Abstract

Flexibility has become an important property of the electric power systems and currently plays a crucial role in delivering efficient balancing to supply-demand operations. The rise of an environmental concern from governments to mitigate CO_2 emissions and ensure a sustainable future for next generations has increased over the last decades the interest of investing in Renewable Energy Sources (RES). The integration of RES has rapidly transformed the power system since some of them, especially solar and wind power, cannot control its power output. These Variable Renewable Energy Sources (VRES) bring uncertainty and inflexibility to the power system. Additional flexible sources and new players must be also integrated, causing an additional cost due to this inflexibility.

Consequently, the concept of flexibility is changing and must incorporate new elements. Classical flexibility definitions can no longer include the different scenarios provoked by the deployment of VRES that the current power market faces within this topic. The present thesis proposes additional ideas to the flexibility concept paying special attention to the curtailment effect on the power markets, demand flexibility, synergy between hydro power generators and VRES, nuclear power role etc. The thesis investigates the concept of flexibility under very short time steps, from minute-to-minute to an hour. These very short time resolution analyses shed new light on the concept of flexibility from a different perspective.

To make this possible, the present research implements a Unit Commitment (UC) model in General Algebraic Modeling System (GAMS) software using CPLEX solver, considering multiple generator constraints, such as ramp rate, maximum power output etc. The UC model has been adjusted after some simulation tests, accurately emulating the actual power markets behaviour.

Moreover, the deployment of VRES and the digitalization of the power sector are forcing the actual power markets to shorten its time resolution. Operators, as California Independent System Operator (CAISO) are leading this transition by implementing 5 minutes time resolution instead of the classical hourly based (NordPool).

Using the developed UC model, the present research shows and analyses the effect of shorten the time resolution for UC problems. Thus, 1 minute, 5 minutes, 15 minutes and 60 minutes timesteps have been considered. This innovative analysis faces many challenges specially from the data collection and computation time. To make it possible, a demand data conversion method, data analysis of Great Britain (GB), Netherlands (NL) and Germany (GE) power demand, a flexibility analysis of UC models and an analysis of optimization complexity, are presented.

Most of these theoretical insights are summarized in the paper *“A Minute-to-Minute Unit Commitment Model to Analyze Generators Performance”*, that will be presented in the 16th International Conference on The European Energy Market 2019 (EEM19). The paper has contributed to understand: 1) opportunities and challenges in converting traditional hourly UC models to finer time-resolutions, 2) how to convert hourly data to shorter time periods, 3) the notion and awareness on how generators might actual behave in real-time operations and 4) the importance of considering shorter time resolution.

To conclude, the thesis analyses a case study where the concept of flexibility (based on very short time steps) is analysed and redefined in order to cover a wider spectrum of the concept. Besides, the high synergy between Hydro power and VRES is demonstrated as well as the incompatibility of nuclear power with high share of VRES. For the given portfolio and demand, the curtailment effect sets a limit of VRES share, motivating the development of flexible demands for a green and VRES future.

Preface

This master's thesis is written at the Norwegian University of Science and Technology (NTNU) throughout the spring semester of 2019 by Rodrigo Villanueva Revenga. The work has been carried out as a part of the Master of Science (MSc) at the Department of Electric Power Engineering (IEL) in collaboration with the Department of Industrial Economics and Technology Management (IØT), and it is my submission to the TET4910 Electric Power Engineering, Master's Thesis, accounting for 30 credits.

During the fall semester of 2018, I submitted the TET4520 Electric Power Engineering and Smart Grids, Specialization Project, accounting for 15 credits. This was the starting point of my thesis, and it was focused on the data collection and first design on the Unit Commitment model. As this work showed significant effect of the VRES deployment on the current flexibility issues.

After my supervisors Prof. Hossein Farahmand, Dr. Pedro Crespo del Granado and Prof. Irina Oleinikova introduced the possibility of submitting our work to the academic community, I quickly decided that I would benefit from this due to the novelty of our topic.

I would like to thank supervisors Prof. Hossein Farahmand, Dr. Pedro Crespo del Granado and Prof. Irina Oleinikova for highly valuable guidance and outstanding help during the process.

Especially thanks to Hossein for his excellent management of administrative aspects and his effort to push my analytical skills further through engagement in captivating discussions. I am truly grateful for the impact of this in strengthening the contribution of my thesis. I must also express our sincere appreciation to the commitment Pedro has shown in giving me advice and specially our called "Brain Storming Meetings". Furthermore, I would like to show our gratefulness to the effort Irina has put into providing us with continuous constructive feedback as well as in finding and establishing contact with the necessary resources.

I have also received crucial advice from many others at IEL and the Department of Industrial Economics and Technology Management (IØT) at NTNU. Thanks to Paolo Pisciella and Markus Löschenbrand (IEL) for patiently answering our programming related questions and sharing their experiences. Also, thank you to my officemates which has been a pleasure to share the office with them, specially Ingvar and Magnus with whom I have had a very good time.

But… specially I would like to thank my girlfriend Raquel for these two years working, enjoying, studying and sometimes suffering together the Master at NTNU.

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IV. List of Abbreviations

(MI)NLP	Mixed Integer Nonlinear Programming
(MI)QCP	Mixed Integer Quadratically Constrained Program
aFRR	Automatic Frequency Restoration Reserve
BRP	Balance Responsible Parties
BSP	Balance Settlement Period
BWR	Boiling Water Reactors
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbines
Cd	Shutdown Cost
CHP	Combined Heat Power plant
C_{hydro}	Hydropower Capacity Factor
CPLEX	IBM ILOG CPLEX Optimization Studio
CPU	Central Processing Unit
Cu	Start-up Cost
DA market	Day-ahead Market
DE	Germany
DSO	Distribution System Operator
DT	Minimum Down Time
EEM	European Energy Markets
Ei	Energimarknadsinspektionen / Energy Markets Inspectorate
ENTSO-E	European Network of Transmission System Operators
EU	European Union
EU ETS	EU Emissions Trading System
FCR	Frequency Containment Reserves
GAMS	General Algebraic Modeling System
GB	Great Britain
GHG	Green House Gas
GT	Gas Turbine
HPC	High-Performance Computer
i	number of generator
IBM	International Business Machines Corporation
ICE	Internal Combustion Engines
ID market	Intraday Market
IVA	The Royal Swedish Academy of Engineering Sciences
LCOE	Levelized Cost Of Electricity
LRMC	Long-Run Marginal Cost
MATLAB	MATrix LABoratory
MC	Marginal Cost of production
mFRR	Manual Frequency Restoration Reserve
MIP	Mixed-Integer Linear Programming
MO	Market Operator
NL	Netherlands

NTNU	Norwegian University of Science and Technology
O&M	Operation and Maintenance
OC	Operational cost
OCGT	Open Cycle Gas Turbine
OF	Objective Function
OPTCA	Absolute Stopping Tolerance
OPTCR	Relative Stopping Tolerance
P_{max}	Active Maximum Power
P_{min}	Active Minimum Power
PWR	Pressurized Water Reactors
RAM	Random Access Memory
RD	Ramp Down rate
RES	Renewable Energy Sources
reslim	Wall-clock time limit for solver
RoR	Run-of-River
RU	Ramp Up rate
SD	Shutdown Ramp Limit
SRMC	Short-Run Marginal Cost
SU	Start-up Ramp Limit
SVK	Svenska Kraftnät
t	time
T	time period
TSO	Transmission System Operator
u	generator state binary variable
u_0	initial generator state
UC	Unit Commitment
UCC	Unit Construction and Commitment
UT	Minimum Up Time
VRES	Variable Renewable Energy Sources
$(\overline{P}_{i,t})$	Upper operating limit
$(\underline{P}_{i,t})$	Lower operating limit
y	turn-on binary variable
z	turn-off binary variable
RES	Renewable Energy Sources

1. Introduction

1.1 General Overview

During the 21th century, the European electricity system has experienced a rapid transformation on the type of power generators used to produce electricity. The main reason to explain the energy transition is due to the rise of an environmental concern from governments to mitigate CO_2 emissions and ensure a sustainable future for next generations. As a consequence of this awareness, first the Kyoto Protocol and more recently the Paris Agreement have established global pathways and goals to combat climate change and accelerate the transition to a sustainable low carbon future [1]. Globally, the electricity and heat production sector play a very important role on these emissions being the main contributor with a 25% share of GHG emissions as shown in Figure 1.

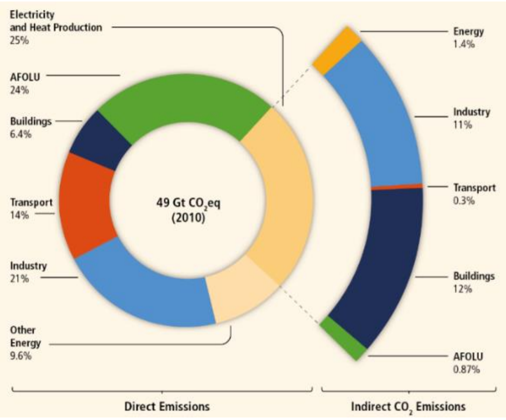


Figure 1. Greenhouse Gas emissions by Economic Sectors [2]

Additionally, the electricity demand is projected to increase a 75% in 2035 (see Figure 2) as the electrification of the transport (electric vehicles) and, heating and cooling (electric heat pumps) sectors takes place and the population increases.

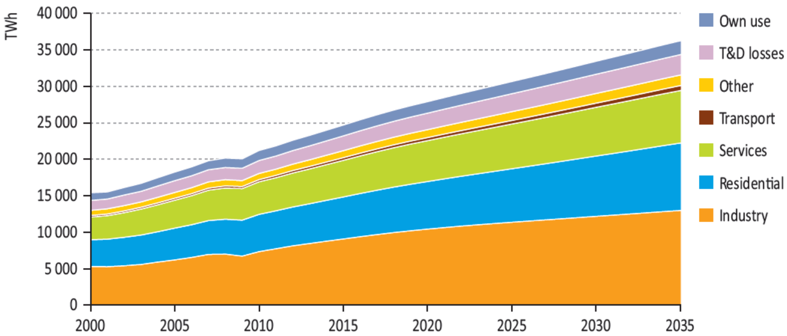


Figure 2. Projected electricity demand by sector, 2010-2035 [2]

In the European context, the European Commission is committed to reduce its environmental impacts provoking a rapid transformation on the entire system. The 2020 climate & energy package has set four key targets for 2020, shown in Table I.

The investment on Renewable Energy Sources (RES) has been promoted by the European Union (EU) via competitive advantages, as subsidies and carbon taxes. This opportunity has been utilized to invest in RES not only by private investors but also by households. The last has entered into the electricity system taking part of the supply and demand side at the same time, commonly called as "prosumers". This new energy actor together with the variable and uncertain output generation from some RES makes the electricity system more complex to design and balance. The investment in flexible, quick and available generators would be required to satisfy the future demand. The main challenge to face in Europe would be how to promote the required investments in generators, transmission, distribution and consumers goods, while not increasing the electricity price for households and energy-intensive industries. Furthermore, the institutions need to understand and identify the actual barriers of the electric power system design to enable and develop the flexibility requested by the deployment of the RES.

Table I. Goals EU 2020 [3, 4]

EU goals by 2020
• 20% reduction in GHG emissions from 1990 levels. • 20% improvement in energy efficiency. • At least 20% of the final energy use covered by RES. • 10% of the transport sector shall be covered by RES.

Among other effects, the deployment of VRES and its inability to freely modify its power generation (e.g. inflexibility) entails higher uncertainty under the power market. Flexible generators, as thermal or hydro power plants, need to be available to face the uncertain supply that can lead to imbalances (e.g. economic costs). In the balance settlement period (BSP) usually in hour time resolution, the Balance Responsible Parties (BRP) try to mitigate the imbalances provoked by the VRES. The BRPs deal with wide time resolution (hour resolution) that gives very little information about the imbalance distribution within the BSP. To fix this problem, the most pioneer power markets are moving their BSP to finer time resolutions mitigating the power imbalances.

1.2 Contribution of the thesis

The objective of this master's thesis is to answer the following questions:

- How can flexibility in the power markets can be captured in Unit Commitment (UC) models?
- What is the effect on simulating with different timesteps same UC problems and which its effect when the deployment of VRES takes place?

- How can a UC model can be designed for simulating with shorten timesteps? Which barriers may it experience, and proposed solutions could be taken to avoid them?
- How can the flexibility concept may change with the deployment of Variable Renewable Energy Sources and depending on the timestep used in Unit Commitment (UC) models?

1.3 Structure of the thesis

The remaining of this thesis are structured as follows.

Chapter 2 Background theory explains the relevant theory and background needed for analysing the role on flexibility and developing a Unit Commitment (UC) problem.

Chapter 3 includes the methods used for developing the UC model as well as statistical analysis and data collection needed for running a simulation. Additionally, it includes the most relevant simulations that have been necessary as a prework for further simulations in the following Chapters. When the UC model is perfectly adjusted, a conference paper for the European Energy Markets 2019 (EEM) which summarizes most of the theory implemented in the UC model as well as a simulation for different timesteps, shown in Chapter 4 EEM PAPER 2019.

In Chapter 5 VRES Case study a deeper UC analysis is developed. This analysis is discussed in Chapter 6 Discussion.

To conclude the thesis, 7 Conclusion & Future Research, englobes the final conclusion of the research, the list of limitations and a proposal for Future Research.

Chapter 8 Appendices includes the most important results, codes, database, among others that will help to understand better the insight of the simulations. In Chapter 9 References you may find the sources consulted and read for the development of the thesis.

2. Background theory

2.1 The Electricity System

The Electricity system englobes a physical infrastructure for generation, transmission, distribution and consumption, and a trading infrastructure to validate the transactions between the demand and the supply. There are many players in the electricity market and different structures depending on the country.

The main function of the electricity system is to provide a safe and reliable system ensuring the trade electricity between supply and demand. The demand is formed by the consumers including households and industries. Whereas, the supply side is composed by the producers, mostly the generators.

Since the electricity cannot be easily stored, the energy produced must be consumed instantly, requiring the supply and the demand to be equal at any time. This characteristic of the electricity market makes it unique and complex to manage. The electricity trading must be instantaneous; thus, the figure of a regulator is required to keep the system functioning. Besides, many other players are needed to ensure the system works efficiently.

2.1.1 Players

As the market is considered very complex, there are different players taking part apart from the consumers and producers.

The producers are responsible for the generation of active power. Producers sell the power to the market at a certain price, earning an economical benefit for the transaction. On the other hand, consumers or end users, consume and pay a tariff for the power. The retailer connects producers with consumers that do not actively take part in the electricity market. Two different markets take place, the retailer market and the wholesale market. Both markets will be explained in Section 2.1.3.

The Market Operator (MO) or Power Exchange collects the bids received from the demand and supply sides, match the bids and, consequently, settle the electricity price and the quantity traded. The main activity of the Market Operator is the operation of the short-term physical electricity market [5], presented in Section 2.1.3.

The Nordic Power Exchange, Nord Pool, established in 1993, is the marketplace for the Nordic power system and responsible for the physical and financial trading. It operates in more than 20 countries and offers day-ahead, called Elspot, and intraday markets to its participants.

The regulator represents the political authorities and their interests. Its main responsibility is to create laws and regulations to increase the efficiency of the market following their interests and ensure that the laws and regulations are being accomplished. For example, in Sweden, the main regulating authority (regulator) in the electricity sector is the Energimarknadsinspektionen / Energy Markets Inspectorate (Ei). Ei core activities are [6]:

- Supervision of the network companies in the electricity market.
- Market monitoring.

- Provide information to customers.
- Enable international collaboration.

The Transmission System Operator (TSO) is responsible for transport the electricity for long distances. The TSO operates at high voltages (36kV-220kV) to reduce the losses on the transport. Its main function is to maintain the balance between consumption and generation. At European level, the TSOs are organized in the European Network of Transmission System Operators (ENTSO-E), which works on network development plans and codes. Interconnections between grids and countries exist and help to balance demand and supply. In Sweden, Svenska Kraftnät (SVK) plays the role of TSO, being responsible for maintaining and developing the Swedish national grid, balancing the production and consumption in the electricity system [7].

The Distribution System Operator (DSO) is responsible of the distribution grid for medium (1kV-36kV) and low voltages (≤1kV). Its main function is to enable the connection between consumers and the transmission system. Indeed, the DSO permits the retail market, collects the data consumption of consumers and communicate the consumption to the retailers.

The responsible of the electricity balance (demand and supply) over hour periods, called Balance Settlement Periods (BSP), are the Balance Responsible Parties (BRP) which englobe retailers, consumers and producers. In Sweden to become a BRP, a balance responsibility agreement must be signed with Svenska kraftnät [8]. In return, the BRP will get paid for the service. In case of imbalance in shorter periods, the TSO will manage the fluctuations by using the ancillary services and will charge the costs to the responsible of the imbalance.

2.1.2 Ancillary reserves

The ancillary reserves are commonly divided in 3 types, depending on its time of respond:

- Primary reserve or Frequency Containment Reserves (FCR) is used when transient disturbances on the frequency of the system appear. FCR control responds within 30 seconds.
- Secondary reserve or Automatic Frequency Restoration Reserve (aFRR) replaces the primary reserve and brings back the system to the set point. The time respond is about 5 minutes and it is automatically controlled.
    - Tertiary reserve or Manual Frequency Restoration Reserve (mFRR) is a tertiary control layer, it works similar to the secondary reserve, but in this case, it works manually and takes 15 minutes.

2.1.3 Electricity Market

The electricity market is formed by two different markets, the wholesale market and the retail market. The retail market is designed to trade local offers, whereas the wholesale market is formed by bigger customers. The wholesale is divided in different markets depending on the time before delivery.

The price of electricity varies between the retail market (households) and wholesale market (industry). In order to promote competitiveness, the industrial consumers usually pay a lower price for electricity.

The Retail Market

The two main actors of the retail market:

- The retailers buy the electricity directly from the generators and offer electricity contracts previously approved by the regulator.
- The consumers choose between different retailers and types of contract.

The retailer will additionally charge to the consumers a price for the transmission and distribution services of the electricity, as well as taxes. Additionally, the retailer can buy electricity from the wholesale market and sell it in the retail market.

The Wholesale Market

In the wholesale market the players are generally the electricity suppliers, the generators and the large industrial consumers. The electricity contracts are negotiated before a time of delivery. Depending on the time left to delivery, there are different markets available. The power market is divided into financial markets and physical power markets (see Figure 3).

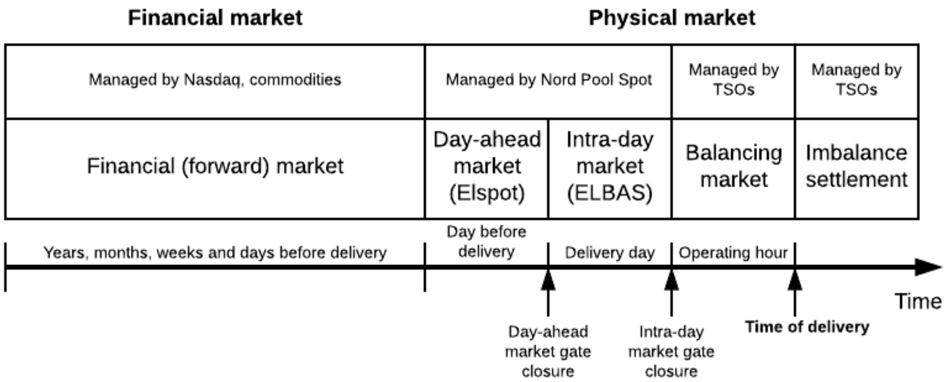


Figure 3.Structure Wholesale Market depending the time before delivery based on [9, 10]

The Financial market is used to trade in the financial contracts. These contracts ensure future sales and provides lower risk for producers. With this tool, producers' profit will decrease its sensitivity to the actual price of the electricity. In addition, the time horizon of the financial contracts goes from days to 6 years.

The Day-ahead market (DA market) trades the electricity until one day to actual delivery and is the largest physical power market [9]. In the Nordic system, the DA market, called Elspot, closes at 12:00 CET on the day previous to delivery.

The Intra-day market (ID market) is a continuous trading market that opens just after DA market closure. Its main function is to recalibrate the DA trades considering more precise forecast of wind and solar power generation, or unexpected failures. The adjustments can be made until an hour ahead delivery. Nord Pool ID market is called Elbas [11].

The Balancing market corrects the power system imbalances before Real-time market takes place. In the Nordic system, the BRP can operate after the Intra-day closure, but it is required to report the contract positions to the TSO.

The BRPs rarely succeed entirely with a planning a perfect power balance. Therefore, the ancillary reserves (so-called balance settlement) described previously, will ultimately fix a possible imbalance of the system. The cost will be charged to the responsible of the imbalance.

The often called "Reserve Markets" permits the TSO to purchase days in advance reserves (ancillary reserves) from the BRPs. Reserves are usually very flexible units that can adapt quickly their electricity production.

The Intra-day market, Balancing market and the Imbalance settlement provide flexibility to the market, ensuring the system reliability.

As we move closer to the time of delivery, the uncertainty and the risk of forecast errors on the demand and supply decrease. The integration of variable and uncertain generators as solar and wind increases the need for balancing after day-ahead closure, rising the power traded in the Intra-day and balancing market, thus demanding more available flexibility.

2.2 Flexibility concept

The definition of flexibility is specified as *"the ability of a power system to respond to change in demand and supply"* [12]. Indeed, there are several interpretations about flexibility. Juha Forsström [9] distinguish between two different concepts: Adequacy of capacity (responded in month or years) and flexibility (responded in hours to minutes). On the other hand, OECD/IEA [13] define flexibility in three different timescales, establishing different issues for six different timescales (Table II).

Table II. Timescales of issues addressed by power system flexibility based on [13]

	Timescale	Issue
	Subseconds to seconds	Provide system stability, i.e. withstanding large disturbances such as losing a large power plant.
Short-term flexibility	Seconds to minutes	Manage fluctuations in the balance of demand and supply, such as random fluctuations in power demand.
	Minutes to hours	Manage ramps of supply and demand, e.g. increasing electricity demand following sunrise or rising net load at a sunset.
Medium-term flexibility	Hours to days	Decide how many thermal plants should remain connected to and running on the system.

Long-term flexibility	Days to months	Manage scheduled maintenance of power plants and larger periods of surplus or deficit of energy, e.g. hydropower availability during wet/dry season.
	Months to years	Balance seasonal and inter-annual availability of variable generation (often influenced by weather) and electricity demand.

The purpose of this specialization project is to focus on the short-term with a timescale from minutes to hours and medium-term flexibility (hours to days) presented in Table II. Therefore, for this thesis, the concept of flexibility will refer to the short-term from minutes to hours and the medium-term of flexibility. That is, the project scope will not cover the stability issues and the ancillary services.

Flexibility is a property that can be developed not only from the supply side but also from the demand. The implementation of smart metering and the digitalization of the electric system has amplified the power system boundaries. Nowadays the consumers can bring flexibility to the system by modifying their demand depending on the price of electricity. Additionally, the smart use of batteries can reduce the peak loads by charging the battery during off-peak hours when the price is low and discharging during peak hours at a higher price, earning money for bringing flexibility [14].

Regarding the supply side, flexibility is provided by the generators. Depending on the type of energy source, the generators can bring higher or lower flexibility to the electric system, which is explained in the next Section, Generator Properties.

2.3 Generator Properties

The main properties of a generator that rule its production behaviour can be summarized in the following concepts.

2.3.1 Cost of Electricity

The cost of electricity is most important aspect of a generator. Since the power system goal is to reduce the cost of electricity, only the cheapest and efficient generators will produce to satisfy the electricity demand. The cost of electricity is usually divided in two different costs: Fixed costs and Variable costs.

The fixed costs consider the investment costs needed to build the power plant and the equipment and services necessary to be able to produce electricity. This cost is “fixed”, since it does not vary depending on the electricity production. Thus, it is the amount of money necessary to be able to produce electricity.

On the other hand, the variable costs are costs derived from the production and operation of the plant. It may include the fuel, labour and maintenance costs [15]. Indeed, it will vary depending on the level of electricity output.

As part of the variable costs, the start-up (Cu) and shutdown (Cd) costs occur while connecting and disconnecting a power plant, respectively. Depending on the type of power plants, Cu and Cd may economically reflect the energy losses, the probability of a failed start or abrasion of the equipment due to connecting or disconnecting the power plant. Both parameters are usually assumed as constant, though in practice they vary depending on the operating hours and the number of starts, as Bakken and Bjorkvoll [16] shown on their research.

The Levelized Cost Of Electricity (LCOE) is a very useful parameter that measures the net present value of the unit-cost of electricity over the lifetime of a generating asset. LCOE considers all the costs over the generator lifetime, variable and fixed costs.

$$LCOE = \frac{\sum Costs\ over\ lifetime}{\sum Electrical\ energy\ produced\ over\ lifetime} \left(\frac{€}{kWh}\right) \tag{1}$$

However, to set an electricity price, most of the power markets (including the Nordic system) uses the "Marginal cost of production" (MC) for Market clearing.

The Marginal cost of production (MC) is the change in total cost for producing an additional item. Referring to the electricity system, the marginal cost reflects the additional cost to produce an additional MWh or kWh, depending the energy unit used. Thus, it does not consider the fixed costs of a power plant and indirect variable costs, like the start-up and shutdown costs.

The MC is not usually constant and varies depending on the power produced. Thermal power plant follows a quadratic fuel cost function [17], shown in Equation 2. Therefore, the MC for a given power produced will be the derivative of the fuel cost function, and since it is not quadratic, the MC cannot be constant.

$$C_i(P_{Gi}) = a + bP_{Gi} + cP_{Gi}^2 \tag{2}$$

$$MC_i(\mathrm{P_{Gi}}) = \frac{\partial C_i(P_{Gi})}{\partial P_{Gi}} = 2cP_{Gi} + b \tag{3}$$

Market clearing is the process to equalize supply and demand. The suppliers and consumers submit their bids, usually at their MC. The market operator collects them. The mechanism to determine the clearing price and power volume traded is based on the merit order curve (Figure 4).

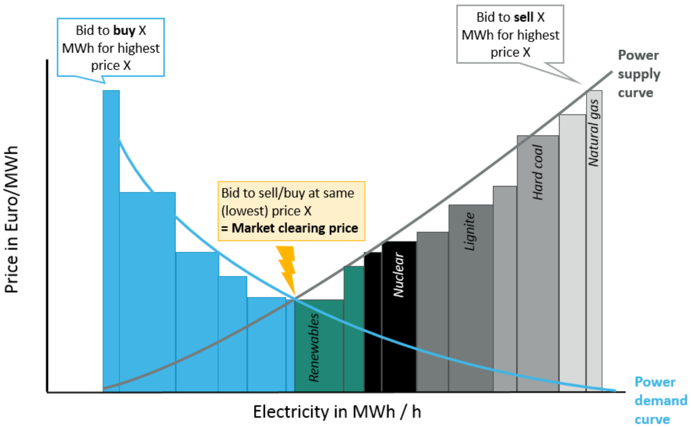


Figure 4. Merit-order-curve for a given demand and supply curve [18, 19]

The bids with the lower MC will be cleared first until demand and supply turn equal. The intersection between demand and supply curve will determine the clearing price and the amount of power traded. This mechanism is becoming an important barrier against flexibility as the VRES share increases.

VRES cannot control its power output, consequently its MC is almost zero. As it is represented in Figure 5, the VRES supply moves the supply curve to the right, decreasing the market clearing price. A low electricity cost reduces the generator profits and, in many cases, causes economical losses in some generators [20], specially the generators with high MC that do not bring an economical benefit to the market but add available flexibility when is required. Certainly, this requirement is not constant during the year (depends between summer and winter season) and only is required at most few hours per day.

In contrast with the LCOE, the MC does not cover all the electricity costs and only considers the change in the cost for producing an additional item.

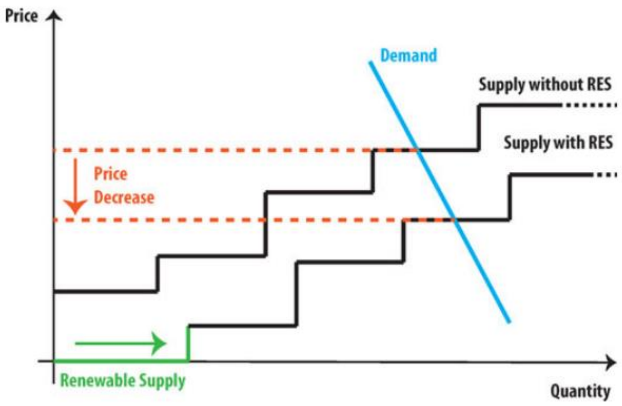


Figure 5. The relationship between prices ($/MWh) and renewable energy output (MWh)[20]

Additionally, since the project scope is to focus on short-medium term of flexibility, the fixed costs will not be relevant.

2.3.2 Generation capacity

The generation capacity is the maximum power output that a power plant can produce. It depends on the type of power plant and its dimensions. The generation capacity is commonly called as active maximum power (P_{max}) and are usually given in MW.

Power plants usually must produce above an active minimum power (P_{min}) for security reasons, technology boundaries or to ensure a minimum efficiency.

2.3.3 Ramp rate

The ramp rate measures how quick a generator can increase or decrease its power output for given period. It is usually given in MW/h or MW/min.

It is subdivided in two rates: The Ramp Up rate (RU) means the capacity to increase the power output whereas Ramp Down rate (RD) the capacity to decrease it. The short-term and medium-term of flexibility deals specially with these concepts.

2.3.4 Minimum Up time and Minimum Down time

The minimum Up time (UT) reflects the minimum required time that a generator will be producing electricity after turning on. An operator may impose this constraint to reduce the operational cost sensitivity to start-ups and shutdowns costs [21].

The minimum Down time (DT) indicates the minimum required time that a generator cannot be turned on after turning it off. The DT constraint emulates the time need to synchronize a generator to the grid frequency [21]. Both parameters are usually given in hours and limit the flexibility of generators, which cannot be constantly turning on and off.

UT and DT are usually given in hours or minutes.

2.3.5 Shutdown and Start-up ramp limit

The shutdown ramp limit (SD) means the maximum operating power output (MW) that enables to turn off a power plant. In case the power plant exceeds the SD limit, it cannot be disconnected until it decreases the power output. For example, a power plant delivering its P_{max} cannot be instantly turned off.

The start-up ramp limit (SU) reflects the maximum operating power output (MW) that a power plant can produce just after turning it on. Therefore, a power plant cannot instantly operate at P_{max} after turning on, it will be limited by its SU.

2.3.6 Type of generation by energy source

Each type of generator behaves differently depending on the energy source used for producing power, thus modifying the generator properties previously defined.

Indeed, there are many types of generators. Therefore, this section will only explain the generators taking place in Sweden power market.

Fossil generation

Fossil generation englobes all the power plants that use fossil fuels, such as Natural Gas, Oil, Waste or Coal, to produce energy, as heating or electricity. The main technologies are:

- Steam turbines
- Open cycle gas turbines (OCGT)
- Combined cycle gas turbines (CCGT)
- Internal combustion engines (ICE)

Fossil flexibility constraints come from their ramp rate, minimum up time and minimum load. Traditionally, fossil generation has been responsible for providing flexibility to the system. OCGT and ICE are the most flexible units and, with the increase of variable renewable energy sources (VRES), are currently taking the role of balancing the variable of the net demand [21]. The main barriers of these technologies are the high investment costs and the gas emissions produced – the carbon taxes increase its operational cost.

Moreover, Combined Heat and Power plants (CHP) produce electricity and steam by using the waste heat previously generated from a central process [22] or biomass waste. CHP usually uses CCGT and provides high energy efficiency to the system. CHP technology is commonly used for district heating production.

Nuclear generation

Nuclear power plants use the heat generated by fission reaction inside a nuclear reactor to drive steam turbines and convert the energy into electricity. There are two mainly technologies:

- Pressurised water reactors (PWR)
- Boling water reactors (BWR)

Both technologies are highly inflexible, therefore they are used as base load units. The major flexibility problem of the nuclear plants does not come from its ramp rates, which are quite large. Indeed, it comes from the time required to connect and disconnect the reactor which usually takes about a day or longer [23]. The disconnection of a nuclear plant during off-peak hours (midnight hours) implies that it could not be used during the peak hours of next day.

Additionally, the Fixed cost of a nuclear plant is enormous, but it provides energy at very low MC. This combination requires the nuclear plant to usually work at maximum power (base load) in order to return the investment. At maximum power, the available ramp up of the plant is almost null.

Moreover, nuclear power plants use uranium and plutonium as fuel and are currently very criticize and unpopular because of the potential risk of using radioactive fuels [22]. Thus, many European countries as Sweden and Germany have decided to decommission their reactors in the next decades [24].

Variable renewable energy generation

For this thesis, Variable renewable energy generation mainly englobes wind power and photovoltaic power. The main advantage of both energies is the zero emissions on the energy generation. On the other hand, their variability and uncertainty require a higher flexibility on the power system, provided by other energy sources. Both types of generation are totally inflexible and, consequently, their marginal cost is considered almost zero, they cannot regulate their production in a big scale. The use of batteries could help to give flexibility to this VRES, but currently the storage capacity of the batteries is still very low and highly cost intensive.

In addition, both types of generations cannot be allocated randomly, they need special conditions to provide an efficient generation. Wind power generators will need to be placed in zones with a proper wind speed distribution. Offshore wind power is becoming more attractive due to the good wind conditions of the sea.

Besides, the photovoltaic energy production depends on the global irradiation, thus, places closer to the equator generally experience higher solar energy generation (Figure 6).

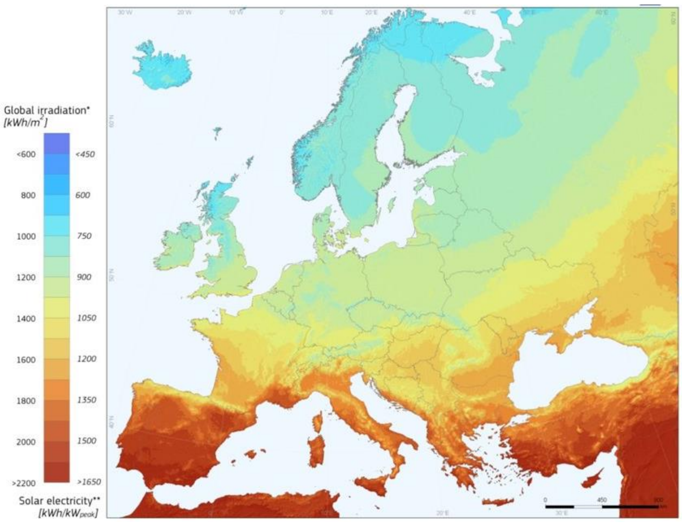


Figure 6. Photovoltaic Solar Electricity Potential in European Countries [25]

Hydropower generation

Hydropower uses the energy of flowing water. Many hydropower plants are positioned in cascade one after the other over the river, so the water's energy can be extracted several times.

Hydropower storage generation is considered as a RES, but not as a VRES. Unlike photovoltaic and wind power, hydropower generation can usually be controlled at any time and provides high flexibility to the system, since water can be stored in the reservoirs until needed [26]. Compared with other types of generation, it can quickly modify its production.

As an exception, a type of hydropower plant often called as run-of-river (RoR) have non or limited capacity of storage and offer very low flexibility. RoR mainly depends on the natural inflow of the river [27], therefore it can be considered as VRES.

One important aspect to consider is the variability of the rainfall (Figure 7) and, consequently, the variability of the water reservoirs between winter and summer season (Figure 8).

The annual hydro production, dependent on the precipitations, is not as flexible (in long-term flexibility) as its short-term/medium-term production where it is considered one of the most flexible power sources. The hydro production is usually higher during the winter, when the power consumption is higher (for Scandinavian countries), than in summer. Consequently, the water reservoirs will increase until the winter starts.

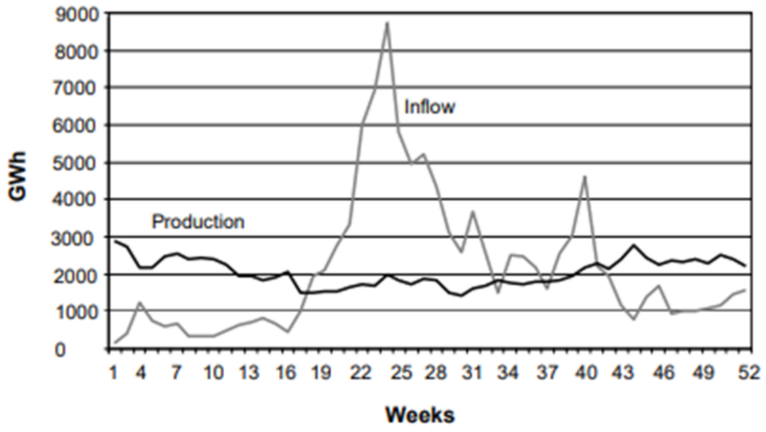


Figure 7. Weekly inflow and production of hydropower in Norway 2003 [28]

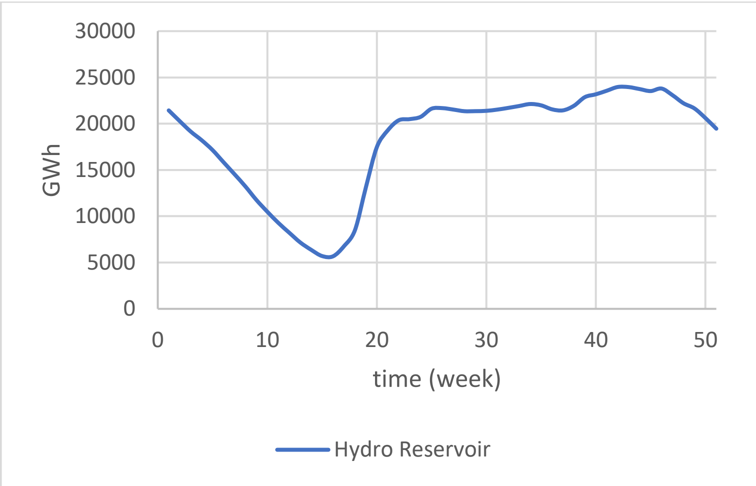


Figure 8. Swedish water reservoir during 2018 based on [29]

Additionally, its cost of electricity varies with the water value, which depends on the hydro reservoirs. When the reservoirs are almost full the water value will be almost zero and the other way around. Therefore, in practice its MC is not constant over a large period of time.

2.4 Related literature on flexibility

Flexibility on power systems has been a topic very well studied in different countries and related work in the literature. Since the available energy sources varies depending on the country, there is not a common established approach to increase flexibility on the system.

Comparing Germany and Sweden systems, Hirth [30] demonstrates the good synergy between Hydro and Wind power and states that the market value of wind electricity declines with its penetration in both systems but tends to decline slower if hydropower is present (Swedish system). Thus, hydropower mitigates the value drop by a third due to its dispatch flexibility. Hirth [30] also affirm that the benefits of hydropower settle at around 20% of wind penetration.

With a more general approach, Ma, et al. [31] present a unit construction and commitment (UCC) algorithm, able to determine the optimal portfolio of flexible units for different cases. One important concept that Ma, et al. [31] add to previous flexibility studies is the idea of quantifying the flexibility of a unit. The flexibility index of a unit is calculated by the next equation.

$$flex(i) = \frac{\frac{1}{2}[P_{max}(i) - P_{min}(i)] + \frac{1}{2}[Ramp(i) \cdot \Delta t]}{P_{max}(i)} \tag{4}$$

For different markets connected by transmission lines that enables exchange of power as Europe, Fattler and Pellinger [32] propose a common Intraday-market which can significantly reduce the flexibility required to compensate forecast deviations on the VRES production. That is, unifying the available capacity used to balance the grid.

Other authors, as Oleinikova, et al. [33], highlight the current problems of clearing the price at MC. Oleinikova, et al. [33] differentiate between Short-run marginal cost (SRMC) and Long-run marginal cost (LRMC). As previously shown, the SRMC used for clearing the price on the spot market is not covering the fixed part of a power plant and could cause in a long-term perspective economic loss, thus disincentivizing flexibility. To solve it, the authors propose to clear the price at its LRMC. LRMC is defined as "*the levelized cost of meeting the increased demand over an extended period of time. The LRMC is the wholesale price that should be earned by a generator, on average, in order to recover the capital and operating costs during a year*" [33]. LRMC includes not only the SRMC but also the annualized fixed costs (including investment).

Although most of the literature is focused on solving or optimizing the supply flexibility, other authors investigate ways to enable flexibility from the demand side. Chen, et al. [34] declare that the number of options to improve building energy demand flexibility for demand response is immense. The use of solar power with energy storage, thermal energy storage, electric vehicles batteries or smart thermostats could bring demand flexibility to the households and mitigate the required flexibility on the supply side [35, 36]. As a consequence, a role of an aggregator could emerge to connect and optimize the both demand and supply flexibilities [37].

In all these modelling approaches, authors stress the need to react to RES variability in short-term operation. However, modelling approaches representation of temporal resolution (minutes, hours, hourly blocks, day) varies greatly, e.g. see review in [38]. There is no agreement or concrete studies addressing the relevance of modelling different time resolutions and the impact on assessing flexibility of the power system.

3. Methodology

The methodology chapter focuses on the development of creating and adjusting a UC model that will be used for the case of study in Chapter 5. The UC model design starts with a preliminary version and several addons are integrated to the model after different simulations and tests, shown in this Chapter.

The UC model slightly varies depending on the timestep simulated. The timesteps (also called time resolution) considered for the simulation are 60 minutes, 15 minutes, 5 minutes and 1 minute. The main scopes of the simulations are to reflect the effect of the timesteps on the UC solution as well as a test for improving the model before applying it to the case of study, shown in Chapter 5.

3.1 Flexibility theory under UC modelling

Before presenting the model, the flexibility under UC modelling has been analysed. From a theoretical perspective, the UC models as [39-41] overestimate the flexibility of the generators due to selecting a countable timestep which is unavoidable.

Considering 1-hour period and a generator with a Ramp Rate of 60 MW/h without considering other constraints, the maximum power that can produce (in a simulation) within the hour period depends on the time scale used. The maximum real energy produced by the generator will be 30 MWh, assuming a constant and linear ramping (See Figure 9).

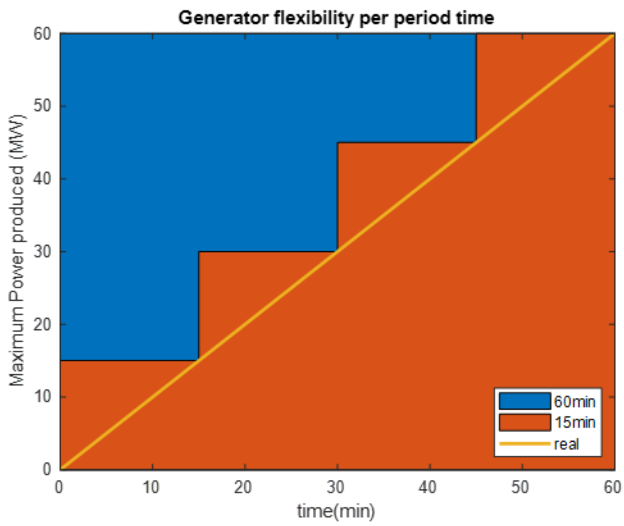


Figure 9. Real power generation versus 15 min and 60 min timestep

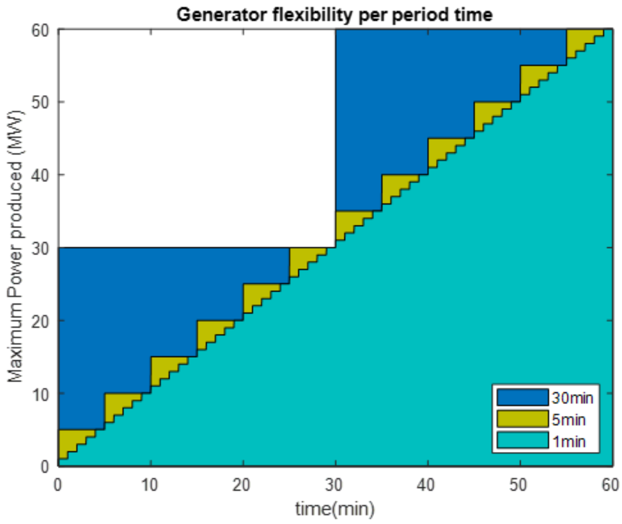


Figure 10. Power generation for 5 min, 15 min and 30 min timestep

Unfortunately, UC models cannot avoid a flexibility overestimation since the timestep cannot be infinitely small. Thus, the shorter the timestep, the less overestimation (See Table III). As shown in Figure 9 and Figure 10, the theoretical maximum energy produced with a timestep of 60 minutes will be 60 MWh, overestimating its production a 100% compared to the real production. Overestimation can be reduced until 1.67 % by selecting 1 minute resolution. Therefore, UC models that reduce the time interval will capture and emulate more precisely the flexibility of the generators.

Furthermore, on the side of the demand, power load data with shorter time resolution will reflect possible peak loads that hourly basis will not be represented. These peak loads play a crucial role in the power market flexibility.

Table III. Theoretical maximum energy produced and flexibility overestimation per timestep

Timestep	Maximum Energy produced (MWh)	Flexibility overestimation with reality (%)
60 minutes	60	100 %
30 minutes	45	50 %
15 minutes	37.5	25 %
5 minutes	32.5	8.33 %
1 minute	30.5	1.67 %

3.2 Unit Commitment optimization

Unit commitment (UC) can be defined as “*an optimization problem used to determine the operation schedule of the generating units at every hour interval with varying loads under different constraints and environments*.” [42]

The proposed UC model can determine the operation schedule at every minute instead of every hour (as it is typical in the literature and energy modelling), bringing higher UC resolution.

The programming language selected to simulate the UC model has been the General Algebraic Modeling System (GAMS) with the solver IBM ILOG CPLEX Optimization Studio, commonly called CPLEX, by IBM. The selection of CPLEX is due to the necessity of selecting a solver able to solve Mixed-integer linear programming (MIP) problems. The CPLEX full license has been provided by the Norwegian University of Science and Technology (NTNU) as well as a High-Performance Computer (HPC) with processor Intel® Xeon® CPU E5-2690 v4 and 384 GB of RAM.

In mixed integer programming (MIP) problems, the decision maker is faced with constraints and objective function that are linear but there exist some integer/binary variables [43]. Indeed, the UC problem proposed in this specialization project uses binary variables.

3.3 Initial model description

UC optimization aims to minimize economic costs while at the same time satisfying the given demand. Many generator constraints should be added by designing specific equations for each constraint. All the equations should interact correctly and generate convergent solutions. In case two equations deny each other, there would be no possible solution. It is very important to understand how the equations will interact with each other.

The first equation that every optimization problem should firstly establish is the Objective Function (OF). The OF is the equation that will be optimized, either by minimizing or maximizing its result. For UC problems, the objective function is minimized, being the total generator costs of satisfying a given demand. The total generator costs will be the sum of operational costs ($OC_{i,t}$), Start-up costs ($Su_{i,t}$) and Shutdown costs ($Sd_{i,t}$) for each generator (i) and time (t).

$$\min OF = \sum_{i,t} \left(OC_{i,t} + Su_{i,t} + Sd_{i,t} \right) \tag{5}$$

$$OC_{i,t} = MC_i P_{i,t} \tag{6}$$

$$Su_{i,t} = Cu_i y_{i,t} \tag{7}$$

$$Sd_{i,t} = Cd_i z_{i,t} \tag{8}$$

To measure the total start-up and shutdown costs during the simulation, it is required to use binary variables that indicate when the generator has turned on (y_i) and when turned off (z_i) until the last period (T). Also, a binary variable (u_i) indicates whether the generator is connected or not. The initial generator states (u_0) are integrated into the simulation by Equation 12.

$$y_{i,t} - z_{i,t} = u_{i,t} - u_{i,t-1} \quad \forall t = 2 \dots T \tag{9}$$

$$y_{i,t} + z_{i,t} \leq 1 \tag{10}$$

$$y_{i,t}\, , z_{i,t}\, , u_{i,t} \in [0,1] \tag{11}$$

$$y_{i,t} - z_{i,t} = u_{i,t} - \mathrm{u}_0 \quad \forall t = 1 \tag{12}$$

The start-up and shutdown ramp limits ($SU_{i,t}$ and $SD_{i,t}$) can be combined with the Ramp Up and Down limit ($RU_{i,t}$ and $RD_{i,t}$), the maximum (P_i^{max}) and minimum power output (P_i^{min}). The integration of multiple parameters in the same equations gives a smaller number of necessary equations and, consequently, brings less complexity to the UC model. The equations are shown below:

$$\underline{P}_{i,t} \leq P_{i,t} \leq \bar{P}_{i,t} \tag{13}$$

$$\bar{P}_{i,t} \leq P_i^{max}\left[u_{i,t} - z_{i,t+1}\right] + SD_i z_{i,t+1} \quad \forall t = 1 \dots T-1 \tag{14}$$

$$\bar{P}_{i,t} \leq P_{i,t-1} + RU_i u_{i,t-1} + SU_i y_{i,t} \quad \forall t = 2 \dots T \tag{15}$$

$$\underline{P}_{i,t} \geq P_i^{min} u_{i,t} \quad \forall t = T \tag{16}$$

$$\underline{P}_{i,t} \geq P_{i,t-1} - RD_i u_{i,t} - SD_i z_{i,t} \tag{17}$$

$$\bar{P}_{i,t} = P_i^{max} u_{i,t} \quad \forall t = T \tag{18}$$

These equations provide the upper ($\bar{P}_{i,t}$) and lower ($\underline{P}_{i,t}$) operating limits of each generator, considering if it is connected, disconnected, turned on or turned off at that time t (binary variable application).

The next constraint to be added is the Minimum Up and Down Time (UT_i and DT_i). The auxiliary parameter k enables to identify the previous states of the generators to ensure that the UT_i and DT_i constraints are fulfilled.

$$\sum_{k=t-UT}^{k=t} y_{i,k} \leq u_{i,t} \quad \forall t = UT_i + 1 \dots T \tag{19}$$

$$\sum_{k=t-DT}^{k=t} z_{i,k} \leq u_{i,t} \quad \forall t = DT_i + 1 \dots T \tag{20}$$

Finally, the power balance constraint needs to be added:

$$Load_t = \sum_{i,t} P_{i,t} \tag{21}$$

The demand simulated in the UC model would be the so-called Net demand. The generation from VRES is discounted form the total demand, giving the net demand that the portfolio must fulfil.

3.4 Creation of a generator database

A small generator database including generator constraints has been created. The database has been a very useful tool and guide to modify the generator portfolio in further simulations. The list of the generators considered in the database is shown in Appendix

A. The database only includes Swedish generators, since there is no need in creating a large database and Swedish portfolio covers many different types of generators by energy source used.

The data creation starts with the finding of the Swedish generators that form the supply side of the power market. ENTSO-E, the European Network of Transmission System Operators, which represents 43 European electricity transmission system operators (TSOs), gives the current installed capacity of each generator above 100 MW installed capacity [44]. In total, ENTSO-E shows 64 generators, with a total current installed capacity of 21.46 GW. Figure 11 shows the installed capacity per type of unit given by ENTSO-E data.

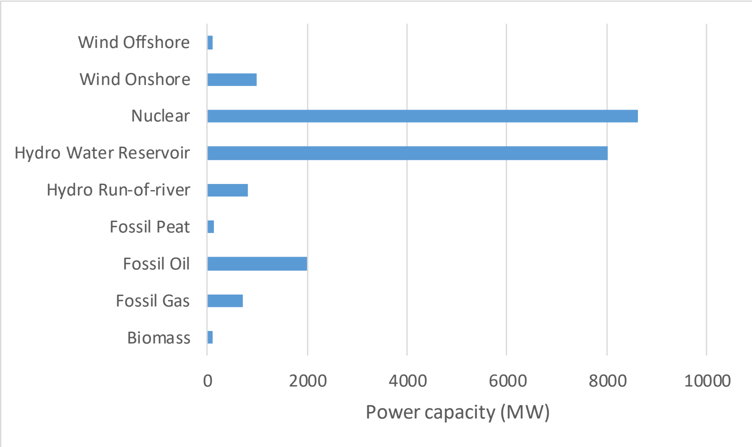


Figure 11. ENTSO-E Swedish generator data [44]

The generators constraints are based on previous research done [42, 43, 45, 46] and include:

- Marginal cost (€/MWmin)
- Maximum and Minimum power output (MW)
- Ramp Up Rate (MW/min) and Ramp Down Rate (MW/min)
- Minimum Up time (min) and Minimum Down time (min)
- Start-up cost (€) and Shutdown cost (€)
- Shutdown ramp limit (MW) and Start-up ramp limit (MW)

The marginal cost is difficult to find or estimate as it varies based on technology and from country-to-country. On one hand, the merit-order-curve uses MC (€/MWh) to clear the electricity price. On the other, the literature provides Capital cost (€/MW), Variable O&M cost (€/MWh) and Fixed O&M cost (€/MWa).

Although the MC may different specially depending on the type of technology used in the Gas turbines and Oil Power, there is an academic consensus [18, 47, 48] that the merit order usually corresponds to the following order:

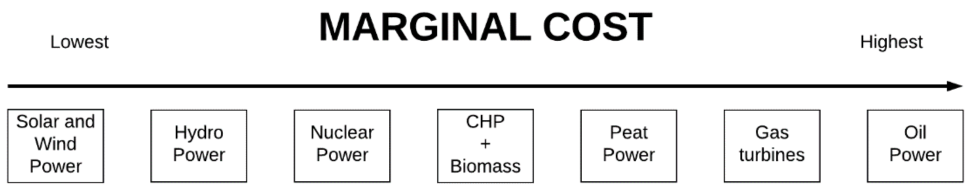


Figure 12. Marginal cost per type of unit

The proposed marginal cost order takes into account the EU Emissions Trading System (EU ETS), which works similarly to a carbon tax.

The proposed MC order does not correspond with a more precise Variable O&M cost (also called Operational cost) given in [15, 22, 49-51]. Many variables and indirect cost may determine the MC of a power plant. Thus, for simplification, the simulation will use the MC given in [18, 47, 48] that follows a more logic merit than the variable O&M costs does.

According to the MC merit order, one important aspect should be highlighted. In practice, the MC is not constant, as previously shown in Section 2.3.1. However, for simplicity the MC used for the simulation will be constant for any power output.

The marginal cost assumed are given in Table IV.

Table IV. Marginal cost per unit type based on [18, 47, 48]

Type of Power Plant	**Hydro Power**	**Nuclear Power**	**CHP + Biomass**	**Peat Power**	**Gas Turbines**	**Oil Power**
Marginal Cost (€/MWh)	6.7	9.5	25	35	63	65
Marginal Cost (€/MWmin)	0.112	0.158	0.417	0.583	1.05	1.083

Regarding the minimum output power, it is possible to estimate it based on the maximum power output given by the ENTSO-E for each type of generator. Table V, Table VI, Table VII and Table VIII present the input data used.

Table V. Minimum power output data

Type of Unit	**Reference Used**	**Minimum power output (%P_{max})**
Hydro Power	Guisández, et al. [52]	6.85%
Nuclear Power	Klobasa, et al. [53]	40%
CHP + Biomass	Steck and Mauch [23]	40%
Peat Power	VDE [54]	40%
Oil Power	Steck and Mauch [23]	40%
Gas turbine	VDE [54]	20%

Table VI. Minimum power output data

Type of Unit	Reference Used	Ram Up and Down Rate ($\pm\%P_{max}$/min)
Hydro Power	Eurelectric [55]	40%
Nuclear Power	Steck and Mauch [23]	3%
CHP + Biomass	VDE [54]	5%
Peat Power	Lambertz [56]	3%
Oil Power	Steck and Mauch [23]	4.5%
Gas turbine	VDE [54]	11%

Table VII. Minimum Up Time and Down Time

Type of Unit	Reference Used	Minimum Up/Down Time (min)
Hydro Power	Own assumption[1]	30
Nuclear Power	Steck and Mauch [23]	1440
CHP + Biomass	Steck and Mauch [23]	60
Peat Power	ECF [57]	240
Oil Power	Steck and Mauch [23]	120
Gas turbine	Steck and Mauch [23]	15

Table VIII. Start-up cost and Shutdown cost

Type of Unit	Reference Used	Start-up and Shutdown cost (€/$MW_{installed}$)
Hydro Power	Arce, et al. [58] & Nilsson and Sjelvgren [59]	3€/$MW_{installed}$
Nuclear Power	Ehlers [60]	140 €/$MW_{installed}$
CHP + Biomass	Ehlers [60]	20 €/$MW_{installed}$
Peat Power	Traber and Kemfert [61]	27.9 €/$MW_{installed}$
Oil Power	Traber and Kemfert [61]	18.92 €/$MW_{installed}$
Gas turbine	Grimm [62]	16.7 €/$MW_{installed}$

The and Start-up and shutdown ramp limit (MW) were not possible to find. Based on previous UC simulations and examples [21] it will be assumed:

$$SD_i = 1.1 \cdot P_{min} \tag{22}$$

$$SU_i = 1.15 \cdot P_{min} \tag{23}$$

[1] Lack precise of data. Hydro's minimum output power is extremely low, so the minimum up and down time will not modify much the simulation.

The data is given per hour. Therefore, a conversion needs to be done for shorter timesteps as 15 minutes, 5 minutes and 1 minute. The database created considers the timestep used and automatically converts the generator constraints.

3.5 Initial demand data creation

For timesteps of 1 minute, 5 minutes and 15 minutes, the power demand, usually hourly given (NordPool), needs to be converted to shorter timesteps.

The main assumption for this conversion is to maintain the power consumption (in MW) for each hourly period. For example, for the first hour from 00:00 until 01:00 the demand will be 8000 MWh, which is the same as demanding 8000 MW of power within an hour. Thus, for each minute the power demanded will be 8000 MW until the next hourly period. An example of the demand is presented in Figure 13.

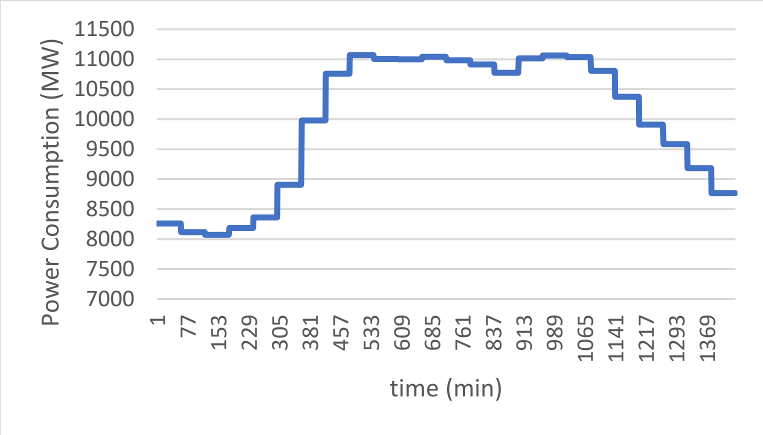


Figure 13. Power consumed per minute over the 14th of December in Sweden

3.6 Simulation 1: Swedish case

The first simulation covers the Swedish demand on the 14th of December 2018 with a representative portfolio of Swedish available generators during that period. The simulation is composed by 4 cases:

- Case 1 will simulate the Swedish demand from the 14th of December 2018, a period of 24 hours (1440 minutes).
- Case 2 will simulate the 120% of the demand from the 14th of December 2018, a period of 24 hours (1440 minutes).
- Case 3 will simulate three times in a row the demand from the 14th of December 2018, a period of 72 hours (4320 minutes).
- Case 4 will simulate three times in a row the 120% of the demand from the 14th of December 2018, a period of 72 hours (4320 minutes).

The main objectives of the simulation are:

- Prove that the UC model works and find possible improvements
- See that the UC model shows a logic solution

- Compare the solution with the real results from that period

The generator portfolio emulates half of the Swedish available capacity during winter periods and the input demand will be half of the total Swedish demand on the 14th of December 2018. This downscale is implemented to reduce optimization complexity and computing time. Solar and wind production are discounted from the demand, since its production cannot be varied, giving the net demand. Appendix B shows a wider explanation of the simulation.

The generator portfolio has been taken from generator database. In total the portfolio is composed by 37 real Swedish generators over 100 MW of installed capacity, including 27 Hydro Water Reservoir, 4 Nuclear plants, 1 ST Gas turbine, 1 ST Oil power plant, 1 ST Peat power plant, 2 CC CHP plant (Using Gas and biomass respectively). The list of power plants can be found in Appendix A. The power generators are only considered for electricity production. District heating production is not considered in the model.

3.6.1 Results and insights

The results and an extended discussion of them are shown in Appendix B. The main insights are shown below.

The proposed UC model does not work perfectly. The assumption of maintaining the power demand constant for each hour (i.e 60 minnutes) creates minor disturbances on the simulations. For example, in Case 3, from 00:00 am to 0:59 am the power demand is constant. But from 0:59 am to 1:00 am the demand jumps up to the next hourly demand. This singularity disturbes the UC solution. In case the hydro power is operating at maximum power and a jump on the demand is coming soon, the hydro will decrease its maximum power and the nuclear power will start increasing/decreasing it in advance because the nuclear power is not able to ramp up/down quickly enough from 0:59 am to 1:00 am. Figure 14 shows the disturbances.

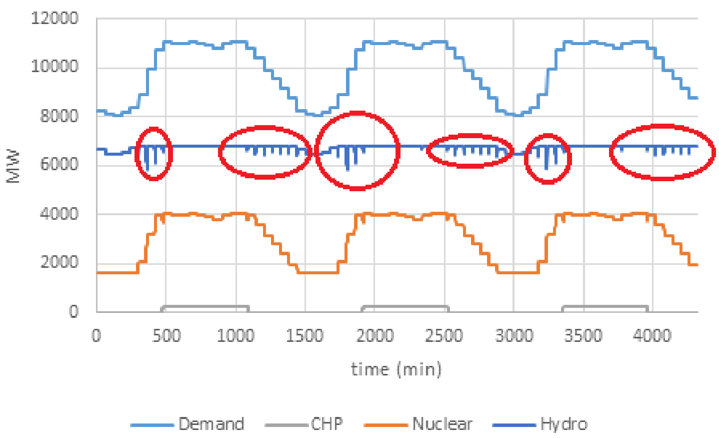


Figure 14. Disturbances highlighted in red, Case 3 results

Although, the disturbances do not considerably impact on the results, it could be possible to make them disappear by using interpolation on the creation of the data demand. A demand conversion model is proposed and added to the UC model for further simulations.

Referring to the data provided by the academia, the results demonstrate that the data seems to be accurate and sustained by the theoretical background of flexibility and generator properties.

The use of real data directly measure from the generators is an important tool to give more precise results. It is important to highlight that the MCs have been assumed constant, which is demonstrated that in reality is not true. In thermal plants, quadratic marginal cost functions will increase the complexity of Unit Commitment and limits its grade of computation.

Related to the MC curves, Skjelbred, et al. [63] shows the MC curve for hydropower plants, assuming a constant marginal water value. In their results, the hydro MC for different operating point is not constant. Furthermore, the hydro electricity price (35-55€/MWh) differs quite a bit to the one assumed in this simulation (6.7€/MWh). The hydro MC depends on the current situation and each generator.

Moreover, additional constraints could be integrated in the UC model, like differentiating between a hot, warm or cold starts in thermal plants where each state has different constraints. Another constraint that could be integrated is the ramping costs [64], it is reasonable that constantly changing the power production cannot be free of charge. This constraint has been added to the model which converts the UC model from MIP to NLMIP, thus creating a more complex model. Consequently, it has been discarded.

Concerning hydro power, it would be meaningful to add the reservoir capacity as well as the water value. The 4 cases shown use hydro power most of the time at maximum power. In practice, it is impossible to maintain such production for a long time since the water reservoirs are limited. Small-size reservoirs can run out of water within one hour. Pereira and Pinto [65] propose a precise way to integrate a variable watervalue for UC models.

Since the main scope of the thesis is to create a feasible UC model able to simulate different share of VRES without increasing considerably its complexity, the addons previously proposed will not be integrated in further simulations.

Although, the hydro power plants production needs to be limited. A simpler and easier way than Pereira and Pinto [65] is proposed and added to the UC model. The limitation is explained in next Section.

3.6.2 Hydro power limitation and Demand Conversion Model

The hydro power limitation is integrated in the UC model by the following equation:

$$C_{hydro,i} \leq \frac{\sum_t P_{hydro,i}}{P_{max,hydro,i} \cdot t} \tag{24}$$

The capacity factor of each hydro power plant over the simulation has been limited. The capacity factor $C_{hydro,i}$ is defined as a fixed number over the simulation. The capacity factor of the hydro power plants can be found based on historical data, finding the total hydro power production over a certain period. The value the of the capacity factor will usually vary between 30% and 70%, depending on the country and season.

With this simple constraint, a hydro power plant is limited to produce a certain amount of energy (MWh) which is quite lower than its maximum production. Therefore, the UC model will aim to schedule the hydro production in a way that not only gives maximum possible flexibility to the supply but also minimizing the total cost. The assumption removes the necessity to model variable water values which are more complex and out of the scope.

Regarding the necessity of simulating power demands more real to power market ones, the power demand is usually available per hour (NordPool), many TSOs are starting to provide data in 15 minutes interval, for example in Great Britain and Netherlands. With digitalization of the power market, the available data is making possible to get closer to real-time balancing decisions.

Due to lack of demand data for 1 minute, 5 minutes and in some cases 15 minutes timestep (NordPool), a conversion method from hourly power demand to shorter timesteps is presented. The proposed hourly-to-minute conversion model does not aim to be an exact representation of the real power markets. Indeed, the tool provides power demand output that reflects variation within the hour and it is not a simple interpolation between two hours. Therefore, reflecting the short-term flexibility constraints not captured in hourly based models.

The present research proposes a conversion method following the next steps:

- The hourly demand is allocated as a point in the middle of each hour interval.
- A line is defined, connecting the demand point with the next one, creating a linearized demand slope.
- The demand slope is divided in 60 points (1 minute), 12 points (5 minutes) or 4 points (15 minutes), depending the timestep simulated. A normal random distribution function is added into each point with a fixed standard deviation to emulate more precisely a real power demand with peak loads during hourly periods.

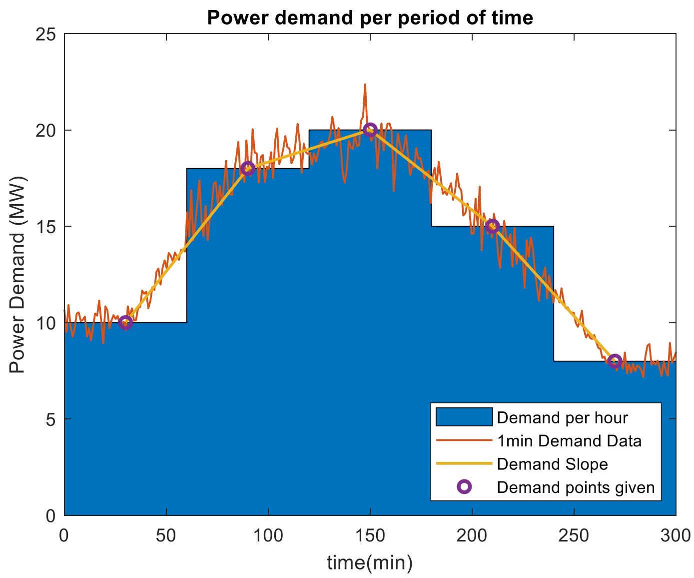


Figure 15. Power demand conversion model for 5 hourly periods

As shown in Figure 15, the approximmation method gives the same total power demand over the simulation since the triangles formed between the demand slope (in yellow) and the hourly demand (in blue) area are symmetric, thus the area (energy) added would be the same as one removed. Although for each hourly demand, the sum of the linearized demand will be slightly different from the hourly demand given.

The selection of a randon normal distribution and its standard deviation needs to be analitically proved. A statistical analysis of NordPool power market is presented in next Section. The analysis will show the type of distribution that the power demand follows for different timesteps and its standard deviation. the normal stadard deviation in the current power markets.

3.6.3 Statistical analysis of Nordpool demand data

The main objectives of the statistical analysis are:

- Identification of the type of distribution followed from hourly power demand data to shorter intervals like 30 minutes, 15 minutes, 5 minutes and 1 minute.

- Extract the standard deviation from hourly power demand data to shorter intervals previously written.

The statistical analysis starts by selecting the available demand. Since ENTSO-E and Nordpool has been the main sources of finding data, the current analysis will use the available data from these two sources.

The data analyzed englobes 3 european countries with the shorter timestep of power demand available: Great Britain (GB), Netherlands (NL) and Germany (DE). The data can be found in the open database [66] which takes the data directly from NordPool and ENTSO-E. The extracted demands cover the period from 01/01/2016 to 31/05/2018.

The exact data extracted is listed below:

- Hourly demand from NL, DE and GB
- 30 minutes demand from GB
- 15 minutes demand from NL and DE

There are two independent comparisons:

- 30 minutes real data compared to 30 minutes interpolated data created from hourly demand.
- 15 minutes real data compared to 15 minutes interpolated data created from hourly demand.

The reason of comparing 30 minutes data is to understand how the type of distribution and its standard deviation may differ for other timesteps than 15 minutes. Since 15 minutes and 30 minutes are the only available data in the european countries, it is not possible to make an analysis for shorter time intervals.

The following figure summarizes the statistical analysis developed.

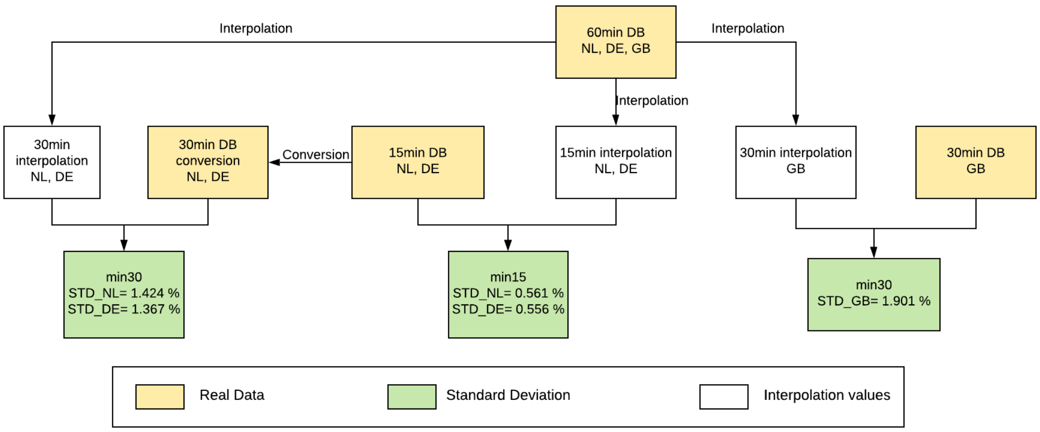


Figure 16. Statistical analysis flow chart and standard deviation results

Referring to 30 minutes analysis, the real GB data is compared to interpolated data from GB hourly based, giving a deviation of 1.901% of the interpolated one[2]. Additionally, since 15 minutes data is available fro NL and DE, it is possible to convert it to real 30 minute based and compared it to the hourly interpolated, showing a deviation of 1.424% for NL and 1.367% for DE.

For 15 minutes analysis, the real 15 minutes data from NL and DE is compared to the interpolated from hourly based, giving a deviation of 0.561% and 0.556% respectively.

Indeed, more important that the exact standard deviation followed by the power markets would be the type of distribution that the deviations followed. Therefore, the following figures shows the histogram of the deviations over the period analyzed for the 5 analysis.

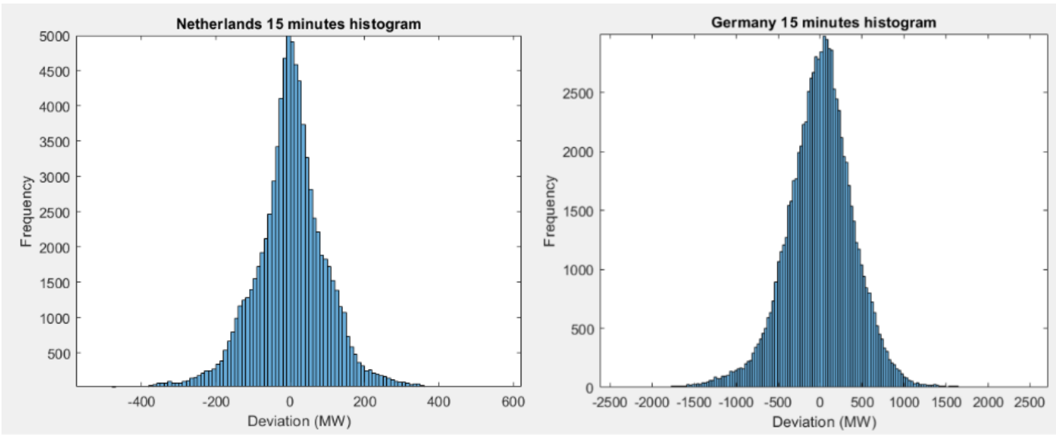


Figure 17. Netherlands and Germany 15 min deviation histogram

[2] The deviation is given in percentage and based on the interpolated value since it will be added as a percentage unit in the conversion model.

The 15 minutes histograms show a symmetric distribution, quite similar in both cases to a normal distribution. Furthermore, the standard deviation in both countries is quite similar, 0.561% for NL and 0.556% for DE.

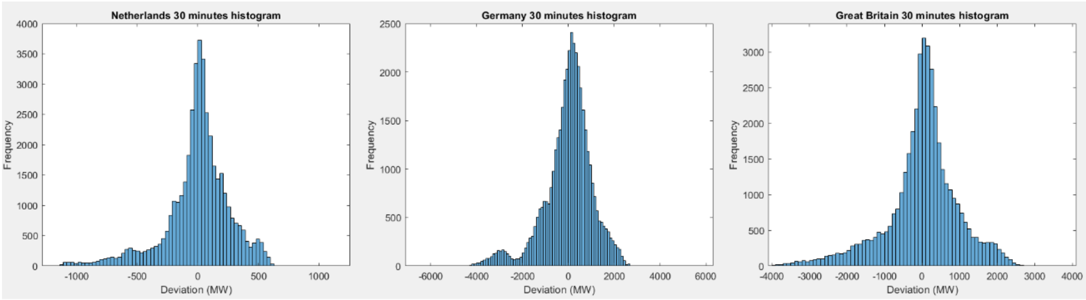


Figure 18. Netherlands, Germany and Great Britain 30 min deviation histogram

On the other hand, in the 30 minutes histogram a symmetry can be appreciated but not as clear as in the 15 minutes. Indeed, in the 30 minutes histogram the negative deviations tend to be more displaced from the centre than the positive ones.

Since the UC model presented will simulate for 1 minute, 5 minutes and 15 minutes timesteps, the 30 minutes results are not crucial for our conversion model. Whereas, the 15 minutes results are quite important for the assumptions of the demand conversion model proposed previously. It is possible to state that 15 minutes data follows a normal distribution with a standard deviation from the interpolated value around 0.56 %, supporting the assumption of adding a normal distribution to the demand conversion model. Indeed, the 30 minutes results show that deviation may vary for different timesteps and reflects that assuming the same standard deviation for different timesteps could not reflect reality. Unfortunately, due to lack of data there is no alternative than assuming the same standard deviation for each timestep.

Regarding the type of distribution, random distribution means that the standard deviation does not follow any logic distribution (e.g. random), thus, taking into account that 1 minute and 5 minutes data forms 15 minutes data, it makes sense to assume that both timesteps follow the same distribution as 15 minutes.

To conclude, the conversion model used for further simulations assumes a standard deviation of 0.561% following a normal distribution for the 3 different timesteps.

The conversion model and statistical analysis has been performed in MATLAB. The codes used are shown in Appendix C.

3.7 Simulation 2: Swedish power market v2

The Swedish case is simulated again with the addition of the Hydro power limitation and the demand conversion model.

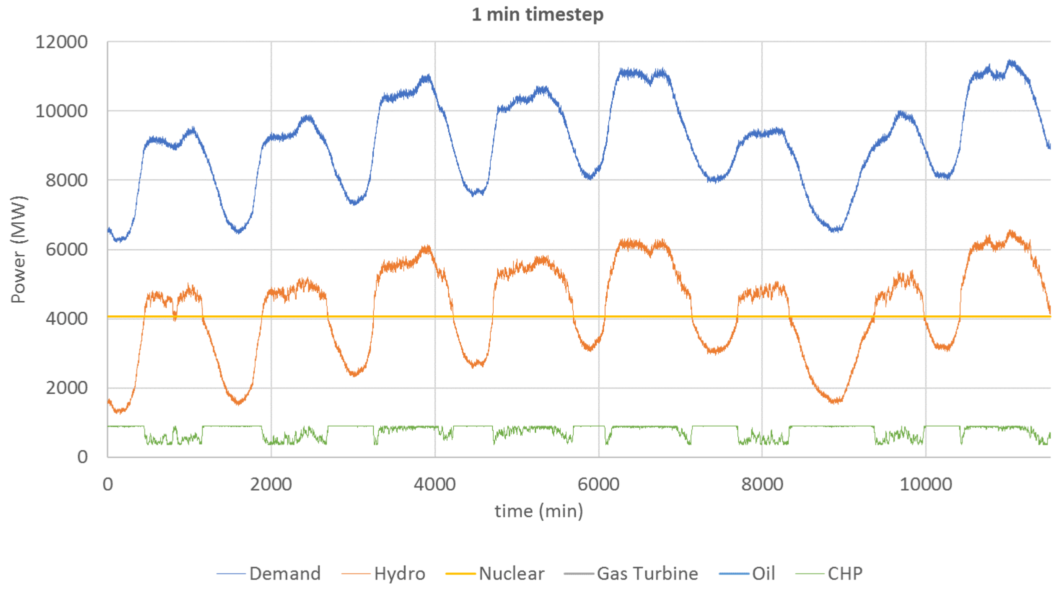
For this simulation, 8 days are simulated from the 10^{th} of December 2018 to the 17^{th} of December 2018 which means that 11520 time periods are optimized for 1 minute timestep, 2304 for 5 minutes timestep, 768 for 15 minutes timestep and 192 for 1 hour timestep. The capacity factor of the hydro power plants has limited to 62.92%. This capacity factor has been calculated from real data given by Nordpool during the 8 days simulated.

Compared to the previous test up to 1440 periods, this new simulation demands more computation time. The software GAMS considers a maximum default time of 1000 seconds for the solver to run before it terminates, which is not enough for this case. The value must be extended to a large value in order to enable the solver to take the necessary time to find an optimal solution for the UC model. The keyword option reslim=20000000000 seconds (e.g. almost infinite) is added to the model. It is important to highlight the complexity of this UC model compared to other optimization models due to the selection of short timesteps as 1 minute and 5 minutes.

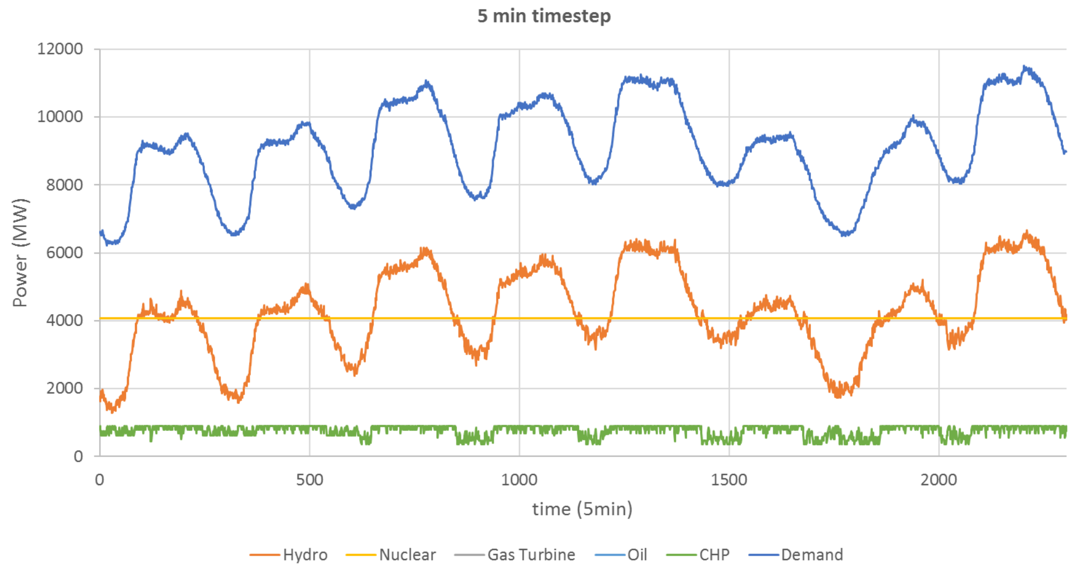
No modification has been done on the generator portfolio.

The results for the 4 different timesteps are showed below in Figure 19.

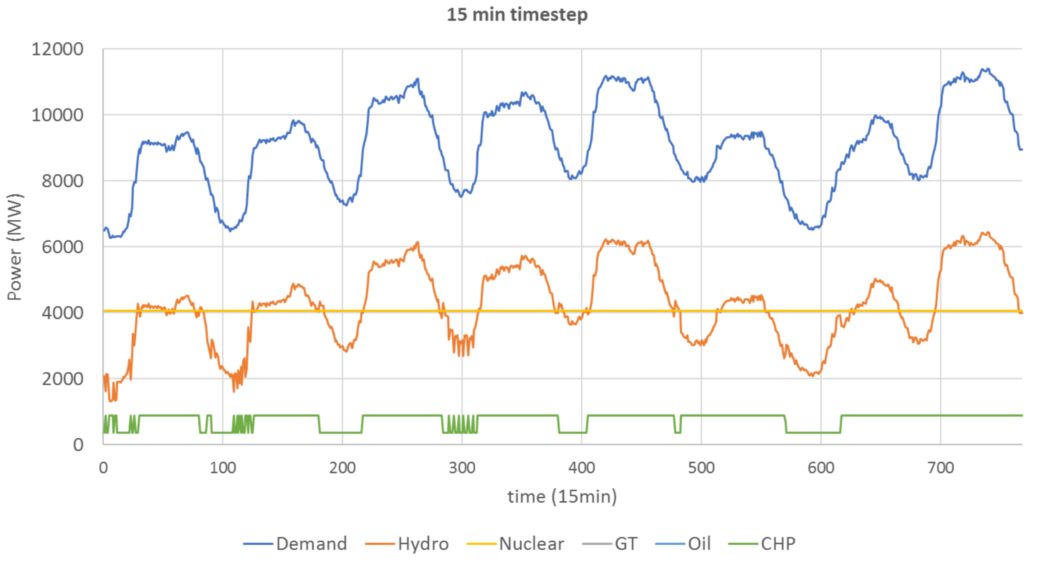
a)



b)



c)



d)

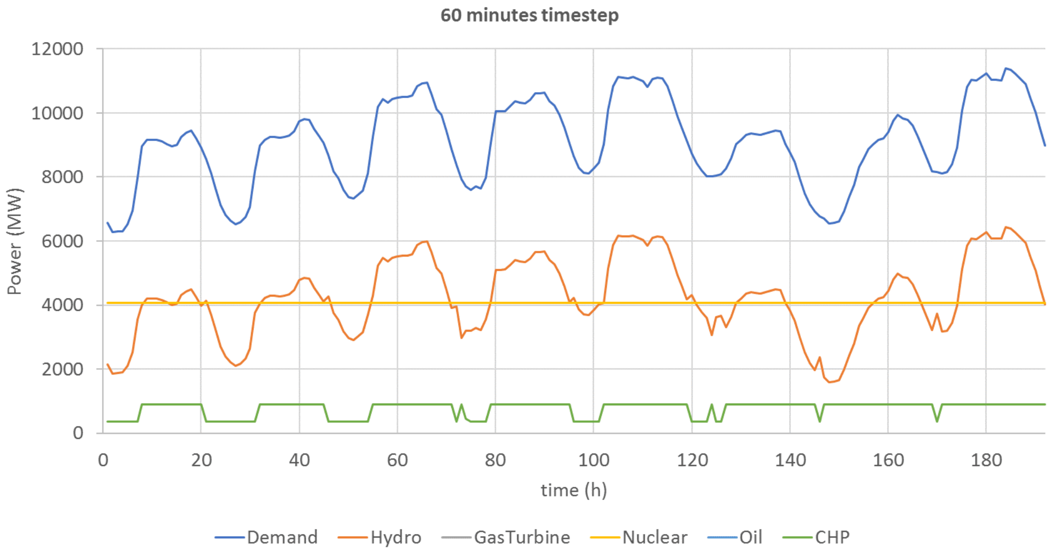


Figure 19. Swedish UC results for: a) 1 minute timestep, b) 5 minute timestep, c) 15 minutes timesteps and d) 60 minutes timestep

From an aggregated point of view, the 4 UC solutions are very similar. The share of production per type of energy source is the same for the 4 timesteps, shown in Appendix D.

Indeed, for 60 minutes and 15 minutes timesteps the CHP connected only worked at maximum or minimum power, non-intermediate states are reflected. In contrast, 1 minute and 5 minutes simulations reflect many intermediate steps, giving more accurate information about CHPs behaviour.

Furthermore, the 4 cases do not experience any switch off on the generators. The UC model decides to leave the CHPs at minimum power instead of disconnecting them. By this way, the model does not need to pay the shutdown costs.

Since no disconnections occurred and the share of production per type of energy source is the same, the total cost of production is the same for the 4 cases, 9.45 M€.

The computation time differs from each timestep used as shown in the following Table IX.

Table IX. Computation time and total cost for each timestep

Timestep	Time periods (n)	Computation time (h:min:s)	Total cost (M€)
1 minute	11520	10:33:38	9.450
5 minutes	2304	0:20:53	9.450
15 minutes	768	0:01:59	9.449
60 minutes	192	0:00:19	9.449

For 1 minute timestep, the computation time last for more than 10 hours due to the number of time periods optimized which increases the number of permutations.

Compared to the real solution of Sweden generators during that week (Figure 20), the UC model shows a quite similar solution to the real one[3]. In the real production, the available nuclear power was slightly higher than the one assumed on the simulations, thus enabled a higher maximum nuclear power. The UC model has scheduled the hydro power quite similarly to the real solution. Indeed, the hydro power production has been higher in the simulation than in practice. This is due to the selection of the capacity factor used that has been calculated based on the Net demand instead of the total demand, which considers wind and solar power production.

Regarding the CHPs behaviour, it is important to highlight that in practice the CHPs are not totally free to modify its production as the UC model assume. The district heating demand plays a very important role on these generators that also generate steam. CHP is not used today for load-balancing, although it is technically possible as The Royal Swedish Academy of Engineering Sciences, so called IVA [67], reflects. In any case, the CHP will be still assumed as only an electric generator on the UC model since the main purpose of the model is to simulate theoretical flexibility of a portfolio rather than creating a very complex UC model.

[3] The Swedish production showed has been downscaled to its half, as the simulation results were also downscaled. Thermal production englobes CHP, Oil and Gas Turbines. It is not available to differentiate between them.

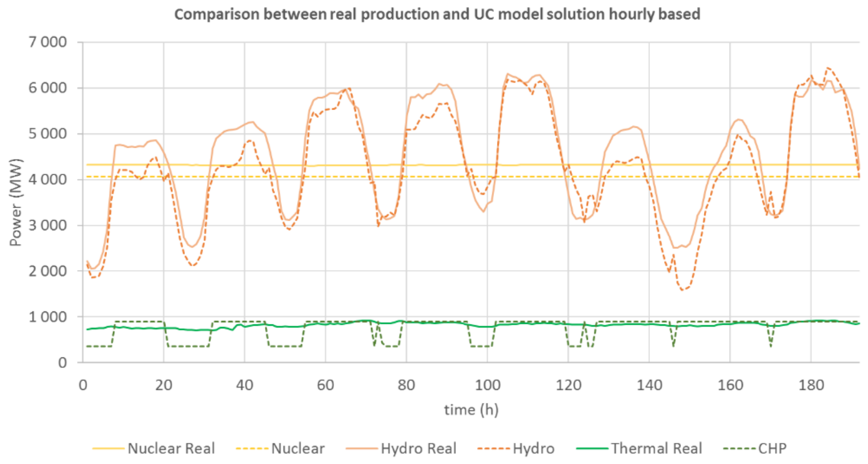


Figure 20.Comparison between real production and UC solution for 60 minutes timestep

To conclude, in all the timesteps the UC model do not consider any disconnections. The main reason could be the large number of generators part of the portfolio as well as a high demand has been simulated. Thus, a simpler problem will be introduced in the next Section to verify that disconnections are working properly as well as confirming that the number of generators and the size of the demand discourage generator disconnections.

3.8 Simulation 3: Simple case UC model

3.8.1 First simulation

As previously mentioned, a simpler UC portfolio is used for the following simulation. The present case aims to give more information about how the UC model works for different simulations by presenting a simpler case with only 6 generators for a given theoretical demand.

The portfolio is composed by 6 generators:

- 1 Hydro power plant
- 1 nuclear plant
- 2 CC Gas turbines
- 1 Oil-fired thermal plant
- 1 CHP plant

For more information about the generators and their constraints, see Appendix E.

The simulation considers a time horizon of 3 days. The demand profile follows a typical pattern profile at a country level. Then, this hourly profile data is converted to the finer time resolutions previously described by using the demand conversion model. For this case, the hydro capacity factor has been limited up to 59.95%.

The results are given below.

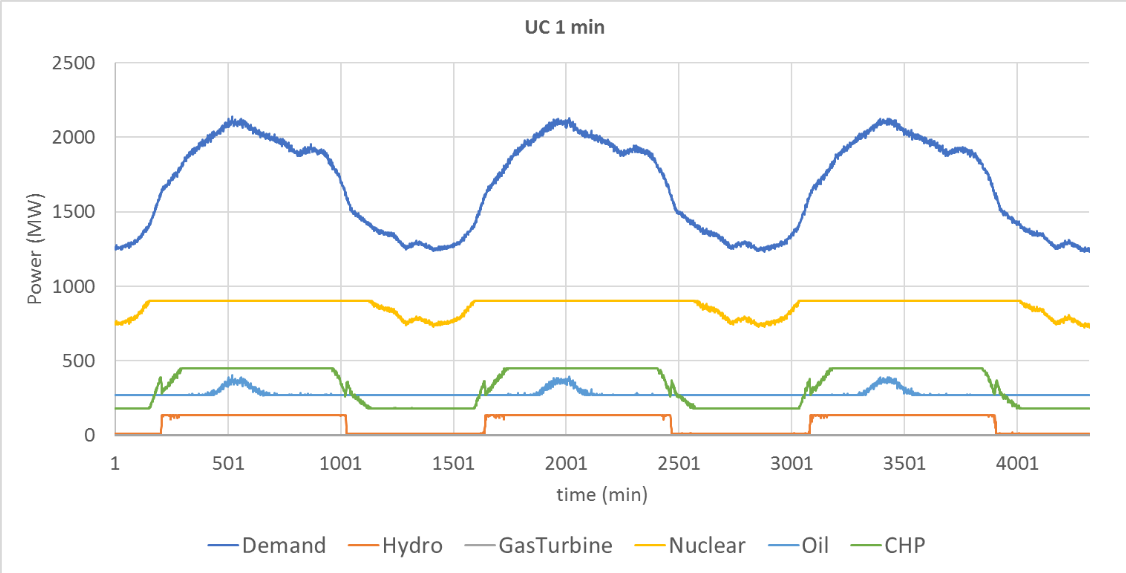


Figure 21. UC solution for 1 minute timestep in the Simple Case simulation

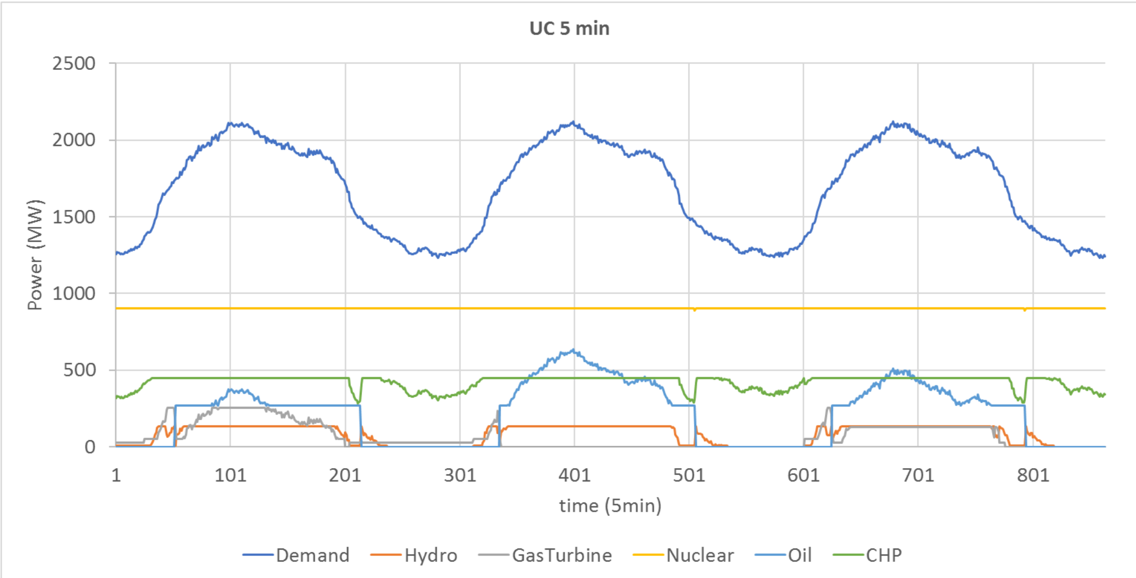


Figure 22. UC solution for 5 minutes timestep in the Simple Case simulation

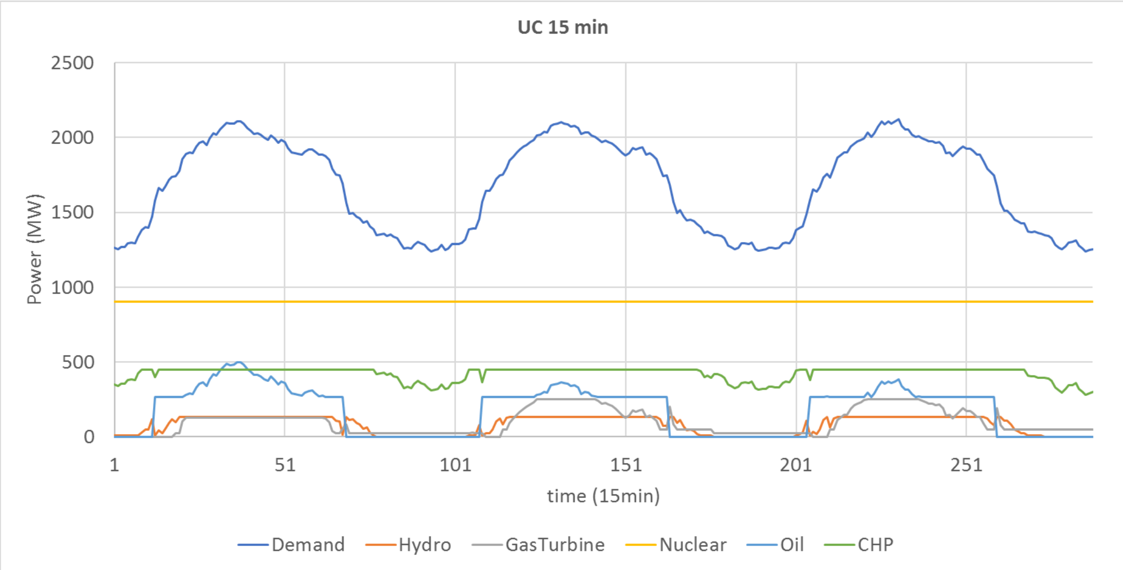


Figure 23.UC solution for 15 minutes timestep in the Simple Case simulation

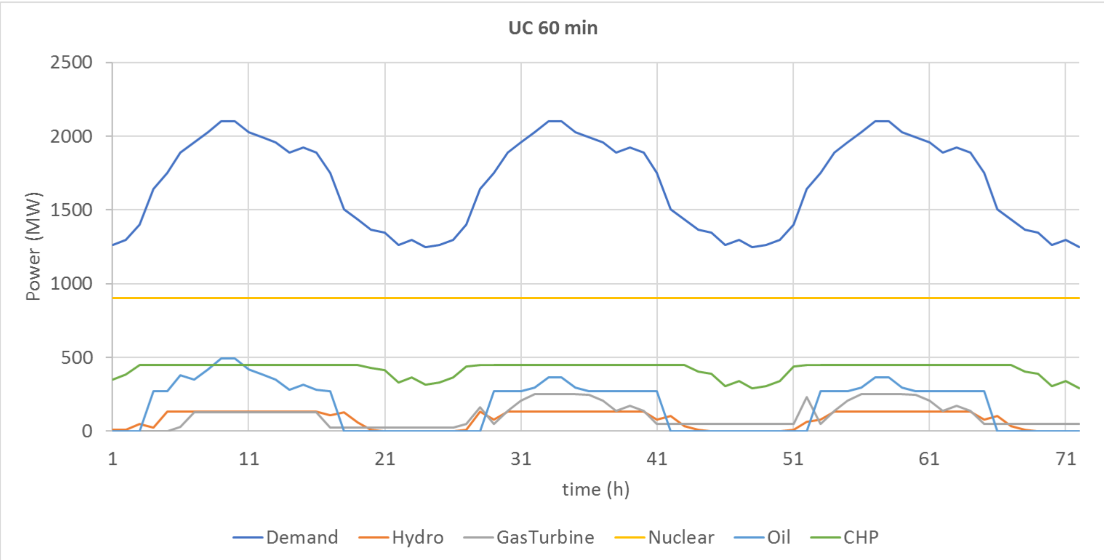


Figure 24. UC solution for hourly timestep in the Simple Case simulation

First of all, in contrast with previous simulations the total costs differ for each timestep. There is a tendency that for shorter timesteps the total cost rises. Additionally, compared to the previous simulations, the computation time is way shorter due to the reduction of time periods simulated as well as the number of generators in the portfolio.

Table X. Total cost and computation time for different timesteps

Timestep	Time periods	Computation time (h:min:s)	Total cost (M€)	Number of disconnections (n)
1 min	4320	0:04:43	2.964	0
5 min	864	0:00:14	2.728	12
15 min	288	0:00:03	2.718	9

60 min	72	0:00:03	2.712	6

Regarding the switching offs, the simulations considering 60 minutes, 15 minutes and 5 minutes timesteps experienced generator disconnections whereas the 1 minute did not. Furthermore, the share of production per type of generator differs for each timestep, especially for 1 minute timestep.

Table XI. Share of production per type of source and timestep

Type of Source	60 min	15 min	5 min	1 min
Hydro	4.71 %	4.71 %	4.71 %	4.71 %
Nuclear	53.81 %	53.81 %	53.81 %	51.81 %
Gas Turbine	6.24 %	5.89 %	3.91 %	7.15 %
Oil	10.27 %	10.46 %	12.44 %	16.55 %
CHP	24.98 %	25.14 %	25.13 %	19.79 %

Comparing the 4 UC solutions (Figure 21, Figure 22, Figure 23 and Figure 24), it is possible to realize that the proposed solution for 1 minute timestep given by the UC model is not an optimal solution, thus, gives a much higher total cost than the other timesteps. For 1 minute, the UC model is disregarding the optimization of the binary variables by connecting all the generators on the first period and not disconnecting any of them during the simulation which makes no sense from an optimization point of view. As a consequence, the nuclear plant cannot produce at maximum power the entire simulation in contrast with the other timesteps.

In previous simulations, it has been shown that the UC solution may not differ much for different timesteps. In this case, it is not fulfilled.

The UC model, solver CPLEX and GAMS default mode have been reviewed. An important finding has been identified:

Branch-and-bound algorithms (like CPLEX), usually used for MIP, (MI)QCP and (MI)NLP, calculate two very important numbers commonly called as:

- Best integer: Best solution that satisfies all integer requirement found so far.
- Best estimate: Provides a bound for the optimal integer solution.

For example, in a UC model minimizing the total cost, the algorithms find an integer solution with an objective function of 7 (best integer = 7). Additionally, the algorithm gives you the “best estimate” solution = 5, so the upper bound for the optimal solution of the UC problem is 5.

Combining these two number it is possible to calculate the “quality” of the best integer. The quality of a solution can be measured as the distance from the optimal solution. Unfortunately, the optimal solution has not been found but a bound of it (“best estimate”). Hence an upper bound for the distance between the best integer and the optimal solution will the “best estimate” minus “best integer”. This value is called the absolute gap (GAMS notation is OPTCA). By providing the option OPTCA in a GAMS program the model allows the solver to stop if the absolute gap drops below the OPTCA level. In the small example the absolute gap would be 2. When the absolute gap goes lower than the OPTCA, the simulation will stop and give the found solution. Another option called OPTCR that GAMS considers is the relative gap which is the absolute gap divided by the maximum value between the "best estimate" and the "best integer".

By default, GAMS establish OPTCA equals to 0 and OPTCR equals to 10%. Usually the OPTCR option reaches first, stopping the simulation before the absolute gap goes to 0.

Back to the simulation, the default relative gap could be enabling the UC model to find solutions too far way away from the optimal one. Thus, this effect seems to be more relevant when the UC complexity increases (1 minute). The relative gap of the previous simulations is given in Table XII.

Table XII. Relative gap of the simulations

Timestep	Relative GAP (%)
1 minute	8.78
5 minutes	1.12
15 minutes	0.80
60 minutes	0.53

The simulation will be repeated on the next Section, forcing the solver to find a solution with a relative gap optcr = 0.

Nevertheless, the simulation has proved that the disconnections are working and that the number of available generators and the size of the demand discourage the disconnections, as previously seen on Swedish simulation. The main reason is that if, for example, 15 generators are used to fulfil a given demand where many of them are hydro power plants (as Swedish case). Hydro power plants with a very low minimum power constraint can produce very low power without being disconnected. Thus, the 15 generators can reach the peak hours demand and also the off-peak hours without any necessity of disconnections, avoiding shutdown costs and future start up ones. On the other hand, in this simulation a portfolio of 6 generators with only 1 hydro plant is forced to experience disconnections during the night due to the minimum power constraint. In this simulation the disconnections come mainly from the Oil power plant which is only used to give necessary capacity power during peak hours.

3.8.2 Simulation 4: Simple case UC model v2

By setting the relative gap to 0, more optimal solutions are found with a lower total cost of production. On the other hand, the computation time increases. The simulation has been run again and the results are given below.

For the 1 minute timestep, the solver has not been able to find an optimal solution with a relative gap equals to 0. After 47 hours of computation, GAMS program crashed, identifying an error coming from CPLEX solver. The relative gap before crashing was 4.50 %. Thus, as an exception, the relative gap has been set to 4.7 % for 1 minute timestep. The following figure shows how the relative gap decreases over the time of computation.

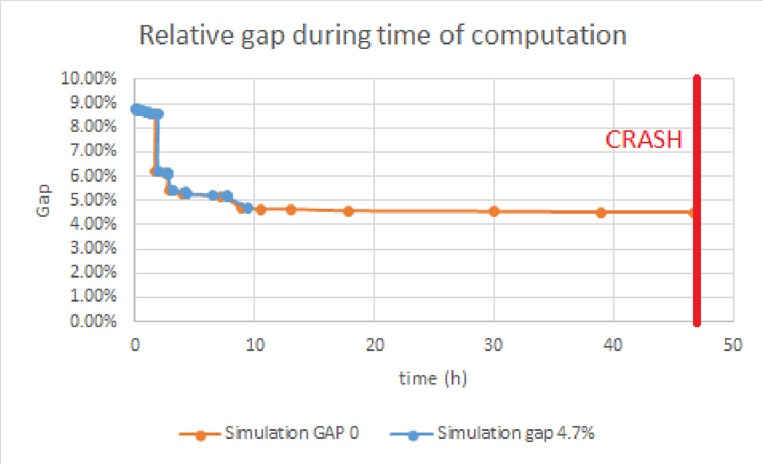


Figure 25. Relative gap decrease over the computing time for 1 minute timestep

The main cause of optimization complexity comes from the number of theoretical permutations (n) present in the UC model, which varies depending on the number of time periods (t) and number of generators (i) simulated (See Equation 24).

$$n = 2^t \tag{24}$$

The results of the simulation are presented below. Table XIII also includes the results from the previous simulation in order to make a comparison between them and gap influence on the results.

Table XIII. Gap, total cost and computation time for the 2 different simulations

	GAMS default rel. gap = 0.1			GAMS rel. gap = 0			
Timestep	**Gap (%)**	**Total cost (M€)**	**Computation time (h:min:s)**	**Gap (%)**	**Total cost (M€)**	**Computation time (h:m:s)**	**Total cost reduction (10^3€)**
1 min	8.78	2.964	0:05:38	4.70	2.844	9:07:33	120
5 min	1.12	2.728	0:00:14	0.00	2.704	0:00:25	24
15 min	0.80	2.718	0:00:03	0.00	2.703	0:00:07	15
60 min	0.53	2.712	0:00:03	0.01	2.704	0:00:03	8

UC solution figures for the different timesteps is shown in Appendix F.

Based on the difference between results, the relative gap plays a very important role in UC models. As a consequence, setting the relative gap to 0 would need to be a must for further simulations. This addon increases the computation time and for 1-minute timestep cannot not be reached. Therefore, 2 assumptions are taken into account to reduce complexity in the UC model.

First of all, the "power-demand" balance equation has been modified. Previously, supply and demand must be equal. In order to give more freedom to the system (less constraints), the equation will be changed so the supply could be equal or higher than the demand (enabling curtailment if required) at any time.

Additionally, since it has been proved that binary variables are adding a high complexity to the UC model, the start-up and shutdown costs will not be considered in further simulations. This assumption does not enable generators to constantly switch on and off, minimum uptime and minimum downtime are still considered and thus limit the switches. As previously explained in Section 2.3.4: "*An operator may impose this constraint to reduce the operational cost sensitivity to start-ups and shutdowns costs*". Furthermore, start-up and shutdown costs are not included in the clearing price, so the UC model will be more similar to the current power market. On the other hand, the total cost of production does not reflect all the costs anymore.

Nuclear MC has been lower down based on an available excel calculator from Farahmand, et al. [68] considering actual prices of uranium and other parameters.

These assumptions have been successfully added in the next Section.

4. EEM PAPER 2019

A Minute-to-Minute Unit Commitment Model to Analyze Generators Performance

***Abstract*— What modelling time resolution will capture more accurately the actual performance of generators in the bulk power system operation? This paper analyses the generation portfolio in a unit commitment (UC) model that represents the generators' behavior for a given demand and renewable generation on very short time intervals (up to 1 minute). The UC model is implemented in General Algebraic Modeling System (GAMS) using CPLEX solver, considering multiple generator constraints, such as ramp rate, maximum power output Furthermore, the results shed light on modelling experiences for the synergy between renewables and hydropower generation, contributing to an innovative and transparent market environment, proper power system organization and renewables integration, and regulatory framework design. Results show similar overall outcome on portfolio of generators under different time resolutions, but the behavior and insights on the operations clearly favor the application of finer time resolutions.**

***Index Terms*— Short term modelling, flexibility, unit commitment, optimal generation, variability**

I. INTRODUCTION

The European electricity system is experiencing a rapid transformation of the type of power generators used to produce electricity. The main reason to explain the energy transition is due to the rise of an environmental concern from governments to mitigate CO2 emissions [1]. Globally, the electricity and heat production sectors play a very important role in these emissions with a 25% share of GHG emissions [2,3].

Additionally, the electricity demand is projected to increase 75% in 2035 [2] with the electrification of the transport (EVs) and, heating and cooling (electric heat pumps) sectors taking place and the population increase. These developments have been utilized to invest in wind and solar not only by private investors but also by households. The last has entered into the electricity system taking part in the supply and demand side at the same time, commonly called as "prosumers". This new energy actor together with the variable and uncertain output generation from some RES makes the electricity system more complex to design and balance.

A changing power system drives the need for a new balancing model. For example, the frequency quality in the Nordic power system has gradually deteriorated, in addition to the system changes there are also regulatory changes. Therefore the 15-minute imbalance settlement periods is being introduced to allow consumption and production to follow each other more closely. The objective is to make operations for the TSO more efficient and reward flexible generators. This tendency towards short-term time-steps is present in today's electricity markets, where some network operation has moved their balance settlement from 30 minutes based to 15 minutes and even to 5 minutes.

As the share of RES increases, the investment in flexible, quick and available generators would be required to satisfy the future net demand (load minus RES). Consequently, the optimization of scheduling these flexible generators, commonly referred as the Unit Commitment problem (UC), will require higher precision to ensure efficient operations to minimize curtailment and under production. Hence, because of the deployment of RES, flexibility in generators has become an important property to look in power markets.

The needs of flexibility vary depending on the timescale, therefore the selection of a time-step (granularity in time resolution) for a UC model influences the flexibility simulated. Figure 1 provides an overview of the interrelation of flexibility needs in perspectives of space and timescale [4] . Thus, an hourly UC representation will probably not show precise real-time balancing needs within that hour compared to a hypothetical minute-to-minute UC model. That is, given the hypothetical demand fluctuations within an hour, would a UC hourly based model provide the same results compared to a minute-to-minute UC model equivalent? What does the traditional hourly based UC model misses if its time granularity assumption is 15min, 5min, or 1min? What is the effect of modelling different time resolutions in the generator's behavior and performance? These questions are not fully addressed in the existing literature mainly because the UC model is already computational difficult to solve and hence increasing the time resolution will likely make it intractable in a large-scale implementation. Another reason, it is the lack of data for finer time steps: 15 min, 5 and 1min load profiles. In this paper, a UC model with a minute-to-minute time resolution explores these questions.

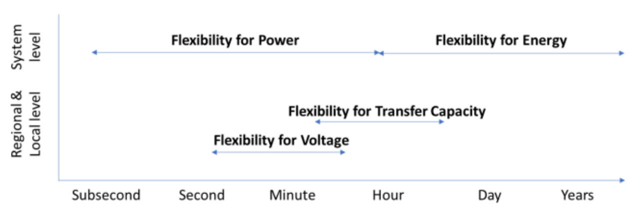


Figure 1. The interrelation of flexibility needs in perspectives of space (local/regional to system level) and time [5]

II. METHODOLOGY: UC MODEL AND TIME RESOLUTION

A. Power system operations and flexibility estimation

Unit commitment (UC) can be defined as "*an optimization problem used to determine the operation schedule of the generating units at every hour interval with varying loads under different constraints and environments.*" [6] UC optimization aims to minimize economic costs while at the same time satisfying the given demand, where many generator constraints should be added by designing specific equations for each constraint.

For UC problems, the objective function will be minimized, being the total generator costs of satisfying the given demand. The total generator costs will be the sum of operational costs ($OC_{i,t}$), Start-up costs ($Su_{i,t}$) and Shutdown costs ($Sd_{i,t}$) for each generator (i) and time (t).

$$\min OF = \sum_{i,t}\left(OC_{i,t} + Su_{i,t} + Sd_{i,t}\right) \tag{1}$$
$$OC_{i,t} = MC_i P_{i,t} \tag{2}$$
$$Su_{i,t} = Cu_i y_{i,t} \tag{3}$$
$$Sd_{i,t} = Cd_i z_{i,t} \tag{4}$$

To measure the total start-up and shutdown costs during the simulation, it is required to use binary variables that will indicate when the generator has turned on (y_i) and when turned off (z_i) until the last period (T). Also, a binary variable (u_i) indicates if the generator is connected or not. The initial generator states (u_0) are integrated into the simulation by Equation 8.

$$y_{i,t} - z_{i,t} = u_{i,t} - u_{i,t-1} \quad \forall t = 2 \dots T \tag{5}$$
$$y_{i,t} + z_{i,t} \le 1 \tag{6}$$
$$y_{i,t}, z_{i,t}, u_{i,t} \in [0,1] \tag{7}$$
$$y_{i,t} - z_{i,t} = u_{i,t} - u_0 \quad \forall t = 1 \tag{8}$$

The start-up and shutdown ramp limits ($SU_{i,t}$ and $SD_{i,t}$) can be combined with the Ramp Up and Down limit ($RU_{i,t}$ and $RD_{i,t}$), the maximum (P_i^{max}) and minimum power output (P_i^{min}) in the following equations:

$$\underline{P}_{i,t} \le P_{i,t} \le \bar{P}_{i,t} \tag{9}$$
$$\bar{P}_{i,t} \le P_i^{max}\left[u_{i,t} - z_{i,t+1}\right] + SD_i z_{i,t+1} \quad \forall t = 1 \dots T-1 \tag{10}$$
$$\bar{P}_{i,t} \le P_{i,t-1} + RU_i u_{i,t-1} + SU_i y_{i,t} \quad \forall t = 2 \dots T \tag{11}$$
$$\underline{P}_{i,t} \ge P_i^{min} u_{i,t} \quad \forall t = T \tag{12}$$
$$\underline{P}_{i,t} \ge P_{i,t-1} - RD_i u_{i,t} - SD_i z_{i,t} \tag{13}$$
$$\bar{P}_{i,t} = P_i^{max} u_{i,t} \quad \forall t = T \tag{14}$$

These equations will provide the upper ($\bar{P}_{i,t}$) and lower ($\underline{P}_{i,t}$) operating limits of each generator, considering if it is connected, disconnected, turned on or turned off at that moment (binary variable application).

The next constraint to be added will be the Minimum Up and Down Time (UT_i and DT_i). The auxiliary parameter k enables to identify the previous states of the generators to ensure that the UT_i and DT_i constraints are fulfilled.

$$\sum_{k=t-UT}^{k=t} y_{i,k} \le u_{i,t} \quad \forall t = UT_i + 1 \dots T \tag{15}$$
$$\sum_{k=t-DT}^{k=t} z_{i,k} \le u_{i,t} \quad \forall t = DT_i + 1 \dots T \tag{16}$$

Additionally, a restriction on the hydropower plant capacity factor (C_{hydro}) has been added, limiting its maximum energy delivered.

$$C_{hydro} \le \frac{\sum_t P_{hydro}}{P_{max,hydro} \cdot t} \tag{17}$$

Finally, the power balance constraint needs to be added:

$$Load_t \le \sum_{i,t} P_{i,t} \tag{18}$$

This interval, so-called time-step, can be considered for shorter time-steps than an hour. As noted earlier, we argue that a UC model could be more precise in reflecting the behavior of generators operations if a finer time-step resolution is considered. However, time-steps resolution is usually selected based on computational limitations, scope (e.g. model details and objectives) or data availability.

The main cause of computational complexity comes from the number of theoretical permutations (n) present in the UC model, which varies depending on the number of time periods (t) and number of generators (g) simulated (See Equation 19).

$$n = 2^{gt} \tag{19}$$

For instance, assuming a UC of 3 days duration and considering 6 generators, *n* would be around 10^{7800} for a 1-minute time-step resolution while 10^{130} for hourly time-step. Theoretical permutations are considerably increased.

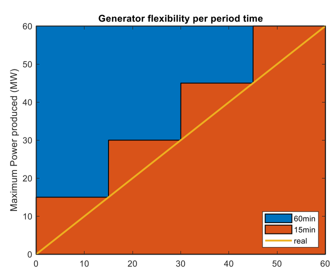


Figure 2. Real power generation versus 15 min and 60 min timestep

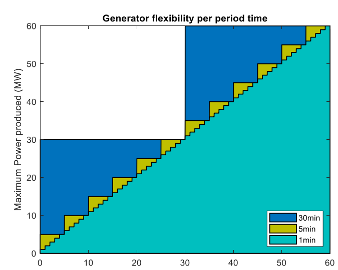


Figure 3. Power generation for 5 min, 15 min and 30 min timestep

From a theoretical perspective, it could be that the UC models as [7-9] misrepresent the operations of the generators due to selecting a pre-determined (usually data based) time-step (typically hourly) which is common practice in the literature. For example, consider 1-hour period and a generator with a Ramp Rate of 60 MW/h and disregard other constraints, the maximum power that can produce (in a UC model calculation) within the hour period depends on the time scale used. The maximum real energy produced by the generator will be 30 MWh, assuming a constant and linear ramping

The **theoretical** maximum energy produced with a timestep of 60 minutes will be 60 MWh, overestimating its production a 100% compared to the real production. Overestimation[1] can be reduced until 1.67 % by selecting 1 minute resolution. Therefore, UC models that reduce the time interval will capture and emulate more precisely the flexibility of the generators and more precise simulation of actual supply-demand operations.

Furthermore, on the side of the demand, power load data with shorter time resolution will reflect possible peak loads that hourly basis are not able to represent. These peak loads variations play a crucial role in the power market flexibility.

TABLE I. THEORETICAL MAXIMUM ENERGY PRODUCED AND FLEXIBILITY OVERESTIMATION PER TIMESTEP

Timestep	Maximum Energy produced (MWh)	Flexibility overestimation with reality (%)
60 minutes	60	100 %
30 minutes	45	50 %
15 minutes	37.5	25 %
5 minutes	32.5	8.33 %
1 minute	30.5	1.67 %

B. *Power demand resolution: hour-to-minute conversion method*

Although the power demand is usually available per hour, some TSO's are starting to provide data in 15 minutes interval, for example in Great Britain and Netherlands [10]. With digitalization of the power market, the available data is making possible to get closer representation (and modelling) of real-time balancing decisions. However, due to lack of demand data for 1 minute and 5 minute time-steps, a conversion method from hourly power demand to shorter timesteps was developed. The tool provides power demand output that reflects variation within the hour and it is not a simple interpolation between two hours points. These demand variation breakdown provides a new dimension in short-term flexibility constraints not captured in hourly based models.

In this paper we proposed and developed a conversion method following the next steps:

1. The hourly demand is allocated as a point in the middle of each hour interval.
2. A line is defined, connecting the demand point with the next one, creating a linearized demand slope.
3. The demand slope is divided in 60 points (1 minute), 12 points (5 minutes) or 4 points (15 minutes), depending the time step simulated. A random value is generated based on a normal distribution function which is then added into each point. The normal distribution has a fixed standard deviation (5.61% of the linearized value) to emulate more precisely a real power demand with peak loads during hourly periods. The standard deviation selected is based on analyzing and comparing 15 min data demand with 60 min data from Netherlands between 2016 and 2018.

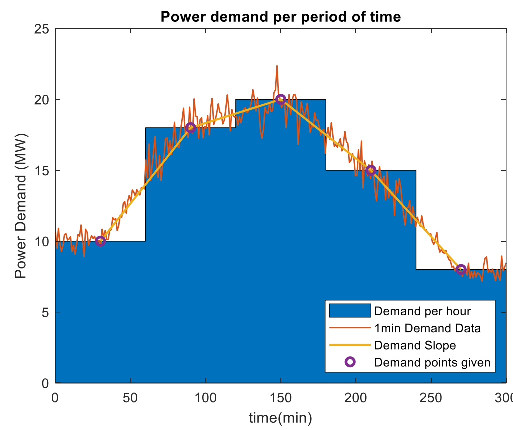


Figure 4. Power demand conversion model for 5 hourly periods

As shown in Figure 4, the approximmation method gives the same total power demand over the simulation since the triangles formed between the demand slope (in yellow) and the hourly demand (in blue) area are symmetric, thus the area (energy) added would be the same as one removed. Although for each hourly demand, the sum of the linearized demand will be slightly different from the hourly demand given.

C. *Proof of concept and small example*

Before implementing and presenting a more complex UC simulation, a simple and theoretical case is presented to discuss the previous theoretical concepts and hypothesis.

The following case presents two available generators, a Gas turbine and a CHP generator that need to fulfill a demand of 100 MW for 1 hour. The demand starts from 64 MW to 118 MW. The simulation is modelled for 4 different timesteps: 1 minute, 5 minutes, 15 minutes and 60 minutes. The aim of the case is to minimize the cost of production to fulfil the given demand.

As shown in [4], the UC problem is quite different for each timestep resolution as well as the total cost. For 60 minutes timestep, CHP generation is enough to fulfil the demand giving a total cost of 4000 €. On the other hand, for a 15 minutes timestep, Gas Turbine (GT) is needed for the last period when the demand exceeds the maximum power of the CHP, giving 4138 € in costs. The same happens with 5 minutes timestep, experiencing a curtailment of 0.16 MW during the 6th period with a final cost of 4233 €.

The curtailment appears even more on the minute timestep up to 2.56 MW. Increasing the share of GT due to capacity and flexibility needs. Therefore the final cost rises to 4342 €.

[1]A UC model is an approximation of the power markets reality. Regarding the flexibility of the generators, this approximation differs from the reality since a finite time step needs to be considered. For example, a generator working initially at 40 MW with a ramp rate of 60 MW/h could change from 00:00 AM to 00:01 AM to a power of 100 MW (being 100 MW the entire hour), as a stair ramp, since the timestep considered is an hour. On the other hand, considering a timestep of 1 minute, the generator could only reach 61 MW at 00:01 AM.

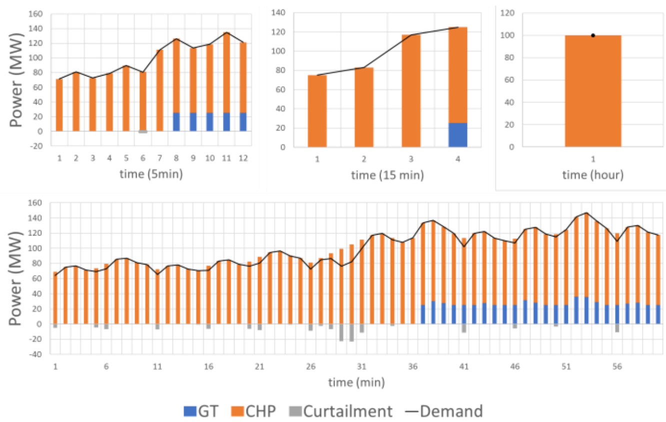


Figure 5. Proof of concept simulations

III. RESULTS AND DISCUSSION

A. A more complex UC model: Case study

To analyze the hypothesis discussed in the previous section, a more detail UC model based on a typical generation portfolio is setup in a case study. This still a relatively small case study but it is in line and similar to established IEEE test cases and MATPOWER examples. The case study considers a portfolio of 6 generators: 1 Hydro power, 1 nuclear plant, 2 CC Gas turbines, 1 Oil-fired thermal plant and 1 CHP plant. The generator data used on the simulation was previously used in [11]. The generators constraints include:

- Marginal cost, MC (€/MWmin)
- Maximum and Minimum power output (MW)
- Ramp Up Rate (MW/min) and Ramp Down Rate (MW/min)
- Minimum Up time (min) and Minimum Down time (min)
- Start-up cost (€) and Shutdown cost (€)
- Shutdown ramp limit (MW) and Start-up ramp limit (MW)

The simulation considers a time horizon of 3 days. The demand profile considered follows a typical pattern profile at a country level. Then, this hourly profile data is converted to the finer time resolutions previously described. The UC model is implemented in General Algebraic Modeling System (GAMS) using CPLEX solver. The computational time for 1-minute time step has been 16 minutes and 53 seconds. The PC used has a processor Intel® Xeon® CPU E5-2690 v4 and 384 GB of RAM.

B. Results and discussion

The results for the 4 different time steps are given in the following figures.

TABLE II. MAIN RESULTS FOR A THREE DAY HORIZON CASE WITH 6 GENERATORS

Timestep	Total production cost (M€)	Curtailment (MWh)
60 minutes	1.397	0
15 minutes	1.392	0
5 minutes	1.393	0
1 minute	1.392	6.34

The objective function, total production cost, for the four different time-steps is almost the same in contrast with the hypothesis and results derived in the proof of concept (small example). The main reasons are the amplitude of available flexible generators compared to the previous simulation and the easy performance for the portfolio to satisfy the designed power demand. The Oil-fired thermal plant stays disconnected for the 4 cases, showing that the portfolio is not under stressed capacity conditions and is comprised of a strong flexible portfolio.

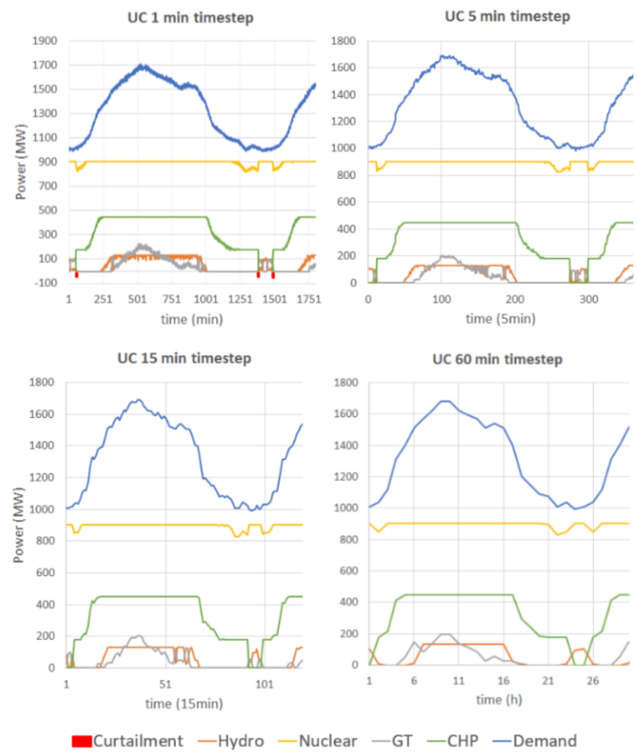


Figure 6. Results on units behaviour under different time-steps

The CHP works as the first flexible generator to turn on when power demand is ramping up. Figure 6 presents an overview of generators behavior and simulation results. When it reaches its Pmax the hydropower and GTs give the extra flexibility required. For the ramping down, the GTs take the initiative, followed by the hydro and finally the CHP.

At some point when the demand stays low for a relevant time interval, the UC model finds more optimal to disconnect the CHP some hours than leave it at Pmin and forcing the nuclear to decrease its production. For CHP disconnection the nuclear plant must previously slow down its production in order to enable itself to ramp up when CHP disconnects. For 1 min time step, GTs and Hydro are connected to fulfil the production gap that the CHP leaves. In contract, in the rest of the time steps Hydro connection is only required. This is because of the overestimation of flexibility previously explained, for shorter time steps the flexibility is more limited therefore more flexible sources are required (GTs). Additionally, the 1 min time step enters into curtailment when CHP disconnects, showing the limitations on flexibility for these conditions.

Regarding the precision of the UC model, based on the results it is reasonable to state that moving to shorter time-steps gives more accuracy on the generators behavior. Furthermore, the results for 60 minutes time-steps are quite imprecise for the real operations of the generator owner. Meaning that uncertainty in operations based on hourly intervals will lead to inefficient power system operations.

For example, within an hour period a GT should deliver 100MWh, but the model doesn't give information about the power distribution during that period, whereas with 1-minute time step the owner would know to distribute the 100MWh. This misinformation could deal with higher curtailments and indeed higher total production costs.

Curtailment can be fixed in several ways that the UC model does not consider. The generators inertia could store the curtailment energy for short amounts and deliver it in further periods. Additionally, the installation of batteries could be a feasible solution for small curtailments.

Also, it is important to differentiate between 3 flexibility conditions shown on the results:

- Demand Ramping Up
- Demand Ramping Down
- Demand Low for a period of time, flexibility needed for disconnection of large generators

Since the hydropower production is limited to a fixed amount of energy, having the lowest MC in the portfolio and highest flexibility availability, the UC model distributes the hydropower fixed MWh in the best way that can bring the highest flexibility to the simulation, minimizing the necessity of GTs.

All in all, the hypothesis presented in the previous section still holds. The overall similarity in results can also be explained because the UC model works with perfect information on the future (i.e., a determinist model with perfect foresight on the future demand), therefore it optimally allocates its decision based on the demand pattern supplied to it. Meaning that achieves an optimal scheduling for a given demand, which in reality would not be the case as there is variations in short-term demand as our conversion method (hour-to-minute) showed. In this regard, a worth area of future research is to explore a stochastic unit commitment model that could apply the same granularity in time resolution as we have presented here. Applying the concept noted in the paper together with stochastic UC model with rolling horizon features will certainly yield to greater differences in the time-horizon overall results.

IV. CONCLUSIONS

Power system operation requires continuously maintaining balance between generation and demand. To handle the changing power system and enable the energy transformation several actions are needed, where increase of digitalization, automation and larger variability implies a need for flexibility. Also, it is necessary to handle decentralized resources and variable renewable energy sources (wind and solar) as potential suppliers of ancillary services. In the new operational challenge, it is important to allow consumption and production to follow each other more closely to real-time, all these reveals value of flexibility of different time frames: rapid random fluctuations, slow periodical fluctuations and rare abrupt changes. Therefore, to keep system balanced it is important to estimate/measure the quantitative generators flexibility. Through generation adequacy metric the total generation capacity in the system can be evaluated, with disregard towards the deliverability of this capacity. Also, quantification of the deliverable flexibility will contribute to generation scheduling, short-term and long-term planning.

It is also important to mentioned European Market coupling initiative and dimensioning of Frequency Restoration Reserve (FRR). The European market coupling requires an increased automation and harmonized balancing processes, combining all balancing energy bids across Europe and activating them in merit order. For the TSOs it will requires the following time frames of the auctions for mFRR each 15 (or 1) minutes and aFRR each 4 seconds. Where shorter imbalance and settlement period makes the energy system more cost effective and it will give the bigger roles for market players in the balancing of the energy system.

This paper has contributed to understand: 1) opportunities and challenges in converting traditional hourly UC models to finer time-resolutions, 2) how to convert hourly data to shorter time periods, 3) the notion and awareness on how generators might actual behave in real-time operations and 4) the importance of considering shorter time resolution. In short, the study shows the advantages as well as the requirements needed (create proper data for simulating per minute) to decrease the time step simulated in a UC model and, thus, and capture a more realistic flexibility of the generators.

V. References

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5. VRES Case study

The final version of the UC model programmed in GAMS for 1 minute, 5 minutes timestep, 15 minutes and 60 minutes timesteps can be found in Appendix G.

The present case study aims to analyse:

- the VRES and Hydro power effect on the UC problems and its synergy
- the effect of using shorter timesteps
- Analyse the flexibility concept more deeply than in previous simulations
- Categorize the different flexibilities according to specific situations

There will be 12 different scenarios simulated for each timestep, varying both the share of hydro and VRES as shown in Figure 26.

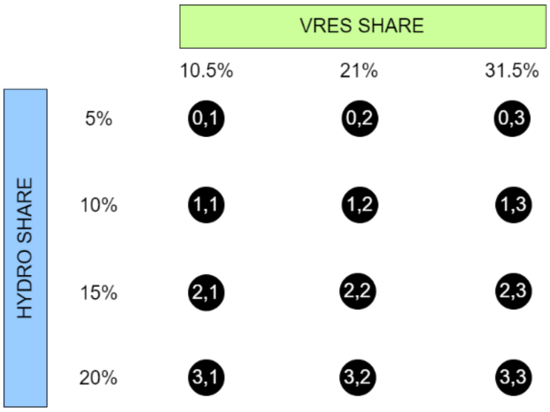


Figure 26. Different scenarios of the case study

The VRES share englobes wind and solar power and will go from 10.5% to 31.5% share of the total production, whereas the Hydro Share from 5% to 20%.

The generator portfolio simulated is taken from the Simple Case Simulation previously shown. Thus, the 6 generators from previous simulation form the current portfolio. For high share of hydro, the only hydro power plant that is part of the portfolio would run at maximum power which as previously explained is not realistic. Therefore, an additional hydro power plant has been added to the portfolio, reducing the capacity factor needed for the different scenarios.

The share of hydro is added to the UC model by restricting the capacity factor of the hydro plants, so 5% of hydro share would be equivalent to a capacity factor of 16.55%, as shown in Table XIV.

Table XIV. Equivalences between share of hydro and capacity factor

Share of Hydro (%)	Capacity factor (%)
5	16.55
10	33.10
15	49.67

20	66.22

Regarding the VRES data, there is only 15 minutes available data in EU and the conversion model cannot be implemented for VRES since the type of distribution of both energy sources do not follow a normal distribution. Weather impacts on their power output, which is not a random parameter, thus cannot follow a normal distribution, as previously explained in Section 3.5.3. Indeed, California Independent System Operator (CAISO), which has not been considered until now, provides data on 5 minutes interval. The demand data and VRES data have been taken from CAISO database for this simulation.

The conversion model has been used for converting the 5 minutes demand data to 1-minute interval and the VRES data has been directly converted to 1 minute based by using normal interpolation and without adding a deviation. The 5 minutes data has also been converted to hourly based. The MATLAB codes can be found in Appendix G.

The simulation covers 5 days (3 working days and 2 weekend days) from the 12th of December 2018 to the 16th of December 2018. The share of solar and wind power production in CAISO during the 5 days mentioned was 7.7 % and 2.8 % of the total demand respectively giving a solar ratio over wind of 2.75. In total the share of VRES was 10.5 %. This share will be considered as a base scenario for the following simulation, increasing the share up to 31.5 %, as previously mentioned. The solar/wind ratio will be fixed for all the VRES share scenarios.

The demand extracted from CAISO database has been downscaled 12.5 times, so the demand is dimensioned to the installed capacity of the portfolio.

The timesteps simulated are 1 minute, 5 minute and 60 minutes. 15 minutes timestep has been removed from the case study due to the large number of scenarios and simulations (36 in total).

5.1 Results

The results of the case study are shown in Table XV, Table XVI, Table XVII and Table XVIII and in Appendix G.

Table XV. Total costs, number of disconnections and curtailment for 1 minute timestep

	Total cost (M€)			Nº disconnections			Curtailment		
	Share VRES								
Share Hydro	**10.5%**	**21%**	**31.5%**	**10.5%**	**21%**	**31.5%**	**10.5%**	**21%**	**31.5%**
5%	4.444	3.603	3.140	76	74	68	1	22.3	9326.5
10%	3.748	2.911	2.451	77	116	152	0.5	20.85	9326.2
15%	3.060	2.251	1.897	112	63	52	0.5	9.6	9315.1
20%	2.521	1.814	1.460	59	51	46	0	9.6	9315.1

Table XVI. Total costs, number of disconnections and curtailment for 5 minutes timestep

	Total cost (M€)			Nº disconnections			Curtailment		
	Share VRES								
Share Hydro	10.5%	21%	31.5%	10.5%	21%	31.5%	10.5%	21%	31.5%
5%	4.443	3.602	3.139	62	70	65	0	0	9305.9
10%	3.747	2.91	2.449	70	117	119	0	0	9307
15%	3.059	2.249	1.893	106	55	48	0	0	9307
20%	2.516	1.812	1.455	43	42	36	0	0	9307

Table XVII. Total costs, number of disconnections and curtailment for 60 minutes timestep

	Total cost (M€)			Nº disconnections			Curtailment		
	Share VRES								
Share Hydro	10.5%	21%	31.5%	10.5%	21%	31.5%	10.5%	21%	31.5%
5%	4.443	3.611	3.166	42	41	47	0	0	9163.4
10%	3.747	2.919	2.478	35	48	45	0	0	9163.4
15%	3.059	2.252	1.892	47	35	31	0	0	9163.4
20%	2.519	1.814	1.454	30	31	27	0	0	9163.4

Table XVIII. Total cost comparison between timesteps

	Total cost comparison								
	60 minutes – 1minute time (k€)			60 minutes – 5 minutes time (k€)			5 minute – 1 minute timestep (k€)		
	Share VRES								
Share Hydro	10.5%	21%	31.5%	10.5%	21%	31.5%	10.5%	21%	31.5%
5%	-1	8	26	0	9	27	1	1	1
10%	-1	8	27	0	9	29	1	1	2
15%	-1	1	-5	0	3	-1	1	2	4
20%	-2	0	-6	3	2	-1	5	2	5

6. Discussion

The case study shows in total 36 simulations, 12 per timestep varying the share of hydro and VRES.

As expected, the total cost decreases for higher share of VRES since its marginal cost is neglected and the net demand that the portfolio needs to fulfil also decreases. Furthermore, higher limitation on the share of hydro implies lower total costs since it is the cheapest energy source in the portfolio.

Comparing the total cost for same scenarios and different timesteps, it is possible to appreciate a considerable difference between total costs for Scenarios (0,3) and (1,3), see Table XVIII. In these scenarios, 1 minute and 5 minutes timesteps lower the total cost up to 29.000 € compared to hourly based. This value is quite relevant since it would annually save 2.117 M€ for a very short portfolio of only 7 generators. Scenarios (0,2) and (1,2) show a reduction of 8-9 k€ total cost for short timesteps. On the other hand, for the rest, the difference in the total cost is minimum. Thus, even if a 60 minutes timestep overestimates the flexibility of the generators as previously show in Section 3.1 , it faces higher total costs when the share of VRES is high (+31.5%) and there is a scarcity of available hydro (<10%) in the portfolio (e.g. available flexibility).

The main reason of the higher total cost in hourly based can be extracted from the share of production per type of generator. On one hand, 1 minute and 5 minutes timesteps demand higher GT production (3.15% and 3.42% respectively) than 60 minutes (2.20%) due to the necessity of higher flexibility on shorter timesteps. Contrarily, for 60 minutes timestep, the share of oil (2.20%) is way higher than for 1 minute (0.83%) and 5 minutes (0.56%).

Table XIX. Share of demand covered per type of source, Scenario (1,3)

	1-minute timestep		**5 minutes timestep**		**60 minutes timestep**	
Type of Source	**Production (GWh)**	**Share of demand (%)**	**Production (GWh)**	**Share of demand (%)**	**Production (GWh)**	**Share of demand (%)**
Hydro	22.72	10.01 %	22.72	10.01 %	22.72	10.01 %
Nuclear	93.78	41.30 %	93.77	41.30 %	93.41	41.14 %
Gas Turbines	7.15	3.15 %	7.77	3.42 %	5.00	2.20 %
Oil	1.89	0.83 %	1.27	0.56 %	4.83	2.13 %
CHP	39.32	17.32 %	39.31	17.31 %	38.72	17.06 %
VRES	71.50	31.50 %	71.50	31.50 %	71.50	31.50 %
Curtailment	-9.33	-4.11 %	-9.31	-4.10 %	-9.16	-4.04 %
Total Demand	**236.13**	**100 %**	**236.13**	**100 %**	**236.13**	**100 %**

Certainly, the main reason why 60 minutes demands more Oil comes from a problem of resolution. Although simulating per hour gives flexibility overestimation to the UC model, it disables the generators to switch on and off within an hour interval due to the lack of enough resolution. On the other hand, 1 minute and 5 minutes timestep permits the GTs to connect and disconnect when necessary within an hour period. The unique alternative for hourly timestep is using oil power plants instead of GTs. It also provokes that the Oil will stay connected the following hour (since it cannot connect and disconnect in the same period t) generating more energy. Although the MC considered between GT and Oil is not quite different. A lower cost on GTs would increase the total cost reductions for short timestep. An indirect effect of using short timesteps is that they can reach higher share of nuclear and CHP (low MC) than hourly based due to, again, its higher resolution.

As a prove, Table XX shows the disconnections in Scenario (1,3) per type of generator. The number of GTs and Hydro disconnections increases for shorter timesteps (145 for 1 minute and 113 for 5 minutes) whereas oil ones increase on 60 minutes timestep supporting the previous analysis.

Table XX. Number of disconnections per type of source, Scenario (1,3)

	Number of disconnections		
Type of Source	**1-minute timestep**	**5 minutes timestep**	**60 minutes timestep**
Hydro	45	42	17
Nuclear	0	0	0
Gas Turbines	100	71	18
Oil	3	2	6
CHP	4	4	4
Total	**152**	**119**	**45**

As well, the same tendency occurs in Scenario (0,3). In this case the total number of disconnections is way lower than in Scenario (1,3).

Table XXI. Number of disconnections per type of source, Scenario (0,3)

	Number of disconnections		
Type of Source	**1-minute timestep**	**5 minutes timestep**	**60 minutes timestep**
Hydro	43	38	21
Nuclear	0	0	0
Gas Turbines	18	20	16
Oil	3	3	6
CHP	4	4	4
Total	**43**	**38**	**21**

As shown in Table XV, Table XVI and Table XVII, the 3 timesteps scenarios follow a pattern regarding number of total disconnections. Indeed, as explained below, the available capacity and flexibility limits the number of disconnections in a scenario. It is possible to categorize the scenarios in 3 types:

- Type I: Scenarios with the high capacity to fulfil the demand (e.g. high share of VRES) and/or high hydro share. In these cases, the share of hydro is so high that there is no need for extra capacity neither flexibility. The hydro power is capable to fulfil the demand requirement; thus connections/disconnections of Hydro and GTs are minimum.

- Type II: For scenarios with lower VRES and/or Hydro share than Type I, the necessity of flexibility and capacity increase, dealing to more connections and disconnections of Hydro and GTs.
- Type III: For these scenarios, the share of Hydro is minimum (<10%). So, there is a commitment of capacity that can only be fulfil by the thermal plants (Oil and GTs). Since the portfolio is close to its capacity limits, the switching on/offs are minimum. The GTs stay connected during large periods.

Table XXII shows the categorization of each scenario by type.

Table XXII. Scenario categorization based on number of disconnections

	Share VRES		
Share Hydro	**10.5%**	**21%**	**31.5%**
5%	Type III	Type III	Type III
10%	Type III	Type II	Type II
15%	Type II	Type I	Type I
20%	Type I	Type I	Type I

There is no direct correlation between the Share of Hydro and VRES, and the number of disconnections. Indeed, for shorter timestep the disconnections occur more often in all the scenarios (Table XV, Table XVI and Table XVII).

Consequently, even if a portfolio has a high flexibility capacity, it could not take advantage if the power capacity is not fulfilled from base-loads generators. The flexible generators will work as capacity loads.

In respect to the curtailment, there are three causes that explain why the curtailment takes place in the simulation. The most important one is the limitation on the deployment of VRES. This limitation is defined by the total demand and the nuclear role.

The total demand can only be fulfilled by VRES until a limit where net demand begins to be negative, dealing into direct curtailment from the VRES. Based on the simulations, the net demand is negative up to -220 MW for 31.5% share of VRES (See Scenario (0,3)). Thus, the limit where the net demand reaches zero would be a little bit lower than 31.5%. The deployment VRES limit can be extended either if the peak power demand is aligned with the peak solar production or if the demand is flexible to absorb the curtailment.

Additionally, the nuclear role in this portfolio deals also into curtailment. As expected, nuclear power plant works as a base load producing most of the electricity during the 5 days. There is a great limitation on the nuclear connections and disconnections, due to its high Minimum Up Time (UT) and Minimum Down Time (DT) of 24 hours. Consequently, the nuclear plant cannot be disconnected and stays at minimum power when net demand is low, as it is shown in Scenario (0,3), (1,3), (2,3) and (3,3). The deployment VRES limit is lower for nuclear portfolios and supports the little synergy between both technologies.

The last cause is only related with flexibility needs and it is only present in 1-minute timestep. Indeed, its impact and size are much lower than the previous ones. There are two types of scenarios present in the simulations:

1) The UC model finds more optimal to experience little curtailment, when the connected generators are not flexible enough to follow the demand oscillations, than connecting an additional generator. For example, in the case study, when only nuclear is connected, it is more optimal experience curtailment rather than adding a flexible/auxiliary generator (e.g. GT). This type of curtailment only occurs for 1-minute timestep. For 5 minutes and 60 minutes timestep, the overestimation of nuclear flexibility permits the nuclear to follow the power oscillations. In reality, this curtailment is more connected with power stability than UC modelling. For a so a short timestep as 1 minute, UC and power stability are interconnected.

2) Curtailment also appear when big/medium size generators are connected or disconnected. The reason comes from the instant power step up/down that they generated by switching. To balance this step, other generators have to modify its production, and, in some cases, it is necessary to enter into some curtailment until the mix generation gets balance.

The following figure shows these two curtailment scenarios previously defined.

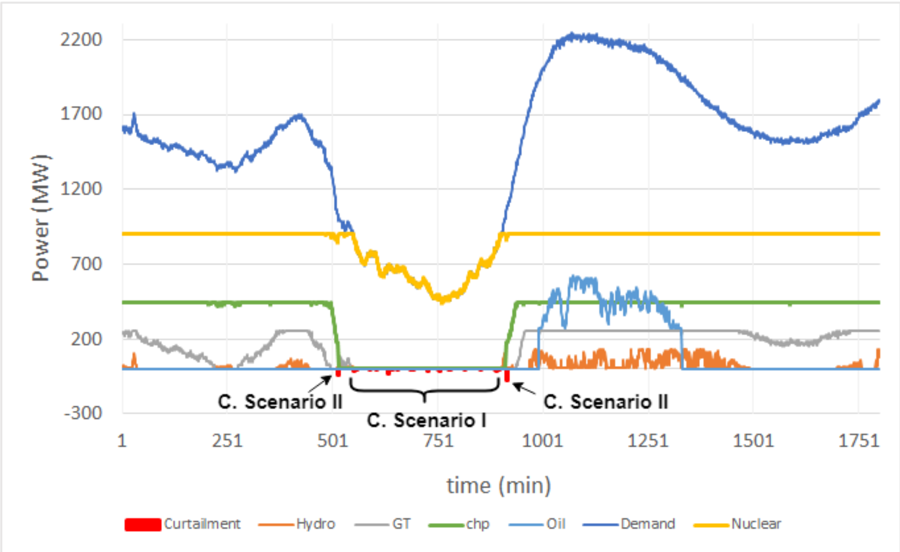


Figure 27. Type of curtailments example, screenshot from Scenario (0,2) and 1 minute timestep

Comparing between timesteps, the curtailment is almost the same for 3 of them and mostly takes place for a VRES share of 31.5%. This is because most of the curtailment is caused by the VRES deployment limit and the role of the nuclear previously explained. Indeed, the higher resolution on the short timesteps leads to a more precise curtailment from these causes. Additionally, the curtailment coming from the flexibility needs only is experienced in 1 minute timestep.

6.1 Effects of finer time resolution

The effects of finer time resolution are summarized in Table XXIII.

Table XXIII. Effects of finer time resolution

Effects of finer time resolution	
Advantages	**Disadvantages**
• Greater UC resolution & Closer to real-optimal UC solution: ○ Lower grade of uncertainty ○ Less imbalances ○ Less need of BRP and reserves • Minimum overestimation of the generators • Important reduction on costs for high Share of VRES	• High computation time • Lack of available data and infrastructure • Lack of harmonization in time resolution

The developed UC model do not consider uncertainty effect in the simulations. It assumes perfect information about the demand and perfect imbalance over the time resolution. Therefore, the differences between the UC solutions for different timesteps are not quite distinct. Only high share of VRES and low Share of Hydro lean the scale to finer resolution.

Since uncertainty is not modelled and the UC model is deterministic, the hourly resolution takes advantage these starting points. In practice, hourly resolution faces higher uncertainty and gives incomplete information to the BSP during imbalance settlement period (ISP). The low resolution does not provide enough information to the BSP about how to distribute their production within the ISP (hourly based). The lack of information leads to higher imbalance than for a 15 minutes time resolution.

Additionally, Hansen, et al. [71] states that the hourly ISP can lead to two undesirable consequences compared to a finer imbalance settlement period.

1. Imbalances that net out over the hour are not settled as an imbalance
2. Large jumps in imbalances occur around hour shifts because of this (see Figure 28)

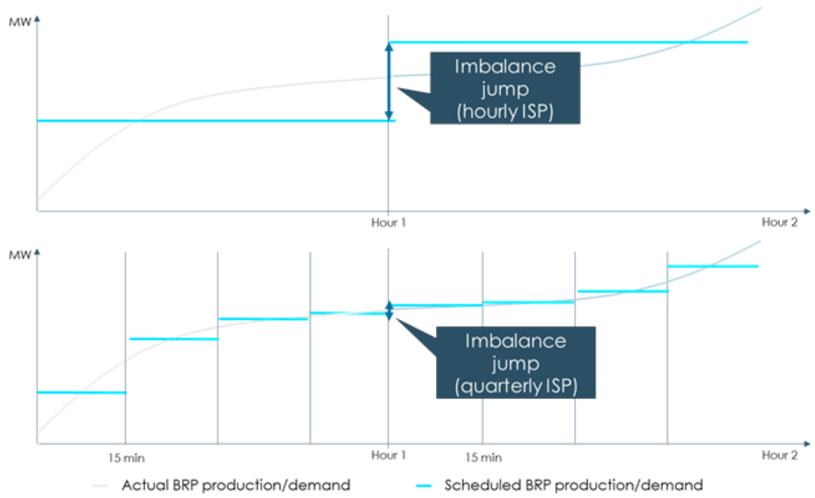


Figure 28. Imbalance jumps reduction for finer time resolutions [71]

The reduction in change in imbalance during hour shift to 15 minutes would be around 22.2 % in Norway based on Copenhagen Economics estimations [71]. As a consequence, reduced imbalances could lead to a reduce need for reserve capacity.

Secondly, not only is it a resolution advantage but also finer timesteps considers generators flexibility closer to reality, as previously explained in Section 3.1. As an example, in Chapter 4 simulation, the UC solution for hourly timestep shows that the hydro can lonely deal with the flexibility need whereas 15 minutes and 5 minutes based also requires the GT. 1 minute timestep experiences curtailment even if the Hydro and GT are connected during the period. In practice, the hourly UC solution would have led to power imbalance.

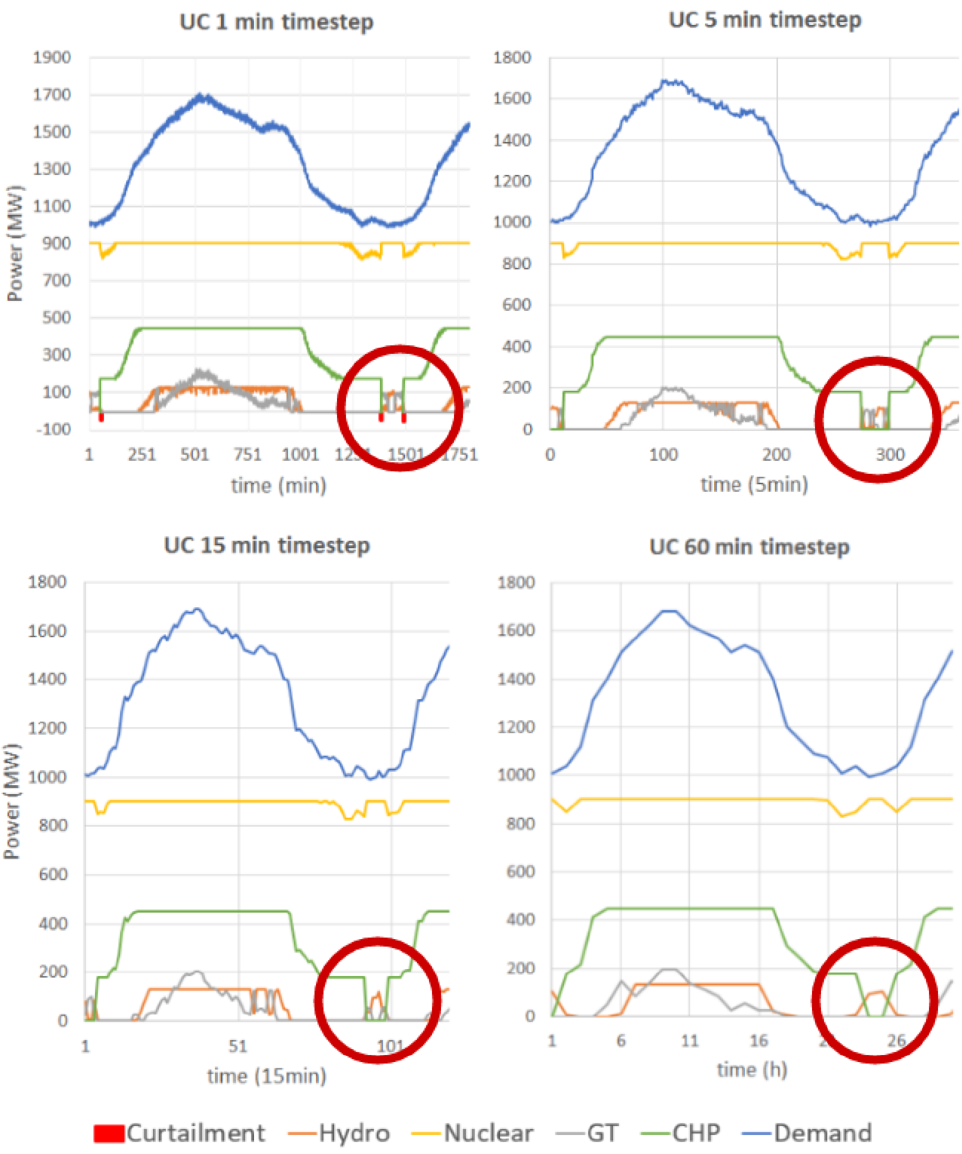


Figure 29. EEM Paper simulation Results on units behaviour under different time-steps

Finally, the case study shows the direct total cost reduction by implementing finer timesteps when the Share of VRES is high and Hydro power is limited. Since flexible generators can switch on/off within one-hour period, finer timesteps permit generators to adjust and optimize better its production, lowering its final costs.

On the other hand, finer time resolution entails adding complexity and, in the end, larger computation time for UC models, as experienced over the previous simulations, complicates the ahead time decision.

The lack of data becomes a barrier when implementing more resolution in a power market. Therefore, a necessary investment in the required infrastructure must be done by the particular TSO.

And finally, but never the least important, the lack of harmonization in time resolution restrict the coupling between different imbalance settlement periods (ISP) in Europe. Energinet, et al. [72] (Danish TSO) and the ENTSO-E Network Code in Electricity Balancing (NCEB) among others remark the importance of using a common time resolution of 15 minutes within Europe which would contribute to settle imbalances between countries easier than nowadays as well as a common time resolution for intraday market.

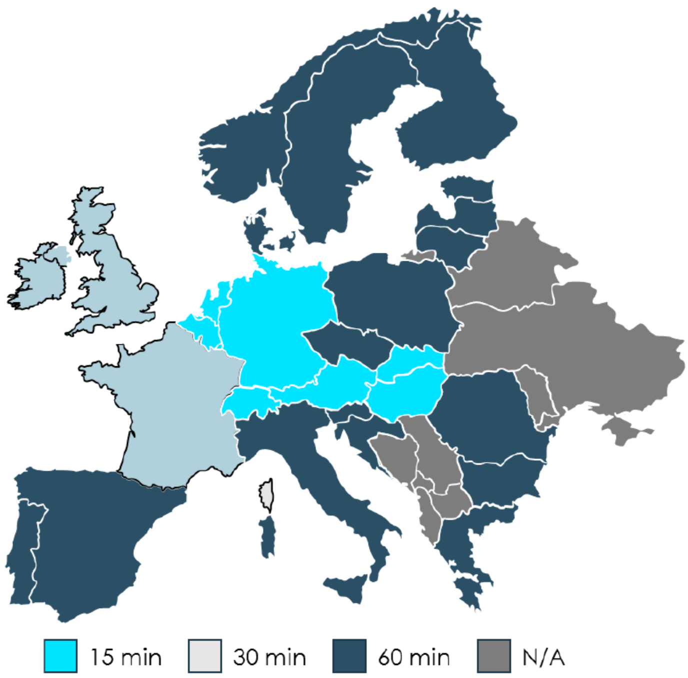


Figure 30. Current Imbalance Settlement Periods (ISP) in Europe [71, 72]

To conclude, the European Commission has approved the Electricity Balancing guideline [73], where all EU countries (including EEA members) should implement an ISP of 15 minutes no later than Q4 2020.

The election of 15 minutes instead of 5 minutes has not been explained. Indeed, the transition from hourly time resolution to 5 minutes quite more difficult than 15 minutes, since no country is currently balancing within 5 minutes, contrary to 15 minutes where many countries have already implemented it (Figure 30).

With the continuous deployment of VRES in Europe, a future transition from 15 minutes to 5 minutes resolution is quite likely, as other operators like CAISO have already implemented it.

Although one-minute resolution gives even more accurate power balancing, the current infrastructure, technology and operators are not yet prepared for this change. Additionally, the differences between 1 minute and 5 minutes resolution are minimum as shown in the Case Study and in the Flexibility Theory (Section 3.1). Therefore, most likely 5-minute resolution will lead the future power markets.

6.2 The concept of flexibility: Lessons learned

As previously shown in Section 2.4, the academia usually links generator flexibility with ramp up/down rates, as [31, 74]. Based on the case study results previously shown this definition falls short. There are many factors that elaborate and modify the concept of flexibility rather than ramp rates:

First of all, instead of linking flexibility with ramp up/down rates, the upper and lower operation limits, ($\overline{\mathrm{P}}_{\mathrm{i,t}}$) and ($\underline{\mathrm{P}}_{\mathrm{i,t}}$), for each time t, defined in Section 3.3, reflect more accurately the real flexibility of a generator. Indeed, ($\overline{\mathrm{P}}_{\mathrm{i,t}}$) and ($\underline{\mathrm{P}}_{\mathrm{i,t}}$) are dependent on the previous state of the generator ($P_{i,t-1}$), so the way the generator is used on the portfolio modifies its flexibility besides ramp rates. As an example, nuclear ramp rates are quite wide and previous research [75] state that nuclear is a very good source for flexibility. In practice, its flexibility is very limited: On one hand, nuclear power usually operates at maximum power, so its upper operation limit is almost zero. On the other hand, it is a technology very reactive to switching on/off due to its large UT and DT. Additionally, the nuclear power plants usually are much bigger than other types of generators. Its size also becomes a barrier for flexibility. Furthermore, nuclear power plants are quite sensible to the net demand, becoming also a barrier for VRES.

Secondly, a switching can also bring direct flexibility just by the step jump generated. As an example, looking into Scenario (1,2) for 5 minutes timestep in the case study, the oil plant is giving flexibility just by turning on, relieving the Hydro and GTs production and, consequently, increasing their upper operation limit for further time periods (e.g. flexibility). Regarding the flexibility of a portfolio, adding power plants (even if they are inflexible) to a portfolio increases its flexibility potential ergo the number of generators in a portfolio affects to the UC solution and its flexibility.

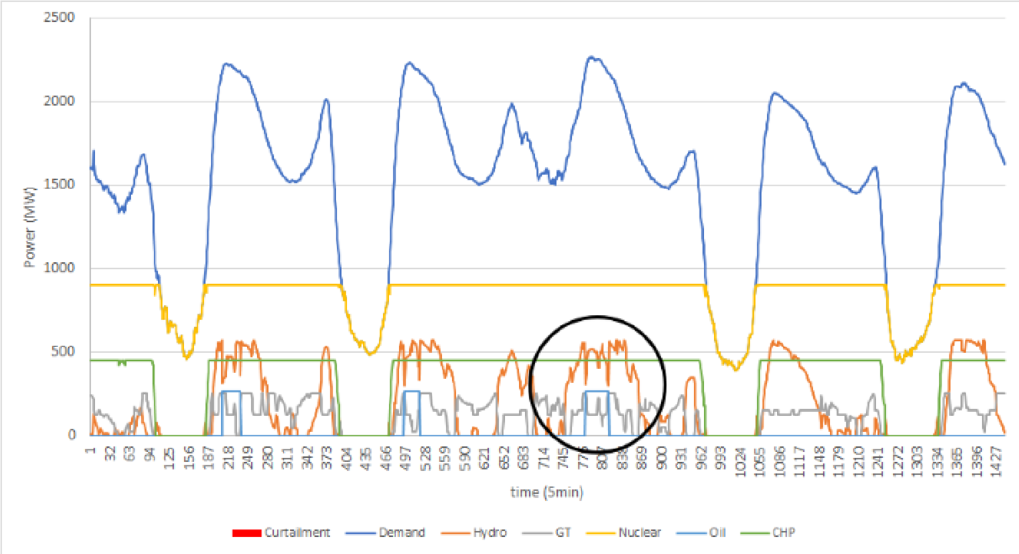


Figure 31. Case study: Scenario (1,2) for 5 minutes timestep

Furthermore, as seen in the case study, a portfolio flexibility is highly dependent on its power capacity. In case the portfolio power capacity limit and power demand are close, the flexible generators would have to work as base loads, reducing its capable flexibility and possible switching on/offs. Thus, flexibility is dependent on the power capacity of the portfolio.

6.3 Curtailment of VRES

Curtailment is a serious concern in power markets with high share of VRES, as CAISO [69]. In California, the installed capacity of solar is much higher than the one that the power system can absorb. Therefore, the amount of curtailment facing is beating record as shown in the following figure. Last April, CAISO experienced the record of almost 225,000 MWh of curtailment [69].

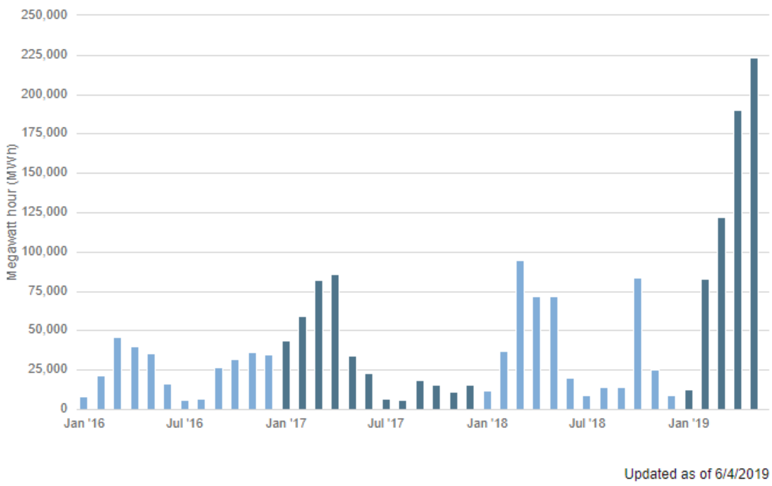


Figure 32. Wind and solar curtailment totals by month [69]

An important detail can be extracted form CAISO curtailment data and the results of the Case Study presented. With a High Share of VRES and with the same rate between solar and wind production as CAISO, the curtailment usually happens from 9:00 am to 2:00 pm in the Case Study results, whereas in California it mostly appears around 11:00 am [69]. The reason comes from the peak of power production coming from the solar power.

Figure 33. California location [70]

Indeed, the geography of California harms its production of solar power. Since there is no further terrain on the west limits of the State of California, transferring the excess of solar to a western state is impossible since there is the ocean. Additionally, the direction of the sun goes from East to West, so, for example, considering a curtailment in CAISO from 9:00 am to 2:00 pm, at 9:00 am CAISO is starting to experience curtailment, whereas the Eastern States close to California with at least one hour ahead would have already experience 2 hours of curtailment (assuming the same proportional solar capacity as CAISO). Therefore, the California geography plus the direction of the sun may provoke higher curtailments than in being situated on the eastern coast. Indeed, non-previous research has been developed yet within this area.

7. Conclusion & Future Research

The purpose of this master's is to examine how deployment of VRES affects the current power markets with specially focus on the flexibility issues.

As the literature review shows in Chapter 2, the deployment of VRES is provoking many inefficiencies taking place in the current power markets. First of all, its deployment has increased the flexibility needs due to its intermittence, uncertainty and inflexibility. This required flexibility is fulfil by flexible generators (thermal plants). These plants are experiencing economic losses because of the clearing price which only overs MC and power generated. Flexibility provided to the system is not optimally paid as Oleinikova, et al. [33] reflects. Consequently, the present thesis aims to analyse the flexibility under share of VRES and see its effect on the power market as well as see the time resolution effect on flexibility.

Chapter 3 develops a complete UC model which not only includes optimization programming and generator constraints but also a generator database, a demand data conversion method, a data analysis of the European power demand and a theoretic analysis of flexibility under UC models. The developed UC model is adjusted after some simulations (Swedish case, Simple Case).

In the EEM paper (Chapter 4), these ideas are summarized, identifying different scenarios that form the flexibility concept.

In Chapter 5, the VRES Case Study permits to dig inside the VRES effect on flexibility by designing total 36 simulations, 12 scenarios per timestep used (1 minute, 5 minutes and 60 minutes). The results are quite impressive. Finer time resolution reduces the total costs of production up to 2.117 M€ for high share of VRES (31.5%) and low share of Hydro (<10%) even if uncertainty is not considered in the UC model. Apart from the economic benefit, finer time resolution gives more precise information about the power generators. In practice, this information would reduce the power imbalance in the system. The UC solution differs from 60 minutes resolution to 5 and 1 minute. The number of generator disconnections is analysed, concluding that disconnections are dependent on the capacity availability of the portfolio. The curtailment is also analysed in detail and 3 different causes are identified: The negative net demand, the nuclear role and the flexibility need.

Finally, deeper insights are extracted not only from the Case Study simulation but also from the previous ones. Section 6.1: Effects of finer time resolution analyses the performance of the different timesteps used on the simulations and connect them with the current discussion of harmonizing a finer time resolution for ISP and Intraday Market in the European countries. Both analyses agree on the positive effects of selecting finer time resolution due as a result of the VRES deployment.

Section 6.2 analyses the concept of flexibility and proposes special considerations when analysing flexibility of a portfolio or generator. The concept of flexibility is wider than the generator ramping rates, indeed the synergy between types of generators, the upper and lower bound limit, the switches and number of generators, and the power capacity of the portfolio change and redefine the concept of flexibility.

Section 6.3 shows the real problems of the curtailments provoked by the high share of VRES and a geographical cause, among others, of CASIO curtailments.

7.1 Limitations

The thesis has faced many limitations and barriers since the beginning. First of all, flexibility is a very wide and trending topic where many expertise and fields are interconnected. Setting the boundaries of the thesis is necessary but at the same time challenging to establish.

The most relevant limitations made in this work are:

- The lack of available online tutorials and learning courses of GAMS has meant a huge amount of time on self-learning. Furthermore, none of the supervisors knew about GAMS optimization so a lot of time has been used to master the program. Indeed, it is not a popular program.
- The lack of available data has also consumed a lot of time. The generator database has been the first step of the thesis and a puzzle difficult to fit. Assumptions needed to be done due to lack of data.
- Linear Unit Commitment assumption is, indeed, a limitation of the developed UC model. The election of simulating shorter timesteps involves high complexity that needs to be removed from other side. Thus, the election of a linear unit commitment enables the model to simulate per minute without facing large time of computation (which has occurred anyways).
- Grid congestion and constraints has not been added to the UC model. Neither frequency, voltage nor inertia control.
- The UC model do not consider uncertainty since it is a deterministic model and there is perfect information about the demand which it does not occur in the real power markets. Additionally, all the markets are integrated in the UC model which in practice is divided into different markets.
- The computation time has limited the scope of the simulations. Many tests and simulations not included in the present document have been tested for giving the simulations shown in the thesis. The level of complexity has been managed in the best possible way. Therefore, the assumption of not considering the start-up and shutdown costs has given fluidity to the further simulations.
- The number of generators and the period of time simulated has been limited due to computation time and CPLEX solver limitations.
- A greater sensitivity analysis for the VRES Case Study has not been done due to GAMS limitations. Contrarily to other programs as Pyomo, GAMS do not permit sensitivity analysis and the scenarios have been modified manually (demanding a lot of time). Additionally, the extraction of the output data from GAMS to Excel could be optimized. Being necessary in some cases to change the templates manually.
- Data demand form CAISO has not been used for the statistical analysis due to the late knowledge of CAISO available data. Anyhow, currently CAISO only provides 5 minutes data per day, so annual data cannot be downloaded from a single csv file. It would have required to download excel day one by one.
- The lack of time has limited the VRES Case Study scope. Many prework has been done in order to simulate the Case study. As a consequence, 15 minutes timestep has not been considered in the Case Study. It would have been very enriching to compare 15 minutes result with 5 minutes and 1 minute.

7.2 Future work

The future work can be divided based on the output given by the thesis. The future work has been divided in the following subsections.

7.2.1 Unit Commitment Model

The developed unit commitment model could be a very important tool used for many different topic and purposes. Since it replicates the power markets behaviour it could be used for further research on the demand flexibility and its effect on the power market as well as the require flexibility size from the demand.

Alternatively, the UC model could be used for finding the best generator portfolio for a given annual demand, so the solver chooses the portfolio mix.

Indeed, the UC model could be used for many different purposes and develop it more, for example by convert it to stochastic UC and simulate the effect of VRES uncertainty.

Regarding hydro power limitation, as previously shown, the hydro power can be modelled in different ways, depending on the grade of accuracy needed and complexity constraints. For hydro power analysis under UC modelling, it would be reasonable to implement Pereira and Pinto [65] proposal to integrate a variable watervalue for UC models.

7.2.2 Generator database

The generator database is quite small and can be added new generator types differentiating between age, type of model, among others. Certainly, more accurate and updated data could also replace the actual one.

7.2.3 Data demand conversion method

The proposed method is, undeniably, simple and do not replicates the real demand behaviour. By using Machine Learning and Deep Learning Algorithms, more precise data can be created for short timestep. Many within this area has been developed, like Berriel, et al. [76] uses Deep Learning for forecasting consumption.

7.2.4 Concept of flexibility

As the power markets are always evolving with the integration of new technologies, the concept of flexibility also evolves and needs to be often reviewed by the academia.

7.2.5 Deployment of VRES

There is no doubt that VRES will conquest the future power markets. In order to happen, new technologies should be developed. Based on the results and insights given in this thesis. The demand flexibility (e.g. consumers) will play a very important to enable further deployment on VRES.

Furthermore, non-previous research has been found about the connection between high share of VRES and the geographical allocation of a power market, which would be quite interesting to analyse.

8. Appendices

Appendix A

List of the generators considered in the database

Type	Code	Name	Installed Capacity at the beginning of the year	Current Installed Capacity	Location	Voltage Connection Level	Commissioning Date
Biomass	46WPU0000000063L	Åbyverket G3	100	100	SE3	130	01.11.2014
Fossil Gas	46WPU00000000040	Öresundsverket CHP	448	448	SE4	130	01.11.2014
Fossil Gas	46WPU0000000062N	Rya KVV	261	261	SE3	130	01.11.2014
Fossil Oil	46WPU0000000005Z	Karlshamn	670	670	SE4	400	01.11.2014
Fossil Oil	46WPU0000000057G	Stenungsund B4	260	260	SE3	130	01.11.2014
Fossil Oil	46WPU0000000056I	Stenungsund B3	260	260	SE3	130	01.11.2014
Fossil Oil	46WPU00000000024	Gasturbiner Halmstad	250	250	SE4	130	01.11.2014
Fossil Oil	46WPU0000000064J	Aros G3	245	245	SE3	130	01.11.2014
Fossil Oil	46WPU0000000023X	Värtaverket	190	190	SE3	110	01.11.2014
Fossil Oil	46WPU00000000032	Gasturbiner Malmö	126	126	SE4	130	01.11.2014
Fossil Peat	46WPU0000000055K	Uppsala KVV	120	120	SE3	40	01.11.2014
Hydro Run-of-river and poundage	46WPU0000000080L	Harrsele	223	223	SE2	130	01.10.2014
Hydro Run-of-river and poundage	46WPU0000000103Z	Kvistforsen	150	150	SE1	130	01.10.2014
Hydro Run-of-river and poundage	46WPU0000000104X	Korsselbränna	130	130	SE2	200	01.10.2014
Hydro Run-of-river and poundage	46WPU0000000106T	Olden (Oldå og Långså)	112	112	SE2	200	01.10.2014
Hydro Run-of-river and poundage	46WPU00000000210	Krokströmmen	103	103	SE2	130	01.11.2014
Hydro Run-of-river and poundage	46WPU0000000105V	Järnvägsforsen	100	100	SE2	200	01.10.2014
Hydro Water Reservoir	46WPU0000000029L	Harsprånget	830	830	SE1	400	01.11.2014
Hydro Water Reservoir	46WPU0000000042T	Stornorrfors	581	581	SE2	400	01.07.2014
Hydro Water Reservoir	46WPU0000000035Q	Letsi	487	487	SE1	400	01.11.2014
Hydro Water Reservoir	46WPU0000000032W	Messaure	452	452	SE1	400	01.11.2014
Hydro Water Reservoir	46WPU0000000028N	Porjus	440	440	SE1	400	01.11.2014
Hydro Water Reservoir	46WPU0000000031Y	Ligga	343	343	SE1	400	01.11.2014
Hydro Water Reservoir	46WPU0000000018Q	Trängslet	330	330	SE3	130	01.11.2014
Hydro Water Reservoir	46WPU0000000027P	Vietas	325	325	SE1	400	01.11.2014
Hydro Water Reservoir	46WPU0000000026R	Ritsem	320	320	SE1	400	01.11.2014
Hydro Water Reservoir	46WPU0000000036O	Porsi	275	275	SE1	130	01.11.2014
Hydro Water Reservoir	46WPU0000000045N	Kilforsen	275	275	SE2	400	01.11.2014
Hydro Water Reservoir	46WPU0000000085B	Krångede	250	250	SE2	220	01.01.2015
Hydro Water Reservoir	46WPU0000000033U	Seitevare	225	225	SE1	400	01.11.2014
Hydro Water Reservoir	46WPU0000000039I	Gallejaur	214	214	SE1	130	01.11.2014
Hydro Water Reservoir	46WPU0000000037M	Laxede	202	202	SE1	130	01.11.2014
Hydro Water Reservoir	46WPU0000000054M	Hojum	172	172	SE3	130	01.11.2014
Hydro Water Reservoir	46WPU0000000107R	Akkats	160	160	SE1	130	01.01.2017
Hydro Water Reservoir	46WPU0000000051S	Bergeforsen	160	160	SE2	130	01.11.2014
Hydro Water Reservoir	46WPU0000000066F	Sällsjö	160	160	SE2	220	01.11.2014
Hydro Water Reservoir	46WPU0000000044P	Lasele	157	157	SE2	220	01.11.2014
Hydro Water Reservoir	46WPU0000000048H	Midskog	155	155	SE2	220	01.11.2014
Hydro Water Reservoir	46WPU0000000047J	Forsmo	155	155	SE2	220	01.11.2014
Hydro Water Reservoir	46WPU0000000050U	Hölleforsen	140	140	SE2	220	01.11.2014
Hydro Water Reservoir	46WPU0000000022Z	Höljes	135	135	SE3	130	01.11.2014
Hydro Water Reservoir	46WPU0000000043R	Stalon	133	133	SE2	220	01.11.2014
Hydro Water Reservoir	46WPU0000000049F	Stadsforsen	132	132	SE2	220	01.11.2014
Hydro Water Reservoir	46WPU0000000040X	Vargfors	131	131	SE1	400	01.11.2014
Hydro Water Reservoir	46WPU0000000053O	Älvkarleby	125	125	SE3	70	01.11.2014
Hydro Water Reservoir	46WPU0000000019O	Järpströmmen	116	116	SE2	220	01.11.2014
Hydro Water Reservoir	46WPU0000000046L	Nämforsen	113	113	SE2	220	01.11.2014
Hydro Water Reservoir	46WPU0000000052Q	Torpshammar	110	110	SE2	220	01.11.2014
Hydro Water Reservoir	46WPU0000000041V	Tuggen	105	105	SE2	130	01.11.2014
Hydro Water Reservoir	46WPU0000000038K	Bastusel	100	100	SE1	130	01.11.2014
Nuclear	46WPU0000000061P	Oskarshamn 3	1400	1400	SE3	400	01.11.2014
Nuclear	46WPU0000000017S	Forsmark block 3	1159	1159	SE3	400	01.11.2014
Nuclear	46WPU0000000016U	Forsmark block 2	1116	1116	SE3	400	01.11.2014
Nuclear	46WPU0000000014Y	Ringhals 4	1106	1106	SE3	400	01.11.2014
Nuclear	46WPU00000000121	Ringhals 3	1065	1065	SE3	400	01.11.2014
Nuclear	46WPU0000000015W	Forsmark block 1	986	986	SE3	400	01.11.2014
Nuclear	46WPU00000000113	Ringhals 2	904	904	SE3	400	01.11.2014
Nuclear	46WPU00000000105	Ringhals 1	881	881	SE3	400	01.11.2014
Wind Offshore	46WPU0000000058E	Lillgrund	110	110	SE4	130	01.11.2014
Wind Onshore	46WPU00000000016	Vindpark Björkhöjden	288	288	SE2	145	01.11.2014
Wind Onshore	46WPU0000000068B	Blaiken	235	235	SE2	400	01.11.2014
Wind Onshore	46WPU0000000065H	Jädraås Vindkraftpark	203	203	SE3	130	01.11.2014
Wind Onshore	46WPU0000000112Y	Sidensjö	144	144	SE2	130	01.01.2018
Wind Onshore	46WPU00000001020	Ögonfägnaden	105	105	SE2	145	01.10.2014

Appendix B

Swedish context

Sweden is directly connected to Norway, Finland, Denmark, Germany, Poland and Lithuania. The grid connections facilitate the power exchange and balancing supply and demand.

As part of the Nord Pool power market, Sweden is divided in 4 area prices: SE1, SE2, SE3 and SE4 (Figure 34). The division generates 4 different electricity prices in the country that usually will not differ much from each other.

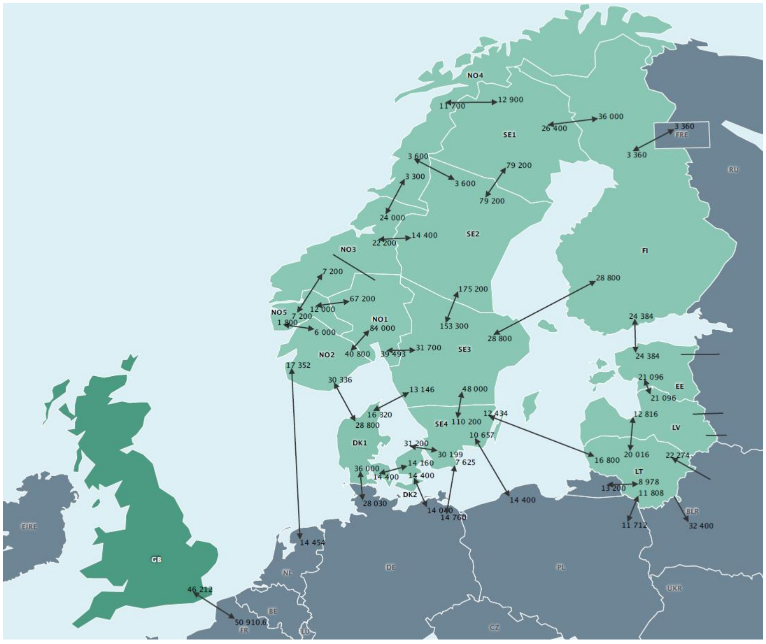


Figure 34. Exchange capacities between area prices in the Nord Pool[29]

As it is shown in Figure 35, each Swedish area has very different consumption and production. SE3, where most of the population is allocated, consumes and produces much more than other Swedish areas. All Swedish nuclear plants are placed in SE3 and help to cover the huge demand. On the other hand, SE1 and SE2 areas have a considerable energy surplus where most of the hydropower plants are placed. Finally, the area S4 usually has electricity deficit, requiring additional power from other areas.

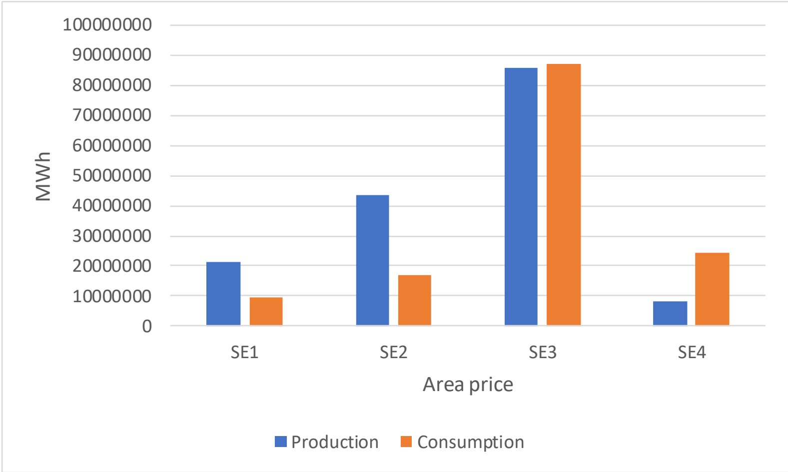
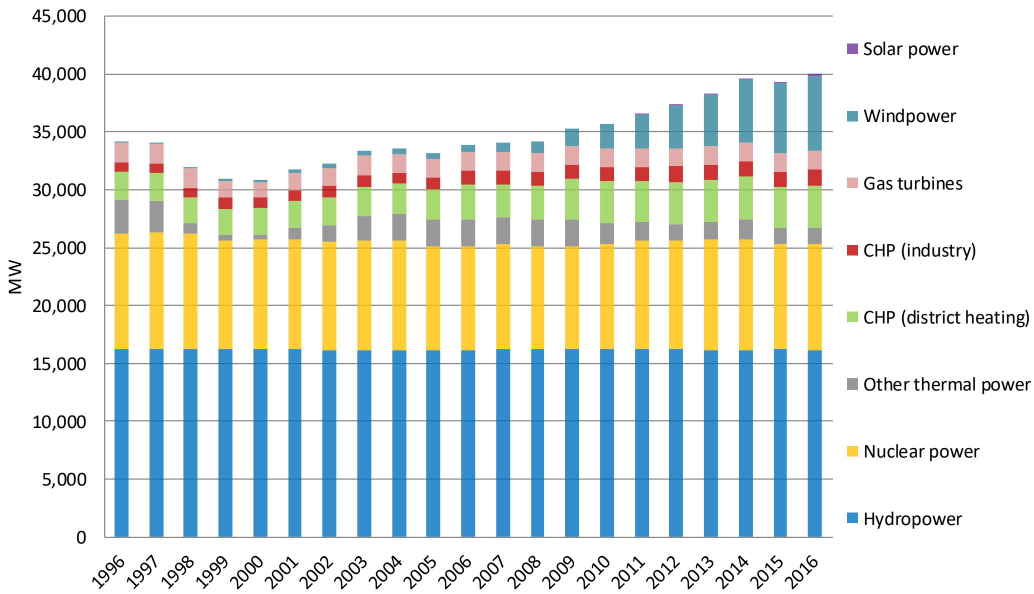


Figure 35. Annual consumption and production for different Swedish areas in 2017 based on [29]

Sweden has a strong power balance and, under normal conditions, is able to export electricity. The total Swedish installed capacity is around 40.03 GW [4] where more than a half of the capacity comes from nuclear and hydro power (see Figure 36). The highest power output over the last 3 years has been 26.7 GW on the 16th of January 2017 between 7:00 am and 8:00 am, 24.34 GW were consumed in Sweden and 2.13 GW were exported[4] [29]. The Swedish TSO Svenska Kraftnät [77] responsible for guaranteeing the country's short-term power balance, stated that highest consumption for the following year is expected to be 25.6 GW for a normal winter and 27.1 GW for a "10-year winter" (cold winter).



[4] The electricity consumed in Sweden plus the electricity exported is not equal to the power output due to transmission power losses.

Figure 36. Electricity installed capacity from 1996 based on [34]

Swedish power capacity

The installed capacity seems to be enough to supply the peak winter consumptions. Unfortunately, it is not possible to count all the installed capacity as available capacity. The installed capacity may be considered constant over a year, whereas the available capacity continually changes and is always lower than the installed capacity. For instance, hydropower and fossil generation are more readily available than wind power that only produces if the wind is blowing. Statistically, the wind is always blowing in some part of Sweden, therefore wind power is assigned a certain capacity value, but much lower than the installed [67].

For the winter of 2015/2016, Svenska Kraftnät [77] expected an available capacity of 28.2 GW out of 40.4 GW installed to deal with the power balance. As show in Figure 37, solar power and most of the wind power installed cannot be considered as available capacity. Furthermore, the gas turbines (GT) are mainly for the ancillary reserves and not included as available capacity.

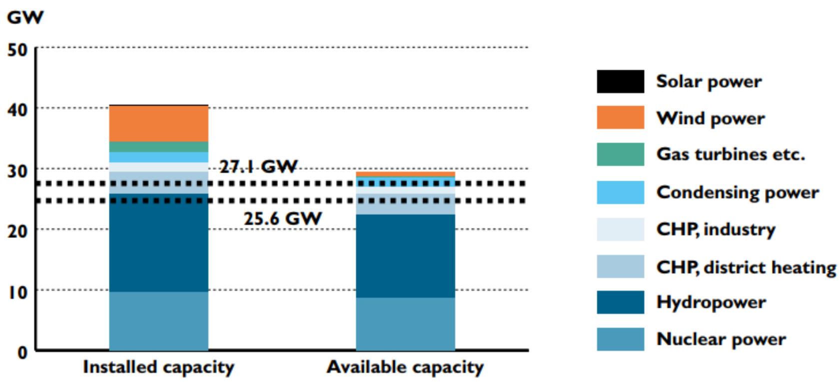


Figure 37. Svenska Kraftnät estimated power balance before winter 2015/2016 with the levels marked for 10-year (cold) winter (27.1 GW) and normal year winter (25.6 GW) [67]

An availability factor is proposed by Svenska Kraftnät in [78] (see Table XXIV). It should be noted that these are average that may vary substantially, in different situations.

Table XXIV. Availability factors for different energy sources based on [78]

	Availability factor *(excl. plant not in operation)*	Availability factor *(incl. plants not in operation, gas turbine as part of the disruption reserve)*
Hydropower	85 %	85 %
Nuclear power	90 %	84 %
Other condensing power	90 %	58 %
Wind power	11 %	11 %
CHP	90 %	70 %
Gas turbines	90 %	15 %
Solar power	0 %	0 %

In order to maintain a reliable power system during the coldest winter days where electricity consumption looks set to exceed production, Svenska Kraftnät secures a special power reserve during the period between 16th of November and usually the 15th of March [79]. The Swedish TSO can integrate power generators that have backup power plants, providing additional electricity generation or either enter into contracts with large electricity users and suppliers, concerning them to reduce their electricity consumption [80].

Under normal conditions, the power balance should be also maintained. This requires access to baseload production reserves, such as hydropower, CHP and gas turbines, or imports from other countries [67]. Nevertheless, flexible power consumption can contribute.

Hydropower is not only the main electricity production source but also the most important load-balancing source in Sweden. It is used in a wide range of situations from seasonal load balancing to maintain the frequency in the system, although hydro annual energy production varies between dry (50TWh/y) and wet year (80TWh/y) [67].

CHP plants produce heating and electricity at the same time. CHP delivers mainly during the winter when Swedish heating demand is higher. Consequently, the available capacity that the CHP provides is higher during the winter. Currently, CHP is not integrated in the load-balancing system, but it is technically possible [40].

Nuclear power has a high capacity value, but usually does not take part of the load-balancing, since it is considered too slow to modify its production.

As previously presented, Wind turbines are highly dependent on the wind conditions has a low available capacity value. On the other hand, wind turbines are easily used to regulate electricity production downwards [67] and can actively be integrated in the reserve capacity [81].

8.1 Future potential of different power resources

Referring to the future electricity production in Sweden, the system is experiencing a rapid transformation from large central plants with long operating periods over the year to smaller and decentralised ones where production is totally dependent on the weather. This transformation is modifying the situation not only for the existing plants but also the investment in new ones.

Large power plants with an intensive required investment (nuclear plants) are experiencing a substantial reduction on their operating hours when an increasing proportion of wind power with very low variable costs puts pressure on the electricity price [67], pushing down the electricity price. The low prices make more difficult to invest in new plants. This trend is also affecting the European markets [67].

Consequently, in 2015 Vattenfall and E.ON. decided to close four older nuclear reactors by 2020, removing 2.7 GW [82]. The main reason for the closure is the poor profitability of the plants. Indeed, Sweden introduced an additional tax for nuclear production about 0.75€/kWh, increasing 33% its operating costs and aggravating the nuclear power crisis. The tax will be phased out by 2019 [82]. To conclude, in 2016 the Swedish government announced its intention to shut down all the present operating nuclear reactors (9.1 GW) by 2050.

Swedish environmental scopes (Table I) combined with the government decision to shut down the actual nuclear power plants enables new possible scenarios in the future electricity production. The potential of different production methods will be covered in this section.

Hydropower installed capacity is around 16.2 GW, but the power delivered can vary between 2.5 GW and 13.7 GW depending on the annual precipitation [34]. Some authors, as Korsfeldt [83] declares that the technical potential to expand hydropower will be by around 30 TWh (today Swedish hydropower delivers around 65 TWh a year). However, most of the potential cannot be built due to the political decision to protect the four national rivers: Kalixälven, Piteälven, Torneälven and Vindelälven [84]. Indeed, hydropower could be adapted to offer more storage capacity and load-balancing capacity, but with the actual regulations it is not possible [67].

Onshore wind power potential seems to be a very important tool to achieve Swedish goals. The Swedish Energy Agency [85] estimates in 160 TWh the onshore wind energy potential (see Figure 38).

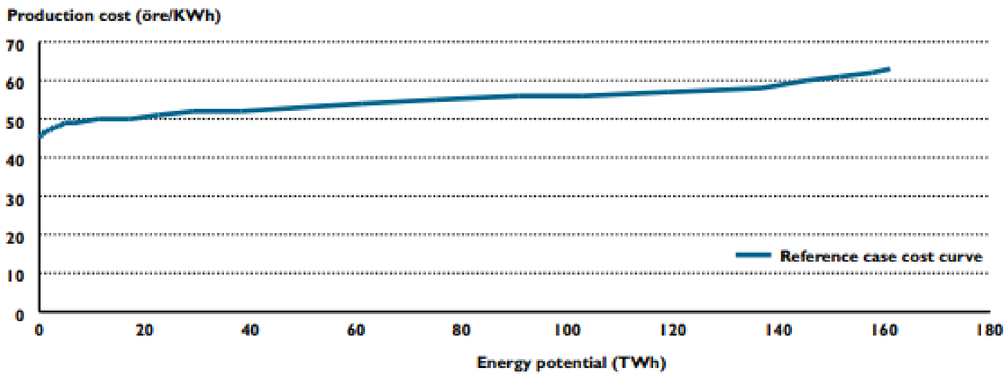


Figure 38. Production cost curve for wind power projects in Sweden [85]

Additionally, offshore wind power is getting more popular over Swedish neighbours (Norway, Denmark and UK) and will also play an important role in Swedish electricity production.

Referring to solar power, its production is mainly produced between March and October. It is not assigned any capacity value since the peak loads take place in winter and will not help to balance the grid. Nevertheless, Kamp [86] studies shows a potential solar power of 48 GW. Unfortunately, this potential will not resolve the lack of available capacity during winters.

Bioenergy can also be an important source for electricity production in Sweden. It is determined by the availability of bio raw materials and the technology used. In 2016, 139 TWh were produced by biomass, 14 TWh for electricity production (see Figure 39). Svenska Energi [87] estimates that biomass extraction could increase in 25-45 TWh in current conditions without competing with agriculture and forest production and up to 55-70 TWh within 30 years. Alternatively, the biomass can be used to produce biofuels and biogas.

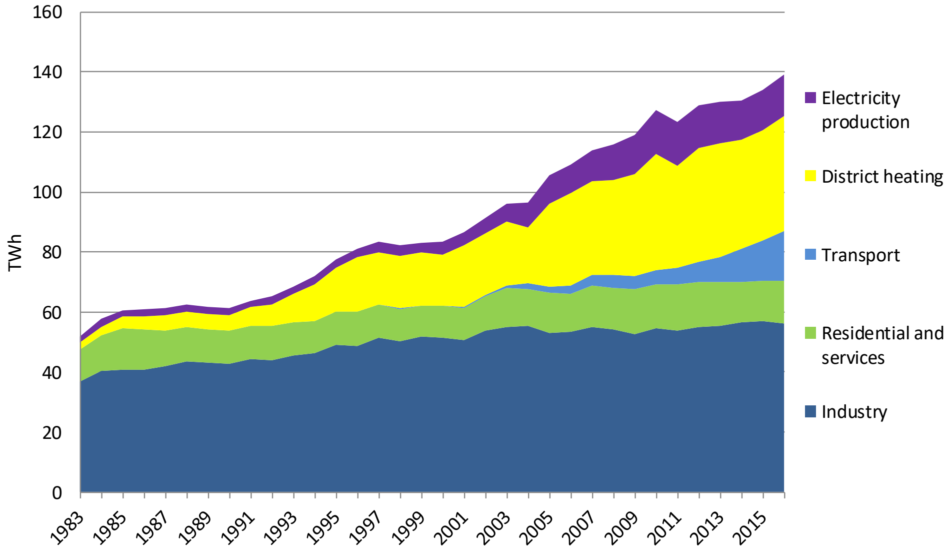


Figure 39. Use of biomass, per sector, from 1983 in Sweden based on [4]

Electricity production based on biofuels takes mostly place in the CHP plants producing heat and electricity, whereas the biogas is replacing the natural gas in CCGT. CCGT is highly suitable as load-balancing source [67]. New CHP technologies, supported by Vattenfall, are aiming to provide 55-60% of efficiency [88], instead of 25-28% of the current CHP plants [89]. Indeed, these technologies could double the CHP electricity generation but are still developed in a small scale.

Furthermore, electricity and heat markets may experience better coordination in the future. Electric heating is one of the main causes of consumption peaks during the winter. There are two options to reduce the peaks loads: better building insulation or use another form of heating [67]. Electric heating can be replaced by district heating, the installation of a small CHP generator would be a possibility, reducing the peak loads during winter and adding more available electric capacity.

This is exactly the tendency that Sweden is following. The use of fuel oil and electric heating as heat sources has dramatically decreased over the last decades, contrary to the district heating share Figure 40.

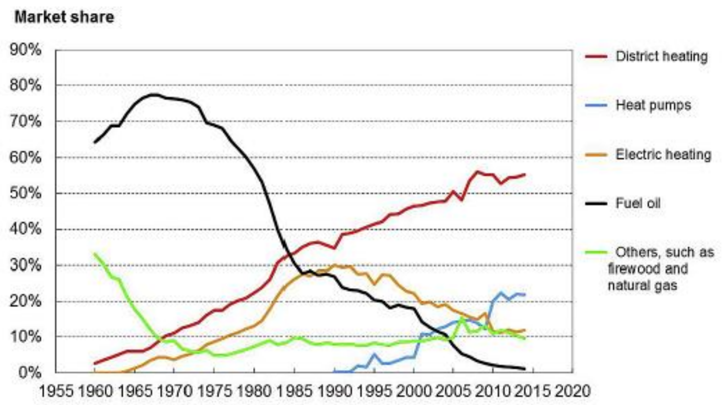


Figure 40. Market shares for heat supply to residential and service sector buildings in Sweden between 1960 and 2014 with respect to heat delivered from various heat sources [90]

Nevertheless, the heat supplied from district heating comes mostly from recycled heat and CHPs, as it is shown in Figure 41. Biomass has become the principal fuel of district heating replacing the fossil fuels and provides significant available capacity for the electricity market.

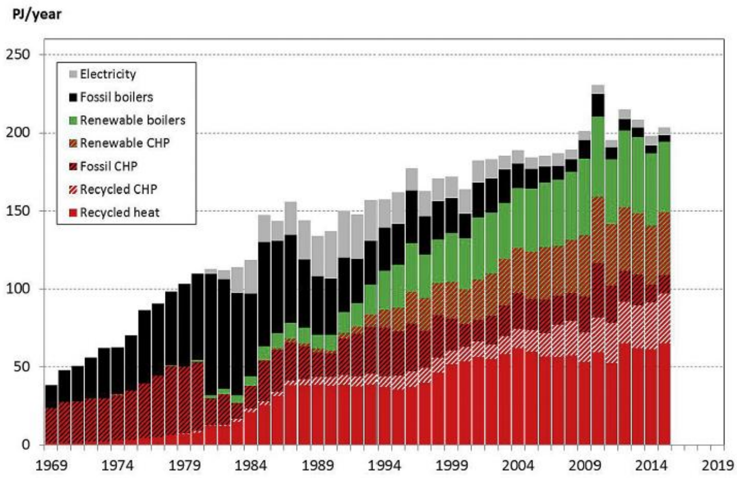


Figure 41. Heat supplied into Swedish district heating systems 1969-2015 according to seven different heat supply methods [90]

To conclude, The North European Power Perspectives (NEPP) organisation anticipates a considerable increase on Sweden's capacity until 2050 for a 100% renewable electricity system case. The expectations are shown in Figure 42. In 2045, the installed capacity will increase up to 62 GW while the maximum electrical power requirement is expected to increase at slower and reach just over 30 GW [91].

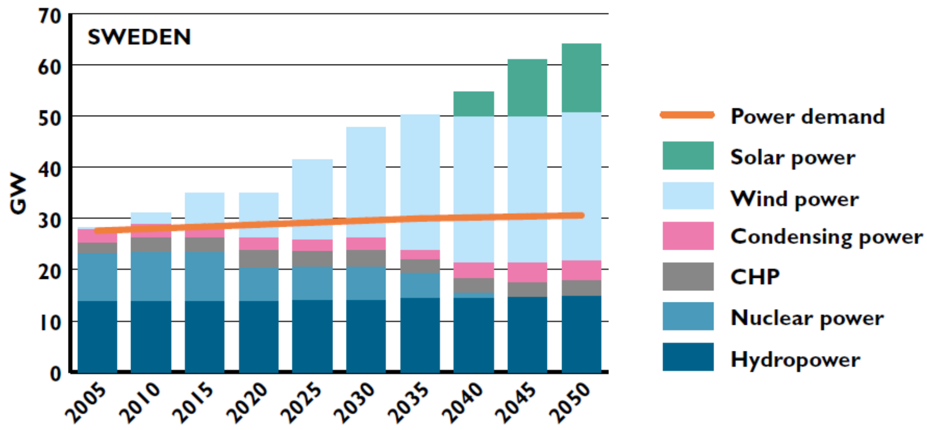


Figure 42. Future installed capacity in Sweden from [91]

In contrast, most of the installed capacity will not be totally available during peak hours. The report from IVA Electricity Crossroads project [91] analyses NEPP predictions stating that "*a capacity deficit may still occur during periods when wind and solar cannot produce*".

Certainly, the power source election will increase the installed capacity of Sweden but not its available capacity during peak loads, requiring the import of additional power to balance the grid and increasing the volatility of the electricity price.

Demand and Supply data creation

The data creation starts with the finding of the Swedish generators that form the supply side of the power market. ENTSO-E, the European Network of Transmission System Operators, which represents 43 European electricity transmission system operators (TSOs), gives the current installed capacity each generator above 100 MW installed capacity [92]. In total, ENTSO-E shows 64 generators, with a total current installed capacity of 21.46 GW. The data does not cover generators under 100 MW, therefore the data cannot consider complete. Figure 43 shows the installed capacity per type of unit given by ENTSO-E data.

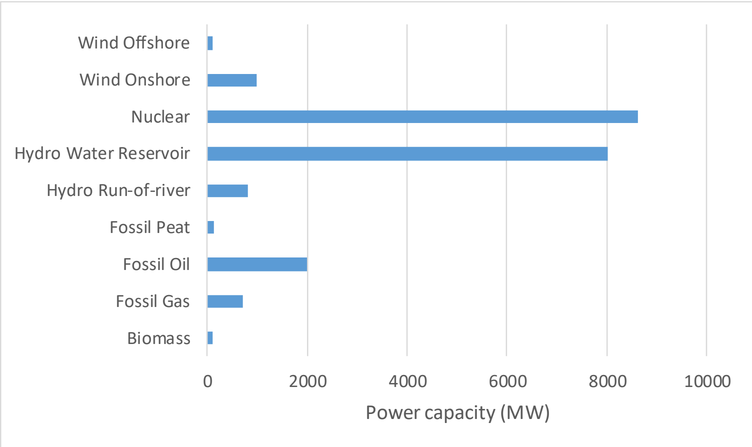


Figure 43. ENTSO-E Swedish generator data [92]

Photovoltaic energy is not included, Energymyndigheten [93] shows that the Photovoltaic generation was still the 0.1% of the total supply in 2017 (Figure 44), thus it can be removed from the simulation.

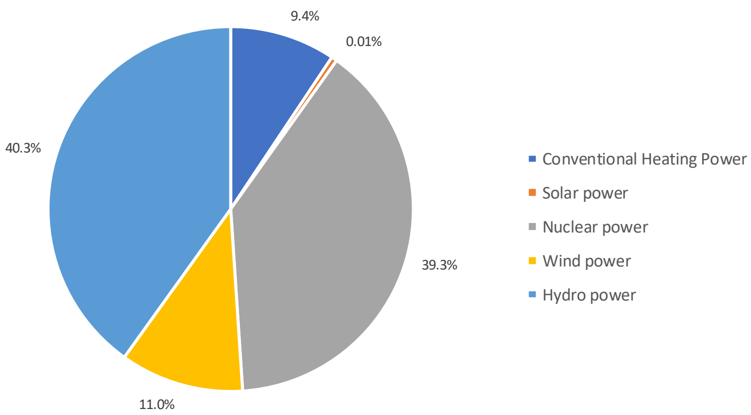


Figure 44. Swedish electric production per type of power 2017. Based on [55]

Variable energy sources will not be simulated. Instead, the power generated from these sources will be removed from the demand, simplifying the UC problem. Variable energy sources include Offshore wind power, Onshore wind power and Solar power.

As previously presented, Svenska Kraftnät [77] expected an available capacity of 28.2 GW for the winter 2015/2016. The available capacity was calculated in the following Table XXV. Removing the available capacity of wind power gives 27.5 GW.

Table XXV. Expected available capacity winter 2015/2016, Sweden without considering Wind Power, based on [77]

Power type	Capacity share (%)	Available capacity (GW)
Hydropower	49.82	13.7
Nuclear power	29.67	8.16
Gas turbines + other	0.84	0.23
Condensing power	5.75	1.58
CHP	13.93	3.83
Solar power	0	0
Total	100	27.5

The generators that will be simulated in the UC problem will emulate the available mix capacity of 27.5 GW previously calculated. The data from ENTSO-E gives the maximum power output of Swedish generators as well as the type of unit. The generator constraints (minimum power output, ramp rate, etc.) that are unknown will be assumed based on academic reports.

To make connections between both findings, some assumptions need to be done. Based on the background theory, the available mix capacity from Svenska Kraftnät is referred to the type of generator unit, given by ENTSO-E, shown in Figure 45.

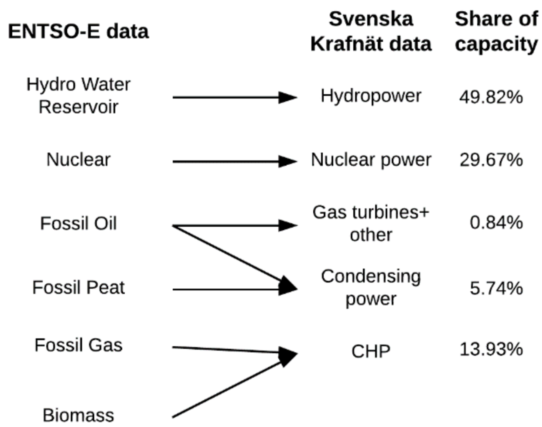


Figure 45. Connections between findings

Due to solver computational limitations the total available capacity will be downscale to half of it. Therefore, instead of 27.5 GW, the UC problem will simulate for around 13.75 GW, but with the same capacity share per power type. The demand side will be also downscaled.

The next step is to select the generators of each type of unit. In total, 37 generators will be simulated: 25 Hydro Water Reservoir, 4 Nuclear plants, 1 Gas turbine, 2 Condensing plants and 5 CHP plants[5], with a total capacity of 13.67 GW.

Availability factors are not considered for this simulation and run-of-river generators will not be taken into account due to lack of data. As well, it is not a crucial type of generator in unit commitment problems.

The demand simulated will correspond with the Swedish consumption over the 14th of December 2018. The data can be found on the Nord Pool website [29] and it is hourly given.

The selected day coincides with one of the highest Swedish consumptions over the present winter until now (see Figure 46). Therefore, it is an interesting period to analyse how the available generators behave to maintain the power balance.

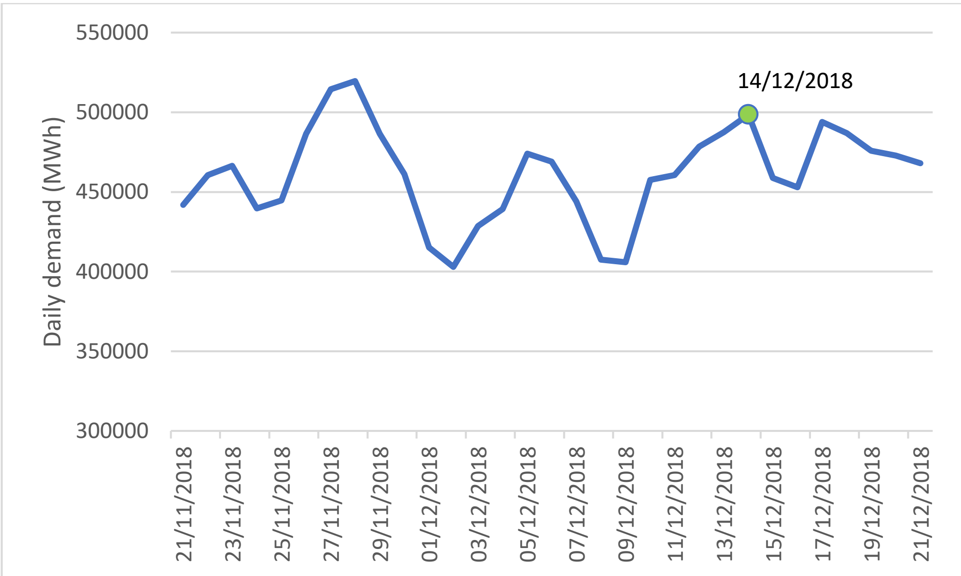


Figure 46. Swedish daily consumption from 21/11/2018 until 21/12/2018 based on [29]

Figure 47 shows the hourly Swedish consumption and wind power generation. Since the UC commitment simulation will not consider the wind power generation as part of

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[5] Öresundsverket CHP plant is repeated 4 times since it is the only CHP plant in ENTSO-E. Most of the Swedish CHP are Small-scale biomass CHP (<20MW), and therefore are not listed in ENTSO-E data units [56]M. Salomón, T. Savola, A. Martin, C.-J. Fogelholm, and T. Fransson, "Small-scale biomass CHP plants in Sweden and Finland," *Renewable and Sustainable Energy Reviews*, vol. 15, no. 9, pp. 4451-4465, 2011/12/01/ 2011.

the supply side, the wind power generation should be removed from the demand. The resulting demand is also plotted in the Figure 47.

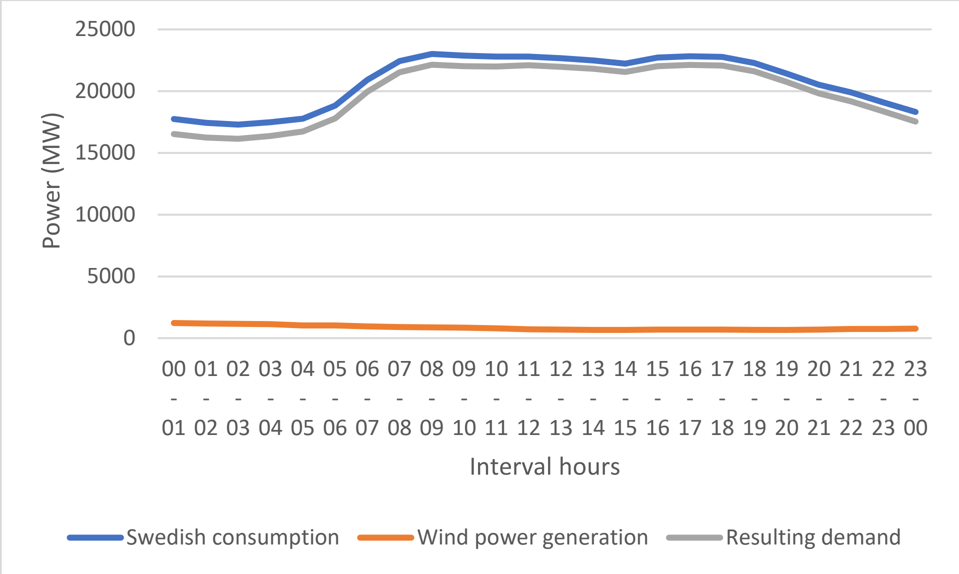

Figure 47. Hourly Swedish Consumption, Wind power generation and demand simulated based on [29]

As previously highlighted, due to computational limitations the demand simulated will be half of the resulting demand. Thus, supply and demand have been equally downscaled. Downscaling the demand and supply permits to increase the number of time periods without altering the flexibility constraints.

The demand is given per hour whereas the UC commitment simulation will simulate in intervals of a minute. An additional assumption should be done:

For each hourly period the power consumption (in MW) will be maintained. For example, for the first hour from 00:00 until 01:00 the demand will be 8259.5 MWh, which is the same as demanding 8259.5 MW of power within an hour. Thus, for each minute the power demanded will be 8259.5 MW until the next hour period.

Sweden simulation results

Case 1

- Simulation for 24 hours (1440 minutes).
- Demand from the 14th of December 2018.

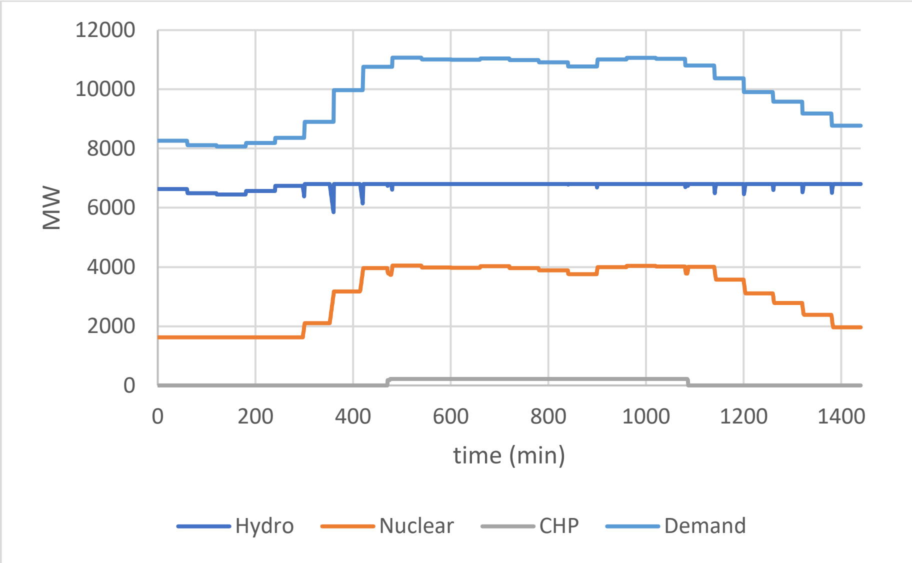

Figure 48. Case 1: Power delivered per type of unit

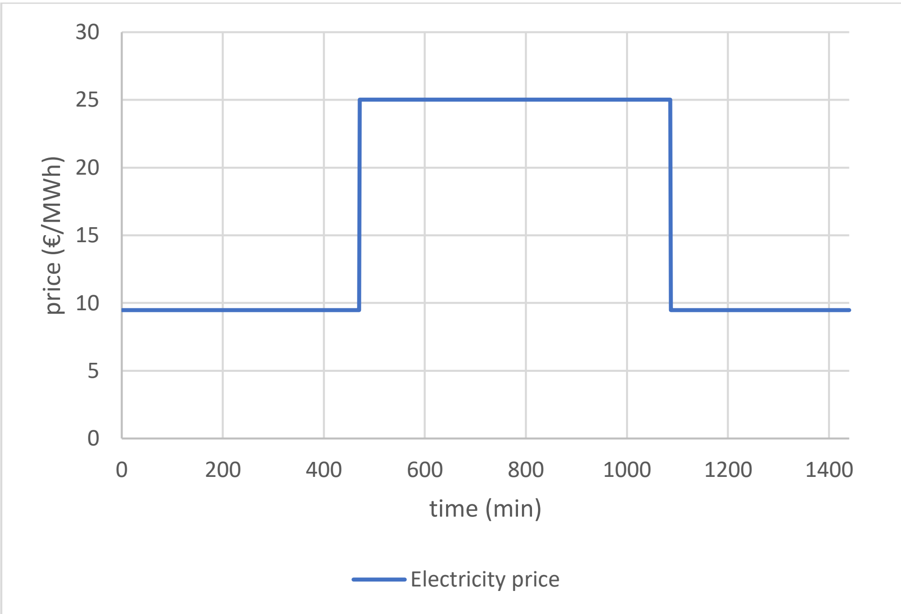

Figure 49. Case 1: Electricity price

Case 2

- Simulation for 24 hours (1440 minutes).
- 120% of the demand from the 14th of December 2018.

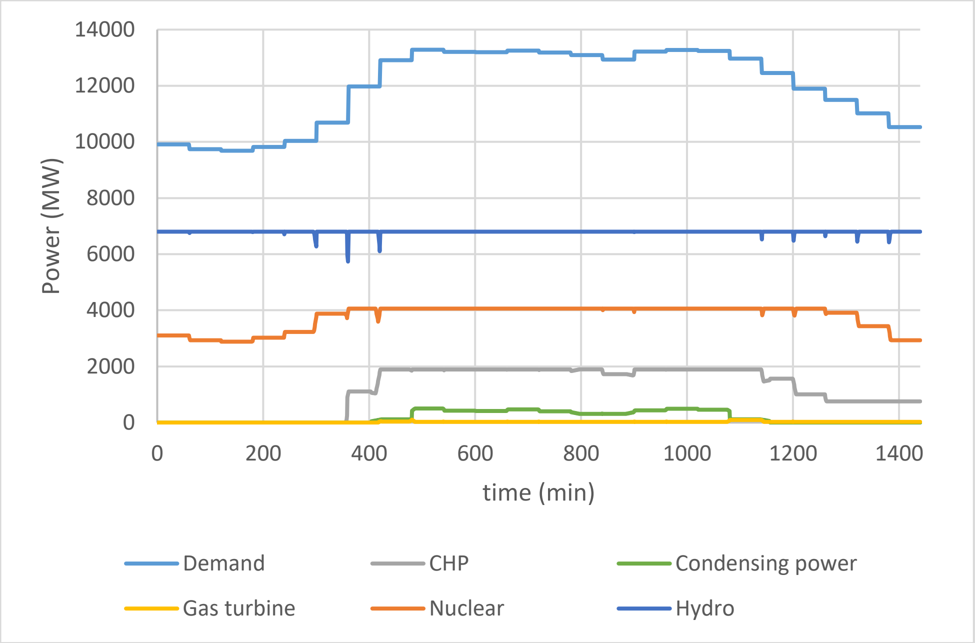

Figure 50. Case 2: Power delivered per type of unit

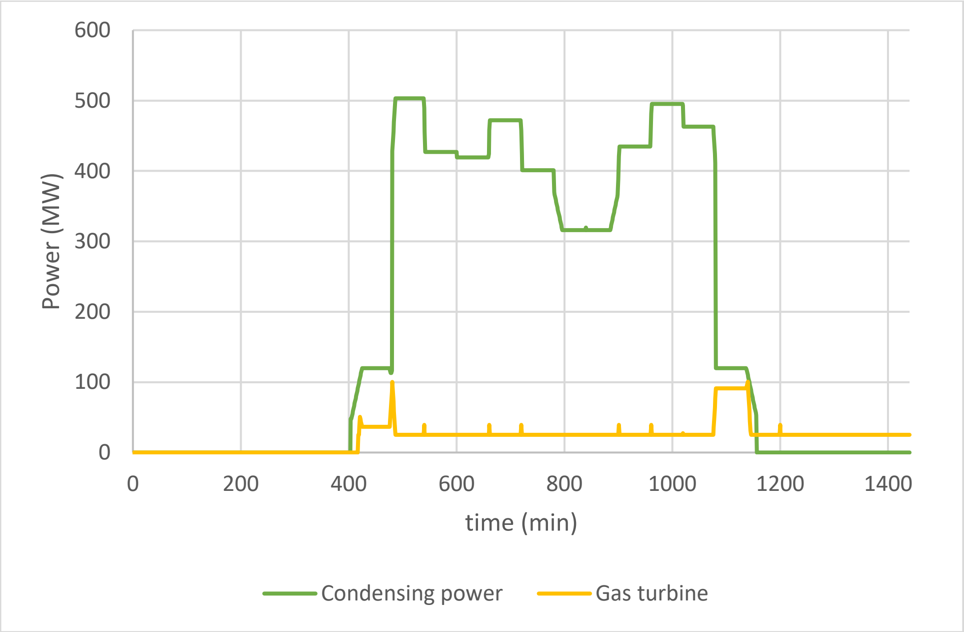

Figure 51. Case 2: Power delivered by Condensing power and Gas turbine

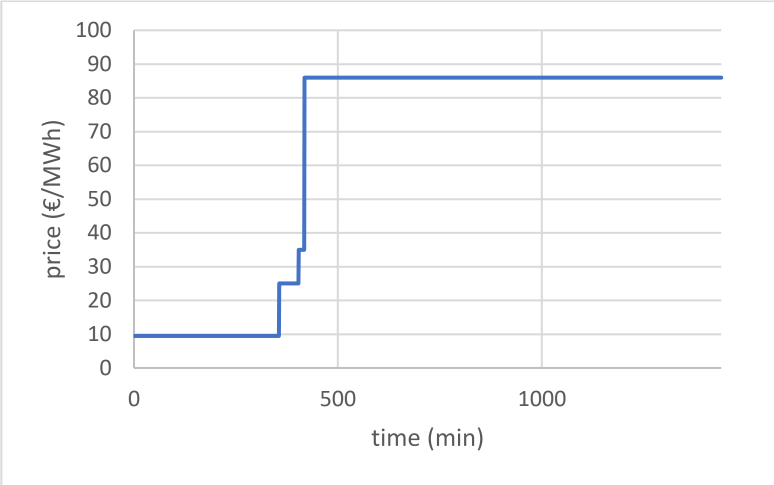

Figure 52. Case 2: Electricity price

Case 3

- Simulation for 72 hours (4320 hours).
- Demand from the 14th of December 2018, repeated 3 times.

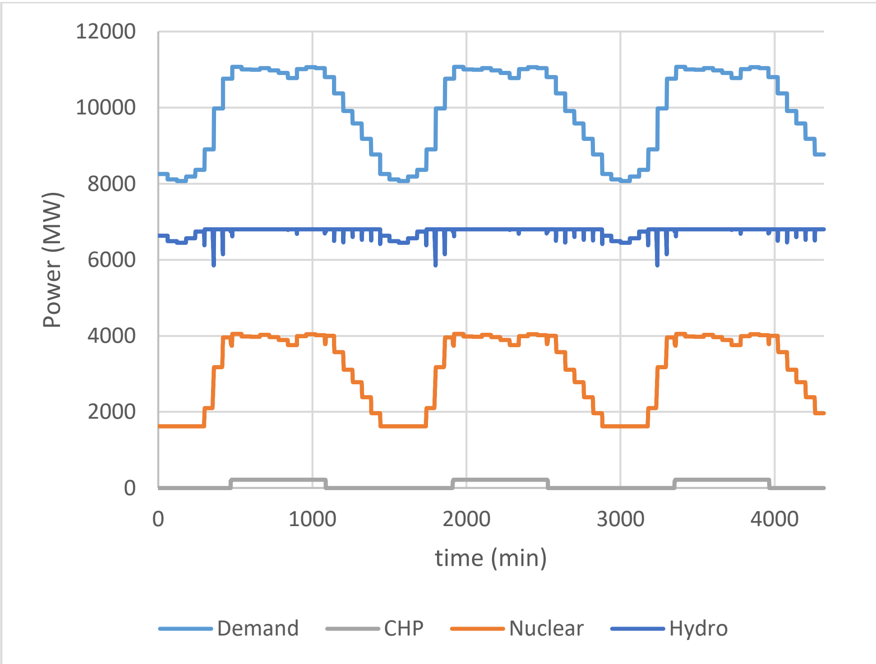

Figure 53. Case 3: Power delivered per type of unit

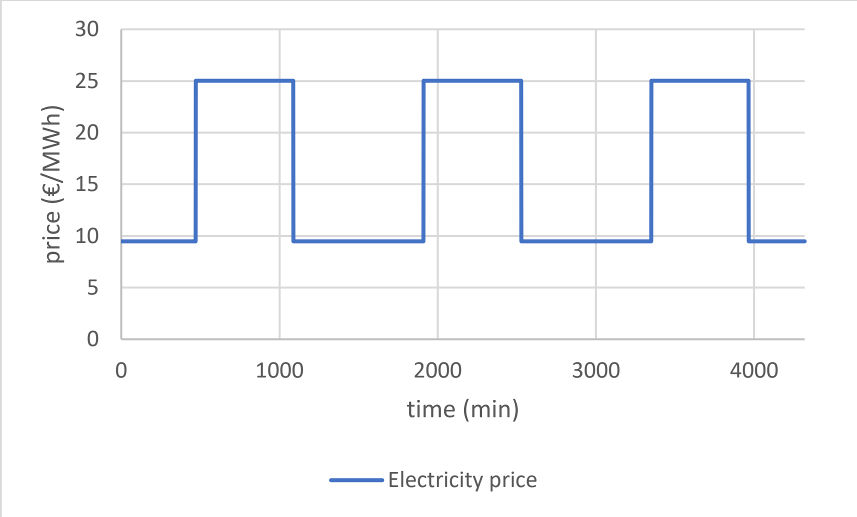

Figure 54. Case 3: Electricity price

Case 4

- Simulation for 72 hours.
- 120% of the demand from the 14th of December 2018, repeated 3 times.

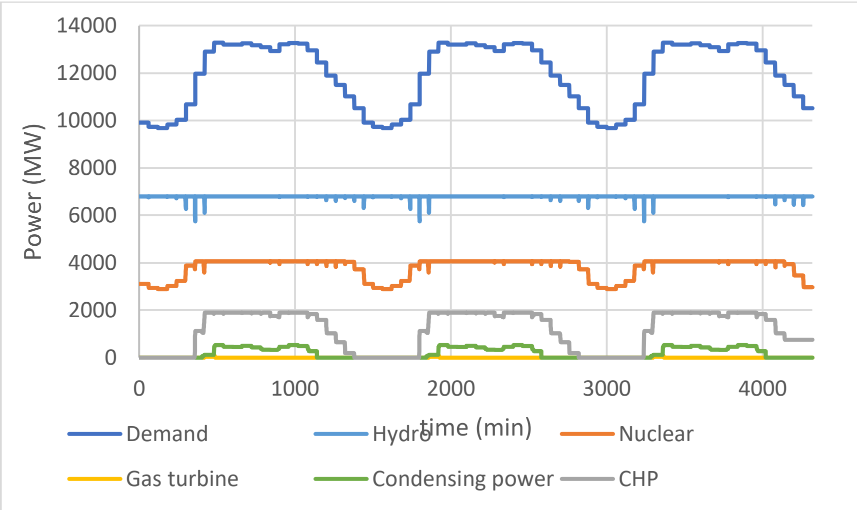

Figure 55. Case 4: Power delivered per type of unit

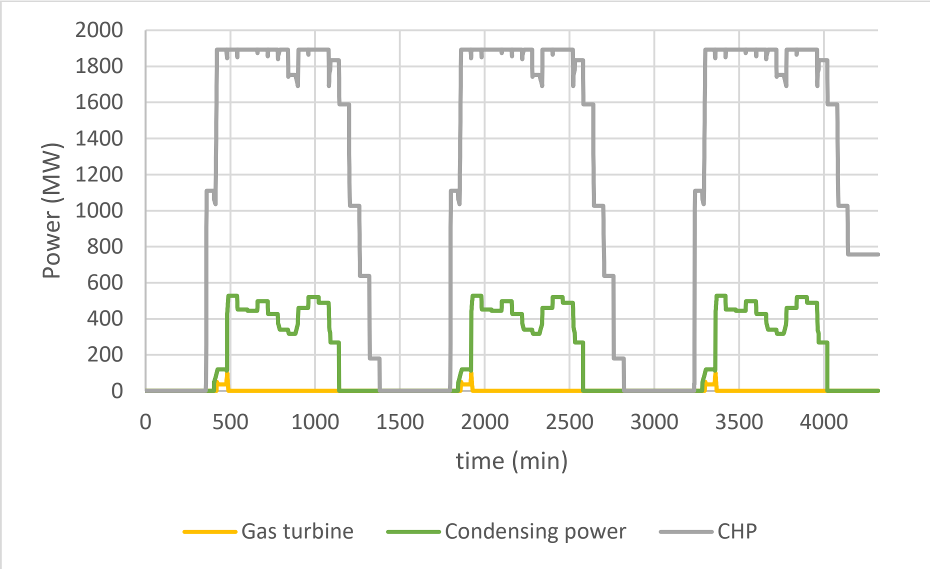

Figure 56. Case 4: Power delivered by CHP, Condensing power and Gas turbine

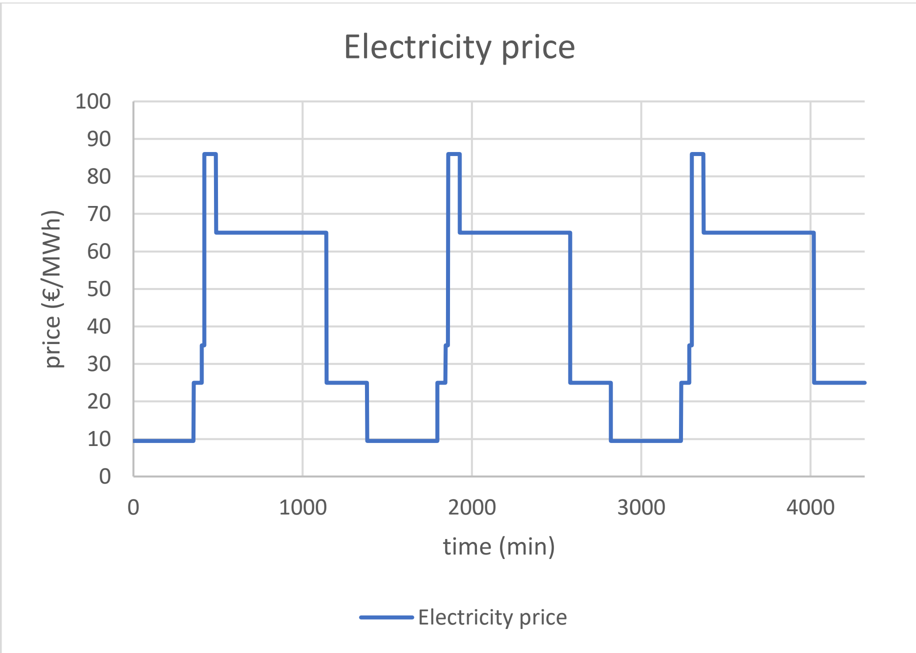

Figure 57. Case 4: Electricity price

Discussion on the Sweedish simulation

With the results presented in the previous Appendix sections, it is possible to confirm that the supply side has successfully fulfilled the power demand at any time for the 4 different cases.

As expected, in Case 1 hydro power (67.71% of total production) and nuclear power (31.35%) have been the main suppliers, working most of the time at maximum power and with a capacity factor of 99.20% and 76.20% respectively (Table XXVI). The nuclear plant started working at minimum power output. Due to high nuclear shutdown costs and minimum down time, the model did not find optimal to turn off one nuclear plant and letting the hydro power operate at maximum power. Instead, hydro reaches its maximum power hours later.

Nevertheless, CHP plants (0.94%) have been turned on between 7:51 am and 18:06 pm to give support during the peak-load hours (see Figure 48). During this period, hydro and nuclear do not steadily operate at maximum power. CHP is needed to fulfil the demand when hydro and nuclear are already working at their maximum. This requirement occurs two periods, from 8:01 am to 9:01 am and from 16:01 am to 17:01 pm. Between both, instead of disconnecting the CHPs, the model finds more optimal to let them operate at minimum power.

The electricity price can be divided in 2 periods. When CHPs are operating, the price rises to 25€ €/MWh, corresponding with the peak hours of the day. The remaining hours (off-peak hours), from 00:00 am to 7:50 am and from 18:07 pm to 23:59 pm, the price remains at 9.5 €/MWh, cleared by the nuclear plants.

Table XXVI. Case 1: Total production, capacity factor and share per type of unit

Type of unit	Total production (GWh)	Share of production (%)	Capacity factor (%)
Hydro power	161.95	67.71	99.20
Nuclear power	74.98	31.35	76.57
CHP	2.25	0.94	4.95
Total	**239.18**		

In constrast, Case 2 required the 5 types of unit simulated due to the increase on the demand simulated (See Figure 50). As in Case 1, hydro power (56.84% of total production) and nuclear power (31.45%) remain as base-loads. CHP (9.95%), Condesing power (1.58%) and the GT (0.18%) have been turned on during the peak-load hours (Figure 50).

It is important to analyse the GT's behaviour. First of all, the GT turns on at 6:58 am and does not disconnect during the simulation. It stays at minimum power until the end avoiding the shutdown costs. Secondly, it is possible to distinguish two periods where GT increases its production (see Figure 51). Both periods do not match with the maximum peak loads. Instead, occur when the load is going to change widely. Thus, the GT is helping when the other units that cannot rapidly change its production (i.e. ramp rate). The first period corresponds with the ramp up and the second one with the ramp down of the demand. Consequently, the electricity price dramatically rises to 86 €/MWh at 6:58 am when GT turns on until the end of the day (Figure 52).

Compared to Case 1, nuclear capacity factor increases (92.61%) and work under maximum power most of the day because for case 2 the demand is 20% higher than in the previous one. CHP works with a capacity factor of 62.89%, which is quite high for non base-loads. Analyzing both electricity prices together, it is possible to conclude that a 20% increase on the demand can widely rise the price of electricity, since units with a high MC clear the price.

Table XXVII. Case 2: Total production, capacity factor and share per type of unit

Type of unit	Total production (GWh)	Share of production (%)	Capacity factor (%)
Hydro power	163.13	56.84%	99.92%
Nuclear power	90.26	31.45%	92.61%
CHP	28.56	9.95%	62.89%
Condensing power	4.54	1.58%	23.93%
Gas turbine	0.52	0.18%	17.20%
Total	**287.01**		

Moving on to the 3-days simulations, Case 3 gives a very similar operation schedule of the generating units as Case 1 does (Figure 53). CHP plants are daily connected from 7:51 am to 18:08 pm and operate in the same way as in Case 1. As Table XXVI and Table XXVII reflect, the share of production and the capacity factor per type of unit are almost the same for both cases.

The electricity prices also follow the same distribution as in case 1. The peak hour price is 25€/MWh and 9.5 €/MWh for off-peak hours (Figure 54).

Table XXVIII. Case 3: Total production, capacity factor and share per type of unit

Type of unit	Total production (GWh)	Share of production (%)	Capacity factor (%)
Hydro power	485.83	67.71%	99.20%
Nuclear power	224.94	31.35%	76.93%
CHP	6.75	0.94%	4.95%
Total	**717.51**		

To conclude, Case 4 results (Figure 55) are very similar to Case 2 ones (Figure 50). Just by comparing the capacity factors it is possible to declare that Hydro and Nuclear power almost behave in the same manner in both cases. Though, the GT only is connected during the ramp up of the demand (Figure 56). Afterwards, it turns off. Unlike Case 2, the GT is not needed when the demand ramps down. Thus, GT capacity factor (1.55%) is much lower than in case 2 (17.20%).

The electricity price experience a wide range of prices (Figure 57):

- From 00:00 am to 5:56 am, the electricity price is 9.5€/MWh, cleared by the nuclear power.
- From 5:57 am to 6:43 am, the CHPs turn on and price rises to 25€/MWh.
- From 6:44 am to 6:57 am, the Peat power plant (condensing power) clears the price at 35€/MWh.
- From 6:58 am to 8:07 am, the GT is turned on, being the Oil power plant (condensing power) still disconnected, and price reaches its maximum (85€/MWh).
- From 8:08 am to 19:00 pm, begins its descent and the Oil power plant clears the price for several hours at 65€/MWh.

- From 19:01 pm to 23:00 pm, the price goes again to 25€/MWh.
- From 23:01 to 00:00 am, the nuclear power establish the price at 9.5€/MWh until next day. This period do not occur during the last day of the simulation.

During the last day of the simulation the CHP plants do not turn off. As previously explained, the model finds more optimal to keep them connected and avoid the shutdown cost.

Table XXIX. Case 4: Total production, capacity factor and share per type of unit

Type of unit	Total production (GWh)	Share of production (%)	Capacity factor (%)
Hydro power	489.39	56.84%	99.93%
Nuclear power	273.93	31.81%	93.68%
CHP	82.83	9.62%	60.80%
Condensing power	14.72	1.71%	25.88%
Gas turbine	0.14	0.02%	1.55%
Total	**861.01**		

The UC model minimizes the total cost of generation. This approach generates certain decision making that collides with the reality in power system. For example, as previously highligthed, some generators are maintained connected during the end of the simulation to avoid the shutdown costs. In practice, there is no way to avoid the shutdown costs, since the time horizon is infinite. Thus, a UC model could not avoid but at least delay it or minimize its effect by expading the time horizon of the simulation. Unfortunately, due to the solver computational limitations it is not always possible to expand it. A well-designed, sophisticated and efficient code (i.e using optimization shortcuts) can provide a wider time horizon but it will not make an important difference.

The decision of simulating per minute has limited not only the time horizon but also the number of generators. Indeed, the simulation is very accurate and also models the GT behaviour to support quick ramp up and ramp down of the demand. Therefore, simulating per minute or per hour has in both cases different advantages. Depending on the approach of future research, one of the choices will be selected for further work.

The present simulation has proven the diverse grades of flexibility that different generators can offer to the power system. The MC is not the only parameter to take into account to solve a unit commitment problem. In some cases, as Case 2 represents, during drastic changes in the demand the GTs can provide support to base-loads unit with lower ramp rate (i.e nuclear plants), although GT is the most expensive unit. Additionaly under special conditions, GT can have preference over cheaper units, as in Case 4, where the Oil plant remains disconnected while the GT is operating. GT provides higher flexibility than other types of unit.

The simulation also shows the volatility of the electricity prices due to the integration of VRES with a low MC. The VRES requires additional available and flexible capacity to satisfy the power demand. When the VRES are not able to fullfil the demand (specially during Swedish winter season) these capacities are turned on, clearing the market at a high price. In contrast, when there is an excess of capacity the price plummets.

The generators that support the power system when the VRES are not producing are getting paid by its MC. Unfortunately, it will not cover all the production expenses. The start-up and shutdown cost are not considered, neither its investment cost. Therefore, most of these generators are disappearing from the current power markets. The capacity markets are providing these generators with additional income. Yet, these markets have not been critical to initite new investments, as Caplan [94] emphasizes, and have been difficult to design due to the difficulty in anticipating required levels and types of capacity Milligan [95]. Also, the fall in the price of electricity does not help.

The proposed UC model does not work perfectly. The assumption of maintaining the power demand constant for each hour (i.e 60 minnutes) creates minor disturbances on the simulations. For example, from 00:00 am to 0:59 am the power demand is constant. But from 0:59 am to 1:00 am the demand jumps up to the next hourly demand. This singularity disturbes the UC solution. In case the hydro power is operating at maximum power and a jump on the demand is coming soon, the hydro will decrease its maximum power and the nuclear power will start increasing/decreasing it in advance because the nuclear power is not able to ramp up/down quickly enough from 0:59 am to 1:00 am. Figure 58 shows the disturbances.

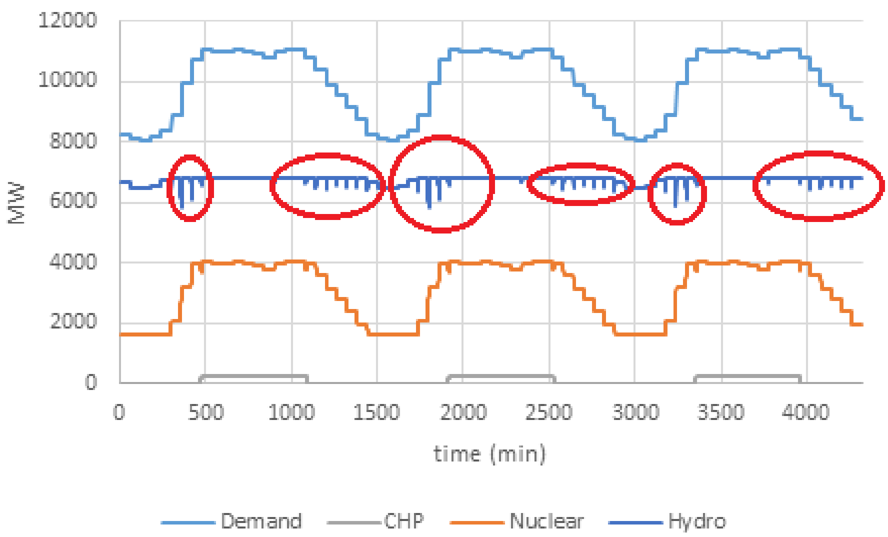

Figure 58. Disturbances highlighted in red, Case 3 results

Although, the disturbances do not considerably impact on the results, it could be possible to make them disappear by using interpolation on the creation of the demand. For simplicity and due to lack of time, this assumption was not considered.

Appendix C

Code 1. Hourly demand conversion model to 1 minute based

```
clear all
clc

power_min=zeros(1,11520);
A=xlsread("DATA INPUT.xlsx","DEMANDG","F3:F194");

% dataa is the demand per hour given by NordPool
[row, col] = size(A);
B=A;
B(1)=[];
B(row)=B([row-1]);
W(1)=1;
W(2:row)=A(1:row-1);
W=W';

% The for loop works for the creation of stair demand.
%power_min is the final demand, you can see it in the plot
%In 60min power_min is 1x192, 15min -> 1x768, 5min -> 1x2304
for i=1:192

 if i==1
    for n=60*(i-1)+1:60*i-30
        power_min(1,n)=normrnd(A(i,1),0.00561*A(i,1));
    end
    for n=60*i-29:60*i
        mm=n-60*(i-1);
        power_min(1,n)= normrnd((61-mm)/30*A(i,1)+(mm-
31)/30*(A(i,1)+0.5*(B(i,1)-A(i,1))),0.00561*A(i,1));
    end
 end
 if i>1
    for n=60*(i-1)+1:60*i-30
        m=n-60*(i-1);
    power_min(1,n)= normrnd((30-m)/30*(A(i,1)+0.5*(W(i,1)-
A(i,1)))+m/30*A(i,1),0.00561*A(i,1));
    end
    for n=60*i-29:60*i
        mm=n-60*(i-1);
```

```
        power_min(1,n)= normrnd((61-mm)/30*A(i,1)+(mm-31)/30*(A(i,1)+0.5*(B(i,1)-A(i,1))),0.00561*A(i,1));
    end
 end
end

X=power_min.';
ttt=sum(power_min)/11520;
plot(power_min)
filename="C:\Users\Rodrigo\Desktop\Thesis 2.0\sim1Sweden\DEMAND DATA.xlsx";
xlswrite(filename,X,"demand", "H3")
```

Code 2. Hourly demand conversion model to 5 minutes based

```
clear all
clc

power_min=zeros(1,2304);
A=xlsread("DATA INPUT.xlsx","DEMANDG","F3:F194");

% dataa is the demand per hour given by NordPool
[row, col] = size(A);
B=A;
B(1)=[];
B(row)=B([row-1]);
W(1)=1;
W(2:row)=A(1:row-1);
W=W';

% The for loop works for the creation of stair demand.
%power_min is the final demand, you can see it in the plot
%In 60min power_min is 1x192, 15min -> 1x768, 5min -> 1x2304

for i=1:192
   if i==1
    for n=12*(i-1)+1:12*i-6
        power_min(1,n)=normrnd(A(i,1),0.00561*A(i,1));
    end
    for n=12*i-5:12*i
        mm=n-12*(i-1);
```

```
        power_min(1,n)= normrnd((13-mm)/6*A(i,1)+(mm-
7)/6*(A(i,1)+0.5*(B(i,1)-A(i,1))),0.00561*A(i,1));
    end
   end

 if i>1
    for n=12*(i-1)+1:12*i-6
        m=n-12*(i-1);
    power_min(1,n)= normrnd((6-m)/6*(A(i,1)+0.5*(W(i,1)-
A(i,1)))+m/6*A(i,1),0.00561*A(i,1));
    end
    for n=12*i-5:12*i
        mm=n-12*(i-1);
        power_min(1,n)= normrnd((13-mm)/6*A(i,1)+(mm-
7)/6*(A(i,1)+0.5*(B(i,1)-A(i,1))),0.00561*A(i,1));
    end
 end



end

X=power_min.';
ttt=sum(power_min)/2304;
%plot(power_min)
filename="C:\Users\Rodrigo\Desktop\Thesis 2.0\sim1Sweden\DEMAND DATA.xlsx";
xlswrite(filename,X,"demand","B3")
```

Code 3. Hourly demand conversion model to 15 minutes based

```
clear all
clc

power_min=zeros(1,768);
A=xlsread("DATA INPUT.xlsx","DEMANDG","F3:F194");

% dataa is the demand per hour given by NordPool
[row, col] = size(A);
B=A;
B(1)=[];
B(row)=B([row-1]);
W(1)=1;
```

```
W(2:row)=A(1:row-1);
W=W';

% The for loop works for the creation of stair demand.
%power_min is the final demand, you can see it in the plot
%In 60min power_min is 1x192, 15min -> 1x768, 5min -> 1x2304
for i=1:192

 if i==1
    for n=4*(i-1)+1:4*i-2
        power_min(1,n)=normrnd(A(i,1),0.00561*A(i,1));
    end
    for n=4*i-1:4*i
        mm=n-4*(i-1);
        power_min(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-
3)/2*(A(i,1)+0.5*(B(i,1)-A(i,1))),0.00561*A(i,1));
    end
 end
 if i>1
    for n=4*(i-1)+1:4*i-2
        m=n-4*(i-1);
    power_min(1,n)= normrnd((2-m)/2*(A(i,1)+0.5*(W(i,1)-
A(i,1)))+m/2*A(i,1),0.00561*A(i,1));
    end
    for n=4*i-1:4*i
        mm=n-4*(i-1);
        power_min(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-
3)/2*(A(i,1)+0.5*(B(i,1)-A(i,1))),0.00561*A(i,1));
    end
 end
end


X=power_min.';
ttt=sum(power_min)/768;
%plot(power_min)
filename="C:\Users\Rodrigo\Desktop\Thesis 2.0\sim1Sweden\DEMAND DATA.xlsx";
xlswrite(filename,X,"demand", "D3")
```

Code 4. Netherlands statistical analysis

```
%NETHERLANDS
```

```
clear all
clc
A15 = [];
A = [];

% dataa is the demand per hour given by NordPool
[row, col] = size(A);
B=A;
B(1)=[];
B(row)=B([row-1]);
W(1)=1;
W(2:row)=A(1:row-1);
W=W';

% The for loop works for the creation of stair demand.
%power_min is the final demand, you can see it in the plot
%In 60min power_min is 1x192, 15min -> 1x768, 5min -> 1x2304
for i=1:21168

 if i==1
    for n=4*(i-1)+1:4*i-2
        Ab(1,n)=normrnd(A(i,1),0*A(i,1));
    end
    for n=4*i-1:4*i
        mm=n-4*(i-1);
        Ab(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-3)/2*(A(i,1)+0.5*(B(i,1)-
A(i,1))),0*A(i,1));
    end
 end
 if i>1
    for n=4*(i-1)+1:4*i-2
        m=n-4*(i-1);
    Ab(1,n)= normrnd((2-m)/2*(A(i,1)+0.5*(W(i,1)-
A(i,1)))+m/2*A(i,1),0*A(i,1));
    end
    for n=4*i-1:4*i
        mm=n-4*(i-1);
        Ab(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-3)/2*(A(i,1)+0.5*(B(i,1)-
A(i,1))),0*A(i,1));
    end
 end
end
```

```
Ab=Ab';
for i=1:84672
    dev(i)=Ab(i)-A15(i);
end
%histogram(dev);

X=mean(A);
devt= sum(abs(dev))/(length(dev)*X)*100;

%% A30 basado en 15min
for i=1:42336

    A30(i)= (A15(2*i-1)+A15(2*i))/2;
end

A30=A30';
% Ab30 interpolar de 60min

for i=1:21168

 if i==1
    for n=2*(i-1)+1:2*i-2
        Ab30(1,n)=normrnd(A(i,1),0*A(i,1));
    end
    for n=2*i-1:2*i
        mm=n-2*(i-1);
        Ab30(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-3)/2*(A(i,1)+0.5*(B(i,1)-
A(i,1))),0*A(i,1));
    end
 end
 if i>1
    for n=2*(i-1)+1:2*i-2
        m=n-2*(i-1);
    Ab30(1,n)= normrnd((2-m)/2*(A(i,1)+0.5*(W(i,1)-
A(i,1)))+m/2*A(i,1),0*A(i,1));
    end
    for n=2*i-1:2*i
        mm=n-2*(i-1);
        Ab30(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-3)/2*(A(i,1)+0.5*(B(i,1)-
A(i,1))),0*A(i,1));
    end
```

```
 end
end

Ab30=Ab30';
for i=1:42336
    dev30(i)=Ab30(i)-A30(i);
end

%%

histogram(dev30);
title('Netherlands 30 minutes histogram')
xlabel('Deviation (MW)')
ylabel('Frequency')

X=mean(A);
devt30= sum(abs(dev30))/(length(dev30)*X)*100;
```

Code 5, Great Britain statistical analysis

```
%% 1-01-2016 // 31-05-2018
clc
clear all

A30=[];
A=[];
% dataa is the demand per hour given by NordPool
[row, col] = size(A);
B=A;
B(1)=[];
B(row)=B([row-1]);
W(1)=1;
W(2:row)=A(1:row-1);
W=W';

% The for loop works for the creation of stair demand.
%power_min is the final demand, you can see it in the plot
%In 60min power_min is 1x192, 15min -> 1x768, 5min -> 1x2304
for i=1:21168

 if i==1
```

```
    for n=2*(i-1)+1:2*i-2
        Ab(1,n)=normrnd(A(i,1),0*A(i,1));
    end
    for n=2*i-1:2*i
        mm=n-2*(i-1);
        Ab(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-3)/2*(A(i,1)+0.5*(B(i,1)-
A(i,1))),0*A(i,1));
    end
 end
 if i>1
    for n=2*(i-1)+1:2*i-2
        m=n-2*(i-1);
    Ab(1,n)= normrnd((2-m)/2*(A(i,1)+0.5*(W(i,1)-
A(i,1)))+m/2*A(i,1),0*A(i,1));
    end
    for n=2*i-1:2*i
        mm=n-2*(i-1);
        Ab(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-3)/2*(A(i,1)+0.5*(B(i,1)-
A(i,1))),0*A(i,1));
    end
 end
end


for i=1:42336
    dev(i)=Ab(i)-A30(i);
end
histogram(dev);

title('Great Britain 30 minutes histogram')
xlabel('Deviation (MW)')
ylabel('Frequency')

X=mean(A);
devt= sum(abs(dev))/(length(dev)*X)*100;
```

Code 6. Germany statistical analysis

```
clear all
clc
A15 = [];
A = [];
```

```
% dataa is the demand per hour given by NordPool
[row, col] = size(A);
B=A;
B(1)=[];
B(row)=B([row-1]);
W(1)=1;
W(2:row)=A(1:row-1);
W=W';

% The for loop works for the creation of stair demand.
%power_min is the final demand, you can see it in the plot
%In 60min power_min is 1x192, 15min -> 1x768, 5min -> 1x2304
for i=1:21168

 if i==1
    for n=4*(i-1)+1:4*i-2
        Ab(1,n)=normrnd(A(i,1),0*A(i,1));
    end
    for n=4*i-1:4*i
        mm=n-4*(i-1);
        Ab(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-3)/2*(A(i,1)+0.5*(B(i,1)-
A(i,1))),0*A(i,1));
    end
 end
 if i>1
    for n=4*(i-1)+1:4*i-2
        m=n-4*(i-1);
    Ab(1,n)= normrnd((2-m)/2*(A(i,1)+0.5*(W(i,1)-
A(i,1)))+m/2*A(i,1),0*A(i,1));
    end
    for n=4*i-1:4*i
        mm=n-4*(i-1);
        Ab(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-3)/2*(A(i,1)+0.5*(B(i,1)-
A(i,1))),0*A(i,1));
    end
 end
end

Ab=Ab';
for i=1:84672
    dev(i)=Ab(i)-A15(i);
end
```

```
histogram(dev);

X=mean(A);
devt= sum(abs(dev))/(length(dev)*X)*100;

%% A30 basado en 15min
for i=1:42336

    A30(i)= (A15(2*i-1)+A15(2*i))/2;
end

A30=A30';
% Ab30 interpolar de 60min

for i=1:21168

 if i==1
    for n=2*(i-1)+1:2*i-2
        Ab30(1,n)=normrnd(A(i,1),0*A(i,1));
    end
    for n=2*i-1:2*i
        mm=n-2*(i-1);
        Ab30(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-3)/2*(A(i,1)+0.5*(B(i,1)-
A(i,1))),0*A(i,1));
    end
 end
 if i>1
    for n=2*(i-1)+1:2*i-2
        m=n-2*(i-1);
    Ab30(1,n)= normrnd((2-m)/2*(A(i,1)+0.5*(W(i,1)-
A(i,1)))+m/2*A(i,1),0*A(i,1));
    end
    for n=2*i-1:2*i
        mm=n-2*(i-1);
        Ab30(1,n)= normrnd((5-mm)/2*A(i,1)+(mm-3)/2*(A(i,1)+0.5*(B(i,1)-
A(i,1))),0*A(i,1));
    end
 end
end

Ab30=Ab30';
for i=1:42336
```

```
    dev30(i)=Ab30(i)-A30(i);
end
%histogram(dev30);

title('Germany 15 minutes histogram')
xlabel('Deviation (MW)')
ylabel('Frequency')
X=mean(A);
devt30= sum(abs(dev30))/(length(dev30)*X)*100;
```

Appendix D

Table XXX. Share of production per type of source for the Swedish simulation in the four timesteps

Share of production

Type of Source	1-minute timestep		5 minutes timestep		15 minutes timestep		60 minutes timestep	
	Energy produced (GWh)	Share of production (%)	Energy produced (GWh)	Share of production (%)	Energy produced (GWh)	Share of production (%)	Energy produced (GWh)	Share of production (%)
Hydro	821	47%	821	47%	821	47%	821	47%
Nuclear	779	44.6%	779	44.6%	779	44.6%	779	44.6%
Gas Turbines	0	0%	0	0%	0	0%	0	0%
Oil	0	0%	0	0%	0	0%	0	0%
CHP	146	8.4 %	146	8.4 %	146	8.4 %	146	8.4 %

Appendix E

Table XXXI. Generator portfolio and its constraints for the Simple Case simulation of 6 generators

Source	DB code	Marginal Cost *(€/MWh)*	Pmax *(MW)*	Pmin *(MW)*	Ramp Up *(MW/h)*	Ramp Down *(MW/h)*	Start Up limit *(MW)*	Shutdown limit *(MW)*	Minimum Up Time *(h)*	Minimum Down Time *(h)*	Initial state	Initial ON counter *(h)*	Initial OFF counter *(h)*	Start up cost *(€)*	Shutdown cost *(€)*
Hydro	g25	1.5	132	9.0	3168	3168	10.4	9.9	0.5	0.5	1	120	0	396	396
Nuclear	g29	3.0	904	361.6	1627.2	1627.2	415.84	397.76	24	24	1	120	0	126560	126560
Gas	g30	62.0	126	25.2	831.6	831.6	28.98	27.72	0.25	0.25	0	0	120	1700	1700
Gas	g30	62.0	126	25.2	831.6	831.6	28.98	27.72	0.25	0.25	0	0	120	1700	1700
Oil	g31	63.0	670	268	1809	1809	308.2	294.8	2	2	0	0	120	7000	7000
CHP	g33	40.0	448	179.2	1344	1344	206.1	197.1	1	1	0	0	120	2250	2250

Appendix F

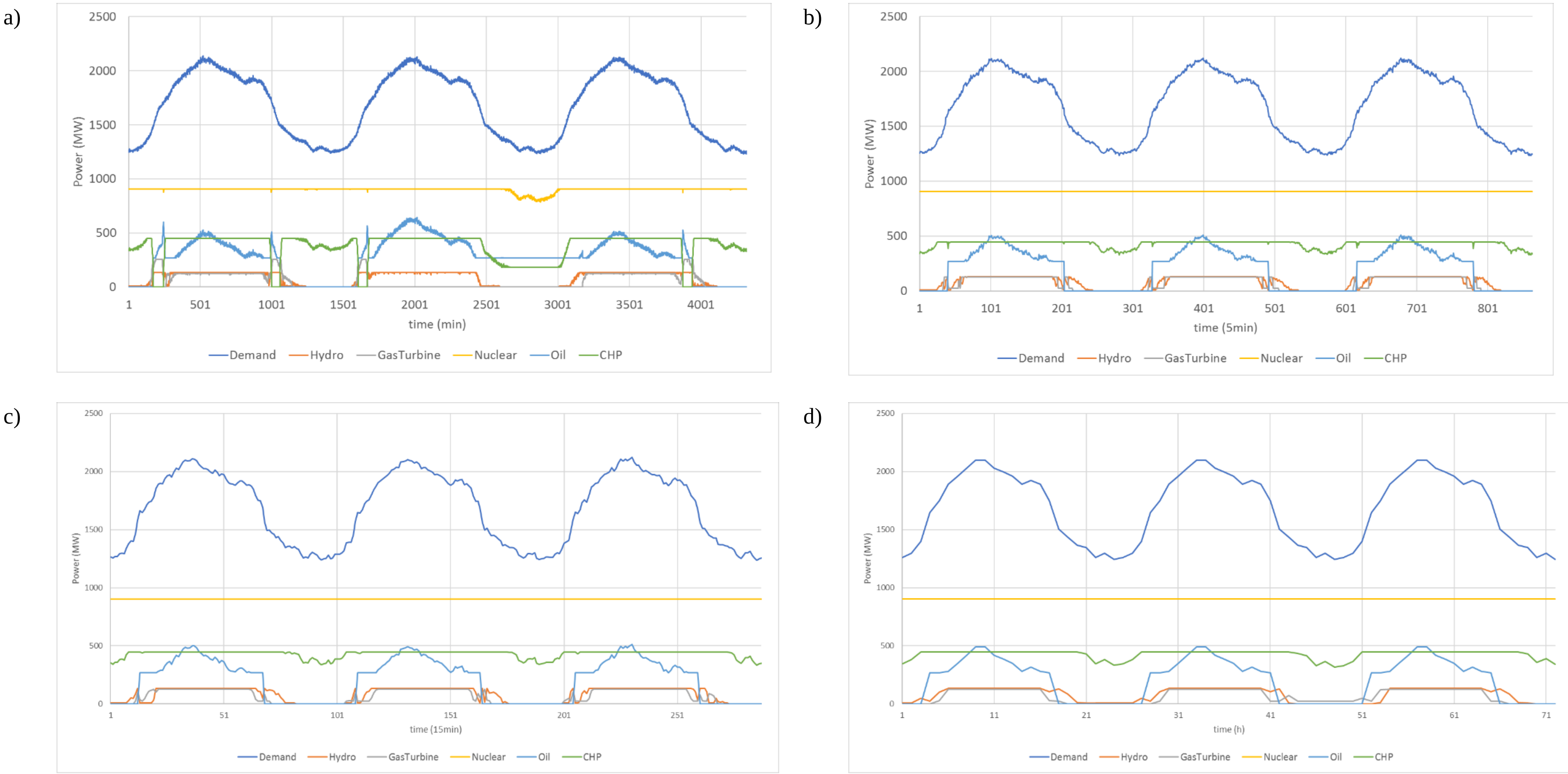

Figure 59. Results for Simulation 4: a) 1 minute timestep, b) 5 minutes timestep, c) 15 minutes timestep and d) 60 minutes timesteps.

Appendix G

Code 7. Final version UC model for 1 minute timestep

```
Sets t hours        /t1*t7200/
     i thermal units /g1*g7/;
Alias (t,h);

table gendata (i ,*) 'generator cost characteristics and limits'
$include tgen1.txt
;

Table dataLP(t,*)
$include demand1.txt
;

Variables costThermal Cost of thermal unit
Positive Variable pu(i,t), p(i,t);
Binary variable  u(i,t), y(i,t), z(i,t);

p.up(i,t)= gendata(i,"Pmax");
p.lo(i,t)= 0;
pu.up(i,t)=gendata(i,"Pmax");

Equations eMinTUp,eMinTDown,Ramp0,Ramp1, Ramp2, Ramp3, Ramp4, Ramp5, CostCalc,balance
Bin1,Bin2,Bin3,UpperBoundHydro1,UpperBoundHydro2;

eMinTUp(i,t).. sum(h$(ord(h)>= ord(t)-gendata(i,"DT") and ord(h)  <= ord(t)), y(i,h)) =l= u(i,t);
eMinTDown(i,t).. sum(h$(ord(h)>= ord(t)-gendata(i,"UT") and ord(h)<=ord(t)), z(i,h)) =l= 1 - u(i,t);
Bin1(i,t)$(ord(t)>1).. y(i,t)-z(i,t)=e= u(i,t)-u(i,t-1);
Bin2(i,t).. y(i,t)+z(i,t)=l=1;
Bin3(i,t)$(ord(t)=1).. y(i,t)-z(i,t)=e= u(i,t)-gendata(i,"Uini");

CostCalc .. costThermal=e=sum((t,i),gendata(i,'MC')*p(i,t)+0*gendata(i,"Cu")*y(i,t)+0*gendata(i,"Cd")*z(i,t));

Ramp0(i,t)$(ord(t)=7200).. pu(i,t)=l=u(i,t)*gendata(i,"Pmax");
Ramp1(i,t)..             p(i,t-1) - p(i,t) =l= U(i,t)*gendata(i,'RD') + z(i,t)*gendata(i,"SD");
Ramp2(i,t)..             p(i,t)  =l= pu(i,t);
Ramp3(i,t)$(ord(t)<7200).. pu(i,t)  =l=  (u(i,t)  - z(i,t+1))*gendata(i,"Pmax") + z(i,t+1)*gendata(i,"SD");
Ramp4(i,t)$(ord(t)>1)..  pu(i,t) =l= p(i,t-1) + U(i,t-1)*gendata(i,'RU') + y(i,t)*gendata(i,"SU");
Ramp5(i,t)..            p(i,t)=g=gendata(i,"Pmin")*u(i,t);
UpperBoundHydro1 .. sum(t,sum(i$(ord(i)=1), p(i,t)))=l= 2*0.1655*7200*132;
UpperBoundHydro2 .. sum(t,sum(i$(ord(i)=2), p(i,t)))=l= 2*0.1655*7200*440;
balance(t).. sum(i,p(i,t))=g=dataLP(t,'load')-3*dataLP(t,'solar')-3*dataLP(t,'wind');


Model Draftsolution /all/;
option reslim=20000000000;
option optcr=0.00015;
*option optca=0;


Solve Draftsolution using MIP minimizing costThermal;

Variable Hydro(t), Nuclear(t), GasTurbine(t),Oil(t),CHP(t), Demand(t), price(i,t);

price.l(i,t)=gendata(i,"MC")*u.l(i,t);
Hydro.l(t)=sum(i$(ord(i)<3),p.l(i,t));
Nuclear.l(t)=sum(i$(ord(i)=3), p.l(i,t));
GasTurbine.l(t)=sum(i$(ord(i)>3 and ord(i)<6), p.l(i,t));
Oil.l(t)=sum(i$(ord(i)=6),p.l(i,t));
CHP.l(t)=sum(i$(ord(i)=7),p.l(i,t));
Demand.l(t)=dataLP(t,'load')-3*dataLP(t,'wind')-3*dataLP(t,'solar');

*=== First unload to GDX file (occurs during execution phase)
execute_unload "resultsd.gdx" p.l z y u price costThermal.l Hydro.l Nuclear.l GasTurbine.l Oil.l CHP.l Demand.l

*=== Now write to variable levels to Excel file from GDX
execute 'gdxxrw.exe resultsd.gdx o=13otresults1.xlsx var=z rng=TurnOFF! var=y rng=TurnON! var=u rng=Connected!
var=price.l rng=Price! var=costThermal rng=Cost! var=p.l rng=Power!A1 var=Hydro.l rng=Power!B40 var=Nuclear.l
rng=Power!B43 var=GasTurbine.l rng=Power!B46 var=Oil.l rng=Power!B49 var=CHP.l rng=Power!B52 var=Demand.l
rng=Power!B55'
```

Code 8. Final version UC model for 5 minutes timestep

```
Sets t hours         /t1*t1440/
     i thermal units /g1*g7/;
Alias (t,h);

table gendata (i ,*) 'generator cost characteristics and limits'
$include tgen5.txt
;

Table dataLP(t,*)
$include demand5.txt
;

Variables costThermal Cost of thermal unit
Positive Variable pu(i,t), p(i,t);
Binary variable  u(i,t), y(i,t), z(i,t);

p.up(i,t)= gendata(i,"Pmax");
p.lo(i,t)= 0;
pu.up(i,t)=gendata(i,"Pmax");

Equations eMinTUp, eMinTDown, Ramp0,Ramp1, Ramp2, Ramp3, Ramp4, Ramp5, CostCalc, balance, Bin1, Bin2,
Bin3,UpperBoundHydro1, UpperBoundHydro2;

eMinTUp(i,t).. sum(h$(ord(h)>= ord(t)-gendata(i,"DT") and ord(h) <= ord(t)), y(i,h)) =l= u(i,t);
eMinTDown(i,t).. sum(h$(ord(h)>= ord(t)-gendata(i,"UT") and ord(h)<=ord(t)), z(i,h)) =l= 1 - u(i,t);
Bin1(i,t)$(ord(t)>1).. y(i,t)-z(i,t)=e= u(i,t)-u(i,t-1);
Bin2(i,t).. y(i,t)+z(i,t)=l=1;
Bin3(i,t)$(ord(t)=1).. y(i,t)-z(i,t)=e= u(i,t)-gendata(i,"Uini");

CostCalc .. costThermal=e=sum((t,i),gendata(i,'MC')*p(i,t)+0*gendata(i,"Cu")*y(i,t)+0*gendata(i,"Cd")*z(i,t));

Ramp0(i,t)$(ord(t)=1440).. pu(i,t)=l=u(i,t)*gendata(i,"Pmax");
Ramp1(i,t)..              p(i,t-1) - p(i,t) =l= U(i,t)*gendata(i,'RD') + z(i,t)*gendata(i,"SD");
Ramp2(i,t)..              p(i,t)   =l= pu(i,t);
Ramp3(i,t)$(ord(t)<1440).. pu(i,t) =l= (u(i,t) - z(i,t+1))*gendata(i,"Pmax") + z(i,t+1)*gendata(i,"SD");
Ramp4(i,t)$(ord(t)>1)..  pu(i,t) =l= p(i,t-1) + U(i,t-1)*gendata(i,'RU') + y(i,t)*gendata(i,"SU");
Ramp5(i,t)..             p(i,t)=g=gendata(i,"Pmin")*u(i,t);
UpperBoundHydro1 .. sum(t,sum(i$(ord(i)=1), p(i,t)))=l= 0.1655*1440*132;
UpperBoundHydro2 .. sum(t,sum(i$(ord(i)=2), p(i,t)))=l= 0.1655*1440*440;
balance(t).. sum(i,p(i,t))=g=dataLP(t,'load')-1*dataLP(t,'solar')-1*dataLP(t,'wind');


Model Draftsolution /all/;
option reslim=20000000000;
option optcr=0.0001;
*option optca=0;


Solve Draftsolution using MIP minimizing costThermal;

Variable Hydro(t), Nuclear(t), GasTurbine(t),Oil(t),CHP(t), Demand(t), price(i,t);

price.l(i,t)=gendata(i,"MC")*u.l(i,t);
Hydro.l(t)=sum(i$(ord(i)<3),p.l(i,t));
Nuclear.l(t)=sum(i$(ord(i)=3), p.l(i,t));
GasTurbine.l(t)=sum(i$(ord(i)>3 and ord(i)<6), p.l(i,t));
Oil.l(t)=sum(i$(ord(i)=6),p.l(i,t));
CHP.l(t)=sum(i$(ord(i)=7),p.l(i,t));
Demand.l(t)=dataLP(t,'load')-1*dataLP(t,'wind')-1*dataLP(t,'solar');

*=== First unload to GDX file (occurs during execution phase)
execute_unload "resultsd.gdx" p.l z y u price costThermal.l Hydro.l Nuclear.l GasTurbine.l Oil.l CHP.l Demand.l

*=== Now write to variable levels to Excel file from GDX
*=== Since we do not specify a sheet, data is placed in first sheet
execute 'gdxxrw.exe resultsd.gdx o=01otresults5.xlsx var=z rng=TurnOFF! var=y rng=TurnON! var=u rng=Connected!
var=price.l rng=Price! var=costThermal rng=Cost! var=p.l rng=Power!A1 var=Hydro.l rng=Power!B40 var=Nuclear.l
rng=Power!B43 var=GasTurbine.l rng=Power!B46 var=Oil.l rng=Power!B49 var=CHP.l rng=Power!B52 var=Demand.l
rng=Power!B55'
```

Code 9.Final version UC model for 15 minutes timestep

```
Sets t hours          /t1*t288/
     i thermal units /g1*g6/;
Alias (t,h);

table gendata (i ,*) 'generator cost characteristics and limits'
$include tgen15.txt
;

Table dataLP(t,*)
$include tdemand15.txt
;

Variables costThermal Cost of thermal unit
Positive Variable pu(i,t), p(i,t);
Binary variable  u(i,t), y(i,t), z(i,t);

p.up(i,t)= gendata(i,"Pmax");
p.lo(i,t)= 0;
pu.up(i,t)=gendata(i,"Pmax");

Equations eMinTUp, eMinTDown,Ramp0, Ramp1, Ramp2, Ramp3, Ramp4, Ramp5, CostCalc, balance, Bin1, Bin2,
Bin3,UpperBoundHydro;

eMinTUp(i,t).. sum(h$(ord(h)>= ord(t)-gendata(i,"DT") and ord(h) <= ord(t)), y(i,h)) =l= u(i,t);
eMinTDown(i,t).. sum(h$(ord(h)>= ord(t)-gendata(i,"UT") and ord(h)<=ord(t)), z(i,h)) =l= 1 - u(i,t);
Bin1(i,t)$(ord(t)>1).. y(i,t)-z(i,t)=e= u(i,t)-u(i,t-1);
Bin2(i,t).. y(i,t)+z(i,t)=l=1;
Bin3(i,t)$(ord(t)=1).. y(i,t)-z(i,t)=e= u(i,t)-gendata(i,"Uini");

CostCalc .. costThermal=e=sum((t,i),gendata(i,'MC')*p(i,t)+0*gendata(i,"Cu")*y(i,t)+0*gendata(i,"Cd")*z(i,t));

Ramp0(i,t)$(ord(t)=288).. pu(i,t)=l=u(i,t)*gendata(i,"Pmax");
Ramp1(i,t)..              p(i,t-1) - p(i,t) =l= U(i,t)*gendata(i,'RD') + z(i,t)*gendata(i,"SD");
Ramp2(i,t)..              p(i,t)  =l= pu(i,t);
Ramp3(i,t)$(ord(t)<288).. pu(i,t) =l= (u(i,t) - z(i,t+1))*gendata(i,"Pmax") + z(i,t+1)*gendata(i,"SD");
Ramp4(i,t)$(ord(t)>1)..  pu(i,t) =l= p(i,t-1) + U(i,t-1)*gendata(i,'RU') + y(i,t)*gendata(i,"SU");
Ramp5(i,t)..             p(i,t)=g=gendata(i,"Pmin")*u(i,t);
UpperBoundHydro .. sum(t,sum(i$(ord(i)=1), p(i,t)))=l= 0.0471*0.8*sum(t,dataLP(t,'load'));
balance(t).. sum(i,p(i,t))=g=0.8*dataLP(t,'load');


Model Draftsolution /all/;
option reslim=20000000000;
option optcr=0;
option optca=0;


Solve Draftsolution using MIP minimizing costThermal;

Variable Hydro(t), Nuclear(t), GasTurbine(t),Oil(t),CHP(t), Demand(t), price(i,t);

price.l(i,t)=gendata(i,"MC")*u.l(i,t);
Hydro.l(t)=sum(i$(ord(i)=1),p.l(i,t));
Nuclear.l(t)=sum(i$(ord(i)=2), p.l(i,t));
GasTurbine.l(t)=sum(i$(ord(i)>2 and ord(i)<5), p.l(i,t));
Oil.l(t)=sum(i$(ord(i)=5),p.l(i,t));
CHP.l(t)=sum(i$(ord(i)=6),p.l(i,t));
Demand.l(t)=0.8*dataLP(t,'load');


*=== First unload to GDX file (occurs during execution phase)
execute_unload "resultsd.gdx" p.l z y u price costThermal.l Hydro.l Nuclear.l GasTurbine.l Oil.l CHP.l Demand.l

*=== Now write to variable levels to Excel file from GDX
*=== Since we do not specify a sheet, data is placed in first sheet
execute 'gdxxrw.exe resultsd.gdx o=otresults15.xlsx var=z rng=TurnOFF! var=y rng=TurnON! var=u rng=Connected!
var=price.l rng=Price! var=costThermal rng=Cost! var=p.l rng=Power!A1 var=Hydro.l rng=Power!B40 var=Nuclear.l
rng=Power!B43 var=GasTurbine.l rng=Power!B46 var=Oil.l rng=Power!B49 var=CHP.l rng=Power!B52 var=Demand.l
rng=Power!B55'
```

Code 10. Final version UC model for hourly timestep

```
Sets t hours          /t1*t120/
     i thermal units /g1*g7/;
Alias (t,h);

table gendata (i ,*) 'generator cost characteristics and limits'
$include tgen60.txt
;

Table dataLP(t,*)
$include demand60.txt
;

Variables costThermal Cost of thermal unit
Positive Variable pu(i,t), p(i,t);
Binary variable  u(i,t), y(i,t), z(i,t);
```

```
p.up(i,t)= gendata(i,"Pmax");
p.lo(i,t)= 0;
pu.up(i,t)=gendata(i,"Pmax");

Equations eMinTUp, eMinTDown, Ramp0,Ramp1, Ramp2, Ramp3, Ramp4, Ramp5, CostCalc, balance, Bin1, Bin2,
Bin3,UpperBoundHydro1, UpperBoundHydro2;

eMinTUp(i,t).. sum(h$(ord(h)>= ord(t)-gendata(i,"DT") and ord(h) <= ord(t)), y(i,h)) =l= u(i,t);
eMinTDown(i,t).. sum(h$(ord(h)>= ord(t)-gendata(i,"UT") and ord(h)<=ord(t)), z(i,h)) =l= 1 - u(i,t);
Bin1(i,t)$(ord(t)>1).. y(i,t)-z(i,t)=e= u(i,t)-u(i,t-1);
Bin2(i,t).. y(i,t)+z(i,t)=l=1;
Bin3(i,t)$(ord(t)=1).. y(i,t)-z(i,t)=e= u(i,t)-gendata(i,"Uini");

CostCalc .. costThermal=e=sum((t,i),gendata(i,'MC')*p(i,t)+0*gendata(i,"Cu")*y(i,t)+0*gendata(i,"Cd")*z(i,t));

Ramp0(i,t)$(ord(t)=120).. pu(i,t)=l=u(i,t)*gendata(i,"Pmax");
Ramp1(i,t)..              p(i,t-1) - p(i,t) =l= U(i,t)*gendata(i,'RD') + z(i,t)*gendata(i,"SD");
Ramp2(i,t)..              p(i,t)  =l= pu(i,t);
Ramp3(i,t)$(ord(t)<120).. pu(i,t) =l= (u(i,t) - z(i,t+1))*gendata(i,"Pmax") + z(i,t+1)*gendata(i,"SD");
Ramp4(i,t)$(ord(t)>1)..  pu(i,t) =l= p(i,t-1) + U(i,t-1)*gendata(i,'RU') + y(i,t)*gendata(i,"SU");
Ramp5(i,t)..             p(i,t)=g=gendata(i,"Pmin")*u(i,t);
UpperBoundHydro1 .. sum(t,sum(i$(ord(i)=1), p(i,t)))=l= 0.6622*120*132;
UpperBoundHydro2 .. sum(t,sum(i$(ord(i)=2), p(i,t)))=l= 0.6622*120*440;
balance(t).. sum(i,p(i,t))=g=dataLP(t,'load')-3*dataLP(t,'solar')-3*dataLP(t,'wind');


Model Draftsolution /all/;
option reslim=20000000000;
option optcr=0.0001;
*option optca=0;


Solve Draftsolution using MIP minimizing costThermal;

Variable Hydro(t), Nuclear(t), GasTurbine(t),Oil(t),CHP(t), Demand(t), price(i,t);

price.l(i,t)=gendata(i,"MC")*u.l(i,t);
Hydro.l(t)=sum(i$(ord(i)<3),p.l(i,t));
Nuclear.l(t)=sum(i$(ord(i)=3), p.l(i,t));
GasTurbine.l(t)=sum(i$(ord(i)>3 and ord(i)<6), p.l(i,t));
Oil.l(t)=sum(i$(ord(i)=6),p.l(i,t));
CHP.l(t)=sum(i$(ord(i)=7),p.l(i,t));
Demand.l(t)=dataLP(t,'load')-3*dataLP(t,'wind')-3*dataLP(t,'solar');

*=== First unload to GDX file (occurs during execution phase)
execute_unload "resultsd.gdx" p.l z y u price costThermal.l Hydro.l Nuclear.l GasTurbine.l Oil.l CHP.l Demand.l

*=== Now write to variable levels to Excel file from GDX
*=== Since we do not specify a sheet, data is placed in first sheet
execute 'gdxxrw.exe resultsd.gdx o=33otresults60.xlsx var=z rng=TurnOFF! var=y rng=TurnON! var=u rng=Connected!
var=price.l rng=Price! var=costThermal rng=Cost! var=p.l rng=Power!A1 var=Hydro.l rng=Power!B40 var=Nuclear.l
rng=Power!B43 var=GasTurbine.l rng=Power!B46 var=Oil.l rng=Power!B49 var=CHP.l rng=Power!B52 var=Demand.l
rng=Power!B55'
```

Code 11. Conversion from 5 minutes to hourly based

```
clear all
clc


D=xlsread("DEMAND CREATION.xlsx","input","B2:D1441");
P=D(:,1);
W=D(:,2);
S=D(:,3);



data_hour(:,1) = mean(reshape(P, 12, []));
data_hour(:,2) = mean(reshape(W, 12, []));
data_hour(:,3) = mean(reshape(S, 12, []));
```

```
filename="C:\Users\Rodrigo\Desktop\Thesis 2.0\simVRES\DEMAND CREATION.xlsx";
xlswrite(filename,data_hour,"conversion60", "B2")
```

Code 12. Conversion from 5 minutes to 1 minute based

```
clear all
clc
W=zeros(1440,3);
A=xlsread("DEMAND CREATION.xlsx","input","B2:D1441");
% dataa is the demand per hour given by NordPool
%%
P=A(:,1);
S=A(:,2);
W=A(:,3);
f=3/5;
ff=1440+2/5;
xq=linspace(f,ff,7200);

average=sum(P)/1440;

F=griddedInterpolant(1:1440,P);
xx=F(xq);

for i=1:7200
PP(i)=normrnd(xx(i),0.00561*xx(i));
end

F=griddedInterpolant(1:1440,S);
SS=F(xq);

F=griddedInterpolant(1:1440,W);
WW=F(xq);

X=[PP;SS;WW];
X=X';

averagef=sum(PP)/7200;
%%
filename="C:\Users\Rodrigo\Desktop\Thesis 2.0\simVRES\DEMAND CREATION.xlsx";
xlswrite(filename,X,"conversion1", "B2")
```

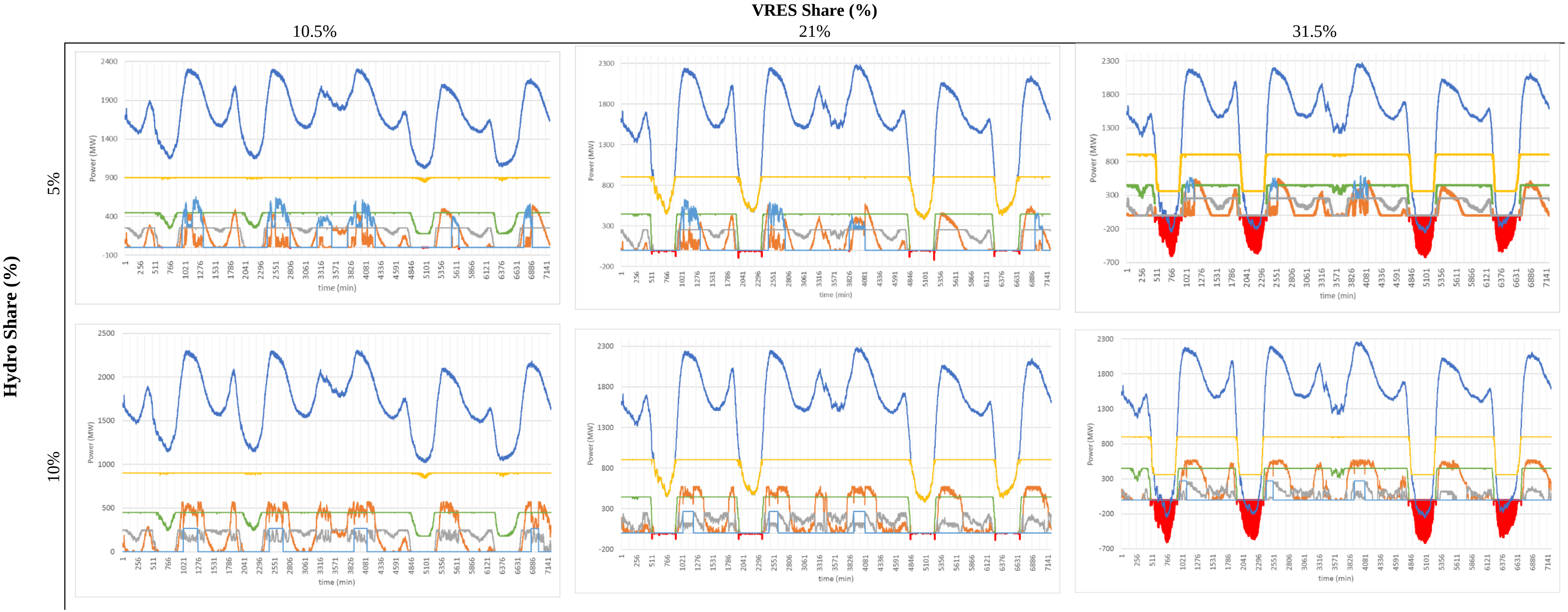

Figure 60. Case study results for 1 minute timestep, 10% and 5% of Hydro

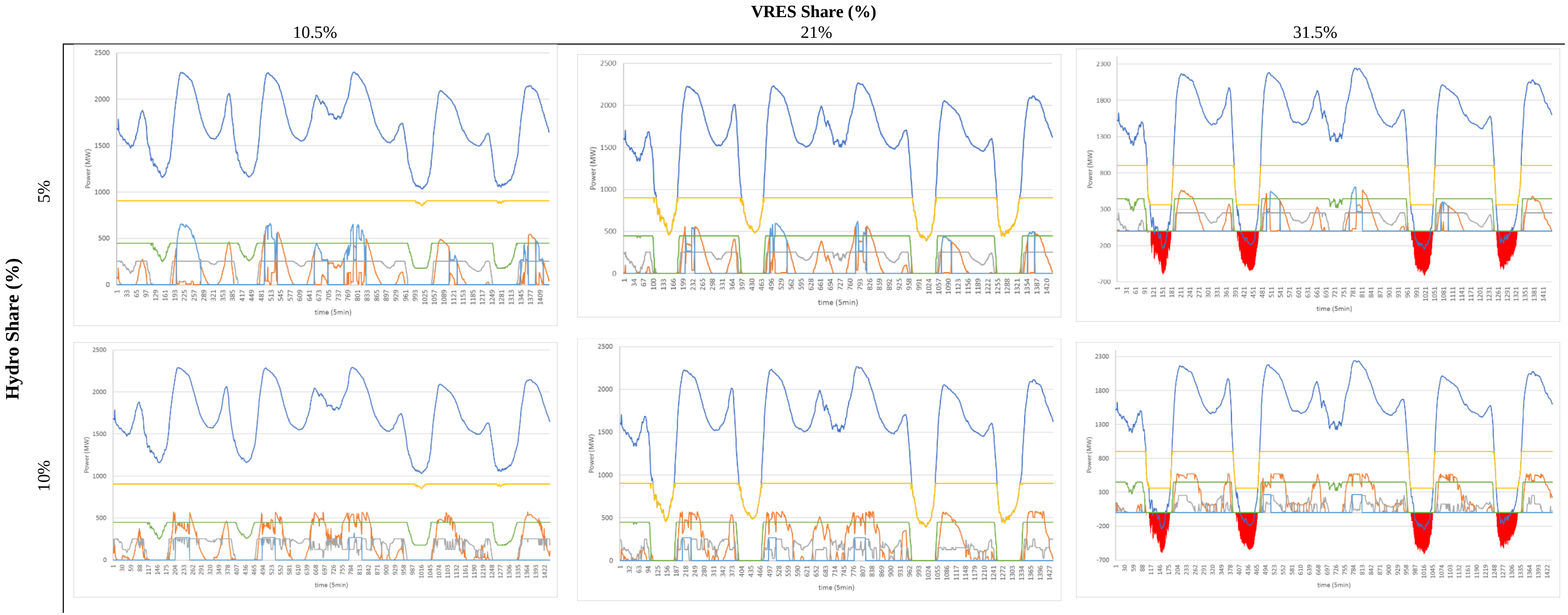

Figure 61. Case study results for 5 minutes timestep, 10% and 5% of Hydro

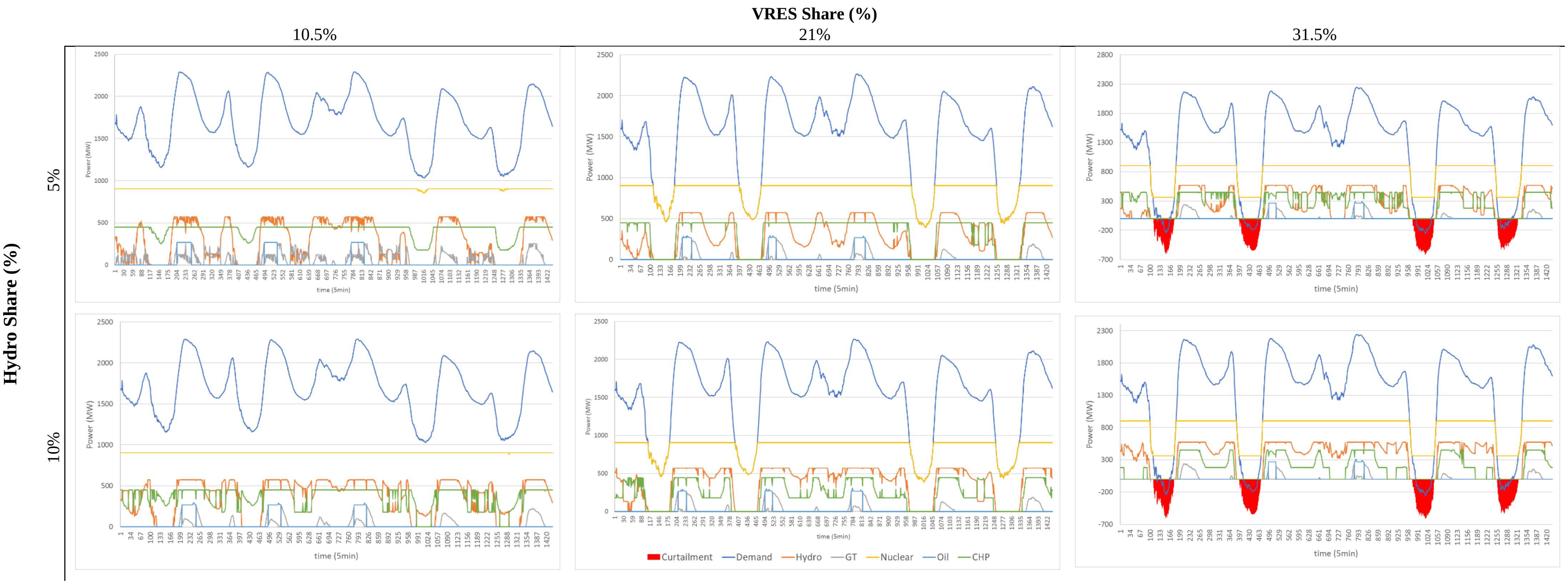

Figure 62. Case study results for 5 minutes timestep, 15% and 20% of Hydro

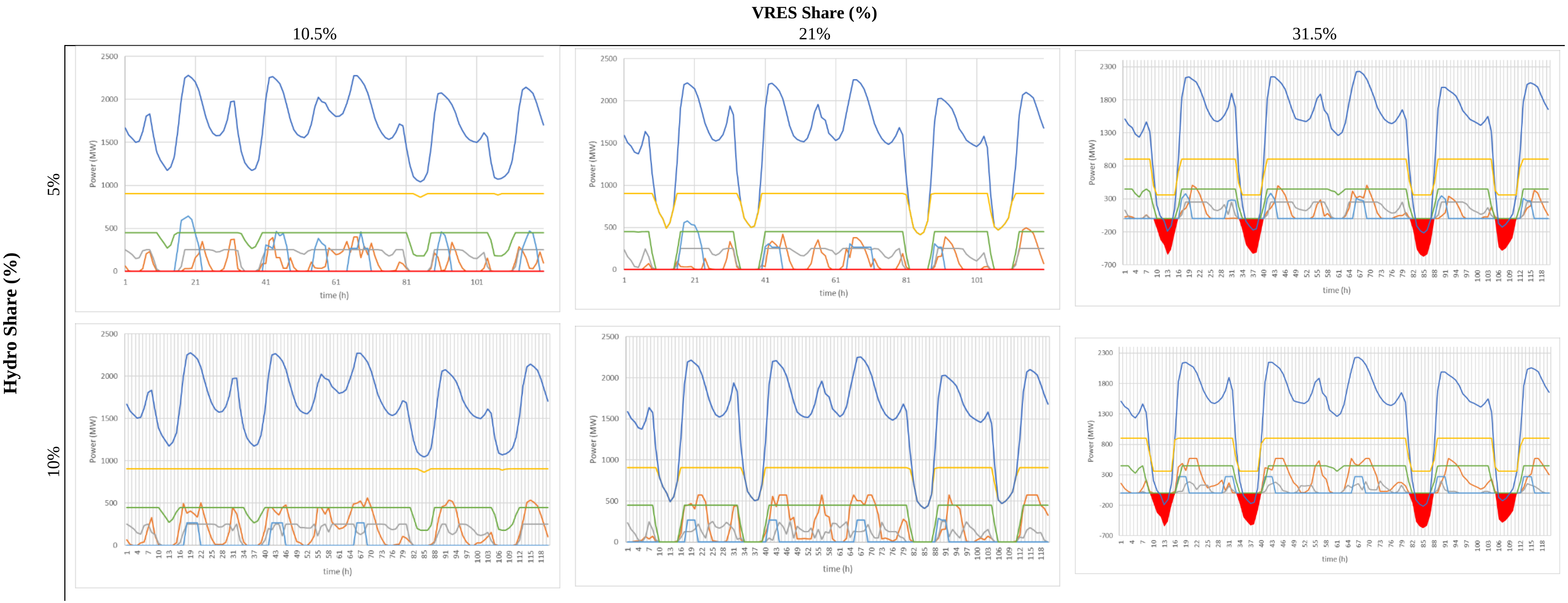

Figure 63. Case study results for 60 minutes timestep, 10% and 5% of Hydro

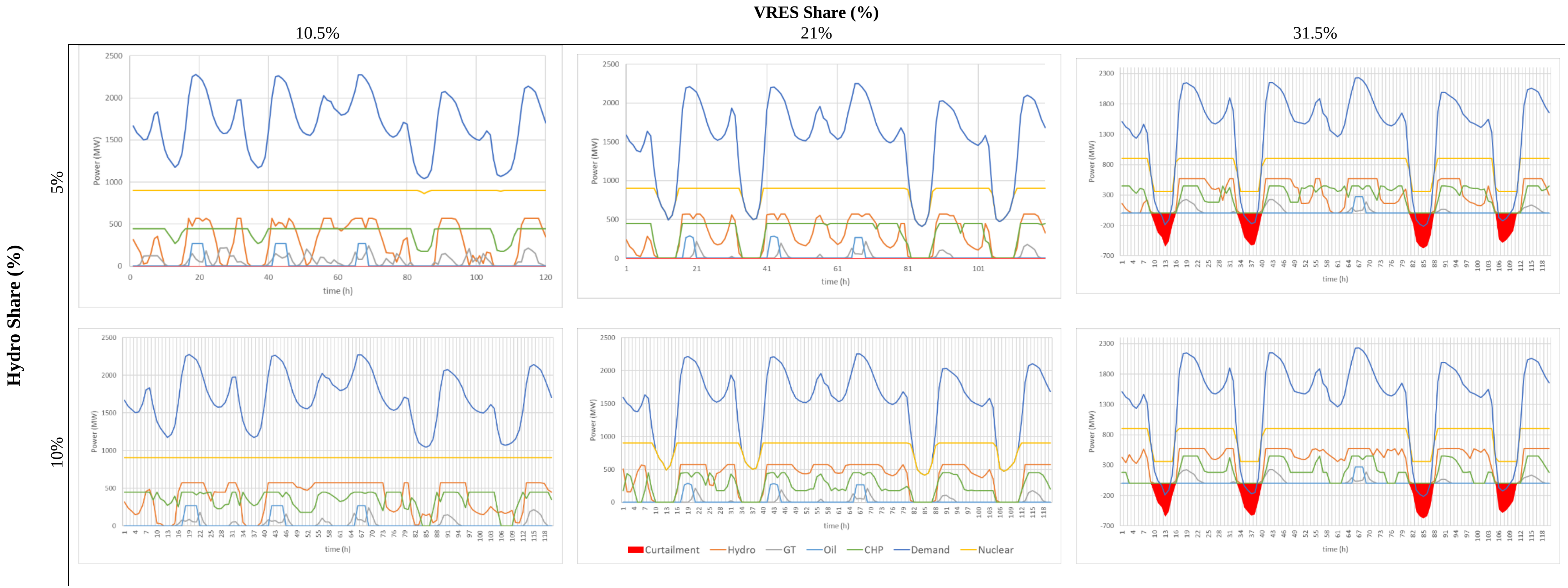

Figure 64. Case study results for hourly step, 15% and 20% of hydro

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