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The Different Roles of Energy Storage in Highly Renewable Power Systems

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Voorwoord

Deze tekst vormt het eindpunt van een zeer boeiend, uitdagend en leerrijk academiejaar. Ik heb met veel plezier een jaar lang rond dit onderwerp gewerkt en daarom zou ik graag mijn promotor, prof. dr. ir. Geert Deconinck en mijn begeleider ir. Arne van Stiphout bedanken voor het aanreiken van dit onderwerp, de ondersteuning tijdens het werk en de nuttige feedback tijdens onze ontmoetingen. Verder wil ook Hanspeter Höschle bedanken voor de hulp doorheen het jaar.

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Abstract

The European Union has committed itself to reducing the emission of greenhouse gases (GHG) by 80% towards 2050. The power sector has the biggest potential for cutting the GHG emissions. The substitution of power generation from fossil fuels by renewable energy sources (RES) will make the largest contribution to this reduction. However, the variability and unpredictability of most RES poses serious balancing challenges to the power system and results in an increased need for operational flexibility. At the same, the conventional generation capacity decreases. Thus, other sources of operational flexibility must be searched. The availability of sufficient generation capacity capable of providing operating reserves is no longer evident. This will impact the way generation portfolios are constituted and should be taken into account when making generation capacity expansion planning decisions.

This thesis presents a generation expansion planning model integrating a detailed representation of the operational constraints and reserve requirements. As such, the variable and only partly predictable nature of intermittent RES can be incorporated in a generation expansion planning model formulation. This model is able to calculate the socially optimal solution for the generation portfolio, electrical dispatch and allocation of operating reserves of a power system including various conventional generation technologies, renewable energy sources and energy storage technologies. Elaborate attention is given to the extensions of the model equations which allow incorporating energy storage. Further, a dynamic reserve sizing process, based on the imbalances caused by the forecast errors of intermittent RES, is developed.

The model is applied to a conceptual test system containing a limited set of representative conventional generation technologies, renewable energy sources and energy storage technologies. This conceptual test system was subjected to a large number of scenarios in order to investigate the different roles of energy storage in highly renewable power systems and assess the impact of the operating reserve requirements.

The results show that energy storage will play a crucial role in highly renewable power systems. The energy storage technologies provide two vital services; the provision of operating reserves and temporal energy arbitrage. Both short-term and seasonal storage are part of the optimal generation portfolio for all scenarios considered.

The introduction of the operating reserve requirement has far-reaching consequences for the operation of the power system. However, the impact on the optimal generation portfolio is rather limited.

Samenvatting

De klimaat doelstellingen van de Europese unie beogen een reductie van de uitstoot van broeikasgassen met 80% tegen 2050. Om deze doelstelling te halen, zal het volledige energie systeem van de huidige samenleving aangepast moeten worden. Voor de opwekking van elektrische energie kan de uitstoot van broeikasgassen relatief eenvoudig en goedkoop, in vergelijking met andere sectoren, gereduceerd worden door steenkool en gas centrales te vervangen door hernieuwbare energiebronnen zoals wind turbines en photovoltaïsche cellen. Deze hernieuwbare energiebronnen leveren echter een variabel en slechts gedeeltelijk voorspelbaar vermogen. Het integreren van een hoog aandeel hernieuwbare energie veroorzaakt problemen om het elektriciteitssysteem in balans te houden. Bijgevolg zal de nood aan operationele flexibiliteit in het elektriciteitssysteem toenemen. Het verhogen van het aandeel hernieuwbare energie gaat onmiddellijk samen met een lager beschikbaar vermogen aan de conventionele thermische centrales, die traditioneel de operationele flexibiliteit leverden, waardoor men op zoek moet gaat naar alternatieve bronnen van flexibiliteit. Het beschikbaar zijn van voldoende operationele flexibiliteit is niet langer een evidentie, waar dat voordien meestal wel het geval was. Dit zal op termijn de samenstelling van het productiepark mee bepalen en moet bij de huidige investeringsbeslissingen reeds in rekening genomen worden.

In deze thesis wordt een generation expansion planning model uitgewerkt dat de bovenstaande vereiste in rekening neemt. Daartoe wordt een gedetailleerde beschrijving van de operationele randvoorwaarden van het elektriciteitssysteem, de technische eigenschappen van de opwekkingseenheden en vereisten op de beschikbaarheid van operationele reserves opgenomen in het model. Zodanig is het ontwikkelde generation expansion planning model in staat om de gevolgen van het integreren van hernieuwbare energie bronnen in het energiesysteem correct in te schatten. De bekomen oplossingen bestaan uit de optimale mix aan elektriciteitscentrales, hernieuwbare energie bronnen en opslag eenheden enerzijds en de optimale dispatch van deze centrales alsook de toewijzing van de operationele reserves aan deze centrales anderzijds.

Bij de beschrijving van het model wordt de nadruk gelegd op de vergelijkingen die het modeleren van energieopslag in het elektriciteitssysteem mogelijk maken. Daarnaast wordt er uitvoerig aandacht besteed aan de dynamische methode om de vereiste operationele reserves te bepalen.

Voor het generen van numerieke resultaten is een conceptueel test systeem ontwikkeld waar het model wordt op toegepast. Het test systeem is relatief eenvoudig. Het bevat vier types conventionele elektriciteitscentrales en drie technologieën voor energie opslag. Verder zijn wind energie, zonne-energie en biomassa centrales opgenomen als hernieuwbare energiebronnen. Een groot aantal mogelijke scenario’s wordt onderzocht m.b.v. dit test systeem.

De doelstelling van deze studie is de rol die energie opslag speelt in het energie systeem te identificeren alsook het inschatten van de impact van het introduceren van de vereiste reserve capaciteit op de oplossing bekomen door een generation expansion planning model.
De resultaten tonen aan dat energie opslag een cruciale component is voor hernieuwbare energie systemen. De rol van energie opslag is gecentreerd rond twee cruciale functies, namelijk het leveren van operationele reserves en het balanceren van vraag en aanbod op verschillende tijdsschalen. Zowel korte termijn opslag als seizoensopslag zullen deel uitmaken van de optimale mix aan opslag technologieën voor een hernieuwbaar energiesysteem.
Verder wordt aangetoond dat het effect van het introduceren van de vereiste aan operationele reserve een grote invloed heeft op de werking van de elektriciteitscentrales en energie opslag eenheden maar dat de impact op de optimale investeringen in de elektriciteitssector eerder beperkt zijn.

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Abbreviations

RES	Renewable Energy Sources
TSO	Transmission system operator
BRP	Balance Responsible Party
CCGT	Combined Cycle Gas Turbine
OCGT	Open Cycle Gas Turbine
GFPP	Gas Fired Power Plants
FCR	Frequency containment reserves
FRR	Frequency restoration reserves
aFRR	automatic frequency restoration reserves
mFRR	manual frequency restoration reserves
RR	replacement reserves
p2g	power-to-gas
PHS	Pumped Hydro Storage
GEP	Generation expansion planning
UCM	unit commitment model
FLH	Full Load Hours
CF	Capacity Factor
CHP	Combined Heat and Power
UCTE	Union for the Co-ordination of Transmission of Electricity
ENTSO-E	European network of transmission system operators for electricity
VOLL	Value Of Lost Load
MUT	Minimum up-time
MDT	minimum down-time
LNG	Liquefied Natural Gas
CHG	Compressed Hydrogen Gas
PEM	Polymer Electrolyte Membrane
SOE	Solid Oxide Electrolyte

Chapter 1: Introduction

1.1 Context

The European Union energy policy pursues sustainable, safe and affordable energy provision for all citizens [1]. The EU climate targets play a crucial role in the energy policy and will induce a transformation of the energy system in the following decades. The climate objectives towards 2050 aim at reducing the greenhouse gas emissions by at least 80% compared to the level of 1990, in accordance with the promise to limit the average global temperature rise to 2°C. The implementation of these climate objectives and the implications for the industry and power sector are worked out in the Energy roadmap 2050 [2]. In general, the objectives strive to reduce the greenhouse gas emissions, reduce the energy intensity and increase the share of renewable energy. The last objective also aspires other strategic and social benefits, namely lowering the import dependency of Europe, raising the gross domestic product and stabilizing the energy prices. However, the large-scale introduction of intermittent renewable energy sources (RES) will result in an increased need for operational flexibility in the power system.

At present, the problems occurring due to the introduction of intermittent RES are limited to certain, often weakly interconnected, areas and do not occur frequently. The situation might change quickly given the rapid expansion of wind and PV capacity. The integration of intermittent RES requires the power system to hold enough operational flexibility to balance the electricity supply and demand. Especially the limited predictability and controllability of the output power, the output variations and the large distance between the intermittent RES and the load centers causes more complex temporal and spatial balancing. Various sources of operational flexibility and advanced operational techniques to manage these sources of flexibility will be indispensable to overcome these challenges.

The different sources of operational flexibility the system operator possesses are summarized in Fig. 1. Some of these sources are a direct responsibility of the system operator, others are available through contracts with balance responsible parties (BRPs). The operational flexibility provided by the BRPs is part of the ancillary services and is divided in different classes of operating reserves depending on the activation time. On the other hand, the BRPs will also address their own sources of flexibility in order to balance their portfolios in the first place. In short, the sources of flexibility listed in Fig. 1 exceed the (current) functioning of the operating reserve markets.

This work will specifically focus on the operating reserves in the power system. Other aspect of operational flexibility, e.g. demand side involvement and transmission measures are not considered. The tools of flexibility employed to provide operating reserves are displayed in grey in Fig. 1. Residential demand response and time varying available storage such as grid-connected electric vehicles could be able to provide operating reserves. However, it is not possible in the current network system and regulatory framework. The implementation of smart grids is expected to access the potential of these sources of flexibility.

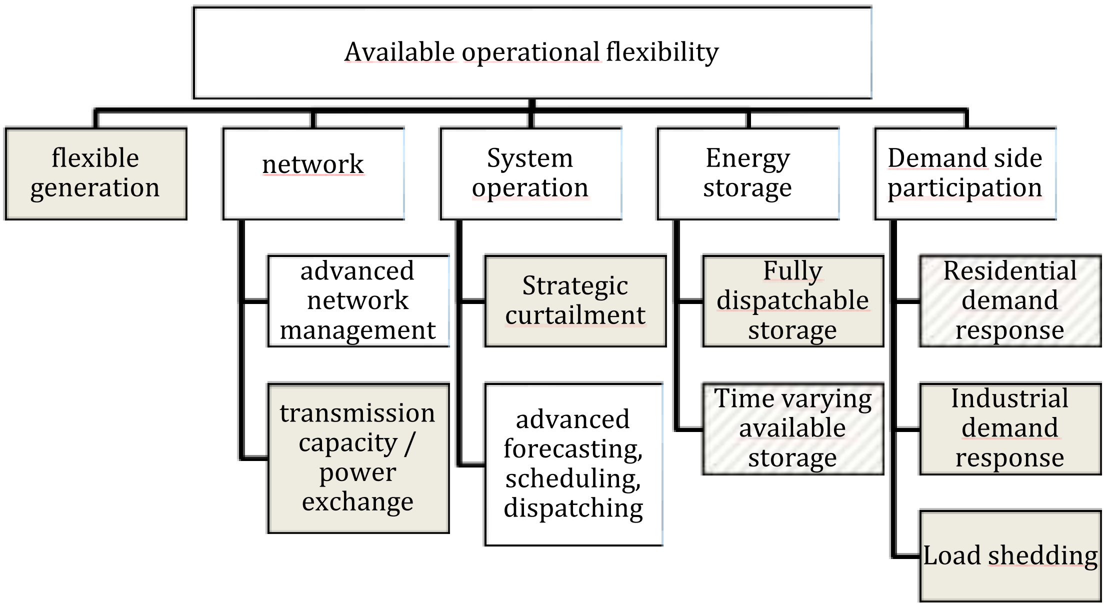

Fig. 1: Sources of operational flexibility in power systems (based on [3])

Currently, the vast majority of the operating reserves is provided by conventional flexible generation and transmission capacity. Industrial demand response, contractual load shedding and fully dispatchable energy storage, e.g. pumped hydro storage (PHS) supplement the conventional generation nowadays. As the share of conventional generation technologies in electricity generation will decline due to the renewable energy targets and the need for operational flexibility will increase, these alternative sources of operational flexibility will only grow in importance. This thesis will focus on one of these alternative sources of operational flexibility, energy storage.

1.2 Problem statement

The previous section briefly demonstrated that operational flexibility covers a lot of topics and touches almost every aspect of the power system. In this section, the problem statement is specified more clearly in order to develop some specific research questions.

This thesis will develop a model to investigate the role of energy storage in the future energy and reserve markets for an increasing target on the share of renewable energy in the total electricity demand. The flexibility provided by conventional power plants, strategic curtailment and load shedding is also incorporated in the model.

The model does not consider demand side response nor power exchange. Of course, this involves a strong simplification of the power system and will consequently overemphasize the role of energy storage as a source of flexibility. This simplification will most probably affect the numerical results for the installed capacity of energy storage, flexible generation, etc. In any case, the exact numerical results of this model are of secondary importance. This work does not seek to propose an optimal generation portfolio or roadmap for the development of the power sector. Instead, this work attempts to discern the qualitative trends and distinguish the different roles of energy storage in renewable power systems. Therefore, the above-mentioned simplification is acceptable.

The model considers short-term balancing as well as seasonal balancing of supply and demand. The dynamic model simulating a time period of one year is particularly well-suited to assess the value of seasonal storage, as will be explained later on. Power-to-gas technology will represent seasonal storage in this work. The interactions of power-to-gas with the current gas infrastructure and strategic underground storage reservoirs are investigated.

These topics are evaluated in the framework of a generation expansion planning model, which determines the economically optimal capacity investments and operation of the power system from a public point of view. As such, the impact of introducing energy storage on the generation portfolio can be assessed. The influence of the operating reserve requirements on the optimal generation portfolio is also considered.

1.3 Aim of this thesis

The following research question is regarded central throughout this thesis:

What are the different roles of energy storage in the energy market, operating reserve market and generation expansion planning decisions for various scenarios of highly renewable power systems?

The research question is still quite broad and in order to give a comprehensive answer, some sub-questions are specified which outline the general aims of this thesis:

- How do storage technologies accommodate the integration of intermittent RES
- What is the minimum renewable energy target to make the introduction of energy storage cost-effective
- What is the influence of energy storage on the generation portfolio and the system costs (operational and investment costs)
- What is the role of flexible thermal power plants and base-load thermal plants towards 2050
- What is the effect of an increasing renewable energy target on the total energy surplus and curtailment
- Which technologies provide the required operating reserve power in the presence of energy storage
- How should the state-of charge of the energy reservoirs be managed
- What is the role of the underground gas storage reservoir and the line-pack flexibility of the gas network
- What is the impact of introducing biomass for power generation on all these questions
- How sensitive are the results on the input data

1.4 Main Contributions

The main contribution of the presented model consists of the introduction of operating reserve requirements and detailed operational constraints in a generation expansion planning model formulation. Thus, the effect of integrating intermittent RES capacity can be incorporated correctly in a GEP model.
This work will particularly focus on the extensions to this GEP model formulation required to incorporate energy storage in the generation portfolio, and the implementation of a dynamic reserves sizing process, based on the Network Code of the European network for transmission system operators for electricity (ENTSO-E). These two measures aim at facilitating the integration of intermittent RES. In fact, Previous research on this GEP model demonstrated that a power system which does only incorporate the flexibility of conventional generation technologies and uses a static reserves sizing process is just not capable of integrating a large share of renewable energy [4]. The perceived limit on the maximum achievable share of renewable energy was a direct consequence of the introduction of the operational constraints.
The results show the extensions to the GEP model solve the issue and now even 100% renewable energy targets become attainable while still obeying the operating reserve constraints. The extended model will be applied to a conceptual test system.

The analysis of the obtained results will concentrate on the role of energy storage and the allocation of operating reserves.
In conclusion, the model develops a generation portfolio capable of dealing with the variability and unpredictability of the intermittent RES and introduces energy storage as an alternative to conventional generation technologies to provide the required operational reserves.

1.5 Structure of the text

Chapter two will present a concise literature review. First, an overview of power system simulation models which investigate the integration of RES is presented, followed by a short technology review of power-to-gas which was needed to build the conceptual model of these storage plants for this work.
Chapter three works out the model formulation. This chapter will deal with objective function, system constraint, technological constraints and operating reserve constraints.
Chapter four introduces the conceptual test system that will be used to generate all numerical results. Technological and economic input data, as well as input data about characteristics of the power system are given.
Chapter five discusses the results. The first part of the results will consider the generation portfolio and system cost as a function of the renewable energy target. The following part will focus on the operation of fully renewable power systems. Finally, a sensitivity analysis is performed.
Chapter six recapitulates the most important conclusions and offers opportunities for future research.

Chapter 2: Literature Review

2.1 Introduction

This chapter presents a summary of the knowledge and insight acquired from the literature review as part of this thesis. First, an overview of the current trends in the field of power system modeling is given. The focus lies on power system models assessing the role of energy storage in renewable power systems. These power system models can be roughly divided into two categories; short-term power system models (typically unit commitment models) and long-term power system models (Generation expansion planning models). The characteristics of both categories are summarized and subsequently compared with the characteristic of the model presented in this work. Thereby, it is demonstrated that the model is filling a gap in the existing research on power system models. Afterwards, some often-mentioned results and conclusions concerning the role of energy storage in power systems encountered in the literature are given. Finally, an introduction to the power-to-gas technology (p2g) is presented. The optimal configuration of a p2g storage plant for the purpose of this work is selected and the choice for this configuration is justified.

2.2 Types of power system models

Many countries have committed themselves to an ambitious reduction of the greenhouse gas emissions. The substitution of electricity generation from fossil fuels by RES can deliver a large contribution to these goals. The resultant challenges for the power sector have motivated academic researchers to investigate the impact of a high share of RES on the power system. Consequently, numerous articles concerning power system models have been published over the last 10 years. Besides, several commercial power system simulation software packages have been released, e.g. PLEXOS, energyPLAN, TIMES. The power system simulation models can generally be categorized as long-term generation and transmission expansion planning models and short-term operational simulations. Market analysis models make up a smaller third category. The commercial software packages mostly offer the functionalities of more than one category of models. There also exist alternative types of power simulation models. Some of them are presented in the last paragraph of this section.

2.2.1 Short-term power system models

The short-term power system models focus on the operational aspects of the power system. The literature study of short-term models is restricted to unit commitment models (UCM). Other types of short-term models, such as optimal power flow models, do not explicitly focus on electricity generation and provision of operating reserves and do not deliver a relevant contribution to the literature research of this thesis.

The unit commitment models perform an economic dispatch of the generation capacity and look at which generators are turned on or *committed*. Furthermore they integrate a detailed description of the power plants' technological constraints and mostly include the operating reserve needs. The results of UCM comprise of the optimal scheduling and dispatch of power plants and the allocation of operating reserves. These results give an accurate picture of the operational challenges of integrating RES and present a good estimation of the operational costs. The high temporal resolution and extended set of operational constraints make UCM expensive to solve. Simulating long time periods is problematic and the time horizon is generally limited to a few days. It is possible, though, to simulate an entire year using techniques implementing a rolling time horizon [5]. This is particularly useful to investigate the role of seasonal storage with UCM. However, the seasonal storage units have to be implemented with care since the model will have the tendency to withdraw all energy from the storage units in every time interval. Therefore a (monetary) value has to be assigned to the energy in the storage units which is calculated via a reduced long-term model [5]. The value-of-energy approach is also at hand in most UCM software packages like PLEXOS and powrsym3. The studies of Foley & Lobera [6] and Ummels et al. [7] apply this approach to examine the short-term operation of seasonal storage. Due to the before mentioned modeling difficulties, seasonal storage is frequently neglected in short-term models, even when energy storage is the main focus of the study. The study of de Boer et al. (2014) for example compares the economic value of pumped hydro storage, compressed air energy storage and power-to-gas storage without considering seasonal storage. All storage units are controlled in order to minimize the operational costs considering a time window of 12 hours [8].

The UCM are not capable of determining the optimal capacity of generation and storage units endogenously. The generation portfolio is crucial input data for every UCM and can influence the result significantly. Generally, researchers either simulate several possible scenarios [9], [10] or implement a generation portfolio obtained from another study. Jentsch et al. (2014) for instance use the generation portfolio of the 85% renewable energy scenario provided by the German ministry of environment. A simplified determination of the optimal capacity of storage units is possible by means of a cost-benefit analysis on the results obtained from several scenarios [11].

The economic value of storage units, specifically p2g units, is often underestimated by UCM since they only consider the reduction of operational costs and the provision of ancillary services. Further, the occurrence of negative prices on the electricity market due to imperfect operation of the market is usually not possible in UCM. Nevertheless, the occurrence of negative electricity prices is determining for the economic value of storage units [12]. In addition, p2g units provide some economic benefits at system level which are not included in UCM like the deferral of investments in transmission capacity and peak load generation units. The study of Jentsch et al. mitigates these shortcomings by including the substitution of electrical transmission capacity with natural gas transmission capacity.

2.2.2 Long-term power system models

Long-term power system models, usually generation expansion planning (GEP) models, determine the optimal generation capacity investments and in some cases also the optimal network asset investments. GEP models consider the investment and decommissioning costs of power plants and network assets as well as the operational costs. In contrast to the UCM, GEP models only consider a very simplified formulation of the operational constraints. Technological constraints are omitted and the operating reserve requirements are neglected or calculated after the generation portfolio optimization.

The determination of the operational costs is founded on a reduced economic dispatch formulation. Typically, the minimization of the investments costs and operational costs is included in GEP models through the screening curve method (or a numerical derivative of this method [13]). These screening curves represent the total cost of electricity generation per technology as a function of the number of operating hours and include investment cost, variable operating & maintenance costs and fuel costs. The intersections of these curves indicate the minimum number of operating hours where higher investments cost outweigh the higher variable costs and fuel costs. Projecting these intersections on the residual load duration curve lead to the solution for the optimal capacity investments. The graphical solution for the optimal capacities investment using screening curves is pictured in Fig. 2 for a conceptual power system with three generation technologies [14].

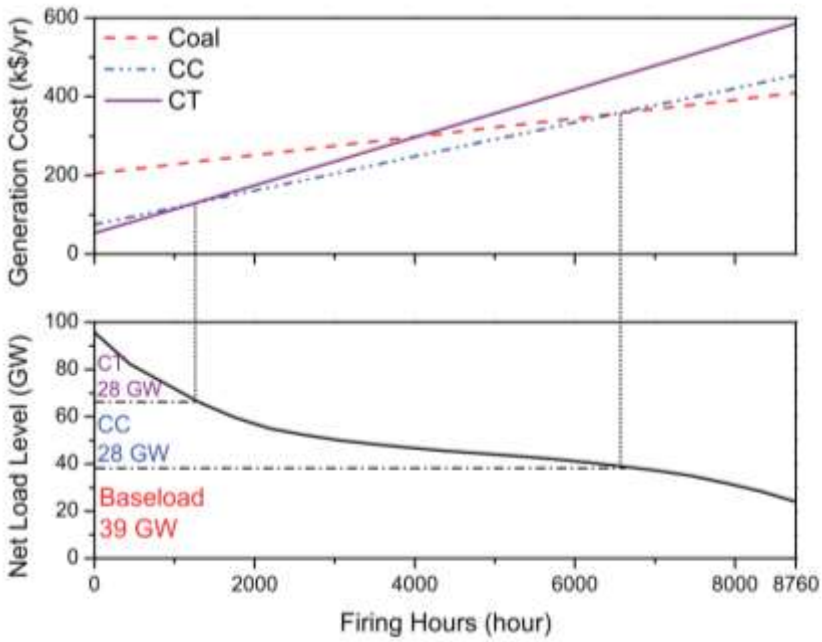

Fig. 2: Graphical solution of the capacity investment problem using screening curves

Applying the screening curve method implies some major simplifications with regard to the operational aspects in comparison to UCM. All ramping costs, start-up costs, etc. are not taken into account. Furthermore, the chronological information about demand and generation profiles is disregarded altogether. Therefore, the screening curve method is also called the integral method [15]. This method has already been applied to examine the impact of a high share of intermittent RES [16] and to investigate the role of energy storage in a renewable energy system [17] [18].

Probabilistic production simulations are a variant of the integral method which take the unexpected loss of load and generation capacity outages into account. The basis of this method is the construction of the equivalent load curves, see [19].

Alternative methods to determine the operational costs in GEP models do exist. Haller & Bauer for instance present a model integrating two time scales. A long-term time scale is used to determine the investment costs and a short-term time scale to determine the operational costs [20]. The short-term time scale consists of a few time slices representing some distinctive situation in electricity demand and RES generation. As such, these time slices represent various characteristic combinations of supply and demand, but do not considered the short-term fluctuations of demand and renewable generation as captured by a sequential dataset. An economic dispatch method is applied to these time slice and results in a representative value for the operational costs. This method must be seen as a compromise between a correct representation of short-term variability and computation time. Haydt et al. classify this method as semi-dynamic [15]. Such semi-dynamic methods can also be implemented in software packages like TIMES. These software packages can calculate the economic dispatch of capacities for power generation, transmission and heat production. This is demonstrated in the study of Fehrenbach et al. [21].

Next to the models integrating the short-term and long-term time scale in a single intertemporal model, the two time scales can be implemented in different models of which the results are soft-coupled. A long-term investment model calculates the optimal capacity investments and a short-term UCM model determines the operational costs, starting from the generation portfolio provided by the long-term model. The investment model can subsequently take these operational costs into account and recalculate the optimal generation portfolio. Through iterative feedback, the generation portfolio convergences to a solution minimizing the total system costs. Rosen et al. (2007) apply soft-coupling to analyze the effects of large-scale wind production. The capacities calculated using PEREUS are coupled to the short-term power plant dispatch simulation model AEOLIUS [22].

Palmintier & Webster (2011) integrate the mathematical formulation of generation expansion planning models and unit commitment models, evaluated using a single time scale with hourly temporal resolution. To reduce the calculation time, they developed a group integer unit commitment approach [13]. This means individual power plants are grouped into categories with similar characteristics. Nevertheless the number of categories was restricted to four technologies, this model remains very expensive to solve [13].

2.2.3 Other power system models

Apart from the GEP models and UCM, there exist some alternative methods to investigate the power system. This review is restricted to models specifically investigating the role of energy storage. In addition to the numerical power system simulation models, the required storage capacity and the value of energy storage can also be determined via an analytical model. Two examples of such approaches can be found in [23], [24]. A last category of (numerical) power system models, market analysis models, are also applied to investigate the role of energy storage. These models do not consider the socially optimal investments or operation of the power system. Instead of minimizing the total system or operational costs, these models try to maximize the operational profit of the generation companies. In other words, the viewpoint of the operator investing in storage units is central is in this approach. These models consider the economic profitability of a storage plant for a given generation portfolio and market conditions. The results can provide an estimation of the economic potential of storage technologies. In a liberalized competitive energy market, the economic potential of a technology will better capture the investment decisions of competitive operators. A market analysis model auditing the economic viability of power-to-gas is developed by Kroniger&Madlener [25] and Baumann et al. [26]. In general, market analysis models are quite inflexible and very dependent on input data like generation portfolio, demand profile, RES generation profile, market prices, etc.

2.3 The position of this work in the literature

The literature review reveals most GEP models only consider a simplified version of the economic dispatch. Technological constraints and reserve capacity requirements are often omitted. Instead, this work presents a model that does include a detailed representation of these operational constraints in a GEP formulation. Further, this model is a dynamic power system simulation model, i.e. it adopts full chronological data using a single time scale. A time period of one year with an hourly resolution is used for all input data. The transition to a dynamic model is an improvement compared to the existing GEP models when investigating energy systems with a very high share of intermittent RES. Indeed, the majority of the GEP models are founded on a numerical derivation of the screening curve method. Even GEP models implemented in extended software packages like MARKAL/TIMES rely in essence on load duration curves [13]. Consequently, all information about the dynamic operation of the power system is lost. These models founded on non-sequential data cannot incorporate an (exact) determination of the operational reserves. This simplification does not have a large impact on the solution when the overall flexibility of the generation portfolio is sufficient to handle the variability of the residual demand, defined as the difference between demand of electrical energy and the must-run generation like the feed-in of RES [26]. This condition was fulfilled for traditional power systems [13]. However, the introduction of intermittent RES largely aggravated the variability of residual demand and reduced the availability of flexible thermal plants. Hence, this simplification will no longer lead to realistic results for highly renewable power systems and the GEP model will present generation portfolios which are no longer capable to deal with the short-term fluctuation of RES. This conclusion was supported by investigating the short-term operation of the solutions for the generation portfolio proposed by standard GEP models with UCM. Misjudging the required operational flexibility because of neglecting the system dynamics will result in overestimation of the uptake of renewable energy, an underestimation of the operational costs and suboptimal investment in generation capacity [13] [27] [28].

Just one other work presenting a dynamic generation expansion planning model was encountered in the literature, the aforementioned paper of Palmintier & Webster. In comparison to the model of Palmintier & Webster, this model includes a more detailed description of the ramping constraints, sizing of the operating reserves and allocation of the operating reserves. Besides, more categories of generation technologies are included. Most importantly, the model of Palmintier & Webster does not include storage technologies and only considers renewable energy targets up to 20% share of total demand. The accurate description of operational constraints, stringent system constraints and introduction of energy storage while keeping the computation time of the model acceptable is possible thanks to the transition from a mixed integer to a linear problem.

In summary, the shift to a dynamic generation expansion planning model, integration of detailed representation of the operating reserve requirements and the introduction of storage technologies make the presented model innovative and particularly well-suited to study renewable energy systems. The model is applied in the context of the European climate policy and extents the time horizon towards 2050. Therefore, even 100% renewable energy systems are considered.

2.4 Qualitative conclusions regarding the role of energy storage

This paragraph presents some generally accepted conclusions concerning the role and value of energy storage in renewable power systems. These conclusions will not be linked to specific categories of models or studies. The overview should only serve as a benchmark to evaluate the results of this work.

Several studies have shown that a reasonably high share of intermittent RES is required to make large-scale energy storage cost-effective for the power system and economically viable for the operator. Low round-trip efficiency storage technologies like p2g could even require a minimum share of intermittent energy sources in order to reduce the operational costs [10]. High efficiency storage technologies always lower the operational costs, even in non-renewable power systems, via the reduction of ramping costs and start-ups costs. This results in a greater share of base load plants and increased number of full load hours of base load plants [8]. Generally, this implies that the overall investment costs increase. In energy system without renewable energy targets, the greenhouse gas emissions increase when introducing storage as a consequence of the shift from gas fired power plants to coal fired power plants and the energy losses in storage units [8].

To improve the business case of storage technologies, the investment cost should decrease and the utilization increase. However, the storage unit operators must maintain a balance between high utilization and flexible operation. The future prices on the reserve market will be a decisive parameter for this balance. The potential benefit from providing operating reserves is also strongly dependent on the future technical requirements of the system regulators. For example, the current regulatory framework does not allow p2g technologies to provide primary reserves despite that it is technically possible.

Market analysis revealed power-to-gas units are not profitable in the current energy system [25] and this situation won't change in the near future [26]. Furthermore, p2g isn't cost-effective from a public perspective in the medium run [29]. This is mainly attributed to the availability of much cheaper option to provide operational flexibility. Power-to-heat application, e.g. district heating units with large thermal storage tanks, is one of those cheaper options that limit the need for storage [18]. To clarify, the Danish energy system, having a large share of central CHP units, does not present a lot of potential for seasonal energy storage [30]. On the other hand, a limited interconnection capacity could seriously boost the potential for seasonal energy storage. Investing in transmission capacity is however cheaper than investing in storage capacity [20]. One of the major problems for the business case of p2g is to find a way to monetize the social benefits it provides. In conclusion, the main challenges for p2g are economical challenges instead of technological challenges. The

business case of short-term energy storage providing peak shaving and load levelling is commonly positive.
Solutions for the optimal dispatch of renewable power systems unequivocally show curtailment of wind and PV energy will play an important role [18]. Minimization of the total system cost gives rise to a balance of the uptake of the surplus energy with capital intensive storage technologies and the curtailment of the available and free surplus energy [31].
The majority of the studies investigate power systems with renewable energy share of 20-40%. Under these circumstances, the operation of the storage units is generally driven by the demand profile and especially the day and night variation in demand [6] [7].

2.5 Power-to-gas, a technology review

Integrating a large capacity of intermittent RES in the power system poses balancing challenges due to the variable and only partly predictable nature of these intermittent RES [32]. Investigation of the residual demand profiles, indicates that the operational flexibility of the power system will have to cope with imbalances at different time-scales, from intra-hour to seasonal level [32]. The least expensive options for operational flexibility should be deployed first, e.g. flexible demand, curtailment and power-to-heat. Highly renewable power systems will also require a significant seasonal energy storage capacity [31]. In addition, energy storage is advantageous from the viewpoint of primary efficiency since it can integrate the energy surpluses which would be curtailed otherwise. Currently, power-to-gas shows the best prospects to provide seasonal energy storage. Other energy storage technologies like CAES and PHS cannot support the large need for energy capacity in renewable energy systems [12]. Therefore, power-to-gas will be implemented in the conceptual test system presented in chapter 4 of this text as the only seasonal storage technology. Since p2g is still in demonstration phase, reliable data about the technical and economic parameters is hard to find. A standardized or generally accepted design of a p2g plants doesn't exist either. In fact, the term p2g covers a whole range of technologies which are currently in research or demonstration phase. This part of the literature review will give a concise overview of the existing technologies and legitimize the choice of technology on which the input data will be based. This knowledge is necessary to construct the conceptual model of the seasonal storage plants. The corresponding technical and economic parameters found in the literature are presented in section 4.3.

2.5.1 Power-to-gas concept

First of all, this review of p2g technologies is restricted to designs which can support re-electrification of the stored energy. Since the model only considers the power sector, other options would not be relevant for this study. In other words, p2g plants

offering hydrogen, synthetic fuels or other chemicals to the market for industrial or commercial use are not considered.
Furthermore, the transmission and distribution of hydrogen and subsequent re-electrification is not allowed in this study. There exist two possible ways for transmission of hydrogen; a dedicated transmission network and injection of hydrogen gas in the natural gas network. Both are disregarded in this study because the former proves to be technically difficult and imply major investment cost [33], the latter is just not capable of providing the desired seasonal storage capacity. This follows from the restriction on the admissible molar fraction of hydrogen in the gas network. The technically allowable limit varies between 7-10 mol% [34], [35], [36] which will seriously impede the transportation and storage of hydrogen in power system with a large capacity of power-to-gas.
Considering the above mentioned limitation, only two possible p2g design remain; power-to-gas including methanation, subsequent injection in the gas network and re-electrification through GFPP (power-to-methane) and power-to-gas with local storage of hydrogen gas and local re-electrification. In this study, the base-case scenario will only include power-to-methane because of following reasons: (1) power-to-methane can make use of the existing gas network, underground seasonal storage and GFPPs (2) natural gas is largely integrated in the current energy system, limiting the cost and time needed for technology conversion and facilitating the public acceptance (3) The use of the gas transmission network can substitute large investments in the electricity transmission network (4) methanation is a well-known process [37], pilot plants have demonstrated prolonged reliable operation of the methanation unit [34] (5) The re-electrification technologies for hydrogen are not reliable (e.g. PEMFC) or are still in research phase (e.g. Oxy-hydrogen steam turbines and regenerative solid oxide fuel cells) (6) the local storage of hydrogen is technically difficult, implies significant energy losses and is expensive [38].
In conclusion, local storage and re-electrification of hydrogen is not included in the base-case scenarios because it is uncertain large-scale and reliable conversion technologies will be commercially available. Nevertheless, these conversion technologies show the potential to build power-to-gas plants which can attain round-trip efficiency greatly surpassing the round-trip efficiency of power-to-methane. To be precise, power-to-gas plants using PEMFC or oxy-hydrogen steam turbines could achieve roundtrip efficiencies up to 50% [39], [40]. Regenerative oxide fuel cells show the potential to increase the round-trip efficiency even further [41] and simultaneously reduce the investment costs [42]. Round-trip efficiencies of 70% would be achievable [43]. Whether this inherent advantage over power-to-methane is enough to outweigh the increased investment cost and the need for dedicated storage facilities is assessed in the sensitivity study of this work (see paragraph 5.3.4).

2.5.2 Electrolysis technology

The electrolysis of water is at the core of all power-to-gas technologies. The chemical reaction is well understood and described (for example [37], [44], [45]). Currently,

there exist three main technologies for water electrolysis; alkaline electrolysis, polymer electrolyte membrane (PEM) electrolysis and solid oxide electrolyte (SOE) electrolysis.
Alkaline electrolysis is the most mature technology. Several projects have already demonstrated the operation of these electrolysis cells in experimental power-to-gas facility [46] [47] [48]. Efficiencies of these electrolysis cells range from 62% to 82% [49]. A cold start requires 10 minutes, consequently these electrolysis cells can provide automatic FRR. However, alkaline electrolysis cells cannot handle rapid fluctuation of the input power [40], show low part-load efficiency and poor reliability when operated dynamically [50].
PEM electrolysis responds to the short-comings of alkaline electrolysis, allowing reliable dynamic operation, efficient part-load operation and supporting ramping rates of 10-100% of the nominal power per second [51]. PEM electrolysis cell have also been demonstrated to operate in pilot projects [34]. The biggest technological challenge consists of scaling up the electrolysis cell nominal power towards the MW range [34]. The efficiency of PEM electrolysis cells is generally a few percentage points higher than the efficiency of alkaline electrolysis [37].
The third technology, SOE electrolysis is in development phase and will still require technological breakthroughs to become applicable for commercial use. The majority of the challenges are coupled to the very high working temperature of 600-1000°C [52] in comparison to the other two technologies (50-80°C [45]). These elevated temperatures improve the reaction kinetics and the thermodynamics of the reaction, thereby removing the need for expensive catalyst and increasing the efficiency of the electrolysis cell to 90% and more [37].
Regarding the investment cost, both alkaline and PEM electrolysis cells are expected to be available at a cost of 250 €/kW_e towards 2050 [53]. Reliable estimations of the investment cost of SOE are not yet possible, although the investment cost will be substantially higher than for the other two technologies anyhow.
In the light of the above-mentioned characteristics, PEM electrolysis is chosen as the most promising technology towards 2050. Especially the improved dynamic operation will be of utmost importance for integration in highly renewable power systems. This choice is supported by several researchers (for instance [54], [55])

2.5.3 Methanation technology

The second main step of the power-to-methane process is the methanation, converting hydrogen gas and a source of carbon (generally CO_2) to synthetic methane. Two main routes for methanation are currently under investigation. The first route is chemical methanation, a process known from petrochemical industry. The basis of this process is the Sabatier reaction, converting CO and H_2 to synthetic methane and water. In combination with a water-gas-shift-reaction the total reaction equation reads:

$$\mathrm{CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O}$$

This reaction is highly exothermic and takes place in large and high temperature fixed bed, fluidized bed or bubble column chemical reactors [37]. These reactor show poor dynamic operation and long start-up times. Efficiencies range from 75% to 85% [56]. The second route promotes biological methanation. This process is also well-known since it constitutes the last step of a standard biogas plant. The conversion of CO_2 and H_2 via micro-organism in a bioreactor prospers best at temperature of 35-70°C [57]. Consequently, fast start-up is possible. In addition, manufacturers claim that biological methanation reactors support dynamic operation and fast ramping rates [58]. On the other hand, biological methanation is not yet demonstrated at large industrial scale. Moreover, data about investment cost and operational cost is currently very scares. Therefore the input data for this work will be founded on chemical methanation. The drawback of the poor dynamic operation of chemical methanation can be solved by installing a (small) intermediate storage reservoir for hydrogen gas. The corresponding additional investment costs are included in the input data.

2.6 Summary

A lot of research investigating the role of energy storage in the power system has already been performed. Long term generation expansion planning models, short term operational models and some alternative models have been applied to simulate power systems and specifically examine the operation, value and/or optimal capacity of energy storage. All these types of power system models have their advantages and shortcomings. All existing models either put the emphasis on finding the optimal capacity investments or the optimal operation of energy storage. The purpose of this work is to develop a model that combines these two objectives and presents an optimal generation portfolio capable of dealing with all operational challenges coupled to the integration of intermittent RES.

The characteristics of the model, being a GEP model integrating detailed description of the operational constraints, a dynamic balance method [15] simulating a time period of one year with an hourly resolution and the availability of short term and seasonal energy storage give it a unique position among the existing power system models. Furthermore, this model considers very stringent renewable energy targets and even 100% renewable power systems. Such targets are still rare in the literature on power system simulations.

A review of the current progress in the field of the power-to-gas technology brought insight about the operation of p2g plants and helped in constructing the operational constraints of p2g implemented in this model. The literature review revealed power-to-methane is the most promising p2g concept. Moreover, power-to-methane corresponds best to the expectation of seasonal energy storage. The technical and economical input data is based on the predicted characteristics of large-scale industrial p2g plants with a PEM electrolysis cell and a chemical methanation unit.

Chapter 3: Model Description

3.1 Introduction

This work presents a generation expansion planning model which integrates a detailed representation of the operational constraints. It is an optimization model minimizing the total system cost as seen by a single centralized operator. The total system cost consists of investment costs (represented by an annuity cost and fixed operating & maintenance costs), operational costs related to the commitment, dispatch, start-up, shut-down and ramping of power generation units (being fuel cost, variable operating and maintenance cost, start-up cost, etc.) and the operational costs of energy storage units.

The operational constraints integrated in this GEP model comprise of an accurate description of the technological constraints (ramping constraints, minimum up-time, minimum downtime, etc.) and detailed system constraints (operating reserve requirements, balancing of the gas supply, etc.) via a linear, technology-clustered formulation of the unit commitment problem. The operating reserves are sized probabilistically and dynamically following the Network Code on Load Frequency Control and Reserves of the European Network of Transmission System Operators for electricity (ENTSO-E). The reserve power capacity needed to deal with imbalances caused by forecast errors is determined endogenously, based on the actual generation forecasts of intermittent RES. The reserve power needed to deal with other imbalance drivers is determined exogenously, as the result of a probabilistic analysis of historic imbalances. This is translated into specific requirements for the different reserve products determined by ENTSO-E. These reserves can be provided by conventional thermal power plants, storage plants as well as RES in the case of downward reserves.

3.2 Purpose of the model

The model must be seen as an expansion of the GEP model described in [4]. This paper investigates the consequences of introducing detailed operational constraints and reserve capacity requirements in a GEP model on the optimal generation portfolio in highly renewable power systems. The major deficiency of the

aforementioned paper is the minimal set of sources of operational flexibility. Only conventional generation plants are available to provide reserve capacity. The results of this original model show that the impact of such reserve requirements is very significant at higher shares of intermittent RES if the supply of reserves is limited to conventional dispatchable generation. Therefore, additional sources of flexibility are indispensable to operate a power system with a high share of intermittent RES.
This study will examine how the introduction of energy storage and the active participation of renewable energy sources in the reserve market can support the integration of RES in the power system. The role of interconnections and demand response in dealing with the variable output of RES is not considered. Consequently, the goal of this work is not to propose specific generation portfolios, but to assess the added value and the need for energy storage in highly renewable energy systems, by considering its role in the reserve market, studying the interaction between different storage and/or renewable technologies, etc. The underlying trends then allow to draw clear and qualitative conclusions concerning the future role of energy storage in the power system.

3.3 Problem formulation

The objective function, subject to the operational constraints, sums all costs of the generation expansion planning model. The operational constraints are represented by a technology-clustered unit commitment problem formulation. Contrary to the standard unit commitment problem, the clustered formulation does not consider individual power units. Instead, power units are grouped or "clustered" per fuel type or technology depending on the desired level of detail of the model. A standard unit commitment formulation looks at which individual units are turned on and off. A clustered unit commitment formulation considers how many units (of a standardized nominal power) per aggregated technology are online, started and shut down at every time step. The number of start-ups, shut-downs and online units per technology are all represented by a separate integer variable. A detailed description of the operational constraints can be found in the paper "A Clustered Unit Commitment Problem Formulation for Integration in Investment Planning Models" [59]. The transition to a clustered formulation hugely reduces the number of possible states per time step [13] [59]. As a consequence the calculation time reduces correspondingly, making it possible to integrate such detailed operational constraints into a generation expansion planning framework.
Besides, all unit commitment variables are implemented as linear variables instead of integer variables. Consequently, the model is no longer a mixed integer linear problem but linear problem which allows using a linear programming solver. A linear problem is much easier and faster to solve numerically, reducing the calculation time of the model further. On the other hand, the accuracy of the result is reduced [59].
This work builds on the model presented in [4] which considers the system constraints and the technological constraints of conventional generation technologies. The objective function, system constraints and operational reserves are

all modified and/or extended. A separate formulation for the technological constraints of the storage technologies is developed as well. An overview of the model equation is presented in section 3.4.

The model is a one-node model and does not consider transmission grid constraints. Neither does it consider import or export to and from other regions. The influence hereof definitely merits further research, especially when considering high RES penetrations. However, due to time limits and given the emphasis on the role of electricity storage, this has not been included.

The optimization model is solved for a one year time period with an hourly resolution. The evolution equations describing the energy balances of the storage units make use of circular lag operators [60], meaning that the state-of-charge of the storage units at the end of the simulation period must equal the state-of-charge at the beginning of the period.

3.4 Model equations

The following sections elaborate the objective function, system constraints, technological constraints and operating reserve constraints step-by-step.

3.4.1 Objective function

The model minimizes the total system cost, consisting of investment costs and operational costs. The former includes an annuity corresponding to the direct investment costs C_{INV} [€/MW] and fixed operating & maintenance costs C_{FOM} [€/MW] proportionally related to the installed capacity of dispatchable generation $cap(DG)$, renewable energy sources $cap(R)$ and storage plants $cap(S)$. Expanding the energy capacity of the storage units $E_{inv}(S)$ gives rise to a specific investment cost of C_{ENERGY} [€/MWh].

The operational costs of dispatchable generation units encompass the fuel cost C_{FUEL} [€/MWh] and variable operating & maintenance cost C_{VOM} [€/MWh]. The operational costs linearly depend on the scheduled generation level $gen(DG, t)$. The influence of part-load efficiency of the power plants is thus not considered. The storage technologies do not experience a direct fuel cost but give rise to a variable operating and maintenance cost. In this model, the variable operating and maintenance cost of storage plants $C_{VOM}(S)$ is connected to the instantaneous charging power $P_{ch}(S, t)$. Their cost factor $C_{VOM}(S)$ does incorporate the variable costs of the entire storage cycle (just charging for power-to-methane or charging and discharging for all other storage technologies). Storage units and dispatchable generation units incur an additional operational cost due to ramping C_{RAMP} [€/MW]. The ramping cost is identical for ramping up or down, in charging or discharging operation.

Additionally, long-term storage units (subset *S3*) and dispatchable generation units experience a start-up cost. The long-term storage units also offer the possibility to be kept in a warm state without charging or discharging for a certain period of time, this in order to eliminate start-up costs when the output power is raised again. Keeping the plant in a warm state gives rise to a cost of C_{IDLE} per hour per storage unit. Finally, a cost of curtailment VOC [€/MWh] and load shedding VOLL [€/MWh] is introduced. Minimizing this objective function results in an optimal generation portfolio and a corresponding optimal scheduling of the hourly generation levels and reserve power. Real-time economic dispatch is not considered in this model. Consequently certain costs like the activation cost of reserves are not included in the objective function.

$$
\begin{aligned}
min\Bigg(&\sum_{DG}\big(C_{INV}(DG)+C_{FOM}(DG)\big)\cdot cap(DG) \\
&+\sum_{DG,t}\big(C_{FUEL}(DG)+C_{VOM}(DG)\big)\cdot gen(DG,t) \\
&+\sum_{R}\big(C_{INV}(R)+C_{FOM}(R)\big)\cdot cap(R) \\
&+\sum_{R,t}\big(C_{FUEL}(R)+C_{VOM}(R)\big)\cdot gen(R,t) \\
&+\sum_{DG,t}C_{RAMP}(DG)\cdot\Big(ramp_{up}(DG,t)+ramp_{dn}(DG,t)\Big) \\
&+\sum_{S}\big(C_{INV}(S)+C_{FOM}(S)\big)\cdot cap(S) \\
&+\sum_{S}C_{ENERGY}(S)\cdot E_{inv}(S)+\sum_{S,t}C_{VOM}(S)\cdot\ P_{ch}(S,t) \\
&+\sum_{S,t}C_{RAMP}(S)\cdot\Big(ramp_{up,c}(S,t)+ramp_{dn,c}(S,t)\Big) \\
&+\sum_{S,t}C_{RAMP}(SE)\cdot\Big(ramp_{up,d}(SE,t)+ramp_{dn,d}(SE,t)\Big) \\
&+\sum_{DG,t}C_{SU}(DG)\cdot ramp_{su}(DG,t)+\sum_{S3,t}C_{SU}(S3)\cdot n_{su}(S3,t) \\
&+\sum_{S3,t}C_{IDLE}(S3)\cdot n_{IDLE}(S3,t)+\sum_{R,t}VOC\cdot curt(R,t) \\
&+\sum_{t}VOLL\cdot ls(t)\Bigg)
\end{aligned}
\tag{1}
$$

3.4.2 System constraints

The system constraints describe general conditions concerning the electricity market and the gas market which have to be fulfilled. In contrast to the technological constraints, the system constraints are not linked to a specific technology. First, the system constraints concerning the electricity market are treated, afterwards, the system constraints concerning the gas market are presented.

All European countries which are part of the UCTE synchronous area have to maintain the frequency level within a 49.99Hz to 50.01Hz range [61]. This requires that the infeeds and offtakes to the power grid are balanced in real-time. In practice, each balance responsible party (BRP) is responsible for providing a balanced portfolio on a quarter-hour time basis. The TSO monitors the real-time imbalance in its control area, called the current system imbalance. The TSO will correct the current system imbalance by exchanging imbalances with foreign TSOs or calling upon the reserve capacity. In the presented model, this procedure is captured by the balance equation and the operating reserve requirement constraints. Given the temporal resolution of one hour of the model, the real-time balancing cannot be considered. In other words, the model ensures sufficient operating reserve capacity is available in every time step to guarantee real-time balancing, but the actual activation of operation reserves is not considered. Consequently the activation cost is not taken into account. This leads to a minor underestimation of the operating costs.
The balance equation ensures total energy offtake of demand and charging storage units is met by the total energy supply from generation units and discharging storage units in every time step. Load shedding is also possible but will only be applied when the value of lost load (VOLL) is reached.

$$\forall t \qquad \begin{aligned} &\sum_{DG} gen(DG,t) + \sum_{R} gen(R,t) - \sum_{S} P_{ch}(S,t) \\ &\qquad = DEM(t) - ls(t) - \sum_{SE} P_{dch}(SE,t) \end{aligned} \tag{2}$$

Obviously, the total amount of load shedding is limited by the total demand in every time step

$$\forall t \qquad ls(t) \leq DEM(t) \tag{3}$$

The model considers the operating reserve requirements with the main focus being on the automatic frequency restoration reserves (aFRR) and manual frequency restoration reserves (mFRR). The frequency containment reserves (FCR) and replacement reserves (RR) can be included as well, however these reserve products are not considered in the rest of this work. The reason for this approach will be explained in section 4.4. The operating reserve requirements for FRR, denoted as $Q^{UP}_{AFFR}(t)$, $Q^{UP}_{MFFR}(t)$, $Q^{DN}_{AFFR}(t)$ and Q^{DN}_{MFFR}.(t), consist of a fixed deterministic part and a time-dependent probabilistic part. The actual methodology to calculate these operating reserve requirements is strongly depending on the national power system regulations. Consequently, these methodologies are part of the input data discussed in chapter 4. All categories of operating reserve products can be provided by dispatchable generation units and storage units. Furthermore, the renewable energy sources are allowed to deliver some downward operating reserves depending on the forecasted hourly generation level which can be guaranteed with a certain statistical probability. According to the requirements imposed by the Belgian TSO, whose interpretation of the ENTSO-E Network Code is applied in part here, the aFRR need to be fully available within 7.5 minutes. These stringent conditions exclude non-spinning reserves from providing aFRR. Spinning reserves and fast-acting storage technologies can provide the aFRR, as well as variable RES in case of downward aFRR. It is assumed that after the ramping phase, the aFRR should be capable to deliver the reserved capacity for at least another 7.5 minutes, at which point the mFRR are supposed to take over. A minimum required ramping rate can also be imposed by the TSO [62]. Notice that the storage technologies can deliver upward reserves by reducing the charging power $res^{up}_{afrr,ch}(S,t)$ and increasing the discharging power $res^{up}_{afrr,dch}(SE,t)$ if reconversion to electrical energy is possible (subset SE). A similar reasoning is applicable for downward reserves. The contribution of the conventional power plants to the upward aFRR is captured by a single variable $res^{up}_{afrr}(DG,t)$.

$$\forall t \qquad Q^{UP}_{AFRR}(t) \leq \sum_{DG} res^{up}_{afrr}(DG,t) + \sum_{S} res^{up}_{afrr,ch}(S,t) + \sum_{SE} res^{up}_{afrr,dch}(SE,t) \tag{4}$$

The downward aFRR requirement includes the renewable participation $res^{dn}_{afrr}(R,t)$

$$\forall t \qquad Q^{DN}_{AFRR}(t) \leq \sum_{DG} res^{dn}_{afrr}(DG,t) + \sum_{R} res^{dn}_{afrr}(R,t) + \sum_{S} res^{dn}_{afrr,ch}(S,t) + \sum_{SE} res^{dn}_{afrr,dch}(SE,t) \tag{5}$$

The mFRR take over the reserves addressed by the TSO after 15 minutes. Consequently the required activation time and ramping rate is less stringent. The activation time of 15 minutes allows fast-starting units to deliver non-spinning upward reserves $res^{up}_{mfrr,ns}(DG,t)$ while online units which can shut down within 15 minutes are allowed to deliver their full output power as downward reserves $res^{dn}_{mfrr,sd}(DG,t)$. For the storage technologies the model does not distinguish between spinning and non-spinning reserves since all storage technologies are flexible enough to start up within 7.5 minutes and attain any power output within 15 minutes whether being online or not. So when evaluating the aFRR and mFRR, all information about the reserves provided by storage units is contained in one variable.

$$\forall t \qquad Q^{UP}_{MFRR}(t) \leq \sum_{DG} \left(res^{up}_{mfrr,s}(DG,t) + res^{up}_{mfrr,ns}(DG,t) \right) + \sum_{S} res^{up}_{mfrr,ch}(S,t) + \sum_{SE} res^{up}_{mfrr,dch}(SE,t) \tag{6}$$

$$
\forall t \qquad Q_{MFRR}^{DN}(t) \leq \sum_{DG}\left(res_{mfrr,s}^{dn}(DG,t) + res_{mfrr,sd}^{dn}(DG,t)\right) + \sum_{R} res_{mfrr}^{dn}(R,t) + \sum_{S} res_{mfrr,ch}^{dn}(S,t) + \sum_{SE} res_{mfrr,dch}^{dn}(SE,t) \tag{7}
$$

A final system constraint concerning the power system determines the potential output of wind and PV power. The maximum available output in every time step is determined by the installed capacity and the weather conditions. In this model, the meteorological conditions are represented by a normalized feed-in profile $VRES(R,t)$. The feed-in profile is deterministic and independent of the installed capacity. The total output of the variable RES is either brought to the electricity market and included in the balance equation by $gen(R,t)$ or curtailed $curt(R,t)$.

$$
\forall\, t,R \qquad gen(R,t) + curt(R,t) \leq VRES(R,t) \cdot cap(R) \tag{8}
$$

Balancing the gas market is far less complex than balancing the electricity market because the gas transmission network possesses an inherent means of gas storage through the compression of gas, which is called the line-pack [63]. Therefore, there is no need for real-time balancing to safeguard a reliable operation. In contrast to the electricity system where the voltage level and frequency have to be kept in a very narrow range, the pressure level in the gas transmission network is allowed to fluctuate between certain pressure limits. The feasible pressure variation creates a sort of energy buffer which acts as a source of flexibility. Line-pack is used passively by absorbing the imbalances in gas demand and gas supply due to forecast errors or supply issues. Line-pack is also used actively by extracting more during peak load and injecting more during off peak in order to flatten the import profile. Other sources of flexibility in the gas market consist of local storage, seasonal storage, flexible industrial consumers and flexible imports [63]. In this work, the model of the gas market is restricted to an hourly gas balance incorporating only two flexibilities, line-pack and seasonal gas storage. The other types of flexibility are not regarded. Line-pack is treated as an energy buffer with a certain storage capacity based on the dimension of the transmission network. The Following equations represent the simplified model.

Equation 9 describes the evolution of the energy level of the line-pack buffer $E_{res}^{linepack}(t)$ in MWh. Extracting gas from the seasonal storage units $P_{released}^{gas}(t)$, importing fossil natural gas $P_{imported}^{fossil\,gas}(t)$ and producing synthetic methane through power-to-gas plants $P_{ch}(S3,t) \cdot \eta_{ch}(S3)$ raise the line-pack energy level. Storing gas in seasonal storage units $P_{stored}^{gas}(t)$, consuming fossil gas in gas fired power plants $P^{fossil\,gas}(t)$ and consuming synthetic gas in gas fired power plants $P_{dch}(S3,t)$ lowers the energy level.

$$\forall t \quad \begin{aligned} E_{res}^{linepack}(t+1) &= E_{res}^{linepack}(t) + P_{released}^{gas}(t) - P_{stored}^{gas}(t) \\ &- P^{fossil\ gas}(t) + P_{imported}^{fossil\ gas}(t) + P_{ch}(S3,t) \cdot \eta_{ch}(S3) \\ &- P_{dch}(S3,t) \end{aligned} \tag{9}$$

Limiting the allowable range of the line-pack energy buffer $E_{res}^{linepack}(t)$ to 0 - $E_{MAX}^{linepack}$ ensures the balance of gas demand and supply and includes the flexibility from seasonal storage and line-pack at the same time.

$$\forall t \qquad E_{res}^{linepack}(t) \leq E_{MAX}^{linepack} \tag{10}$$

Other system constraints keep track of the energy level of the seasonal gas storage units $E_{res}(S3,t)$, limit the rate at which gas can be injected and extracted from the seasonal storage units and restrict the hourly import of fossil gas.

$$\forall t \qquad E_{res}(S3,t+1) = E_{res}(S3,t) + P_{stored}^{gas}(t) - P_{released}^{gas,}(t) \tag{11}$$

$$\forall t \qquad P_{stored}^{gas}(t) \leq P_{stored}^{MAX} \tag{12}$$

$$\forall t \qquad P_{released}^{gas}(t) \leq P_{released}^{MAX} \tag{13}$$

$$\forall t \qquad P_{imported}^{fossil\ gas}(t) \leq P_{imported}^{MAX} \tag{14}$$

Of course, modeling line-pack as an energy buffer which can be filled or emptied at will is a simplification. Yet, the lack of any spatial resolution disables the possibility to model it more accurately. The introduction of a gas transmission network and an administration of all individual injection and offtakes could resolve this problem. However, calculating the amount of gas stored by compression would require the use of non-linear equation. Consequently, the computation time would increase unacceptably. In addition, the current approach is sufficient for the purpose of this work. A detailed study of line-pack management and gas storage operation based on gas flow equation can be found in [64].

The total storage capacity of seasonal gas storage is determined by the sum of the present storage capacity $E_{present}(S3)$ and the additional investments $E_{inv}(S3)$. This offers the possibility to include a minimum storage capacity in the model which represents the current capacity of storage facilities that will still be available in 2050.

$$\forall t \qquad E(S3) = E_{present}(S3) + E_{inv}(S3) \tag{15}$$

3.4.3 Technological constraints

Dispatchable generation technologies

As already mentioned, the technological constraints of the dispatchable generation units are based on the model presented in [4]. The first set of equations defines the variables representing the number of online plants $n(DG,t)$, start-ups $n_{su}(DG,t)$ and shut-downs $n_{sd}(DG,t)$ per technology. Equation 16 describes the evolution of the number of online plants per technology and links it with the number of start-ups and shut-downs.

$$\forall\, t, DG \qquad n(DG,t+1) = n(DG,t) + n_{su}(DG,t) - n_{sd}(DG,t) \qquad (16)$$

The number of online units is limited to the total available number of plants per technology $N(g)$. This number is determined by the capacity investments and the technology specific typical unit size $P_{MAX}(g)$

$$\forall\, t, DG \qquad n(DG,t) \leq N(DG) = \frac{cap(DG)}{P_{MAX}(DG)} \qquad (17)$$

The maximum number of start-ups per technology per time step is limited to the number of off-line units. Moreover the introduction of a minimum down town *MDT(DG)* is further restricting the maximum number of start-ups to the number of unit which have been offline for at least *MDT(DG)* hours. A similar reasoning applies to equation 19 limiting the number of shut downs.

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$$\forall\, t, DG \qquad n_{su}(DG,t) \leq N(DG) - n(DG,t) - \sum_{z=1}^{MDT(DG)-1} n_{sd}(DG,t-z) \qquad (18)$$

$$\forall\, t, DG \qquad n_{sd}(DG,t) \leq n(DG,t) - \sum_{z=1}^{MUT(DG)-1} n_{su}(DG,t-z) \qquad (19)$$

Equations 20-21 impose a minimum and maximum on the hourly generation level per technology according the number of online plants and the technology specific minimum and maximum stable output power of a unit.

$$\forall\, t, DG \qquad gen(DG,t) \leq n(DG,t) \cdot P_{MAX}(DG) \qquad (20)$$

$$\forall\, t, DG \qquad gen(DG,t) \geq n(DG,t) \cdot P_{MIN}(DG) \qquad (21)$$

The evolution equation of the hourly generation level $gen(DG,t)$ links the total generation output per technology with the ramping variables. The variables $ramp_{up}(DG,t)$ and $ramp_{dn}(DG,t)$ represent the ramping up and down of units that are and remain online. $Ramp_{su}(DG,t)$, $ramp_{sd}(DG,t)$ represent the change in generation level of a generation technology due to power units starting up and shutting down respectively.

$$\forall\, t, DG \qquad \begin{aligned} gen(DG,t+1) &= gen(DG,t) + ramp_{up}(DG,t) - ramp_{dn}(DG,t) \\ &\quad + ramp_{su}(DG,t) - ramp_{sd}(DG,t) \end{aligned} \qquad (22)$$

The ramping variables are restricted by the dynamic capabilities of the technology. The maximal up- and downward ramping rate is expressed as a percentage of the typical unit size of the technology $P_{MAX}(DG)$. This maximum ramping rate is also applicable when starting up or shutting down. Besides, the variable $Ramp_{su}(DG,t)$ must at least amount to the product of the number of units stating up $n_{su}(DG,t)$ and the minimum stable output power. Analogously, $Ramp_{sd}(DG,t)$ must be greater than the number of units shutting down $n_{sd}(DG,t)$ times the minimum stable output power.

$$\forall\ t, DG \qquad ramp_{up}(DG,t) \leq \big(n(DG,t) - n_{sd}(DG,t)\big) \cdot RU(DG) \cdot P_{MAX}(DG) \tag{23}$$

$$\forall\ t, DG \qquad ramp_{dn}(DG,t) \leq \big(n(DG,t) - n_{sd}(DG,t)\big) \cdot RD(DG) \cdot P_{MAX}(DG) \tag{24}$$

$$\forall\ t, DG \qquad \begin{aligned} n_{su}(DG,t) \cdot P_{MIN}(DG) &\leq ramp_{su}(DG,t) \\ &\leq n_{su}(DG,t) \cdot RU(DG) \cdot P_{MAX}(DG) \end{aligned} \tag{25}$$

$$\forall\ t, DG \qquad \begin{aligned} n_{sd}(DG,t) \cdot P_{MIN}(DG) &\leq ramp_{sd}(DG,t) \\ &\leq n_{sd}(DG,t) \cdot RD(DG) \cdot P_{MAX}(DG) \end{aligned} \tag{26}$$

Finally, the ramping variables $ramp_{up}(DG,t)$ and $ramp_{dn}(DG,t)$ are restricted by the maximum available change in output power of a technology, taking into account the operating range and the number units that are and remain online.

$$\forall\ t, DG \qquad \begin{aligned} &ramp_{up}(DG,t) \\ &\leq \big(n(DG,t) - n_{sd}(DG,t)\big) \cdot P_{MAX}(DG,t) \\ &\qquad - \big(gen(DG,t) - ramp_{sd}(DG,t)\big) \end{aligned} \tag{27}$$

$$\forall\ t, DG \qquad \begin{aligned} &ramp_{dn}(DG,t) \\ &\quad \leq \big(gen(DG,t) - ramp_{sd}(DG,t)\big) \\ &\quad \big(n(DG,t) - n_{sd}(DG,t)\big) \cdot P_{MIN}(DG,t) \end{aligned} \tag{28}$$

Combined, equations 16-28 describe the unit commitment, ramping constraints, minimum up- and down-times and operating limits per aggregated generation technology.

Storage technologies

The storage technologies considered in this model are divided in three categories with the associated subsets *S1, S2* and *S3*. These three categories depict short-term storage, mid-term storage and seasonal storage. In this work, the equations of the subset *S3* are specifically designed to model power-to-methane. Accordingly, the modelling of the gas supply is also largely connected to the variables of the subset S3. The equation of the subset S1 and S2 are technology agnostic and can represent any short or mid-term electrical energy storage technology. The following paragraphs subsequently present the technological and operational constraints of each category.

Seasonal storage

All equations belonging to this paragraph (defined over the subset *S3*) were designed in line with the characteristics of power-to-methane. Notice that other potential options for seasonal storage such as power-to-hydrogen with local storage and re-electrification or flow batteries can be incorporated in the subset *S2*. The operational constraints of the power-to-methane technology are very similar to those of conventional generation technologies described in the previous paragraph. As already mentioned in section 3.3, a technology-clustered formulation of the unit commitment equations is used. Therefore, some logical conditions have to be introduced which keep track of the total number of online plants, start-ups and shut-downs per technology in every time period. Recall that the number of online plants, start-ups and shut-downs are continuous variables in this model. As for the conventional generation units, the typical unit size of the seasonal storage plants is characterized by a nominal capacity $P_{MAX}(S3)$ and a minimum stable output $P_{MIN}(S3)$.

$$\forall t \qquad n(S3,t) \leq N(S3) = \frac{cap(S3)}{P_{MAX}(S3)} \tag{29}$$

The evolution in the number of online plants is directly linked to the number of start-ups and shut-downs as described by equation 30.

$$\forall t \qquad n(S3,t+1) = n(S3,t) + n_{su}(S3,t) - n_{sd}(S3,t) \tag{30}$$

Similarly to the equation 18-19 for conventional generation technologies, the number of start-ups and shut-downs is limited by the total number of units per seasonal storage technology $N(S3)$, the number of online units per storage technology $n(S3,t)$ and the minimum up- and down-time.

$$\forall t \qquad n_{su}(S3,t) \leq N(S3) - n(S3,t) - \sum_{z=1}^{MDT(S3)-1} n_{sd}(S3,t-z) \tag{31}$$

$$\forall t \qquad n_{sd}(S3,t) \leq n(S3,t) - \sum_{z=1}^{MUT(S3)-1} n_{su}(S3,t-z) \tag{32}$$

Online power-to-methane plants can either be in charging operation or in idle state. The variable $n_{ch}(S3,t)$ and $n_{idle}(S3,t)$ represent those two states respectively. When operating, a minimum charging power has to be maintained at all time. In contrast, when being idle the power-to-gas plant cannot charge at all. However, there is a cost factor associated to idle plants because the electrolyzer has to be kept warm. Therefore, keeping a plant in idle state is only useful for bridging a short period of zero output.

$$\forall t \qquad n(S3,t) = n_{ch}(S3,t) + n_{idle}(S3,t) \qquad (33)$$

$$\forall t \qquad P_{ch}(S3,t) \leq n_{ch}(S3,t) \cdot P_{MAX}(S3) \qquad (34)$$

$$\forall t \qquad P_{ch}(S3,t) \geq n_{ch}(S3,t) \cdot P_{MIN}(S3) \qquad (35)$$

The power-to-methane units do not have dedicated gas storage reservoirs. Instead, the synthetic methane is injected in the existing natural gas grid. The gas infrastructure, described by the system constraints presented in paragraph 3.4.2, is responsible for storing the synthetic methane coming from the power-to-methane plants. This is fulfilled by introducing the synthetic methane production in the gas balance as already satisfied in equation 9. Thus, the underground seasonal gas storage as well as the line-pack energy buffer can store synthetic methane. The input data for the size of the line-pack energy buffer has to incorporate the fact that the flexibility of line-pack is also needed for the balancing of the other gas flows. This is discussed further in paragraph 4.3.4.

The model relies on the traditional gas fired power plants (GFPP) to reconvert the synthetic methane to electricity. For the rest of this work, OCGT and CCGT are considered as the representative GFPP technologies. This corresponds to the input data of the test case presented in chapter 4 of this work which is used to generate all results discussed in chapter 5. The following equations show that the set of GFPP technologies can easily be extended or reduced by adding or removing equations similar to equation 36 and 38 and implementing the accompanying variables in equations 40 and 41. The introduction of power-to-methane does not alter the operational constraints of GFPP. These are still described by equations 16-28. In addition, six new equations are necessary to determine the origin of the consumed gas (synthetic or fossil) and to ensure the total consumption of the GFPP equals the total demand for gas. The first two equations determine the gas demand [$MWh_{thermal}$] of OCGT and CCGT separately for every time step. The next two equations express the possibility to either use synthetic or fossil gas to cover this demand. The last two equations determine the total consumption of synthetic and fossil gas respectively. These variables are needed in equation 9 to calculate the overall gas balance.

$$\forall t \qquad P_{ccgt}^{gas}(t) = gen('ccgt', t)/\eta('ccgt') \qquad (36)$$

$$\forall t \qquad P_{ocgt}^{gas}(t) = gen('ocgt', t)/\eta('ocgt') \qquad (37)$$

$$\forall t \qquad P_{ccgt}^{gas}(t) = P_{ccgt}^{syngas}(t) + P_{ccgt}^{fossil\ gas}(t) \qquad (38)$$

$$\forall t \qquad P_{ocgt}^{gas}(t) = P_{ocgt}^{syngas}(t) + P_{ocgt}^{fossil\ gas}(t) \qquad (39)$$

$$\forall t \qquad P_{dch}(S3,t) = P_{ocgt}^{syngas}(t) + P_{ccgt}^{syngas}(t) \qquad (40)$$

$$\forall t \qquad P^{fossil\ gas}(t) = P_{ccgt}^{fossil\ gas}(t) + P_{ocgt}^{fossil\ gas}(t) \qquad (41)$$

Mid-term and short-term storage

In comparison to the other technologies, the number of operational constraints required to describe mid-term storage and short-term storage is largely reduced. This follows from the extreme operational flexibility of these storage technologies. Pumped hydro storage and battery storage for sure can start-up, shut down or attain any output power within 7.5 minutes, the shortest time period considered in the model. Within one hour they can start up and shut down several times. Consequently it would be totally irrelevant to keep track of the number of start-ups and shut-downs with a time step of one hour. The number of online plants can vary between zero and the total number of installed plants. There is a separate variable for the number of plants in charging and discharging operation, the sum of which can never exceed the total number of online units per technology. These two variables determine the maximum charging power and discharging power per storage technology.

$$\forall\ t, SE \qquad n(SE,t) = n_{ch}(SE,t) + n_{dch}(SE,t) \tag{42}$$

$$\forall\ t, SE \qquad P_{ch}(SE,t) \leq n_{ch}(SE,t) \cdot P_{MAX,ch}(SE) \tag{43}$$

$$\forall\ t, SE \qquad P_{ch}(SE,t) \geq\ n_{ch}(SE,t) \cdot P_{MIN,ch}(SE) \tag{44}$$

$$\forall\ t, SE \qquad P_{dch}(SE,t) \leq n_{dch}(SE,t) \cdot P_{MAX,dch}(SE) \tag{45}$$

$$\forall\ t, SE \qquad P_{dch}(SE,t) \geq\ n_{dch}(SE,t) \cdot P_{MIN,dch}(SE) \tag{46}$$

Both the mid-term and short-term storage technologies considered in this model are capable of re-electrification. Therefore, it is convenient to define a subset *SE* containing both short-term and mid-term storage technologies. In addition, both sets of technologies have their dedicated storage medium. For instance, the storage reservoirs of pumped hydro storage for mid-term storage or the energy stored in the batteries or capacitors themselves for short-term storage. The energy balance of the storage medium is described by the following evolution equation.

$$\forall\ t, SE \qquad E_{res}(SE,t+1) = E_{res}(SE,t) + P_{ch}(SE,t) \cdot \eta_{ch}(SE) - \frac{P_{dch}(SE,t)}{\eta_{dch}(SE)} \tag{47}$$

The energy storage capacity [MWh] of short-term storage technologies covered by the subset S2 (typically battery storage) is directly coupled to the nominal charge or discharge rate [MW].

$$\forall\ S2 \qquad E(S2) = \frac{E_{unit}}{P_{unit}} \cdot cap(S2) \tag{48}$$

The nominal charging and discharging power of the storage technologies covered by the subset *S1* is independent of the size of the reservoir (typically pumped-hydro storage and compressed air energy storage). Both the nominal power and energy storage capacity have a specific investment cost, expressed in €/MW and €/MWh respectively. Moreover, the model offers the possibility to include a minimum available storage capacity ex-ante. The reason for this extension is the very long life-time of water reservoirs of PHS and underground gas storage reservoir. Consequently, the storage capacity available today $E_{present}(S1)$ will most likely still be available in 2050.

$$\forall S1 \qquad E(S1) = E_{present}(S1) + E_{inv}(S1) \tag{49}$$

The variable $E_{inv}(S1)$ makes it possible to extent the storage capacity of the reservoirs. The total storage capacity per energy storage technology can be restricted to $E_{MAX}(S)$, for example to take the maximum geological potential of PHS or CAES into account. The numerical value of $E_{MAX}(S)$ is part of the input data.

$$\forall S \qquad \mathrm{E}(S) \le E_{MAX}(S) \tag{50}$$

Logically the energy level of the reservoirs is at all times limited by the installed energy storage capacity $E(S)$.

$$\forall t, S \qquad E_{res}(S,t) \le E(S) \tag{51}$$

3.4.4 Operating reserve constraints

Dispatchable generation

The operating reserve constraints of the conventional generation plants remain largely unchanged compared to the original model. Because of the great importance of the operating reserve constraints, all model equations are presented. An elaborate explanation can be found in [4].

The first set of operating reserve constraints restricts the reserve power according to the ramping capacity which is actually available to deliver upward or downward reserves. The available ramping capacity can only be contracted once, thus the ramping capacity available for mFRR must be subtracted by the already contracted aFRR. The adjusted ramping rates RU have to be defined carefully in order to prevent the plants from ramping over 100% of their nominal capacity.

$$\forall t, DG \qquad res_{afrr}^{up}(DG,t) \le \big(n(DG,t) - n_{sd}(DG,t)\big) \cdot RU_{AFRR}(DG) \cdot P_{MAX}(DG) \tag{52}$$

$$\forall t, DG \qquad res_{afrr}^{up}(DG,t) + res_{mfrr,s}^{up}(DG,t) \le \big(n(DG,t) - n_{sd}(DG,t)\big) \cdot RU_{MFRR}(DG) \cdot P_{MAX}(DG) \tag{53}$$

$$\forall\, t, DG \qquad res_{afrr}^{dn}(DG,t) \leq \Big(n(DG,t) - n_{sd}(DG,t) - n_{sd,mfrr}(DG,t)\Big) \cdot RD_{AFRR}(DG) \cdot P_{MAX}(DG) \tag{54}$$

$$\forall\, t, DG \qquad res_{afrr}^{dn}(DG,t) + res_{mfrr,s}^{dn}(DG,t) \leq \Big(n(DG,t) - n_{sd}(DG,t) - n_{sd,mfrr}(DG,t)\Big) \cdot RD_{MFRR}(DG) \cdot P_{MAX}(DG) \tag{55}$$

The next two equations address the non-spinning upward mFRR. The nominated capacity of non-spinning reserves is constrained by the minimum stable output power, the maximum ramping rate and the number of plants available for start-up.

$$\forall\, t, DG \qquad n_{su,mfrr}(DG,t) \cdot P_{MIN}(DG) \leq res_{mfrr,ns}^{up}(DG,t) \leq n_{su,mfrr}(DG,t) \cdot RU_{MFRR}(DG) \cdot P_{MAX}(DG) \tag{56}$$

$$\forall\, t, DG \qquad n_{su}(DG,t) + n_{su,mfrr}(DG,t) \leq N(DG) - n(DG,t) - \sum_{z=1}^{MDT(DG)-1} n_{sd}(DG,t-z) \tag{57}$$

The same reasoning holds for the provision of downward mFRR by shutting down plants.

$$\forall\, t, DG \qquad n_{sd,mfrr}(DG,t) \cdot P_{MIN}(DG) \leq res_{mfrr,sd}^{dn}(DG,t) \leq n_{sd,mfrr}(DG,t) \cdot RD_{MFRR}(DG) \cdot P_{MAX}(DG) \tag{58}$$

$$\forall\, t, DG \qquad n_{sd}(DG,t) + n_{sd,mfrr}(DG,t) \leq n(DG,t) - \sum_{z=1}^{MUT(DG)-1} n_{su}(DG,t-z) \tag{59}$$

The following four equations incorporate the ramping constraints, adjusted for the provision of operating reserves, and substitute the ramping constraints expressed by the equation 23-26. The available ramping capacity can only be allocated once, so the margin for altering the generation level is decreased by the capacities already allocated to the different reserve products.

$$\forall t, DG \qquad ramp_{up}(DG,t) + res_{afrr}^{up}(DG,t) + res_{mfrr,s}^{up}(DG,t) \leq \big(n(DG,t) - n_{sd}(DG,t)\big) \cdot RU_{hour}(DG) \cdot P_{MAX}(DG) \tag{60}$$

$$\forall t, DG \qquad \begin{aligned} &ramp_{dn}(DG,t) + res_{afrr}^{dn}(DG,t) + res_{mfrr,s}^{dn}(DG,t) \\ &\quad \leq \Big(n(DG,t) - n_{sd}(DG,t) - n_{sd,mfrr}(DG,t)\Big) \\ &\quad \cdot RD_{hour}(DG) \cdot P_{MAX}(DG) \end{aligned} \qquad (61)$$

$$\forall t, DG \qquad \begin{aligned} &ramp_{up}(DG,t) + res_{afrr}^{up}(DG,t) + res_{mfrr,s}^{up}(DG,t) \\ &\quad \leq \big(n(DG,t) - n_{sd}(DG,t)\big) \cdot P_{MAX}(DG,t) \\ &\quad - \big(gen(DG,t) - ramp_{sd}(DG,t)\big) \end{aligned} \qquad (62)$$

$$\forall t, DG \qquad \begin{aligned} &ramp_{dn}(DG,t) + res_{afrr}^{dn}(DG,t) + res_{mfrr,s}^{dn}(DG,t) \\ &\quad \leq \Big(gen(DG,t) - ramp_{sd}(DG,t) \\ &\quad - res_{mfrr,sd}^{dn}(DG,t)\Big) \\ &\quad - \Big(n(DG,t) - n_{sd}(DG,t) - n_{sd,mfrr}(DG,t)\Big) \\ &\quad \cdot P_{MIN}(DG,t) \end{aligned} \qquad (63)$$

Renewable energy sources

Due to their variable and uncontrollable output, wind and PV power do not serve very well for providing operating reserves. Currently, these intermittent RES are not allowed to provide any operating reserves albeit the Belgian TSO is investigating the participation of wind power in the delivery of spinning reserves [65]. When aiming for a 100% renewable energy system, the focus of this work, the participation of RES in the operating reserve market will become indispensable. Rules and standards will have to be developed by the TSOs and network regulators to organize the participation of wind and PV power. Prediction and statistical analysis of the available generation capacity will undoubtedly play an important role in these regulations. Indeed, the provision of operating reserves is only allowed when the allocated power can actually be delivered when the TSO calls upon these reserves. So when offering a bid on the day-ahead or intraday reserve markets, the operator has to be sure that the proposed bid will be available when needed. Dealing with uncontrollable generation of intermittent RES, the operator will have to guarantee the reserves can be provided with a statistical reliability based on generation forecasts. How renewable participation will be integrated in the reserve markets of 2050 is hard to predict. In the current work, a simplified reasoning is applied. It is supposed that the generation forecast and the corresponding limits of the 99% confidence interval of the intermittent RES are known within the time frame considered by the reserve markets. Fig. 3 represents this information graphically for the case of wind power.

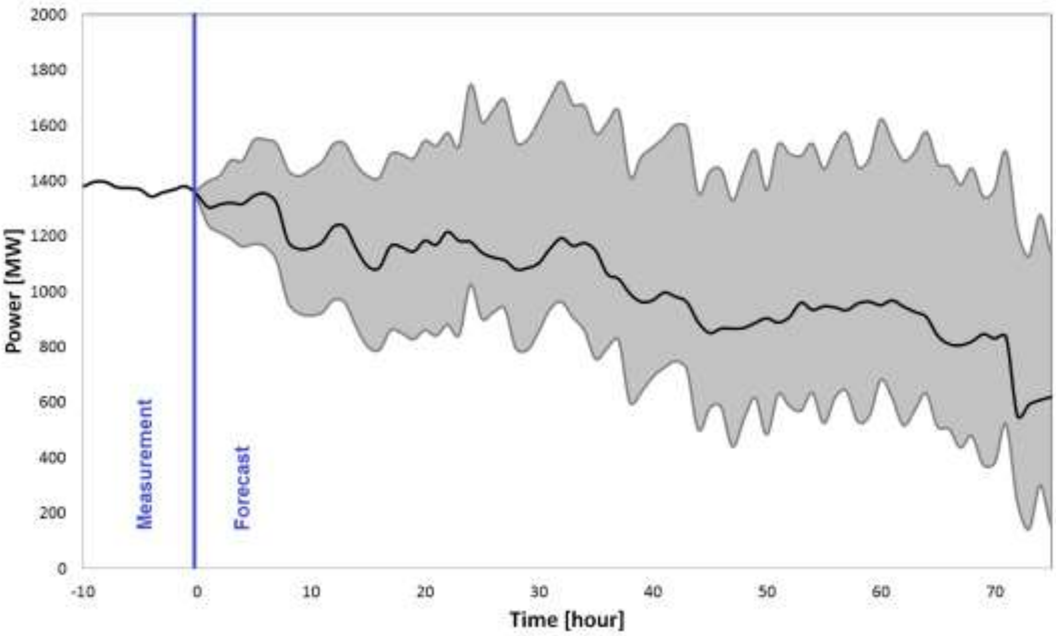


Fig. 3: Wind-power generation forecast and its 99% confidence interval

In order to provide downward operating reserves, the generation level that will be available with a very high probability has to be known, as the power system planning will count on the availability of these reserves. Indeed, if the RES fail to deliver the allocated reserves when called upon, a system shortage of reserves might follow, jeopardizing system operation. For this work, the lower limit of the 99% confidence interval is assumed to be the guaranteed output. In case of fully controllable curtailment of the RES output, all power levels below the lower 99% limit are feasible. Consequently, downward operating reserves as high as the lower limit of the 99% confidence interval can then be offered on the reserve markets for the provision of downward reserves.

Providing upward operating reserves with RES is more complex. In order to make sure that there is capacity available to provide upward operating reserves, the RES should nominate a generation level below the lower 99% limit on the day-ahead energy market. The gap between the nominated power and the 99% limit would subsequently be available for providing upward operating reserves. Indeed, when called upon to deliver the contracted upward reserves, the sum of the scheduled generation and upward reserve power would be available in 99% of the time, the design reliability chosen for this work. This illustrated by means of an example.

Fig. 4 depicts how a 2GW wind farm has to be operated in order to provide 200MW of upward reserves. The green line presents the nominations on the day-ahead market, i.e. the generation level delivered to the electricity market. The maximum potential generation level given the weather conditions is situated somewhere in the grey area. This figure clearly shows that an enormous amount of renewable energy needs to be curtailed in order to provide upward reserves with RES. As a consequence, it is very unlikely providing upward operating reserve with intermittent RES would be economically relevant, motivating again why RES will not be considered for the provision of upward operating reserves in this work.

In real time, when available RES output exceeds the planned output, the RES could increase their actual output if the system is short (as reserve power or in the intraday market). This would even lead to a more economic operation of the system. However, as this power is not available with a probability of at least 99% of the time, the system is not planned to rely on this.

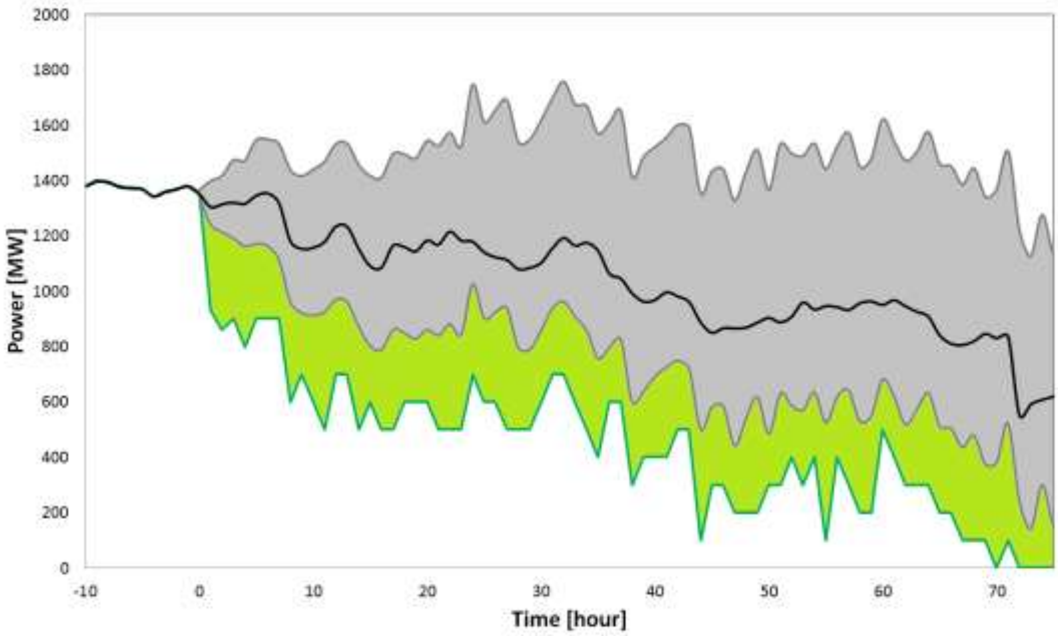


Fig. 4: upward reserve provision of a wind farm ensuring scheduled generation and upward reserve power is available with 99% reliability

As already mentioned, deterministic normalized generation profiles of the intermittent RES are implemented in this model. Through a probabilistic analysis, the level of generation available with 99% certainty could be calculated, depending on the forecasted output level. However, due to time limitation, a simple formulation was introduced where a steady fraction of the generation level is available for providing downward reserves:

$$\forall\, t, R \qquad res_{afrr}^{dn}(R,t) + res_{mfrr,s}^{dn}(R,t) \leq\, VRES(R,t) \cdot cap(R) \cdot 0.25 \qquad (64)$$

A sensitivity analysis was performed on the exact level of this fraction. The results hereof show a non-negligible sensitivity to this level. However, this is more due to the complexity of supplying sufficient downward reserves in highly renewable systems. Consequently, it is logical that the result is sensitive to the level of the precise contribution of the RES, as this is a very flexible and easily activated source of downward reserves. The actual level of RES generation that will be available with 99% certainty will depend strongly on the evolution of forecast methods towards 2050, as well as the evolution of the reserve markets. The closer the gate closure time of the reserve markets to real time, the greater the RES power that will be available for reserve provision. I.e. the level of RES generation that is known to be available with 99% certainty is higher intraday than it is day-ahead. The 25%

fraction of forecasted generation proposed here is considered to be a conservative estimate, when considering these future evolutions.
Furthermore, downward operating reserves can never exceed the generation level

$$\forall\, t, R \qquad res_{afrr}^{dn}(R,t) + res_{mfrr,s}^{dn}(R,t) \leq\ gen(R,t) \tag{65}$$

3.4.4.1 **Storage technologies**

The storage technologies included in this work can reach any power within 7.5 minutes, the smallest time step considered in the reserve markets for aFRR and mFRR. As a result, the provision of operating reserves is not hindered by any limitation of the dynamic ramping abilities. All operating reserve constraints regarding the ramping rates can be discarded for storage technologies. The constraints limiting the available reserve capacity to the remaining part of the online capacity remain valid, still taking into account the capacity already allocated to other types of reserves and ramping. If re-electrification is possible (technologies of the subset SE), reducing the charging power as well as increasing the discharging power can provide upward reserves. Similarly, an increase in charging power or decrease in discharging power is able to serve as downward reserves.

$$\forall\, t, S \qquad \begin{gathered} ramp_{up}^{ch}(S,t) +\ res_{afrr,ch}^{dn}(S,t) +\ res_{mfrr,ch}^{dn}(S,t) \\ \leq cap(S) - P_{ch}(S,t) \end{gathered} \tag{66}$$

$$\forall\, t, S \qquad ramp_{dn}^{ch}(S,t) +\ res_{afrr,ch}^{up}(S,t) +\ res_{mfrr,ch}^{up}(S,t) \leq\ P_{ch}(S,t) \tag{67}$$

$$\forall\, t, SE \qquad \begin{gathered} ramp_{up}^{dch}(SE,t) +\ res_{afrr,dch}^{up}(SE,t) +\ res_{mfrr,dch}^{up}(SE,t) \\ \leq cap(SE) - P_{dch}(SE,t) \end{gathered} \tag{68}$$

$$\forall\, t, SE \qquad \begin{gathered} ramp_{dn}^{dch}(SE,t) +\ res_{afrr,dch}^{dn}(SE,t) +\ res_{mfrr,dch}^{dn}(SE,t) \\ \leq\ P_{dch}(SE,t) \end{gathered} \tag{69}$$

The temporal evolution equations describing the charging and discharging power complement these four ramping constraints.

$$\forall\, t, S \qquad P_{ch}(S,t+1) =\ P_{ch}(S,t) +\ ramp_{up}^{ch}(S,t) -\ ramp_{down}^{ch}(S,t) \tag{70}$$

$$\forall\, t, SE \qquad \begin{gathered} P_{dch}(SE,t+1) =\ P_{dch}(SE,t) + ramp_{up}^{dch}(SE,t) \\ -\ ramp_{down}^{dch}(SE\ ,t) \end{gathered} \tag{71}$$

The regulation concerning the operating reserves requires that the aFRR should be able to remain available for 7.5 minutes once fully activated and the mFRR 45 minutes once activated, resulting in a total maximum activation T_{AFFR} and T_{MFFR} of 15 min and 60 min respectively. This requires the introduction of energy constraints for the provision of reserve power. The energy flows associated with the activation of the reserves can be quite large and the storage units should be able to handle these energy flows. In other words, the state-of-charge must suffice to permit the allocated increase in discharging power. Similarly, the remaining energy storage capacity must be enough to absorb an increase in charging power.

$$\forall t, SE \qquad \begin{aligned} \{ P_{dch}(SE,t) \cdot T_{MARKET} + res_{afrr,ch}^{dn}(SE,t) \cdot T_{AFFR} \\ + res_{mfrr,ch}^{dn}(SE,t) \cdot T_{MFFR} \} / \eta_{dch}(SE) \\ \leq E_{res}(SE,t) \end{aligned} \tag{72}$$

$$\forall t, SE \qquad \begin{aligned} \{ P_{ch}(SE,t) \cdot T_{MARKET} + res_{afrr,ch}^{dn}(SE,t) \cdot T_{AFFR} \\ + res_{mfrr,ch}^{dn}(SE,t) \cdot T_{MFFR} \} \cdot \eta_{ch}(SE) \\ \leq E(SE) - E_{res}(SE,t) \end{aligned} \tag{73}$$

These constraints do not apply to power-to-gas because of the possibility to inject the synthetic methane in the gas network.

3.5 Additional constraints

The model equations are extended with constraints that allow to simulate different scenarios by imposing the share of renewable energy, forcing a limit on the CO_2 emissions or limiting certain possibilities in the energy system.

3.5.1 Renewable energy target

The imposed share of renewable energy is a highly influential parameter regarding the composition of the generation portfolio. The renewable energy target will be a main driver to move away from fossil fuel power generation. Due to the presence of storage technologies in the power system and synthetic methane in the gas supply, determining whether the electricity brought to the market is originally produced from renewable or fossil energy sources isn't straightforward. For reasons of modelling complexity and more time-efficient resolution, an indirect target was formulated for the share of RES, rather than a direct target. As a consequence, it is the supply of conventional electricity that is restricted to a certain maximum, rather than the supply of renewable electricity being raised to a certain minimum. The result is the same, yet the model complexity and computation time is much lower in the case of an indirect target.

$$nRESgen = \sum_t (gen(coal,t) + P_{oct}^{fossil}(t) \cdot \eta_{oct} + P_{ccgt}^{fossil}(t) \cdot \eta_{ccgt}) \tag{74}$$

$$nRESgen \leq (1 - RESshare) \cdot \sum_t DEM(t) \tag{75}$$

Notice that the electric energy generation [$MWh_{electric}$] is used to calculate the share of generation using fossil fuels in the final electricity consumption. The primary energy consumption is not considered.

3.5.2 Restricting the capacity and energy potential

The model offers the possibility to restrict the yearly primary energy consumption of each generation technology. This is particularly useful to restrict the primary energy consumption of biomass power plants to the maximum potential biomass energy use of the power sector.

$$\sum_{t} \frac{gen(G,t)}{\eta(G)} \leq E_{MAX}(G) \tag{76}$$

Finally, the model can put an upper limit to the capacity of renewable energy sources. This could represent the scarcity of suitable locations to install renewable energy sources. Indeed, the potential to expand the wind and PV capacity isn't endless.

$$\forall t \qquad cap(R) \leq cap_{MAX}(R) \tag{77}$$

3.6 Limitations of the model

Representing the power system with a linear model implicitly and explicitly introduces several approximations. Some of these approximations were already discussed in the previous sections. This section presents an overview of the most important deviations from the real-life operation of the power system. This should give a better understanding of the limitations of this model.

First of all, the spatial resolution of the model is very limited, namely a one-zone model. The electricity market and the gas market are modelled with a single balance equation which includes all injection and offtakes without considering their origin. Transmission and distribution networks and their corresponding costs and restrictions are thus neglected in this model.

The model is free to constitute the generation portfolio from scratch. Power plants with a lifetime reaching till 2050 and beyond, like for example hydro power are not included. Neither does the model consider the decommission of power plants.

Important sources of flexibility are not considered, e.g. demand side response of residential consumers could seriously reduce the need for operating reserves. Further, demand side response of industrial consumers and district heating with thermal energy storage will likely be available at large scale to actively participate in the operating reserve markets in the future. Last but not least, the balancing role of interconnection capacity is not included in the model.

Information about the part-load efficiency of the generation units is not included in the model. Hence, the marginal cost of electricity production of each generation technology is constant.

The model does not consider the real time dispatch of the generation units. Consequently the actual activation of the reserve capacity is disregarded. The costs associated to the activation of the contracted reserves in order to maintain the power system balance in real time are thus ignored.

The optimization model has full knowledge of the (deterministic) demand profile and intermittent RES generation profile over the entire simulation period. In other words, the model has perfect foresight perspective. Consequently, the storage reservoirs can be managed optimally since they can predict perfectly how the state-of-charge should evolve over the year. In reality, uncertainty about the weather conditions requires risk analysis to determine the minimum allowable state-of-charge of the storage reservoirs.

As already mentioned, the model minimizes the total system cost as seen by a centralized operator. In other words, the model has insight of the economy wide costs. In reality, investment decisions and the operation of the energy and reserves markets are determined by the producers and balance responsible parties. They will not seek to minimize the total system cost. Instead they try to maximize their own revenue. This will definitely lead to different solutions. As mentioned in the literature review, market analysis models could better predict the investment decisions of a profit-maximizing operator. However, the regulator and system operator do play a mitigating role in this discussion. By imposing appropriate regulations and pricing systems, they can direct the operators toward a socially optimal solution. The purpose of this work is to look for the socially optimal solution and the role of energy storage in this solution. This offers new insights on the actions the regulator and system operators should undertake in order to direct the market toward a socially optimal solution.

The instantaneous penetration of intermittent RES in the electricity supply is not limited. For example, the entire demand can be met by wind energy and all upward reserve capacity can be provided by storage plants in charging operation. I.e., in such periods no (conventional) dispatchable generation is online. TSOs could limit the share of intermittent renewables in the instantaneous generation output for operational reasons, e.g. in order to safeguard the frequency stability and dynamic stability of the grid. In the current system, the maximum share of intermittent RES is estimated at 60 to 80% of the demand [30]. In the future, new solutions might emerge that accommodate higher instantaneous penetrations of intermittent RES, e.g. synthetic inertia supplied by intermittent RES or storage units. Exact regulations concerning this topic do not exist to date, therefore such constraints are not included in the model. However, this could be adapted very easily in this model.

The determination of the output of intermittent RES using (deterministic) normalized generation profiles holds some approximations. The normalized generation profiles are constituted using historical data. These profiles are scaled linearly in order to obtain the output of any installed capacity RES in this model. Consequently, the effect of largely expanding the RES capacity is not included. The variability of the RES output might be overestimated since the output profile is

expected to flatten somewhat when increasing the installed capacity to a great extent. Besides, when expanding the installed capacity of intermittent RES largely, the additional capacity might have to be built at the remaining and likely less favorable locations. As a consequence the average capacity factor might decrease.
Finally, the conceptual model of the power-to-gas units does not consider the auxiliary need for a concentrated CO_2 source. It is assumed sufficient (industrial) CO_2 sources will still be available. Even if concentrated CO_2 would not be available, CO_2 could be extracted from atmospheric air. In this model, it would only mean an increase in the variable operating & maintenance costs of power-to-gas.

3.7 Conclusion

The model described in this chapter presents a tool to simulate power systems and provides a solution for the (socially) optimal generation portfolio, dispatch of power generation units and storage units and allocation of operating reserves requirements. The operational constraints are implemented via a technology-clustered formulation of the unit commitment problem. Thus, all generation and energy storage technologies have to be considered at technology level instead of power plant level. Apart from that, the model is very flexible and allows integrating various types of generation and energy storage technologies. The model is also adapted for the possible integration of power-to-methane technology. As such, it is possible to investigate an arbitrary conceptual or real power system by implementing the desired input data. The next chapter will deal with required input data and demonstrate the application of the model on a conceptual test system.
Further, the additional constraints enable to investigate different scenarios. This feature will be extensively used for the generation of the results in chapter 5. Especially the possibility to impose a renewable energy target will be used.
The model formulation, integrating a detailed representation of the operational constraints and an endogenous determination of the reserve requirement in a generation expansion planning formulation distinguishes this model from existing GEP models. Thus, the balancing challenges of renewable power system due the variability and unpredictability of intermittent RES are correctly captured in a GEP model. This will allow to get a better understanding of the impact of a high share of renewable energy on the composition of generation portfolio and reserve markets. A more realistic estimation of the integration costs of RES, compared to existing GEP, can be obtained.

Chapter 4: Input Data

4.1 Introduction

The model described in the previous chapter requires a list of input data characterizing the power system. The input data comprise technical and economical parameters of the generation and storage technologies, demand profile, intermittent RES generation profile and forecast data and the operating reserve sizing method. This offers the flexibility to simulate various power systems with the model. For this work, the model will be applied to a conceptual test system. The test system which is presented in this chapter is fairly simply, containing four representative conventional generation technologies, three storage technologies and three RES technologies, namely biomass, wind and PV. The economic parameters are based on projection for 2050. The rest of the input data is based on the Belgian power system. This chapter presents the input data used for all the different scenarios discussed in chapter 5, expect for the scenarios of the sensitivity analysis. The adaptions to the input data for use in the sensitivity analysis will be mentioned explicitly in chapter 5. In this chapter, special attention will be paid to the operating reserve sizing method.

4.2 Purpose of the test case

The test case describes a simple, yet representative power system. The number of generation and storage technologies has been deliberately kept low in order to facilitate the analysis of the results and limit the computation time. The test case is sufficiently realistic to answer the research question of this thesis. Although the number of generation technologies is limited, their operational characteristics are still represented precisely.

The test case does not serve to constitute a roadmap for the future power system, i.e. the model does not propose an ideal generation portfolio for a renewable power system. This not only true for this specific test case. Independent of the detail of the input data, the model is not designed to propose realistic generation portfolios. Recall that it does not consider transmission grid constraints, interconnection capacity and demand response. Consequently, the numerical results themselves are

of lesser importance. The model and the presented test case do serve well to distinguish the underlying trends, investigate the role of energy storage in the future power system, assess the impact of the variable nature of wind and PV on the operation of the power system, etc.
Although most of the input data (demand profile, wind and PV generation profile, potential to expend RES and storage capacity,...) is extracted from the Belgian power system, there is no intention to draw any conclusion about the Belgian power system.

4.3 Input data

4.3.1 Input data for the conventional generation technologies and renewable energy sources

The conventional generation technologies (subset *DG*) included in the conceptual test system represent base, mid, peak and high peak generation technologies. The technical and economic parameters are based on projections for 2050 of respectively Nuclear, Coal, CCGT and OCGT plants. These parameters are shown in Table 1 and Table 2. The technical parameters consist of the typical unit size P_{MAX}, the minimal stable output power of unit P_{MIN}, ramping rate, Minimum up-time (MUT) and minimum down-time (MDT). These parameters are all obtained from the report of the Deutsches Institut für Wirtschaftforschung on *Current and Prospective Costs of Electricity Generation until 2050* [66]. The ramping rates RU, RD, RU_{AFRR}, RD_{AFRR}, etc. introduced in the technological constraints and operating reserve constraints (paragraph 3.4.3 and 3.4.4) are all derived from ramping parameter of Table 1. The economic parameters of the conventional generation technologies were defined in paragraph 3.4.1 when describing the objective function. Notice that the investment cost is converted to an annuity cost C_{INV} [€/MW.year] for implementation in the objective function. Therefore, a discount rate of 8% is used. The economic parameters are obtained from the JRC-EU-TIMES model [67] except for the variable operating and maintenance cost and fuel cost of Nuclear. These were obtained from the paper of De Jonghe et al. [16].

Techn.	P_{MAX} [MW]	P_{MIN} [%-P_{MAX}]	Ramping [%-P_{MAX}/min]	MUT [h]	MDT [h]
Nuclear	400	50	2	24	24
Coal	300	50	4	6	4
CCGT	200	50	6	4	1
OCGT	100	10	10	0	0
Biomass	300	40	4	6	4
PV	5	0	100	0	0
Wind	5	0	100	0	0

Table 1: Technical parameters of the generation technologies

Techn.	Inv. Cost [k€/MW]	Fix. O&M [k€/MW]	Fuel cost [€/MWh]	Var. O&M [€/MWh]	Ramping cost [€/ ΔMW]	Start-up cost [€/MW]	Life time [years]
Nuclear	5000	42	10	5	1.3	200	50
Coal	1700	33	28	10	1.3	50	35
CCGT	855	20	61	10	0.25	37	25
OCGT	472	12	95	10	0.66	25	15
Biomass	3800	95	57	15	1.3	50	35
PV	650	10	0	0	0	0	25
Wind	1110	21	0	0	0	0	30

Table 2: Economic parameters of the generation technologies

Next to the conventional generation technologies and intermittent RES, biomass is also added to the set representative technologies. The characteristics of biomass power plants are based on the report of National Renewable Energy Laboratory on *cost and performance data for power generation technologies* [68]. The introduction of biomass is justified by the fact that this renewable generation technology can play a crucial role in a 100% renewable energy system with regard to providing spinning reserves on the one hand and bridging time periods of low wind and PV energy production on the other hand [31] [18].

4.3.2 Input data storage technologies

Given that the model considers the optimal scheduling of generation and reserves power for a one year time period, it is well suited to assess the value of seasonal storage. Therefore, power-to-methane is expected to have an important share in the solution for the optimal generation mix. However, if power-to-methane is the only available storage technology introduced, its value would be overestimated as it would be employed to provide all temporal energy arbitrage, short-term as well as long-term. Other storage technologies exist which are better adapted to provide the short-term flexibility at a lower cost. In other words, when introducing power-to-methane, other storage technologies should also be introduced to compete with it.

The conceptual test system introduces pumped hydro storage (PHS) as mid-term and NaS battery storage as short-term storage technology. These are mature technologies which have already been installed in large scale projects. They both have the potential to expand their capacity further [69] [70]. Estimations for the future investment costs are found readily. The input data of the test system is based on the report of National Renewable Energy Laboratory: *cost and performance data for power generation technologies* [68] and the report of Deutsches Institut für Wirtschaftforschung: *Current and Prospective Costs of Electricity Generation until 2050* [66].

Projections for the future cost of power-to-gas plants are much harder to find. Various researchers and manufactures come to different estimations. The majority of the estimations for the investment cost of power-to-methane range from 800 to

2000€/kW [40] [56] [71]. The uncertainty about the investment cost makes a sensitivity analysis necessary.

The technical and economical input parameters of the storage technologies are presented in Table 3 (power-to-methane based on data from [40], [58], [56], [72], [37] [73]). The input data used for power-to-hydrogen, an alternative seasonal storage technology, is also included in this table. As already discussed in section 2.5, it will not be included in the base case scenarios. The effect of including power-to-hydrogen in the power system is investigated in paragraph 5.3.4.

	Power-to-methane	**Power-to-hydrogen-to-power**	**Pumped hydro storage**	**NaS battery storage**
Investment cost [k€/MW]	1200	1500	1500	2615
Fixed O&M cost [k€/MW]	20	25	20	20
Variable O&M cost [€/MWh]	10	20	10	48[1]
Lifetime [y]	20	20	60	40[2]
Investment cost Storage reservoir [k€/MWh]	8	10	100	N/A
Efficiency [%]	68[3]	55[4]	81[4]	87[4]
P_{MAX} (charge)	20	20	200	7
P_{MAX} (discharge)	N/A	20	230	7
P_{MIN} (charge)	1	1	180	0
P_{MIN} (discharge)	N/A	1	160	0
Ramping [%P_{MAX}/sec]	10	10	1	20

Table 3: Technical and economic parameters of the storage technologies

[1] Variable O&M cost includes the cost of replacing the batteries after 5000 working hours

[2] Lifetime of the plant and auxiliary equipment, not the batteries itself

[3] $HHV_{methane}/E_{electric}$

[4] Round-trip efficiency

The investment costs of the storage reservoir of power-to-methane and power-to-hydrogen are based on Liquefied Natural Gas storage (LNG) and Compressed Hydrogen Gas (CHG) storage tanks respectively. There is no separate investment cost for storage reservoirs in case of NaS batteries. All investment costs of NaS batteries are included in the capacity investment and the energy to power ratio is fixed at 8 MWh/MW for the purpose of this test case.
The cost factor C_{IDLE}, defined for power-to-methane units in paragraph 3.4.1, is fixed at 50 €/hour.unit and covers the cost of keeping the PEM electrolyser warm.

4.3.3 Market Data

All market data is based on the regulations and real-time measurement of the Belgian power system. Data provided by the Belgian TSO Elia was used to determine the demand profile (scaled to a 10GW peak demand system), generation profile of wind and PV power, forecast errors on the predicted wind and PV power generation and regulations on the sizing techniques for the operating reserves. These sizing techniques are discussed in detail in section 4.4.

4.3.4 Additional input Data

The system constraints presented in paragraph 3.4.2 require some additional information about the power system regarding the potential expansion of RES capacity, storage capacity and the gas infrastructure. Again, all data is based on the Belgian power system. All remaining necessary input data is listed here.
Equations 15 and 49 offer the possibility to include a minimum size of the storage reservoirs for seasonal and mid-term storage technologies. In the test case, these technologies are represented by p2g and PHS. A minimum size of the storage reservoirs is included based on Belgian's current PHS storage capacity (5.8 GWh [74], [75]) and underground gas storage facility of Loenhout (7.52 TWh [76]).
Equation 50 can restrict the energy storage capacity of the reservoir of any storage technology to a maximum value $E_{MAX}(S)$, e.g. based on the geological potential of a certain region. In Belgium, there is no potential to expand the underground gas storage. Therefore, the specific investment costs for the storage reservoir of power-to-methane and power-to-hydrogen were based on LNG storage and CNG storage. The maximum size of the total energy storage capacity of these energy storage options is not limited by any geological conditions. On the contrary, the possibility to extend the storage capacity of PHS is strongly dependent on the availability of favorable geological sites. Moreover, the decreasing public acceptance of large reservoirs and the restriction to develop PHS in nature protection areas further reduces the potential of PHS [77]. A recent assessment of the potential for pumped hydro storage in Europe concluded that Belgium has minimum potential [69]. The most optimistic scenario estimates the total potential at 12 GWh. Non-conventional PHS technologies like underground pumped storage in abandoned coal mines or artificial energy islands could raise this number. The construction of a 2000 MWh

artificial energy island is already proposed. Therefore, the test system assumes a maximum storage capacity of 15 GWh.
Regarding the gas infrastructure, the model requires input data about the import capacity or interconnection capacity of the gas transmission network. This data is obtained from the Belgian operator of the natural gas transmission system [78]. Further, equation 12 and 13 limit the injection and send-out capacity of the underground gas storage. These parameters are also based on the Loenhout storage facility. Finally, equation 10 determines the size of the line-pack energy buffer. Data about the inherent storage capacity of line-pack for the Belgian gas transmission grid could not be found. Based on the calculation found in the paper "multi-time period combined gas and electricity network optimization" [69] an estimation can be made. However, this model only considers the gas flows connected to the gas demand of the power sector while the other gas flows will also require part of the line-pack flexibility. Hence, the test case uses a conservative estimation of 100 GWh storage capacity in the network.
Equation 76 and 77 offer the possibility to restrict the primary energy use and the total installed capacity of each storage technology. Equation 77, restricting the installed capacity, is useful to take the maximum potential for installing wind energy into account. However, it is not activated in the test case. Equation 76, restricting the primary energy use, is applied to Biomass. Three possible scenarios for $E_{MAX}('Bio')$ are envisioned; no biomass, low estimate and high estimate. The numerical value for the high estimate is founded on a study of the Flemish Institute of Technical Research (vito) on the Belgium energy system. This study expects a potential biomass use in 2050 of 150 PJ/year [79] [80]. This value is corrected for the scaling factor of the demand profile. This results in a potential biomass use of 65TWh/year for the conceptual test system. The low estimate is based on the study of Sterner [56]. His estimation for the worldwide economic biomass potential for 2050 in power generation amounts 150 EJ/year. An allocation according to the 2050 population of Belgium and a similar rescaling results in a potential biomass use of 43 TWh/year.

4.4 Sizing the reserve requirements

This section presents the method for calculating the reserve requirements $Q^{UP}_{AFFR}(t)$, $Q^{UP}_{MFFR}(t)$, $Q^{DN}_{AFFR}(t)$ and $Q^{DN}_{MFFR}(t)$, introduced in equation 4-7 of the model. The method for calculating these reserve requirements can vary from TSO to TSO, therefore it is part of the input data of the power system.

4.4.1 Operating reserve requirements

The operating reserve requirements prescribe the generation capacity that should be kept available as reserve power. The reserve power enables the transmission system operator to react to unexpected changes in electricity generation or demand. The quarter-hour balance and the activation of the contracted reserves together ensure a

reliable operation of the power system and a stable frequency. Consequently, the allocation of operating reserve power is an essential aspect of the operation of the power system. A realistic minimization of the operational costs therefore requires the co-optimization of energy and reserve markets as is the case for this model.
The unexpected changes in generation and demand or imbalances can have different causes. The European network for transmission system operators for electricity (ENTSO-E) identifies five types of imbalances drivers [81]:

- Disturbance or full outage of a Power Generating Module, HVDC interconnector or load
- Continuous variation of load and generation
- Stochastic forecast errors of load and intermittent RES generation
- Deterministic imbalances
- Network splitting

A TSO has to take all these imbalance drivers into account when sizing the required operating reserve capacity. According to the network code of the ENTSO-E [82], the operating reserves can be divided in three different types; frequency containment reserves (FCR), frequency restoration reserves (FRR) and replacement reserves (RR).
FCR maintain the balance of generation and consumption in the synchronous area after an imbalance in the time frame of seconds [81]. The FCR capacity is shared among all TSOs of the synchronous area and automatically activated at the level of the synchronous area. The FCR capacity of the synchronous area of continental Europe is able to compensate for the simultaneous loss of two 1500 MW production units. The FCR capacity has to be fully deployed within 30 seconds after the imbalance occurred and be able to remain online for 15 minutes [61]. The contribution to the FCR of Belgium, used as reference for the test system, amounts 95-110 MW [65].
FRR regulate the frequency and restore the balance in the control area of the TSO in case an imbalance occurs, thereby relieving the system wide activated FCR. The FRR are divided in automatic FRR (aFRR) and manual FRR (mFRR). The aFRR regulate the frequency continuously and are activated automatically by the TSO's dispatching center. The mFRR on the other hand are activated manually. The activation of mFRR balancing energy is an ad-hoc decision of the TSO's dispatchers [83]. Such activation is only needed in the event of [84]:

- A major or systematic imbalance in the TSO's control area
- Significant frequency variation
- Major congestion problems
- The aFRR capacity is insufficient
- The aFRR has to be relieved for further imbalances

All FRR capacity has to be able to be fully delivered within at most 15 minutes [85]. The dimensioning of the FRR is based on the combination of a deterministic and probabilistic assessment [81]. The deterministic assessment dictates that the FRR capacity shall at least be able to cover the positive and negative dimensioning incident of the control area (the biggest deterministic loss in both directions, i.e. the N-1 principle, e.g. the loss of an HVDC interconnector) [86]. The probabilistic assessment determines the minimum FRR capacity based on a probabilistic sizing technique ensuring that system imbalances can be compensated at least 99% of the time in both directions. In case the minimum capacity of the probabilistic assessment exceeds that of the deterministic assessment, the dimensioning of the FRR is based on the former.

The RR are manually activated reserves with a full activation time between 15 minutes and up to one hour. The RR replace or support the FRR reserves. The allocation of RR is not compulsory but can be integrated in the dimension methodology of the FRR for economic reasons. The Belgian TSO Elia does not contract RR since the replacement role is already fulfilled by the market parties in the Belgian electricity system. Consequently, the test case will not consider RR.

4.4.2 Integrating the operating reserve requirements

This work focusses on the impact of RES and more specifically the reserve requirements following from their forecast errors. Following the approach of the Belgian TSO, that does not contract RR, but rather leaves this to the market [65], the imbalances caused by intermittent RES impact only the dimensioning of the FRR capacity. However, as the absolute magnitude of the forecast errors is not known, given that in an investment model the installed RES capacities are not known beforehand, an adjusted sizing procedure is developed. As such, the dimensioning of the FRR breaks down into two parts: an exogenous part and an endogenous part.

The exogenous part considers all imbalance drivers except the RES forecast errors. A combined deterministic and probabilistic assessment performed beforehand results in a fixed demand per reserve category (up- and downward automatic and manual FRR), independent of the installed RES capacity.

The endogenous part considers only the RES forecast errors and is consequently limited to a probabilistic assessment. The magnitude of a system imbalance caused by a forecast errors depends on the installed capacity of the intermittent RES [4]. Consequently the corresponding operating reserve requirements also depend on the installed capacity, which is determined endogenously within the investment model. To be able to implement this in a linear way a novel approach is developed. For each intermittent RES a normalized probability density function (PDF) is introduced. Such a PDF describes the normalized forecast error, obtained by comparing the normalized day-ahead forecast with the normalized real time output and describing the difference between the two in a distribution. Following the minimum reliability requirements imposed by ENTSO-E, the 99th percentile of this PDF is then the normalized FRR demand, i.e. the required amount of MW reserve power per MW of capacity installed for this type of intermittent RES. This requirement can now be integrated in a linear model. A more detailed description of this sizing method can be found in "The impact of operating reserves in generation expansion planning with high shares of renewable energy sources" [4].

One final adjustment needs to be made. The method described above for dealing with the RES forecast errors is a *static* sizing method, prescribing an amount of reserve power to be held independent of the predicted output of the intermittent RES. While

acceptable at low renewable penetrations, this results in very large amounts of reserve power to be held at high penetrations, sometimes even surpassing the actual renewable output. At such high levels of renewable penetration, it is therefore economically more interesting, while ensuring reliability, to use *dynamic* reserve sizing methods [87]. Given the targeted renewable penetrations in this work (up to 100%), such a *dynamic* sizing method will also be used here. Instead of introducing a single PDF per RES type, a PDF is drafted per generation output interval (e.g. 40%-60% of nominal capacity). This allows to determine the normalized 99% confidence interval, which is passed along to the model in the form of 2 time series per RES type (one for the upper boundary and one for the lower boundary). The difference between the forecast and the 99% confidence interval boundaries describes then the need for FRR, while accounting for scheduled curtailment.
The proposed methodology is clarified using the sizing of the upward FRR as an example. Fig. 5 shows the wind power generation forecast (black line) of a 2000 MW wind farm and the 99% confidence interval of this forecast (gray lines), the real-time generation (red line) and actual nominated capacity (green line) are drawn. Satisfying the 99% reliability imposed by the ENTSO-E now implies that the total upward FRR capacity should be able to provide the difference between the forecast and the lower limit of the 99% confidence interval, minus the scheduled curtailment (blue area). This is represented by the green area. This figure also shows that the need for upward FRR due to forecast errors can even be zero.

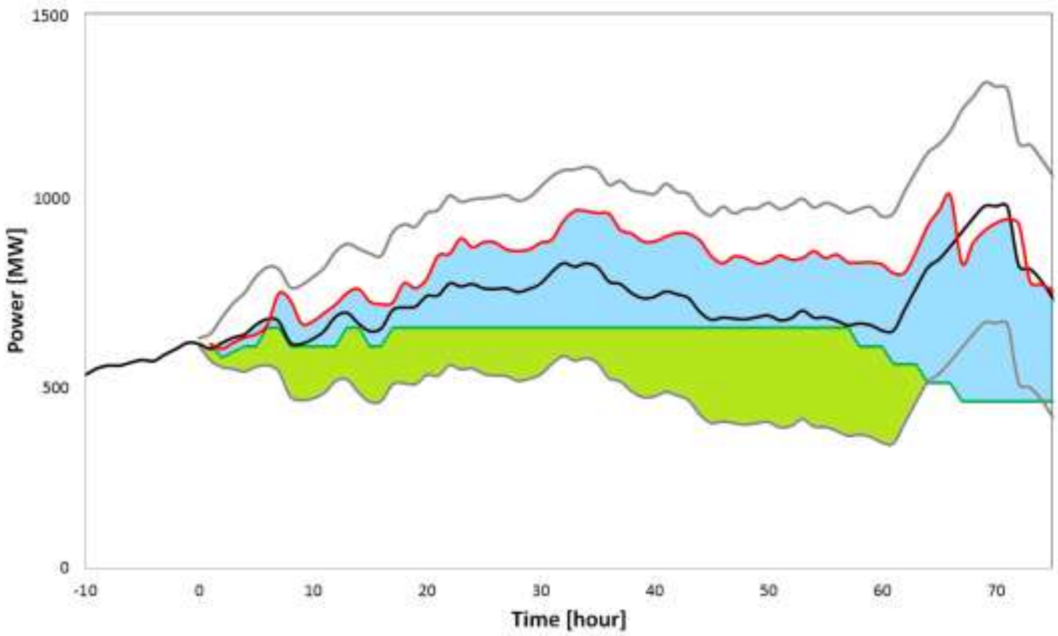


Fig. 5: determining the probabilistic upward FRR due to forecast errors of intermittent RES

In the terminology of the model description and including the lower limit of the 99% confidence interval of the forecasts as $VRES_{99\%}^{forecast}(r,t)$, this method is expressed as equation 78.

$$\forall t \quad Q_{AFRR}^{UP}(t) + Q_{MFRR}^{UP}(t) \geq \sum_{R} \left(VRES(R,t) - VRES_{99\%}^{forecast}(R,t) \right) \cdot cap(R) - curt(R,t) \tag{78}$$

While this method does allow for an endogenous calculation of the need for FRR driven by RES forecast errors, it does not allow to benefit of the possible coincidence of imbalances of different RES types. Also it assumes that the shape of the normalized PDFs does not change as the installed capacity increases. A possible reduction in the relative size of forecast errors, resulting from a greater geographical spread of RES installations as the installed RES capacity increases, is thus not considered. Overall, this method could thus result in an overestimation of the reserve power need. This, however, is the compromise that had to be made to include the requirements in an endogenous way.

4.4.3 Input data

Given that the main focus of this work is on the impact of the RES, the FCR requirement will not be included. As the requirement would only amount to around 100 MW, the influence hereof will be limited.
First, the exogenous part of the FRR requirements is determined. Reconsidering the imbalance drivers, this part encompasses all imbalance drivers except the forecast errors of RES. The assessment of the exogenous part is based on a study of the current Belgian power system. ENTSO-E network codes dictate that historic system imbalance data of at least a full year need to be considered. A combined probabilistic and deterministic assessment of the system imbalances of the Belgian power system for the year 2011 point to a 121 MW need for aFRR and 879 MW for mFRR (both upward and downward). The ELIA ancillary services study for 2018 indicates a need for aFRR ranging from 152 MW to more than 300 MW (symmetric), a need for downward mFRR ranging from 1 138 MW to more than 1750 MW and, finally, a need for upward mFRR ranging from 1078 MW to more than 1700 MW. Taking into account both these estimates, the fact that the ELIA study already considers some additional RES deployment and the 10 GW_{peak} size of the test system, the exogenous FRR requirements used in the test system are presented in Table 4.

	Automatic FRR		**Manual FRR**	
	upward	downward	upward	downward
2011 data	121 MW	121 MW	879 MW	879 MW
2018 ELIA low	152 MW	152 MW	1 078 MW	1 138 MW
2018 ELIA high	> 300 MW	> 300 MW	> 1 700 MW	> 1 750 MW
Model input	200 MW	200 MW	1 000 MW	1 000 MW

Tabel 4: FRR requirements of the Belgian power system and the exogenous FRR requirements of the test case

For the endogenous part of the FRR requirement, it is assumed that no additional downward reserve power is needed to deal with RES forecast errors. This stems from the assumption that TSOs (and/or BRPs) can perfectly control the real-time output of the intermittent RES in their system. In Spain this is already the case for wind power, where the TSO can remotely control 96% of the installed wind capacity [88]. In case of excess intermittent RES generation and insufficient downward flexibility in the rest of the power system, the excess renewable output can simply be curtailed. It would not be sensible to procure additional downward reserve power specifically for this, as this would simply entail additional costs.

Unfortunately, insufficient time was available to perform the probabilistic analysis needed to construct all required PDFs for the dynamic sizing method. As a compromise, the need for upward FRR due to forecast errors was implemented as a fixed percentage of the RES generation being $\bar{Q}^{UP}_{AFRR}(R)$ and $\bar{Q}^{UP}_{MFRR}(R)$, as formulated in equations 82-83. A thorough sensitivity analysis was performed for these percentages, showing that the results were almost completely insensitive to their exact level. The numerical values for $\bar{Q}^{UP}_{AFRR}(R)$ and $\bar{Q}^{UP}_{MFRR}(R)$ were varied for a range of 3-10% and 10-50% respectively, leading to over 1GW aFRR and 5GW mFRR in a 100% renewable scenario. However, the impact of even these reserve requirements was negligible. It seems there is a synergy between supplying dynamic upward reserves and back-up generation. When RES output is high, a lot of dispatchable generation is scheduled to supply reserve power. When RES output is low, little reserve power is needed and the previously scheduled generation becomes available to generate. The proposed simplified approach can thus be said to be sufficient.

$$\forall t \qquad Q^{UP}_{MFRR}(t) = \sum_{r} \bar{Q}^{UP}_{MFRR}(R) \cdot gen(R,t) \qquad (79)$$

$$\forall t \qquad Q^{UP}_{AFRR} = \sum_{r} \bar{Q}^{UP}_{AFRR}(R) \cdot gen(R,t) \qquad (80)$$

Chapter 5: Results and Discussion

5.1 Introduction

This chapter presents an objective overview of the most relevant numerical results, focusing on the impact of energy storage and the provision of operating reserves in a renewable power system. More interesting data could be obtained from the model, however the statement of results deliberately centers around the role energy storage and operating reserves since the availability of this data is the main distinguishing characteristic of this GEP model. To obtain these numerical results, the model is applied to the conceptual test system described in the precious chapter. For the most relevant topics a deeper analysis, clarification and qualitative interpretation of the numerical results is also included in this chapter.

First, the optimal generation portfolio, investment costs and operational costs are investigated as a function of an increasing share of renewable energy in the supply of electricity demand. A minimum share of renewable energy is always imposed as a constraint in the presented results. The share of renewable energy is increased from 0% to 100% in steps of 10%. This analysis is performed for the base-case scenario without biomass and the base-case scenario including the high estimate for biomass use in the power system.

Subsequently, the focus will be put on the 100% renewable energy scenario without biomass, as here the role of storage will be the most outspoken. The deployment of the charging and discharging capacity of storage plants and the evolution of the state-of-charge of storage reservoirs are studied in detail. The role of the different storage technologies in the power system is compared. Then, the electrical dispatch of all generation technologies for a typical summer week is considered. The allocation of the operating reserves also receives extensive attention. Finally, the operation of the gas infrastructure is considered.

At last a sensitivity analysis is performed, also concentrating on the 100% renewable energy target. The impact of decreasing investment costs of RES, rising fuel costs, different renewable generation profiles and the availability of power-to-hydrogen storage plants is assessed.

5.2 Base-case scenario

All the subsequent results are founded on exactly the same input data, namely the test system of chapter 4, except for the minimum target for renewable energy and the availability of biomass. As already mentioned, power-to-hydrogen will not be included in this set of generation and storage technologies. Demand profile and intermittent RES generation profile of these scenarios are all based on the Belgian power system for the metrological year 2013. The test system has a peak demand of 10 GW. An underground gas storage reservoir of 7.52 TWh and pumped hydro storage reservoir of 5.8 GWh are always included

.

5.2.1 Generation portfolio

This paragraph considers the evolution of the generation portfolio for a renewable energy target rising from 0% (equivalent to no target) to 100% in steps of 10%. Initially, biomass is excluded. Figure 6 shows the installed capacities of dispatchable generation (shaded area) and intermittent RES (hatched area). The installed charging capacity of the storage technologies is shown in figure 7.

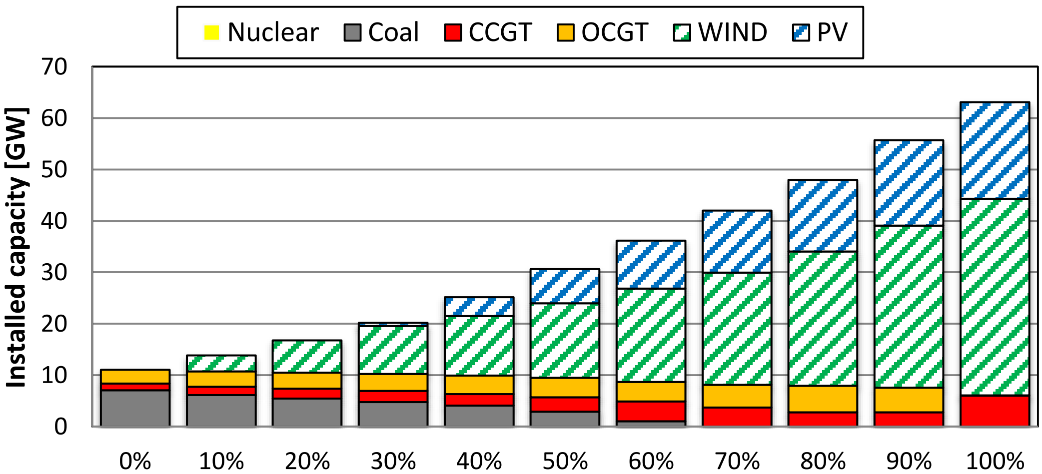


Fig. 6: Installed capacity of electricity generation technologies as a function of imposed share of renewable energy

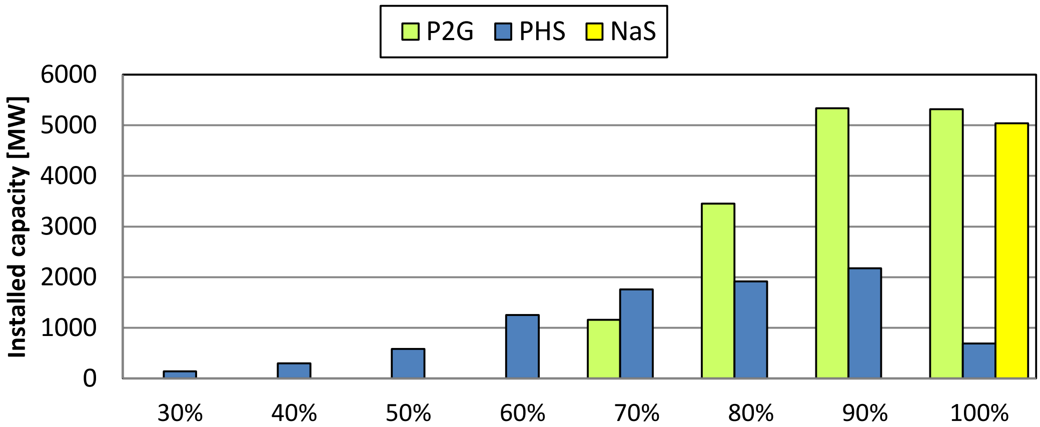


Fig. 7: installed charging capacity of energy storage technologies as a function of imposed share of renewable energy

Several important conclusions can be drawn from these two figures. First of all, imposing the renewable energy targets will massively increase the total installed generation capacity from approximately 10 GW to over 60 GW. In addition, the 100% renewable energy system needs over 10 GW of storage plants. Evidently, the share of wind power and PV power increase in accordance with the renewable energy target. The low capacity factor of these intermittent RES and the increasing amount of curtailment due to the mismatch in supply and demand are the main reasons for the massive increase of the installed capacity.

The 0% target scenario shows that the intermittent RES are not part of the most cost-effective generation portfolio. Thus, the intermittent RES are not competitive given the cost data presented in Table 2 of chapter 4. However, notice that the calculation of the total system cost disregards all external (environmental) costs. This result implies that subsidies or CO_2-emission costs are required to make the RES economically relevant for this cost data. No nuclear capacity is installed, independent of the renewable energy target. Even for base load operation with a maximum number of operating hours, the low fuel costs do not outweigh the higher investment costs compared to coal fired power plants, again given the cost data of chapter 4 and in absence of e.g. CO_2-emission costs.

PHS is cost-effective from a system's perspective starting from a 30% renewable energy target. The installed capacity increases monotonically towards the 90% target. As from 70% renewable energy, the energy reservoir capacity is extended from 5.8 GWh to the maximum allowed value of 15 GWh. The maximum potential for the energy storage reservoirs, based on the geological potential to expand PHS, prevents the PHS from reaching even higher cost-effective installed capacities.

Power-to-gas will become attractive from a societal point of view for the 70% renewable energy target and higher. The large installed capacity for 80-100% targets shows that p2g technology is an indispensable part of the generation portfolio towards 2050. The large-scale implementation of p2g enables the preservation of a significant capacity of gas fired power plants in the 100% renewable energy scenario. The capacity of GFPP first increases from 3790 MW at 0% targets towards 8160 MW at a 70% targets and subsequently decreases to 6050 MW at the 100% target.

Finally, the results emphasize that a major adjustment in generation portfolio, especially storage capacity, is required when raising the renewable energy target from 90% to 100%. NaS batteries, which are too expensive in the other scenarios, suddenly become a vital part of the generation mix. With 5 GW of charging (and discharging) power and 40 GWh storage capacity, NaS batteries become the dominant source of flexibility and operating reserves and push OCGT and PHS out of the market.
Another important conclusion contained in these results is the fact that a 100% renewable generation portfolio complying with the operating reserve requirements and technological constraints is found, only relying on the flexibility provided by dispatchable generation and energy storage. Recall that the model excluding the flexibility of energy storage could not generate a solution for a highly renewable energy system [28]. This upper limit on the share of renewable energy was a consequence of the growing demand for operating reserves as the share of intermittent RES increases. In absence of other sources of flexibility, these operating reserves must be provided by conventional generation units. Part of these operating reserves must be covered by spinning units, thereby imposing a minimum generation level of the conventional generation plants. This thermal must-run requirement prohibits the RES from delivering their energy to the market and at certain point the operating reserve requirements block a further increase in the share of renewable energy. A maximum share of renewable energy imposed by reserve requirements does not occur in this work. So the storage plants and GFPP running on synthetic methane offer enough flexibility to fulfill the reserve requirements in a 100% renewable energy system.

Intelligent reserve strategies

The introduction of storage technologies is not the only difference which facilitates the introduction of intermittent RES compared to the aforementioned study regarding this GEP model. The transition from a static reserve sizing process based on the installed capacity of intermittent RES to a dynamic reserve sizing process based on the instantaneous output of the intermittent RES has a large effect as well. After all, the static reserve sizing caused an overestimation of the required reserves most of the time. Because the sizing was based on the installed capacity, the reserve requirements were growing out of all proportion when imposing high renewable energy targets. When applying the dynamic reserve sizing process based on the generation level presented in the previous chapter, the upward aFRR requirement is limited to approximately 500 MW even if the demand is almost completely met by intermittent RES. This amount of upward aFRR can, in the extreme situations and without the availability of energy storage, be provided with an OCGT generation level of 55 MW and all OCGT units running at minimal stable power i.e. 10% of nominal power. All upward mFRR can be covered by non-spinning reserves if the installed capacity of CCGT and OCGT is large enough. The introduction of renewable participation for downward operating reserves makes it possible to cover the downward aFRR and mFRR requirements with the intermittent RES themselves. In other words, the minimum thermal must-run needed to provide the spinning reserves in a power system only relying on the flexibility of conventional generation technologies, amounts approximately 55 MW at all times. Investigation of the load duration curve of the OCGT plants proves that this behavior actually takes place in a highly renewable scenario without energy storage. This small amount of thermal must-run allows integrating a large share of renewable energy. The system simulations making use of dynamic reserve sizing show that an 80% share of renewable energy is attainable only relying on the flexibility of the conventional power plants. The argument for installing energy storage starting from a 30% renewable energy target is found in the reduction in total system cost. They are not strictly needed to cope with the variability of RES, but they do allow to cope with variability in a more economic way. The alteration in generation portfolio as a result of excluding storage technologies is shown in Fig. 8.

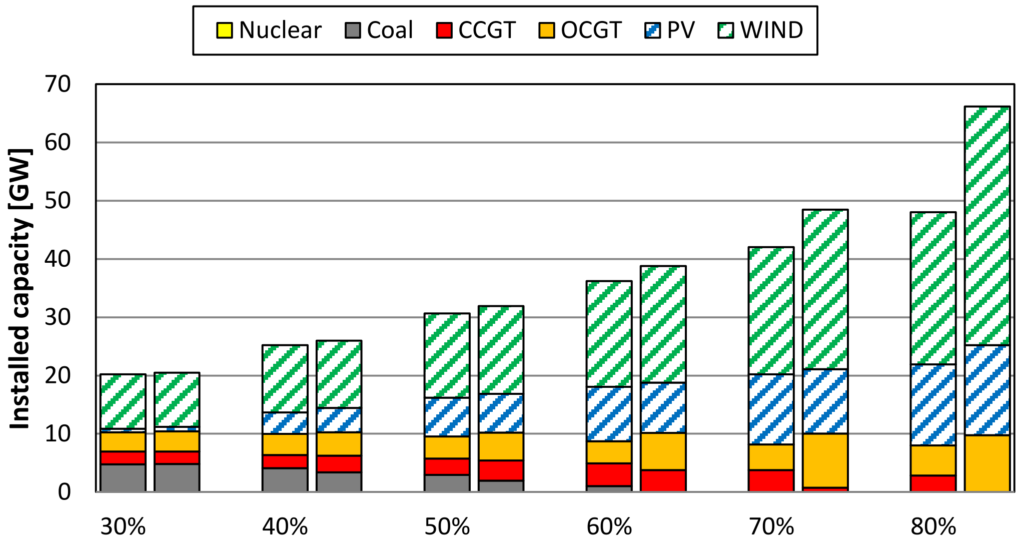


Fig. 8: Installed capacity of electricity generation technologies as a function of imposed share of renewable energy (no storage technologies included)

Clearly, the installed capacity of intermittent RES has to increase and the thermal base-load plants are pushed out of the market earlier when excluding energy storage. The dominance of high peak capacity strengthens and the total installed capacity of thermal plants has to remain at a level of 10 GW to overcome periods of marginal output of the intermittent RES. The larger installed capacity of RES and the impossibility to use any surplus energy results in a significant increase of the energy curtailed. The curtailment in the 80% target scenario more than quadruples from a volume the size of 15% of the yearly demand to almost 75% of the yearly demand.

Arbitrage vs. reserve provision

Energy storage delivers two crucial services to the renewable power system, the provision of operating reserves and temporal energy arbitrage. The latter ensures the energy system can bridge periods of low RES output. Therefore it stores part of the energy surpluses, accommodates short-term or long-term storage and bring the energy back to the market when needed. Which of these two crucial services determines the dimensions of the storage capacity is not obvious from the previous data. For that reason, the operating reserve requirements are deactivated and the results re-evaluated. Under these conditions, a power system consisting of solely wind and solar energy would be theoretically possible. The energy storage will only be needed to provide temporal arbitrage, meaning the model searches for the economic equilibrium between additional RES capacity and curtailment of the surpluses and the storage of energy surpluses. Fig. 9 gives a comparison of the installed storage capacities in case the reserve requirements are active (shaded area) and inactive (hatched area).

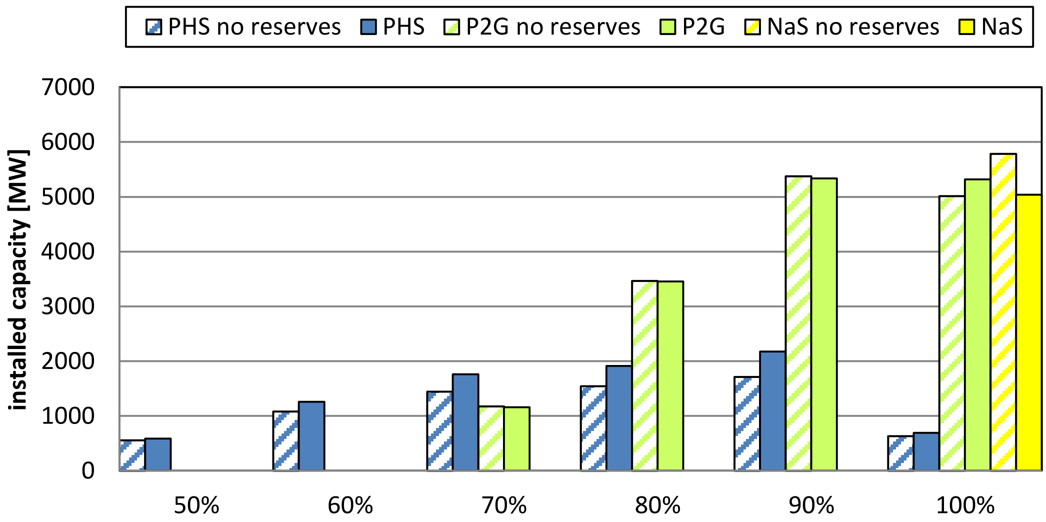


Fig. 9: installed charging capacity of energy storage technologies as a function of imposed share of renewable energy (comparing of model with/without operating reserve requirements)

The results show that the need for temporal energy arbitrage basically determines the dimensioning of the storage capacities. Although the provision of operating reserves could be as important as or even more important than the provision of temporal energy arbitrage, the economic optimal capacities required for temporal energy arbitrage also appear to be sufficient for the provision of operating reserves in all scenarios. The installed capacity of PHS is consistently 10 to 20% lower in case the reserve requirements are inactive. Further investigation showed that these flexible units do provide a lot of upward operating reserves which increases the value of PHS. The installed capacity of p2g matches very neatly in all scenarios. This proves that the need for temporal energy storage dictates the dimension of the capacity of seasonal storage. This important observation implies that a simpler formulation of the operational constraints would suffice to investigate the optimal capacity of seasonal storage.

With biomass

Biomass is now made available for the power sector. The impact on the generation portfolio is investigated. The input data showed that biomass power plants have very high investment costs and fuel costs. Therefore they cannot compete with conventional generation plants. Nevertheless, biomass will become part of the optimal generation mix starting from the 50% target for renewable energy since it can generate renewable energy regardless of the meteorological conditions and provide reserve power without adding to the need for reserves. This beneficial characteristic seriously diminishes the need for intermittent RES capacity in the 80-100% target scenarios. Fig. 10 shows the installed capacities of generation and storage technologies.

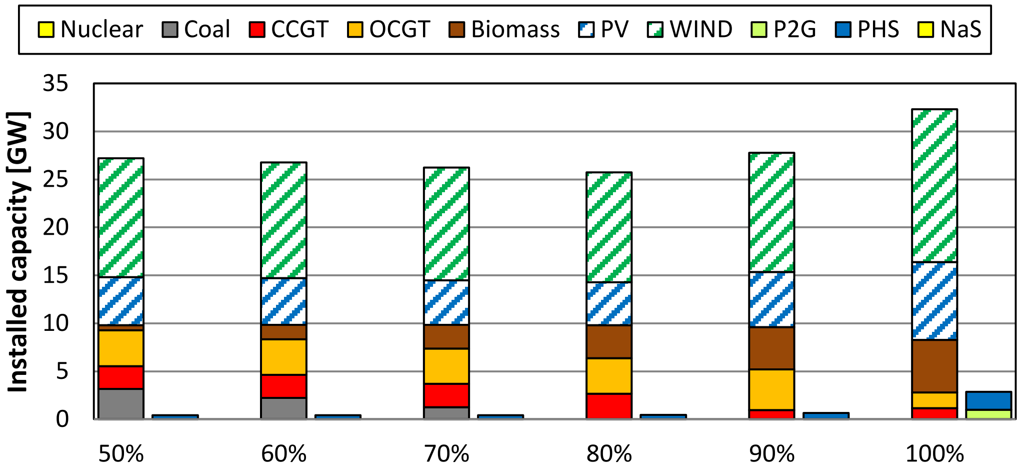


Fig. 10: installed capacity of electricity generation and energy storage technologies as a function of imposed share of renewable energy (scenario including biomass)

The figure shows that the total generation capacity in the 100% renewable energy scenario is reduced from approximately 60 GW to 30 GW thanks to the introduction of biomass. This is mainly due to the reduction of wind and PV capacity. But the reduction in storage capacity is even more dramatic. Only 1 GW of p2g and 1.8 GW of PHS capacity are required at the 100% target. The large need for NaS batteries is eliminated altogether. This is in line with the conclusion of the previous paragraph, namely the dimensioning of storage capacity is determined in the first place by the need for temporal energy arbitrage. If biomass can cover the periods of low intermittent RES generation, the need for storage is reduced greatly. The 1.8 GW of PHS and 2.5 GW of GFPP, combined with the spinning reserves of biomass suffice to provide all operating reserves in the 100% renewable power system.

Recall that the yearly energy potential of biomass was restricted. This constraint is binding starting from the 90% target. The effect hereof is clear from the change in trend toward the 100% target. Initially the biomass simply substitutes the fossil fuel thermal base-load plants. To reach the 100% target, energy storage and extra RES capacity are required.

5.2.2 Investment and operational costs

Since the target on the share of renewable energy is always binding, the total system cost increases monotonically as a function of this target. This is represented in Fig. 11 for the base case scenario (operating reserve requirement always included).

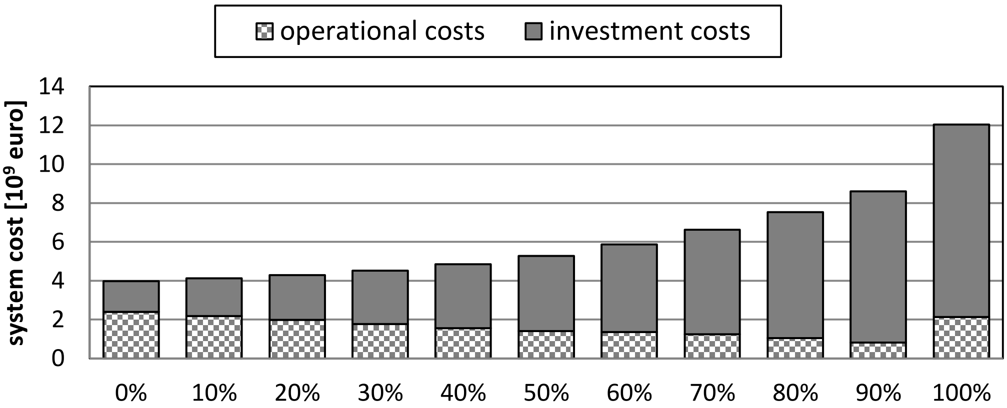


Fig. 11 total system cost as a function of imposed share of renewable energy

The overall trend in system cost is nearly exponential. The additional costs of the renewable energy targets are quite moderate at first. To clarify, a 60% target means the system cost increases by 50%. Eliminating the final percentages of fossil energy is however very costly. The 90% target doubles the system cost, the 100% target even triples the system cost. The effect largely results from the increase in investment cost which is directly coupled to the findings of the previous paragraph. The need for capital intensive storage and RES capacity triggers the exponential increase. The operational costs show an anomaly in the 100% scenario which is yet again attributed to the large capacity of NaS batteries. At first, the operational costs decrease steadily due to the fuel savings. The upswing in the 100% scenario follows from the high variable operating & maintenance costs of NaS batteries.

The previous paragraph showed the introduction of biomass seriously reduced the installed capacities of generation and storage technologies. Accordingly, the investment costs decrease. Table 4 and 5 present these investment costs and the operational costs expressed relative to the total system cost of the 0% target scenario (3.99 $*10^9$ euros). The operational costs of the 50%-90% target scenarios are higher for the scenarios with biomass due to the large fuel and variable operating & maintenance cost of biomass. This difference almost disappears at the 100% target as a consequence of avoiding the necessity to install NaS batteries and the corresponding operational costs.

no biomass	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
System cost	133%	147%	166%	189%	216%	302%
Investment cost	97%	113%	135%	163%	195%	249%
Operation cost	35%	34%	31%	26%	20%	54%

Table 5: system cost expressed relatively to the situation with 0% target for renewable energy. Scenarios without biomass, with an increasing share of renewable energy

With biomass	50%	60%	70%	80%	90%	100%
System cost	133%	144%	155%	166%	180%	207%
Investment cost	91%	95%	99%	103%	117%	150%
Operation cost	42%	49%	56%	63%	63%	57%

Table 6: system cost expressed relatively to the situation with 0% target for renewable energy. Scenarios with biomass, with an increasing share of renewable energy

Finally, the effect of excluding all energy storage technologies from the generation portfolio on the total system costs is analyzed. The results of the previous paragraph indicated that the installed capacity increases and consequently the investment costs will rise as well.

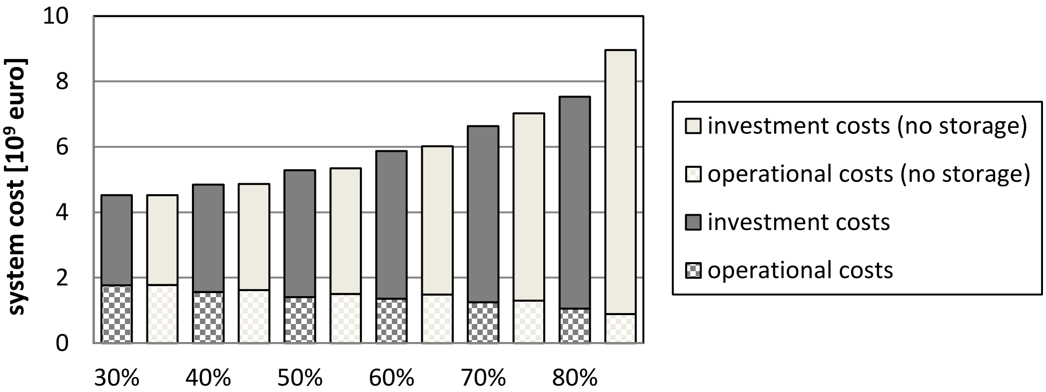


Fig. 12: total system cost as a function of imposed share of renewable energy. Comparison of scenarios with/without storage

The change in total system costs appears to be quite moderate for renewable energy targets up to and including 50%. Even at a 60% renewable energy target, excluding energy storage only involves a 4% rise in total costs. More stringent targets will significantly increase the possible reduction in system costs of energy storage. In case of 80% target, energy storage realizes a cost reduction of 16% or 1430 M€. Recall that a higher share of renewable energy is not attainable without energy storage for this conceptual system.

The importance of seasonal storage in fully renewable power systems

In order to estimate the value of seasonal storage specifically, the simulation were repeated for a scenario with PHS and NaS storage but without p2g. This situation does provide a solution for the 100% renewable energy target. However the numerical results are not very relevant. In absence of any alternatives, the model will employ NaS battery storage for long-term storage. The need for a high energy storage capacity leads to a solution with 38 GW of NaS batteries in the 10 GW peak system. The installed capacity of wind and PV power nearly doubles, and as a result the system cost explodes. This solution can be rejected and it can be concluded that seasonal energy storage will be a crucial part of the generation portfolio for fully renewable energy systems.

Evaluating the 80% renewable energy scenario without seasonal storage does allow to draw some conclusions. An additional 3 GW of wind, 4 GW of PV and 1.5 GW of NaS battery storage take the place of the 3.5 GW of p2g. Total system cost rises by 5.6% or 4.2 10^8 euro. Remarkably, the operational cost increases by just 19 10^6 euro. This is a very important observation. Recall that most benefits of p2g mentioned in literature focus on the operational aspects and associated reduction of the operational costs, e.g. load levelling and providing ancillary services. The results of this model indicate that the benefits of reducing the installed capacity of RES and other (more expensive) storage technologies largely dominates the total benefits of p2g for the power system. Thus, it can be concluded that incorporating the change in generation portfolio is vital to assess the value of seasonal storage. Consequently, operational power system models will not be able to correctly estimate its full value.

5.2.3 Capacity factors and load duration curves

A load duration curve shows the cumulative frequency distribution of the load or generation level [89]. Load duration curves lose all chronological information, however they give a synoptic representation of the load and generation level data over a whole year and are easy to interpret. The duration curve of a generation technology gives a good picture of the capacity utilization. The utilization can also be captured by one number, the capacity factor (the ratio of the average power over a whole year and the nominal power). In this work, load duration curves are used to clarify the differences in the operation of generation and storage technologies, residual load and provision of operating reserves caused by the increasing target on the share of renewable energy.

Fully renewable power system

The load duration diagram in figure 13 gives an overview of the generation and curtailment levels in the power sector for a 100% renewable energy system without biomass. Figure 14 does the same for the 50% target without biomass.

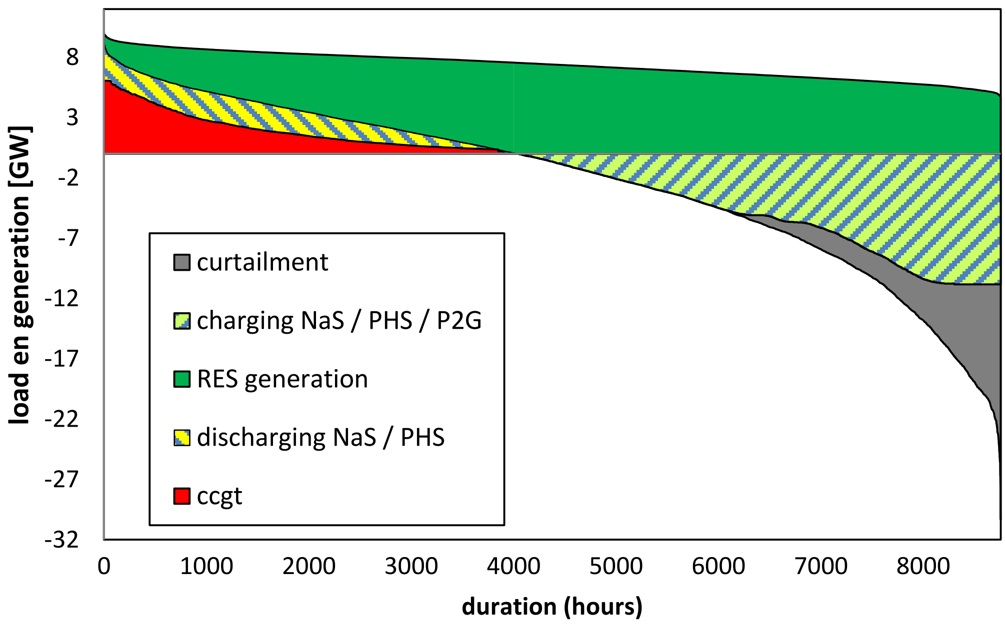


Fig. 13: load duration curve of the electricity generation, charging, discharging and curtailment level over a whole year for a 100% target on the share of renewable energy

The impact of the intermittent RES is very clear for the case of a 100% targets . The surplus generation has a pronounced peak and reaches a maximum of 30.3 GW, necessitating a peak curtailment of over 20 GW. Nevertheless most of the surplus energy is captured by storage plants. To be precise, 25.7 TWh of the 34.2 TWh of surplus energy is captured by p2g, NaS and PHS plants. The stored energy is reconverted to electricity via discharging of the NaS batteries and PHS plants (9.5 TWh) and CCGT plants running on synthetic methane (7.8 TWh). The discharging fully covers the residual demand since fossil back-up power is not allowed in a 100% renewable energy system. Notice that wind and PV energy meet the full electricity demand during 4710 hours.

Two plateaus exist in the duration curve of the charging power. This is a consequence of the installed capacity of p2g and the total installed storage capacity. Remarkably, during 2060 hours curtailment is applied despite that the storage capacity is not charging at full capacity. Analysis of the chronological data shows that the limited energy reservoirs of the short- and mid-term storage units cause this effect. Indeed, the operation of storages units is not only restricted by its nominal power, the limited size of the energy reservoir can prevent further charging or discharging as well. The data shows that PHS and NaS batteries frequently hit their energy capacity limit. The seasonal gas storage capacity on the contrary does not restrict the operation of the p2g units. Consequently, the first 5 GW of surplus are always used. This also explains the first plateau at 5 GW, the installed capacity of p2g. The extra curtailed energy, which would not be found using a screening curve method, accounts for 3.6 TWh of the total 8.5 TWh of curtailment.

50% renewable power system

A similar load duration diagram is drafted for the 50% target on the share of renewable energy. This is presented in Fig. 14.

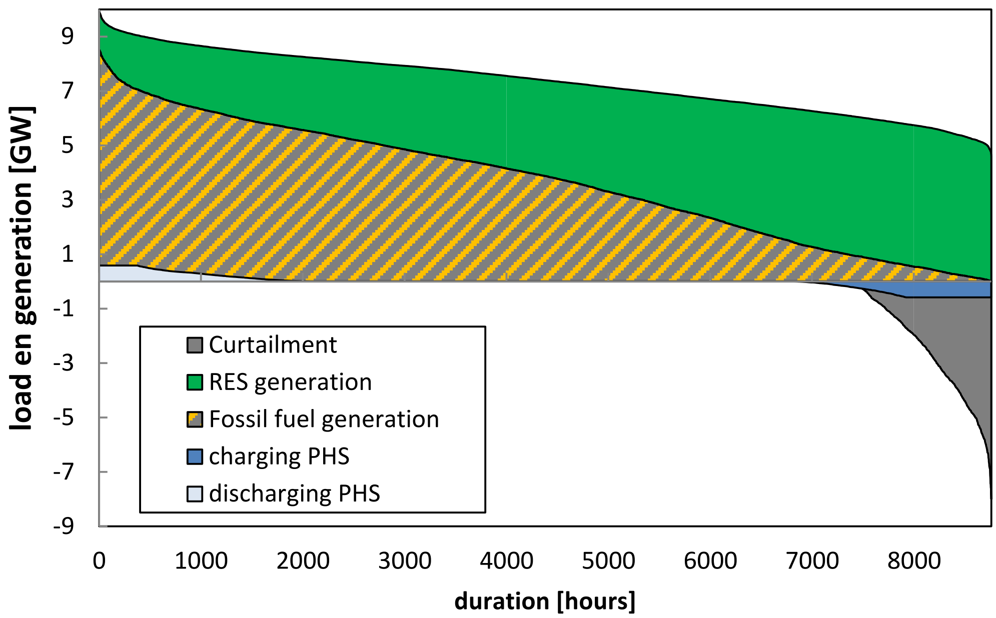


Fig. 14: load duration curve of the electricity generation, charging, discharging and curtailment level over a whole year for a 50% target on the share of renewable energy

The load duration diagram for the 50% renewable energy scenario without biomass shows a different picture. The peak in surplus energy tops at 8 GW. The total excess of renewable energy amounts 3.51 TWh. 0.74 TWh of the excess energy is used by PHS, the rest is curtailed. 31.48 TWh or 49.1% of the total demand is directly met by wind and PV, the final 0.3% needed to reach the renewable energy target is provided by PHS. This demonstrates that the contribution of energy storage is rather limited in the 50% renewable energy scenario. The chronological data shows that the PHS capacity is mainly needed to provide the upward aFRR in periods of high RES generation. In absence of spinning reserves in these periods, the upward aFRR can only be provided by flexible storage technologies. In total, PHS delivers 58% of the upward aFRR (see Fig. 15). This strengthens the idea that the PHS capacity could be needed to provide operating reserves rather than allowing temporal energy arbitrage.

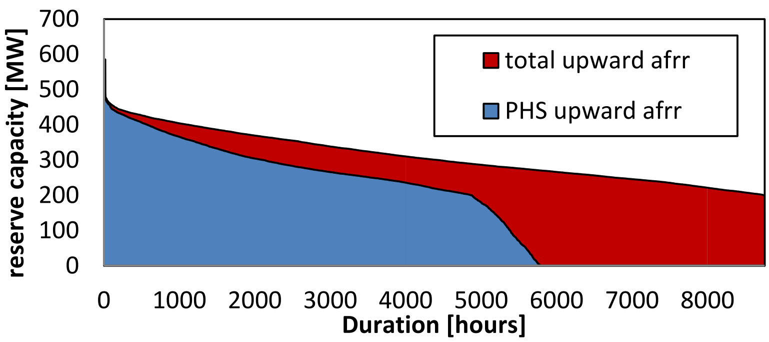


Fig. 15: load duration diagram of the upward aFRR in case of 50% renewable energy target

The load duration diagram of the 50% renewable energy case holds another interesting observation. The thermal generators do not simply cover the residual demand, they are running more hours than is strictly necessary, as the overlap of the area of fossil fuel generation and curtailment indicates. The chronological data confirms curtailment of RES generation and fossil fuel based electricity generation does take place simultaneously. This occurs in a large number of instances but for very short time periods, typically a few hours. The inflexibility of thermal base-load plants and the avoidance of start-up costs explain this behavior. Such effects are only visible when using a dynamic model evaluating chronological data and incorporating a detailed description of the operational constraints. This underscores the added value of the model formulation.

Capacity factors of thermal generation technologies

The effect of an increasing renewable energy integration is most clear for CCGT units. The changing role of CCGT is exemplified in Fig. 16. The normalized duration curves accentuate the capacity problem which occurs at high renewable energy targets and especially hits CCGT units. The number of full load hours drops from 4311h to 1345h, seriously undermining the profitability of CCGT units. The similarity of the 0% target and 50% target curve is striking. This proves that the generation of intermittent RES substitutes coal fired power plants in the first place. The tail of both duration curves deviates, indicating that the 0% renewable energy case requires a small output of CCGT more often. This effect follows from the need for fast-acting downward operating reserves which imply a thermal must run on the GFPP. For the 50% target case, PHS and RES take over this role. PHS can provide the downward operating reserves by allocating charging power. Keeping the charging power available has practically no cost in this model since activation costs are not considered. Providing the downward reserves with CCGT causes fuel costs, consequently the model will preferably rely on PHS.

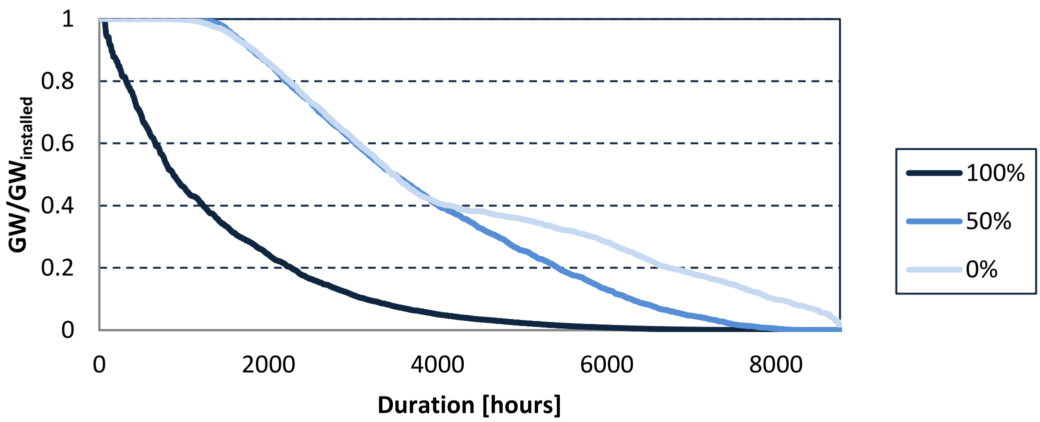


Fig. 16: load duration curves of CCGT plants for a 0%, 50% and 100% share of renewable energy

The decreasing number of full load hours with a rising renewable energy targets is a more general problem affecting all thermal power plants and endangering the business case of these technologies. Because the capital intensive base-load plants are most sensitive to a decrease in full load hours, they will be the first to exit the market. This is also reflected in the socially optimal generation portfolio which does not contain coal fired power plants for renewable energy target over 70%.
The low capacity factor of the intermittent RES is the main reason for the large expansion of the total installed capacity. Even more, installing an extra MW of intermittent RES will always aggravate the problem of the low capacity factors since the model applies linear upscaling of a deterministic RES generation profile. I.e., the peaks in RES generation will become more pronounced and more curtailment will be necessary. Furthermore, the availability of renewable energy generation reduces the capacity factors of thermal base load technologies (Coal and Biomass). Table 7, representing the number of full load hours of the thermal generation technologies, supports this statement.

	No biomass			**With biomass**			
	coal	OCGT	CCGT	coal	OCGT	CCGT	biomass
0%	8132	371	4311	8132	371	4311	
20%	7679	425	4258	7679	425	4258	
50%	6257	800	3810	6503	693	3820	7591
80%		1608	3049		756	3798	7253
100%			1345		121	740	5327

Table 7: number of full load hours of coal, OCGT, CCGT and biomass

OCGT unit follow an opposite trend, attaining a higher number of full load hours in renewable power systems. This underscores the importance of good dynamic characteristics in a renewable power system. Further, the difference in base, mid and peak units is clearly reflected in the number of FLH. The higher investment costs of biomass plants compared to coal fired power plants result in an even higher number of FLH for biomass when both are part of the generation portfolio.

Capacity factor of RES and energy storage technologies

Energy storage will counter the capacity problem by taking up the energy surpluses which would be curtailed otherwise. As such, the capacity factor of the RES is increased again. Table 8 shows that the economic optimal level of curtailment remains more or less the same from the 80% to the 100% target, despite the 42% increase in capacity of the intermittent RES. This translates in an increased number of full load operating hours for both wind and PV power. This is another proof of the importance of temporal energy arbitrage in fully renewable power systems.
The total yearly generation of the RES is also striking. To cover 100% of the demand with renewable energy, a RES capacity capable of providing a volume the size of 151.1% of the yearly demand should be installed. Thereof, 73.1% directly covers the electricity demand, 30.3% is curtailed and 47.7% is captured by energy storage.

	Energy produced [TWh]	energy [% total demand]	Energy Curtailed [TWh]	FLH [h]
20%				
Wind	12.881	20.1%	0.017	2053.2
solar	0	0	0	0
50%				
Wind	29.765	46.4%	1.949	1921.4
solar	6.496	10.1%	0.455	910.7
80%				
Wind	53.660	83.6%	7.465	1770.0
solar	13.663	21.3%	2.174	823.5
100%				
Wind	78.614	122.5%	8.063	1845.2
solar	18.370	28.6%	1.766	885.2

Table 8: Energy produced, curtailed and full load hours of intermittent RES per year

The storage technologies also suffer from a low capacity factor, which could result in a negative return on investment in a liberalized market given the elevated investment costs. The capacity factors for the 50, 80 and 100% renewable energy target are shown in Table 9.

Target	50%			80%			100%		
technology	NaS	P2g	PHS	NaS	p2g	PHS	NaS	p2g	PHS
CF			16.5%		16.4%	13.7%	10.9%	42.8%	32.1%

Table 9: Capacity factor of energy storage technologies for a 50%, 80% and 100% share of renewable energy

The chronological data reveals that storage plants do not only suffer from a low number of full load hours, they are typically committed for short periods of time and have to sustain high ramping rates. In conclusion, despite the fact that the provision of temporal energy arbitrage will determine the installed capacities of storage technologies, the storage plants have to be very flexible. Thus, the fast-ramping PEM electrolysis cells are the appropriate electrolyzer technology from a power system's perspective. This justifies the design choices of section 2.5.

5.2.4 Management of the energy reservoirs

The model has a perfect forecast perspective, consequently the state-of-charge of the storage reservoirs is managed optimally. In this sections, the long-term and short term trends of the state-of-charge are discussed.

First, the seasonal underground gas storage is considered. The most meaningful information concerning seasonal storage is contained in the long term evolution. Therefore the profile of the state-of-charge for a one year time period is considered. Fig. 17 presents this profile for underground seasonal gas storage in case of a 100% renewable energy target. Recall that the seasonal gas storage reservoir has a predetermined minimum size of 7.52 TWh, thus the maximum energy limit is not a binding constraint in this scenario.

Analysis showed that the evolution of the state-of-charge of the seasonal storage is directly coupled to the (time averaged) residual demand. The moving average with an interval of 168 hours (or one week) of the residual demand is also displayed in Fig. 17.

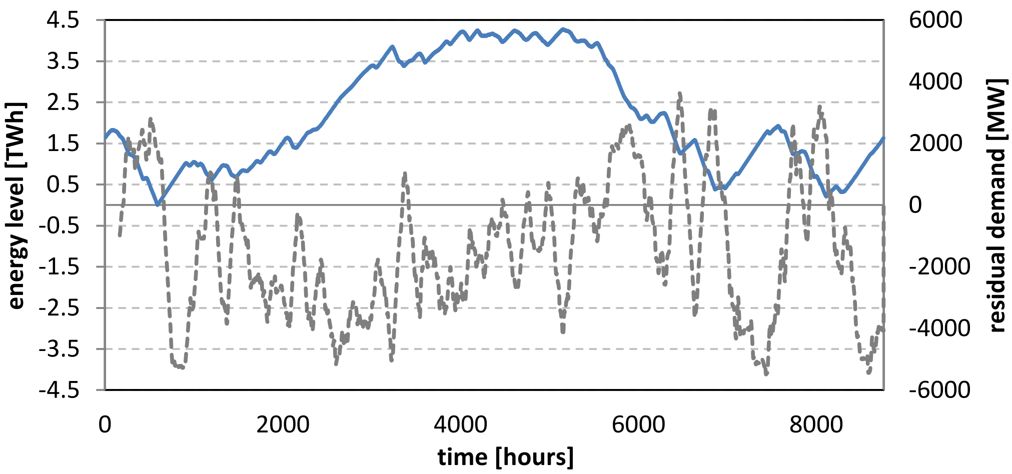


Fig. 17: Energy stored in seasonal gas storage and residual demand over a whole year, 100% target

The picture is quite different in case of a 80% target. Here, the energy capacity of 7.52 TWh is clearly a binding constraint. However, the model does not decide to address the possibility to expand the seasonal storage capacity with LNG storage. The fact that the operation of the p2g plants will be restricted by the energy limit of the seasonal storage reservoir explains the lower capacity factor of p2g in case of 80% target. This unexpected behavior, namely the larger need for seasonal storage in case of an 80% target, is caused by the massive capacity of NaS batteries and intermittent RES in the fully renewable power system. The larger capacity of RES causes periods of negative residual demand throughout the whole year. Moreover the periods of enduring positive residual demand become shorter by expanding the RES capacity. In case of a 100% renewable power system these periods are often that short they can be covered with short-term storage and consequently the need for seasonal storage decreases. In addition, the p2g plants can operate more flexible in the power system in this way. It is concluded that short-term storage and seasonal storage do compete each other instead of being complements.

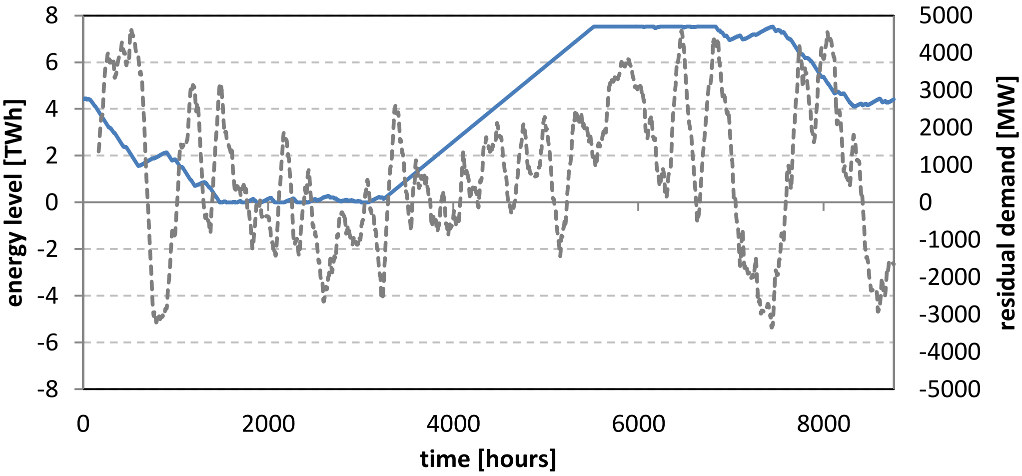


Fig. 18: energy stored in seasonal gas storage and residual demand over a whole year, 80% target

The impact of introducing biomass on the value of seasonal storage is unmistakably large. Power-to-gas as a storage technology is banned from the optimal generation mix in the 80% renewable energy scenario and reduced to 978 MW in case of a 100% target. The shape of the state-of-charge profile is still largely the same, however only 980 GWh of the storage reservoir is actually used.

Notice that the introduction of a time-dependent gas price, more expensive in winter months and cheaper in summer months, results in an utilization of the full underground storage capacity for the 0% and 20% renewable energy scenarios. The storage reservoir is filled at rated capacity during 96 days of low gas prices. Then, the gas demand of GFPP during spring and autumn is mostly covered by gas imports. The demand during the winter months is completely met by stored gas. This behavior might change when introducing the industrial and residential gas demand. Moreover, the operation of the underground gas reservoirs should also incorporate the need for strategic gas reserves.

To get a better understanding of the short term operation of the storage reservoirs, heat-maps representing the state-of-charge of the reservoirs are constructed. These heat-maps are particularly useful to track reflexive daily patterns. Figure 19 demonstrates its use for evaluating the role of NaS batteries for the 100% renewable scenario. The time range on the vertical axis is limited to 100 days. The represented time range falls in the period May-June-July-August. During these months, the state-of-charge consistently reaches its daily maximum in the afternoon and its minimum during the morning peak demand. The state-of-charge follows a daily pattern determined by the PV generation. No clear daily pattern can be distinguished during the winter months. Instead, the state-of-charge is kept at a certain level for much longer periods, typically 5 to 10 days. Apparently, the state-of-charge of the NaS batteries then follows the generation of wind instead of PV power. It turns out that the introduction of biomass does not significantly alter the operation of the short-term storage technologies.

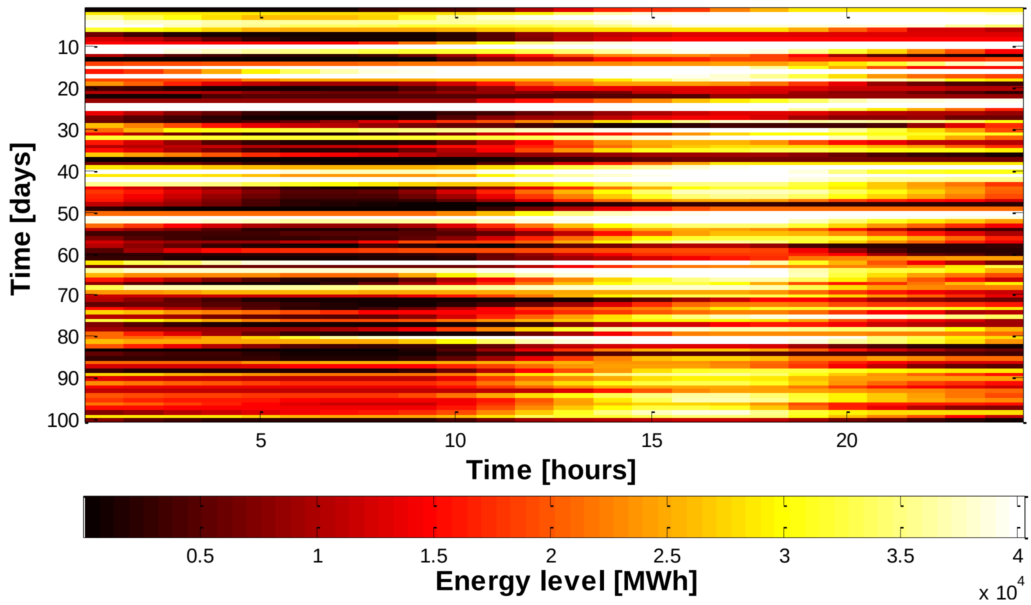
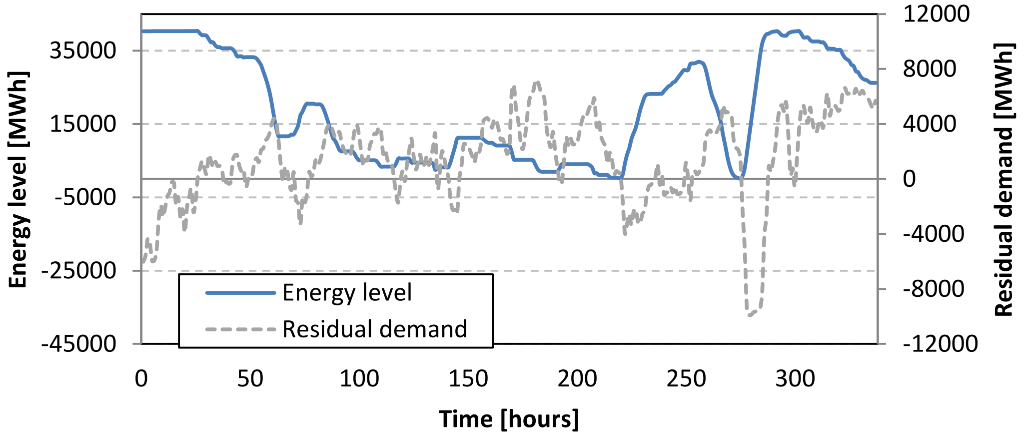


Fig. 19: heat-map representing the state-of-charge of NaS batteries over a whole year, 100% renewable energy target

Finally, graphs representing the time series data of the state-of-charge over a small time period are constructed. These figures help to identify the main drivers for managing the short-term operation of storage technologies. Fig. 20 presents chronological data of the energy level of NaS batteries for the 100% target (40 GWh energy storage capacity) for a time period of two weeks during winter and summer respectively. The residual demand is added on these graphs and represented on a secondary axis. Clearly, the charging of the NaS batteries is determined by the occurrence of a negative residual demand.



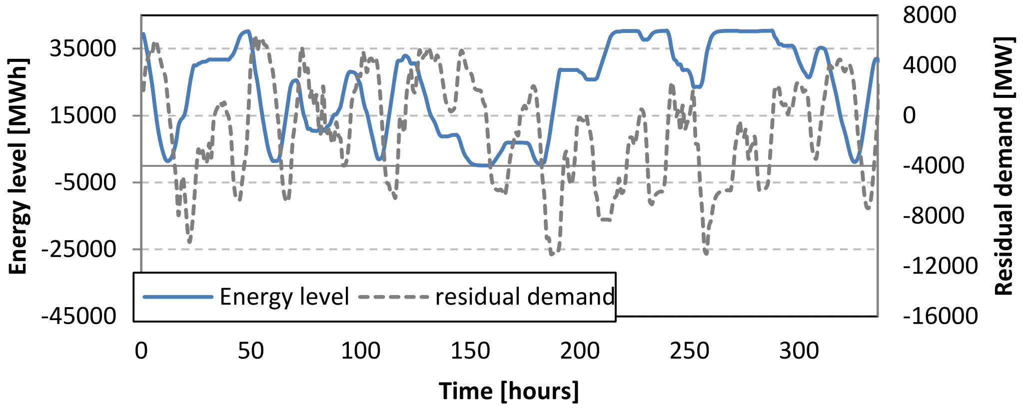


Fig. 20: energy level of NaS battery storage over a period of 2 weeks in winter (above) and summer (below)

The decision to discharge is less obvious from these figures and cannot be explained by the residual demand only. Since the 100% renewable power system cannot rely on any electricity generation from fossil fuels, a positive residual demand has to be covered with either storage technologies or GFPP running on synthetic methane. The choice between those two options is determined by the dynamic characteristics of the residual demand. Fast variation and the highest peaks in residual demand are covered with NaS batteries and PHS. The CCGT units, capable of providing much more energy, cover longer periods of positive residual demand. Again, this picture does not alter significantly when introducing biomass. Longer periods of positive residual demand will now be covered by biomass but the operation of short-term storage remains the same.

The two previous figures show that the state-of-charge of the NaS batteries frequently hits its maximum capacity. Complete depletion of the energy reservoir is however avoided most of the time. Since the model has perfect foresight perspective, this behavior is not expected. Apparently, this effect results from the introduction of the operating reserve requirements. Namely, the NaS batteries are vital for the provision of upward operating reserves. The allocation of upward operating reserves requires maintaining a minimum level of energy to be able to actually deliver these reserves when addressed by the TSO. The fraction of the energy reservoir that should be retained in order to provide the operating reserves is displayed in Fig. 21 as the shaded area. The figure also demonstrates that the highest levels of reserve capacity are provided during periods of charging or discharging.

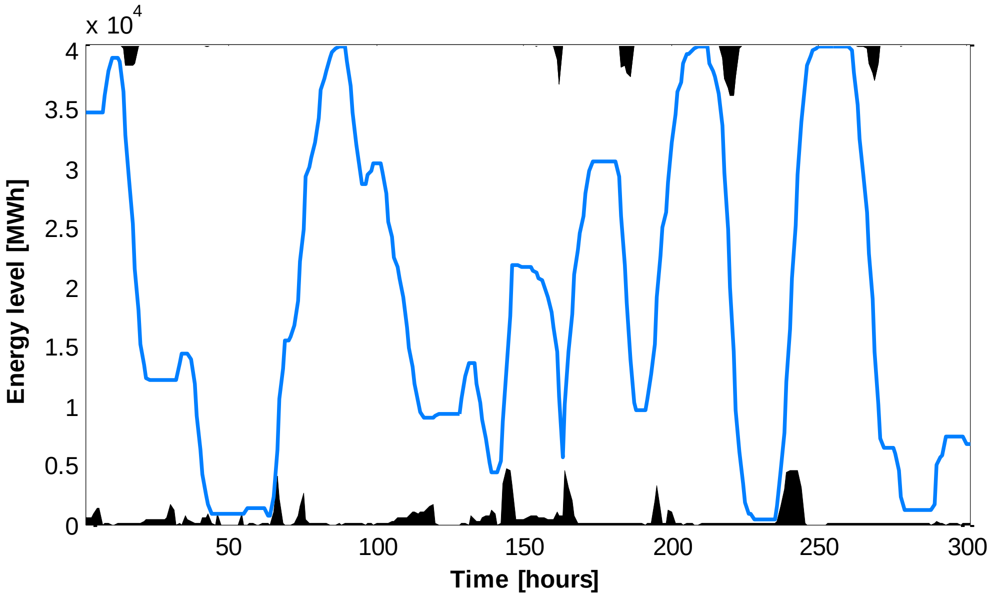


Fig. 21: Energy level of NaS battery storage over a period two weeks in summer. Shaded area represents the energy needed to provide the allocated operating reserves

Of course, the most drastic differences in energy management originates from the difference between seasonal storage and short-term storage. The difference between short-term and seasonal storage can be displayed by the power to energy ratio of the storage technology. Recall that NaS batteries have a fixed power to energy ratio. The power to energy ratio of PHS and p2g can vary depending on the investments in storage reservoirs. The balance of the various investment costs and the requirements of the power system determine the optimal ratio. A second parameter is introduced to distinguish between seasonal and short-term storage, being the ratio of the total energy stored per year over the storage capacity of the reservoir. This gives an idea of the number of charge and discharge cycles per year.

	100%			**80%**		**100% biomass**	
technology	p2g	PHS	NaS	p2g	PHS	p2g	PHS
Energy/power	1415	21.8	8	2178	7.8	7690	8.1
$E_{stored}/E_{reservoir}$	2.65	128.97	119.04	1.3	153.47	0.38	143.37

Table 10: comparison of charging capacity and energy reservoir capacity of the storage technologies

Apparently, the operation of PHS and NaS is quite similar in this model and they both tend to follow short-term, daily variations. It also demonstrates that the p2g plants are operated more flexible in the 100% renewable energy target scenario. Besides the PHS is operated more dynamically in case of an 80% target. Finally, the same parameters for the 100% renewable energy scenario including biomass is presented. As the rest of the data analysis points out, the functioning of the short-term storage technologies is very similar. The available seasonal storage reservoir however is only partly employed.

5.2.5 Electricity dispatch of a particular week

The dynamic model formulation makes it possible to access full chronological data about the electricity dispatch and the allocation of reserve capacity over the full year. This data holds an enormous amount of information and enables a very detailed analysis of the operation of the electricity system. Due to the limited amount of time and to keep the presented data comprehensible, the analysis is restricted to a general consideration of a particular week.

A representative week with high renewable energy generation is chosen, namely the third week of June 2013. The weekly averaged residual demand is negative so the energy storage reservoirs will be charged during this week. The selected week is particularly interesting because the wind production is low during the first days and relatively high at the end of the week. Fig. 22 shows the electricity dispatch of this week.

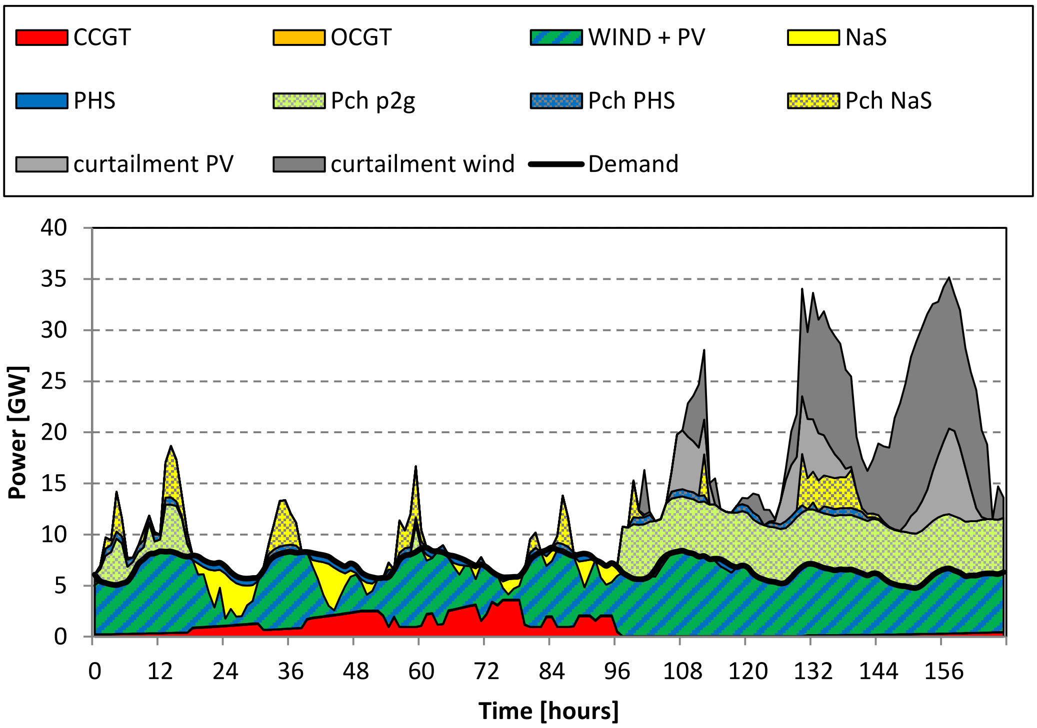


Fig. 22: electricity dispatch during a typical summer week, 100% renewable energy scenario

During the period of high wind generation at the end of the week, demand is met completely by renewable energy generation and p2g is charging at its maximum capacity of 5.3 GW. In addition, large curtailment of renewable energy is necessary.

During the first four days, the RES are not sufficient to meet the full electricity demand. CCGT plants support the RES production, especially during the evening and night. The NaS batteries and PHS clearly follow a daily pattern, charging at noon and discharging in the evening and night. This daily pattern was already perceived when evaluating the evolution of the state-of-charge in paragraph 5.2.4. As the load duration curve of Fig. 13 already indicated, the first 5 GW of surplus power is always captured by energy storage. The limited size of the energy reservoirs inhibits short-term and mid-term storage from charging during prolonged periods of negative residual demand.

Fig. 23 gives a detailed picture of the electricity generation during the first four days. This accentuates the strong variability of PV power. It appears that PHS is operated quite inflexible while all strong output variations are absorbed with NaS batteries.

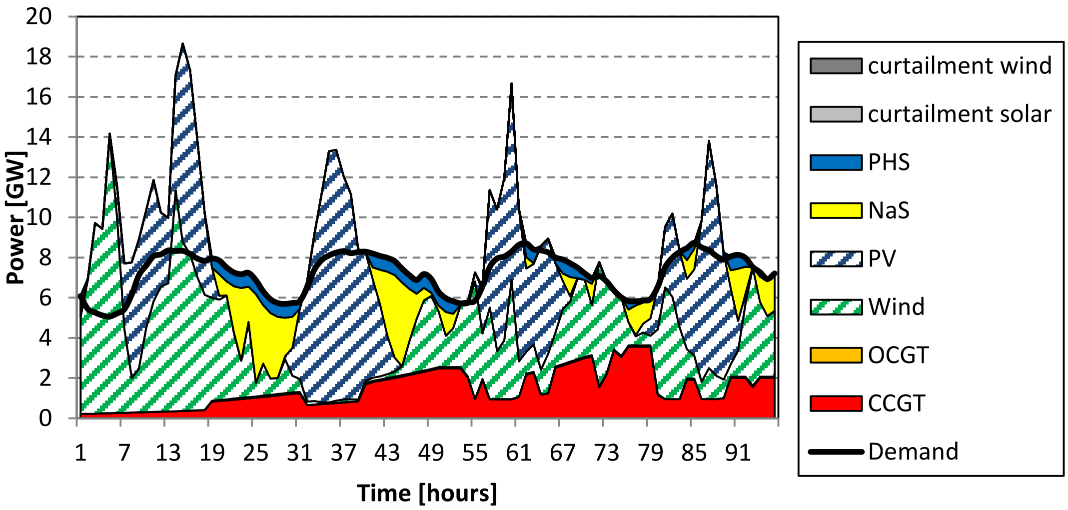


Fig. 23: electricity generation during a typical summer week (first 4 days)

The reserve requirement constraints allow to retrieve time series information about the allocation of the operating reserves. Fig. 24 shows the allocation per generation or storage technology for the upward automatic and manual FRR respectively.

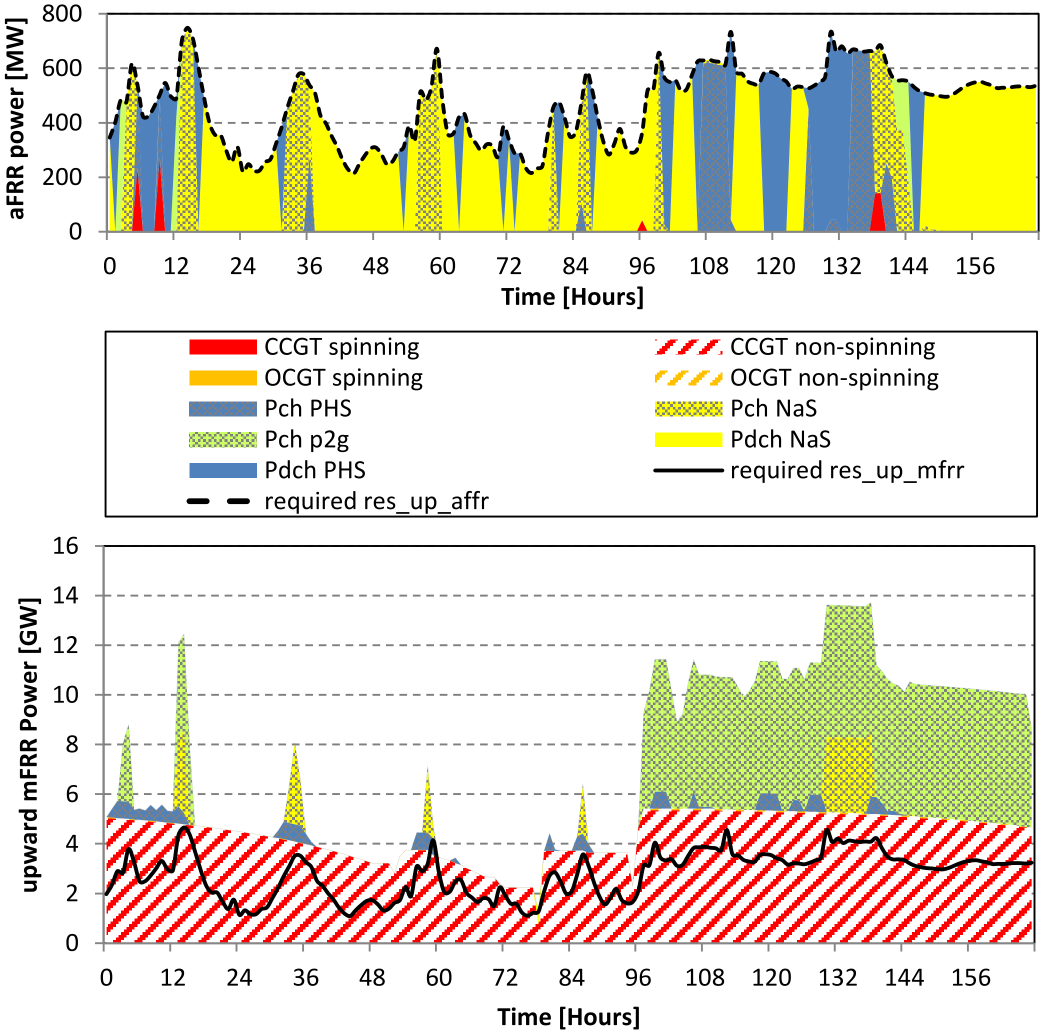


Fig. 24: dispatch of the upward aFRR and mFRR during a typical summer week

Notice that the variability of the reserve requirement for upward FRR is directly coupled to the hourly generation level of the RES through the dynamic reserve requirements. It is evident that the storage technologies are essential to provide the upward automatic FRR in a renewable power system. During this particular week, all storage technologies combined provide 98.9% of the required upward aFRR. The situation is completely different for the manual FRR. Here, the thermal power plants provide the majority of the operating reserves, mainly via non-spinning reserves. The non-spinning reserves of the CCGT power plants suffice most of the time to cover the total need for upward mFRR and provide 61.4% of the total required mFRR. The introduction of an activation cost would probably alter the situation since it is much more costly to start a CCGT plant than increase the discharging power or reduce the charging power of storage plants.

To end this paragraph, the dispatch of the storage technologies is studied. Fig. 25 and Fig. 26 summarize the charging and discharging capacity as well as the allocation of reserves for PHS and NaS respectively. The blue area represents the charging power in the upper half-plane and the discharging power in the lower half-plane. The dark blue area is the part of the charging or discharging power allocated as upward or downward operating reserve capacity respectively. The purple area represents the allocated reserve capacity by promising the availability of charging or discharging capacity. These allocated reserve capacities need to be withhold from the actual charging and discharging power.

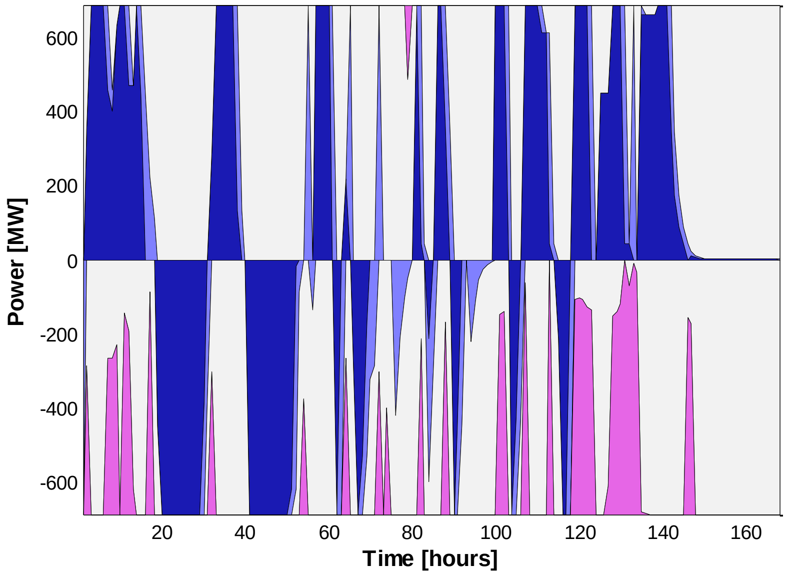


Fig. 25: Charging, discharging and reserve power delivered by PHS for a typical summer week

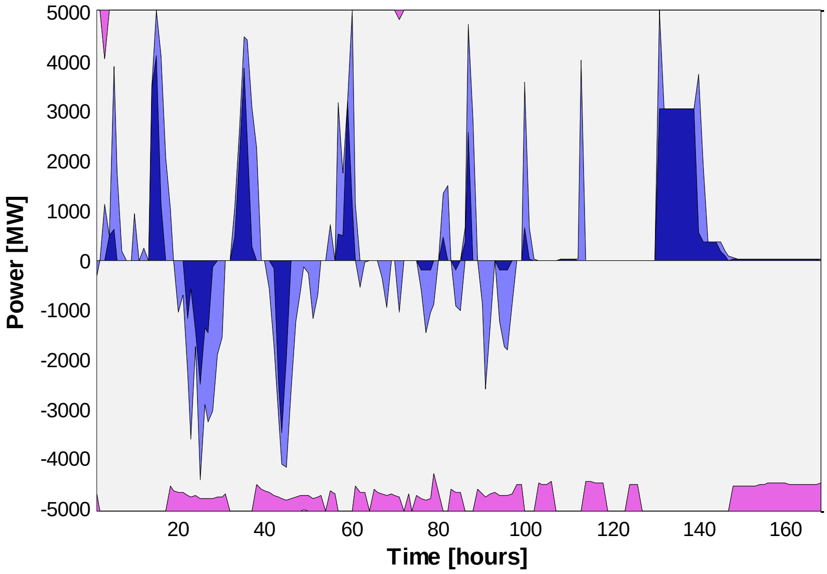


Fig. 26: Charging, discharging and reserve power delivered by NaS for a typical summer week

The two previous figures give an idea about the utilization of the storage technologies. The system will only need the full capacity of NaS batteries in extreme situations. The PHS plants experience a higher utilization. Nevertheless, in terms of energy the NaS batteries make a larger contribution for both charging and discharging power and operating reserve capacities for the fully renewable power system.

5.2.6 Gas supply

A simplified representation of the gas infrastructure is included in this model. As for the electricity system, no network is considered. Further, only the gas demand of the power sector is taken into account. The balance equation considers the flexibility of line-pack as an energy buffer with a certain storage capacity.
The gas demand can be covered by synthetic methane coming from the p2g plants or fossil natural gas. The use of fossil natural gas introduces an additional system cost equal to the purchase price of the natural gas. The price is deterministic but time dependent. The use of synthetic methane does not add an additional system cost. All cost factors are already associated to the p2g plants. The use of (less expensive) fossil natural gas is not restricted directly, it is the binding renewable energy target that will force the model to use synthetic methane. The import rate of fossil natural gas is limited according to the interconnection capacity of Belgium [90]. Both fossil and synthetic natural gas can be stored in the underground gas reservoir.
The evolution of the state-of-charge of the seasonal gas storage was already discussed the previous section. Here, the analysis will look at the profile of the energy stored in line-pack and gas imports for the 0%, 50% and 100% renewable energy scenario.
The 100% renewable energy target does not allow using fossil gas. Consequently, there are no gas imports at all and the whole gas demand is covered by domestically produced synthetic gas. The overall shape of the gas import profile for the 0% and 50% target, presented in Fig. 27, is quite similar. During spring and autumn there is a moderate level of gas imports which covers the demand of GFPPs. During summer, a period of low gas prices, elevated gas import volumes are observed which are partially consumed by GFPP and partially stored. The profile of the 50% renewable energy scenario shows large fluctuations. These fluctuations follow directly from the fluctuations in residual demand. The flexible operation of GFPPs in the 50% renewable energy scenario is reflected in the import volume profile because the line-pack storage buffer capacity and maximum injection rate of the seasonal storage reservoir do not suffice to smoothen all peaks in gas demand.

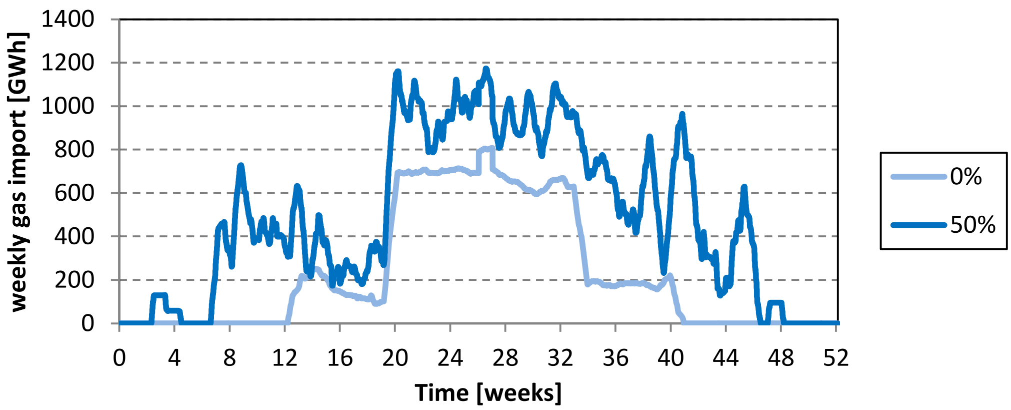


Fig. 27: weekly import volume of fossil natural gas over the whole year for 0% and 50% target

The evolution of the energy stored in line-pack is clearly determined by the gas prices for the 0% and 50% scenario (Fig. 28). The economic optimization without considering the physical constraints of the gas network simply tries to maximizes the benefits from deferring and advancing the gas demand given the deterministic price profile. It is concluded that the current model of the gas market is insufficient to realistically describe its behavior. Further research should therefore focus on a better description of the gas balance and especially a more detailed allocation of cost drivers in the gas market, e.g. the cost of using the line-pack flexibility in the gas market, the cost and/or energy losses coupled to seasonal storage, the cost of gas transmission, etc.

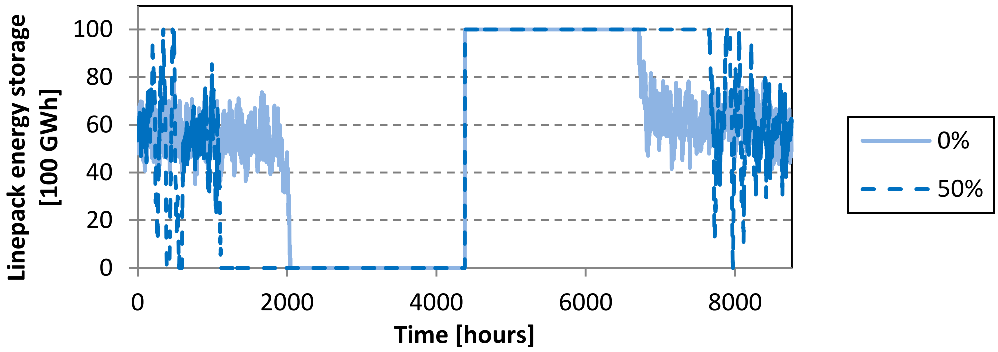


Fig. 28: Energy stored in line-pack buffer over a whole year for, comparison of 0% and 50% target

The profile of the energy stored in the line-pack energy buffer for the 100% renewable target does not hold a clear yearly pattern. The short-term evolution is directly coupled to the output of p2g and GFPPs. This data does not bring any new insights.

When investigating the gas balance closely, a strange effect became apparent. Fig. 29, representing all elements of the gas balance and the line-pack energy storage, illustrates this effect for a particular day in case of a fully renewable power system (the first day of the week considered in the previous paragraph).

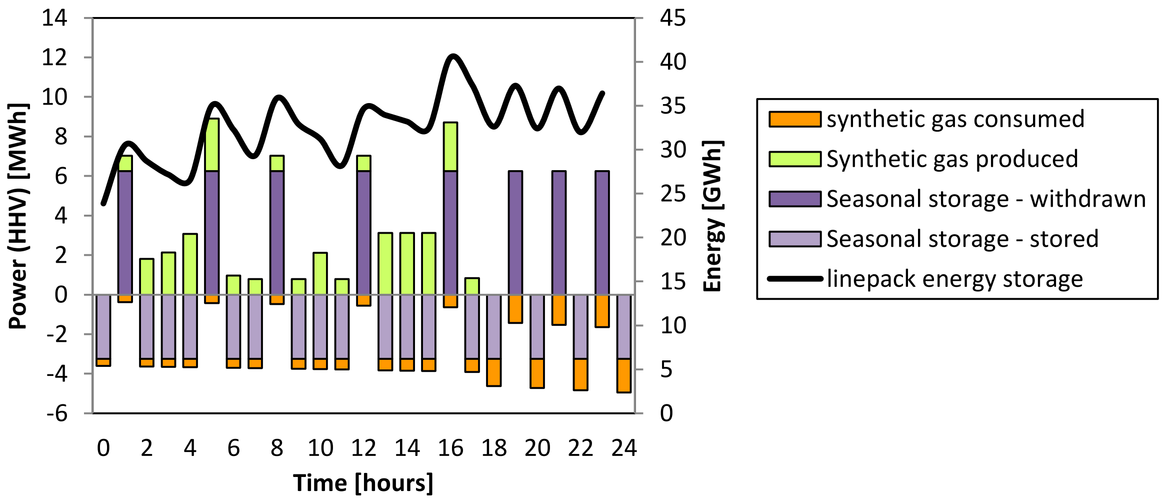


Fig. 29: addends of the gas balance and energy stored in the line-pack energy buffer on a typical summer day

The model appears to withdraw gas from the seasonal storage reservoir in periods the synthetic gas production suffices to cover the demand of GFPP. Vice versa, it will also store gas in periods of a positive net demand for gas. This behavior leads to unnecessary fluctuation in energy level of the line-pack. No well-founded reason for this behavior is found. Anyway, it does not cause any costs in this model. Again, introducing additional cost factors incorporating the cost of using the flexibility of the gas network would probably solve this issue.

5.3 Sensitivity analysis

The sensitivity analysis will investigate the dependence of the results on changing the input data of chapter 4. Performing a sensitivity analysis on the results is essential due to the large uncertainty about certain cost factors, particularly the investment cost of p2g. Meteorological condition determining the generation profile of the intermittent RES can also fluctuate significantly from year to year and will thus be part of the sensitivity analysis. In addition, the impact of introducing a fourth storage technology, power-to-hydrogen, will be studied. The sensitivity analysis will mainly concentrate on the fully renewable power system and specifically focus on the impact on the generation portfolio. The sensitivity analysis will indicate which results are robust and help interpret the results.

5.3.1 Investment cost p2g

The investment cost of p2g in the base-case scenario was fixed at 1200 €/kW based on the projections for the future investment cost of large scale industrial p2g plants. Given the fact that the p2g technology is still in the demonstration phase, there is uncertainty about the exact value of investment cost. This is reflected in the broad range of plausible future investment costs found in literature. Most investment cost projections are contained in a range of 800 to 2000 €/kW. These two estimates are now used as input for the 100% renewable energy scenario without biomass. The effect on the generation portfolio is shown in Fig. 30.

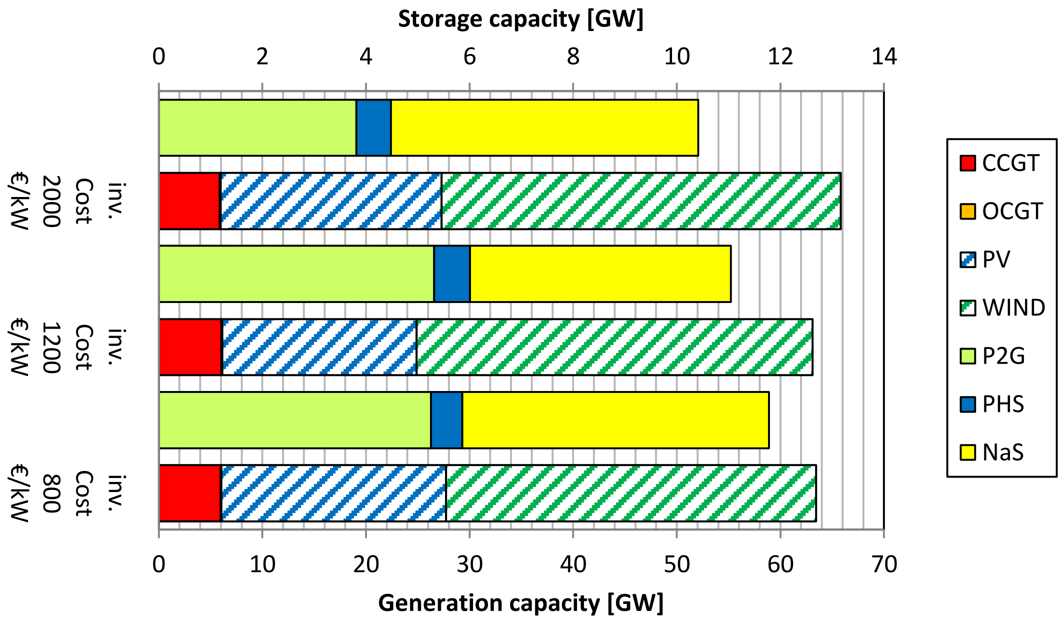


Fig. 30: installed capacity of electricity generation and storage technologies. Comparison of different cost scenarios

An investment cost of 2000 euro/kW causes a reduction of the installed capacity of pg2 from 5.3 GW to 3.8 GW. At the same time, the installed capacity of NaS batteries raises 900 MW and an extra 3 GW of photovoltaic cells are needed to compensate the decrease in seasonal storage capacity. Despite the fact that the generation portfolio changes slightly, the operation of the storage technologies and reservoirs remains practically the same. A reduction of the investment cost to 800 euro/kW does not impact the installed capacity of p2g. Remarkably, it does cause a minor decrease in PHS capacity, an 800 MW increase in NaS battery capacity and the substation of 3GW wind by PV power. The reason for this effect could not be traced.
In conclusion, the difference in investment cost caused a change in capacity of p2g of 28%. The overall operation of the power system is not altered too much as a consequence of this effect.

5.3.2 Investment cost of RES and fossil fuel cost

Other cost factors of the input data experiencing a high level of uncertainty are the investment costs of RES due to disagreement over the extent of learning curve effects. Predicting the future fuel cost of coal, oil and gas is also problematic. To capture the maximum effect of the different cost projections for these two factors, a scenario with a high estimate for the fuel costs and a low estimate for the investment costs of RES is built. This should promote the use of RES relative to fossil fuel technologies. Therefore it will be most interesting to look at the impact at the lower targets for renewable energy. The numerical values of the adapted input data are presented in Table 11.

	Base case	Sensitivity analysis
C_{INV} wind [€/kW]	1270	1110
C_{INV} solar [€/kW]	895	650
C_{INV} biomass [€/kW]	3800	2018
C_{FUEL} coal [€/MWh]	11.9	13.8
C_{FUEL} gas [€/MWh]	25.6	40.6

Table 11: adjusted economic parameters of base-case scenario and sensitivity analysis

The system simulations show that the intermittent RES are still too expensive to be competitive, in other words the renewable energy target is always a binding constraint. Nevertheless some changes in the optimal generation portfolio arise (Table 12). The most striking difference is the substitution of coal for CCGT at 0% target, a faster phase-out of coal fired plants and a higher installed capacity of PV. The latter reduces the need for p2g and NaS. Exactly the same trends occur when biomass is available.

	0%		20%		50%		80%		100%	
COAL	7082	6175	5449	3932	2944					
CCGT	1285	2318	1914	3609	2783	5884	2793	2638	6049	6014
OCGT	2691	2566	3154	2977	3804	3767	5178	5242	66	87
PV					6634	7711	13952	16027	18758	23000
WIND			6274	6266	14477	13798	26099	25578	38236	38141
P2G							3455	2796	5316	4337
PHS					585	511	1915	2006	690	714
NaS									5041	4853

Table 12: Comparison of the installed capacities in MW for changing cost data (results of sensitivity analysis in shaded gray columns)

A back of the envelop computation shows that the RES are on the edge of being competitive in case of the 0% target, with an average electricity cost of 68.4 €/MWh for PV. The coal fired power plants, achieving 8132 FLH in this scenario, have an average electricity cost of 61.9 €/MWh.

5.3.3 Low estimate for the potential biomass use

In chapter 4, two different estimates for the potential biomass use for the power sector were introduced. The high estimate was applied for all previous simulations in this work. Now, the effect of a lower potential biomass use is investigated. Table 13 offers a comparison of the generation portfolio for the high and low estimate.

	0%		20%		50%		80%		100%	
COAL	7082	7082	5421	5421	3146	3139				
CCGT	1285	1285	1960	1960	2360	2368	2640	2505	1146	2775
OCGT	2691	2691	3136	3136	3746	3745	3701	3902	1628	1307
PV					4982	4984	4447	8704	8134	13130
WIND			6265	6265	12400	12396	11484	16593	15912	24737
P2G									978	3933
PHS					407	408	437	1299	1855	2304
NaS										148
Biomass						555	556	3467	5474	3376

Table 13: Comparison of the installed capacities in MW for low and high estimate of potential biomass use (results of low estimate in shaded gray columns)

The effect in the 0%, 20% and 50% renewable energy scenario is negligible. This should not come as a surprise since the limit on the biomass energy potential is not binding in these scenarios. The 80% and 100% renewable energy scenario clearly show a reduction in biomass capacity. The reduction in capacity implies that the biomass plants are still fulfilling the role of base-load generation despite the lower energy potential. Alongside this reduction, the installed capacity of intermittent RES and all storage technologies must increase in order to attain the renewable energy targets. Most striking is the large capacity of p2g in the 100% renewable energy scenario. This proves that seasonal storage is most probably an important part of a renewable energy system even in case biomass is available.

5.3.4 Power-to-hydrogen

The literature study indicated that power-to-methane is the most promising option among the power-to-gas technologies. Direct use of hydrogen is not considered at all in this work. The commercial availability of reliable and affordable hydrogen to electricity conversion technology still requires technological breakthroughs. Therefore, local storage and re-electrification of hydrogen was not included in the previous scenarios. Now, the potential value of reliable power-to-hydrogen technologies for the power system is assessed by adding this technology to the set of available storage technologies. The influence of including power-to-hydrogen on the optimal generation portfolio is presented in Table 14 for the 100% renewable energy target.

	No biomass		Biomass	
	Base-case	P2Hy	Base-case	P2Hy
CCGT	6049	3523	1146	1022
OCGT	66	312	1628	1461
PV	18758	19811	8134	7437
WIND	38236	33505	15912	16215
P2G	5316	5383	978	522
P2Hy		3987		1340
PHS	690	1911	1855	1056
NaS	5041			
Biomass			5474	5205

Table 14: Installed capacities [MW] of generation and storage technologies for scenarios including/excluding power-to-hydrogen and biomass

Comparing the installed capacities with the values for the base-case scenario shows that introducing power-to-hydrogen might have a serious impact on the optimal generation portfolio. First of all, it pushes the costly NaS batteries out of the market. This also implies that the presented model does not strictly need short-term storage. A direct consequence of not considering intra-hour balancing and frequency containment reserves. The results also show that P2Hy does not take over the role of p2g nor PHS. Apparently, this storage technology has a new specific role in the power system. This is supported by the evolution of the state-of-charge of the compressed hydrogen storage reservoirs which shows cycles of typically 2-5 weeks. The ratio of the energy storage capacity of the reservoirs over nominal power of 73 GWh/GW falls in between the corresponding ratio of p2g and PHS (see Table 10). Analysis of the time series data revealed that P2Hy is mainly employed to absorb the variation in wind power output. Indeed, the time frame of these fluctuations is too long to be absorbed by PHS. At the same time, wind generation contains more variations then just a seasonal pattern. This advocates the benefits of a storage technology for temporal energy arbitrage in the time frame of several days to weeks. Future research could investigate whether CAES or flow batteries could also fulfil this role.

5.3.5 Meteorological year

The profiles of demand and intermittent RES generation implemented in all previous simulations are based on data of the Belgian TSO for the year 2013. Here, the dependence of the result on using another meteorological year is assessed. A comparison of the potential generation of wind and PV power, translated in the maximum attainable FLH given the meteorological condition in the base-case scenario (2013) and alternative scenario (2014) is presented in Table 15.

	2013	2014
Wind	2056.1	2530.7
PV	979.3	1013.7

Table 15: Maximum number of FLH of wind and PV in 2013 and 2014

The number of FLH of wind was almost 25% higher in 2014. Such an increase is remarkable but not exceptional as empirical data for the German wind generation shows [18]. Nevertheless, it will definitely have an influence on the optimal capacity investments. Fig. 31, presenting the normalized load duration curve of wind generation, shows that the shape of these curves deviates significantly for both years. The number of hours with low output (CF < 0.2) hardly changes. This has serious repercussion for renewable power systems with a very large installed capacity of wind power because the extra wind generation will mostly be curtailed. In other words, the greatest reduction in RES capacity is expected in case of a low target on renewable energy.

The influence of changing the RES generation profile on the installed capacities of generation technologies and storage technologies is presented in Fig. 32 and Table 16 respectively.

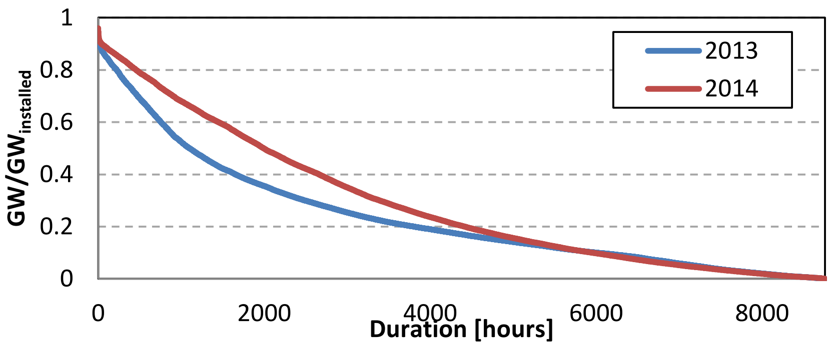


Fig. 31: normalized load duration curve of wind power for the year 2013 and 2014

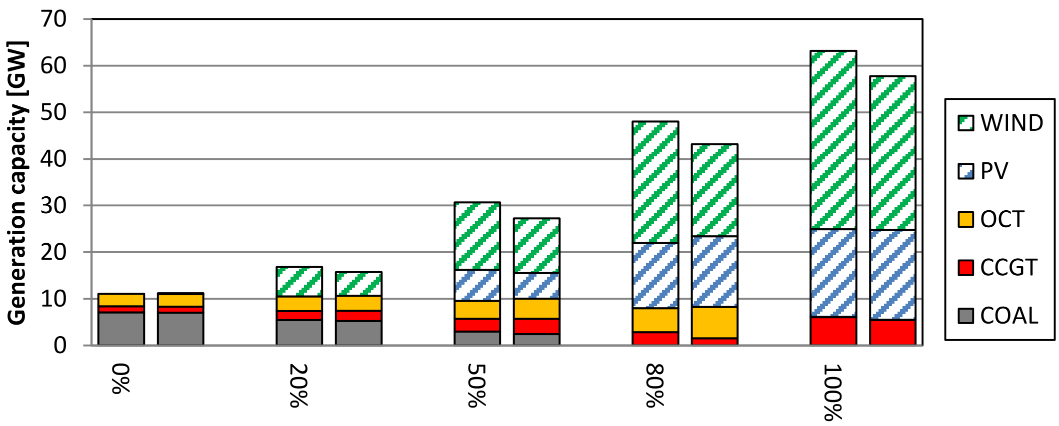


Fig. 32: installed capacity of electricity generation technologies as a function of the renewable energy target (comparison of 2013 and 2014 RES generation profile)

	50%		80%		100%	
P2g			3454.9	3104.2	5316.1	3986.9
PHS	585.3	413.0	1914.9	1946.9	689.6	551.5
NaS					5040.6	6541.9

Table 16: installed capacity of energy storage technologies (comparison of 2013 and 2014 RES generation profile)

The results show that the higher capacity factor allows a reduction of the wind capacity of 5 GW for the fully renewable power system. At same time, the need for seasonal storage capacity drops from 5.3 GW to 4 GW. The reason for this effect can be found in the time series data of the wind generation. The wind power generation has particularly increased during autumn and winter, a period largely responsible for the depletion of the seasonal storage reservoirs in the base-case scenario. This is also obvious from the evolution of the state-of-charge of the seasonal storage unit, presented in Fig. 33. Consequently the installed capacity of p2g decreases and the installed capacity of GFPP drops accordingly.

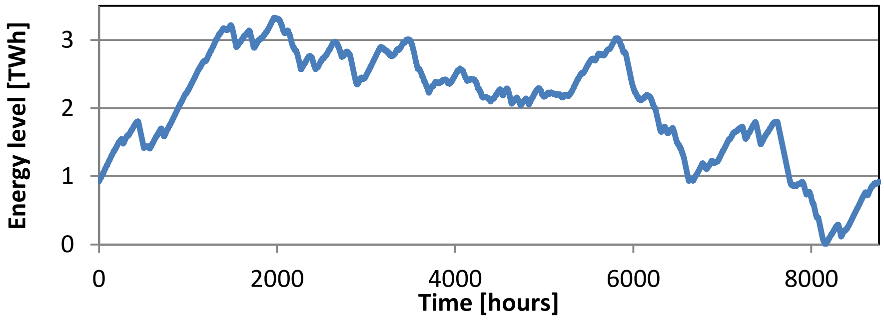


Fig. 33: Energy level of the seasonal gas storage reservoir over the whole year (2014 RES generation profile)

In order to offset the drop in capacity of GFPP during periods of marginal RES generation, the capacity of NaS increases by 1.5 GW. All these effects combine to a reduction in system cost of just over 10%

Fig. 32 also proves that the change in capacity of wind power is proportionally higher for the 20% and 50% target. However, no big changes in the management of the power system occur for these targets. Intriguingly, the model does invest in 198 MW of wind capacity in the 0% renewable energy scenario. In other words, the increase in the number of FLH has a larger impact on the cost-effectiveness of RES than the reduction of investment cost considered in paragraph 5.3.2. Indeed, the average cost of electricity generation by wind power with 2530 FLH, 146 €/kW.year fixed costs and no variable costs amounts 57.7 €/MWh, which is less than the average cost of base load plants calculated in paragraph 5.3.2.

Summarized, the choice of the historic feed-in profile is a determining factor and sensitivity analysis considering the feed-in profiles is recommended for all power system simulations. Especially GEP models must further investigate the impact of the yearly meteorological conditions since investment decisions should be based on a long term average production of the RES.

5.4 Discussion

Main contribution of the results to the literature

The integration of operating reserve requirements is clearly an added value for the GEP model formulation when investigating highly renewable power systems. The variability of the intermittent RES is correctly assessed, leading to a more accurate calculation of the operational costs. Another advantage is the availability of detailed time series data about the electricity dispatch and allocation of operating reserves as discussed in paragraph 5.2.5. The introduction of operating reserve requirements did not alter the optimal generation portfolio drastically, as presented in paragraph 5.2.1. However, the influence on the operation of generation and storage technologies is large in all scenarios.

The upward FRR requirements in particular have a large impact on the operation of the power system. To be more precise, the upward aFRR require the availability of spinning reserves or flexible storage technologies. As such, the aFRR requirements impose either a small thermal must-run (55-200 MW) or demand for storage capacity. The operation of the storage technology providing the aFRR is significantly altered since its charging or discharging capacity is partially allocated to reserves and moreover because enough energy has to be hold back to actually provide the reserves when needed. The upward mFRR influence the operation to a lesser extent but can have a considerable impact on the generation portfolio. After all, these reserves do not have to be online but a much larger average reserve capacity is required. The large capacity requirement and the precondition to provide the mFRR capacity for 60 minutes involve a considerable amount of energy is associated with these reserves. The state-of-charge of the energy reservoir has to allow these energy flows. For that reason, PHS and NaS batteries rarely provide mFRR. Due to the vast storage capacity connected to the gas grid, p2g is able to provide mFRR.

Another distinguishing characteristic of this GEP model is the dynamic balance method simulating a time period of a full year with hourly time resolution. This method has some additional advantages. First, this method entirely incorporates the variability of the intermittent RES. Second, a correct optimization of the energy capacity and operation of the storage reservoirs can be performed. Indeed, the storage reservoirs are matched to the actual profile of demand and supply of intermittent RES. Third, the short-term operation of seasonal storage and long term operation or returning patterns in the operation of short-term storage can readily be investigated.

As expected, the target on the share of renewable energy has a decisive impact on the generation portfolio, total system costs and power system operation as all previous results point out. The general trends perceived when increasing the renewable energy target are similar in all scenarios considered. However, the impact of the availability of biomass in the power sector cannot be underestimated. The integration of reserve requirements even reinforces the importance of this dispatchable source of renewable energy. Nevertheless, when moving to a 100% renewable energy scenario, seasonal storage will still be necessary. In other words, biomass alone will not be enough to overcome all periods of low output of wind and

PV power. The lower the potential biomass use, the stronger the need for seasonal storage. Hence, seasonal storage is an indispensable part of the generation portfolio of each 100% renewable energy scenario with capacities ranging from 1 GW to over 5 GW. Seasonal storage could already have social benefits starting from a 70% target. Therefore, when drawing plans for the power system towards 2050, seasonal storage should always be considered.

Furthermore, short-term and mid-term storage both have a specific role in the power system. They can accommodate a reduction in the operational costs, proving to be cost-effective for a 30% renewable energy target and higher. The increasing ramping rates in residual demand result in a higher need for the fast responding short-term storage in highly renewable energy scenarios.

The sensitivity analysis showed that the general trends in the result are independent of the cost data. On the contrary, the input profiles of the intermittent RES generation have a significant influence on the generation portfolio and costs. Yet, the operation of the power system is not really altered. This observation indicates that GEP models should always consider the impact of the chosen generation profiles of the intermittent RES carefully. After all, the generation portfolio must be able to cope with any meteorological year, so the dimension should be based on the most challenging year. Further investigation of the impact of the generation profile of intermittent RES is necessary for this model. Not only to assess the impact of meteorological conditions, the effect of greatly expanding the RES capacity on the profile has to be examined as well.

Qualitative comparison with the results of other researchers

Reconsidering the literature on power system simulation, the presented model provides some valuable qualitative conclusions. The fact that p2g will not be cost-effective in the medium run is confirmed. However when extending the time horizon towards 2050, p2g will become a vital part of the power system. Other researcher already pointed out that p2g will play a crucial role in a sustainable energy system because of the possibility to convert wind and solar energy into fuels. This work demonstrates that p2g is not only an essential part of a renewable energy system, but also an essential part of a renewable power system specifically, because of its seasonal storage capabilities. In addition, mid-term storage absorbing the variations in residual demand caused by the changing wind generation and short-term storage providing peak shaving of the PV generation and peaks in demand will be part of the optimal generation portfolio of a fully renewable power system as well. Remarkably, power-to-gas with local storage and re-electrification shows good characteristics to play the role of mid-term storage, given the input data of the test case. The investment cost for this storage technology is based on a large scale unit with a PEM electrolysis cells, compressed hydrogen storage tanks and PEM fuel cells. Generally, the literature on power system models states that power-to-hydrogen is too expensive to provide long-term storage compared to power-to-methane, especially because of the high investment cost per kWh. Indeed, it will not be employed for seasonal storage. Nevertheless the sensitivity analysis showed that power-to-hydrogen can play a crucial role in 100% renewable energy system if reliable high efficiency conversion technologies are developed.

Limitations apparent from the numerical results

An extensive list of the approximation inherent to the model formulation was presented in section 3.6. Some of these approximations are directly reflected in the results. However, the results demonstrate some extra limitations of the model. First of all, the model of the gas infrastructure should be extended with additional cost factors as explained in paragraph 5.2.6. This will result in a more realistic behavior in the gas supply. Secondly, the capacity problem, i.e. the issue of a high peak demand/output and a much lower average demand/output, is more pronounced than expected and affects almost all technologies. Thermal plants, storage plants and even the gas infrastructure experience high peak demands and low capacity factors in renewable energy scenarios. In other words, the central optimization of the power system minimizes the total system costs, but puts serious pressure on the profitability of investments for the market actors. An assessment of the business case of each technology might give a better insight on this problem. The issue of a low number of operating hours, capital intensive technologies, large installed capacity and the massive availability of renewable energy at zero marginal costs opens the discussion about the feasibility of a 100% renewable energy system with the current pricing systems and market functioning. In short, the major obstacles on the way towards a renewable energy system might rather be economical than technical. Third, the consequences of neglecting the activation costs of the operating reserves are more serious than expected. To clarify, the model prefers to deliver upward mFRR with non-spinning reserves of CCGT plants over mFRR provided by storage technologies. The start-up cost of CCGT plants implies a significant activation cost which is not incorporated in the model.

5.5 Summary and conclusion

This chapter presented the numerical results obtained from applying the conceptual test system, outlined in chapter 4, to the model. Data analysis, interpretation and if possible explanation of these test results were also included in this chapter. Furthermore, some essential and robust qualitative trends have been distinguished.
The numerical results of this chapter can be separated in three main parts: (1) The effect of imposing an increasing target on the share of renewable energy in the supply of electricity demand (2) detailed analysis of the operation of the storage technologies, provision of operating reserves and gas supply for a fully renewable power system (3) a sensitivity analysis. Here, an overview of the conclusions for each of these parts is given.
First of all, the constraint imposing the share of renewable energy is always binding for the base-case scenario. The RES are not competitive given the cost-data of the

conceptual test model. Increasing the share of renewable energy gives rise to some consistent trends, independent of the scenario. The total installed capacity of generation technologies increases largely. This is basically the responsibility of the increase in installed capacity of intermittent RES. At the same time, the installed capacity of thermal generation technologies remains fairly high. Even the 100% renewable energy scenario with or without biomass still require 7250 MW and 6050 MW of thermal generation capacity respectively. Besides, the increasing renewable energy target enlarges the need for energy storage. PHS appears to be cost-effective starting from a 30% target, p2g from 70% and NaS batteries are only cost-effective in a 100% renewable power system. The availability of biomass strongly influences the need for seasonal storage, however p2g is always part of the optimal generation portfolio in case of a 100% target. Depending on the potential biomass use, the capacity of p2g varies from 1 GW to 5.3 GW. The renewable energy target has a major impact on the total system cost as well. A 50% renewable energy target causes the system cost to rise by 30%. A 100% target will double the system cost in case biomass is available and even triple if biomass is unavailable for the power system. Further, the system benefits of installing storage capacity was exemplified by mutually comparing the result of the base-case scenario and a similar power system without energy storage. The analysis of this data proved that the avoidance of the investments in additional RES capacity is the main benefit of energy storage, seasonal energy storage in particular. Finally, the data demonstrates that the curtailed energy rises drastically with an increasing renewable energy target, regardless of the large-scale deployment of energy storage. Even worse, the number of full load hours of quasi all technologies appears to diminish.

The analysis of the operation of the power system for a 100% renewable energy target highlights the importance of short-term storage for providing aFRR and p2g and GFPPs for providing mFRR. Furthermore, the consideration of the electricity dispatch of a particular week gives a good picture of the variability the RES introduce in the power system and stresses the balancing role of short-term energy storage and CGGT. The analysis of the state-of-charge of the energy reservoirs showed the differences and analogies between short-term and long-term storage. The charging and discharging operation of all energy storage technologies is basically determined by the residual demand. CCGT plants and p2g will generally be activated during prolonged periods of respectively positive and negative residual demand. PHS and NaS regularly follow a daily pattern in summer, taking up the generation of PV and covering the evening peak in demand. During winter, their operation is mostly determined by the duration of the period of negative/positive residual demand and the interaction with p2g/CCGT plants.

A sensitivity analysis was performed to investigate the dependence of the results on the exogenous input data of the conceptual test model. The sensitivity analysis showed that the results are quite insensitive to a change in the economic parameters of the storage and generation technologies. The influence of the wind and PV power generation profile is however significant. This work only compared the historical generation data of 2013 and 2014 obtained from the Belgian TSO. Further research assessing the influence of this data is necessary.

Chapter 6: Conclusion

This chapter recapitulates the most important conclusions of the previous chapters. The distinguishing characteristics of the model are repeated and the most important qualitative conclusions that were drawn throughout the analysis of the results are listed. Finally, some topics for future work are suggested.

6.1 General conclusions

This thesis presents a generation expansion planning model integrating a detailed representation of the operational constraints and reserve requirements. This model is able to calculate the socially optimal solution for the generation portfolio, electrical dispatch and allocation of operating reserves of a power system including various conventional generation technologies, renewable energy sources and energy storage technologies. The model is applied to a conceptual test system containing a confined set of representative conventional generation technologies, renewable energy sources and energy storage technologies. This conceptual test system was subjected to a large number of scenarios. The analysis of the results focused on the highly renewable scenarios, the impact of the reserve requirements and the different roles of energy storage.

Electricity storage provides two important balancing services to the power system in this model, namely the provision of operational reserves and temporal energy arbitrage. The former is one of the main drivers for the dispatch of the short- and mid-term storage technologies. However, temporal energy arbitrage determines the capacity investments in energy storage. The social benefit of energy storage is mainly following from avoiding additional intermittent RES capacity and correspondingly the reduction in total investment costs. Including energy storage does realize a reduction of the operational costs for highly renewable energy system but these savings are small compared to the reduction in total investment costs.

Power-to-gas is a vital part of the optimal generation portfolio of a fully renewable power system for all scenarios considered in this thesis. The availability of a (large) energy potential of biomass for electricity generation does lower the need for seasonal storage but it is unlikely it will eliminate the need for power-to-gas. The

installed capacity of power-to-gas in the 100% renewable energy scenarios varies between 1 GW and 5.3 GW for a 10 GW_{peak} power system. Power-to-gas can be cost-effective from a social perspective starting from a 70% renewable energy target.
For renewable energy targets below 30%, energy storage is not cost-effective. The impact of energy storage on a 50% renewable power system is still rather small. Its role is limited to peak shaving and the provision of upward aFRR in periods of high RES generation. Starting from 60%-70% renewable energy, the charging and discharging of storage technologies become crucial to be able to cover the demand at all times. This model, not including the operational flexibility of demand responds and interconnections, is unable to find a solution for renewable energy targets above 80% without energy storage, i.e. the operational flexibility of energy storage units is indispensable for the provision of operating reserves starting from a 80% renewable energy target.
The various storage technologies do compete for capacity investments. A reduction of the cost and the subsequent larger installed capacity of one storage technology will reduce the capacity of the other storage technologies. Even short-term storage technologies and seasonal storage technologies behave as concurrent rather than complements. All storage technologies compete for the surplus energy of renewable generation. The uptake of large peaks in surplus generation with short-term storage and a subsequent transfer to seasonal storage via simultaneous discharging and charging does never occur. Nevertheless, the optimal generation portfolio does contain a combination of various energy storage technologies, each fulfilling a different role in the power system. The results showed that at least three different categories of storage technologies will make part of the optimal generation portfolio in order to absorb the short-term variability of PV generation and electricity demand, the mid-term variability of wind generation and the seasonal variations.

The main contribution to the academic research of this model consists of incorporating the correct impact of the variable and only partly predictable nature of intermittent RES in a generation expansion planning model. The variability of the intermittent RES, short-term and long-term, is fully captured since the model considers chronological data of a whole year obtained from historical measurement of wind and PV power generation. The impact of partly predictable nature is captured by the model's operating reserves requirements. To that end, the sizing of the operating reserves includes a probabilistic sizing method which determines the reserve capacity necessary to absorb the forecast error with a design reliability of 99%. This methodology is consistent with the network code of the European network of transmission system operator for electricity. Thus, the balancing challenges due to the dynamic behavior of intermittent RES are properly integrated in a GEP model. Consequently, this model is able to calculate an optimal generation portfolio that is designed to cope with the RES variability. Even more, given that the electricity dispatch and allocation of reserve capacity are calculated, the corresponding operational costs can be taken into account when designing the optimal generation portfolio.

6.2 Future research

Future work on this model should concentrate on the correct implementation of the sizing methods for the reserve requirements and available downward reserve capacity of RES as described in sections 3.4 and 4.4. This is mainly a question of finding and implementing the correct data. Besides, the model of the gas infrastructure should be extended with additional cost factors.

Further adaptions and extensions to the model can include the potential of other sources of flexibility, such as transmission capacity and demand response.
A transformation towards a multiple-node model incorporating the RES generation profiles of several regions and transmission grid constraints based on a DC load flow calculation with endogenous investments in transmission capacity is also possible maintaining the linear methodology presented in this thesis.
The system constraints imposing the policy target now only enforce a renewable energy target. The model can be extended to assess effect of a CO_2 limit, an emission trading system, quotas, feed-in tariffs, etc.

Appendices

Appendix A: Additional operating reserve constraints

Two additional constraints should be introduced to describe the TSO requirements for aFRR. In order to provide an aFRR bid of P_{BID} MW, the TSO requires a ramping rate of $15\%P_{BID}$ per minute [62]. It is up to the balance responsible parties to assemble a bid that fulfils these conditions. The actions of BRPs are not included in the model. Instead of being assembled from different plants belonging to the portfolio of a BRP, the bids in this model have to be assembled from a single generation technology because of the clustered unit commitment formulation. The TSO requirements can only be included approximately by checking whether all spinning reserves of a certain technology combined could reach the required ramping of the aFRR bid corresponding to that same technology.

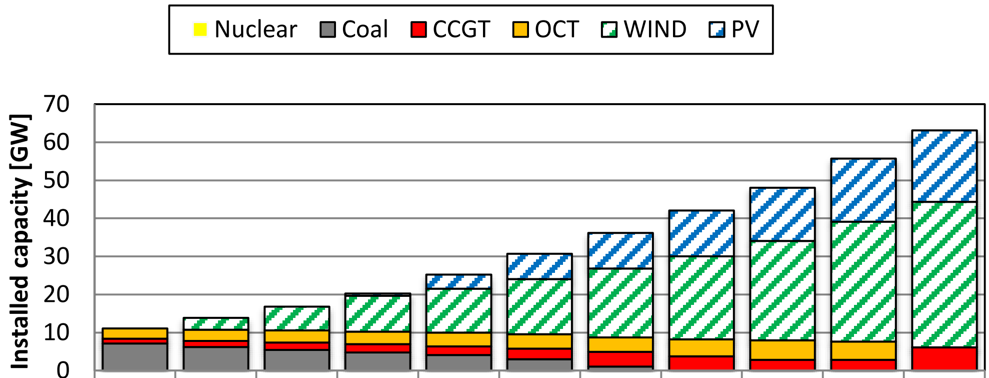
$$\forall t \qquad n(DG,t) \cdot RU_{60sec}(DG) \cdot P_{MAX}(DG) \geq res_{afrr}^{up}(DG,t) \cdot 0.15 \qquad (81)$$

$$\forall t \qquad n(DG,t) \cdot RD_{60sec}(DG) \cdot P_{MAX}(DG) \geq res_{afrr}^{dn}(DG,t) \cdot 0.15 \qquad (82)$$

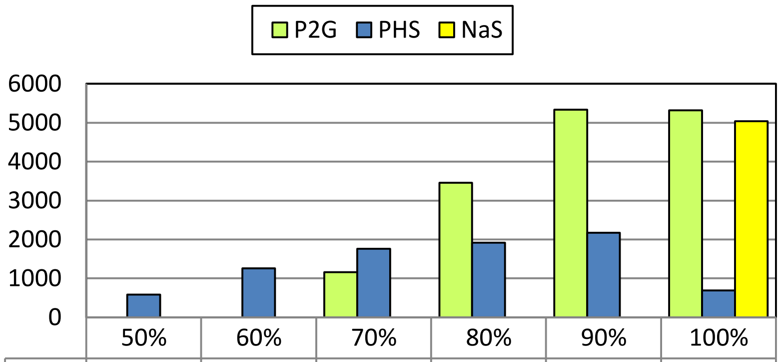
This formulation has some drawbacks. In reality, the available ramping capacity of less flexible power plants can be combined with fast ramping power plants to compose a bid which satisfies the requirements even if the inflexible technology on its own would violate the above mentioned constraints. The ramping rate per minute RD_{60sec} and RU_{60sec} are very hard to estimate, certainly for a clustered technology. Finally, these constraints are only binding in very extreme events. The model always prefers peak load plants or storage plants to provide aFRR which do not suffer from this constraint. Therefore the impact of adding these constraints on the results is negligible. Because including these constraints has serious consequence for the computation time, they were finally omitted.

Appendix B: Numerical data of the installed capacities for base-case scenario

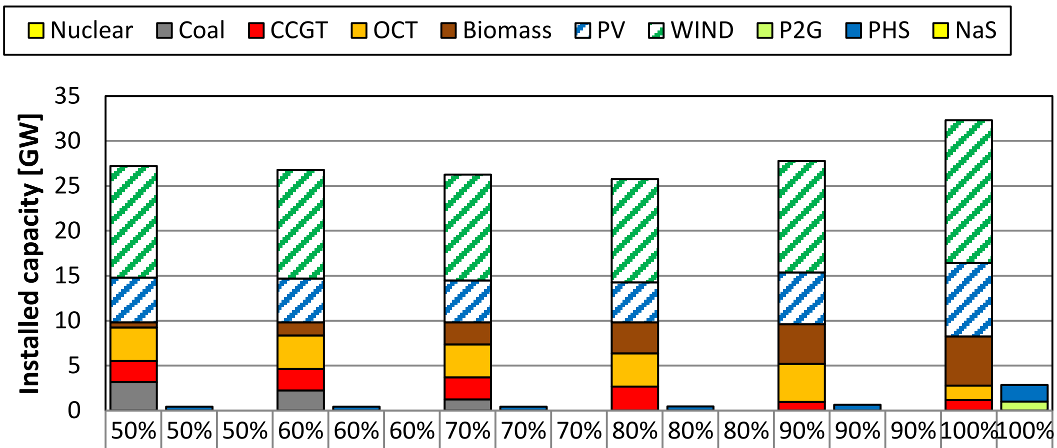
The numerical data corresponding to figure 6,7 and 10 in the main text are given below. The installed capacity is expressed in MW.



	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
PV				583.8	3690	6634	9330	12013	13952	16579	18758
WIND		3119	6274	9370	11573	14477	18117	21829	26099	31551	38236
OCT	2691	2973	3154	3285	3612	3804	3845	4419	5178	4767	65.9
CCGT	1285	1603	1914	2205	2261	2783	3857	3747	2793	2802	6049
Coal	7082	6177	5449	4749	4069	2944	1023				
Nuclear											



	50%	60%	70%	80%	90%	100%
P2G			1159.767	3454.86	5337.574	5316.133
PHS	585.2659	1255.986	1757.455	1914.913	2173.355	689.5788
NaS						5040.594



	50%	50%	50%	60%	60%	60%	70%	70%	70%	80%	80%	80%	90%	90%	90%	100%	100%
NaS																	
PHS		407			409			424			437			633			1855
P2G																	978
WIND	1240			1207			1175			1148			1241			1591	
PV	4982			4872			4665			4447			5766			8134	
Biomass	555			1486			2453			3467			4397			5474	
OCT	3746			3728			3687			3701			4250			1628	
CCGT	2360			2393			2440			2640			933			1146	
Coal	3146			2215			1232										
Nuclear																	

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