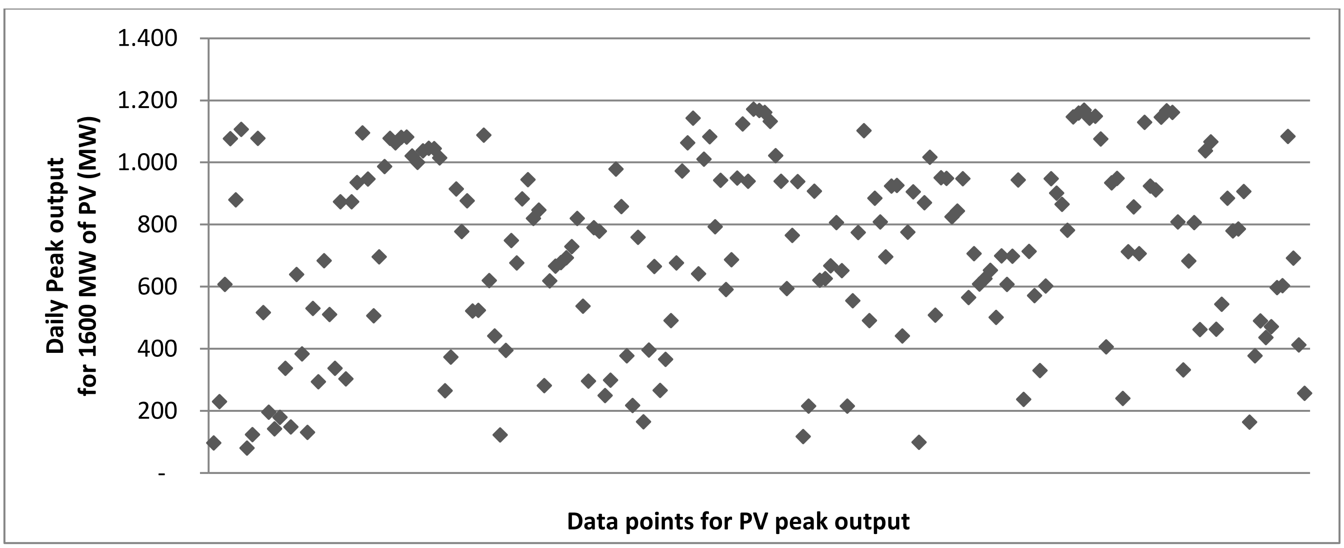
$$PV_d = AV_m \times C \ \ [MW]$$

With:

PV_d = Daily pattern for PV production [MW]
AV_m = Average daily pattern for a given month [MW]
C = Correction Factor [-]

This correction factor was chosen "at random" from the available PV production data (Figure 36), based on the daily peak output of 1600 MWp of PV capacity monitored by Elia (2013). Combining the 12 months resulted in a random PV production pattern for a given year. The model creates random PV production patterns that result in yearly capacity factors between 10% and 12% for PV in Belgium, which is normal for this region.

Figure 36: Daily peak output of PV-systems in Belgium (based on data from Elia, 2013)



5.1.3 Final model

On top of this random pattern from PV and wind electricity we add the production of 'must-run' baseload technologies, namely biomass, CHP and nuclear. We thus obtain the 'minimal' electricity production for a given moment. We then compare this minimal production with data from actual electricity load in Belgium from 2005-2012. The model compares the load and the electricity production in all the 15 minute intervals during a whole year.

We are aware that the total load in the transmission grid can be different from the total demand. More specifically, load is an underestimate of total demand, especially in days with a lot of PV-electricity production. When analysing the shortage issues, this difference is not problematic since peak demand occurs when there is no sun. When analysing surpluses we face a trade-off. In 2008-2012 there was much more PV capacity then in 2005-2007, leading to larger differences between measured load and total demand including auto-production. As a consequence, an analysis based on load data under-estimates demand and over-estimates the chance of a generation surplus. However, in case we only use data from the period 2005-2007 or the years with a very limited PV capacity but before the strong economic recession, we would strongly underestimate the chance of a surplus. As we cannot predict to which extent total demand will recover, we decided to use all the available load data for 2005-2012 to create variability for the next decades in our model. We argue that the mixture of under- and overestimates will result in the most robust outcomes. Table 10 summarises the load data used in this model. It shows that average demand in 2009-2012 is lower compared to 2005-2008. Also, peak load is decreasing since 2007, while minimal load seems to follow a more random pattern, with two exceptional years of a min load below 6000 MW (2008 and 2012).

Table 10: Load data for Belgium (2005-2012) source: Elia

Year	Peak Load (MW)	Min Load (MW)	Demand (TWh)
2005	13 603	6 168	87
2006	13 702	6 520	89
2007	14 040	6 464	89
2008	13 479	6 393	88
2009	13 531	5 901	82
2010	13 845	6 278	87
2011	13 208	6 232	83
2012	13 362	5 845	82

For a given demand profile and for one production profile, a surplus occurs if:

$$IN + MR + NUC > D \qquad \text{or} \qquad IN + MR + NUC - D > 0$$

With:

IN = Intermittent production (PV + Wind)
MR = Must Run (Biomass + CHP)
NUC = Nuclear
D = Demand

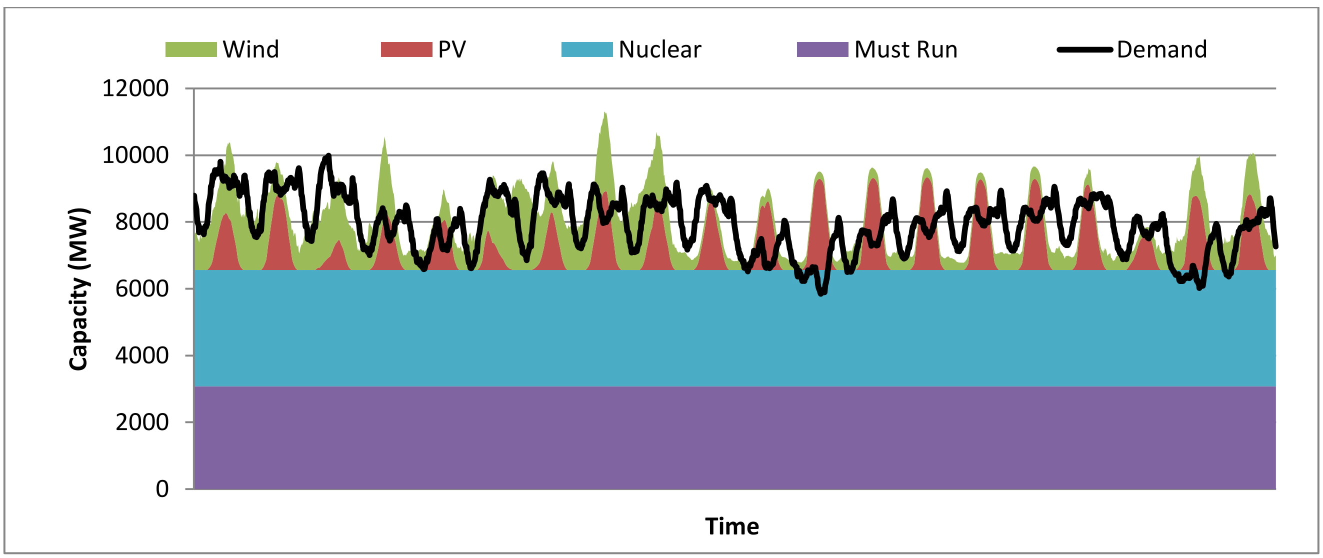
The probability of a surplus will be lower in years with high demand (strong winter) and low solar and wind output. This situation will be referred to as the “Min” case, with “Min” standing for minimal surplus issues. A year with low electricity demand (recession, mild climate) and high wind and PV output by contrast will be a “Max” year with a high amount of surpluses. The results will be presented in graphs, showing the probability (in % of time) of a surplus, in 3 cases, namely “min”, “av”, and “max”.

In addition to the frequency of surpluses, we also obtain information on the height of surpluses. We do this by repeating the surplus analysis with a higher threshold, and thus obtain the frequency of surpluses above, for example, 1000 MW. This is done up until a > 6000 MW surplus threshold. **Since the export capacity of Belgium is around 3 500 MW, we consider surpluses above 3 000 MW as problematic and above 4 000 MW as (very) dangerous.**

As mentioned before, we have included 2 “surplus policies” in this study. The first is the CFD-case, where there is no limit on renewable output, the second is the CFD-MP (market participation) case, where wind and PV can be curtailed to a small extent and biomass is used very flexibly. In this specific chapter on surpluses, we will split up the CFD-MP-scenario in two separate scenarios to identify the effect of the flexible use of biomass. We will present a CFD-MP-intermittent renewables (CFD MP IR) and a MP-all renewables (including biomass) (CFD MP ALL) scenario.

Figure 37 depicts a visualization of a surplus analysis. A surplus occurs when the colored regions are higher than the black line, notice that even without intermittent production we can have a surplus, when nuclear and Must Run combined are higher than demand (in the middle of the picture, the black line falls below the blue zone).

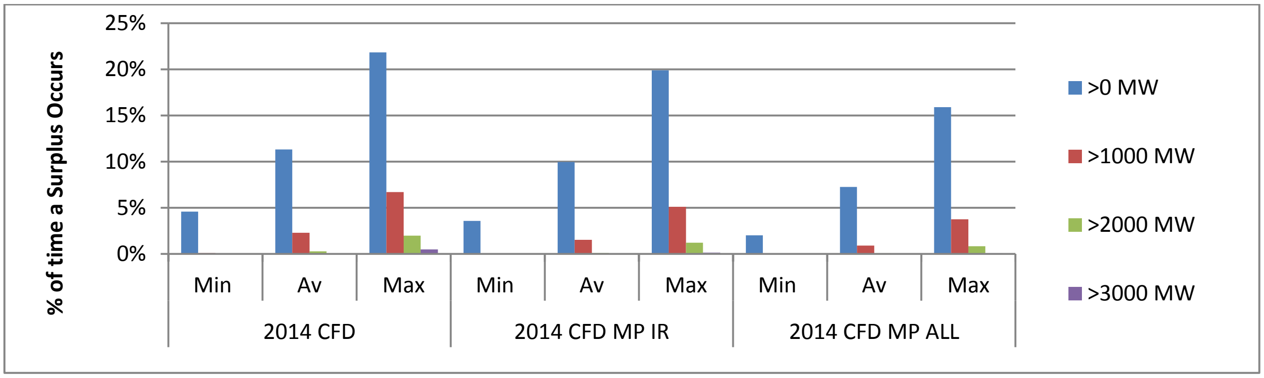
Figure 37: Illustration of a surplus analysis based on the model (data from FOD Economy, 2012 & Elia, 2013)



5.1.4 2014 Surplus Risk

As a reference point, we present the results for 2014. As Figure 38 shows, the risk of having a surplus in 2014 is - fortunately - relatively low. The highest surplus is in the 3 000 - 4 000 MW range, which occurs only 0,5% of the time in the “max” case. The ability to curtail PV or Wind (CFD MP IR scenario) decreases the overall risk of a surplus, be it in a modest way. The additional effect of using biomass in a flexible way is also relatively modest. These results are not surprising since the share of renewables in 2014 is not that large. As mentioned in section 2.3, the import/export capacity of Belgium is about 3.5 GW, so in theory all these surpluses can be exported when they occur.

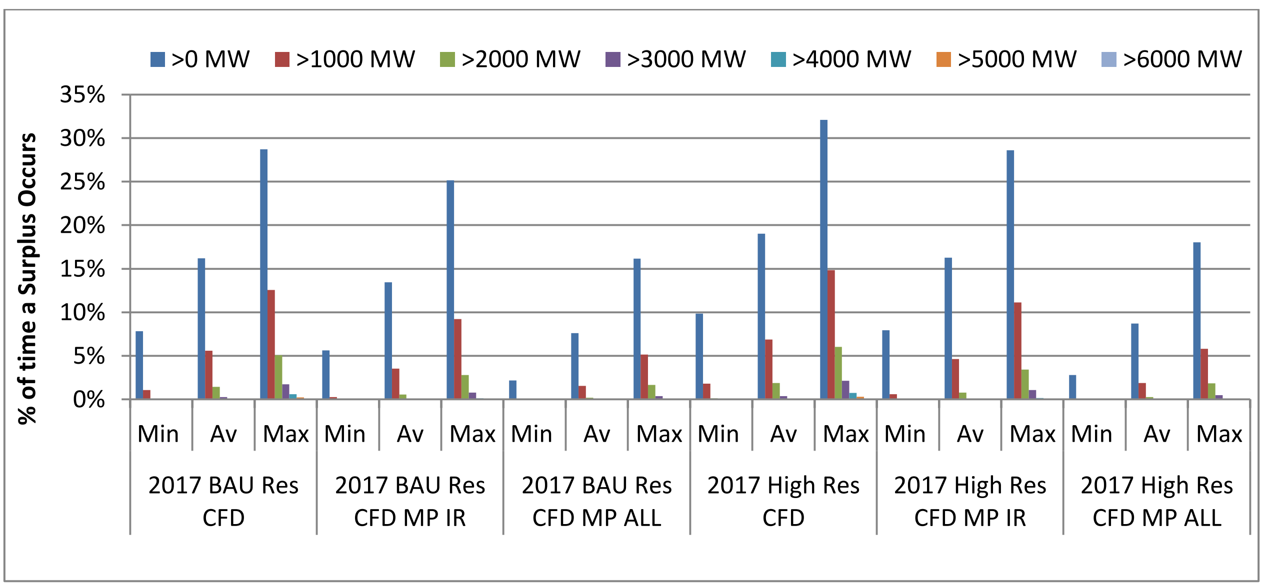
Figure 38: Surplus risk in 2014



5.1.5 2017 Surplus risk

As can be expected, the impact of the scenarios becomes much more apparent in a world with more renewables. Figure 39 shows that in 2017, even in a BAU RES scenario, the size of the surpluses becomes a lot higher. In a world with no limits to the output of renewables, and still a large share of nuclear electricity, there is only a limited amount of flexibility on the grid. The increased market participation of all renewables is likely to be needed to keep the surpluses below 4 000 MW in all scenarios (BAU RES and High res). Also, notice that, in the scenarios with no market participation the overall probability of a surplus in the "average year" is around 17%, compared to about 10% in 2014.

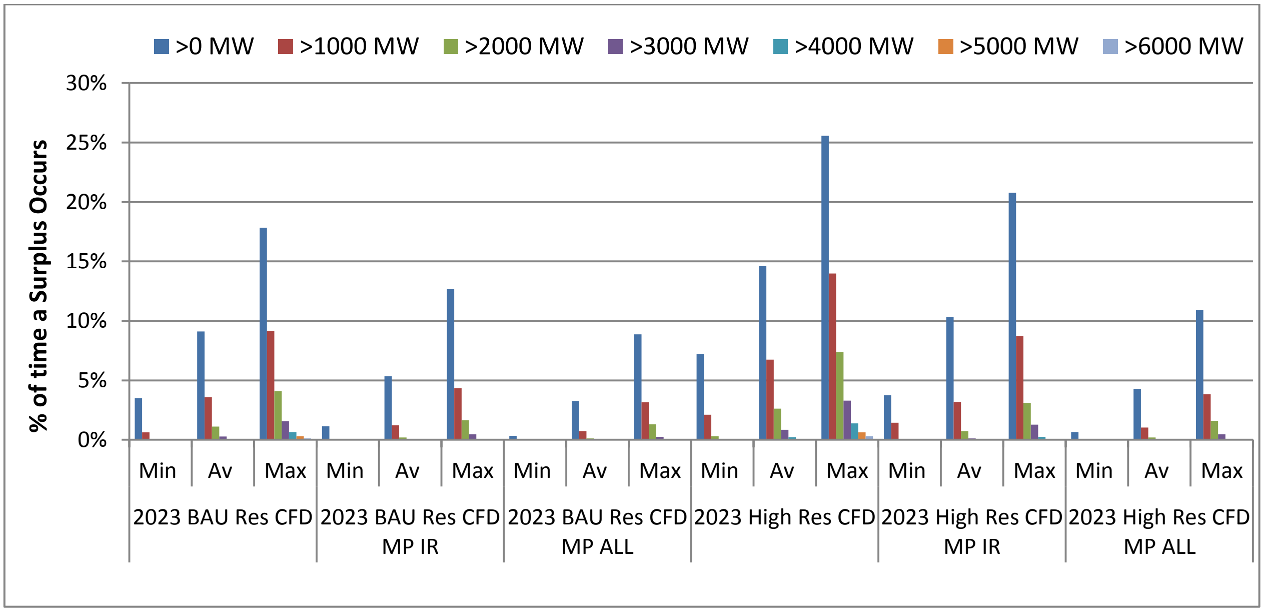
Figure 39: Surplus risk in 2017



5.1.6 2023 Surplus risk

The year 2023 is special since it is right before the full nuclear phase out. Surpluses are likely to be high because of a high share of renewables, combined with a nuclear capacity of 3000 MW. Figure 40 shows that this is especially true for the High Res scenario. The impact of a given renewable scenario (High or BAU RES) is much more apparent in 2023 than in 2017. On average, the amount of surpluses is slightly lower compared to 2017. This is due to the phase out of 2 000 MW in 2022. However, the size of surpluses is still very worrying. In case of a low-demand year (Max-situation) surpluses above 6000 MW can occur, even in the “BAU RES” scenario. These high surpluses will fortunately only occur with a low probability (0,3% in High Res and 0,1% in BAU RES). Again, the market participation of all renewables is needed to keep the height of the surplus below 4 000 MW at all times.

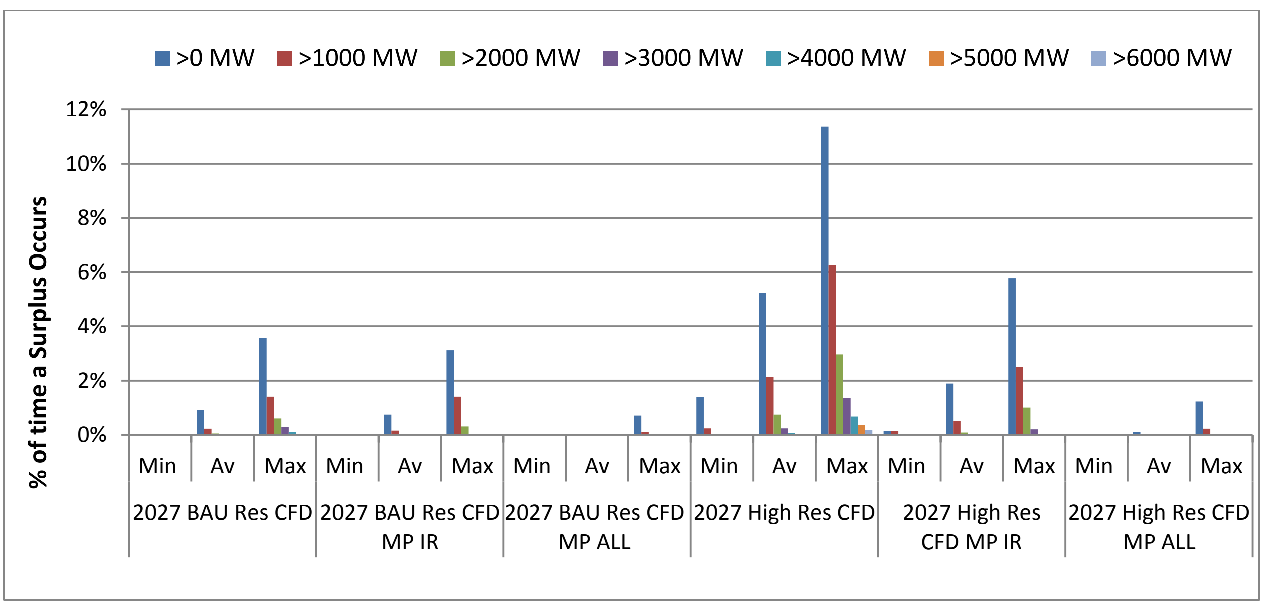
Figure 40: surplus risk in 2023



5.1.7 2027 Surplus risk

In 2027, the nuclear phase out will be complete, and the share of renewables in the system (especially biomass) will be significant. Therefore, the way renewables will participate in the market will have a very crucial effect on the risk of surpluses (Figure 41).

Figure 41: Surplus risk in 2027



The difference between a low or high renewables scenario is now very clear. Actually, in a BAU RES scenario, the flexible use of biomass is not really needed to keep surpluses below 4 000 MW. In an average year, curtailment of PV or wind is no longer necessary, provided the gas assets are used very flexibly. However, if a large share of the nuclear capacity is replaced with biomass (instead of CCGT's), the situation is different. Obviously, in the High Res case a flexible approach to renewable electricity production is needed. If not, surpluses could go beyond 6 000 MW at times with low demand (High Res Max-case). If on the other hand renewables are used more flexibly, the surpluses disappear almost completely and are even below the 2014 scenario.

5.1.8 Discussion

The surplus analysis has shown that some of the scenarios presented in sections 4.2 and 4.3 are in fact not feasible in practice, due to over-supply issues. Increased interconnection, smarter grids and more storage possibilities can alleviate part of this, but it is hard to predict how this all will evolve. Also, the surplus analysis has shown that the issues already become apparent in the next 5 years, a very short time for these possible solutions to make a difference. Table 11 summarizes the results of the surplus study.

To interpret the data, keep in mind that the maximal export capacity of Belgium is 3500 MW. Thus, surpluses of > 4000 MW can be regarded as very problematic. We show the maximum surplus (Max-Scenario, highest possible surplus), the average surplus (Average scenarios, highest surplus) and the % chance of having any surplus (above 0 MW) in the average scenario. The first two parameters give an idea on the magnitude of surpluses, the last on the frequency if the surpluses. We mention only CFD and CFD-MP scenario results here, with CFD-MP referring to market participation of all renewable (CFD-MP-ALL scenario).

Table 11: Overview of results on the surplus analysis

Year	Scenario	Max year Surplus (MW)	Av. year Surplus (MW)	% of time Surplus (Av)
2017	BAU RES CFD	6000	3000	16,2
	BAU RES CFD-MP	3000	2000	7,6
	High Res CFD	6000	3000	16,3
	High Res CFD-MP	4000	2000	8,7
2023	BAU RES CFD	6000	4000	9,1
	BAU RES CFD-MP	3000	2000	3,3
	High Res CFD	6000	5000	14,6
	High Res CFD-MP	3000	2000	4,3
2027	BAU RES CFD	4000	2000	0,9
	BAU RES CFD-MP	2000	0	0,0
	High Res CFD	6000	4000	5,2
	High Res CFD-MP	4000	1000	0,1

In general, we observe that the "High Res" and "BAU RES" results are quite similar before the full phase out. Only after the complete nuclear phase the results start to diverge. Obviously, in a "High Res CFD" case where renewables produce more than 50% of total electricity, surplus issues become very apparent.

However, even in 2017 the scenarios without market participation result in possibly very high surpluses in a "max"-case (low demand combined with sun & wind). In an average year, on the other hand, the surplus issues do not seem that problematic, indicating that the option for curtailment might not be necessary in every year.

In 2023 it appears that a scenario without market participation is not longer feasible, even in an average year, with surpluses reaching respectively 4 000 or 5 000 MW in the Low and High Res cases. Over all years and all scenarios analyzed here, the 2023 "High Res CFD" is the most extreme one with surpluses reaching 6 000 MW in a "max" year and 5 000 MW in an "average" year and a 15% chance of having a surplus at any given moment in that year.

By 2027 the phase out is complete, and the share of flexible capacity in the system increases, due to the large share of CCGT and OCGT plants in the system. In the BAU RES scenario, even the CFD-case becomes feasible, with a surplus frequency of only 0,9% in an average year and an average surplus of 2 000 MW. A CFD-MP-system would even result in surpluses disappearing overall.

However, in the 2027 High Res case, a system without market participation is less attractive since the large share of biomass added in the phase-out year is not used flexibly in a CFD scenario. If the biomass is used flexibly, and PV and wind have curtailment options, the risk of oversupply is reduced significantly, even in a High Res scenario. In fact, it is reduced to a level below that of 2017.

In the conclusions (see chapter 6) we will refer to the "High RES CFD" scenario as high surplus risk, the "BAU RES CFD" scenario as medium risk and the "CFD-MP" scenarios as low surplus risk. As the surplus problems mainly occur before the full phase out, we focus on the 2015-2025 period.

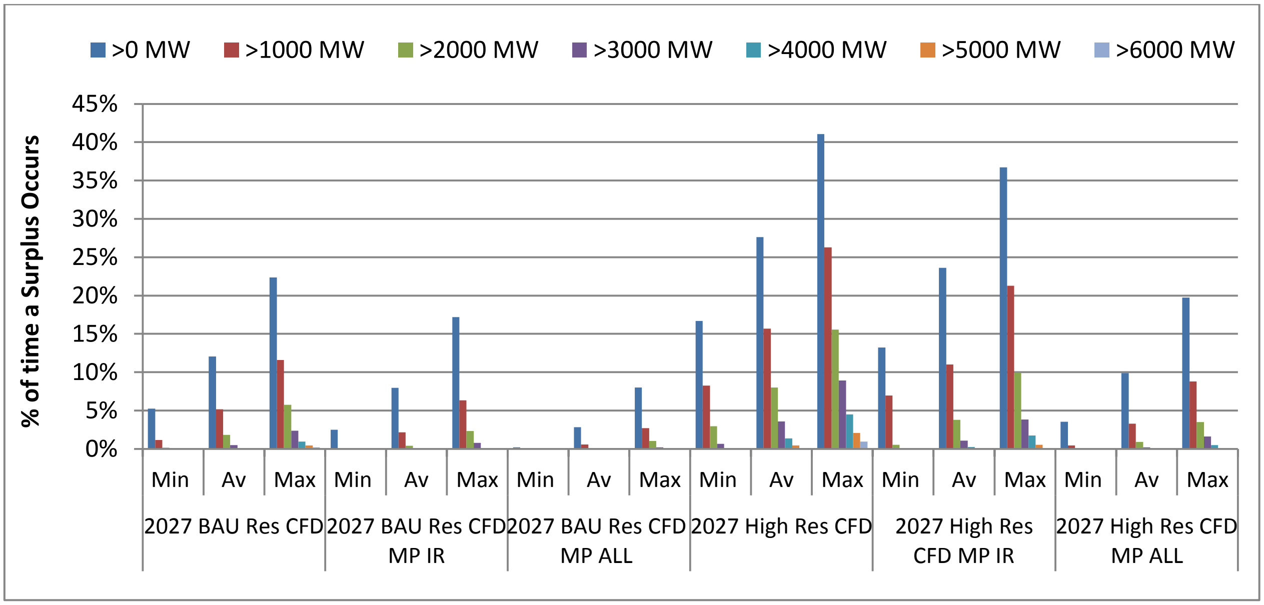
Alternative Scenario: Nuclear prolongation

Up until now we have only discussed scenarios in line with the current "Plan Wathelet". However, as the impact of the phase out in the year 2020-2030 on the total available capacity is immense, one can imagine that the current phase out plan could be adapted in the future for the sake of security of supply. In this additional section we analyse the impact of postponing the phase out of the last three reactors beyond 2027. It is not surprising that with more nuclear capacity in the system, the probability of a surplus will increase when compared to the full phase out case presented in Figure 41.

Figure 42 shows that with 3 000 MW of additional nuclear capacity in the system, the surplus risk in a BAU RES case is significantly higher and flexible use of all renewables is needed to keep the surplus risk at an acceptable level. In the "BAU RES CFD MP ALL" case surpluses above 3000 MW disappear completely. This is a sign that a modest increase and flexible use of renewables make it possible to prolong the nuclear capacity. However, without any market participation of the RES, surpluses can go beyond 6 000 MW. Fortunately this is a rare event, occurring only in the MAX-case and for only 0,2% of the time. By contrast, In the average case, the surpluses are limited to 4000 MW, occurring 0,1% of the time.

A high RES scenario combined with a prolonged phase out will require the flexible use of all renewables in order to keep the system manageable, but even under these conditions the surplus risks are significant. However, it will probably be technically possible, given the latter assumptions on flexibility. Keep in mind *that by 2027 more interconnection will also be available and possibly also more demand side participation. Anyway, the functioning of the electricity system in a world with a large share of renewables and a significant amount (3 000 MW) of old nuclear assets will be very different from what we see today.*

Figure 42: Surplus risk in 2027 in case of a prolonged nuclear phase out (3000 MW of nuclear in 2027)



6 Conclusion

Starting from the nuclear phase out plan as mentioned in the 'plan Wathelet' we evaluate possible options to transform the Belgian electricity system in order to become more sustainable, reliable and affordable. To guarantee reliability, we have set as a baseline condition that the reserve margin of the electricity system in Belgium should never go below a 5% threshold. We then evaluate the trade-offs between affordability – total system costs and subsidy costs for the generation portfolio – and sustainability (here restricted to the share of renewable electricity). Since reliability is also related to the overall stability of the electricity system, the surplus risk of each scenario was evaluated as well. Various scenarios for the future evolution of the electricity system are analysed and compared. The resulting scenarios (16 in total) are a combination of one of the following policy options:

1. *High vs. 'Business As Usual' Renewable scenarios (High RES and BAU RES - in Table 12)*
2. *Investments focusing on new capacity only (New-scenario) or also on existing thermal capacity (OT-scenario)*
3. *Constant or increasing potential for demand side management (DSM -scenario)*
4. *Focus on DSM and "Old Thermal" incentives first, new capacity later (DSM OT scenario)*
5. *Continuing the unconstrained grid priority of renewables (CFD-scenario) or increase the market participation of renewables (CFD-MP-scenario)*

The results in Table 12 show that the market participation approach – selective curtailment of PV and wind with a flexible use of biomass – always results in a lower surplus risk. This should be no surprise. However, the MP-approach comes with a disadvantage; the amount of electricity produced by renewable technologies is lower compared to the traditional "contract for difference" (CFD)-approach. There is however a remark to be made here. After the phase-out (post 2025), the need to use biomass in a very flexible way - with a load factor of 35% - has decreased as more flexible gas-fired capacity is available to balance the grid. So from 2025 onwards, biomass could be used at higher load factors, and the share of renewables can be increased without putting too much stress on the electricity system. This will however result in higher overall system costs, since biomass feedstock is likely to be rather costly[10].

In general we see that the costs to guarantee security of supply at all times are lowest in the scenarios with a lower share of curtailable renewables (CFD-MP-scenario), and where demand side management (DSM) is combined with support for old thermal assets (OT). We also find that it is cheaper to install more renewable capacity, but use these assets in a flexible way (High Res MP-scenarios) than to have a lower share of installed renewable capacity that is however not used in a flexible way (BAU RES CFD-scenarios). The use of installed technologies is as important as the mix of installed capacities. The total share of renewable electricity is in both scenarios similar (around 40%) but cumulative costs and surplus risks are lower in the "High Res-CFD-MP" case.

The highest share of renewables can be found in the "High Res CFD" scenarios, in which the renewables still enjoy grid priority at all times. However, the surplus risk (in the period 2015-2025) in this scenario will be very high as well. Therefore, this cannot be a realistic scenario. However, we have to keep in mind

[10] Keep in mind that feedstock costs for biomass plants are difficult to predict, especially beyond 2020

that DSM is assumed only to participate in the capacity market, not in the "flexibility" market. This is an assumption, but in practice DSM could participate on both sides (oversupply vs. shortage in capacity). This could alleviate some of the oversupply issues, and reduce the need to curtail renewable electricity from wind or PV.

The cumulative system (and subsidy) costs of the most expensive scenario (High RES CFD New) are roughly € 20 Billion higher compared to the cheapest scenario (BAU RES CFD MP DSM OT), with the former having a cumulative system cost of about € 160 Billion, and the latter about € 180 Billion. **As a consequence, appropriate policy choices to minimize the cumulative cost of energy security can be € 20 Billion less expensive between 2014 and 2030 than the most expensive policy options.** The share of renewables is twice as high in the most costly scenario, but without market participation of biomass and curtailment of PV and wind, surplus risks will also increase.

Table 12: Overview of results from this study

Scenarios		Res Share (%)	Cumul. Subsidy Cost (Mio EUR)	Cumul. System Cost (Mio EUR)	Annual System Costs (Mio EUR)	Surplus risk
		2030	2014-2030	2014-2030	2030	2015-2025
BAU RES	CFD New	44%	34 233	172 012	10 916	Medium
	CFD DSM	40%	31 525	169 177	10 559	Medium
	CFD OT	44%	33 459	170 609	10 916	Medium
	CFD DSM OT	40%	30 576	166 315	10 444	Medium
	CFD MP New	29%	23 934	162 676	10 303	Low
	CFD MP DSM	27%	21 938	161 115	10 094	Low
	CFD MP OT	29%	23 455	162 143	10 303	Low
	CFD MP DSM OT	27%	21 351	159 187	9 979	Low
High RES	CFD New	57%	40 996	178 417	11 585	High
	CFD DSM	53%	37 178	173 926	11 274	High
	CFD OT	57%	38 999	176 191	11 585	High
	CFD DSM OT	53%	36 102	171 078	11 153	High
	CFD MP New	38%	28 219	166 843	10 758	Low
	CFD MP DSM	36%	25 810	164 337	10 599	Low
	CFD MP OT	38%	27 298	165 837	10 758	Low
	CFD MP DSM OT	36%	25 134	162 495	10 484	Low

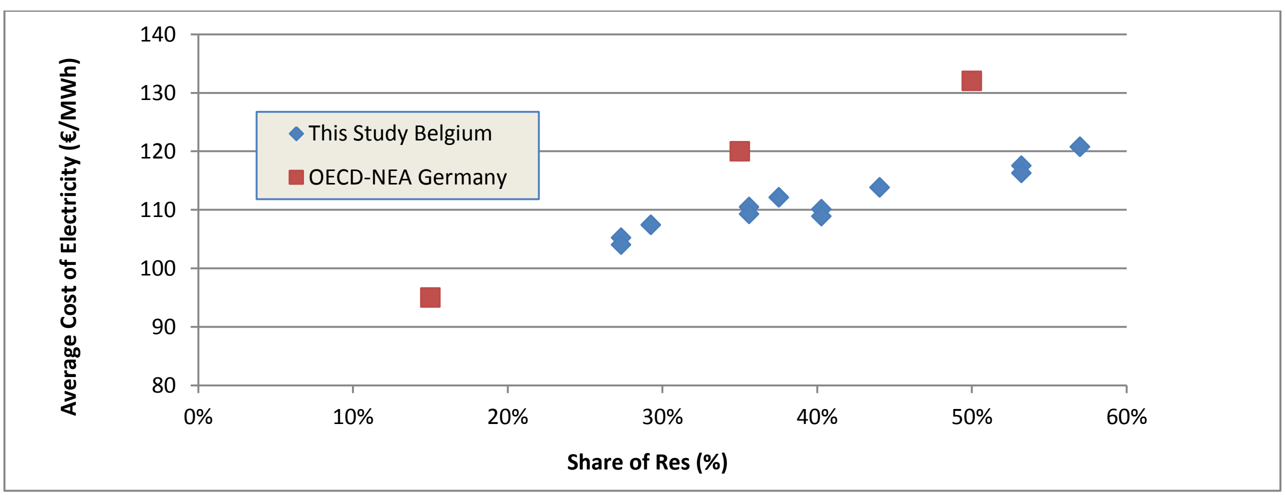
It is important to stress the limitations of this study. One of the most important limitations is the strong focus on the Belgian situation. Since the European electricity market is going through an important phase of liberalisation and market integration, Belgium is increasingly influenced by the energy policies in its neighbouring countries. Already today, we feel the impact of cheap coal-based electricity production from Germany and cheap nuclear electricity from France (CREG, 2014). In this respect it is important that Belgium cooperates with its neighbours on any kind of flexibility remuneration or capacity mechanism, in order to prevent additional distortions and market failures in the Central-West-European electricity system. Ideally, any major change in energy policy should be discussed on a more regional level, and not only at the national level.

Another limitation relates to storage capacity. In the presence of sufficient storage capacity (e.g. pumped hydro or battery systems), surplus risks will be radically different. Modelling storage capacity is however difficult because storage can also have an impact on the use of gas and biomass plants. Once storage capacity exists, operators will try to maximize returns based on electricity price levels. With massive storage, the frequency of high prices can be impacted and hence the profitability of CCGTs. Expected investments in storage capacity can reduce the willingness to invest in OCGTs and CCGTs. In this study, we do not assume additional storage capacity in Belgium before 2030.

One of the most fundamental assumptions in this study is the assumption that the reserve margin will always remain above 5 percent. This is a very strong assumption and implicitly ignores the reality of construction planning, possible delays, and many other factors that can prevent the timely installation of new capacity. Especially the huge drop in the reserve margin in 2024-2026 will be very challenging.

Overall, we need to realise that the findings in this study are pragmatic estimates based on current trends and evolutions. Therefore it is useful to compare our findings with other studies. No similar study for Belgium is available but we can compare our results with those of the OECD-NEA report for Germany. Figure 43 indicates that our results are very much in line with those found in this report. However, the cost estimates seem to diverge when the share of renewable electricity increases. Obviously, it is hard to compare these results, since the underlying methodology and assumptions are different. And the Belgian electricity system is very different from the German one. Nevertheless, the results from the OECD-NEA report do provide a useful benchmark.

Figure 43: Average electricity supply costs[11] in Belgium and Germany with increasing shares of renewables (Own data and OECD-NEA 2013)



[11] Average supply cost is calculated by dividing total system cost (Billion €) by total electricity demand in 2030 (96 TWh)

Despite its limitations, we feel that the following conclusions can be drawn from this study:

Main Conclusions

1. Market participation by renewables is essential for an affordable and sustainable energy-mix in the future. Whether the government chooses a future with higher or lower shares of renewables, market participation by renewable technologies will make any policy choice less expensive. On top of this, a policy that gives grid priority to all types of renewables will result in high surplus risks (especially in 2015-2025) and should definitely be avoided. This means that the current system with grid priority for renewables will have to be adapted, *precisely* in order to make a wider expansion of renewables technically possible.

2. Demand Side Management (DSM) offers many benefits. Not only does it provide a cheaper alternative than investing in new capacity. In the short run it is likely to be easier to increase DSM opportunities than to build new power plants. Also, DSM is a long term solution. More intelligent systems and revolutions in ICT are likely to make DSM easier, more important but also more affordable in the next decades.

3. A higher share of renewables will result in higher overall system costs in the next decades. The levelized cost of electricity (LCOE) for renewables is still higher than “traditional” energy sources (this is partly due to a low carbon price). Intermittent renewables also result in higher overall system costs. The feedstock costs of biomass will be a main driver in the overall costs of any energy mix with high shares of renewable energy technologies. The good news is that with the right policy choices, we can achieve a given target for renewables at a reasonable cost.

4. Remunerations for availability of capacity are likely to be essential to trigger investments in flexible and controllable assets (‘firm capacity’). Such assets are vital facilitators on a pathway towards a future with a high share of intermittent renewable electricity production.

5. A clear overall conclusion is that there is no “silver bullet” technology or policy. A multi facetted approach is vital. DSM and market participation can help. The essential problem however remains that system reliability and system flexibility do not have ‘a fair value’ in the market organisation of today.

Acknowledgements

We want to thank GDF-Suez-Electrabel for the strong support during the whole process of this research. Special thanks go to Luc Van Nuffel, Francis Hanssens, Bernard Carrette and Olivier Desclée.

We also thank many researchers and energy professionals for their relevant inputs and suggestions when we presented partial results of this analysis in Belgium or abroad.

We would also like to thank Dr. Ilse Ruyssen and Prof. Dr. Gerdi Everaert for their contribution to the Matlab modelling.

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