Sensitivity scenario's underpinning choices for the Belgian Energy Pact

Draft Final Report

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Executive Summary

Greenpeace, BBL and IEW have asked EnergyVille to recalculate scenarios within the framework of TIMES Belgium model, same as in EnergyVille (2017), in order to gain a better understanding of the impact of the impact of the latest natural gas price projections in Europe, as both the World Bank (2017) and the IEA (2017), have lowered their respective forecasts by more than 20% for the year 2030 relative to previous publications (IEA, 2015). The two scenarios developed for the study are:

- ***'UP18':*** an update of EnergyVille (2017)'s central scenario (called '*EV2017*'), which considers the full closure of nuclear power capacity by 2025, as currently planned in legislation. Main difference compared to previous study is the updated natural gas price assumption for 2020, 2025, 2030, 2040 now based on World Bank (World Bank. 2017).
- ***'UP18-NUC':*** an update of the 'Nuclear Extension' scenario of EnergyVille (2017). It is based on the new central scenario UP18, but considers a 10 year lifetime extension of the existing 2 GW nuclear reactors (Doel 4 and Tihange 3)

Main difference compared to previous study is the updated natural gas price assumption for 2020, 2030 and 2040 (by extrapolation), which are now based on World Bank (2017). Updates on the existing stock of natural gas power plants, nuclear reactors availability profile, import prices assumptions and installed capacity of offshore wind in 2020 were also implemented in order to have a better depiction of current and future conditions of the Belgium energy system. Additionally, reporting years were extended to 2040.

Outcomes Relative to Belgium Power Sector

Results show that, in 2020, the lower gas prices and the 2.2 GW capacity of wind offshore partly delay investments in wind onshore (from 6.6 GW to 3.7/3.8 GW) and solar PV technologies (from 4.7 GW to 3.0 GW) in both UP18 and UP18-Nuc relative to EV2017. Still, most of the power capacity in Belgium, more than 70%, will come from renewable energy sources in 2030 and in 2040, as offshore wind will correspond to approximately 3 GW and the PV capacity doubles to 10.6 GW in 2040. **This confirms that according to the Belgium TIMES model the 10-year nuclear extension has a limited impact on the expansion of renewables.**

This steep increase in renewable electricity supply in both UP18 and UP18-Nuc is also driven by the increase in electricity demand, as electric vehicles uptake grows further after 2030 and corresponds to 13% of total electricity demand in 2040, according to the Belgium TIMES model results.

'UP18 scenario' Highlights:

Investments in natural gas power plants and CHPs bring the natural gas-based generation capacity of UP18 scenario in 2030 to the same level as in EV2017, to approximately 6 GW. However, the production of gas-fired power plants is about 25% higher in 2030 due to lower gas prices. Similarly, import of electricity is 40% lower than the previous scenario (9.3 TWh versus 15.6 TWh). As for 2040, the increase in the renewable capacity enables a small decrease of gas-fired power plants, which corresponds to 5.53 GW.

'UP18-Nuc scenario' Highlights

UP18-Nuc scenario results shows that natural gas capacity is the most impacted by the nuclear phase-out: investments are postponed and capacity levels remain lower than 4.8 GW in 2030, meaning 1.5 GW is not added to the system in this period. The corresponding generation output by gas-fired plants is approximately 30% lower (28.7 TWh versus 40.2TWh) and import is 20% (7.5 TWh versus 9.3 TWh) compared to the UP18 scenario.

In 2040, after the complete closure of the two nuclear reactors, natural gas-based capacity and generation levels are equated at 5.5 GW and 39 TWh, same levels of UP18. Overall, the capacity and generation mix of both UP18 and UP18-Nuc in 2040 are very similar, showing that **a 10-year nuclear extension would lead to an acceleration of investments in gas-fired units after 2035 in order to meet the increasing electricity demand.**

With a technical lifetime of 30 years, these gas plants will likely remain in service until 2065, **making it difficult to reconcile with the long-term -80 to -95% CO_2 reduction targets by 2050**. Consequently, significant developments and costs reduction in power-to-gas technologies are needed to provide fuel for these gas-fired plants to reach deep carbon reductions.

Costs of ‘UP18’ and ‘UP18-Nuc’ scenarios:

The UP18 scenario has lower annual power generation system costs in 2030 due to lower levels of fuel expenses and lower import electricity prices and import quantities relative to EV2017 (€ 5.4 billion in UP18 versus € 6.2 billion in EV2017, a 12% reduction). Both causes are linked to the lower gas price projections, which results in a fuel cost 11% lower and a trade cost 37% lower in 2030 for the UP18 scenario relative to the EV2017 scenario.

The 2GW nuclear power extension leads to annual costs of the Belgian electricity system will be approximately 4%, or € 235 million lower in 2030 (UP18-Nuc compared with UP18). For the year 2040, the cost calculations show that both 2018 updated scenarios have similar costs of € 7,2 billion, confirming that the extension of 2 GW of nuclear capacity does not provide a long-term cost advantage to the power system, but that **the cost reduction is a) mainly attributable to lower fuel use during the extended life-time and b) that the development of natural gas prices in the coming years will have the most significant (and uncertain) impact on the power system costs.**

CO_2 Emissions

Regarding CO2 emissions of the public power generation sector (so under ETS), the updated UP18 scenarios result in higher emission levels in 2020 and 2030 (by 12.5% and 15.3%, respectively) than EV2017 mainly driven by the higher usage of natural gas in the power system. When comparing UP18 to the UP18-Nuc scenario, 2030 is the only reporting year where emission levels are significantly different, as the UP18-Nuc results in 20% less emissions (equivalent to 18.1 Mton CO_2 - against 22.3 MtonCO_2 in UP18). **In 2040 emissions levels are equated in both scenarios and still significantly above a 80% emission reduction level relative to 1990.**

Introduction

1.1. Objective

In January 2017, VITO/EnergyVille released the study “Energy Transition in Belgium – Choices and Costs” (EnergyVille, 2017). This study explored on possible energy scenarios in Belgium in 2020 and 2030, including their implication on energy production and costs for the Belgian Industry. As study’s results show a steep increase in renewable electricity production until 2030, it also points to the importance of natural gas generation capacity to remain at current levels, i.e. at least 6,000 MW, in order to balance the more volatile supply of renewable sources.

The World Bank (World Bank, 2017) released its latest commodities price forecast in October 2017, including the latest gas price projections for Europe. The projected prices are approximately 22-23% lower for 2030 than estimated in the World Energy Outlook 2015. A very similar adjustment can be found in the latest World Energy Outlook 2017 (IEA, 2017), which also lowered its gas price projections by more than 20% mostly driven by the interpretation of geopolitical developments, such as the changing role of the USA from a fossil fuel importer to a fossil fuel exporter in the next decade.

Because of the fact that natural gas based generation in Belgium will play an important role in the foreseeable future, it is expected that any cost calculations for the power system in Belgium should be significantly influenced by natural gas price projections. This is of course also applicable to the comparison of different energy pathway scenarios with varying degrees of natural gas use.

The current draft Energy Pact[1] gives food for discussion on some of the covered topics, mainly on the role and costs for a nuclear extension of 2GW. Greenpeace, BBL and IEW asked to build further on the EnergyVille (2017) study, with the TIMES model, and to (re-)calculate with the latest gas price projections the central scenario, which is based on current policies (including the complete nuclear closure by 2025), and the 10-year/2 GW nuclear extension scenario. In addition, refinements regarding the availability of the 2 reactors under consideration for lifetime extension were implemented and the reporting period was extended to the year 2040.

The main objective of this exercise is assessing impacts on costs and power mix capacity and generation towards distinct scenarios for the power sector. This should allow a better depiction of the relevant role of the nuclear capacity, offshore wind and natural gas-fired power technologies in the country.

This study provides facts and figures regarding technology choices and consequential impacts on the energy system as a whole. It does neither directly nor indirectly predict electricity prices in general or for certain sectors. The scenario analysis with the Belgian TIMES model is based on a system cost optimization approach. It provides a technical and economic analysis framework to evaluate choices and resulting cost for the energy system of Belgium and can contribute valuable insights into consequences certain policy choices might have for the future.

1.2. Content of this Report

The report is divided in six sections from executive summary to references. Chapter one consists of a brief introduction; chapter two explains the rationale of TIMES and the most recent updates in the Belgian TIMES model, besides outlining the considered scenarios of the study; chapter three reports and discusses the results; chapter four summarizes the conclusions of the study and; chapter five lists the references adopted.

2 Methodology for Scenario Development

The EnergyVille TIMES Belgium Model is based on the TIMES modelling framework, used for energy system analysis by leading research institutes in 63 countries. This framework is continuously improved and further developed to stay abreast the latest technology developments and challenges the energy systems of the world are facing. Vito/EnergyVille contributes actively for over 20 years to the evolution of the TIMES

[1] https://www.energiepact2050.be/

model generator and is an active member of ETSAP, the Energy Technology Systems Analysis Programme of the International Energy Agency[2].

The TIMES model is a bottom-up, technology orientated, multi-regional energy system model. It is based on a linear optimization principle, which minimizes an objective function representing the total discounted energy system costs over the whole modelling time horizon, i.e. from 2014 till 2030 for this study. Under this rationale, the supply of energy commodities has to meet different types of end user demands put in the model as exogenous parameters.

The TIMES model is designed for analysing the role of energy technologies and their innovation for meeting energy and climate change related policy objectives. It models technology uptake and deployment and their interaction with the energy infrastructure in an energy systems perspective (Giannakidis et al., 2015). It is a relevant tool to support impact assessment studies in the energy policy field that require quantitative modelling at an energy system level with a high technological detail. The TIMES model delivers insights both in "planning" and "optimization" by means of its mathematical linear programming methodology based in economic theory on consumer- and producer surplus optimization.

The model covers, on a country basis, the whole energy system. It includes in detail the supply of resources and reserves, the public and industrial generation of electricity and heat as well as the end-use sector industry, commercial, households, transport and agriculture (Figure 2-1). The model considers country-specific particularities, such as decommissioning curves, potentials for renewable energy generation and national carbon storage potentials as well as interregional trade of electricity, biofuels and energy crops.

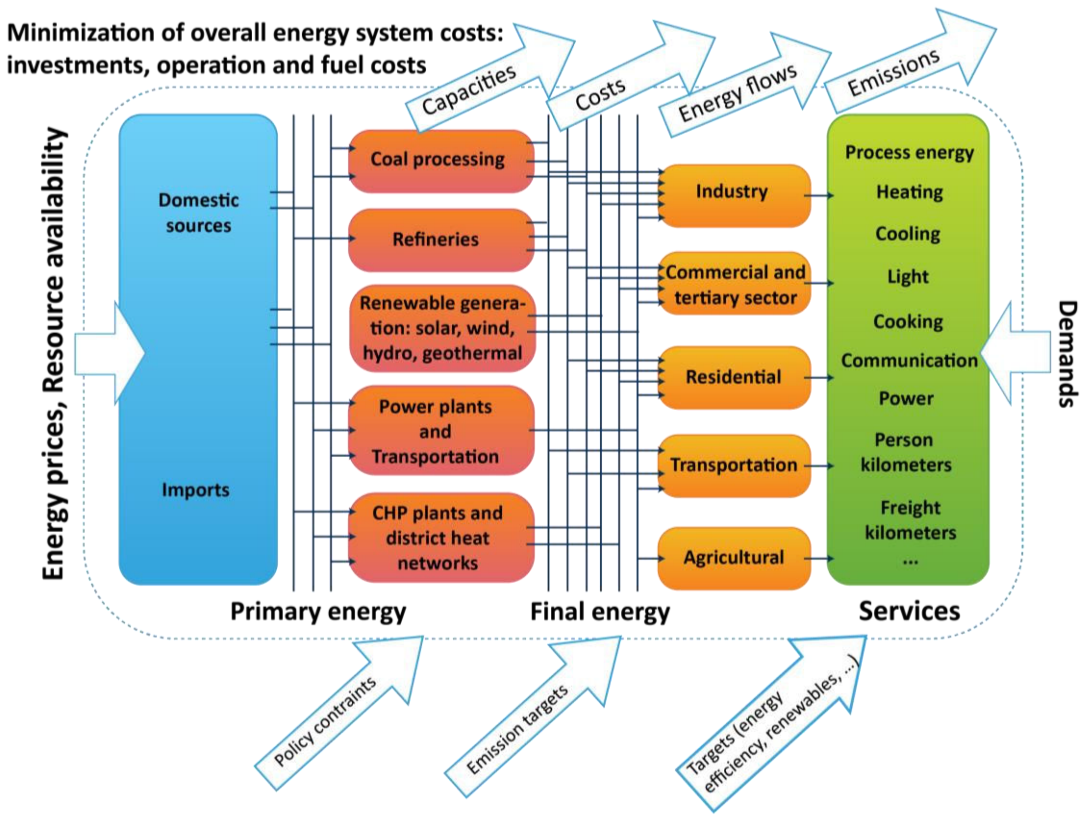


Figure 2-1– TIMES model rationale. Adjusted from source: (IEA-ETSAP, 2016)

In this framework, the Belgium energy system was modelled within the TIMES framework in order to develop short to medium-term scenarios. For this purpose, EnergyVille screened and adopted international credible references, such as (EC, 2013), (EC, 2014) and (IEA, 2015) in order to have appropriate parameters to characterize the energy system.

[2] For more information on TIMES: http://www.iea-etsap.org

2.1. Belgium TIMES Model: recent updates

A detailed exposition and discussion over Belgium TIMES and its assumptions is provided in EnergyVille (2017). For reference, a summary of the main characteristics is listed below:

- Belgium is considered a geographic region interconnected to neighbouring countries;
- The model calibration is based on 2014 statistics (EC, 2016). Newer data from 2016 statistics were also integrated, when available;
- The calculated model time horizon goes up to 2050. For the purpose of this study, the years of 2016, 2020, 2030 and 2040 are reported.
- Demand side response (DSR) by any sector is not taken into account; which means that the DSR costs are not taken into account[3].
- A time resolution of 120 time slices per year (10 representative days with 12 2-hourly time periods) was adopted to capture the daily and seasonal variations of energy generation and consumption;
- Differentiated discount rates for different groups of energy supply and demand technologies were considered, representing the different risk perception of industry versus individuals;
- The technology portfolio available for Belgium's power sector is compatible with the existing stock and planned infrastructure and resource potential for the short and medium-term. For details, see EnergyVille (2017) and section 2.1.b.
- Technologies that will be available in the future until 2030 have their technical and economic characterization based on screened literature review. Main parameters are listed in EnergyVille (2017).
- Regarding trade and grid infrastructure, the model considers a 3.5 GW capacity in 2014 and it foresees the planned transmission investments, reaching a total commercial cross border electricity trade capacity of 6.5 GW, in 2020.
- Additional investments in transmission capacity are considered to be underground.
- Upper and lower limits on annual import and export electricity quantities are also taken into consideration reflecting historical data regarding maximum and minimum annual levels of imports and exports in Belgium.
- The Belgian industry is divided in thirteen different sectors with different final demands. The main structuring of the industry sector is based on the previous TIMES Belgium developed by VITO (Devogelaer et al., 2012).
- Transport sector includes road and rail transport demand, public transport in form of busses and light rail and aviation and navigation demand. Technical and economic assumptions for electrical cars are based on (Roland Berger, 2016).
- Residential, commercial and agriculture sectors (RCA) have their perspectives on growth and energy efficiency regulations according to FPB (2014) and Statistics Belgium (statbel, 2016). New buildings put in place after 2016 have low energy demand following the EU regulation on Near-Zero energy buildings (EC, 2016c). Moreover, investments on new heat pumps are properly modelled accounting for the efficiency variation due to external temperature.
- Regarding CO_2 emissions, production plants and power generation installations are differentiated into belonging to the ETS and the non-ETS sectors for proper representation of ETS carbon prices.
- No other greenhouse gas is considered and the overall emissions of the energy systems correspond to CO_2 only.

For the current exercise, the Belgium TIMES model was updated with the following aspects:

- Natural gas prices;
- Existing natural gas power plant stock and operational lifetime;
- Seasonal profile of nuclear power availability (although the average availability was kept 80%);
- Electricity import prices;
- Total offshore wind capacity in 2020;

In the next subsections, these updates will be further explained.

[3] This has an indirect effects on the on marginal costs of electricity generation in the model, e.g. price peaks caused by high activation costs during peak demand are not reflected in the model..

a. Natural Gas Prices

In EnergyVille 2017 the natural gas and oil prices were based on World Energy Outlook 2015, specifically the ‘New Policies’ scenario. In addition two scenario calculations were performed based on a low gas price development, assuming the natural gas price would remain at 2016 levels and a high gas price development, assuming the gas price would be approximately 50% higher in 2020 and 2030 then projected by the International Energy Agency in 2015.

For this study the latest available gas price projections up to 2030 from the World Bank from October 2017 were used (World Bank, 2017) and extrapolated until 2040. Figure 2-2 shows the new price projections in comparison to EnergyVille 2017 projections. The gas price is assumed to be approximately 22% lower in 2030 and 2040 compared to the 2017 projections, which corresponds to approximately 21 Euro/MWh in 2030 and 25 Euro/MWh in 2040. These new assumptions are in-line with revised gas price projections from the latest World Energy Outlook 2017 (IEA, 2017)[4].

The price projections for oil prices were not modified.

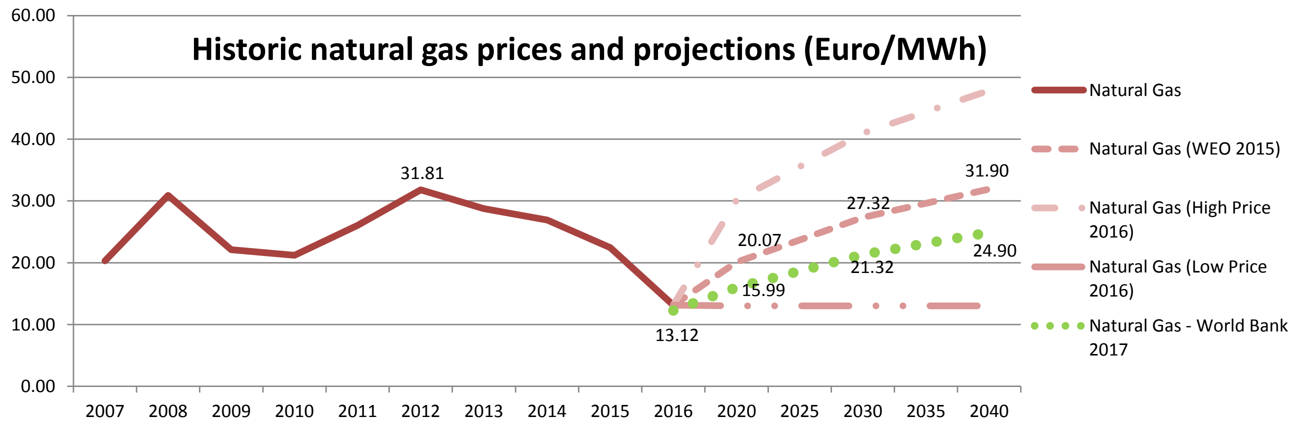


Figure 2-2 – Natural gas historical prices and projections. Source: EnergyVille (2017) and World Bank (2017)

b. Natural Gas Power Plants

The technology portfolio of Belgium’s power sector in the model is compatible with the existing stock and planned infrastructure and resource potential for the short and medium-term. Some small updates were provided relative to EnergyVille (2017). Moreover, the current natural gas power plants units were detailed based on data made available by EDF Luminus for EnergyVille (2018). This allowed a better depiction of existing capacities in 2016 per technology (CCG, OCGT or turbojet), their expected remaining lifetime and their efficiencies. Table 2-1 shows the stock (in GW) in 2016 and following projections as reported in EnergyVille (2017) – EV2017 in the table) and as foreseen in the updated scenarios (UP18 and sensitivities).

The expected lifetime of existing power plants accounts for expected overhauls for these units and the table shows that updates led to a reduction in the existing capacity and in the capacity projections for 2020, 2030 and 2040.

Moreover, other technical and economic parameters, such as O&M costs and average availability factors, as well as the technical and economic profile of investment options, were kept as previous studies, fully aligned with available literature, such as EC (2013) and EC (2014).

[4] In WEO 2015 the New Policies Scenario projected for natural gas in the European Union a price of 11.2 $/MBtu (2030) and 12.4 $/MBtu (2040). In WEO 2017 (OECD/IEA2017) the same policy scenario for the EU projected 8.6 $/MBtu (2030) and 9.6 $/MBtu (2040).

Table 2-1 – Natural Gas Power Plants Stock Update (Source: EnergyVille, 2018 & EnergyVille, 2017).

Existing gas power plants (GW)	EV2017	UP18 and sensitivity scenarios
2016	4,54	3,72
2020	4,54	2,53
2030	1,83	1,85
2040	/	0,69

Considering that the TIMES model allows full competition among technologies due to the perfect foresight characteristic, once natural gas power plants were adjusted regarding their operational lifetime, competition between power plants and CHPs are expected to drive the evolution of the power system. CHPs can have an advantage due to their relatively lower investment costs and higher efficiency depending on the industry they are linked to. In reality, this advantage is not always the case because: 1) CHP units are commonly subject to the same economic conditions as GT units and; 2) CHP efficient operation is controlled by thermal demand and 3) CHP expansion is also closely related to subsidies, which are not represented in TIMES Belgium.

Therefore, in order to consider these market barriers related to CHP expansion and put both natural gas power plants and CHPs into the same level playing field, we have adopted a simple approach of limiting CHP capacity expansion to the Central scenario levels based on EnergyVille (2017). In that sense, electrical capacity of CHP units are capped to no more than 3 GW in 2030, limiting the expansion in the long-term. Compared to the 2014 capacity, this is a growth of more than 25% or 0.6 GW.

c. Levelized Cost of Electricity for Renewables

Figure 2-3 depicts the levelized costs of electricity (LCOE) of PV solar and wind offshore installations in the year 2016, 2020 and 2030 based on a 7.5 % discount rate and the technical and economic parameters listed in EnergyVille (2017). For the residential and commercial PV installations, two cost projections are shown: with and without fixed annual operation and maintenance costs of 46 €/kW of capacity. This cost represents capital expenditures for improvement to the distribution grid infrastructure and/or the cost of local battery storage. It also considers that inverters have to be replaced once during the lifetime of a PV system, which accounts for approximately 11-12 €/kW/year or a quarter of the estimated operation and maintenance costs. This approach reflects the design of the model, but it deviates from presentation of levelized costs for PV solar in other publications that do not take these costs into account. For comparability reasons and to avoid confusion about the cost assumptions regarding PV solar in this study, the levelized costs of PV solar without the fixed operation and maintenance cost of 46 €/KW are also shown.

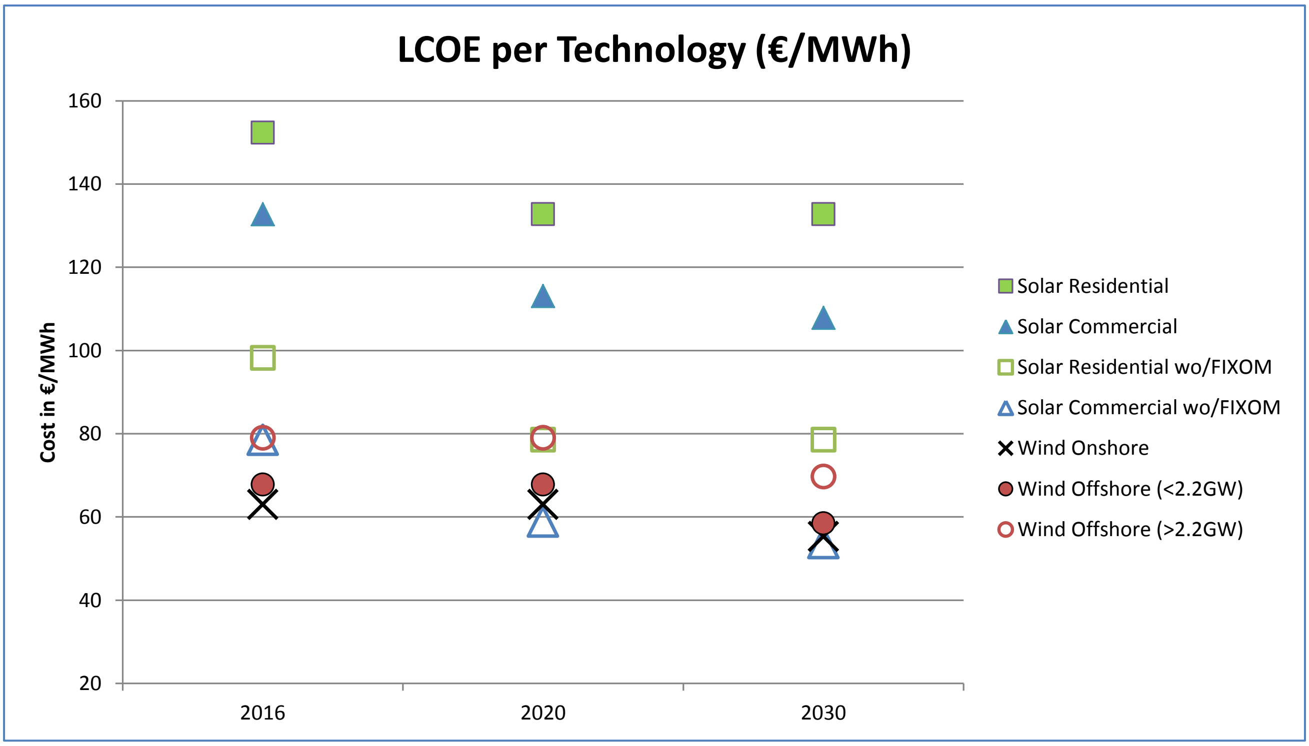


Figure 2-3 – Levelized costs of electricity (LCOE), PV solar, wind offshore, natural gas-based technologies (€/MWh)
Source: Belgium TIMES Model

d. Nuclear Power Generation

While in literature the maximum capacity factor for nuclear installations is listed with 90 % (EC, 2014), the average availability factor is usually below this value. In this study the average availability up to 2025 accounts to 80% and further specified on a detailed time slice level to include unforeseen outages outside regular and planned maintenance downtimes, as have been observed in recent years in Belgium and France. These down times occur based on random patterns in the Belgium model which vary by year. Figure 2-4 shows an illustrative example of the nuclear availability pattern for the year 2020, showing variations from 51% to 100 % availability, averaging to 80% over the whole course of the year.

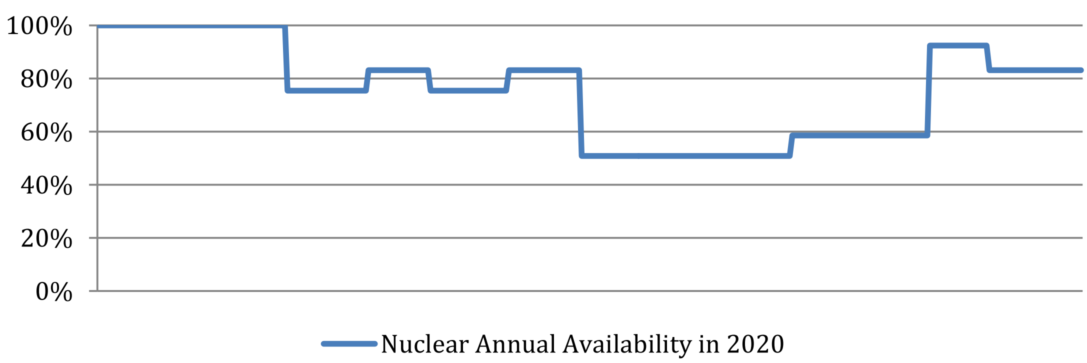


Figure 2-4 – Nuclear availability over the course of a year – 2020 (%)
Source: Belgium TIMES Model

For the 10 year and 2 GW nuclear lifetime extension scenario a more detailed approach was chosen. Since the extension considers only 2 reactors with a capacity of 1 GW each, the 80% average availability was projected to each reactor. This results in a 2 GW, 1 GW or 0 GW generation capacity at various moments in time during the model period from 2025 to 2035. The probability distribution as shown in Figure 2-5 was used for the nuclear availability input, e.g. for 64% of the time an availability of 2 GW was assumed. To ensure that the model calculations take into account extremely challenging time periods for the power system, the 0 GW availability, which has a statistical likelihood of 4%, was placed in the year 2030 during a representative day with the lowest generation output from PV solar and wind (see Figure 2-6).

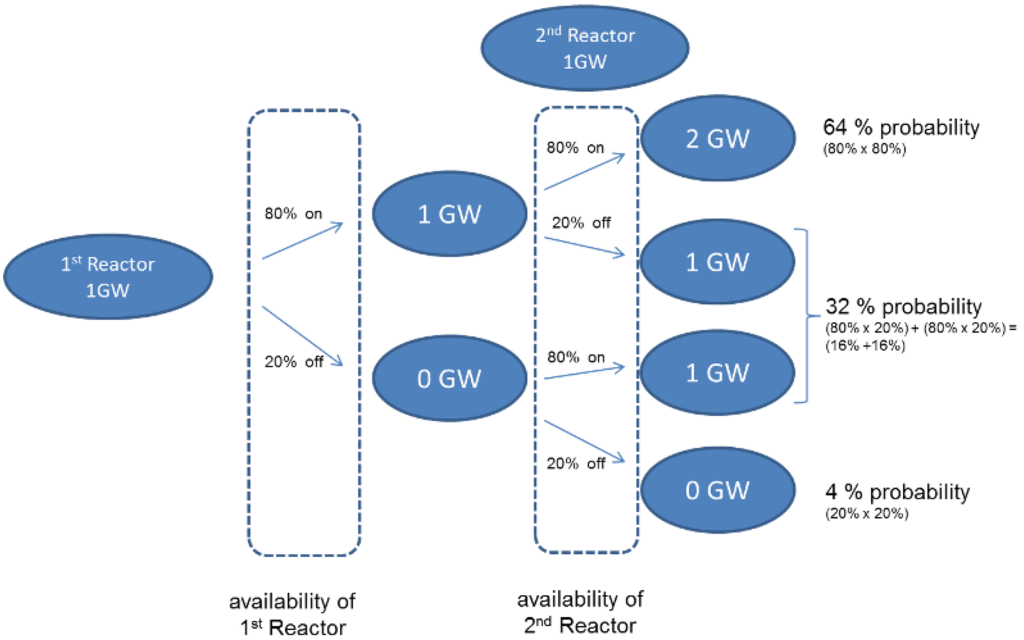


Figure 2-5 – Nuclear capacity during the 10-year 2 GW lifetime extension (2025-2035)
Source: Belgium TIMES Model

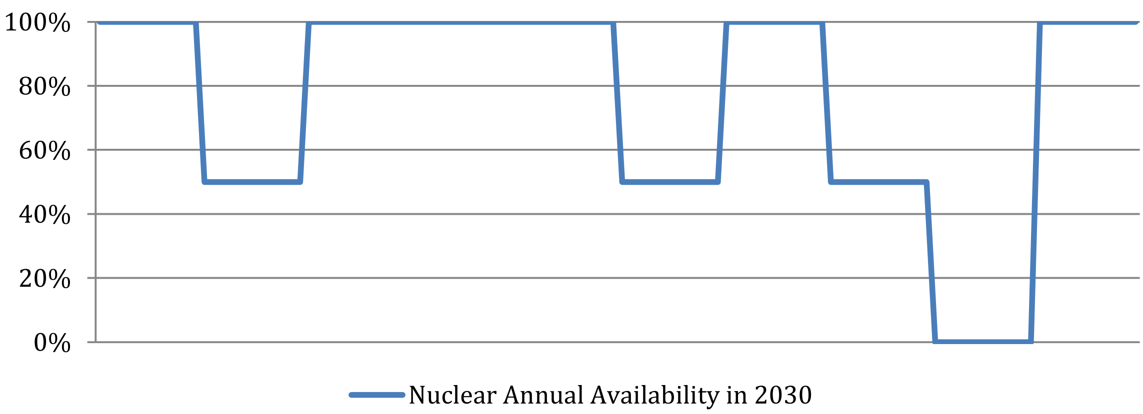


Figure 2-6 – Nuclear availability over the course of a year – 2030 (%)
Source: Belgium TIMES Model

e. Electricity Imports and Exports

As in EnergyVille (2017), the planned transmission capacity expansion from the current 3.5 GW to 6.5 GW in 2020 is considered in the model. This accounts for the new connections planned with Germany (ALEGrO), and the United Kingdom (NEMO) besides the upgrade of the Brabo interconnection with the Netherlands, as stated in ELIA's annual report (ELIA, 2015). Investment costs for the planned grid expansion are equivalent to €500/kW. Any additional investment in the transmission grid is considered to be underground, incurring in higher investment costs by the factor of 3, e.g., €1,500/kW. Regarding import and export flows, these are limited to historical values: electricity import range between 9.4 and 23.9 TWh and electricity export range between 2.5 and 11.5 TWh for the 3.5 GW of transfer capacity in the base year (2014). The additional capacity beyond 3.5 GW is not limited by any predetermined import or export flows.

Besides capacity and import and export quantity limits, the volatility of electricity import costs is also represented in the model. In this study, a stepwise approach which takes into consideration that import prices increase when import flows are high is adopted, as shown in Figure 2-7. On top of this incremental increase, a variable price profile within each period is implemented based on import price variations in the base year (2014). This is replicated from 2016 to 2030. The increasing price profile throughout the time horizon, either in terms of absolute values and of amplitude, are derived from a correlation with the increasing fossil fuel price projections.

This approach for import prices within Belgium TIMES includes the three following conditions:

- The step-wise increment in average import prices reflects the fact that import prices increase when demand is high. When import flow levels use only 1 GW of the current available capacity, import price range from €22/MWh to €37/MWh in 2016. For every additional GW of capacity that is utilized, an increment in these price ranges are foreseen, reflecting the market conditions under high demand periods.
- The import price volatility within the year accounts for the fact that peak load hours within a year have higher prices than average. It takes into account that these high demand periods are approximately the same in the neighbouring countries, due to the proximity and similar climate conditions. During these hours, market competition is high, leading to higher import prices than observed in average.
- The increasing evolution of import prices in the long-term reflects that energy market is integrated and heavily influenced by fossil fuel prices in the context of global markets. It acknowledges the correlation between the fossil fuel projections adopted in the study, based in IEA (2015) and the electricity import price to be paid in Belgium.

Last, electricity import and export activities in the TIMES Belgium do not distinguish from and to which country the electricity flows. Import is assumed to be always available at the above described import price per MWh. Import prices do neither reflect situations of simultaneous scarcity in a wider region beyond Belgium, nor moments of oversupply caused for example by excess renewables generation.

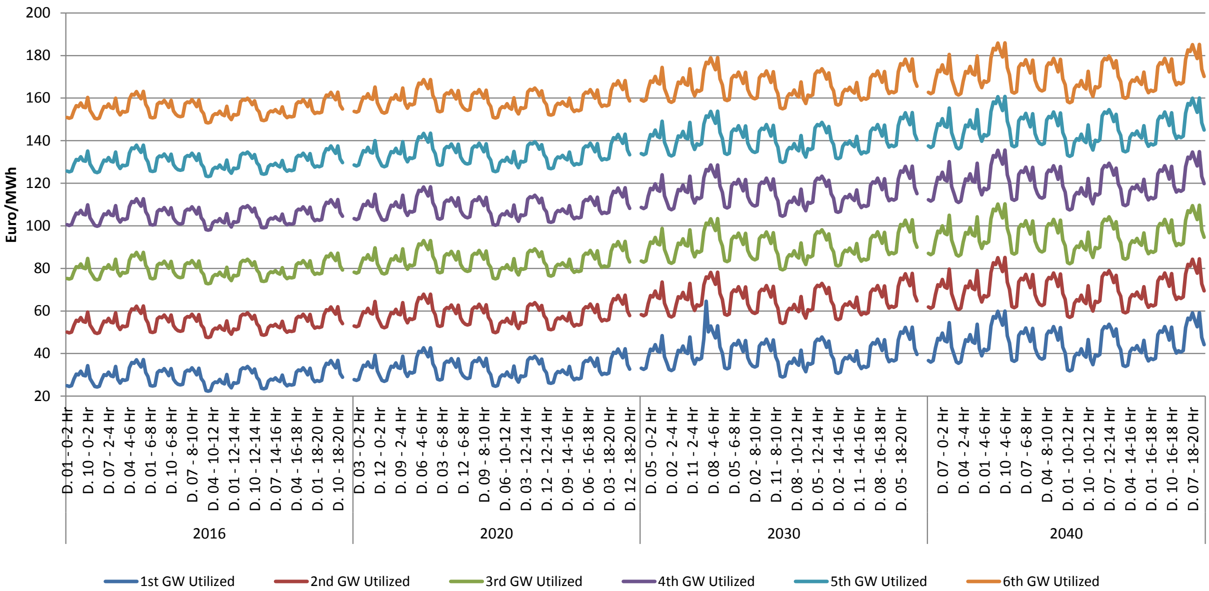


Figure 2-7– Import price profiles.

f. Short–term Wind Offshore Capacity

Although technical and economical parameters of wind offshore technologies remain as of EnergyVille (2017), the installed capacity in 2020 was updated to 2.2 GW in order to reflect investments already directed to new offshore wind units.

2.2. Scenarios Outline for Natural Gas Capacity

The two scenarios considered for this study hold the same assumptions as in EnergyVille (2017) given the updates mentioned in Section 2.1:

- **UP18:** this scenario is an update of EnergyVille (2017)'s central scenario. It foresees the nuclear power plants will be closed as currently planned in legislation, e.g., after 2025. Main difference compared to previous study is the updated natural gas price assumption for 2020, 2025, 2030, 2040 now based on World Bank (World Bank. 2017).
- **UP18-NUC:** this scenario, just as the 'Nuclear Extension' scenario of EnergyVille (2017), is based on the new central scenario UP18, but considers a 10 year lifetime extension of the existing 2 GW nuclear capacity (Doel 4 and Tihange 3)

The reporting years for the study are 2016, 2020, 2030 and 2040. They are 'milestone years' that report on the optimal system configuration within time periods pre-established in the model.

3 Results

This chapter outlines the main results of the Belgium TIMES model for the power sector. Throughout this chapter the two updated scenarios results (UP18 and UP18-Nuc) are depicted in a comparative way with their respective evolution until 2040. The previous central scenario of EnergyVille (2017) is also included to keep transparency regarding the outcomes of recent updates and henceforth is called EV2017. The results presented focus on the evolution of the power capacity and generation, annual power system costs, marginal price of electricity production and CO_2 emissions for the power sector.

Reporting years are 2016, 2020, 2030 and 2040, with 2040 being the first reported year after nuclear closure (taking place in 2035) for the scenarios where nuclear extension is foreseen, as explained previously.

As outlined in chapter 2 the model generates the cost optimal solution to meet end use demands for each sector. The model assumes that all technologies are available at all times according to their technical specifications and it does not take into account unexpected technology failures, with the exception of the exogenously determined and ‘random’ availability of the nuclear plants. At the same time it holds also true that demand has to be met by sufficient supply in every time period over the complete model horizon. Black-outs are not an acceptable solution within the model results. The model objective is not limited to electricity demand, but also includes demand for heat and transport, although the focus of the reporting in this study is on the power sector.

3.1. Power Capacity

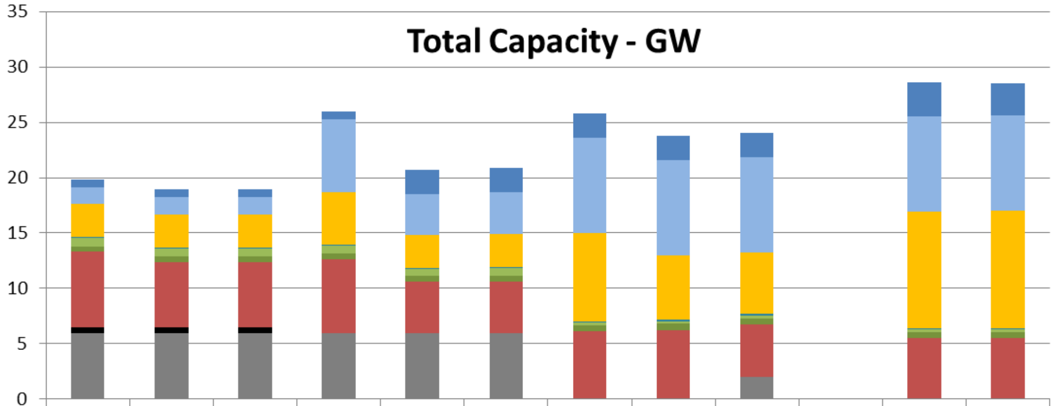
Figure 3-1 shows that the total power capacity in Belgium increases from almost 19 GW in 2016 to more than 28 GW in 2040 in both updated scenarios. The additional capacity required in the long term is explained not only by the macroeconomic assumptions considered, such as population growth, but also by the increase of the electricity demand due to arising technologies in the final sectors that consume electricity, such as electric vehicles. In fact, the electric vehicle fleet will correspond to only 3% of electricity consumption in 2030, but this proportion will rise to 13% in 2040.

If looking to EnergyVille’s 2017 central scenario (EV2017), the lower gas price of the UP18 scenario and the availability of 2.2 GW of offshore wind energy in 2020 mean that the growth of onshore wind and PV is delayed within the time horizon (still with the achievement of the 13% renewable target). Between 2020 and 2030, the results show that investments in new onshore wind turbines are equal to the 2017 scenarios and rise to the maximum potential of 8.6 GW. New PV plants lag somewhat behind (almost 6 GW in 2030 compared to the 7.9 GW in EV2017), mainly because of the lower gas price. Investments in new gas plants (STEG and CHP) bring the total capacity to the same level as in the earlier scenarios, which is more than 6 GW.

Moreover, both scenarios show that most of the power capacity in Belgium in 2030 and in 2040 will come from renewable energy sources, indicating that the choice on extending or not the lifetime of two nuclear reactors should not impact the expansion of RES. In fact, as in 2016 the renewable power capacity share corresponds to 31.8%, in 2030 this share should reach 71.4% in the UP2018 and 69.6% for UP2018-Nucscenario.

Regarding the scenarios with the nuclear extension, results show that natural gas capacity is the most impacted: as investments are postponed, capacity levels remain at 4.8 GW in 2030 for the UP18-Nuc, scenario. This means that 1.5 GW is not added to the system compared to the UP2018 scenario. Renewable sources total capacity are similar between scenarios for each period, as solar PV and wind capacity remains roughly at the same levels (but a slightly lower capacity of solar PV, less than 5%, in UP18-Nuc scenario compared to UP18 scenario).

The 2040 capacity mix for the updated scenarios are very similar, showing that in the UP18 scenario, an acceleration of investments in gas-fired units after 2035 (when the nuclear extension expires) will be needed in order to replace nuclear reactors to meet the electricity supply. With a lifespan of 30 years, these gas plants could remain in service until 2065, making it difficult to reconcile with the long-term -80 to -95% CO_2 reduction targets by 2050. Therefore, it is likely that power-to-gas technologies will be necessary.



	2016			2020			2030			2040		
	EV2017	UP18	UP18-Nuc	EV2017	UP18	UP18-Nuc	EV2017	UP18	UP18-Nuc	EV2017	UP18	UP18-Nuc
Wind Offshore	0,71	0,71	0,71	0,71	2,20	2,20	2,20	2,20	2,20		3,04	2,87
Wind Onshore	1,51	1,51	1,51	6,56	3,68	3,78	8,60	8,60	8,59		8,60	8,60
Solar PV	2,98	2,98	2,98	4,78	2,98	2,98	7,93	5,84	5,57		10,57	10,64
Hydro	0,10	0,10	0,10	0,10	0,10	0,10	0,10	0,11	0,11		0,11	0,11
Biomass & Other Ren.	0,75	0,73	0,73	0,67	0,65	0,66	0,27	0,26	0,27		0,25	0,26
Other Fossil	0,52	0,52	0,52	0,55	0,56	0,56	0,54	0,54	0,54		0,49	0,49
Natural Gas	6,81	5,89	5,89	6,70	4,64	4,64	6,13	6,25	4,75		5,53	5,55
Coal	0,56	0,56	0,56	0,00	0,00	0,00	0,00	0,00	0,00		0,00	0,00
Nuclear	5,93	5,93	5,93	5,93	5,93	5,93	0,00	0,00	2,00		0,00	0,00
Total	19,9	18,9	18,9	26,0	20,7	20,8	25,8	23,8	24,0		28,6	28,5

Figure 3-1 – Power capacity by fuel type, excl. imports (GW)

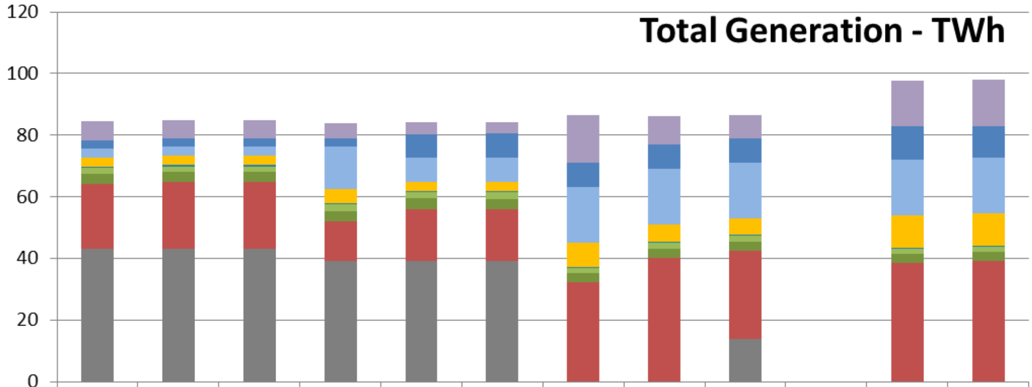
3.2. Electricity Generation

As electricity consumption increases in the final sectors by 2040 due to increase of electric vehicles fleet, results show a 13% increase in power supply from 2030 to 2040 in both UP18 and UP18-Nuc scenarios. This increase is mainly driven by solar PV power generation, which is doubled in capacity relative from 2030 (5.71 TWh in UP18 and 5.44 TWh in UP18-Nuc) to 2040 (10.34 TWh in UP18 and 10.4 TWh in UP18-Nuc), by wind offshore, which rises from 7.82 TWh from 2030 to more than 10 TWh in 2040 in both scenarios, and by net imports, which increases almost 60% relative to 2030 in the UP2018 scenario (9.34 TWh to 14.85 TWh).

When comparing to the EV2017 central scenario (Figure 3-2), one can see that the production of gas-fired power stations in UP18 is 25% higher in 2030 than in EV2017, which is due to the low natural gas prices. Therefore, import levels are also impacted as in the UP18 scenario, net imports are 40% (9.3 TWh) lower than in EV2017 (15.58 TWh).

The UP18-Nuc scenario shows that the nuclear generation extended up to 2035 leads to lower import levels (7.51 TWh, almost 20% lower than the 9.34 TWh in UP18) and lower natural gas-based generation in 2030 (28.67 TWh, almost 30% lower than the 40.17 TWh in UP18).

As similar as generation capacity figures in 2040, the generation profile is almost identical for both UP18 and UP18-Nuc scenarios, reflecting the capacity investments made after 2035 in UP18-Nuc scenario to compensate for the end of nuclear operational.



	2016 EV2017	2016 UP18	2016 UP18-Nuc	2020 EV2017	2020 UP18	2020 UP18-Nuc	2030 EV2017	2030 UP18	2030 UP18-Nuc	2040 EV2017	2040 UP18	2040 UP18-Nuc
Net Imports	6,26	6,12	6,12	5,03	3,83	3,79	15,58	9,34	7,51		14,85	14,98
Wind Offshore	2,53	2,53	2,53	2,53	7,82	7,82	7,82	7,82	7,82		10,79	10,19
Wind Onshore	3,18	3,18	3,18	13,82	7,75	7,95	18,11	18,11	18,09		18,11	18,11
Solar PV	2,92	2,92	2,92	4,68	2,92	2,92	7,75	5,71	5,44		10,34	10,40
Hydro	0,38	0,38	0,38	0,38	0,38	0,38	0,38	0,38	0,38		0,38	0,38
Biomass & Other Ren.	1,94	1,86	1,86	2,05	2,05	2,05	1,78	1,78	1,78		1,74	1,74
Other Fossil	3,16	3,16	3,16	3,46	3,46	3,46	2,99	2,99	2,99		2,74	2,80
Natural Gas	21,13	21,85	21,85	12,82	16,91	16,75	32,15	40,17	28,67		38,62	39,26
Nuclear	43,02	43,02	43,02	39,11	39,11	39,11	0,00	0,00	13,80		0,00	0,00

Figure 3-2 – Electricity generation by fuel type (TWh)

3.3. Costs

The linear optimization of TIMES model takes into account costs related to the energy system as represented in the model: investment cost for new or replacement of installations, fixed and variable operation and maintenance cost, fuel costs and import costs for electricity and other resources. The model does not take into account the amortization of capital expenditures for existing installations (e.g. existing power plants or existing interconnections) and existing installation are considered stock without capital expenditures, although fixed and variable operation and maintenance cost and fuel cost are calculated and considered in the cost optimization.

Although TIMES Belgium is an energy system model, comprising whole national energy system from resources to final sectors, the assessment made in this section is limited to power sector-related costs, which is the main focus of the study.

It is important to emphasize that the model results show costs and do not report on or predict electricity prices. While from an economic point of view costs and prices are closely related in a free market, it is important to use great caution in this context for the following reasons:

- The TIMES model operates in an optimal market and with perfect foresight. It calculates the cost-optimal solution for the overall system (also referred to as societal costs) based on the boundary conditions of the scenario. In the real world the electricity market is highly regulated and a broad variety of support mechanisms and levies are in place impacting the free market.
- The prices of electricity being paid in reality differ significantly depending on the consumer profile and electricity can be bought in many ways, e.g. on the day-ahead market or in the framework of long-term contracts. This has significant impact on the prices being charged to the end consumer.
- Governments often regulate, support or negotiate with power companies about investments in new installations or closures of existing power generation stock. Decisions to invest, mothball or retire plants in the power sector are often heavily influenced by administrative and regulatory actors.

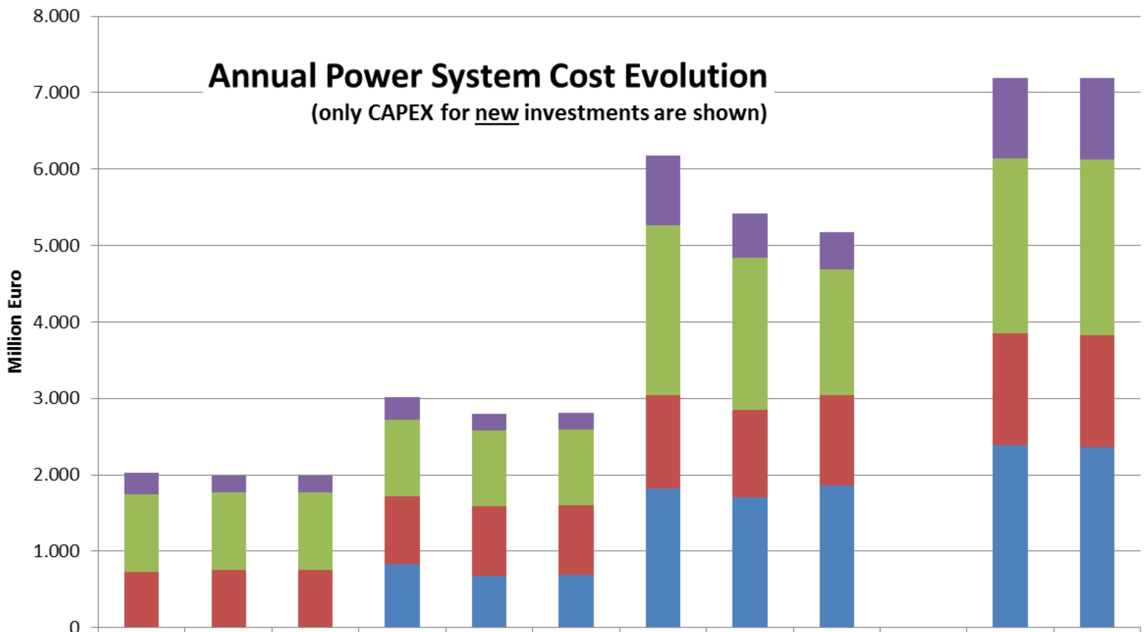
In the next sections the annual power system costs in Belgium and its components will be assessed in order to identify in which extent different levels of natural gas generation capacity impact the cost of the power system.

3.3.1. Annual Power Generation System Costs

Figure 3-3 shows the annual power generation system cost evolution from 2016 to 2040 in Belgium for the three scenarios (EV2017, UP18 and UP18-Nuc) split into its main factors: annualized investment, operation and maintenance (O&M), fuel and trade costs. The 'total' row in the table corresponds to the sum of those values, providing the total power generation system cost per year and per scenario, not discounted to present value. However, it should be noted that annual costs of the power sector are embedded in a broader overall energy system context in the TIMES model. In that context, the numbers provided do not include the cost shifts to other sectors, to other countries and the cost burden imposed by the ETS system.

Additional investments in new power plants can be seen from 2020 onwards, increasing total cost from almost € 2 billion in 2016 to more than € 5 in 2030 and to € 7.2 billion in 2040 in both recent scenarios. Compared to EV2017, the updated scenarios present lower annual costs in 2020 (€ 2.8 billion in UP18 versus € 3 billion in EV2017, a 7% reduction) and 2030 (€ 5.4 billion in UP18 versus € 6.2 billion in EV2017, a 12% reduction) due to lower levels of imports and fuel expenses. Both are a direct or indirect result of the lower gas price projections: as trade costs reduction are explained by the reduction in trade flows due to lower import prices (correlated to fuel prices), the fuel expenses decrease is justified mainly by the lower natural gas prices, which results in a fuel cost 11% lower in 2030 for the UP18 scenario relative to the EV2017 scenario.

The 2018 nuclear extension scenario shows 4% lower overall system costs (or 235 million Euro) for 2030 vis-a-vis the UP18 scenario. For the new reporting year 2040 the cost calculations show that both 2018 up-dated scenarios have very similar costs of 7,194 and 7,196 million Euro. This confirms that the extension of 2 GW of nuclear capacity does not provide a long-term cost advantage to the power system, but that the cost reduction is a) mainly attributable to lower fuel use during the extended nuclear life-time and b) that the development of natural gas prices in the coming years will have the most significant impact on the power system costs.



	2016 EV2017	2016 UP18	2016 UP18-Nuc	2020 EV2017	2020 UP18	2020 UP18-Nuc	2030 EV2017	2030 UP18	2030 UP18-Nuc	2040 EV2017	2040 UP18	2040 UP18-Nuc
Trade	280	224	224	296	217	215	910	576	497		1.061	1.066
Fuel	1.012	1.011	1.011	1.005	994	989	2.230	1.989	1.636		2.280	2.310
O&M	721	756	756	894	908	911	1.221	1.145	1.184		1.472	1.463
Inv.	14	2	2	826	678	690	1.818	1.705	1.864		2.381	2.357
Total	2.027	1.994	1.994	3.021	2.798	2.805	6.179	5.415	5.180		7.194	7.196

Figure 3-3 – Annual Power Generation System Cost Evolution (Million Euro)

However, it should be noted that annual costs of the power sector are embedded in a broader overall energy system context in the TIMES model. In that context, the numbers provided do not include the cost shifts to other sectors, to other countries and the cost burden imposed by the ETS system.

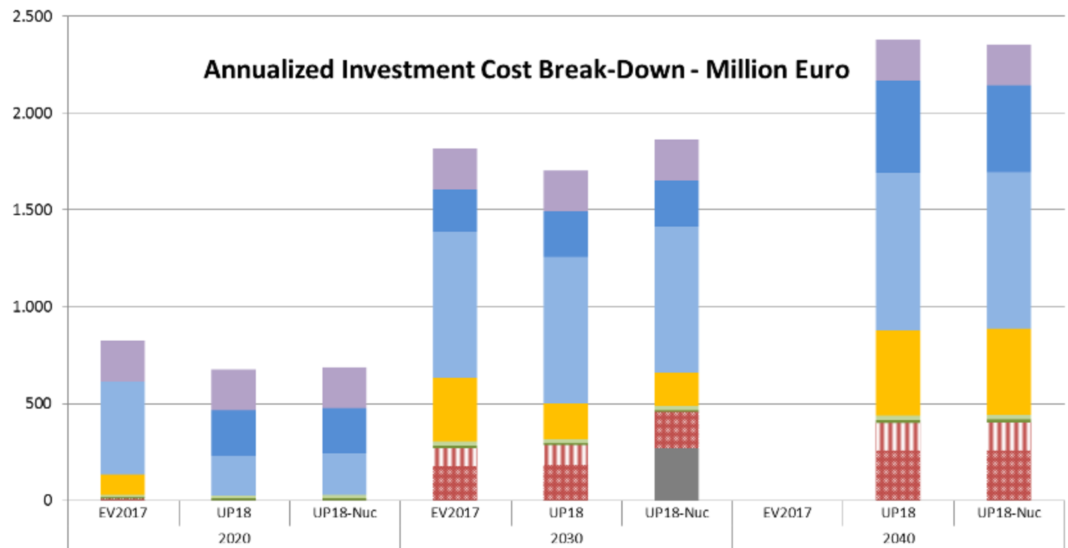
3.3.2. Annualized Investment Cost Break-Down

The investment cost break-down is depicted in Figure 3-4 for 2020, 2030 and 2040, allowing a detailed look at investment shifts caused by nuclear extension. One can notice that although the nuclear extension investment leads to: a) lower investment in solar PV (from € 184 million in UP18 to €171 million in UP18-Nuc in 2030) and; b) no additional investment in natural gas power plants in 2030, it still increases the overall annualized investments in 2030 from € 1.7 billion in UP18 to € 1.86 billion in UP18-Nuc.

Compared to the EnergyVille (2017) central scenario, delayed investments in PV solar can be observed in the up-dated 2018 scenarios. This is caused by the more cost competitive gas prices for gas based power plants and by the higher efficiency and utilization of existing natural gas power plants in these periods (as a direct impact of our update on existing power plants in terms of operational lifetime)[5].

The revised assumption that 2.2 GW of wind offshore will be operational in 2020 may also have impacted investments in PV compared to EV2017, although the mix of different effects does not provide enough evidence to assess in which extent. It is more evident, however, the effect on the investments in on-shore wind in 2020, as the capacity figures indicate a shift from onshore wind capacity (€ 478 million in EV2017 and € 205 million in UP18) to offshore wind capacity (null in EV2017 and € 234 million in UP18). By 2030 and 2040 on-shore wind is on the same investment level in the EV2017 and both UP18 and UP18-Nuc scenarios.

By 2030, investments in natural gas power plants are slightly higher in the UP18 scenario compared to the 2017 calculations, with € 96 and € 101 million of annualized investment costs, respectively. As the nuclear extension (UP18-Nuc) scenario shows the highest total required annualized investments (over 270 million Euros) ,investments in new gas power plants are completely depressed and only reappear in the reporting year 2040 on a comparable level with the UP18 scenario (approximately € 140 million).



	EV2017	UP18	UP18-Nuc	EV2017	UP18	UP18-Nuc	EV2017	UP18	UP18-Nuc
		2020			2030			2040	
Trade	212	212	212	212	212	212		212	212
Wind Offshore	0	234	234	217	234	234		477	447
Wind Onshore	478	205	214	755	754	753		809	809
Solar PV	105	0	0	327	184	171		442	445
Hydro	0	0	0	0	1	1		1	1
Biomass & Other Ren.	14	11	13	23	20	23		21	23
Other Fossil	8	10	10	10	10	10		16	16
Natural Gas - PP	0	0	0	96	101	0		142	144
Natural Gas - CHP	9	6	6	178	188	188		260	260
Coal	0	0	0	0	0	0		0	0
Nuclear	0	0	0	0	0	271		0	0
Total	826	678	690	1.818	1.705	1.864		2.381	2.357

Figure 3-4 – Annualized Investment Cost Break-Down (Million Euro)

[5] Within the updated configuration of natural gas power plants as explained in section 2.1.b, the phase-out of some units are foreseen to happen before 2025 (such as Zandvliet) and even 2020 (such as Saint_Ghislain and Herdersbrug), allowing investment in more modern units able to generate electricity more efficiently.

Figure 3-5 depicts the annual power system costs for the UP18 scenario and the year 2030. It also shows what part of the operation and maintenance (O&M) costs for the solar PV technology is attributable to the distribution grid expansion and what is attributable to the inverter replacement, which is estimated to be required once during the life-time of a PV system. The total solar PV O&M cost are estimated to be 221 million Euro of which 168 million Euro (or 76%) are estimated to be required grid enhancement costs and 53 million (or 24%) are estimated to be invertor replacement costs. These are rough cost component estimates implemented in the model to allocate costs to the evolution of the energy system from a centralized to a decentralised energy system, which likely requires enhancement to the local low voltage grids in Belgium.

It is important to note that there are several factors which show that there is a high level of uncertainty about this approach. EnergyVille is currently involved in several research activities to gain a better understanding of the interplay of decentralized energy generation (for example through small scale solar PV installations), grid integration and the role of decentralized battery storage. One recently submitted research paper by EnergyVille estimates that using a combination of grid injection limits by invertor dimensioning and limited curtailment would allow an up-take of up to 20 GW of PV solar in Belgium without substantial grid enhancements[6].

A second aspect is that the rapid and widespread uptake of other technologies in the energy system will likely also cause stress on the local electricity grid. Therefore this simplification to only attribute the required grid enhancement to PV solar, derogates investments in PV. In particular the charging of electrical cars can be identified as a big challenge in this context. Again, EnergyVille is conducting research in this field and updates of the TIMES Belgium model will incorporate new insights in the next iterations.

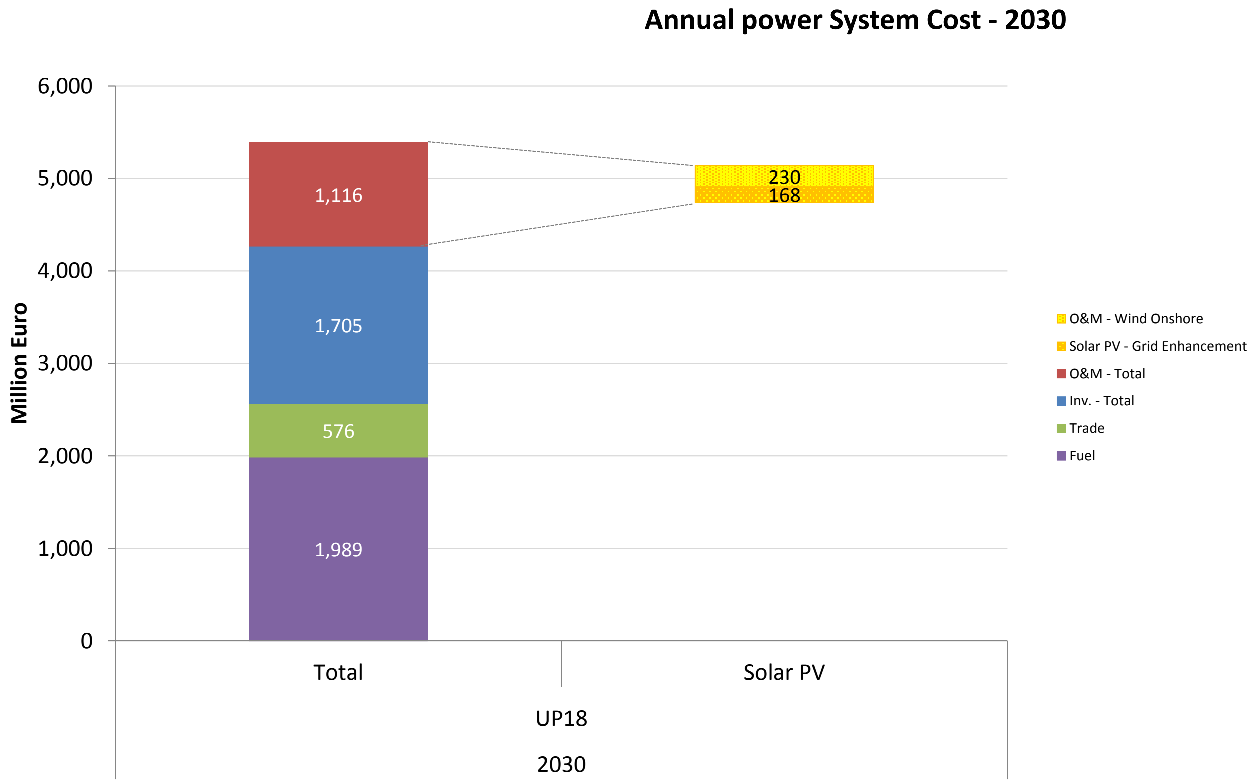


Figure 3-5 – Annual Power System Cost and the Impact of Grid Connection Costs (Million Euro)

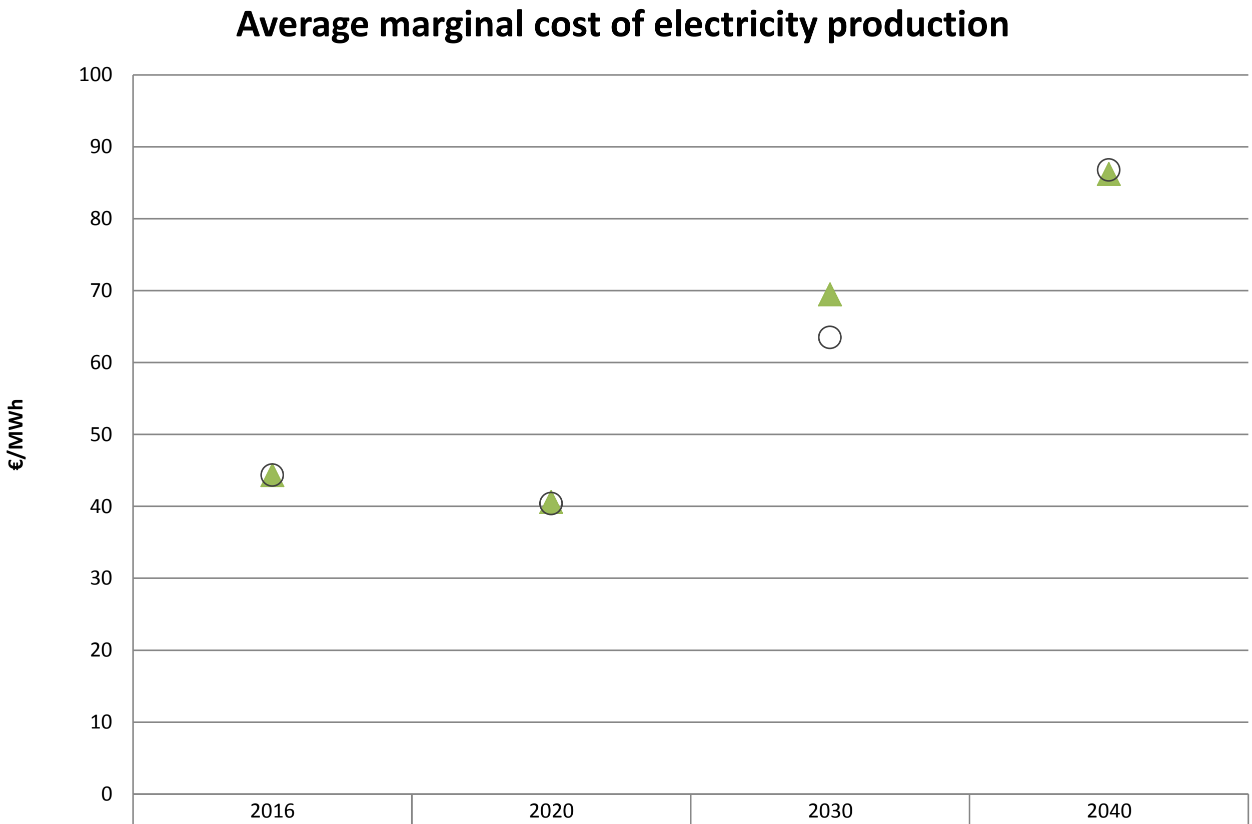
3.3.3. Average Marginal Cost of Electricity Production

Figure 3-6 shows the average marginal cost of electricity production for the updated central scenario and the updated nuclear extension scenario. The values show average annual values of different electricity production technologies for the reporting years, 2016 till 2040. The values do not show predicted electricity

[6] Meuris M. et al (2018) 'Using local storage for managing PV power injection in the electricity grid, enabling a larger direct consumption of renewable energy'; submitted to Applied Energy 2018

prices at any given point in time, but rather provide an indication of the evolution of the average annual marginal production costs. This cost estimation is influenced by the production costs of the marginal technology in every timeslice to satisfy the demand in Belgium.

The TIMES Belgium model calculates average marginal costs of approximately 40 €/MWh for the year 2020, 69 €/MWh for 2030 and 86 €/MWh for 2040 in the central scenario. For the updated nuclear extension scenario a cost variation can be observed for 2030, where the average marginal costs is 63 €/MWh, approximately 9% lower compared to the UP18 scenario. By 2040, after the complete closure of nuclear plants, the average marginal cost is on the same level for both scenarios.



	2016	2020	2030	2040
UP18	44	41	69	86
UP18-Nuc	44	40	63	87

Figure 3-6 – Average marginal cost of electricity production (€/MWh)

3.4. CO_2 Emissions

Figure 3-7 shows the CO_2 emissions of public electricity and heat generation in 2020, 2030 and 2040 aligned with the definition of the Intergovernmental Panel on Climate Change (IPCC) sector 1.A.1.a (IPCC, 2006). The emission from public electricity and heat generation are regulated under the EU emissions trading system (EU ETS).

As explained in chapter 3, the Belgium energy system as modelled in TIMES Belgium represents to a certain extent current national and EU policies related to climate change. A minimum 13% share of renewables in final energy consumption in 2030 is implemented and CO_2 emissions originating from applicable sectors are subject to ETS prices. CO_2 emission shown in the graph are limited to domestic CO_2 emissions and do not take into account emissions originating in neighbouring countries to generate electricity to be exported to Belgium[7].

[7] Following the same approach of EnergyVille (2017), all energy use and emissions of ‘combined heat and power plants’ (CHP’s) are reported in the power sector. We do not differentiate between CHP’s that are under property or operation of an industrial plant (so called auto producers) or owned and operated by the electricity sector, although the heat flows are linked to the correct sectoral demand.

Figure 3-7 shows the evolution of CO_2 emissions in Belgium's power system for the new scenarios, UP18 and UP18-Nuc, as well as for the previous central scenario EV2017. As emission levels in UP18 and UP18-Nuc are quite similar in 2020, results for 2030 show that the extension of nuclear can result in almost 20% less emission in the power sector compared to the UP18 scenario (22.3 $MtonCO_2$ in UP18 and 18.1 $MtonCO_2$ in UP18-Nuc). However, emission levels for both UP 18 and UP18-Nuc are brought to similar levels in 2040, around 19 $MtonCO_2$.

Comparing with the previous EV2017 scenario, CO_2 emissions in 2020 for both new scenarios and for the central (UP18) scenario in 2030 are higher (by around 12.5% in 2020 and by 15.3% in 2030), which is explained mainly by the higher usage of natural gas for electricity generation. This is, as previously discussed, driven by the low natural gas prices adopted in the new scenarios.

One point not depicted in the Figure is that although both UP18 and UP18-Nuc scenarios results in higher CO_2 emission for the power sector – 44.6% for UP18 and 17.8% for UP18-Nuc – in 2030 relative to the 15.4 Mton CO_2 in 2016, the overall CO_2 emission levels in Belgium are reduced – by 3.5% in UP18 and by 8.2% in UP18-Nuc. The same is observed for the 2040 period, when emission levels for the power sector are more than 20% higher than in 2016 (more than 18 Mton CO_2 in 2040 versus 15.4 Mton CO_2 in 2016) in both scenarios, but overall CO_2 emissions in Belgium are reduced by almost 25% relative to 2016 (65 Mton CO_2 versus 87 Mton CO_2). It has to be noted that no (non-ETS) emission constraints or more stringent energy efficiency or renewable goals (13% goal is kept stable for all years) are implemented for the scenario's.

Despite the fact that a 25% emission reduction might sound significant, the political goal of a CO_2 emissions reduction between -80 and -95 % relative to 1990 levels by 2050 (EC, 2018) seems to remain distant. A rough estimative for CO_2 indicates that a 80% CO_2 emissions reduction by 2050 would lead to approximately 24 $MtonCO_2$[8]. Compared to TIMES results for UP18 scenario in 2040 it corresponds to more than 60% less emissions. Moreover, between 2040 and 2050, there is left only a 10-year period to mitigate such an amount of emissions. In that context, the fact that natural gas-based power plants have an expected technical life-time of 30 years and could remain operational till 2065 (as in case of nuclear extension and delayed investments), it is likely to become even more difficult for Belgium to address this long-term goal within the power sector. Hence, mitigation would have to be done in other sectors and with advanced technologies, such as technologies to produce green and synthetic fuels with minimal carbon footprint, for instance.

[8] This estimate is based on Belgium's national inventory (UNFCCC, 2018), which reports an CO_2 emission level (excluding net CO_2 from LULUCF) of 119 MtonCO2.

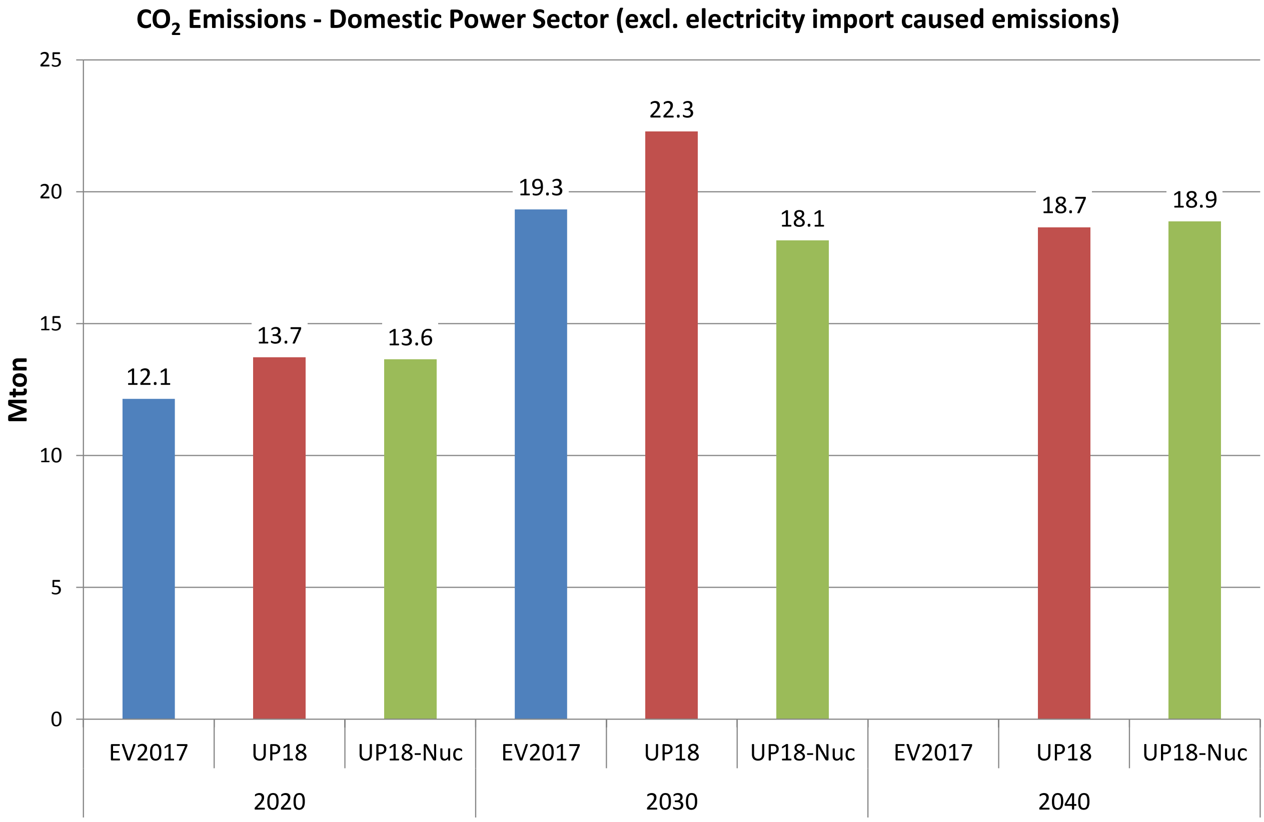


Figure 3-7 – CO_2 Emissions of Belgium Power System (Mton CO_2)

Finally, it is worth repeating that CO_2 emissions accounted in TIMES Belgium relate only to in-country emissions, which means that possible 'carbon leakages' caused by the increase in electricity imports are not accounted for in the model. For example the delay in investments in new and efficient gas power plants in Belgium as represented in the low gas capacity scenario might be compensated by importing electricity from renewables, but could also extend the lifetime of less efficient (and more polluting) power plants in neighbouring countries. In order to assess CO_2 emissions at a broader level, a multi-region approach would have to be considered, which is not the case for this study.

4 Conclusions

This study commissioned by Greenpeace, BBL and IEW calculates updated scenarios with the EnergyVille TIMES Belgium model to gain a better understanding of the impact of the latest natural gas price projections in Europe, as both the World Bank (2017) and the IEA (2017), have lowered their respective forecasts by more than 20% for the year 2030 relative to previous publications (IEA, 2015). Two scenarios, one considering the base assumptions of a complete nuclear phase-out by 2025 (named UP18); and other foreseeing the ten-year nuclear extension (named UP18-Nuc) were re-calculated. Both scenarios were developed based on the same model framework as in EnergyVille (2017).

Moreover, updates on the existing stock of natural gas power plants, nuclear reactors availability profile, import prices assumptions and installed capacity of offshore wind in 2020 were also implemented in order to have a better depiction of current and future conditions of the Belgium energy system.

Results regarding capacity and generation of Belgium's power sector show that in the short-term, namely 2020, the lower gas prices and the 2.2 GW capacity of wind offshore partly delay investments in wind onshore (from 6.6 GW to 3.7/3.8 GW) and solar PV technologies (from 4.7 GW to 3.0 GW) in the new scenarios (UP18 and UP18-Nuc) when compared to the EnergyVille (2017) central scenario (named EV2017). Still, most of the power capacity in Belgium in 2030 and in 2040 will come from renewable energy sources (more than 70% out of a total capacity of 24 GW in 2030 and 28 GW in 2040) for both updated scenarios. This confirms that that the 10-year nuclear extension has a limited impact on the expansion of renewables. Offshore wind will correspond to approximately 3 GW and the PV capacity doubles to 10.6 GW in 2040. In terms of generation, it means that, in average, more than 40% of electricity supply (total around 86 TWh in 2030 and 98 TWh in 2040 including net import) would come from renewable sources in these years.

This steep increase in renewable electricity supply in both UP18 and UP18-Nuc is also driven by the increase in electricity demand, as electric vehicles uptake grows further after 2030 and corresponds to 13% of total electricity demand in 2040.

In that context, investments in natural gas power plants and CHPs bring the natural gas-based generation capacity of UP18 scenario in 2030 to the same level as in EV2017, to approximately 6 GW. However, the production of gas-fired power plants is about 25% higher in 2030 due to lower gas prices. Similarly, import of electricity is 40% lower than the previous scenario (9.3 TWh versus 15.6 TWh). As for 2040, the increase in the renewable capacity enables a small decrease of gas-fired power plants, which corresponds to 5.53 GW.

When assessing the 2GW nuclear extension scenario (UP18-Nuc) vis-a-vis the UP18 scenario , one can see that natural gas capacity is the most impacted: investments are postponed and capacity levels remain lower than 4.8 GW in 2030, meaning 1.5 GW is not added to the system in this period. The corresponding generation output by gas-fired plants is approximately 30% lower (28.7 TWh versus 40.2TWh) and import is 20% (7.5 TWh versus 9.3 TWh) compared to the UP18 scenario.

In 2040, after the complete closure of the two nuclear reactors (in Up18-Nuc) natural gas-based capacity and generation levels are equated at 5.5 GW and 39 TWh in both updated scenarios. Overall, the capacity and generation mix of both UP18 and UP18-Nuc in 2040 are very similar, showing that in the case of nuclear extension, an acceleration of investments in gas-fired units after 2035 will be needed in order to replace the nuclear reactors to meet the electricity demand. With a technical lifetime of 30 years, these gas plants will likely remain in service until 2065, making it difficult to reconcile with the long-term -80 to -95% CO_2 reduction targets by 2050. Consequently, significant developments and costs reduction in power-to-gas technologies are needed to provide fuel for these gas-fired plants to reach deep carbon reductions.

Annual costs for the Belgian power sector are assessed as an outcome of Belgium TIMES. Total annual costs rise from around € 2 billion in 2016 to more than € 5 or 6 billion in 2030 and 7 billion in 2040, depending on the scenario. Compared to EV2017, the updated scenarios present lower annual costs in 2030 (€ 5.4 billion in UP18 versus € 6.2 billion in EV2017, a 12% reduction) due to lower levels of fuel expenses and lower import electricity prices and import quantities. Both are linked to the lower gas price projections, which results in a fuel cost 11% lower and a trade cost 37% lower in 2030 for the UP18 scenario relative to the EV2017 scenario.

The updated scenarios demonstrate that, with the extension of 2GW of nuclear power capacity between 2025 and 2035, the annual costs of the Belgian electricity system will be approximately 4%, or € 235 million lower in 2030 (Up18-Nuc compared with Up18). For the year 2040, the cost calculations show that both 2018 updated scenarios have similar costs of € 7,194 and € 7,196 million. This confirms that the extension of 2 GW of nuclear capacity does not provide a long-term cost advantage to the power system, but that the cost reduction is a) mainly attributable to lower fuel use during the extended life-time and b) that the development of natural gas prices in the coming years will have the most significant impact on the power system costs.

Average annual marginal costs of electricity production were also considered in the analysis, and it shows that for the updated nuclear extension scenario (UP18-Nuc), the only price variation can be observed for 2030, where the average marginal costs is 63 €/MWh, approximately 9% lower compared to the UP18 scenario. By 2040, after the complete closure of nuclear plants, this advantage cannot be sustained and the average marginal is on the same level for both scenarios.

Regarding CO_2 emissions of the public power generation sector, the updated UP18 scenarios result in higher emission levels in 2020 and 2030 (by 12.5% and 15.3%, respectively) than EV2017 mainly driven by the higher usage of natural gas in the power system. When comparing UP18 to the UP18-Nuc scenario, 2030 is the only reporting year where emission levels are significantly different, as the UP18-Nuc results in 20% less emissions (equivalent to 18.1 Mton CO_2 - against 22.3 MtonCO_2 in UP18). In 2040 emissions levels are equated in both scenarios. The CO_2 emission projections are limited to the public power generation sector and are regulated under the EU emissions trading system (EU ETS).

Therefore, main results of the study show that the updates natural gas price projections impacted noticeably Belgium TIMES outcomes. This parameter plays a significant role on the definition of the cost optimal power generation mix and, given the most recent updates available in literature, it remains also the most uncertain parameter.

In that context and based on the updates discussed in the report, results show that the extension of 2 GW of nuclear capacity will have a limited impact on power system costs during the 10 year lifetime extension period. Even though lower power system costs are possible in 2030, the next years will be followed by investments in additional capacity to complement renewables and to cope with the increase in demand. It means that commitment for and investment in gas-fired plants will be needed in either scenario and the development of the gas price in the coming years will be a decisive factor on power system costs.

One aspect to be considered is that delayed investments in natural gas in the UP18-Nuc scenario might also lead to effects not properly captured by the scenario calculations in this study: as new investments in natural gas are done after 2035, this capacity will be expected to remain active for at least 30 years, threatening the long-term climate goals and potentially increasing long-term mitigation costs.

This study aims to provide facts and figures regarding technology choices and consequential impacts on the energy system as a whole. The study does not predict directly or indirectly electricity prices in general or for certain sectors, but focuses on energy system costs. The scenario analysis with the Belgium TIMES model is based on a system cost optimization approach. It provides a technical and economic analysis framework to evaluate choices and resulting cost for the energy system of Belgium and can contribute valuable insights into consequences certain policy choices might have for the future.

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