Energy Transition in Belgium – Choices and Costs

Final Report

Authors:
Frank Meinke-Hubeny
Larissa P. N. de Oliveira
Jan Duerinck

Checked by:
Pieter Lodewijks
Ronnie Belmans

Date: 28/04/2017

Erratum

In Table 3-3 on page 12 an 'average availability/year' of 9,7% was mentioned for Solar PV roof Residential and Solar PV roof Commercial in the report version dated 16/03/2017. In the Belgian TIMES model we however calculated with an 'average availability/year' of 11,2%. This figure has been updated in this version of the report.

Acknowledgement

This study was commissioned by Febeliec, the federation of Belgian industrial energy consumers. The steering committee for this study provided valuable insights from an industry perspective and was instrumental in defining the sensitivity scenarios which were analysed in this study.

The steering committee consisted of the following members: Philippe Alboort, Peter Claes, Marc Clement, Luc Sterckx, Michaël Van Bossuyt, Marc Van Breda, Frank Vandermarliere, Kurt Vinck and Peter Zadora.

Table of Contents

1 Executive Summary

The Belgian energy system, in particular the electricity generation, is in full transition. To gain a better understanding of what the possible pathways are for this energy transition, Febeliec asked EnergyVille to develop an objective analysis of possible scenarios for electricity generation in Belgium for 2020-2030. The following questions are explored: 1) What will electricity generation in Belgium look like in 2020, taking into account current political decisions and in which the model choses the best economic options? 2) What will the Belgian electricity provision look like in 2020 and 2030, taking into account the most recent expert knowledge of technological options? 3) What impact will the possible political choices have on the related cost of the energy system transition?

To get an accurate answer, the EnergyVille Belgium TIMES model, a techno-economic energy system model, is used to generate a set of scenarios in which assumptions on three sensitivity parameters, namely 'the import capacity for electricity', 'the fossil fuel prices' and 'the phase out of nuclear energy' are being altered. Five scenarios are analysed:

- Central Scenario: current trends on policies and global markets are kept;
- 10% Import Restriction: electricity import is limited to 10% of aggregated power generation;
- Nuclear Extension: 10 year extension of 2 GW nuclear power capacity beyond 2025;
- Low Fossil Fuel Price: assumes a low price level trend for fossil fuel prices;
- High Fossil Fuel Price: assumes a high price level trend for fossil fuel prices.

Central Scenario based on current trends on market and policies

In 2016 55% of the electricity generation in Belgium is provided by nuclear power plants and 14 % by renewable energy sources. Based on the cost minimizing objective of the model, the results show that in 2030 electricity generation originates to an equal share from renewable sources and fossil fuel based installations. Wind onshore capacity grows from 1.5 to 8.6 GW, wind offshore from 0.712 to 2.2 GW and residential and commercial PV solar from 3.0 to 7.9 GW in the Central Scenario between 2016 and 2030. The natural gas based power plants and combined heat and power installations (CHPs) remain stable in capacity above 6 GW, but generation output increases from 24.3 TWh to 35.1 TWh by 2030. This generation mix exceeds the 13% share of renewable energy generation in the final energy consumption as specified in the boundary conditions of the model for Belgium in the year 2030.

The anticipated increase in net transfer capacity to neighbouring countries from 3.5 GW in 2014 to 6.5 GW is fully available in 2020 and results show electricity net imports of 15.6 TWh per year in 2030. With the closure of the nuclear plants and the increasing intermittent renewable production, electricity imports and gas plant based generation play a crucial role in the energy system. The two balance the growing and intermittent renewable generation output.

In the Central Scenario, CO_2 emissions in the electricity and heat producing sector increases by 25% between 2016 and 2030 due to the increasing use of natural gas after the closure of the nuclear plants.

Comparison of the sensitivity scenarios

The results show a high level of variation in the amount of net electricity imports across scenarios, ranging from 6.2 TWh per year in the 10% Import Restriction Scenario to 28.4 TWh in the High Fossil Fuel Price Scenario.

The Nuclear Extension Scenario results show less natural gas based generation and less demand for natural gas based capacity compared to the Central Scenario. Investments in new gas plants (compared to the other scenarios) is in part delayed. From 2035 onwards, after the complete closure of the nuclear generation, other technologies will have to fill the gap.

The variation among the overall system costs across scenarios is mainly driven by future natural gas price assumptions and electricity net import levels. Annualized investment costs in all five scenarios are stable with 1,818 to 1,974 M€ per year. The largest cost variation can be observed in the electricity import costs, ranging from 292 to 1,926 M€ per year followed by expenditures for fuels (mainly, but not exclusively natural gas), ranging from 1,259 to 2,678 M€. The overall costs for the power and heat generating system ranges from 4,800 to 6,400 M€ per year in 2030, with the Central Scenario marking the median spot at 6,180 M€.

The nuclear extension scenario and high fuel price scenario have lower CO_2 emissions compare to the other sensitivity analysis. Under these boundary conditions the use of natural gas is to a large extent replaced by nuclear generation in the Nuclear Extension Scenario or avoided by electricity imports in the High Fuel price Scenario.

This study provides facts and figures regarding technology choices and consequential impacts on the energy system as a whole. It does neither directly or indirectly predict electricity prices in general or for certain sectors. 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.

2 Introduction

2.1. Objective

The Belgian energy system, in particular the electricity generation, is in full transition. To gain a better understanding of what the possible pathways are for this energy transition, Febeliec asked EnergyVille to develop an objective analysis of possible scenarios for electricity generation in Belgium for 2020-2030. The following questions are explored: 1) What will electricity generation in Belgium look like in 2020, taking into account current political decisions and in which the model choses the best economic options? 2) What will the Belgian electricity provision look like in 2020 and 2030, taking into account the most recent expert knowledge of technological options? 3) What impact will the possible political choices have on the related cost of the energy system transition?

To get an accurate answer to these questions three sensitivity parameters are developed to generate and compare different scenarios. The parameters are developed together with Febeliec and consist of: 'the import capacity of electricity', 'the fossil fuel prices' and 'the phase out of nuclear energy'. By altering the assumptions on these main parameters different scenarios are generated that represent the possible energy production landscape for Belgium in 2020 and 2030.

It is incorporated into the study to minimally comply with the renewable targets of Belgium (13% renewable energy with regard to the total final energy consumption in 2020 and 2030). The emission sources regulated under the emission trade system (ETS) are given a CO_2 price of 17€/ton in 2020 and 33€/ton in 2030.

The different scenarios are calculated with the TIMES model. The EnergyVille TIMES model for Belgium is a 'techno-economic energy system model', including generation and demand. It calculates different scenarios based on the evolution of technical and economic parameters and focuses on the most cost-efficient solution to comply with demand. External funding of technologies like subsidy schemes are considered a way of financing, i.e. a cost for society, and therefore not included in the model and the study.

This study provides facts and figures regarding technology choices and consequential impacts on the energy system as a whole. It does neither directly or indirectly predict electricity prices in general or for certain sectors. 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.

2.2. Contents of this Report

The report is divided in six sections from executive summary to references. As the main contribution of this project relies on the methodology, assumptions and results, they are the main elements to be reported: chapter three provides a description of the EnergyVille TIMES Belgium model and also depicts the main assumptions adopted for modelling the energy system. Meanwhile, chapter four focuses on reporting the main outcomes of the modelling exercise, providing figures per scenario and comparing the results. The main outcomes and conclusions drawn from the study are reported in chapter five.

3 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 model generator and is an active member of ETSAP, the Energy Technology Systems Analysis Programme of the International Energy Agency[1].

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

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 3-1). 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.

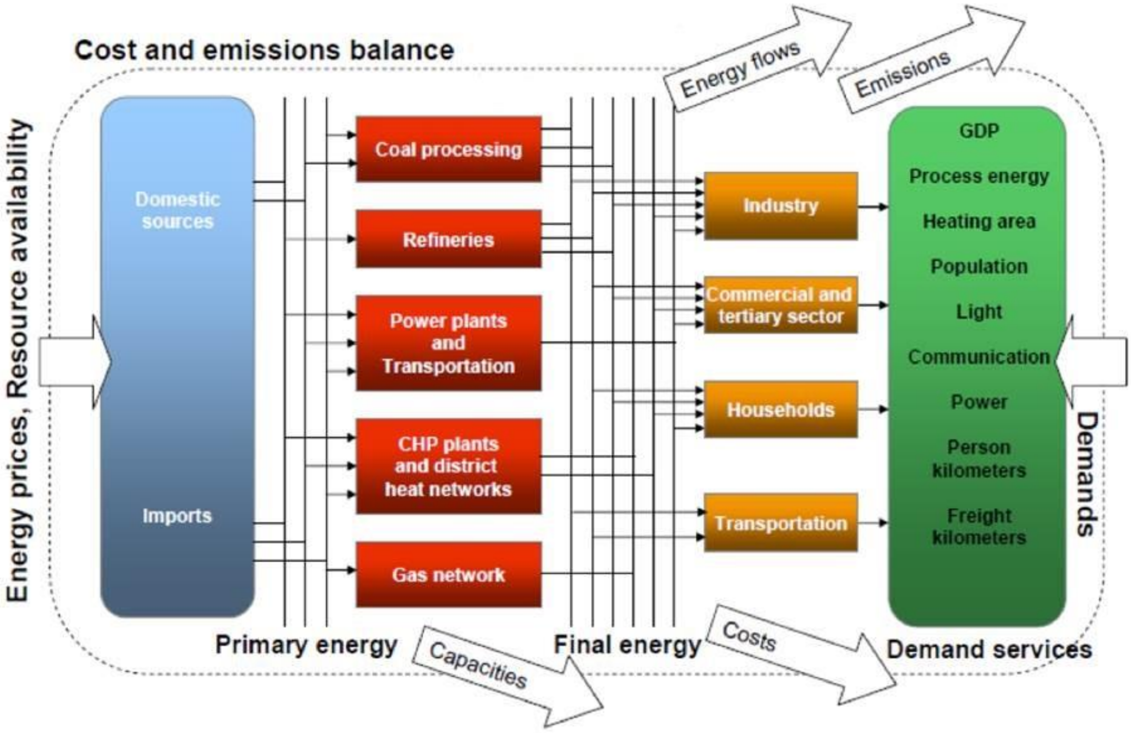

Figure 3-1 – TIMES model rationale. Adjusted from source: (IEA-ETSAP, 2016)

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. Moreover, it could also count on the expertise of their own researchers to make use of the latest available cross-checked figures for Belgium.

In addition and in accordance with the work packages defined for the study, assumptions on policies and strategies and sensitivity scenarios were defined based on discussions with the FEBELIEC steering committee.

The next section summarizes the main parameters and assumptions taken into account when modelling the Belgium energy system in the TIMES model.

3.1. Belgium TIMES Model

The Energyville TIMES Belgium model represents the Belgium energy system as a geographic region interconnected to neighbouring countries. The calibration of the model was based on the 2014 statistics, taken from Eurostat (EC, 2016b) and, when available, data from 2016 were also added. The time horizon considered is up to 2030 and the years 2016, 2020 and 2030 were included as reporting years. It is important to highlight, that the energy balance between supply and demand is met for every year of the time horizon[2] as this is the main requirement of the objective function.

Demand side responds (DSR) by any sector is not taken into account in the context of this study. While DSR can contribute to a certain degree to the integration of renewable energy sources by providing flexibility to the supply and demand balance, the focus of this study is not on DSR management and market design. For a more detailed study regarding DSR potential from industry in Belgium we refer to the study 'Summary results, Elia Febeliec EnergyVille Demand Response Survey', available at the websites of Febeliec, Elia and EnergyVille.

TIMES Belgium includes different technology portfolios for different supply and demand sectors of the energy system. It integrates different energy flows, such as electricity and heat, along the energy system identifying the least cost conversion technologies to fulfil the service demand requirements in industry, transport, residential, commercial and agriculture sectors. They are detailed in the next subsections. Moreover, although results are reported on a yearly basis, it also takes into consideration important variations on load and on intermittent supply sources, such as solar and wind. This approach will also be discussed in the next section.

a. Time Slice Structure

For the purpose of this study, a two-hourly time resolution is considered. This time resolution is able to capture the variations in power supply profiles, such as intermittent renewable sources, and end use demands, such as lighting and cooking. Ten representative days within one year were chosen in order to capture the seasonal variations of energy generation and consumption, totalling 120 time slices per year. The selection of the ten representative days was calculated by an exogenous algorithm tool which takes into account the daily and seasonal variations for the main power generation sources and end use demands. More information about this tool can be found in (Poncelet et al., 2016).

To illustrate how the 120 time slices capture the dynamic in the electricity system, the following comparison is provided: Figure 3-2 shows the real observed load profile in the Belgium electricity grid on a cloudy and cold winter day in January 2017. Figure 3-3 and Figure 3-4 show the profile of a representative winter day in the model for the year 2030 with its two-hourly electricity demand profile by sector and two-hourly electricity generation profile by power source. The TIMES model calculates the objective that for every time slice the power supply has to meet the electricity demand to satisfy the end use demands.

[2] It is important to highlight, that TIMES calculates the outcome (technology mix, capacities, costs, etc.) for every year over the time horizon. 2016, 2020 and 2030 are milestone years which were considered to be sufficient to illustrate the energy transition over time.

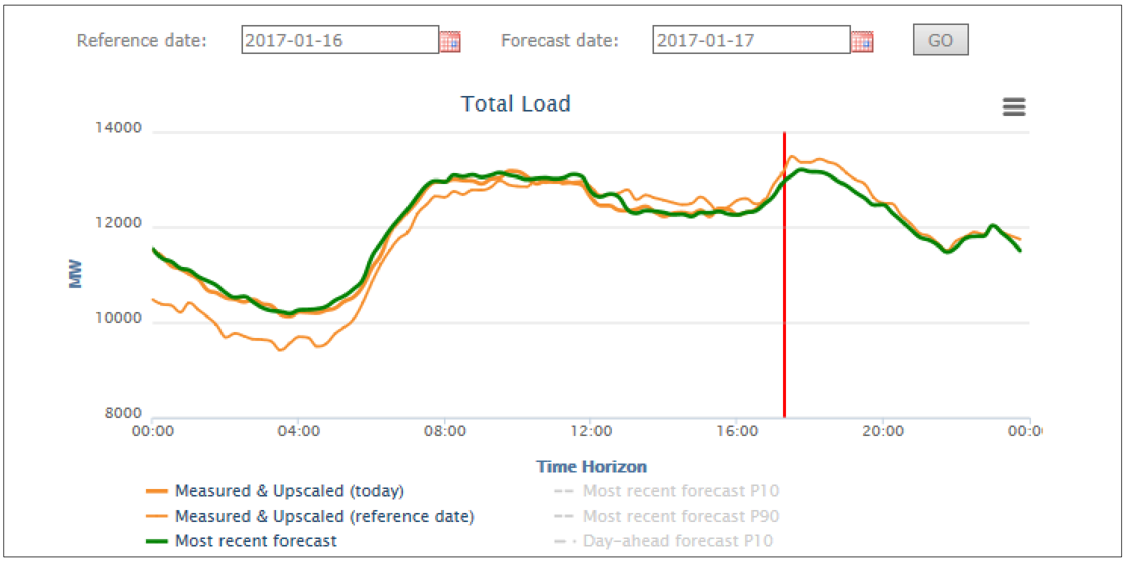

Figure 3-2 – Screenshot of hourly load profile of Belgium on a grey winter day (17.01.2017) Source: (Elia, 2017a)

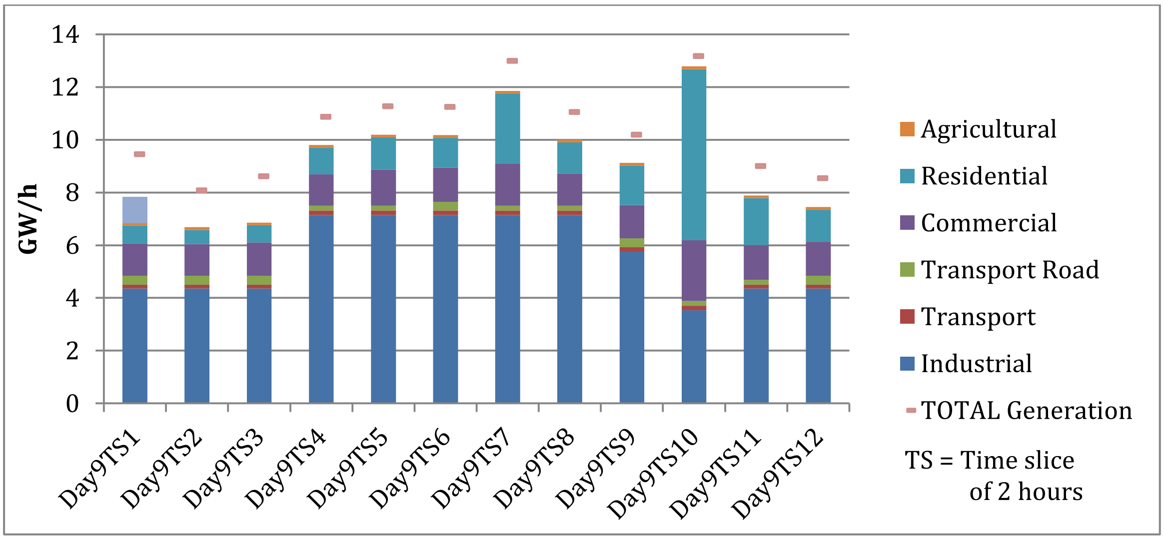

Figure 3-3 –Electricity Consumption during representative Winter Day in 2030 (GW/h), Central Scenario, power sector, power sector self-consumption and grid losses are not included in the graph, Source: Belgium TIMES Model

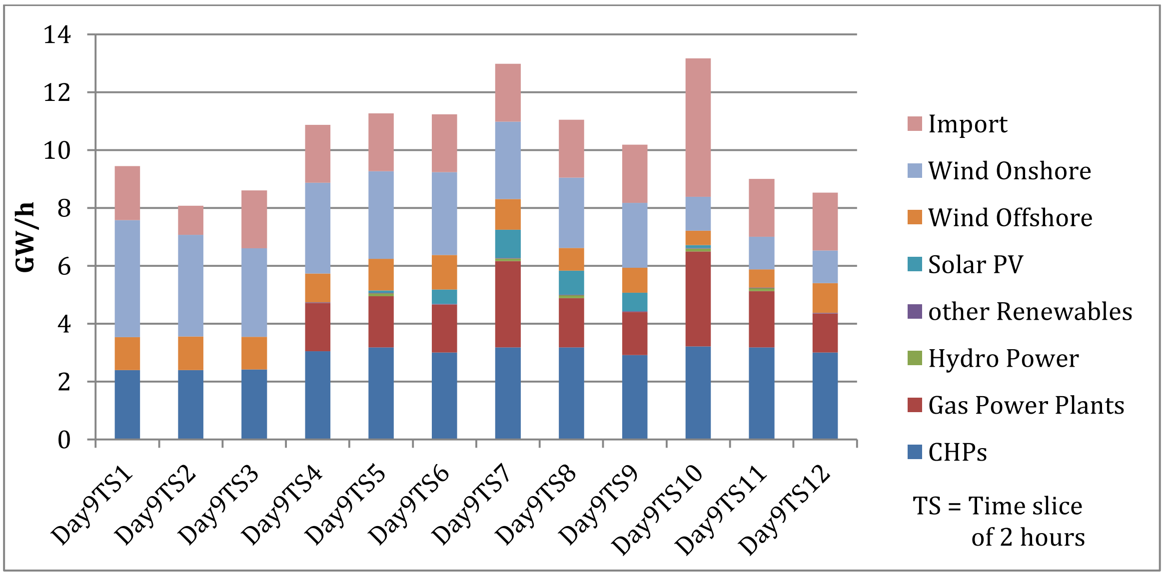

Figure 3-4 –Electricity Generation during representative Winter Day in 2030 (GW/h), Central Scenario, Source: Belgium TIMES Model

b. Constant Prices and discount Rates

All monetary values are expressed in constant prices of 2010 (without inflation).

A discount rate is used for both cost of finance and for risk perception and opportunity cost. The cost of finance is to be compared with concepts like “hurdle rate” or “rate of return” usually calculated in accordance to an annual return on investment. Each individual investment physically occurring in year k, results in a stream of payments towards the amortization of this investment spread over several years in the future. The higher the cost of finance (or hurdle rate), the higher the annual payments spread over the lifetime of an investment and thus the higher the total cost. The hurdle rate affects only the investment costs so the impact is bigger for capital intensive technologies. We consider differentiated hurdle discount rates for different groups of energy supply and demand technologies, representing the different risk perception of industry versus individuals.

The assumed discount rates are in line with the assumptions in the JRC EU TIMES model (EC, 2013), which are on their turn the same as in the PRIMES model (EC, 2016a) and used in the EU Energy Roadmap 2050.

Sector	Discount rate
Centralized Electricity Generation	7.5%
Large Industry	7.5%
Commercial	11%
Residential	12%
Transport	7.5%

Table 3-1 – Discount rates

c. Power Sector

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. Table 3-2 shows the existing capacity of currently available technologies for the base year (in accordance with Eurostat data) and basic assumptions on expansion. No addition of new coal power plants is foreseen for Belgium, in accordance with the recent declining trend of coal use in different sectors of Belgium[3]. Moreover, onshore wind is limited in accordance with the surface available for the installation of new units and some relaxation of the existing legislation, which limits the total capacity (current plus new) to 8.6 GW The Flemish onshore wind potential is based on the ‘REF+ 2030’ scenario of the Renewable Energy atlas for Flanders (Esch et al., 2016). For the Walloon region we have based the wind onshore potential on personal communication we had during the study ‘Onthaalcapaciteit decentrale productie in Vlaanderen 2011-2020’ (Infrax et al., 2012). Offshore wind is limited to the currently planned 2.2 GW without additional grid infrastructure, but the model can invest in offshore wind above the planned 2.2 GW taking into account additional grid investments.

With regard to nuclear power plants, the basic assumption in TIMES Belgium considers the complete phase-out of existing units between 2022 and 2025, in line with the current nuclear closure plans. As will be shown in the next sections, this assumption is relaxed in a sensitivity analysis considering a partial nuclear extension for 10 years.

[3] As observed in IEA (2016), coal use declined in relevant sectors of Belgium, such as iron and steel and power. The last coal power plant, Langerlo, was closed in March 2016. Conversion to biomass did not yet take place (21 Feb 2017).

Technology Name	Existing Capacity (GW 2014)	Model Assumptions - Central Scenario
Gas Power Plants	4.54	• no restrictions
Coal Power Plants	0.56	• no new investments
Combined Heat & Power (CHPs)	2.37	• no restrictions
Biomass Plants	0.39	• no restrictions
Solar PV	2.93	• no restrictions
Wind Onshore	1.51	• up to 8.6 GW total capacity possible
Wind Offshore	0.712	• < 2.2 GW: existing grid infrastructure sufficient • >2.2 GW: additional grid investments required
Nuclear	5.93	• Complete nuclear phase-out according to Belgian policy from 2022 to 2025
Interconnections to neighbouring countries	3.5	• Investments under execution: increase to 6.5 GW total capacity by 2020 (ALEGrO, NEMO, Brabo II and III) • Additional investment possible

Table 3-2 – Base Assumptions for the power Sector – Base Year.

Apart from the proper calibration of the base year with the set of currently available technologies, the model also accounts for technologies that will be available in the future until 2030, which means that the evolution of investment costs over time is considered based on screened literature review. The main parameters characterizing the technologies are efficiencies, investment costs and O&M costs, as described in Table 3-3.

The average availability per year of the technologies as stated in Table 3-3 reflects the maximum availability over the course of a year. For solar and wind technologies a more detailed profile at every two-hourly time slice level was provided to account for their daily and seasonal variations.

Technology	Efficiency (%)	Life-time	Investment Cost (€2010/kW)			Fixed O&M (€2010/kW/year)			Average Availability /Year (%)	Source
			2016	2020	2030	2016	2020	2030		
Solar PV roof Residential (> 2 MW)	N/A	25	1,000	800	800	46[4]	46	46	11,2%	EnergyVille / imec
Solar PV roof Commercial (> 2MW)	N/A	25	800	600	547	46	46	46	11,2%	EnergyVille / imec
Wind Onshore	N/A	30	1,200	1,200	1,050	27	27	24	22%	EC (2013) & EC (2014)
Wind Offshore (< 2,2 GW)	N/A	30	2,000	2,000	1,800	80	80	63	40%	EC (2013) & EC (2014)
Wind Offshore (> 2,2 GW)	N/A	30	2,500[5]	2,500	2,300	80	80	63	40%	EC (2013), EC (2014) & own assumption
Combined Cycle Steam Turbine	59%	30	855	855	855	20	20	20		EC (2013)
OCGT Peak device advanced	42%	20	586	586	586	19	19	19		EC (2013)
Nuclear Existing	33%		N/A	N/A	N/A	43	43	43	80%	EC (2013)
Nuclear Extension by 10 years	33%	10	N/A	1,000	N/A	43	43	43	80%	EC (2013)
Biomass Plant	39%	40	2,000	2,000	2,000	80	80	80		EC (2013)

Table 3-3 – Technology Assumptions for the Power Sector – Projections

Figure 3-5 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 Table 3-3. The declining levelized costs of electricity for all four technologies over the model horizon reflect the declining investments costs as shown in Table 3-3. For the residential and commercial PV installations two cost projections are shown. With fixed annual operation and maintenance costs of 46 €/KW of capacity. 46 €/KW represent capital expenditures for improvement to the local grid infrastructure which will be required in certain areas in order to absorb electricity from PV installation at peak generation periods or the cost of local battery storage and also costs to replace inverters once during the lifetime of a PV system. While this approach reflects the design of the model, 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.

[4] The 46 Euros fixed O&M costs for PV solar represents a) capital expenditures for improvements to the local grid infrastructure which will be required in certain areas in order to absorb electricity from PV installation at peak production periods and b) costs to replace inverters once during the lifetime of a PV system.

[5] The additional investment costs of 500 **€2010/kW** for wind offshore above an aggregate capacity of 2.2 GW compared to wind offshore investment up to 2.2 GW reflect additional investments required to the electricity grid infrastructure, which currently is dimensioned to connect up to 2.2 GW of offshore wind to the mainland grid.

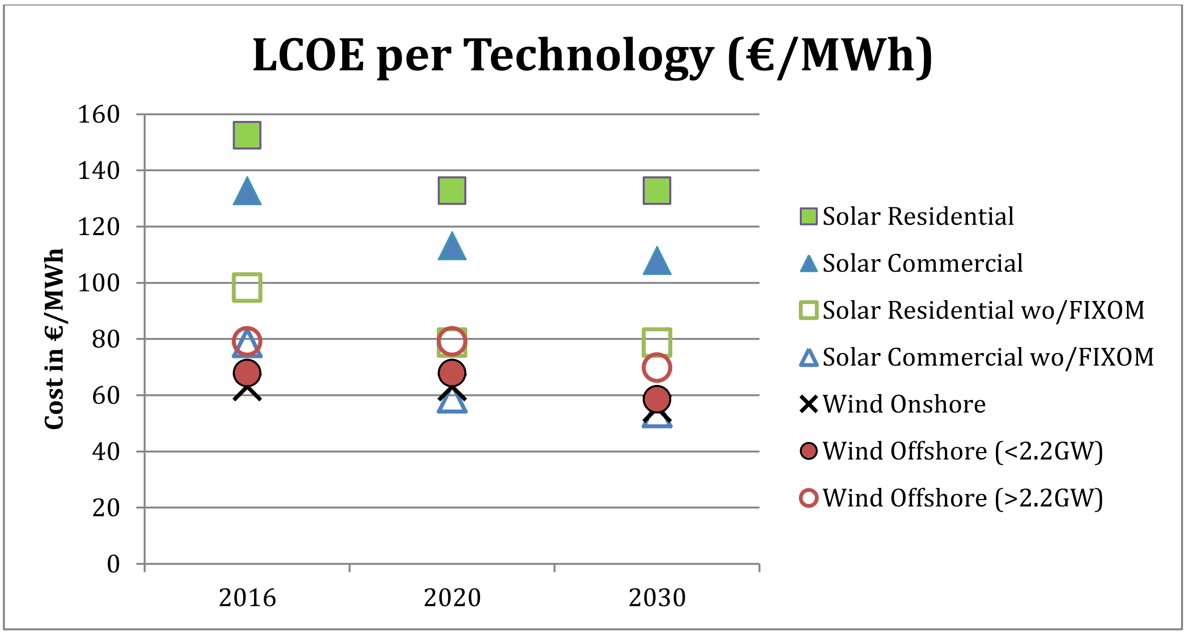

Figure 3-5 – Levelized costs of electricity (LCOE), PV solar and wind offshore (€/MWh)
Source: Belgium TIMES Model

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 is specified with 80% and further specified on a detailed time slice level to include unforeseen disruptions 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 3-6 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.

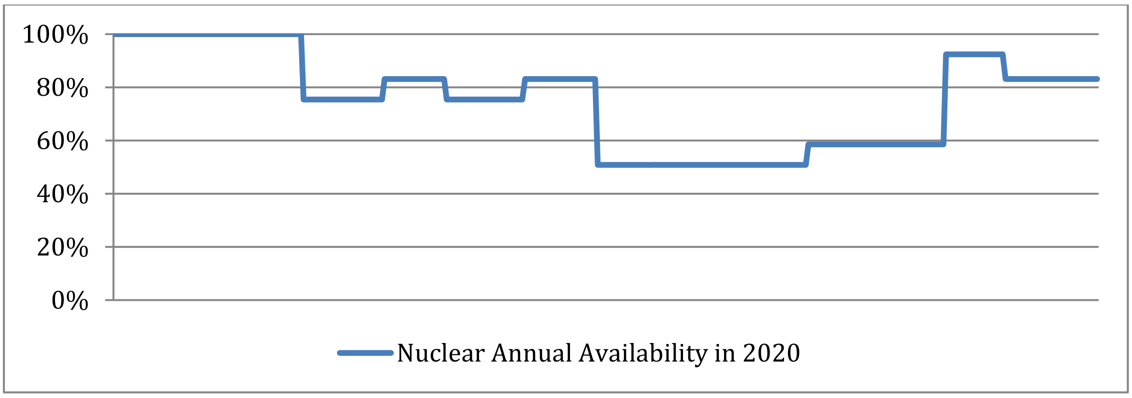

Figure 3-6 – Nuclear availability over the course of a year – 2020 (%)
Source: Belgium TIMES Model

d. Electricity Imports and Exports

For electricity imports and exports and the available cross border grid infrastructure the model considers a 3.5 GW capacity in 2014 and it foresees the planned investments a total commercial cross border electricity trade capacity of 6.5 GW in 2020. 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).

In addition to the planned expansion of the grid, the model is also able to invest in additional capacity. For this extra electricity import and export capacity, it is assumed that these investments will be conducted underground due to topological, political and environmental restrictions. For this reason, investment costs of additional cross border grid capacity, beyond the aggregated capacity of 6.5 GW, are assumed to be three times higher compared to the above ground grid investments.

Apart from the cross-border capacity constraints, limits on annual import and export electricity quantities are also taken into consideration reflecting historical data on total import and export flows, as shown in Figure 3-7. The historical maximum and minimum value of imports and exports are input to the model as upper and lower constraints to electricity flows for the in 2014 already existing 3.5 GW transfer capacity in order to keep the results realistic across scenarios. This results in an annual electricity import range between 9.4 and 23.9 TWh and an annual electricity export range between 2.5 and 11.5 TWh for the 3.5 GW of transfer capacity in the base year (2014). Additional capacity beyond 2014, such as the planned additional 3.0 GW is not limited in the model by these electricity import and export assumptions as shown in Figure 3-7.

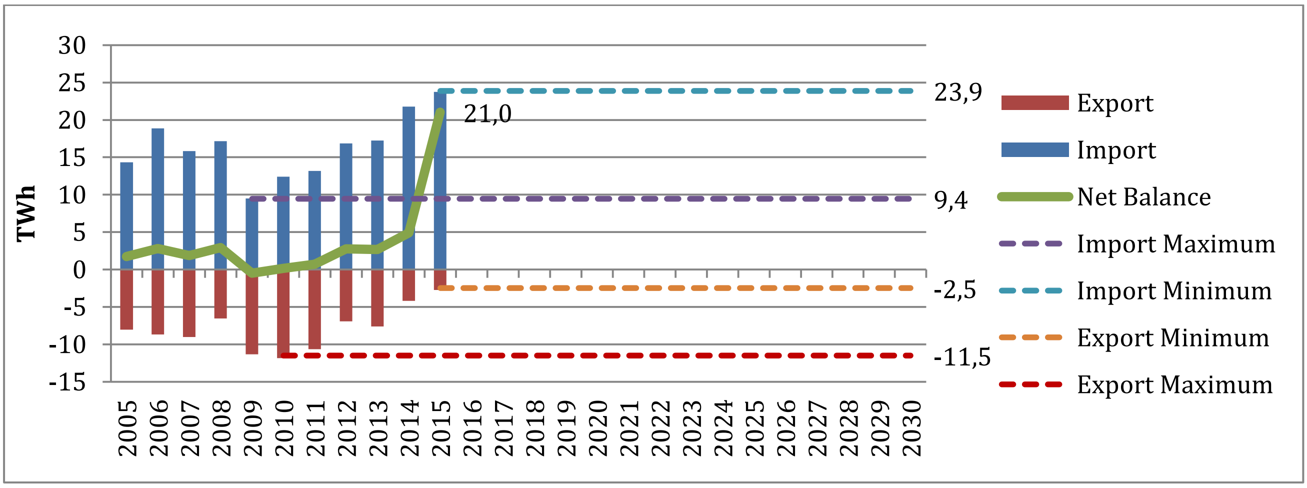

Figure 3-7 – Historical electricity transfer Belgium and upper and lower limit import and export assumptions (TWh), Source: and own assumptions

Besides capacity and import and export quantity limits, the fluctuation of electricity import costs are 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 followed. The initial import price for the first GW of import capacity used is 35 €/MWh, and it is increased by 7 €/MWh when an additional GW of import capacity is used to allow import flows. This stepwise function is derived from the day ahead market prices which were analysed for the year 2014 for Germany, France, UK and the Netherlands.

Electricity import and export as it is modelled in the TIMES Belgium, does not distinguish from and to which country the electricity flows. Furthermore, import is assumed to be always available at the above described import price per MWh.

e. Industry

The Belgian industry was divided in thirteen different sectors with different final demands:

- Iron and steel
- Ammonia
- Chlorine
- Other Chemicals
- Pulp and paper (high and low quality)
- Aluminum
- Copper
- Other non-ferrous metals
- Cement
- Quick lime
- Glass (flat and hollow)
- Other non-metallic minerals
- Other industries

Different steps of the production chain are characterized and modelled when needed for most of the sectors, for instance, the production of crude steel in blast furnace ovens for the steel sector and the production of pulp in the paper sector. The main structuring of the industry sector is based on the previous TIMES Belgium developed by VITO (Devogelaer et al., 2012).

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. The heat flows are linked to the correct sectoral demand.

f. Transport

The transport sector is represented in the model in great detail. This representation includes road and rail transport demand, public transport in form of buses and light rail and aviation and navigation demand. For each of these demands existing and new technologies are represented. One of the main changes currently being debated in the transport sector is the rising share of electrical cars, both in form of plug-in hybrid electric vehicles (PHEV) and battery electric vehicles. Table 3-4 provides an overview of the model assumptions regarding the respective investment cost and fixed annual operation and maintenance costs for selective passenger cars.

Technology	CAPEX (Euro)			FIXOM (€/year)		
	2016	2020	2030	2016	2020	2030
Car Gasoline	20,000	20,000	20,000	2,000	2,000	2,000
Car Diesel	21,800	21,800	21,800	2,180	2,180	2,180
Car Biodiesel	21,800	21,800	21,800	2,180	2,180	2,180
Car LPG	22,200	22,200	22,200	2,220	2,220	2,220
Car Hybrid	22,923	22,686	22,200	2,000	2,000	2,000
Car Plug-In Hybrid	27,775	25,435	23,500	2,000	2,000	2,000
Car Electric (35 KWh)	37,163	30,010	24,500	1,000	1,000	1,000
Car Electric (65 KWh)	53,317	40,447	29,800	1,000	1,000	1,000

Table 3-4 – Assumptions on costs for selected passenger cars (Euro)
Source: (Roland Berger, 2016), own calculations

g. Residential, Commercial and Agriculture

Residential, commercial and agriculture sectors (RCA) have their main structure based on the previous version of TIMES Belgium (Devogelaer et al., 2012). However, quite important improvements are implemented especially in the residential sector in order to reflect new perspectives on growth and energy efficiency regulations. Table 3-5 shows the main assumptions adopted to project future demand of these sectors.

Demographic Assumptions	
Population in 2014	11,204,000
Population in 2030	12,240,000
Households Annual Growth Rate	0.7%

Table 3-5 – Demographic assumptions for Residential sector. Source: (FPB, 2014)

The stock of residential and commercial buildings for the base year (2014) originates from Statistics Belgium (statbel, 2016) and the existing stock of dwellings is further disaggregated between rural and urban and single and multi-apartments according to available data.

New houses built from 2016 onwards have low heat demand levels according to the "near zero energy buildings" regulation implemented at EU level (EC, 2017). Moreover, investments on new heat pumps are properly modelled accounting for the efficiency variation due to external temperature.

h. Batteries and Storage

Centralized and decentralized storage options are represented in TIMES Belgium since they constitute a strategic opportunity to add flexibility to the energy system. The EnergyVille TIMES Belgium model does not take services such as frequency control, local grid congestions or strategic reserves provided by batteries and other storage technologies into consideration. Therefore the results of this study should not be interpreted in a way that when the model does not invest in battery or other storage technology that there might not be a 'business case' for such technologies.

Existing hydroelectric pump storage is included in the stock of existing technologies. The expansion of the Coo-Trois-Ponts pumped storage by 600 MW is also available in the model for investment (Table 3-6).

Technology	**Investment cost**			**Capacity**	**Fixed O&M costs**	**Efficiency**
	2016	2020	2030		(€$_{2010}$/kW/year)	
existing:						
Coo-Trois-Ponts, I & II	N/A	N/A	N/A	1,164 MW	30	0.73
Platte-Taille	N/A	N/A	N/A	144 MW	30	0.73
future:						
Coo III (expansion)	600 M€/ 600 MW	600 M€/ 600 MW	600 M€/ 600 MW	600 MW	30	0.73

Table 3-6 – Cost and technical assumptions for hydroelectric pumped hydro storage
Source: (ELIA, 2017b; Engie-Electrabel, 2017; ESTMAP, 2017) and Belgium Times Model

Investments in large scale electrical storage technologies other than batteries and pumped hydro, such as compressed air energy storages (CAES) have no or limited potential in Belgium. New storage options in form of decentralized batteries and the main assumptions characterizing these technologies are based on (ESTMAP, 2017) and (EC, 2013), as shown in Table 3-7.

Technology	**Investment cost**			**Variable cost**	**Fixed O&M costs**	**Life [years]**	**Efficiency**	
	2014	2020	2030				2014	2030
Battery Lithium Ion Input	100 $\frac{€}{kW}$	70 $\frac{€}{kW}$	50 $\frac{€}{kW}$	0	0	10	1	1
Battery Lithium Ion Storage	752 $\frac{€}{kWh}$	200 $\frac{€}{kWh}$	100 $\frac{€}{kWh}$	0.0026 $\frac{€}{kWh}$	1.4 % Inv.	10	0.9	0.9
Battery Lithium Ion Output	100 $\frac{€}{kW}$	70 $\frac{€}{kW}$	50 $\frac{€}{kW}$	0	0	10	1	1
Battery Lead Acid Input	205 $\frac{€}{kW}$	195 $\frac{€}{kW}$	185 $\frac{€}{kW}$	0	0	8	1	1
Battery Lead Acid Storage	175 $\frac{€}{kWh}$	164 $\frac{€}{kWh}$	154 $\frac{€}{kWh}$	0.0008 $\frac{€}{kWh}$	1.4 % Inv.	8	0.85	0.85
Battery Lead Acid Output	205 $\frac{€}{kW}$	195 $\frac{€}{kW}$	185 $\frac{€}{kW}$	0	0	8	1	1
Battery Redox Flow Input	475 $\frac{€}{kW}$	405 $\frac{€}{kW}$	365 $\frac{€}{kW}$	0	0	10	1	1
Battery Redox Flow Storage	406 $\frac{€}{kWh}$	110 $\frac{€}{kWh}$	86 $\frac{€}{kWh}$	0.002 $\frac{€}{kWh}$	2 % Inv.	10	0.75	0.75
Battery Redox Flow Output	475 $\frac{€}{kW}$	405 $\frac{€}{kW}$	365 $\frac{€}{kW}$	0	0	10	1	1

Table 3-7 – Cost and technical assumptions for decentralized storage options
Source: (ESTMAP, 2017)

i. CO_2 Emissions

In order to properly identify the effects of climate policies in Belgium, production plants and power generation installations are differentiated into belonging to the ETS and the non-ETS sectors in order to distinguish production and electricity generation processes included in the ETS scheme from the ones not included. This way, EU climate policy translated into ETS CO_2 prices can be incorporated into the model and the CO_2 emissions resulting from this can be properly accounted for and reported.

For this version of TIMES Belgium, no other greenhouse gas is considered and the overall emissions of the energy systems corresponds to CO_2 only.

3.2. Scenarios Outline

In accordance with the contents of the deliverables, a series of workshops were organized with the FEBELIEC steering committee in order to identify the committee's main concerns regarding energy security in Belgium. During these workshops, the main assumptions adopted in TIMES Belgium were outlined and, based on them, a base scenario was developed. This scenario is considered to be a 'business-as-usual' that includes current policies related to energy and climate and maintains current trends related to commodity prices.

Moreover, the discussions with the Steering Committee allowed to screen three basic parameters that should be the focus of scenario analysis:

- Fossil fuel prices
- Electricity cross border trade capacity
- Nuclear power availability

Sensitivity scenarios were developed by different assumptions on these three elements, reflecting different market trends or strategies towards energy security. These scenarios were put against the central scenario, in order to identify how the energy system reacts towards variations on energy prices, import/export and nuclear capacities. These reactions are translated into costs variations and changes in the technology mix, reported as results in the next section. Table 3-8 summarizes the outline of scenarios adopted in this study and a detailed description of these scenarios will follow.

Elements/ Scenario	Central Scenario	10% Import Restriction	Nuclear Extension 2GW	Low Fossil Fuel Price	High Fossil Fuel Price
Electricity Trade	According to capacity, 2014/2016: 3.5 GW, 2020: 6.5 GW Investments >6.5 GW possible	Limited to 10% of electricity demand at any point in time	According to capacity, 2014/2016: 3.5 GW, 2020: 6.5 GW Investments >6.5 GW possible	According to capacity, 2014/2016: 3.5 GW, 2020: 6.5 GW Investments >6.5 GW possible	According to capacity, 2014/2016: 3.5 GW, 2020: 6.5 GW Investments >6.5 GW possible
Nuclear Power Generation	Phased-out in 2025	Phased-out in 2025	Investment possible in extension of 2 GW till 2035	Phased-out in 2025	Phased-out in 2025
Fossil Fuel Price Projections (Gas & Oil)	WEO (2015) New Policies Scenario	WEO (2015) New Policies Scenario	WEO (2015) New Policies Scenario	Stable at low 2016 levels, (oil: 35 €/bbl, gas:13 €/MWh)	50% higher compared to Central Scenario

Table 3-8 – Summary of Scenarios.

In order to isolate effects and identify clearly impacts of specific parameters on the energy system, variations were of primary order, which means that for each alternative scenario, only one parameter was changed in comparison to the central one.

3.2.1. Central Scenario

The "Central Scenario" is the main one of the study because it covers current policies and trends for the Belgium energy system. In terms of technical and economic parameters, it is based on cross-checked data as described in TIMES Belgium model description. The restrictions on specific technologies, such as nuclear, are also kept.

Regarding market trends, particularly with regard to electricity trade with other countries, the model was free to import and export electricity within the historical limits specified to the model. With respect to fossil fuel prices, price projections for crude oil and natural gas were based on the 'New Policies' scenario of 2015 World Energy Outlook (IEA, 2015). This is the central scenario of the (IEA, 2015) study and it includes policies and implementing measures adopted until mid-2015 together with relevant declared policy intentions that should affect energy markets.

	2016	2020	2030
Crude oil (€/bbl)	37.6	60.3	85.2
Natural gas (€/MWh)	13.1	20.1	27.3

Table 3-9 – Fossil fuel prices in the Central Scenario, based on the 'New Policies' scenario of 2015 World Energy Outlook (IEA, 2015).

Moreover, it accounts for current EU policies related to renewable energy and climate change. In the model, this is translated into Belgium renewable target within "20-20-20" EU efforts, which is 13% in 2020. This target was extrapolated to 2030, assuming that no changes on policy efforts would be put into effect. Moreover, ETS prices were also considered for ETS sectors within power and industry: 17 €/ton$_{CO2}$ in 2020 and 33 €/ton$_{CO2}$ in 2030 (Figure 3-8), in accordance with (EC, 2016a).

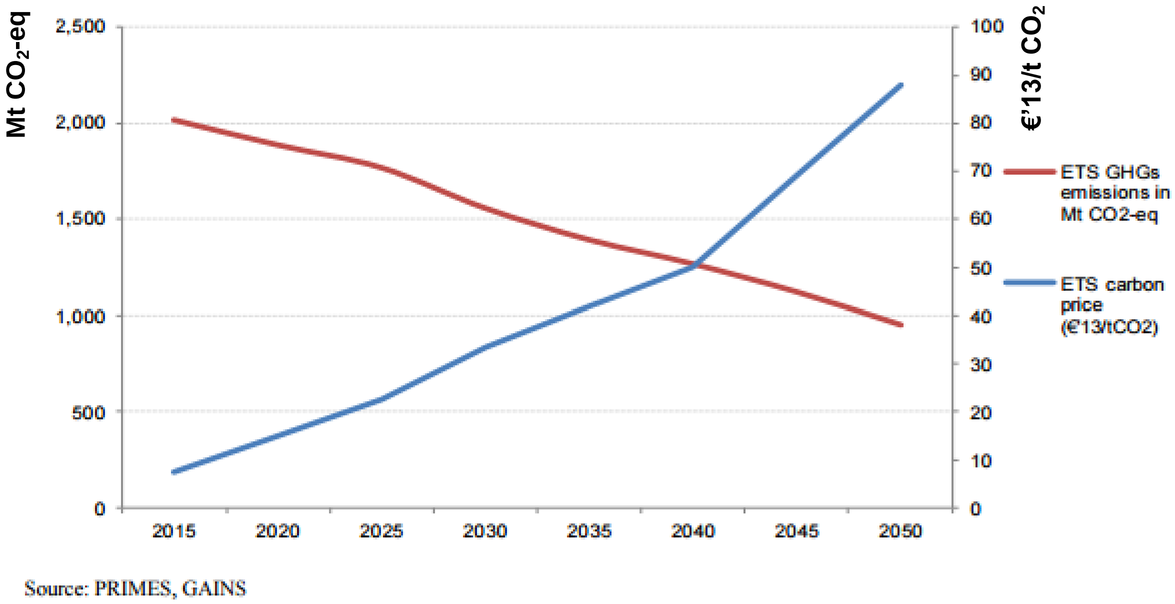

Figure 3-8 – ETS emissions and carbon prices over time in PRIMES model (EC, 2016a).

3.2.2. 10% Import Restriction

The 10% Import Restriction Scenario is a sensitivity scenario that intends to analyse the impact of the assumption that Belgium is not able to rely on a high level of electricity imports from neighbouring countries. In that case, it is acknowledged that in the Central Case Scenario, the cost optimal solution may favour the import of electricity specially under stringent renewable and policy constraints as electricity imports could constitute one of the main balancing tools to provide sufficient electricity supply to meet electricity demands. However, accepting the country's dependence on neighbouring countries may threaten energy security purposes as markets are not aligned and generation strategies might differ across countries.

In this context, an additional constraint was given to TIMES Belgium Model limiting the import capacity to 10% of the country's electricity demand in each 2 hour time slot. This sensitivity scenario should give some insight on critical technologies for energy security and the corresponding impact on the cost.

3.2.3. Nuclear Extension 2GW

The Nuclear Extension 2GW scenario aims at evaluating if the maintenance of nuclear power generation in Belgium will significantly impact the energy system in terms of costs and technology mix, mainly with respect to the renewable energy expansion. As the nuclear phase-out policy in Belgium has been focus of debate among many stakeholders, it was decided to develop and alternative scenario to the central scenario where the model can invest in 2 GW of nuclear power extension for an additional 10 years after 2025 with an investment cost of 1,000 €/kW$_{extended}$ and a fixed operational cost of 43 €/kW$_{extended}$.

3.2.4. Fuel Price High & Fuel Price Low

The last parameter considered is the fossil fuel price since it is exogenously defined and determined by global market trends and geopolitics. This is critical for Belgium as the country imports all its demand for oil and natural gas and, consequently, is exposed to price volatility and risks.

In this context two sensitivity scenarios were defined to reflect high and low price market trends for fossil fuels. The three level price projections for Central, Fuel Price High and Fuel Price Low are depicted in Figure 3-9 for crude oil and Figure 3-10 for natural gas. The Central scenario price assumption corresponds to the New Policies scenario of WEO study (IEA, 2015), as described previously.

As the historical figures show, average price levels for 2016 reflect the lowest prices since 2007. Therefore, the low-price assumption extends 2016 price levels over the model time horizon, which corresponds to 35 €/bbl for crude oil and 13 €/MWh for natural gas.

For the High Price Scenario, it was assumed that prices would be 50% higher than prices adopted in the Central scenario. Hence, crude oil price gets to 127 €/bbl in 2030, while natural gas price reaches 40 €/MWh.

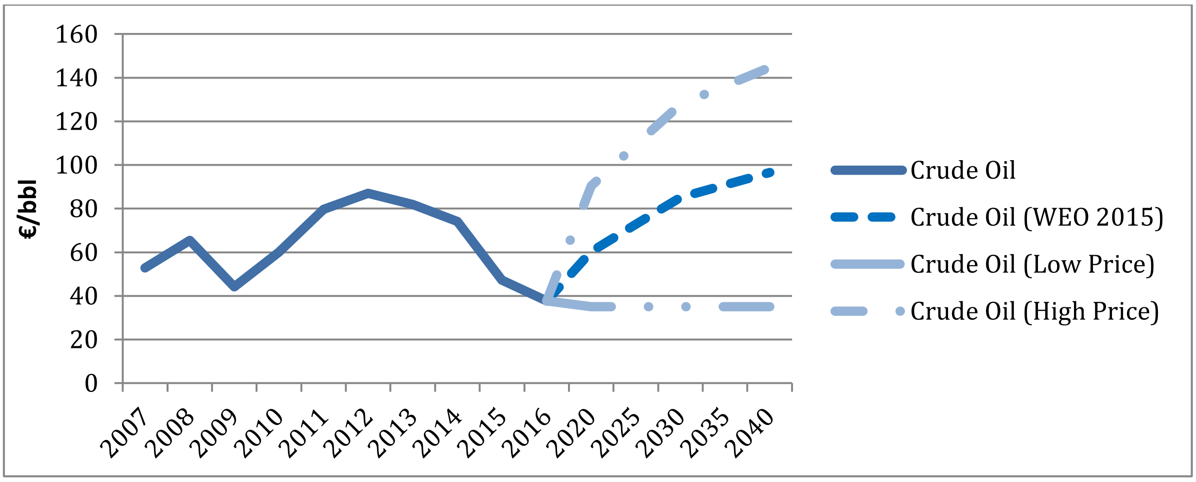

Figure 3-9 – Crude oil price projections (€/bbl) for "Central Scenario", "Fuel Price High" and "Fuel Price Low".

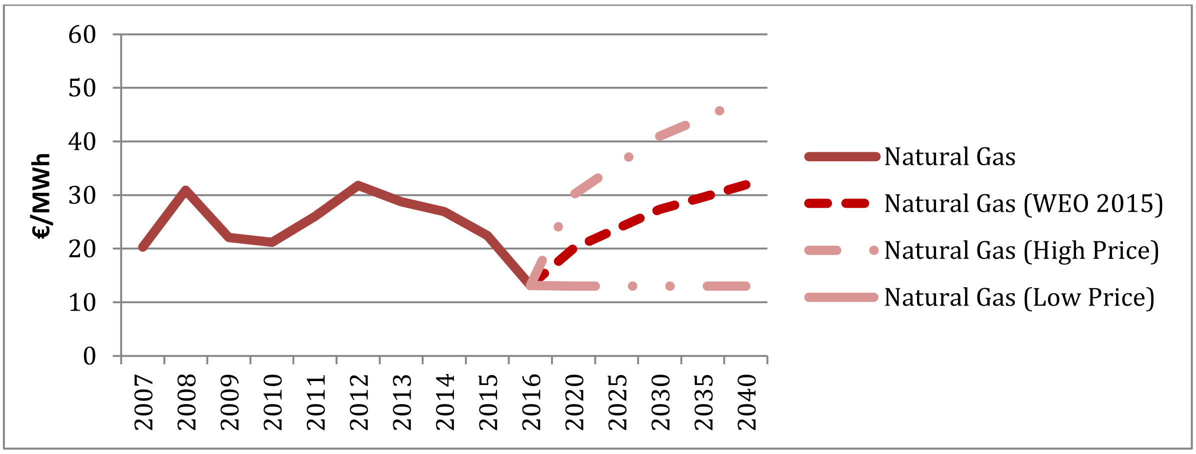

Figure 3-10 – Natural Gas price projections (€/MWh) for "Central Scenario", "Fuel Price High" and "Fuel Price Low".

4 Results

Chapter 4 presents the results of the Belgium TIMES model for the electricity generation and demand. The TIMES model calculates the demand and supply for every time slice and year over the model horizon till 2030, while the chosen reporting years for this study are 2016, 2020 and 2030. As outlined in chapter 3 the model generates the cost optimal solution to meet end use demands for each sector not limited to electricity demand, but also includes demand for heat and transport. The following results will focus on power generation.

4.1. Central Scenario

4.1.1. Overview of Power Generation and Capacity by Fuel Type

From 2016 to 2030 Belgian electricity generation will go through a major transformation. Figure 4-1 and Figure 4-2 provide an overview of electricity generation and generation capacity of this transition in an aggregated format by fuel source.

Based on the cost minimizing objective of the model the results show that in the year 2016 fossil fuel based generation accounts for 30%, nuclear for 55% and renewable generation for 14% of electricity generation (Figure 4-1). In the Central Scenario, based on current policies, the nuclear capacity has retired by 2030, and the generation gap is filled by a growth in natural gas based generation from 24 to 35 TWh (>45% increase) and in renewable generation from 11 to 36 TWh, an increase of over 200%. By the year 2030 50% of Belgian electricity generation originates from renewable and intermittent energy sources according to the model outcomes.

This generation mix results in approximately 14 % share of renewable energy generation in the final energy consumption in Belgium in the year 2030, exceeding the 13% as specified in the boundary conditions of the model. This calculation treats imported electricity neither as renewable nor as non-renewable generation based.

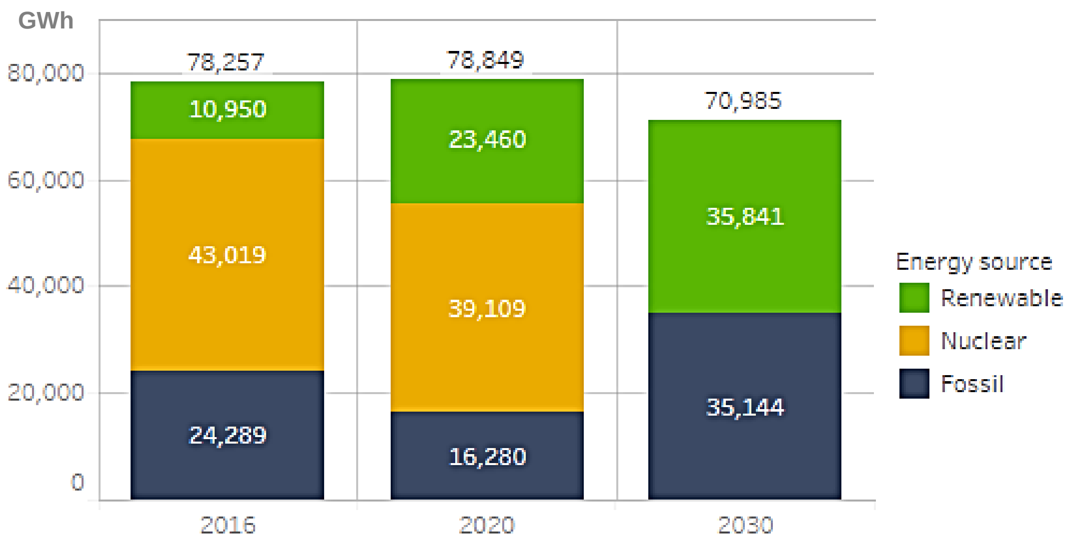

Figure 4-1 - Electricity production by fuel type, excl. imports (GWh)

Figure 4-2 depicts the corresponding power generation capacity transition for Belgium over the model horizon. Fossil fuel generation, which represents mostly natural gas based plants, remains at a similar level with a capacity of over 6.5 GW in all three reporting years, while the nuclear capacity is being closed between 2022 and 2025. The highest growth is observed in renewable capacity which increases more than threefold from 6 GW in 2016 to 19 GW in 2030.

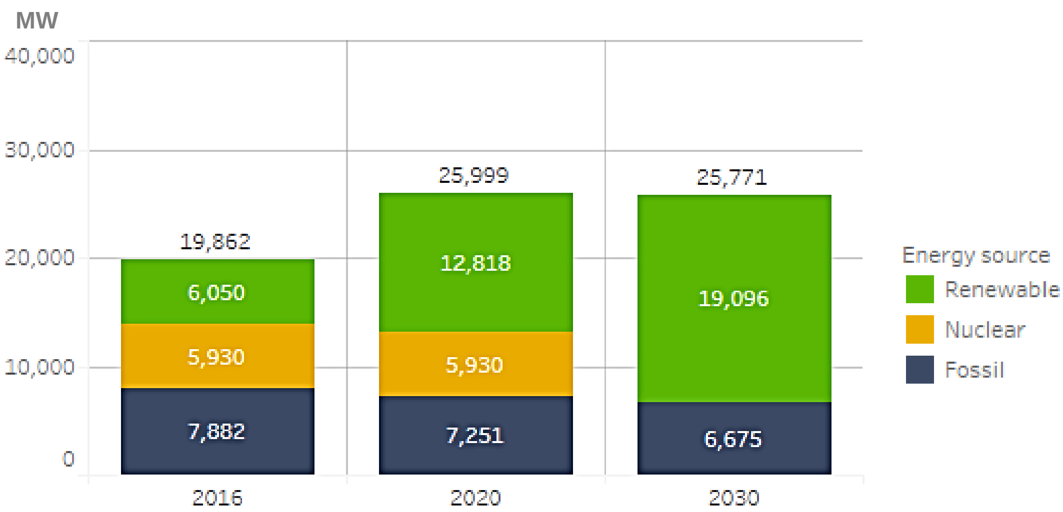

Figure 4-2 - Generation capacity by fuel type (MW)

4.1.2. Electricity Demand

Electricity demand increases slightly over the model horizon from 84.5 TWh in 2016 to 86.5 TWh in 2030. While industrial electricity demand is close to stable, a slight decrease in the commercial and residential sector can be observed from 2016 to 2030. Two trends are underlying this development: On the one hand it is assumed that till 2030 Belgium will experience an increase in population (Table 3-5) and therefore an increase in residential and commercial demand services such as heating, cooking and lighting. On the other hand, energy efficiency measures, such as stricter building requirements for new construction and an increasing market for energy efficient technologies like LED lighting leading to a lower power and heat demand per occupant.

The most significant increase in power demand can be observed in the transport sector. While electrical transport demand of 1.5 TWh in 2016 and 2020 can be mostly attributed to rail transport, by 2030 an up-take of electrical road transport can be observed accounting for additional 2.5 TWh annually. This upcoming demand in electrical road transport is roughly equivalent to 650,000 to 700,000 electrical cars in Belgium by 2030.

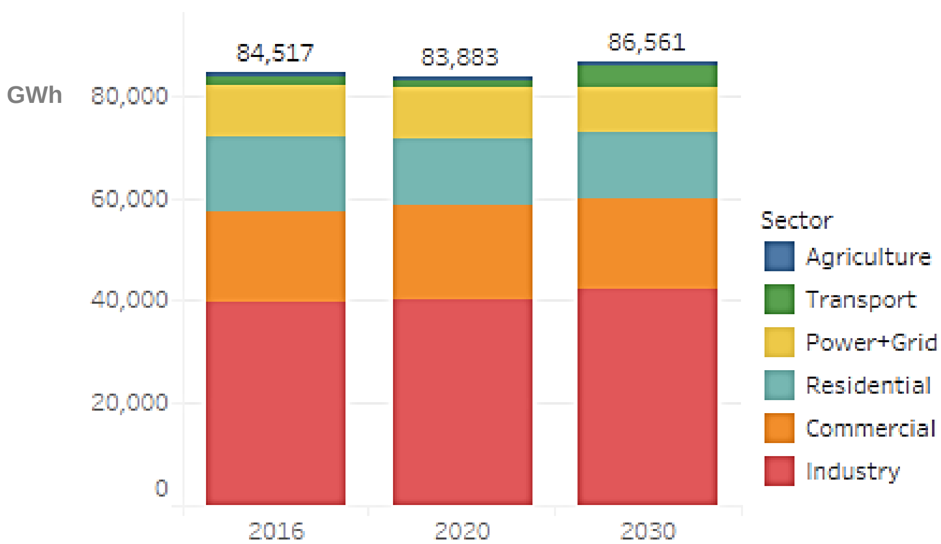

Figure 4-3 - Electricity demand (GWh)

4.1.3. Renewables Electricity Generation

As shown in Figure 4-1, 50% of the generated electricity in Belgium originates from renewable energy sources by 2030 according to the Central Scenario model results. Figure 4-4 depicts in greater detail the split among the renewable generation sources. The increase from 11 TWh in 2016 to 36 TWh in 2030 is based on an increase in wind onshore, wind offshore and PV solar generation by a factor of 5.7, 3 and 2.7 respectively. Hydro power (run of the river) and biomass output remain at a constant level.

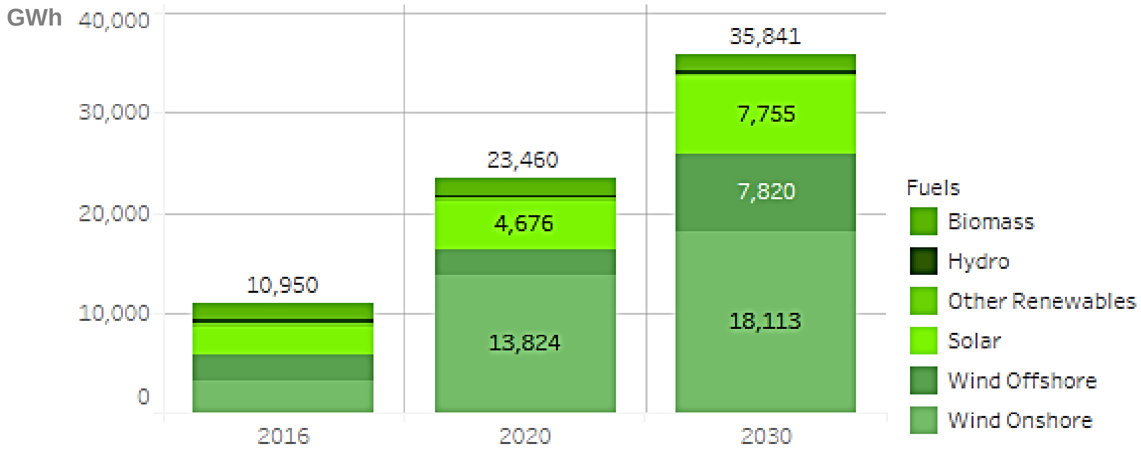

Figure 4-4 - Renewable electricity production (GWh)

Figure 4-5 shows the corresponding development in generation *capacity* of the various renewable energy sources. Wind onshore shows an increase from 1.5 GW in 2016 to 6.5 GW in 2020 and reaches the modelled upper bound of 8.6 GW capacity in 2030. The calculated growth is equivalent to an additional 470 MW of new onshore turbine capacity per year. To compare this projected growth with developments in recent years, Belgium observed the highest capacity installation of wind onshore in 2010 with 200 MW.

For wind offshore an expansion in capacity by a factor of three from currently 712 MW to 2.2 GW are calculated. 2.2 GW is the currently being planned offshore capacity and also the maximum capacity for the existing infrastructure to connect offshore wind energy to the grid in the Central Scenario results. While the model can invest in additional capacity beyond a total of 2.2 GW, additional grid investments have to be made and the option is therefore, based on the parameters of the central scenario, not chosen as a cost-optimal solution.

Solar PV capacity is building up from 3.0 to 7.9 GW in 2030 in the central scenario. The steady build up over the model timespan equals an average growth of 330 MW per year for commercial and residential PV panels combined. The highest installation rate in Belgium in recent years was in 2011 with close to 1,000 MW newly installed.

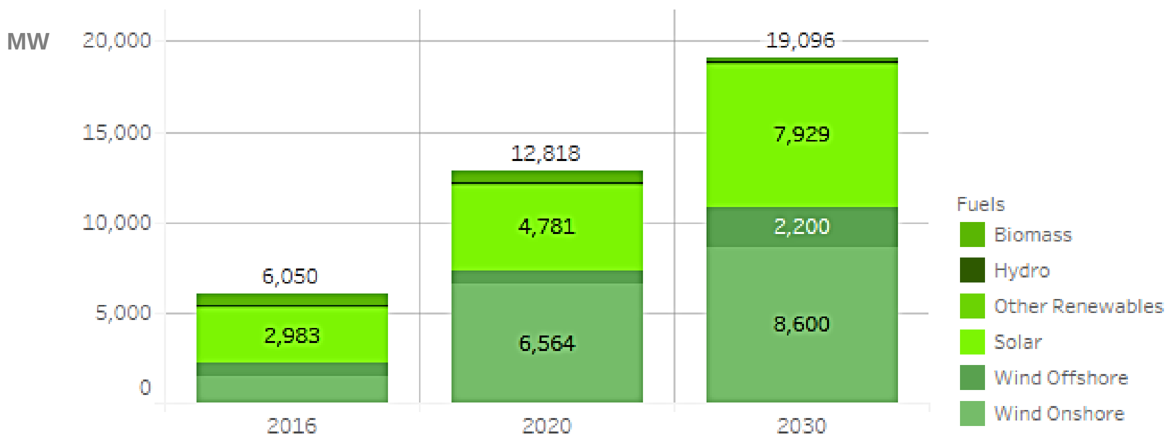

Figure 4-5 - Renewable generation capacity (MW)

4.1.4. Fossil Fuel Electricity Generation

Aggregated fossil fuel power generation increases from 2016 to 2030 by approximately 45%, from 24 to 35 TWh. Natural gas is the main fuel source for fossil fuel power generation in Belgium with a share of over 90% in 2030. The use of waste incineration, industrial heat and blast furnace gas (from steel production) constitute the remaining generation fuels (Figure 4-6).

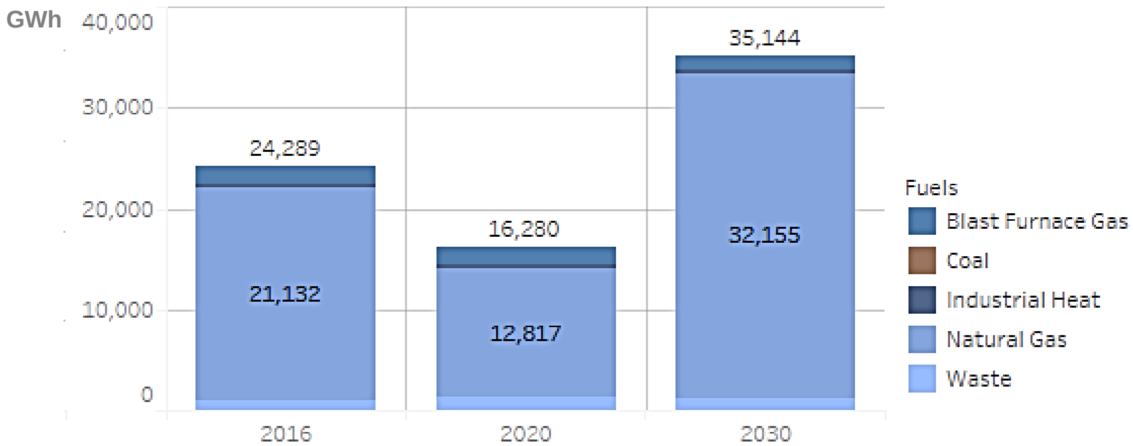

Figure 4-6 - Fossil fuel electricity production (GWh)

The corresponding generation capacity is shown in Figure 4-7. After 2016 the capacity of coal power plant phases out since new investments in coal plant capacity are not allowed in the TIMES Belgium model as shown in Table 3-2. Natural gas plant capacity remains at a stable level above 6,000 MW from 2016 to 2030, consisting of existing CHP's and gas turbines, but also replacements and new investments (Figure 4-11). Based on the boundary conditions of the model and the Central Scenario the gas plants, in combination with electricity imports, play a central role in the energy system in 2030 because of their technical capability to balance the intermittent supply of renewable electricity sources. While the capacity of natural gas plants remains steady, the output increases which means the annual operating hours increase. By 2030 the model has invested in 1.4 GW capacity in new efficient gas turbines (CCGT) which operate for almost 6,000 hours a year in 2030.

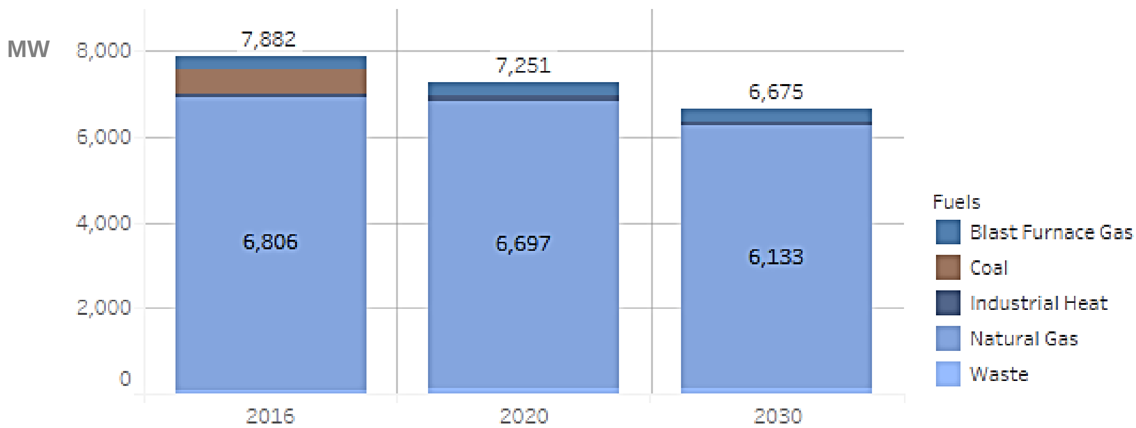

Figure 4-7 - Fossil fuel generation capacity (MW)

4.1.5. Electricity Net Imports

In Table 3-2 the assumptions regarding the increase from 3.5 GW in 2014 to 6.5 GW in 2020 in interconnection capacity to neighbouring countries is presented. Investments in additional capacity after 2020 are possible in the model, albeit at a higher cost to represent the likely undergrounding. The results in the Central Scenario do not show additional investments in transfer capacities beyond 2020 and beyond the planned 6.5 GW. The annual net imports (annual imports minus exports) are increasing during the period of the nuclear phase out to 15.6 TWh representing an increase by a factor of 2.5 from 2016 to 2030.

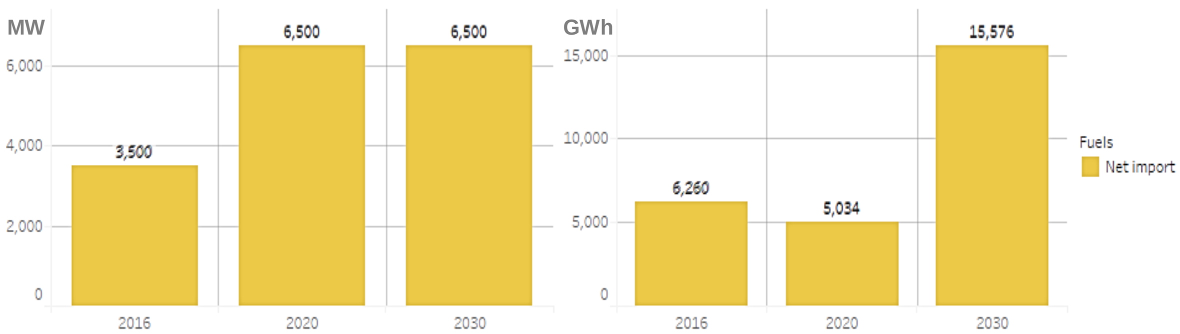

Figure 4-8 – Transmission capacity in MW (left) and Net electricity import in GWh (right).

The significant increase of electricity net import in the central scenario and the issue of dependence of Belgium from electricity generation in neighbouring countries was intensely reviewed and debated during the course of the study. For additional insights in this issues see the Sensitivity Analysis – 10% Import Scenario, chapter 4.2.1.

4.1.6. CO_2 Emissions

The TIMES Belgium model reports on CO_2 emissions. Figure 4-9 shows the CO_2 emissions of public electricity and heat generation in 2016, 2020 and 2030 aligned with the definition of the Intergovernmental Panel on Climate Change (IPCC) sector 1.A.1.a (IPCC, 2006). The CO_2 emissions decrease from 15 to 12 million tons per year till 2020 and then increase till 2030 to approximately 19 million tons per year for the Central Scenario. The increase in emissions is related to the surge in natural gas use as a power generation fuel to replace the closing of nuclear plants.

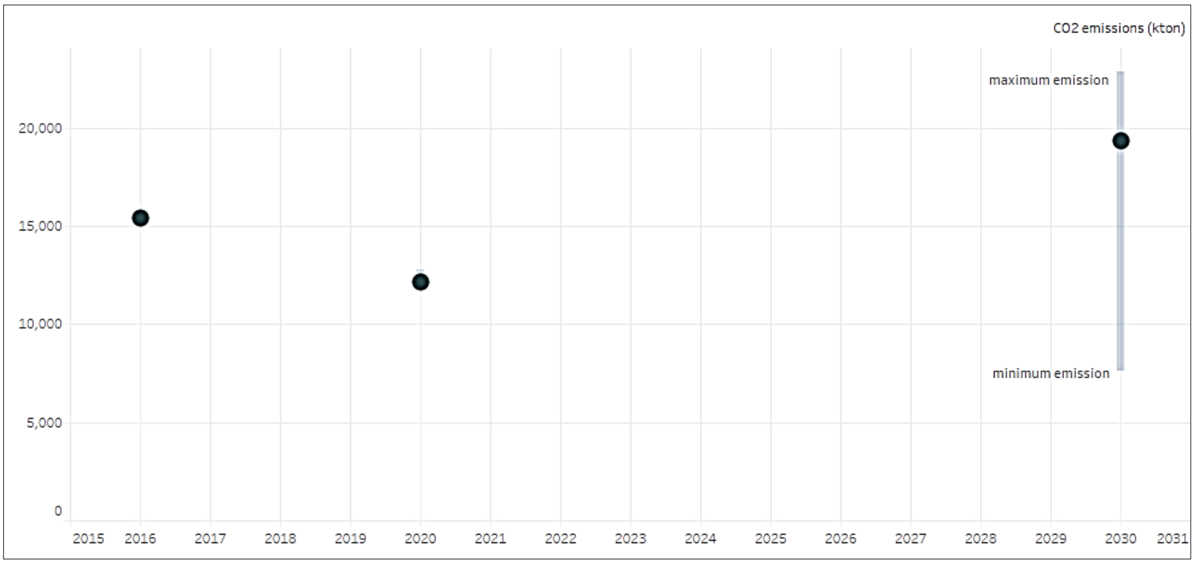

Figure 4-9 – CO_2 emissions of public electricity and heat generation sector (kton)

CO_2 emission reductions in other sectors, e.g. in the residential sector due to the replacement of natural gas based heating systems with electrical heat pumps, are not taken into consideration in this graph. The overall CO_2 emissions in Belgium, taking into account all sectors, decreases by approximately 4% between 2016 and 2030 to 88 million tons per year.

4.1.7. Annual Costs Electricity Production and Imports

Chapter 3 introduces the cost-minimization objective of the TIMES model. The linear optimization of the model takes into account all costs related to the energy system as represented in the model: investment cost for new or replacement of installations, fixed operation and maintenance cost (FIXOM), variable operation and maintenance costs (VAROM), fuel costs and import costs for electricity and other resources. In the TIMES Belgium model CO_2 emitted in the ETS sectors are also burdened with a cost (see section 3.2.1), but this cost is not included in the graphs below. Not taken into account by the model is the amortization of capital expenditures for existing installations (e.g. existing power plants or existing interconnectors). Existing installation are considered stock without capital expenditures, although VAROM, FIXOM and fuel cost are calculated and considered in the cost optimization.

The historical capital expenditure for the existing nuclear reactors as well as the costs for decommissioning and dismantling the reactors is not included in the Belgian TIMES model. The reasoning behind this approach is that historic investments are not reversible at this point in time and that the nuclear plant owner or operator will have to finance the retirement of the nuclear plants independent of the pathway of energy system till 2030 and beyond. The one exception to this approach is the Nuclear Extension Scenario, in which a lifetime prolongation by ten years is assumed to require capital expenditures of 1,000 Euros per KW capacity (Table 3-3).

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.

While these elements constitute or lead to barriers in the market, they are not elements within TIMES modelling approach and, for that reason, costs resulting from TIMES exercise should not be interpreted as electricity price projections.

Figure 4-10 shows the aggregated annual energy system costs in 2020 and 2030. They increase from 3 to 6.2 billion Euros in the central scenario. These annual costs are spread over several cost components.

The component with highest percentage increase – over 300% - is electricity trade cost. The nuclear phase-out and the renewable targets change the system into a more variable supply pattern and importing electricity is one way to balance this intermittency, providing stability to the system. This results in a substantial surge of the electricity import cost, from around 300 M€ in 2020 to more than 900 M€ in 2030.

The fuel costs component in Figure 4-10 includes all fuels expenses for power generation, namely natural gas, nuclear, biomass and blast furnace gas. It has also a significant increase from 2020 to 2030, over 120%, mainly due to changes in natural gas consumption for electricity generation. Natural gas fuel costs show a remarkable increase from 667 M€ to 2,120 M€ in this period, reflecting two trends: the price of natural gas increases from 20 €/MWh to 27 €/MWh and, the generation output of the gas plants intensifies from 12,800 to 32,150 GWh per year. As natural gas power generation in part replaces nuclear power generation because of the nuclear closure in this period, the natural gas fuel cost represents a larger share in the fuel cost break-down: it represents 66% of fuel cost in 2020, but 95% of fuel cost in 2030, displacing nuclear fuel costs.

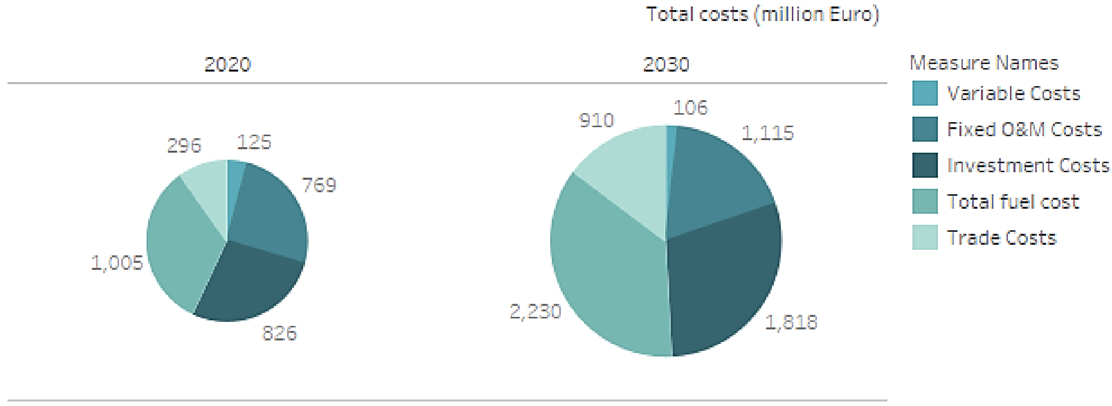

Figure 4-10 – Total energy system costs by component, 2020 and 2030 (million Euro)

Investment costs in new installations, including replacement of retired plants, grow from 826 M€ to 1,818 M€, by 120%. Capital expenditures are mostly attributed to wind onshore projects, followed by investments in solar PV, wind offshore and natural gas generation plants in descending order of magnitude (see graph Figure 4-11).

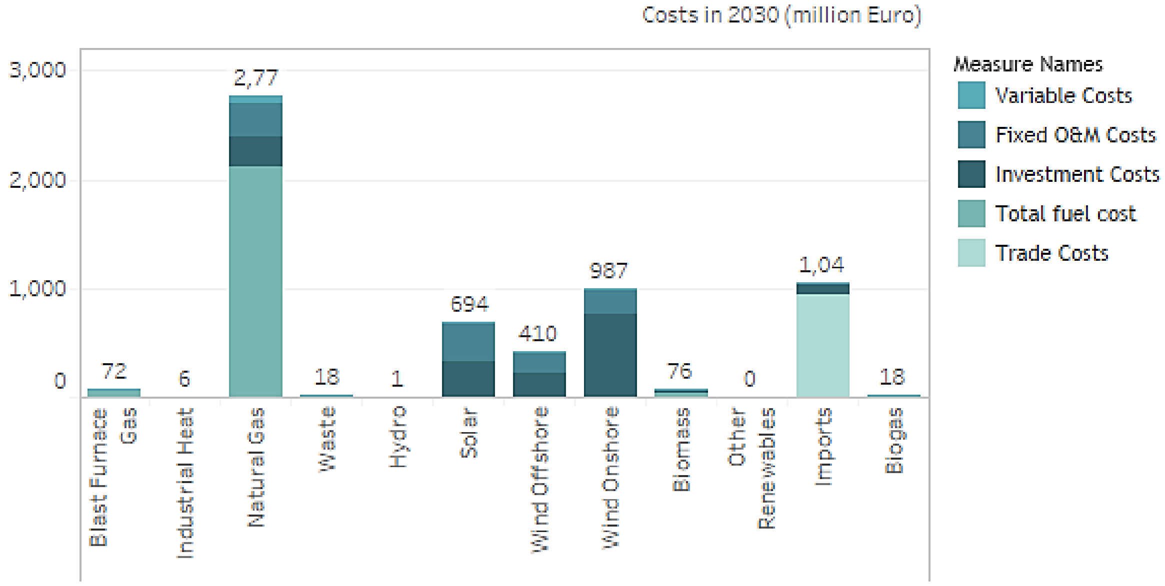

Figure 4-11 – Energy system costs per technology type, 2030 (million Euro)

Reviewing the composition and the size of the cost components it becomes apparent that the main expenses in 2030 are fuel cost (natural gas), followed by investments, mostly in renewable energy generation sources, and thirdly electricity import expenses. In the Central Scenario the energy system cost is heavily influenced by the cost of natural gas in 2030. In Figure 4-20 one can observe that the low fuel cost scenario and high fuel cost scenario are the scenarios with the overall highest and lowest system cost, even when the model shifts among technologies to mitigate high fuel prices.

4.2. Comparison of Scenarios

4.2.1. Sensitivity Analysis – 10% Import Scenario

The details of how the electricity import and export is represented in the TIMES Belgium model is presented in Section 3.1. Nevertheless, two main and crucial issues remain. First, the development of the energy system in neighbouring countries is regulated by and influenced be national governments and therefore neither the private nor the public sector in Belgium has no control over these markets, even given the integrated energy market approach by the EU (Energy Union). Second, the concern seems warranted that during time periods of high electricity demand in combination with unfavourable weather conditions for renewable generation (also called 'Dunkelflaute[6]') in Belgium the same applies in neighbouring countries. Will therefore extra electricity be available on the market and at what price during these critical periods? To answer these questions in detail is beyond the scope of this study and exceeds the capabilities of the TIMES Belgium model. Many factors play a role in this context and it was therefore decided with the steering committee to evaluate the impact and cost on the energy system if imports are limited to a maximum of 10% of total generation during all two-hourly time periods. This approach does not fully answer the questions raised above, but evaluates the 'impact and costs' of an increased independence from electricity imports of the Belgian energy system.

In the central scenario the electricity demand in Belgium is matched by 71 TWh of own generation and 15.5 TWh of net electricity imports in 2030. Figure 4-12 shows that under the 10% import restriction conditions the own generation increases by approximately 8,000 GWh to 79,000 GWh per year.

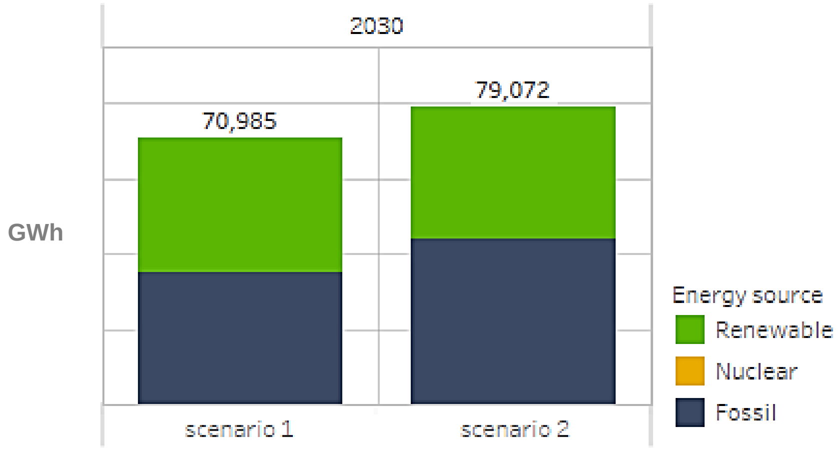

Figure 4-12 – Comparison of electricity production by fuel type, excl. imports (GWh)
Scenario 1: Central Scenario, Scenario 2: 10% Import Restriction

In order to balance supply and demand under the condition of restricted imports the model calculates as a cost optimal solution additional 9 TWh per year of natural gas based electricity generation in comparison with the central scenario (Figure 4-12). The higher natural gas based generation output requires not only additional operating hours of the fossil fuel power plants, but also additional capacity of 1,700 MW (see Figure 4-13). The renewable and intermittent generation capacity is 900 MW lower compared to the central scenario in 2030.

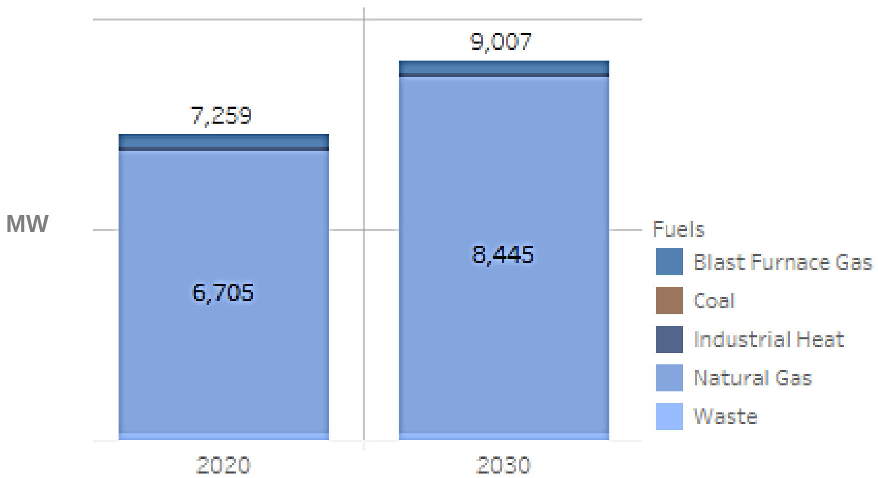

Figure 4-13 - Fossil fuel generation capacity (MW)
Scenario 1: Central Scenario, Scenario 2: 10% Import Restriction

[6] Periods of no or little wind and limited sun shine, in which no or only small amounts of energy can be produced by wind turbines and PV installations.

4.2.2. Sensitivity Analysis – High Fuel Price Scenario

In the High Fuel Price Scenario the cost of natural gas in 2030 is 40.5 €/MWh, 50% higher than in the Central Scenario. The model results show a shift from gas generation to renewable generation and electricity imports. Generation within Belgium decreases from 71 TWh in the central case to 56 TWh with high fuel prices. The fossil based generation declines from 35,000 GWh to 14,000 GWh, while the renewable generation increases from 36 TWh to 41 TWh (Figure 4-14).

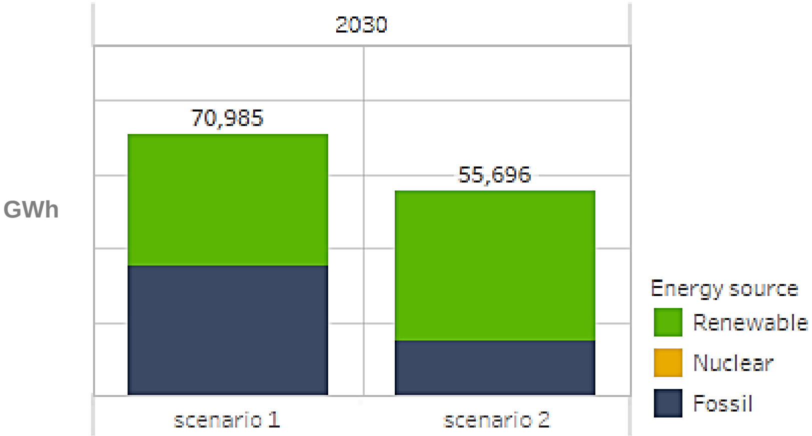

Figure 4-14 – Comparison of electricity production by fuel type, excl. imports (GWh)
Scenario 1: Central Scenario, Scenario 2: High Fuel Price

The model results for the net electricity imports are approximately 13 TWh per year higher to compensate for the declining generation in Belgium. This sensitivity analysis is also the only scenario which shows investment in 1,000 MW additional interconnection capacity beyond the 6,500 MW in all other scenarios.

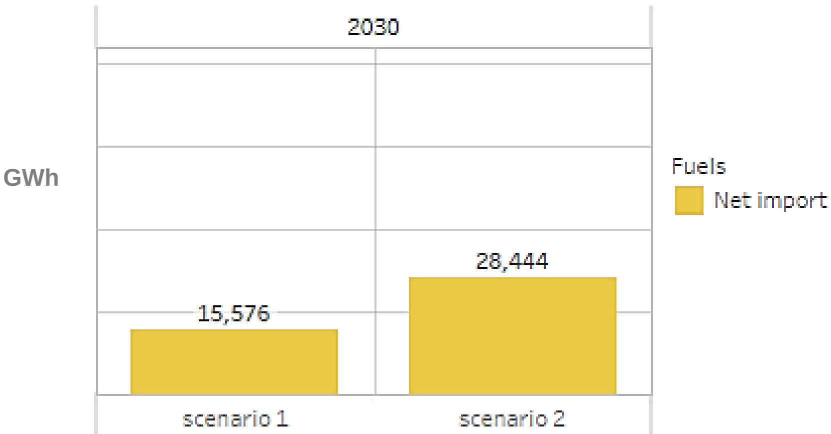

Figure 4-15 –Net electricity import (GWh)
Scenario 1: Central Scenario, Scenario 2: High Fuel Price

4.2.3. Sensitivity Analysis – Low Fuel Price Scenario

In the Low Fuel Price Scenario the natural gas price is 13 €/MWh in 2030, less than 50% of the Central Scenario with 27 €/MWh. The effect on the model results are the opposite of the high fuel price scenario: Increase of own production in Belgium with a generation increase from natural gas power plants and a slight decrease in renewable generation. As Figure 4-16 depicts, the fossil fuel plant output increases from 35 to 44 TWh, while the renewable generation decreases only by 6% to 34 TWh.

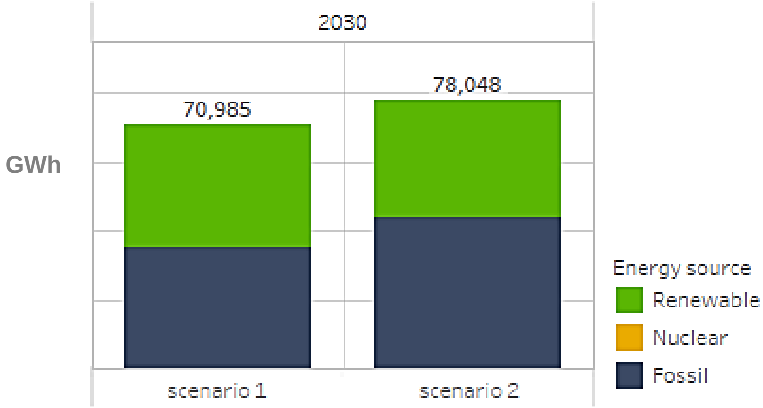

Figure 4-16 – Comparison of electricity production by fuel type, excl. imports (GWh)
Scenario 1: Central Scenario, Scenario 2: Low Fuel Price

The main compensation of the increased gas generation within Belgium is not in reduction in renewable generation, but in an approximately 50% lower net import compared to the Central Case (see Figure 4-17).

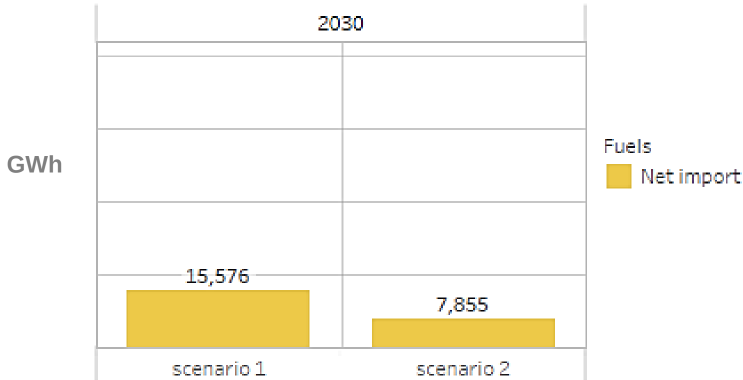

Figure 4-17 – Net electricity import (GWh)
Scenario 1: Central Scenario, Scenario 2: Low Fuel Price

4.2.4. Sensitivity Analysis – Nuclear Extension Scenario

According to current Belgian policy the complete retirement of the 5.93 GW nuclear generation capacity is planned in the period between 2020 and 2025. This study does not evaluate the societal acceptance or health and safety risk of a nuclear extension. The sensitivity analysis of a lifetime extension of 2 GW nuclear capacity for a period of ten years is motivated by the insight that can be gained in terms of impact on electricity generation and generation capacity compared to the Central Scenario.

Figure 4-18 compares the electricity generation in the Nuclear Extension Scenario with the Central Scenario. The model results for 2030 show that the generation in Belgium is only increasing by less than two percent (71 TWh compared to 72.2 TWh) and that correspondingly the net import is also only decreasing by approximately 1.1 TWh per year (Table 4-1).

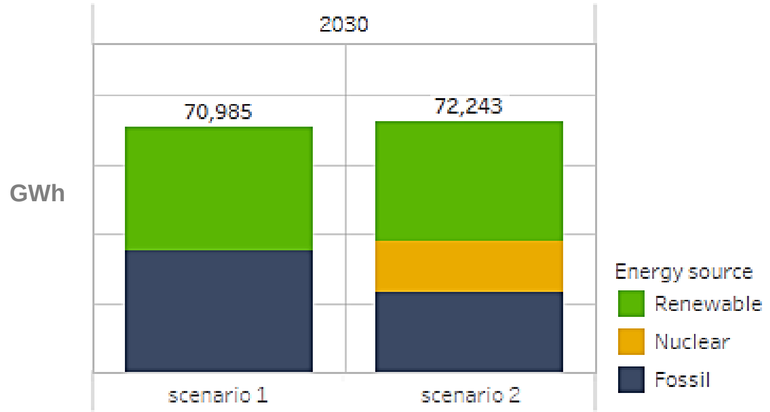

Figure 4-18 – Comparison of electricity production by fuel type, excl. imports (GWh)
Scenario 1: Central Scenario, Scenario 2: Nuclear Extension Scenario

The additional nuclear based generation of approximately 14.8 TWh in 2030 replaces almost exclusively fossil fuel based generation which is 35 TWh in the Central Scenario and 23 TWh in the Extension Scenario. The renewable based generation with its threefold expansion to 35.8 TWh over the model horizon in the Central Scenario is only slightly impacted by the sensitivity analysis. In the Nuclear Extension Scenario the difference is less than 6 % for output from renewable energy sources, namely 34.2 TWh per year in 2030.

This scenario of a nuclear extension also shows an impact on the generation capacity mix. Together with the High Fuel Price Scenario this is the only result that shows a decrease in natural gas plant capacity below 6 GW, in this case down to slightly under 4.9 GW. The capacity of renewable generation is quite resilient to the nuclear extension and comparable with the Central Scenario at a level of approximately 19 GW in 2030 (see Figure 4-19). Although there is a slight shift: offshore wind investments reach up to 1.6 GW by 2030 (compared to 2.2 GW in the Central scenario) and PV capacity is higher in 2030 with 8.3 GW (compared to 7.9 GW in the Central Scenario).

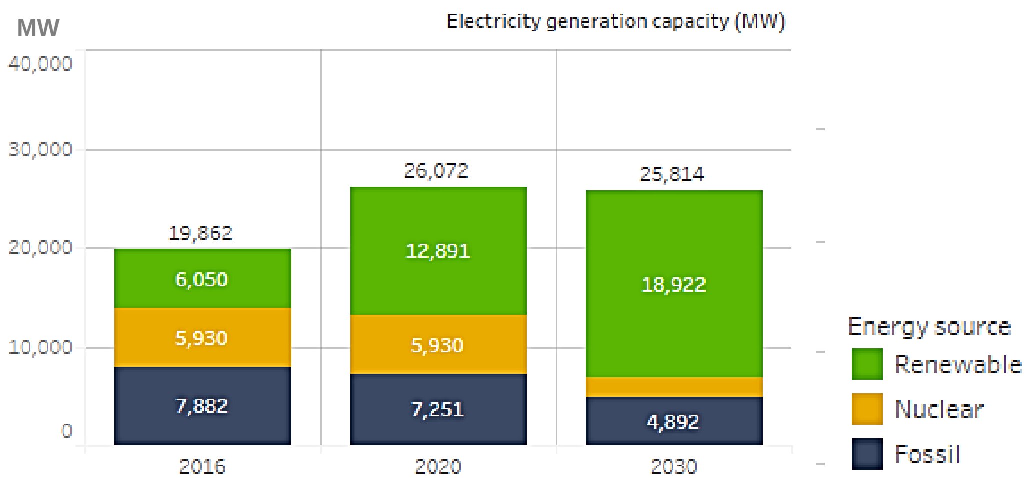

Figure 4-19 - Generation capacity by fuel type, Nuclear Extension Scenario in 2016, 2020, 2030 (MW)

4.3. Comparison of Power and Heat Generating System Costs

Section 4.1.7 presents the overall annual costs for the power and heat generating system in the Central Scenario in the year 2020 and 2030. The chapter also describes in detail which costs component are included in the costs for the years 2020 and 2030.

Figure 4-20 shows a comparison of all scenarios for the year 2030. Comparing the overall cost among the five scenarios several aspects can be observed.

First, the highest and lowest scenario cost are marked by the high and low fuel price scenarios. The assumed price level of natural gas in 2030 heavily impacts the cost of the optimal power and heat generation the TIMES Belgium model calculates. In comparison to the Central Scenario, the aggregated costs for the High Fuel Price Scenario are approximately 4% higher and for the Low Fuel Price Scenario approximately 22% lower. In the high fuel price scenario the model increases the electricity import share to compensate for the high natural gas prices and therefore additional 1,500 M€ for electricity import (labelled ‘Trade Costs’ in the graph) are spent compared to the low fuel cost scenario.

Second, the Nuclear Extension Scenario shows the second lowest power and heat generation cost with 5,571 M€, approximately 10% lower than the Central Scenario. Comparing the cost components of the Nuclear Extension Scenario with the Central Scenario one can observe that almost all cost categories are on similar levels, including annualized investment costs which are mostly attributed to investment in renewable energy sources in both scenarios. The exception being the fuel costs expenditures, which are approximately 575 M€ lower in the Nuclear Extension Scenario.

Third, the cost of the 10% Import Restriction Scenario is only slightly higher than the Central Scenario, but the composition of the cost components shows significant differences. As shown in section 4.2.1 the results of the 10% Import Scenario show the highest natural gas plant capacity of approximately 8,500 MW in 2030 and Figure 4-20 shows that the boundary condition of lower imports is compensated by a high share in natural gas import cost, leading to the highest fuel cost of all scenarios with 2,678 M€.

Lastly, overall one can observe that the cost variations among the scenarios can mainly be found in the costs share for ‘Total fuel cost’, which reflect mainly, but not only, the cost for natural gas, and ‘Trade costs’ which reflects the amount of electricity import. The other cost components, especially investment costs, are resilient to the varying boundary conditions of the scenarios, even investment costs in the Nuclear Extension Scenario are only slightly impacted.

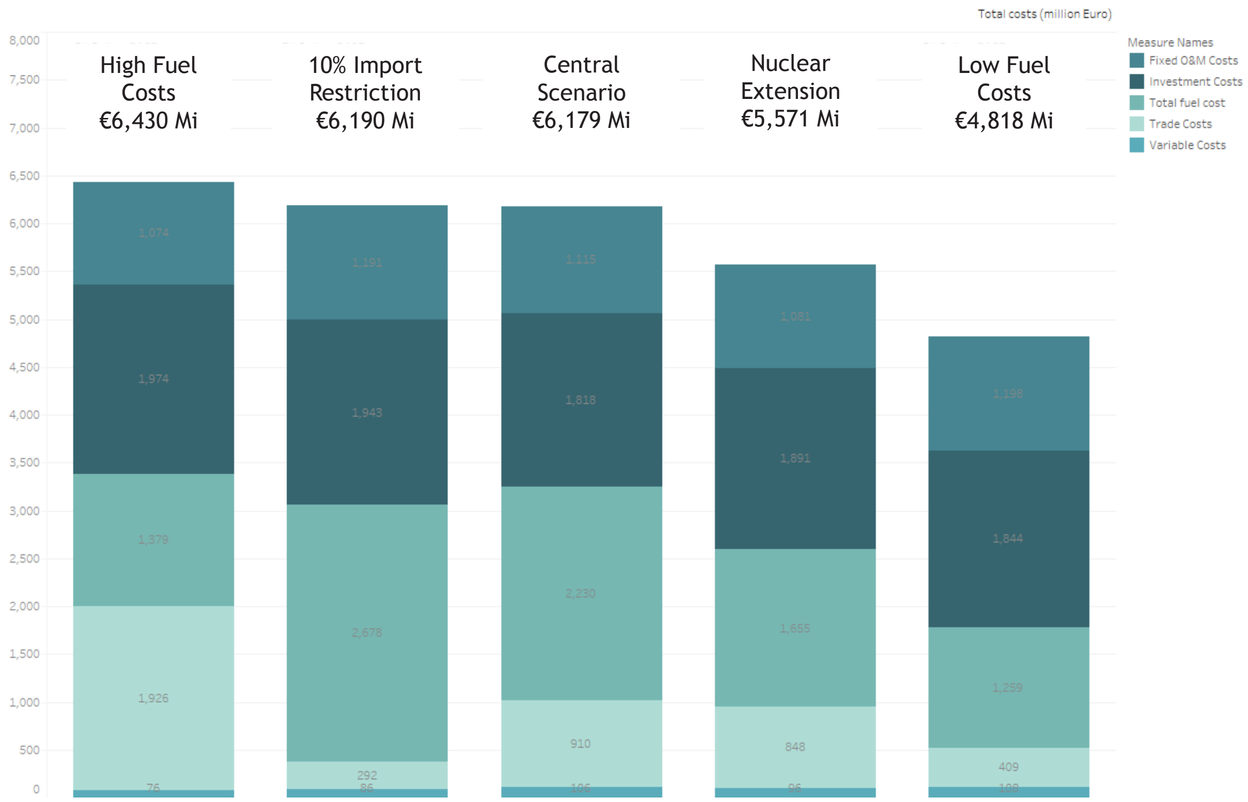

Figure 4-20 - Scenario comparison: annual energy system cost in 2030 (million Euros)

4.4. *Comparative Overview of Key Scenario Results*

Table 4-1 shows an overview of all scenario runs results for the year 2030: power generation capacities, electric energy generated, annual power and heat generation cost in absolute numbers and in comparison to the first reporting year (2016) and CO_2 emissions. In addition the corresponding result values for first reporting year (2016) and under the assumptions of the Central Scenario are provided.

The calculation of the additional annual electricity system costs in 2030 compared to 2016 needs specific attention. The TIMES model, due to its methodological structure, does not account for capex of existing installations, meaning that amortizations of these existing plants are not represented in the system cost for 2016 and subsequent years. This specifically has an impact on the annual system cost for the first reporting year of the model (2016) being underestimated, as no amortizations of existing technologies are accounted for and investments in new technologies have only occurred on a very limited scale in the first two years of the model horizon.

Scenario Power sector	**2016**	**Central**	**10% Import restriction**	**Fuel price high**	**Fuel price low**	**Nuclear extension 2 GW**
Capacities (GW)	19.9	25.8	27.2	27.7	25.3	25.8
RES total	6.1	19.1	18.2	23.5	17.4	18.9
solar PV	3.0	7.9	7.0	12.1	6.2	8.3
wind onshore	1.5	8.6	8.6	8.6	8.6	8.6
wind offshore	0.7	2.2	2.2	2.5	2.2	1.6
nuclear	5.9	0	0	0	0	2.0
fossil	7.9	6.7	9.0	4.1	7.9	4.9
import	3.5	6.5	6.5	7.5	6.5	6.5
Production Belgium (TWh)	78.3	71.0	79.1	55.7	78.0	72.2
RES	11.0	35.8	34.9	40.9	34.2	34.2
nuclear	43.0	0	0	0	0	15.0
fossil	24.3	35.1	44.2	14.8	43.9	23.2
net import	6.3	15.6	6.2	28.4	7.9	14.4
Annual electricity system cost 2030 (billion Euro)	/	6.18	6.19	6.43	4.82	5.57
Additional annual ele. system costs (2030 to 2016, billion Euro)	/	4.49	4.50	4.74	3.13	3.88
CO_2 emissions (Mton)	15.4	19.3	22.5	11.6	22.9	14.7

Table 4-1 – Comparative overview of key scenario results in 2030

5 Conclusions

The objective of this study is to consolidate and report on experts' views on possible energy scenarios for Belgium till 2030 including their implications on energy security and energy system costs. Based on the Belgium TIMES model, a techno-economic cost optimization model, developed and maintained within Vito/EnergyVille, the following conclusion can be drawn from the Central Scenario and the four sensitivity analysis performed in the course of this study.

In 2016 power generation in Belgium is to 55% provided by nuclear power plants while solar PV and onshore and offshore wind account for 14%. By 2030, after the retiring of the nuclear stock, the cost optimization model calculates that the renewable share increases threefold in generation output and in generation capacity.

This means by 2030 electricity generation is provided in an equal share by renewable sources and fossil fuel based installations. Based on the cost minimizing objective of the model the results show that wind onshore capacity grows from 1.5 to 8.6 GW, wind offshore from 0.712 to 2.2 GW and residential and commercial PV solar from 3.0 to 7.9 GW in the Central Scenario. The result is stable across all scenarios with highest variations observed in the predicted growth of solar PV capacity that is far more in the high fuel price scenario. This generation mix results in approximately 14 % share of renewable energy generation in the final energy consumption in Belgium in the year 2030, exceeding the 13% as specified in the boundary conditions of the model. This calculation treats imported electricity neither as renewable nor as non-renewable generation based.

The natural gas based power plants and combined heat and power installations (CHPs) remain stable in capacity above 6 GW in the Central Scenario, while generation output increases from 24.3 TWh to 35.1 TWh by 2030. This goes hand-in-hand with an increase in operating hours and therefore investments in new fossil based power plants and CHPs are, alongside investments in renewable installations, crucial aspects of a successful transition of the Belgian energy system.

In the Belgium TIMES model electricity and heat production needs to meet demand during every time period of the model horizon. With the closure of the nuclear plants and the increasing renewable generation, electricity imports and gas plant based generation play a crucial role in the energy system. The two balance the growing and intermittent renewable generation output. The model utilizes the anticipated increase in net transfer capacity to neighbouring countries from currently 3.5 GW to 6.5 GW. The Central Scenario results show electricity net imports to 15.6 TWh per year in 2030. The four sensitivity scenarios show a high level of variation in the amount of net electricity imports ranging from 6.2 TWh in the 10% import restriction scenario to 28.4 TWh per year in the high fossil fuel price scenario.

The cost of the electricity system in the TIMES Belgium model considers investments in new installations, replacement of retired plants, fixed and variable operation expenses and ETS sector CO_2 emission costs. The latter are taken into account in the cost optimization algorithm, but are not reported in the graphs. The variation among the overall system cost across the scenarios is mainly driven by the assumption of the future natural gas price and electricity trade levels. The level of annualized investment cost in all five scenarios is fairly stable with 1,818 to 1,974 million Euros per year. The largest deviation can be observed in the electricity import costs, ranging from 292 to 1,926 M€ per year and by expenditures for fuels (driven by natural gas), ranging from 1,259 to 2,678 M€. The overall costs for the power and heat generating system ranges from approximately 4,800 to 6,400 M€ per year in 2030, with the Central Scenario marking the median spot at 6,180 million Euros.

The aggregated electricity demand in Belgium till 2030 is relatively stable in the model results. This is based on two compensating trends in the commercial and residential sector: On the one hand the spread of new and more energy efficient technologies and building standards and on the other hand a projected growth in population and end service demands. The sector with the highest growth demand of additional 2,500 GWh by 2030 is the transport sector, which originates from approximately 650,000 to 700,000 electrical cars.

CO_2 emissions as a consequence of technology choices are reported by the Belgium TIMES model, but no fixed boundary conditions for CO_2 targets were set. Costs for emissions in ETS regulated sectors are applied in the model. The CO_2 emissions in the electricity and heat producing sector increases in the model results from 15.4 megatons in 2016 to 19.3 megatons in 2030. The increase can be attributed to the increasing use of natural gas as a power fuel to replace the nuclear electricity generation. Taking into account all sectors a slight overall decline by 4 % between 2016 and 2030 to approximately 88 megatons can be observed. The scenario analysis shows that, the nuclear extension scenario and high fuel price scenario have significantly lower CO_2 emissions based on the fact that under these boundary conditions the utilization of natural gas is substituted by nuclear power or by electricity imports to a large extent, respectively.

The Nuclear Extension Scenario with 2 GW of nuclear capacity from 2025 to 2035 mainly has an impact on the gas powered capacity and power generation compared to the Central scenario. The investments in new renewable capacity remain merely on the same level as in the Central Scenario, reaching a total of 18,9 GW in 2030. In the framework of the Belgium TIMES model the results of the sensitivity analysis show that the energy system costs in 2030 are 10% lower compared to the Central Scenario; 6,179 M€ in the Central Scenario and 5,571 M€ in the Nuclear Extension Scenario. The annualized investment costs are on a similar level with 1,818 M€ in the Central Scenario and 1,891 M€ in the nuclear extension scenario. The main savings can be attributed to fuel costs due to the lower usage of natural gas. While reduced CO_2 emissions in 2030 compared to other scenarios are also an observed benefit in the 2030, investments in new gas capacity (compared to the Central scenario) are in part only delayed. From 2035 onwards, with the complete closure of the nuclear generation, other technologies will have to fill the gap. This should be taken into consideration especially in light of the projected rising demand for electricity post 2030 caused by the rising share of electrical vehicles in the transport sector.

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.

6 References

Devogelaer, D., Duerinck, J., Gusbin, D., Marenne, Y., Nijs, W., Orsini, M., Pairon, M., 2012. Towards 100% renewable energy in Belgium by 2050. Federal Planbureau, Brussels, Belgium.

EC, 2013. The JRC-EU-TIMES model: Assessing the long-term role of the SET Plan Energy technologies. Joint Research Centre - European Comission.

EC, 2014. ETRI 2014 - Energy Technology Reference Indicator projections for 2010-2050. Joint Research Centre - European Comission.

EC, 2016a. EU Reference Scenario 2016 - Energy, transport and GHG emissions - Trends to 2050. European Comission, Luxemburg, p. 220.

EC, 2016b. Eurostat - Your Key to European Statistics, pp. Supply, transformation and consumption of electricity - annual data

EC, 2017. Nearly zero-energy buildings - Energy. European Comission.

ELIA, 2015. AT THE HEART OF THE ENERGY TRANSITION - Annual Report 2015. ELIA, p. 152.

Elia, 2017a. Consumption and grid forecasts - Total Load.

ELIA, 2017b. Generating facilities.

Engie-Electrabel, 2017. Coo: erkende expertise in energieopslag.

Esch, L.V., Meynaerts, E., Vermeiren, K., Uljee, I., Janssen, L., Guisson, R., Engelen, G., Robeyn, H.H.e.N., 2016. Hernieuwbare EnergieAtlas Vlaamse gemeenten. VITO, TerraEnergy, Belgium.

ESTMAP, 2017. Energy Storage Mapping and Planning - Final Report. DG Energy.

FPB, 2014. Het Belgische energiesysteem in 2050: Waar naartoe? Federaal Plabureau, Brussel, Belgium.

Giannakidis, G., Labriet, M., Gallachóir, B.Ó., Tosato, G., 2015. Informing Energy and Climate Policies Using Energy Systems Models: Insights from Scenario Analysis Increasing the Evidence Base.

IEA-ETSAP, 2016. Overview of TIMES Modelling Tool.

IEA, 2015. World Energy Outlook 2015. International Energy Agency, Paris, France.

Infrax, Eandis, Elia, 2012. Onthaalcapaciteit decentrale productie in Vlaanderen 2011-2020, Studie, Belgium, p. 133.

IPCC, 2006. 2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 2 Energy, in: Inventories, I.T.F.o.N.G.G. (Ed.). Intergovernmental Panel on Climate Change.

Poncelet, K., Delarue, E., Six, D., Duerinck, J., D'haeseleer, W., 2016. Impact of the level of temporal and operational detail in energy-system planning models. Applied Energy 162, 631–643.

Roland Berger, 2016. Integrated Fuels and Vehicles Roadmap 2030+. Roland Berger, Germany, p. 138.