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Assessing the impacts of large Scale RES integration in the European Power System

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Submission date: June 2016
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Abstract

This Master's thesis is a part of the course TET4915. It highlights the consequences of increasing the amounts of intermittent renewable energy sources (I-RES) in the European power system. Simulations were carried out using the EMPS model and data sets were created based on future scenarios given by ENTSO-E. Three cases were established – Scenario 1 (S1), 2 (S2) and 3 (S3). The scenarios differ based on several attributes, however the main difference is installed I-RES capacity (with capacity increasing going from S1 to S3).

The analyses investigates how central attributes such as generation mix, prices, transmissions and asset profitability change between the different scenarios.

As I-RES capacity increases, thermal generation is substituted with renewable production. The RES penetration is 39, 57 and 78 % for S1, S2 and S3 respectively. As a result, fossil and nuclear generation is reduced by 66 and 30 % in S3 compared to S1. Combined with low utilization, the results indicate that there's a fair amount of excess thermal power in the system.

Large scale integration of I-RES causes a drop in power prices. Due to changes in fuel- and CO_2 prices, the average power price is fairly similar in S1 (106.3 €/MW) and S2 (105.3 €/MW). In S3, however, the average price plummets to 45.3 €/MW, a 57 % reduction compared to S2.

Transmission lines have increased utilization as the amount of I-RES increases. Very high congestion rates are found for a considerable amount of lines in the system. In S2 and S3, several of the Norwegian lines approach 100 % utilization. The results indicate that certain lines will need to be reinforced in a system where I-RES constitutes a large share of the power production.

The drop in power prices highly affects the profitability of power plants. In a high-RES system such as S3, no assets apart from bio power is profitable. This includes both thermal and renewable assets. Thus, there would be no incentives for investments apart from bio power. This indicates that some form of capacity remuneration mechanisms would need to be deployed for such a system composition to work. Looking at S3, a total of 41 and 175 billion Euros would have to be supported for thermal and RES assets respectively.

For transmission lines the trend is reversed. As price differences are increased going from S1 to S3, so is line profitability. Transmission lines are the most profitable assets in the system by far, incentivizing additional line investments.

An investment analysis performed on S3 resulted in three modified scenarios – S3.1, S3.2 and S3.3. These featured around 50 % reduction in fossil capacity as well as varying capacity increases on certain transmission lines.

Increased lines leads to reduced line utilization for the respective lines as well as lower average prices. The reduction in fossil capacity leads to increased profitability. While still unprofitable, the total support required from thermal assets is now 13, 20 and 23 billion Euros for S3.1, S3.2 and S3.3 respectively. These are large reductions compared to the 41 billion Euros seen in S3.

129 TWh of dump energy is present in S3. Increasing lines contribute to reducing this number, with 115, 110 and 112 TWh being present in S3.1, S3.2 and S3.3 respectively. Examining a scenario with unlimited transmission capacity, 92 TWh is still present in the system. Thus, the installed I-RES capacity is so large that energy production exceeds demand. This clearly shows the need for grid energy storage in high-RES power systems.

Sammendrag

Masteroppgaven er en del av faget TET4915 og belyser konsekvensene av å øke andelen vind- og solkraft (I-RES) i det europeiske kraftsystemet. Simuleringer ble gjort ved bruk av EMPS-modellen og datasett ble konstruert basert på fremtidsscenarier gitt av ENTSO-E. Tre scenarioer ble satt sammen – Scenario 1 (S1), 2 (S2) og 3 (S3). Selv om scenarioene er forskjellige på flere plan er hovedforskjellen mengden installert I-RES-kapasitet i systemet (økende fra S1 til S3).

De gjennomførte analysene undersøker hvordan sentrale atributter som produksjonsmiks, priser og lønnsomhet endrer seg mellom de forskjellige scenarioene.

Etter hvert som I-RES-kapasitet øker blir termisk produksjon erstattet med fornybar produksjon. RES-penetrasjonen er henholdsvis 39, 57 og 78 % i S1, S2 og S3. Dette resulterer i en kraftig reduksjon i produksjon fra fossile kraftverk og kjernekraft i S3, henholdsvis 66 % og 30 % reduksjon sammenlignet med S1. Basert på reduksjonen samt lave bruksfaktorer indikerer at det i S3 er betraktelige mengder overflødig termisk kapasistet i systemet.

Økt kapasitet av I-RES fører til lavere priser. Grunnet endringer i drivstoff- og CO2-priser er gjennomsnittsprisen noenlunde lik i S1 (106.3 €/MW) og S2 (105.3 €/MW). I S3, som er scenarioet med høyest andel I-RES, stuper gjennomsnittsprisen til 45.3 €/MW, en reduksjon på 57 % sammenlignet med S2.

Et annet resultat av økt mengde I-RES er økt bruk av overføringslinjer. Høy bruksfaktor er å finne for flere linjer i systemet. I S2 og S3 nærmer flere av de norske linjene seg 100 %. Tallene tyder på at flere overføringslinjer trenger oppgradering i et system hvor fornybar energi står for en stor andel av produksjonen.

Prisreduksjonen mellom S1 og S3 påvirker i stor grad lønnsomheten til kraftverk. I S3 er ingen kraftverk med unntak av biokraft lønnsomme. Dette gjelder både termiske og fornybare kraftverk. I S3 (som er det mest ekstreme scenarioet) er det nødvendig med 41 og 175 milliarder Euro i støtte for henholdsvis termiske og fornybare kraftverk. Dette tyder på at kapasitetsmekanismer er nødvendig for å opprettholde forsyningssikkerheten i fremtidige kraftsystemer.

Når det gjelder overføringslinjer er trenden reversert. Selv om gjennomsnittsprisene går ned mellom S1 og S3 så øker prisforskjellene innad i systemet. Som et resultat øker lønnsomheten til overføringslinjene. Overføringslinjer er de mest lønnsomme systemkomponentene med stor margin, noe som insentiviserer linjeinvesteringer.

En investeringsanalyse utført på S3 resulterte i tre modifiserte scenarier – S3.1, S3.2 og S3.3. Disse scenarioene innehar en kapasitetsreduksjon på rundt 50 % for fossile kraftverk samt varierende grad av kapasitetsøkning på spesifikke linjer.

Økt linjekapasistet fører til redusert bruksfaktor for de respektive linjene samt lavere gjennomsnittspriser. Redusert fossil kapasitet fører til økt lønnsomhet for de fossile kraftverkene. Selv om kraftverkene fremdeles er ulønnsomme trengs støtte på 13, 20 og 23 milliarder Euro i henholdsvis S3.1, S3.2 og S3.3. Dette er store reduksjoner sammenlignet med 41 milliarder Euro i S3.

Det er 129 TWh overflødig energi i systemet i S3. Økte linjer bidrar til å redusere dette tallet, med 115, 110 og 112 TWh i henholdsvis S3.1, S3.2 og S3.3. Etter å ha undersøkt et scenario med ubegrenset overføringshastighet viser det seg at 92 TWh av energien fremdeles er overflødig. Dermed kan det konkluderes med at installert I-RES-kapasitet er så stor at produksjonen overgår etterspørselen. Dette understreker behovet for energilagring i systemet.

Preface

This Master's thesis is a result of the specialization course TET 4915 in the 5-year Master of Science degree at the Norwegian University of Science and Technology, Department of Electric Power Engineering, spring 2016.

First and foremost we wish to thank Professor Hossein Farahmand at the Department of Electrical Power Engineering for professional supervision throughout the project. We also wish to thank postdoctoral researcher Stefan Jaehnert at SINTEF for excellent counseling in the EMPS model. Lastly, we wish to thank professor Magnus Korpås at the Department of Electric Power Engineering for moral support.

Abbreviations

BI	British Isles
CAPEX	Capital expenditures
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CRM	Capacity remuneration mechanisms
CSP	Concentrated solar power
DSR	Demand side response
EC	European Commission
EFI	Elektrisitetsforsyningens Forskningsinstitutt
EMPS	EFI's Multi-area power-market simulator
ENTSO-E	European Network of Transmission System Operators
EU	European Union
FBMC	Flow based market coupling
GHG	Greenhouse gas
IEA	International Energy Agency
IEM	Internal energy market
IP	Iberian Peninsula
I-RES	Intermittent renewable energy sources
MBER	Missing break-even revenue
MP	Marginal profit
NMP	Net marginal profit
NSN	North Sea Network
NVE	Norwegian Water Resources and Energy Directorate
NWE	North-Western Europe
OCGT	Open Cycle gas turbine
OPEX	Operational expenditures
PCR	Price coupling of regions
PV	Photovoltaics
RES	Renewable energy sources
RoR	Run of river
SDP	Stochastic Dynamic Programming
TSO	Transmission system operator
TVC	Tight volume coupling
TYNDP	Ten Year Network Development Plan

Contents

List of figures

List of tables

1 Introduction

In recent years, the European Union (EU) have stated clear goals for the future related to the reduction of greenhouse gases (GHG). Reaching these goals will require an alteration of the European Power system compared to its present state, increasing the share of renewable energy sources (RES) considerably.

Challenges arise, however, when making a shift from conventional fossil fueled energy sources towards RES. This is mainly due to the variant nature of intermittent renewable energy sources (I-RES) such as wind and solar power, which could cause large variations in production. In turn, this can lead to times where the security of supply is challenged, causing price spikes and possibly rationing.

I-RES have no dispatchability, generally meaning the power has to be spent immediately. In times of high I-RES production this means excess power must be exported elsewhere to be utilized, potentially straining the transmission capacity of the system.

If the share of I-RES in the system reaches high levels it will affect power prices, potentially challenging the profitability of thermal power. In turn this can lead to thermal assets being decommissioned, again putting the security of supply at risk.

In this thesis the impacts of large scale RES integration (with focus on I-RES) in the European power system is assessed. Based on assembled data, three future scenarios for 2050 is investigated using a simulation model. Focusing on certain high-impact countries in the European power system, the performed analyses take a thorough look on how generation, prices, transmissions, and asset profitability is impacted for different shares of I-RES in the system.

Also, an investment analysis is performed on one of the scenarios to investigate how the system composition could be altered to better cope with large amounts of I-RES, and how the resulting composition influences relevant properties such as prices, transmissions and asset profitability.

2 The European power system

2.1 General overview

The European power system as it is today consist of five synchronous[1] grids. The grids operate at 50 Hz and is connected to each other via high-voltage direct current cables. The largest synchronous grid in the European power system covers most of continental Europe, serving approximately 450 million people with electricity. Having a generation capacity of 667 GW and covering 24 countries, it is the largest synchronized power system in the world. The four other synchronous grids cover Scandinavia, Great Britain, Ireland and the Baltics as illustrated in Figure 2.1.

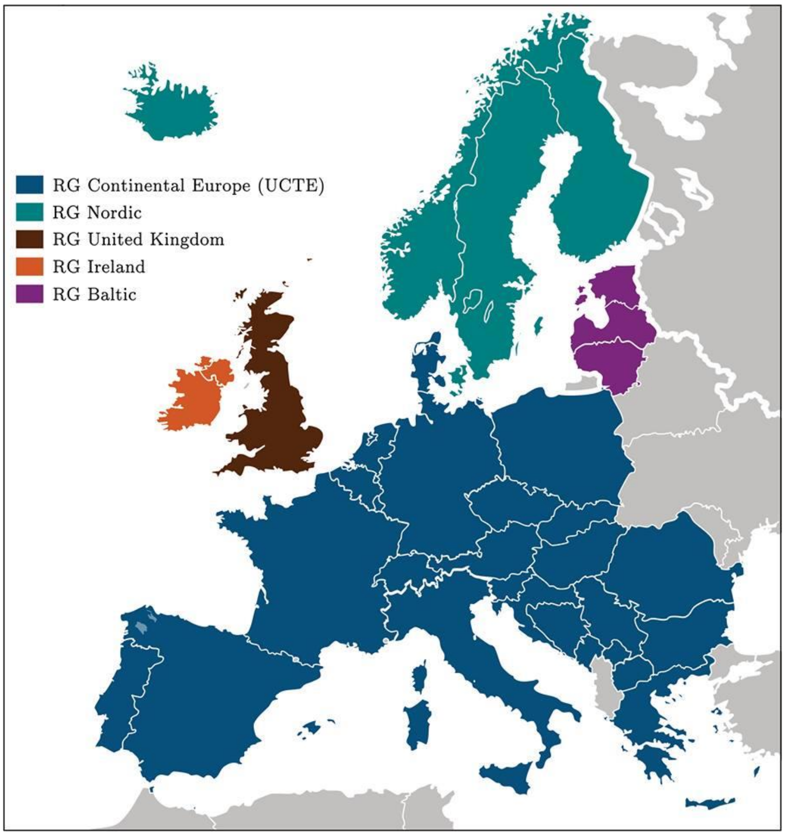

Figure 2.1: Main Synchronous grid of Europe.

The European countries combined had an annual aggregated electricity production of approximately 3450 TWh [1] and an aggregated generation capacity of slightly above 1000 GW [2] in 2014. The generation is distributed

[1] A synchronous grid operates at a synchronized frequency and is electrically tied together during normal system conditions.

between a large range of different power sources, fossil fueled and nuclear fueled generation being the largest and second largest one respectively. Shown in Figure 2.2 is the distribution of the total European power generation in 2014. For reference the total installed capacity in the European power is given in Figure 2.3. As can be seen, coal power represents 41% of the total production while nuclear power represents 27 %. The generation mix varies greatly from country to country. Mountainous countries such as Norway, Sweden and countries close to the Alps will in general have a higher share of their production from hydro power. The 'Other' category seen in the figures consists mainly of bio power.

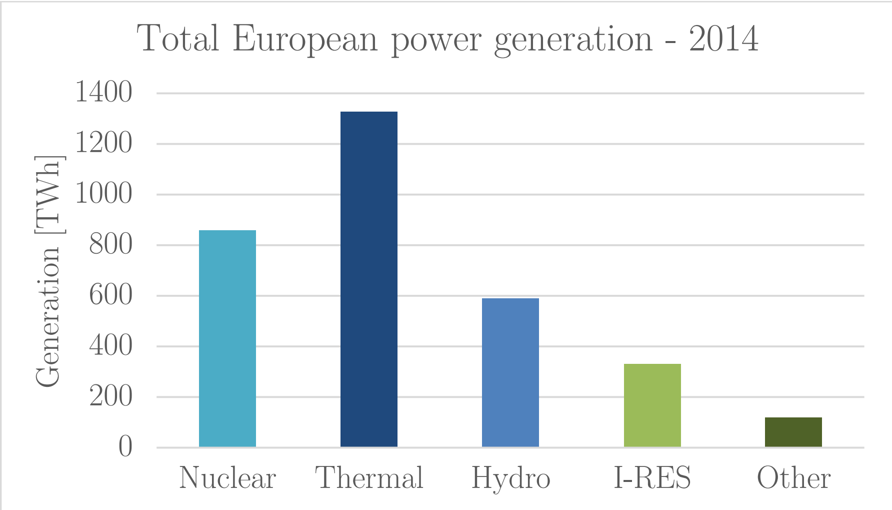

Figure 2.2: Total European power generation - 2014. [1]

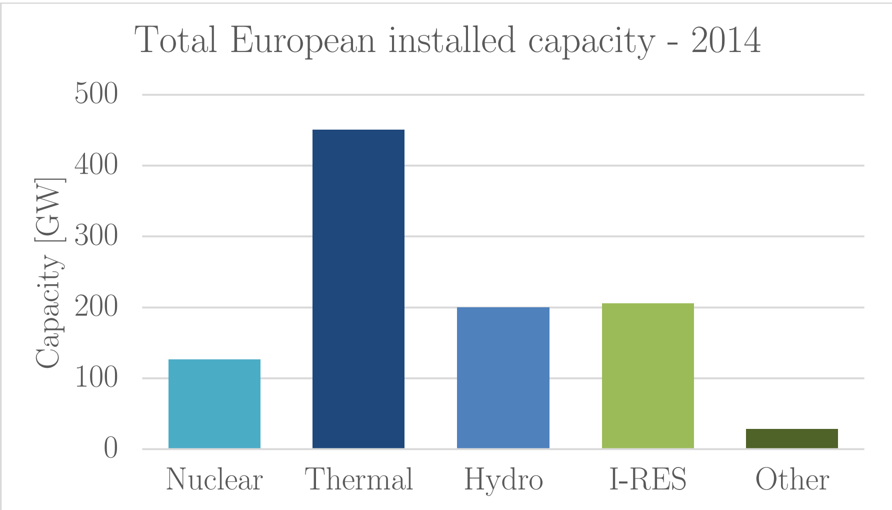

Figure 2.3: Total installed capacity - 2014. [2]

France relies heavily on nuclear power. With a production of over 410 TWh in 2014 as seen in Figure 2.4, France accounts for almost 50 % of all nuclear power production in the European power system. Germany had a relatively high share of their power production from intermittent renewable power sources like solar and wind power compared to most of the European countries. This production accounted for 16 % of their total generation in 2014. Power production from fossil fuel is the biggest power contributor in most of the continental countries with a few exceptions like Norway (where almost 100 % of the production originates from hydro power production) or France (where 77 % of their production originates from nuclear power). The fossil fueled production is distributed between various types of fossil plants, with coal, gas, lignite and diesel being the main fuel sources.

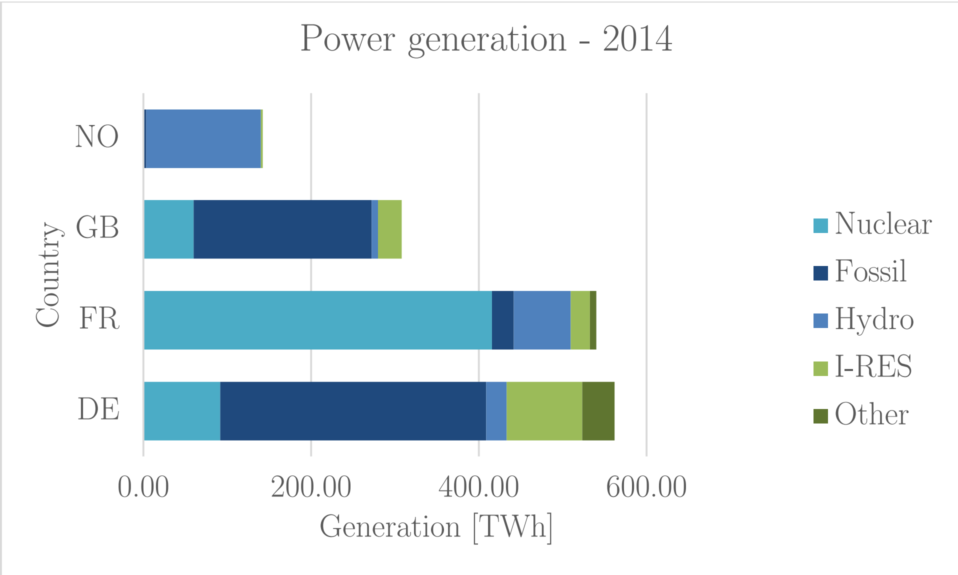

Figure 2.4: Power generation - 2014. [1]

2.2 The European power markets

2.2.1 The North-Western Europe market coupling project

The European power system as it is today consist of numerous power exchanges. Nordpool (Scandinavia and the Baltics), EPEX (Germany, France, Switzerland and Luxembourg), APX (Belgium and Netherlands) are some of the largest power exchanges in the European power system today. The different exchange areas are economically connected via a North-Western Europe (NWE) market coupling project. The project comprises power exchanges and transmission system operators (TSOs) in the participating areas. The NWE market coupling project went live on February 4th, 2014 and uses the pan-European Price Coupling of Regions (PCR) solution (see chapter 2.2.3). The project covered central west Europe, Great Britain, the Nordics and the Baltics at launch. Later Spain, Portugal and Italy joined. The coupled area, now called the Multi-Regional Coupling area, covers 19 countries and approximately 85 % [3] of the power consumption in Europe (as illustrated in Figure 2.5). The project aims to create a single European day-ahead market resulting in a more integrated and harmonized European electricity market.

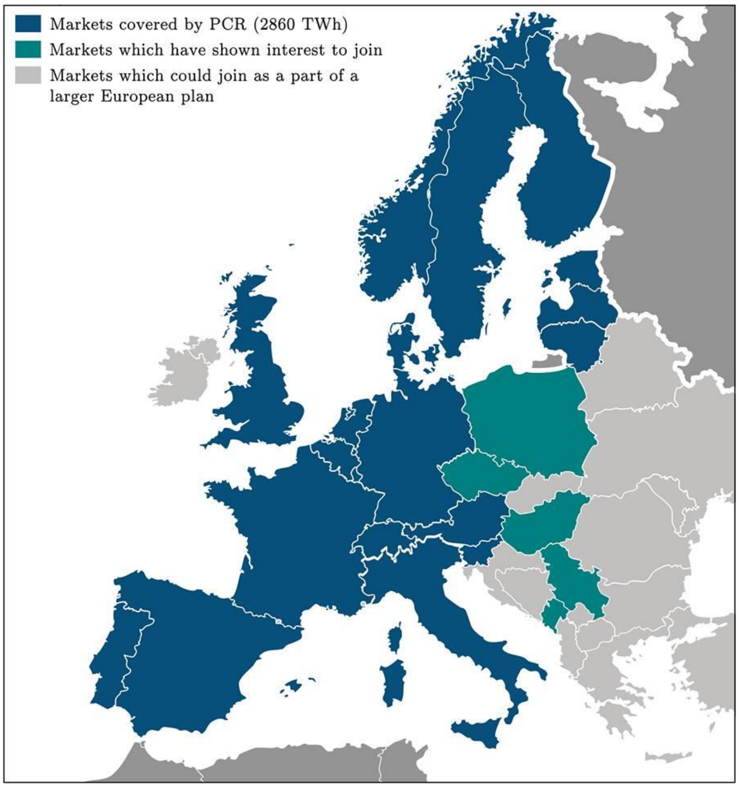

Figure 2.5: Markets covered by PCR.

2.2.2 Market Coupling

Market coupling of power markets contributes to optimizing the allocation process of cross-border capacities. The players only bid for energy on their power exchange, not on cross-region capacity. The power exchanges then uses the available cross-region transmission capacity to minimize the price difference between the regions. Market coupling increases the social welfare and avoids artificial splitting of the markets. Price coupling mechanisms is also expected to increase the liquidity and efficiency of the grid, something which is crucial to handle the effects an increased share of renewables will have on the power system.

2.2.3 The price coupling of regions initiative

The Price coupling of Regions initiative is a project initiated by seven European power exchanges: APX, Belpex, EPEX, GME, Nord Pool, OMIE and OTE in 2009. The PRC project develops a single market coupling algorithm calculating electricity prices, net positions and allocates cross-border capacity between price regions across Europe on a day-ahead basis. The algorithm was at first based on Tight Volume Coupling (TVC), but switched to a more efficient process called flow-based market coupling (FBMC) in May 2015 [3]. The FBMC algorithm uses more sophisticated grid modelling than TVC in order to better account for the impacts of cross-border exchanges on network security constraints when optimizing market flows for the concerned regions. The FBMC offer more trading opportunities with the same level of security of supply, reducing the price differences and increasing the social welfare in the system.

2.3 Interconnections

EU has worked towards building a more integrated European grid over the last decades. The European Commission (EC) has communicated a 10 % electricity interconnection[2] target within 2020 and a proposal to extend the target to 15 % by 2030. A well interconnected European grid is crucial to meet the challenges that arises from an increase in renewable power production. Currently (2014) twelve EU member states remain below the 10% interconnection target. The Baltic countries is now at 10 % interconnection after the Estlink 2 connection was completed in 2014. The connection between the Iberian Peninsula and France have been one of the worst bottlenecks in the European power grid over the last years. A new connection between Spain and France was completed in February 2015, doubling the interconnection capacity to 2800 MW. Another cable is planned and will lift the interconnection level of Spain to 10 % when completed. [4]

[2] Electricity interconnection is a measure of how much of a nation's generation capacity that is available to other countries.

3 Renewable energy sources

3.1 Intermittent renewable energy sources

Due to their fickle nature, increased production from intermittent renewable energy sources (I-RES) creates new challenges in the European power system. Uncontrollable and difficult to predict, the I-RES can result in sudden and unpredictable changes in the power system. As the penetration of I-RES increases, the inherent characteristics of the I-RES will result in an increased pressure on the power system and its capabilities to ensure generation adequacy at a high level.

Generation adequacy is defined by the European Network of Transmission System Operators (ENTSO-E) as: «An assessment of the ability of the generation on the power system to match consumption on the same power system» [5]. Generation adequacy is often divided into three main aspects: short-term reserve, long-term capacity and back-up capacity. Short-term reserves is used to handle rapid changes in the supply/demand on a continuous basis. Long-term capacity is mainly used to cover peak capacity moments during a year. Back-up capacity is necessary when a power producers is not producing. This is particularly relevant for I-RES, as their output can fluctuate greatly on a daily basis. The need for back-up capacity to ensure generation adequacy increases with the share of I-RES in a system. The consequence for more reliable generation assets is that they need to be in stand-by mode for an increased amount of time and thus reducing their number of operating hours. In turn, this will result in a decreased capacity factor[3] for conventional power plants.

Another effect of increased I-RES production is that existing power plants is pushed to the right on the supply curve. This is called the merit order[4] effect. Resulting in a decreased amount of operating hours for existing power plants and a lower wholesale power price. These effects is due to the low marginal cost of I-RES, often simplified to be 0 €/MWh. The lost revenue experienced by existing conventional power plants because of the shift to the right in the merit order is often referred to as "the missing money problem". An example of the decreased amount of operating hours is given in Figure 3.1, were combined cycle gas turbine (CCGT) and coal plants in Spain had a reduction of almost 50 % in operational hours from 2010 to 2014 due to an increased share of I-RES.

[3] The ratio of its actual output over a period of time compared to its potential capacity.

[4] A system for ranking energy sources based on ascending order of price, often based on their short-run marginal cost.

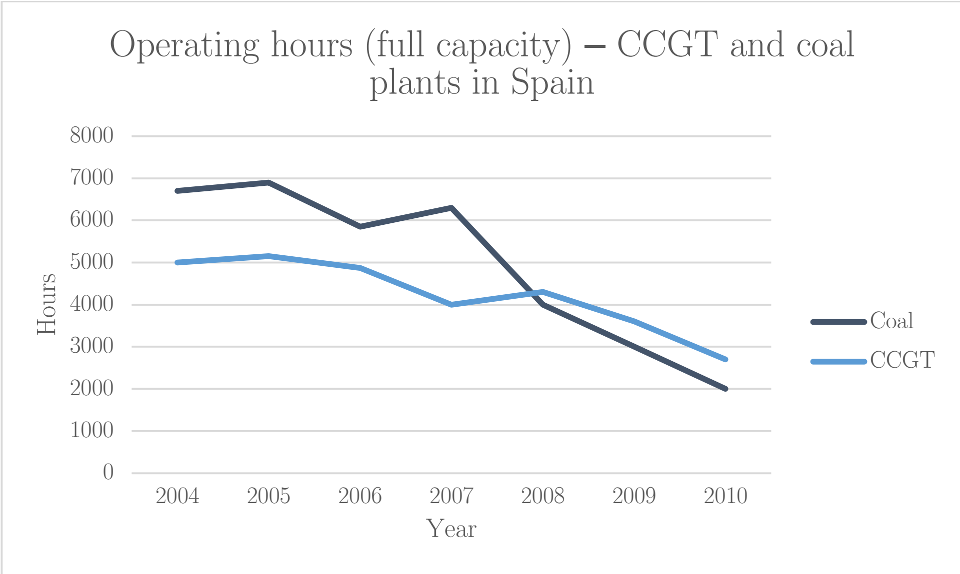

Figure 3.1: Operating hours – CCGT and coal plants in Spain. [6]

The two main contributors to I-RES power production is wind and solar power. Minor contributions are also seen from other I-RES like tidal power, but these are mostly pilot projects and do not contribute with a notable share of the overall production. The installed solar and wind capacities in the European power system is predicted to increase by 60 % and 80 % respectively by 2025 [5]. An important aspect to consider when looking at installed I-RES capacity is that the capacity factor is uncontrollable and much lower than conventional power plants, which are mainly affected by the utilization time.

3.1.1 Wind Power

Wind power production harvests energy from the mass movement of air through the area covered by the rotor blades. The maximum amount of the kinetic wind energy that can be collected is approximately 59%, a limit referred to as the Betz limit. The power production output of a wind power plant depends on wind speeds, air density and the turbine characteristics. Most wind power generators have a cut-in speed of 3-4 mps and a cut-off speed of around 20-35 mps. Thus, wind power is a variable and intermittent power resource with zero dispatchability[5]. A single wind turbine is highly intermittent. The intermittency of large scale wind power production is reduced as the number of wind farms and locations increases in a power system. A large enough number of wind farms located at different geographical locations will theoretically deliver a certain amount of base load power and thus have a percentage of its production as non-intermittent power.

[5] The ability of a given power source to increase and/or decrease output.

3.1.2 Solar Power

Solar power production converts solar irradiance to electricity. This is done either directly or indirectly using photovoltaics (PV) or concentrated solar power (CSP) respectively. PV converts the radiation directly into direct current power. CSP directs the radiation into a concentrated beam, which is then used to heat up a source that is later transformed into electricity via a conventional power plant. The amount of power produced depends on the irradiation received and the efficiency of the solar cell. The solar irradiance received per square meter variates depending on the location, time of the day, day of the year and the climate. Both the temperature and the atmospheric transparency are important climate factors that affects the power production of a solar power plant. Solar power is therefore, similar to wind power, a variable and intermittent power resource with zero dispatchability.

3.2 Hydro Power

Hydro power production harvest the potential energy stored in elevated water by sending it through a water turbine connected to a generator. With an efficiency of around 85%, hydro power is the most efficient power source we have. In addition to being efficient, hydro power has a very low marginal cost which is often – like for I-RES – simplified to 0 €/MWh.

Hydro power plants can roughly be divided into three types based on how the water is stored:

- Storable inflow
- Non-storable inflow
- Pumped storage plant

Plants with storable inflow has the capability of adjusting their production according to demand. The inflow not used is stored in reservoirs. These plants also possess the ability to adjust their output quickly making them well suited to cover rapid changes on the demand side.

Plants with non-storable inflow is most commonly referred to as run of river (RoR). These plants have no reservoirs and must thus produce when the water arrives.

Pumped storage plants pumps water from one reservoir to one at a higher elevation. The stored water is then used for production when needed. The net generation of pumped storage plans is negative due to energy losses related to elevating the water.

4 EMPS model

4.1 General overview

EMPS (EFI's Multi-area Power-market Simulator) is a simulation tool developed by EFI (Norwegian: Elektrisitetsforsyningens Forskningsinstitutt), the predecessor to SINTEF. It is a stochastic optimization model for power systems with a large share of hydro power. It is used for price forecasting, production scheduling and corporate-/governmental production scheduling. Among its users are major Nordic power producers and regulators as well as TSO's. The model objective is to maximize the socio-economic surplus, i.e. the sum of producer and consumer surplus.

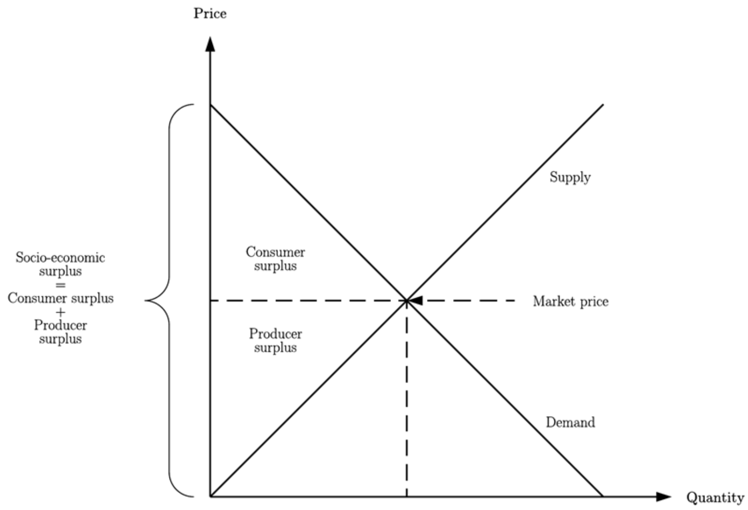

Figure 4.1 Demand and supply curve.

EMPS consists of two parts, a large data set with historic values for inflow, wind, temperatures, consumption etc., as well as an optimization model. The model uses a two-step solution procedure. First, the water values for each individual area are calculated. During this phase, each area is assumed decoupled from the rest. Secondly, a system simulation is performed in which the areas are reconnected. Based on the calculated water values the optimal operation[6] of the connected system is found.

The following sections will briefly go over the methodology of the EMPS model as described in [7] and [8].

[6] Since the problem is non-convex, an optimal solution cannot be guaranteed, but experience and comparison to other existing solutions indicates that the solution usually lies close to the global optimum.

4.2 The strategy phase

Using Stochastic Dynamic Programming (SDP) the expected marginal water values are calculated. To bring computation times down to an acceptable level, all plants and reservoirs within each area are aggregated to one large unit.

When calculating water values in one area, demand, production and exchange potential to other areas must be taken into account. Otherwise, water values would be zero for a typical production area and equal to the rationing cost in a typical demand area. To account for this, two parameters are described for each area - the feedback factor and the form factor. These factors are more thoroughly defined in chapter 4.2.6. The model makes an initial estimation for these parameters, but recalibration is possible through manually changing the values.

4.2.1 Area modelling

EMPS is a multi-area model. The transfer lines are modelled using their transmission capacity[7] (in MW), linear or piecewise linear losses (in percent) and transmission fees (in cent/kWh). Figure 4.2 gives an example of a model used in the EMPS model.

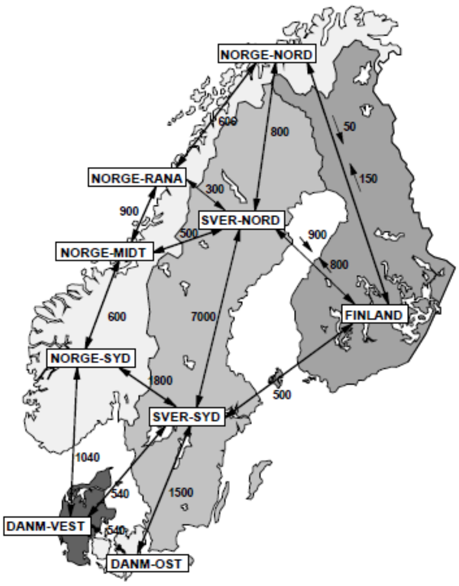

Figure 4.2 Example of an EMPS system model. [7]

Each separate area is modelled with components as shown in Figure 4.3.

[7] May depend on the time of day.

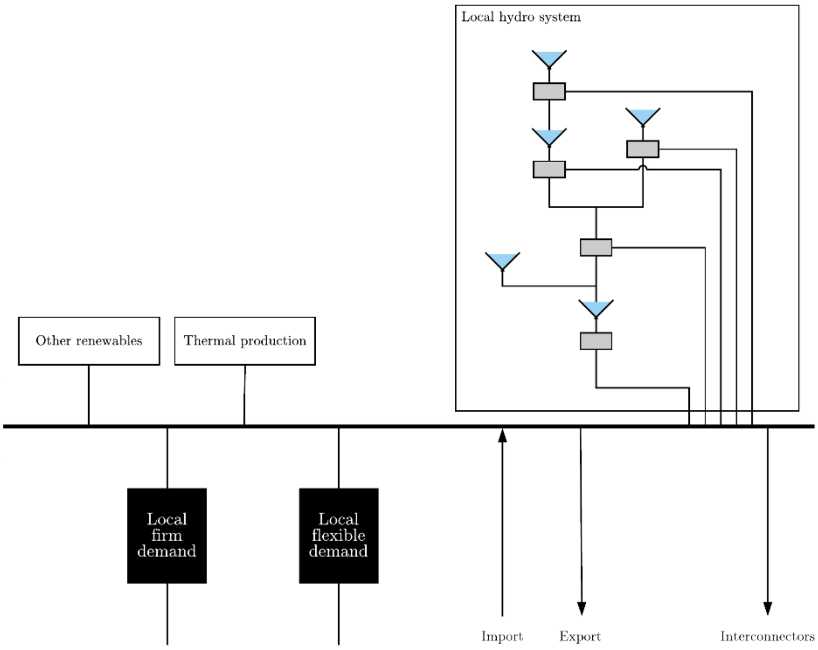

Figure 4.3: Local area model.

4.2.2 Hydro modelling

There is a vast difference between the size, design and overall complexity of a hydro power system. While some may only contain fairly simple Run-of-River plants, other system might include an interconnected system of plants and reservoirs, substantially complicating the system modelling.

The EMPS model has a standard model for defining a module in the hydro system. Each module is described by its reservoir, storable and non-storable inflow, plant discharge, spillage and bypass (see Figure 4.4).

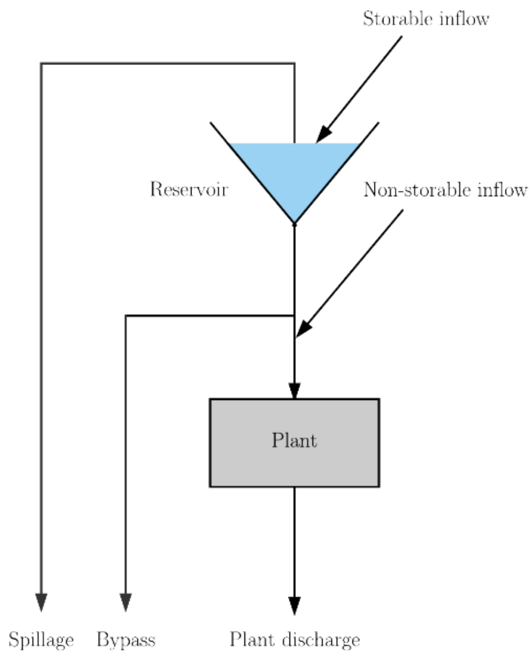

Figure 4.4: Standard hydro power module used in the EMPS model.

4.2.2.1 Plant

Each plant must, as a minimum, have a defined plant discharge capacity (in m^3/s) and an attribute called the energy equivalent (in kWh/m^3). The energy equivalent is calculated based on the plant's head and efficiency:

$$e = \frac{1}{3.6 \cdot 10^6} \cdot \gamma \cdot g \cdot H \cdot \eta \qquad (3.1)$$

γ: Water density $[kg/m^3]$
g: Gravity $[m/s^2]$
H: Head [m]
η: Efficiency

This attribute tells us how much electrical energy can be produced by the plant. It can take two forms, the local and the total one. Distinguishing between these two forms is important. The local energy equivalent gives us information about that hydro module isolated (as given by the formula above). For cascaded plants, however, water may also be used in downstream plants. The total energy equivalent for a plant is the sum of the local energy equivalent of a specific plant and all the downstream plants where the same water is used.

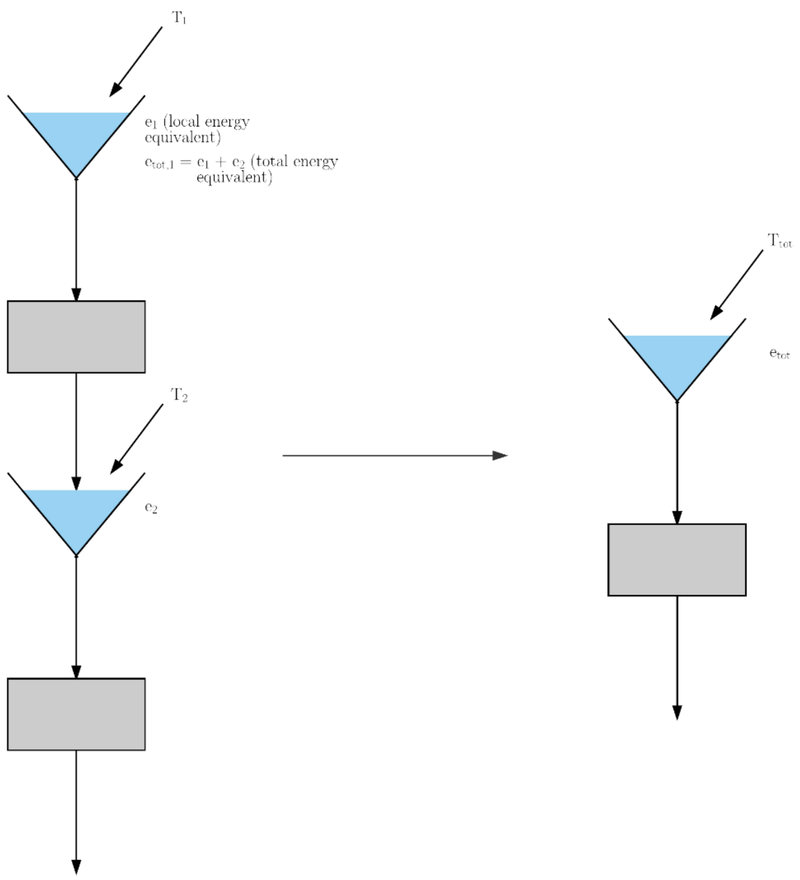

Figure 4.5 Local and global energy equivalents.

4.2.2.2 Reservoir

The reservoir must be given (and may also be zero if the module has no reservoir) in million cubic meters (Mm^3). More advanced characteristics may also be given such as the reservoir curve (the relationship between the reservoir volume and level).

4.2.2.3 Inflow

Inflow is categorized as storable or non-storable, and is measured in Mm^3 per year. Storable inflow enters the reservoir while non-storable inflow goes directly into the plant. Spillage occurs if the non-storable inflow exceeds the plant discharge capacity. In general, non-storable inflow is rarely used at the detailed level. Even if the plant characteristics suggest the inflow is non-storable, such modules are usually modelled with a small intake reservoir (even RoR plants).

The storable inflow is calculated multiplying the total inflow with the regulating factor and the non-storable inflow is the remaining share of the total inflow.

Since future inflow cannot be known, statistical data gathered over certain amount of years for each area is used to account for the uncertainty.

4.2.2.4 Aggregation

To reduce computation time, the EMPS model aggregates all hydro modules within an area to an equivalent reservoir. One unit of water will equal different quantities of energy based on the reservoir it is in. Thus, for aggregation to make sense the water contained in the individual reservoirs has to be converted to a universal unit. Thus, in the aggregate model, all water volumes are converted to energy.

Plant
The equivalent plant is modelled by aggregating maximum capacities for all individual plants. The discharge constraints are also taken into account, and represented as maximum and minimum production constraints for the equivalent plant.

Reservoir
All reservoirs within an area are aggregated to an equivalent reservoir. This is done multiplying the reservoir volume with the total energy equivalent. Reservoir constraints on the detailed level are converted to the equivalent model.

Energy inflow
Even if the non-storable inflow is little used at the detailed level, it is very important to account for at the aggregated level. Otherwise it would not be possible to represent situations where a number of the individual hydro modules in the system are flooded.

Storable and no-storable inflow are calculated as follows [7]:

	Storable inflow =
	Sum production (including time-of-purchase contracts)
−	Energy used for production
+/−	Increase/decrease in reservoir volume

	Non-storable inflow =
	Generation due to non-storable inflow to power stations
+	Generation due to minimum constraints (discharge/bypass)
+	Generation necessary to avoid spillage
−	Energy used for pumping to avoid spillage

4.2.3 Thermal modelling

Thermal plants are modelled based on their capacity (in MW) and variable production cost (in cent/kWh). Variable production cost includes fuel cost, variable maintenance cost, startup-/stopping costs and emission costs. A thermal plant will produce if its variable costs are below the power value (i.e. the system marginal cost) and in stand-by when the variable costs exceed this value.

Other possible specifications include plant availability (in %) and outage rates. Availability is modelled using the Expected Incremental Cost method. Summarized, unavailability of plants with low variable costs will cause a cost increase for plants with a higher variable cost. Essentially, this causes a raising of the thermal cost curve (see Figure 4.6).

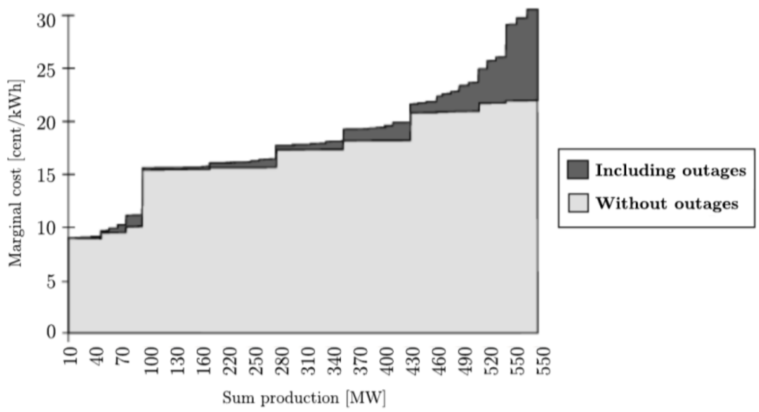

Figure 4.6: Raising of the thermal curve as a result of outages. [7]

The given data basis has aggregated all thermal plants within each category (oil, gas, coal and bio) to one large unit. To get a more realistic representation of the variation within thermal plants in the system, they have been divided into several smaller units with varying efficiencies. Bio, oil and coal are split into three, while gas is split into nine to account for the diversity of gas utilization in the market (conventional gas power, combined- and open cycle gas turbines).

4.2.4 Wind and solar modelling

As with inflow, statistical data over a certain period of time is used to account for uncertainty in future wind intensity and solar irradiance. The data is normalized and scaled to the installed capacity

4.2.5 Demand modelling

4.2.5.1 Firm demand

Firm demand represents the demand from industry and service sectors, and constitutes the majority of total demand. Firm demand is regarded inelastic, and can only be reduced through rationing (see chapter 4.2.5.3).

In the model, firm demand is defined by an annual quantity (in GWh), an annual demand profile (with time step one week) and a distribution between load periods within the week.

4.2.5.2 Price elastic demand

Price elastic demand is "switched off" when the power value exceeds a set value called the switch-off price. It is defined by a weekly quantity (in GWh) as well as the switch-off price (in cent/kWh).

4.2.5.3 Rationing

When the firm demand exceeds the energy supply, one must find a way of reducing the demand so that the numbers are balanced. This can either be done by shedding or curtailing load. In the case of load shedding certain lines might be disconnected from the grid for a required amount of time, while load curtailment means producers and consumers might be forced to hold back production and reduce consumption respectively.

In EMPS, this is modelled as an infinite supply with a very high price (such that the power value will never rise beyond this value). The high price reflects the economic implications rationing has in real life.

4.2.6 Calibration

The value of stored water is in reality not independent of the situation in other areas connected to the same power market. Since EMPS calculates water values independently for each area, information about connectivity with other areas must in some way be included during the water value calculations. This is done using the mentioned parameters feedback- and form factor. In addition, a lot of heuristics are used in the solution process, meaning optimal solution is not guaranteed.

The process of adjusting the mentioned parameters is called calibrating the model, and is done to obtain the best possible operation strategy for the hydro power. When deciding whether to run a calibration or not, one must decide whether the obtained results using the initial parameter values are satisfying or whether better results can be acquired. This is usually done observing simulated reservoir handling and operational costs for the whole system.

The EMPS model has a built-in automatic calibration that adjusts the parameters according to an internal algorithm as well as some user specific input. The user decides in which order the parameters should be adjusted. The model then proceeds with a stepwise adjustments, examining the sosio-economic surplus before and after the adjustment to determine whether or not the adjustment had a positive or negative impact (i.e. positive or negative change in sosio-economic surplus). If the impact of the adjustment was negative, a stepwise adjustment in the other direction is made to examine if that yields a positive impact. If the impact was positive, more stepwise changes in the same direction are made until adjusting the parameter no longer yields a positive change in surplus. After reaching the optimal value for one parameter, the algorithm proceeds to the next in line as per defined by the user. The process is repeated several times for different step lengths until no adjustments yields a positive impact.

Manual calibration is also possible. This process is largely experience-based, but as a rule of thumb it can be said that if the reservoir levels are too high, the feedback factor has to be decreased, and if the reservoir levels are too low the factor has to be increased.

4.2.6.1 Feedback factor

The feedback factor decides how much firm demand in other areas of the power system is taken into account during the water value calculations. Firm demand usually constitutes a large share of the total demand and reduction of firm demand is very expensive. The feedback factor thus has a direct influence on the water values and reservoir handling.

4.2.6.2 Form factor

The form factor decides the annual load distribution. A factor of 0 gives a flat distribution while increasing values gives higher load during the winter compared to the summer. Areas with a significant seasonal variation in load would thus require a higher form factor. The factor scales around the average load value.

4.2.6.3 Elasticity factor

The elasticity factor alters the distance between the iso price curves for an area. A small elasticity factor decreases the quantity available at each price level. In turn, this leads to tighter iso price curves and thus decreases the solution space for the reservoir handling.

4.3 Simulation phase

After the water values for each area are calculated during the strategy phase, one must perform a system simulation to see how the system behaves for the different inflow alternatives. Since the water values are not optimal for any of the inflow scenarios, the simulation will give the expected solution space using the established strategy. The simulation logic is based on:

1. Area optimization: using a network algorithm an optimal solution for the system on the aggregate level is found.
2. Reservoir drawdown: the optimal production from the strategy phase is distributed out among all the reservoirs in the system in a rule-based model. Whether restrictions regarding the different hydro modules in the system are satisfied is controlled during this step.

The interaction between area optimization and reservoir drawdown is illustrated in Figure 4.7

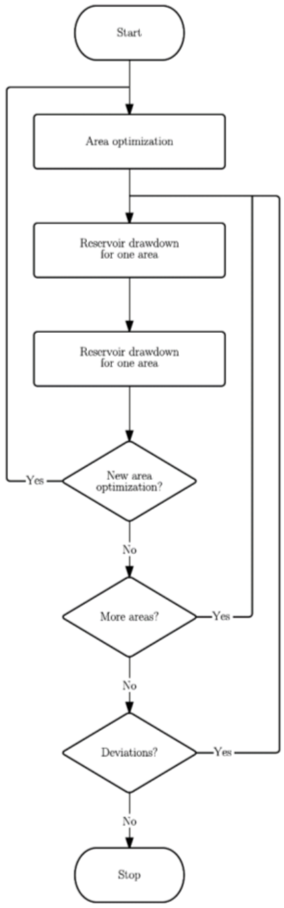

Figure 4.7: The interaction between the aggregate area and reservoir drawdown model.

4.4 Investment module

The EMPS model is no integrated operation and investment model and can only optimize investments with an additional iterative methodology. This additional methodology is called the investment module and can be utilized to either expand capacities of profitable assets or decommission non-profitable assets. By utilizing this functionality, it is possible to adjust the simulated system in a more realistic manner.

Figure 4.8 shows the interaction between the EMPS model and the investment module. Step 2 and 3 describes the input for the model. The latter is the additional input needed for the investment module, such as capital expenditures (CAPEX) and operational- and maintenance expenditures (OPEX) for the examined assets. Parameters such as step length, maximum iterations, maximum capacities etc. are also included. Step 3, 4, 6 and 7 describes the iterative process were capacities are adjusted until the system convergences or the maximum number of iterations is performed. If one of these criteria's are met, the final results are stored (step 10 and 11).

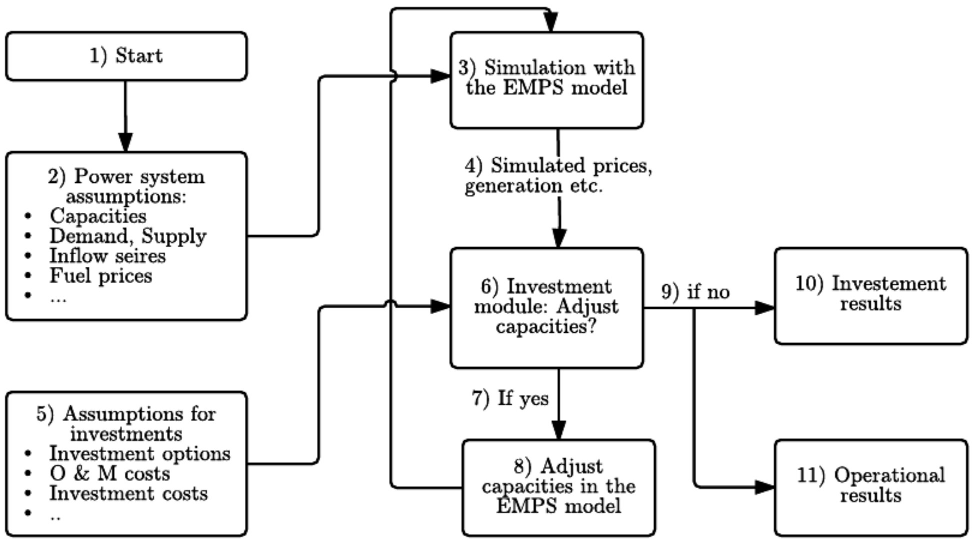

Figure 4.8: Interaction between the EMPS model and the investment module.

The investment decision is based on profitability calculations executed on the simulated results from the EMPS model, which include both CAPEX and OPEX. An asset is profitable if revenue minus CAPEX and OPEX is positive. The capacity of profitable assets will increase iteratively until no longer profitable. This is done using a gradient search method. This method increases highly profitable assets using a larger step length than less profitable. This way, the profitability ratio between different assets is better accounted for.

Calculations concerning the decommissioning of assets only include OPEX as the CAPEX already has occurred. The capacity of unprofitable assets will be decreased until they're profitable or the capacity is zero.

A more thorough description of the investment module in EMPS can be found in [9].

5 Water Values

The objective of most hydro power scheduling models is to minimize the expected value of the system's operational costs. Figure 5.1: Available resources for meeting the power demand illustrates the available resources for meeting the demand. Minimizing total operational costs will be to always use energy from the cheapest available source. To do this, however, the price of all resources must be known. When it comes to hydro, the expected value of the next kWh produced is what is known as the *water value*.

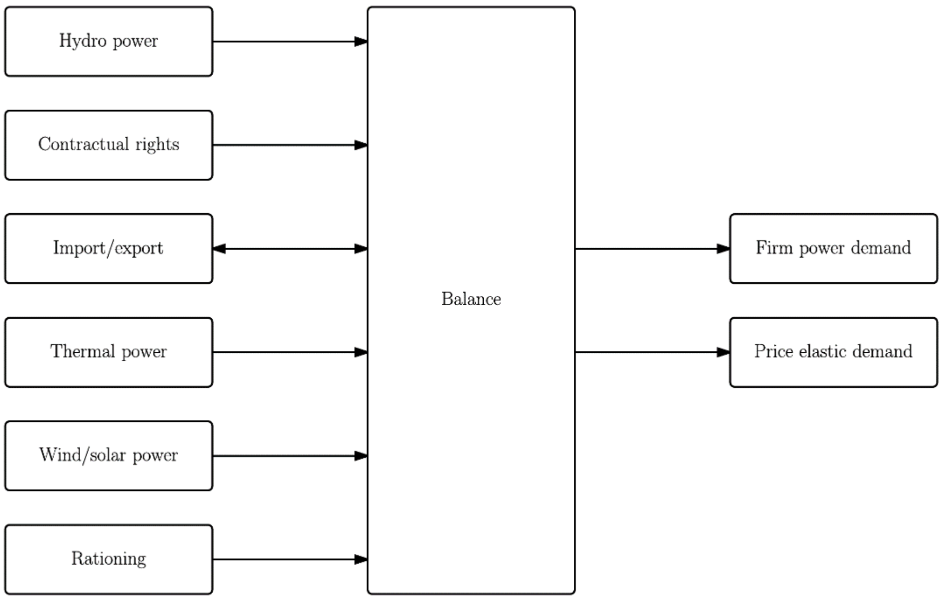

Figure 5.1: Available resources for meeting the power demand.

Finding the water value is no straightforward task. Even though hydro power has no clear fuel cost, water is a limited resource and must be treated as such. Within hydro production we distinguish between two extremes - spillage and overproduction. Spillage can occur during times of restrained production or excessive rainfall. Overproduction can be the result of bad scheduling or unexpected drought, causing reservoirs to empty. Both cases represent lost business for the hydro producer, meaning optimal production must be somewhere in between these extremes.

5.1 Mathematical formulation

Function *J(x,k)* represents the expected value of total operational costs from the start of week *k* until the end of the scheduling period. With a time step of one week, the total operational costs can be expressed as follows:

$$J(x,k) = S(x,N) + \sum_{i=k}^{N} L(x,u,i) = L(x,u,k) + J(x,\mathrm{k}+1) \tag{4.1}$$

S(x,N)	:	The value of the reservoir at the end of the scheduling period as a function of reservoir level *x*.
L(x,u,i)	:	Total operation dependent costs going from period *k* to *k + 1*.
u	:	Energy outtake from own reservoir to produce energy quantity *p*. $u = \mathrm{f(p)}$

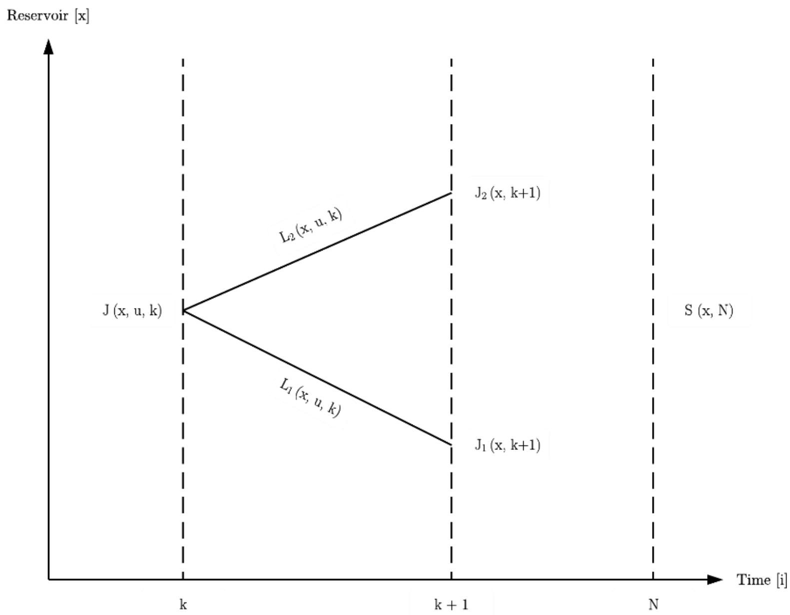

Figure 5.2: The scheduling period split into weeks from *k* to *N*.

The total expected operational costs from time *k* equals the sum of all variable costs *L(x,u,i)* throughout the period plus the value of the reservoir at the end of the scheduling period. If the latter was not included, it would have been emptied due to it being considered a free resource. This is equal to adding the operational costs for week *k* with the cost from week *k + 1* until the end of the planning period.

The variable costs will vary depending on the energy outtake from the reservoir, *u*. This is illustrated in Figure 5.2: The scheduling period split into weeks from *k* to *N*. where line *L1* and *L2* constitutes full production and no production respectively. The goal is to find the energy outtake which minimizes the operational costs. This is done minimizing total operation dependent costs with respect to the energy outtake, *u*, at time step *k*:

$$\min\{J(x,k)\} = \min\{-L(x,u,k) + J(x,k+1)\}$$
$$\frac{dJ(x,k)}{du} = 0 \tag{4.2}$$

Derivating the above term gives an optimality condition for energy outtake throughout the planning period:

$$\frac{dJ(x,k)}{du} = \frac{\delta L(x,u,k)}{\delta u_k} + \frac{\delta J(x,k+1)}{\delta x_{k+1}} \cdot \frac{\delta x_{k+1}}{\delta u_k} \tag{4.3}$$

With the derivative of reservoir level with respect to energy outtake equaling -1, the optimality condition can be expressed:

$$\begin{gathered} \frac{\delta x_{k+1}}{\delta u_k} = -1 \\ \rightarrow \frac{\delta L(x,u,k)}{\delta u_k} + \frac{\delta J}{\delta x_{k+1}} \cdot (-1) = 0 \\ \rightarrow \frac{\delta L(x,u,k)}{\delta u_k} = \frac{\delta J(x,k+1)}{\delta x} \end{gathered} \tag{4.4}$$

$\frac{\partial L}{\partial u_k}$	:	Marginal operation dependent costs associated with sale, purchase, rationing etc.
$\frac{\partial J}{\partial x_{k+1}}$	:	The derivative of total operational costs with respect to reservoir level, i.e. the marginal water value at time *k + 1*.

Thus, we see that the optimal production is found when the marginal operational costs equals the marginal water value. To determine production in week *k*, the production should equal the marginal water value in week *k + 1*

6 Assessing the European power system

The EMPS model requires a data set as input for the simulations. The simulations done in this master thesis thus requires assembly of a data sets describing the entire European power system. Presented in this chapter is the chosen basis for the data sets, as well as the actual data used in the performed simulations.

6.1 The ENTSO-E Visions

EU has initiated several measures for increasing the amount of renewable energy sources in the European power system. One of these initiatives is the establishment of ENTSO-E which represents 41 TSOs from countries across Europe. ENTSO-E's main focus is an increased share of renewable energy sources in the European market as well as creating an internal energy market (IEM) within EU. [9]

ENTSO-E is in charge of delivering a biennial report called the Ten Year Network Development Plan (TYNDP). The report investigates the projected development in demand to the development in installed capacity/generation mix and identifies gaps in the European power system. It provides interested stakeholders about potentially important transmission projects, making TYNDP the main tool used for making network investment decisions in Europe. [10]

The TYNDP-2014 included a set of Visions for the European power system in 2030. They differ based on the pace that the share of RES is increased in the system as well as the generation mix development strategy. The Visions are summarized in Figure 6.1. Located within a coordinate system, the figure illustrates how the Visions change according to decisive factors. As can be seen, the x-axis represents the level of IEM integration [11] while the y-axis depicts the trajectory toward the Energy Roadmap 2050 [12]. More than forecasts, the scenarios are possible extremes of the future. Thus, they are designed in such a way that the actual future developments to a high degree of certainty will lie within the boundaries set by the Visions.

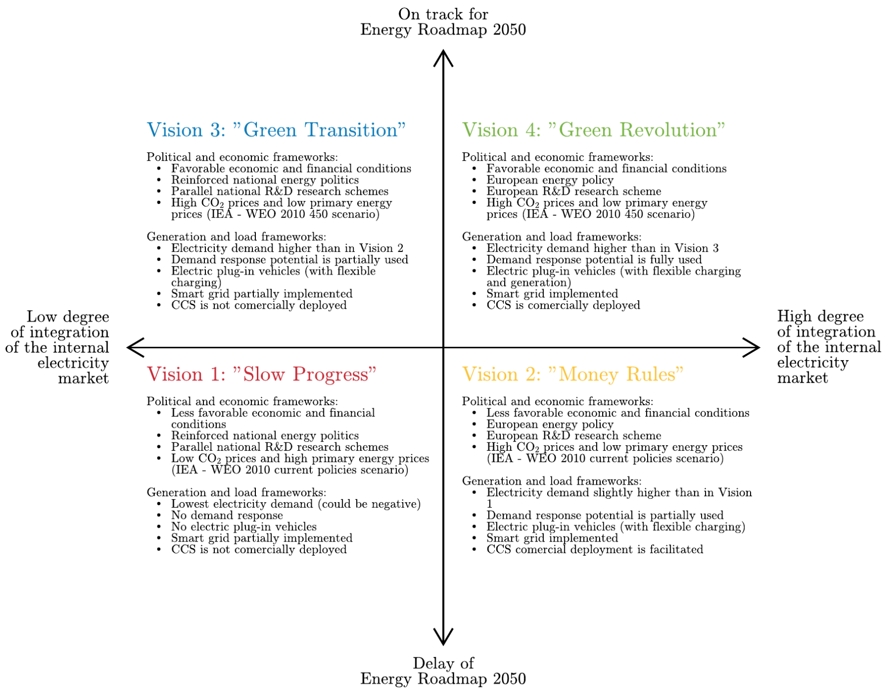

Figure 6.1: Description of ENTSO-E Visions.

The basis for the simulations done in this master thesis is Vision 2 and 4. The following segment features a brief description of these visions.

6.1.1 Vision 2: "Money Rules"

The vision reflects a cautious progress towards the 2050 Energy Roadmap goals. It is driven by high return on investment rates and fails to meet EU's goals for 2030. The vision features a high degree of cooperation within Europe (i.e. high level of IEM integration), resulting in a more homogenous price picture across the region.

Compared to 1990 levels, Vision 2 features a reduction of GHG emissions of 40 percent. Apart from extreme cases, generation is in Vision 2 sufficient to cover the load. High IEM integration also helps eliminate residual spillage of RES.

6.1.2 Vision 4: "Green Revolution"

The vision follows an ambitious path towards the 2050 Energy Roadmap goals. 60% of load is in this vision covered by RES within 2030. As in Vision 2, a high level of cooperation within Europe is assumed. An optimized power supply ensures maximum utilization of every country's situation and interconnection capacity.

Across all countries, the vision features a high increase in installed RES capacity, with emphasis on wind and solar power. Carbon capture and storage (CCS) technology is assumed available in all countries. Compared to Vision 2, this vision includes a threefold increase in CO_2 prices, increasing the importance of CCS.

Emissions are down 78 % compared to 1990 levels. High overall RES penetration contribute to strong price differentials between certain countries, as well as significant residual spillage of RES. These issues could potentially be mitigated by new interconnection investments.

6.2 The Scenarios

Three individual scenarios were created. These scenarios were named Scenario 1 (S1), Scenario 2 (S2) and Scenario 3 (S3)

S1 is the implementation of Vision 2 while S2 is the implementation of Vision 4. Vision 2 and 4 were chosen out of the four Visions described by ENTSO because their progress towards the Energy Roadmap 2050 goals [14] differ greatly, but they both feature a high degree of integration of the internal electricity market. The EMPS model assumes perfect competition, also between countries, and thus fits best with the Visions having a high degree of integration on the internal electricity market.

S3 is based on Vision 4 but with an increase in I-RES capacity to reach approximately 80 % RES penetration. The idea behind this scenario is to test a case with an extreme degree of RES penetration closer to the EU 2050 GHG emission goals. This was done by increasing the I-RES capacity in all countries by 100 % compared to Vision 4. No other changes were made to the S3 dataset compared to S2.

6.3 Data sets

The performed simulations are based upon data provided by ENTSO-E for the 2030 Visions established in the TYDP-2014 [10] as well as supplementary data gathered elsewhere. Data not gathered from TYDP is labeled with their source. The final data sets were assembled manually and tailored for use with the EMPS model. The rest of this chapter gives an overview of the provided data from TYDP-2014 as well as the assembly process and necessary modifications. As with everything attempting to predict future developments, the data is subject to uncertainty.

The focus of this Master's thesis is to examine changes in the power system focusing on generation, prices, transmissions and asset profitability. Some high-impact areas are also examined in more detail. The presented data thus reflects this, giving an overview of the system and the data used for each of the scenarios. Also, more detailed data for the examined areas (Germany, France, Great Britain and Norway) is given.

6.3.1 Areas

The European power system is modelled with 33 areas, each corresponding to an ENTSO-E member state. The geographical scope of the simulations is illustrated in Figure 6.2 with area description being given in Table 6.1.

It should be noted that, due to the geographical perimeter of the simulations, some properties that might otherwise have influenced the results are excluded. Most notably, import from Russia to Finland and from Morocco to Spain is not included.

Country code	Country
AT	Austria
BA	Bosnia and Herzegovina
BE	Belgium
BG	Bulgaria
CH	Switzerland
CZ	Czech Republic
DE	Germany
DK	Denmark
EE	Estonia
ES	Spain
FI	Finland
FR	France
GB	Great Britain
GR	Greece
HR	Croatia
HU	Hungary
IE	Ireland
IT	Italy
LT	Lithuania
LU	Luxembourg
LV	Latvia
ME	Montenegro
MK	Republic of Macedonia
NI	Northern Ireland
NL	Netherlands
NO	Norway
PL	Poland
PT	Portugal
RO	Romania
RS	Serbia
SE	Sweden
SI	Slovenia
SK	Slovak Republic

Table 6.1: Countries and country codes.

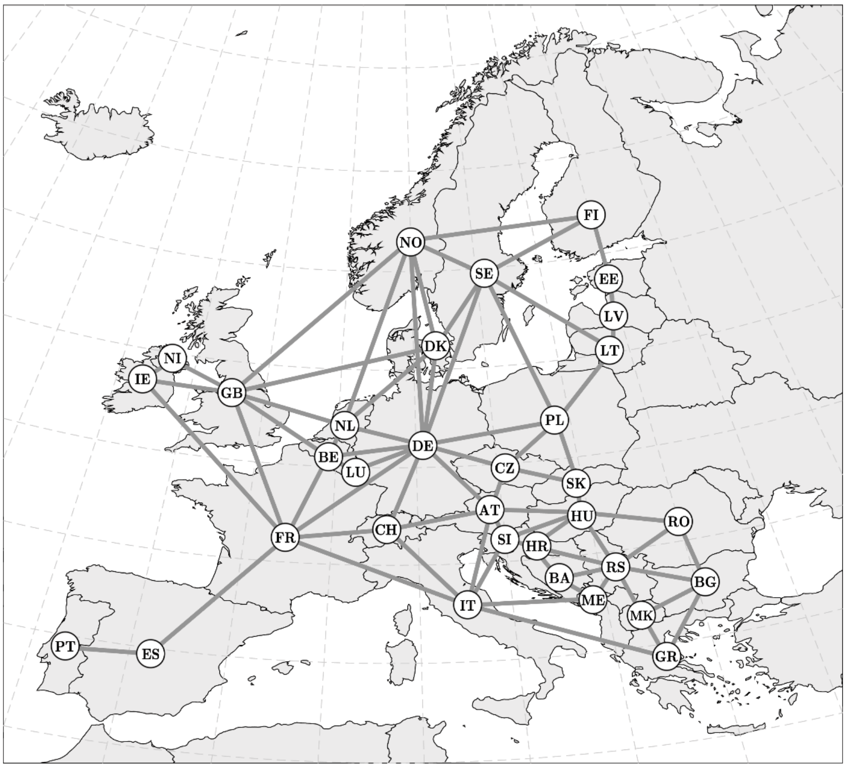

Figure 6.2: The geographical scope of the simulations - nodes and interconnections.

6.3.2 Interconnections

Each area is connected to one or more of the other areas through an interconnection line with a given capacity in megawatts. The capacity may vary depending on the direction (i.e. the import capacity might be different from the export capacity). The development on the grid compared to the status quo is based on transmission projects set to be completed before 2030. An example of such a project would be the North Sea Network (NSN) link connecting Norway and Great Britain set to be completed in 2021 [13].

A graphical representation of the European power grid was given in Figure 6.2. Interconnection capacities for the examined areas are shown in Table 6.2. Note that capacities for Visions 2 and 4 are the same, and thus only one table is presented. For a detailed view on interconnection capacities between all areas, see Appendix B.

Country		Capacity [MW]	
From	To	Export	Import
DE	AT	7500	7500
	BE	1000	1000
	CH	5000	5000
	CZ	2000	2600
	DK	3000	1600
	FR	4100	4100
	LU	2300	2300
	NL	5000	5000
	NO	1400	1400
	PL	2000	3000
	SE	1200	1200
GB	DK	1400	1200
	FR	4400	4400
	IE	1200	1200
	NI	500	500
	NL	1000	1000
	NO	1400	1400
FR	BE	4300	2800
	CH	4700	2800
	DE	4100	4100
	ES	5000	5000
	GB	4400	4400
	IE	700	700
	IT	4350	2200
NO	DE	1400	1400
	DK	1700	1700
	FI	100	100
	GB	1400	1400
	NL	700	700
	SE	3695	3995

Table 6.2: Overview of transmission capacities for Germany, France, Great Britain and Norway. [10]

6.3.3 Generation capacity

The main difference regarding the development of installed capacity between the Visions is the pace at which RES share is increased in the system. Depicted in Figure 6.4 and Figure 6.5 is a breakdown of the installed capacity mix for Vision 2 and 4. For reference, the capacity composition in 2014 is given in Figure 6.3 ENTSO-E has stated that Visions 1 and 2 assume a slow start towards the European energy goals for 2050 with an acceleration after 2030, while Visions 3 and 4 maintains a regular pace throughout the whole period. This is underlined by comparing the given figures.

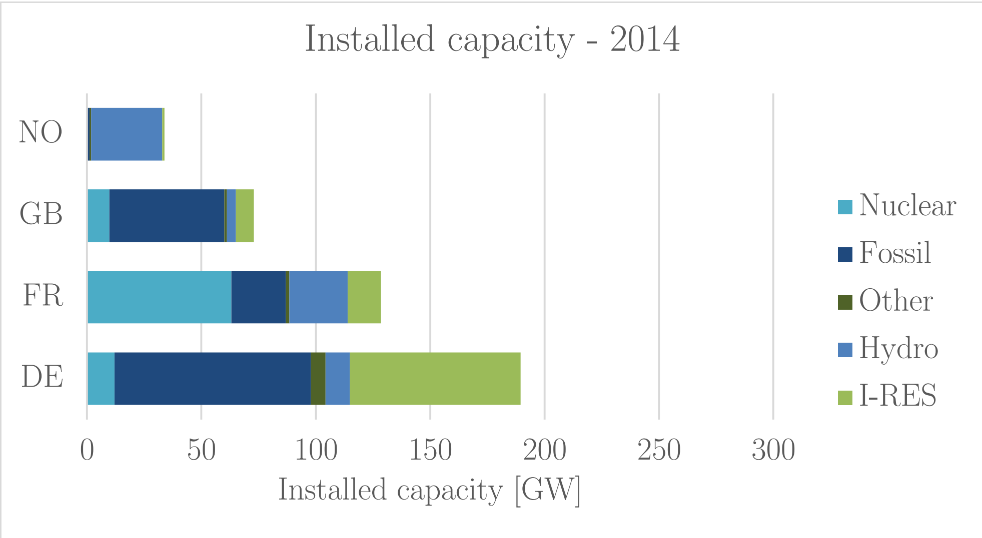

Figure 6.3: Installed capacity – 2014 [2]

6.3.3.1 Scenario 1

Apart from Great Britain (which sees an increase of around 3 TW), S1 does not experience a significant change in total installed capacity compared to 2014 values. The main difference between the two is found examining the mix of energy sources. Among the most notable changes is an increase in I-RES capacity across all countries, with emphasis on Great Britain which see a fourfold increase. Another interesting observation is the reduction of nuclear power in both France and Germany, with the latter completely phasing out nuclear power as a source of energy. Observable is also a reduction in thermal power across all examined countries as well as an increased share from ‘ Other’ energy sources (consisting mainly of bio power).

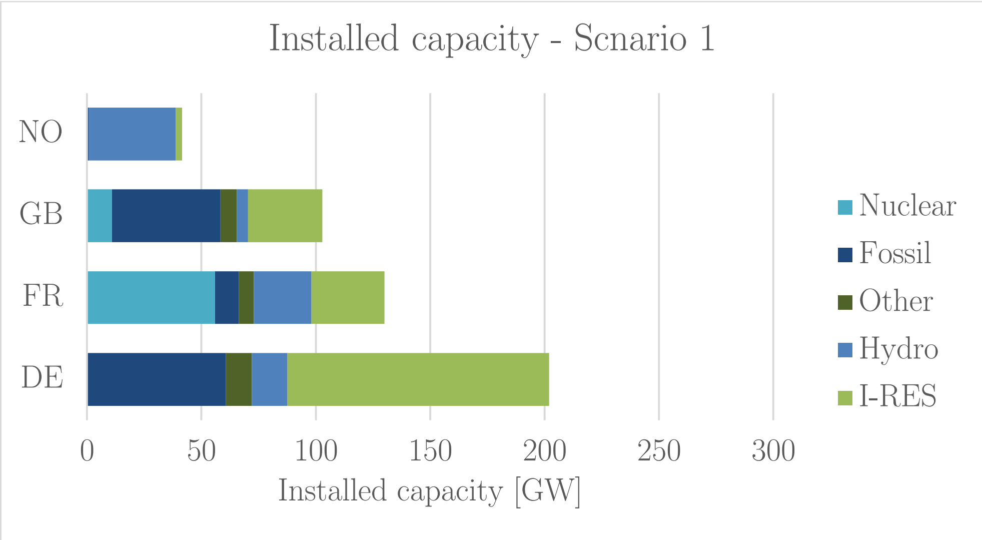

Figure 6.4: Installed capacity – Scenario 1. [10]

6.3.3.2 Scenario 2

Big changes can be observed for all examined countries, in terms of both installed capacity and energy mix. Increases in total installed capacity between 60 and 100 percent compared to 2014 levels can be seen for all countries. As expected, installed thermal capacity is reduced across all countries, but interestingly enough the levels are higher than for S1. With a huge increase in overall I-RES capacity, the system flexibility must be increased to cope with generation swings. The increased thermal capacity compared to S1 is thus caused by an increased share of gas, which in turn increases the system flexibility. Underlined by Figure 6.6, a shift from coal to gas power can be observed going from S1 to S2. Amongst others, the shift is incentivized by different fuel and CO_2 prices between the two scenarios, further discussed chapter 6.2.6.

As for S2, a reduction in nuclear capacity can be observed for France and Germany, while Great Britain sees a moderate increase. Apart from Norway which experiences a considerable increase in hydro power capacity, hydro capacity stays largely the same, with only minor increases across the three other countries. The three do, however, experience a drastic relative increase in bio power (which is the main component of the 'Other' category).

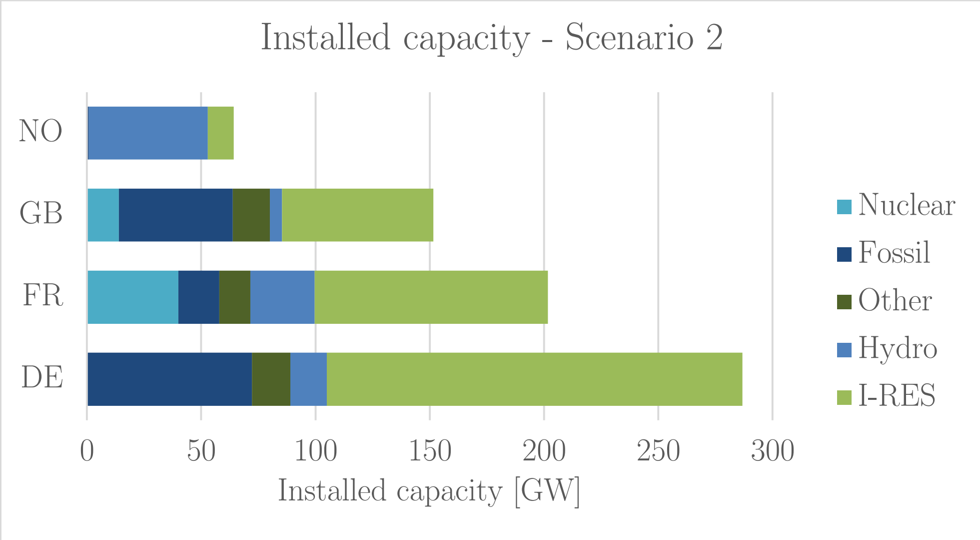

Figure 6.5: Installed capacity – Scenario 2. [10]

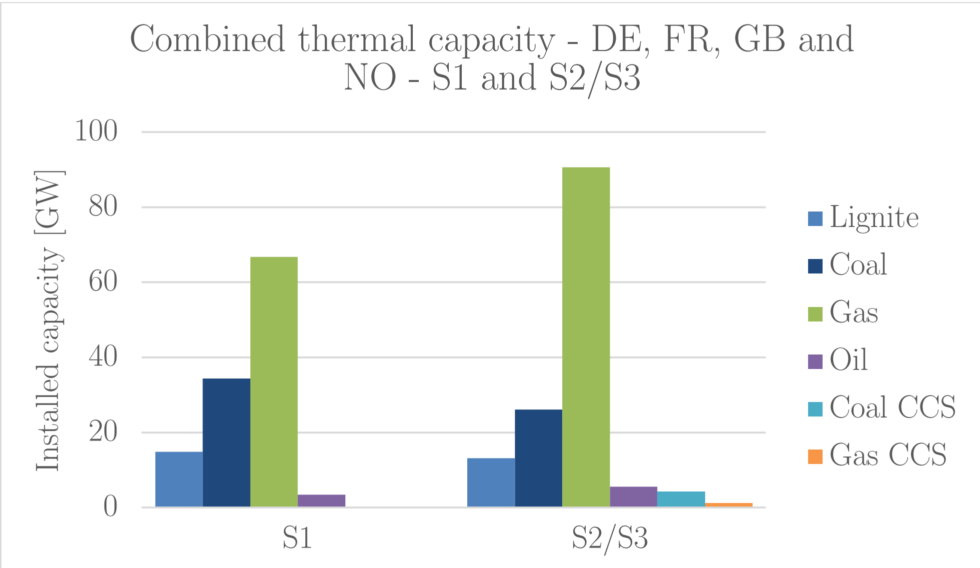

Figure 6.6: Combined thermal capacity – Scenario 1 and Scenario 2/3. [10]

6.3.3.3 Scenario 3

As previously mentioned, S3 is identical to S2 apart from a twofold increase in I-RES capacity. Thus, a 100 % capacity increase is found for wind and solar power, giving the distribution seen in Figure 2.1.

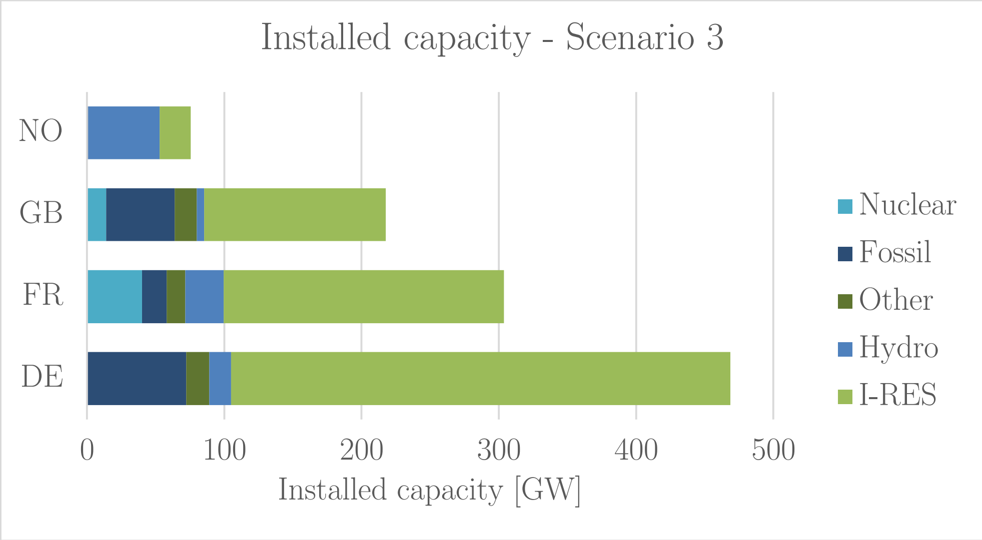

Figure 6.7: Installed capacity - Scenario 3.

6.3.3.4 Total installed capacity

Given in Figure 6.7 is total installed capacity across all countries broken down for each energy source. The overall trend correlates well with what was found examining selected countries, with a clear increase in hydro power, I-RES and biomass (the main component of the ‘ Other’ category) compared to 2014 levels for both Visions. As discussed in chapter 6.2.3.2, a shift from coal to gas power takes place between Vision 2 and 4 with a need for increased system flexibility. The thermal capacity is still, however, considerably lower than in 2014.

Detailed information on installed capacity for all countries can be found in Appendix A.

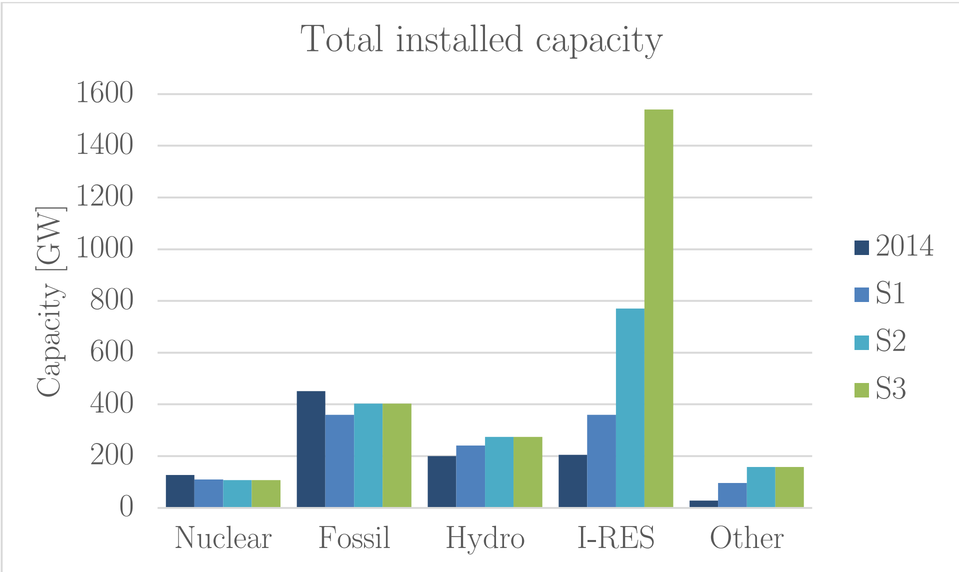

Figure 6.8: Total installed capacity across Europe. [2] [10]

6.3.3.5 Thermal capacity allocation

The availability factor and efficiency range for the different thermal plants is given in Table 6.3. Apart from nuclear, all thermal plant types are given three different efficiencies. To give a more realistic representation of the variation within thermal plants in the power system, thermal units are split into three separate ones with the efficiencies listed below. This goes for all thermal plant types apart from gas which is split into nine to represent the variation within gas units. A representation of the way thermal units are split is given in Table 6.4 and Table 6.5. $X_{i,j}$ represents the total capacity in country i for plant type j, while Y_i represents the total capacity in country i for gas.

Fuel type	Plant type	Availability factor [%]	Efficiency range in NCV [%]		
Bio	Bio	70	30	38	46
Nuclear	Nuclear	80	32		
Lignite	Lignite	70	30	38	46
Lignite	Lignite CCS	70	20	25	31
HardCoal	Coal	75	30	38	46
HardCoal	Coal CCS	75	20	25	31
Gas	Gas Conventional	85	25	34	42
Gas	Gas CCGT	85	33	46	60
Gas	Gas OCGT	90	35	39	44
Gas	Gas CCS	90	25	30	35
Light oil	Oil	95	32	35	38

Table 6.3: Availability factor and efficiency range for different thermal plant types.

Total installed capacity, thermal[8] [GW]		Unit #	Capacity [MW]	Efficiency [%]
X_{ij}	$\rightarrow$	1	$\frac{1}{3} X_{i,j}$	$\eta_{j,1}$
		2	$\frac{1}{3} X_{i,j}$	$\eta_{j,2}$
		3	$\frac{1}{3} X_{i,j}$	$\eta_{j,3}$

Table 6.4: Allocation of thermal capacity in country *i* and plant type *j*. Efficiencies 1, 2 and 3 are found in Table 6.3.

[8] Excluding nuclear and gas.

Total installed capacity, gas [GW]		Unit #	Plant type	Capacity [MW]	Efficiency [%]
Y_i	$\rightarrow$	1	Gas Conventional	$\frac{1}{9} Y_i$	25
		2	Gas Conventional	$\frac{1}{9} Y_i$	34
		3	Gas Conventional	$\frac{1}{9} Y_i$	42
		4	Gas CCGT	$\frac{1}{9} Y_i$	33
		5	Gas CCGT	$\frac{1}{9} Y_i$	46
		6	Gas CCGT	$\frac{1}{9} Y_i$	60
		7	Gas OCGT	$\frac{1}{9} Y_i$	35
		8	Gas OCGT	$\frac{1}{9} Y_i$	39
		9	Gas OCGT	$\frac{1}{9} Y_i$	44

Table 6.5: Allocation of gas power capacity in country *j*.

6.3.4 Demand

Demand data for all modelled countries is given in Appendix C. The demand is modelled as inelastic for 75% of the total demand for each country with a rationing price of 3000 €/MWh. The elastic demand is a linear trajectory between 2990 €/MWh at 75% of the total demand and 30 €/MWh at 100%. From 30 €/MWh at 100%, the price declines further to 0 €/MWh at 110% of total demand. This principle is illustrated in Figure 6.8.

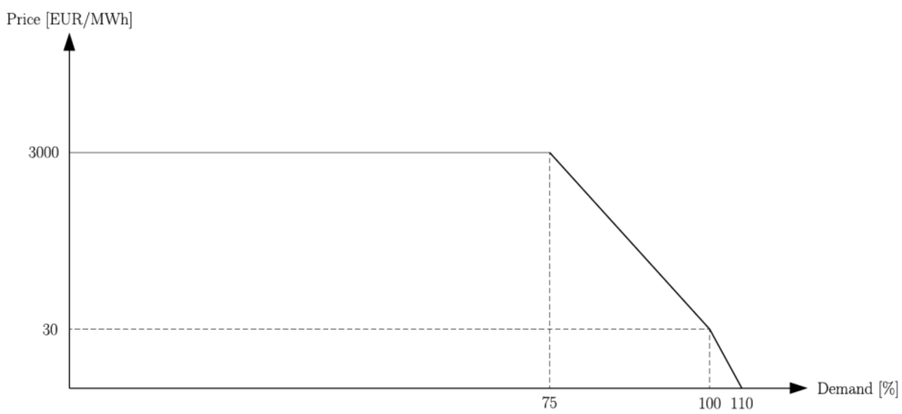

Figure 6.9: Demand modelling.

Demand is expected to grow steadily towards 2050. As illustrated by Figure 6.9, the provided data predicts a 500 TWh increase in total demand compared to 2014 levels in S1, while S2 and S3 experiences a 1000 TWh increase. The demand increase is mostly associated with electrification of heating and transport, and is based on the TSO' s highest forecast for electricity demand growth.

National specific demand is given in Figure 6.10. As can be seen, S1 experiences a moderate growth in demand compared to 2014 values for all areas (0.1 – 0.8 percent yearly increase), while S2 and S3 sees a more substantial increase (0.7 – 1.6 percent yearly). Germany represents the largest share of the total European demand and is also the country that sees the largest increase in demand.

It should be noted that with the forecasted future developments regarding electrification of heating and transport and increased demand side response (DSR)[9], a shift in the demand pattern is expected. Due to the complex nature of modelling and implementing such a shift, this has not been accounted for in the simulations performed in this master thesis.

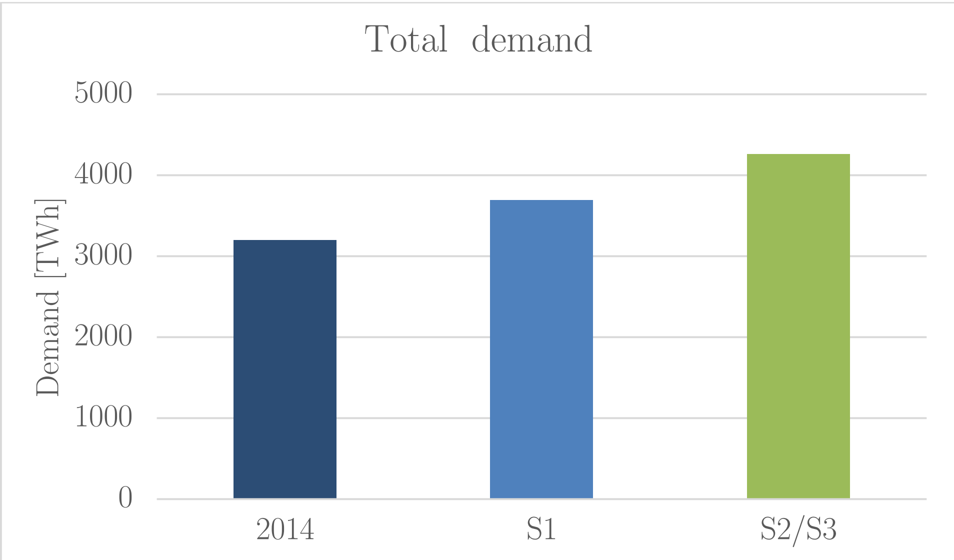

Figure 6.10: Total demand. [10] [1]

[9] The process of, through new technology, allowing consumer to play a more active role in how and when they use electricity. DSR leads to more efficient electricity usage, facilitating integration of RES into the system.

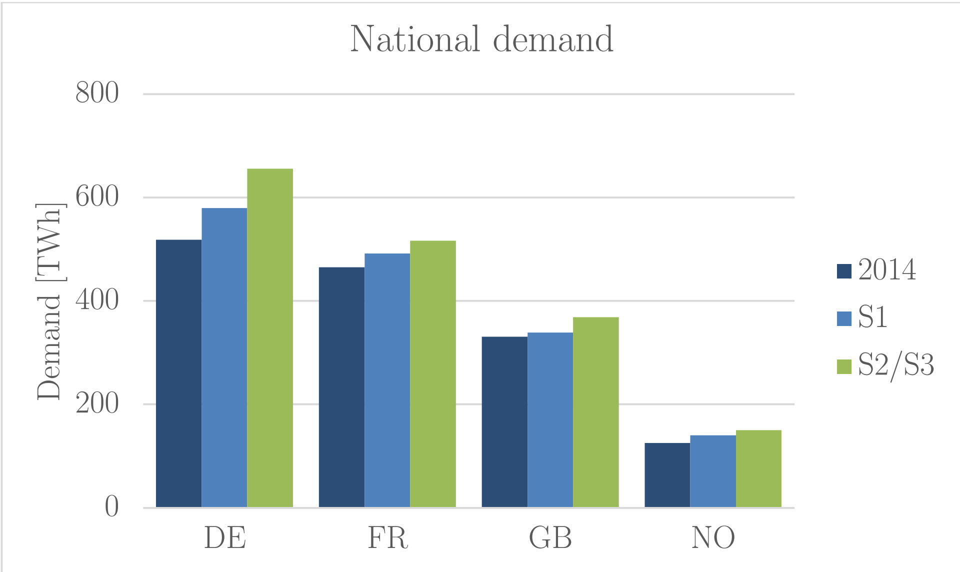

Figure 6.11: National demand. [10] [1]

6.3.5 Inflow, wind and solar irradiance data

75 years of statistical data is used for RES modelling (hydro, wind and solar power). For hydro, 75 years of inflow data is available between 1931 and 2005. Wind data is only available from 1948 to 2005. In order to complete a 75 year cycle, data from 1989-2005 is used for the years 1931-1947 (thus, some data is duplicated). Solar irradiance data is more limited, only available from 1989 to 2005. Applying the same principle as for wind, the solar data series is extended to 75 years.

The statistical data used in this master thesis is the same as used for the SUSPLAN project, completed in 2011 [14]. Taken from SUSPLAN is also hydro reservoir data.

The hydro inflow is divided into regulated and non-regulated inflow according to the regulating factor in Appendix D. Reservoir volume and total inflow data is also defined in this appendix. Note that the Reservoir volume is assumed equal in both Visions.

6.3.6 CO_2 and fuel prices

Table 6.6 and Table 6.7 shows fuel and CO_2 prices used in S1, S2 and S3. Given in euro per net gigajoule, the values had to be converted to the presented units to be used with the EMPS model. These values are collected from the International Energy Agency (IEA) World energy outlook 2011 report. S1 uses the values from the current policies section while S2/S3 uses the values from the 450 scenario section.

As can be seen, S2 and S3 features lower fuel prices but higher CO_2 prices than S1. In general, coal power tends to be favored over gas in the merit order in times of low CO_2 prices. Thus, it can be concluded that S1 favors coal power while S2 and S3 favors gas power (at least to a larger degree than S1).

	Fuel prices		
	S1	S2/S3	Unit
Nuclear	30.78	30.78	EUR/pound
Lignite	6.49	6.49	EUR/t
Hard coal	98.97	62.85	EUR/t
Gas	37.01	28.48	EUR/MWh
Biofuel	0	0	EUR/MWh
Light oil	131.04	94.5	EUR/barrel
Heavy oil	73.49	53	EUR/barrel
Oil shale	8.28	8.28	EUR/MWh

Table 6.6: Fuel prices for Vision 2 and 4. [15]

	CO_2 price [EUR/ton]
S1	31
S2/S3	93

Table 6.7: CO_2 prices for Vision 2 and 4. [16]

6.3.7 Emissions

Emission data is presented in Table 6.8. As can be expected, coal has the highest emissions per unit of mass, but is surpassed by lignite when the values are converted to emission per unit of energy produced. Still, the emission values are overall significantly higher than for gas, a fact that further explains why gas is increasingly favored with higher CO_2 prices. Also, nuclear power and bio power are assumed emission free. This also goes for CCS which is assumed to capture all emission from fossil fuel based power plants.

Energy source	Energy density		Emission intensity			
Uranium	22.68	MWh/pound	0	tCO2/pound	0	tCO2/MWh
Biomass	3.5	MWh/t	0	tCO2/t	0	tCO2/MWh
Lignite	4.1	MWh/t	2.05	tCO2/t	0.5	tCO2/MWh
Lignite CCS	4.1	MWh/t	0	tCO2/t	0	tCO2/MWh
Hard coal	7.9	MWh/t	2.92	tCO2/t	0.37	tCO2/MWh
Hard coal CCS	7.9	MWh/t	0	tCO2/t	0	tCO2/MWh
Gas	1	MWh/MWh	0.20	tCO2/MWh	0.2	tCO2/MWh
Gas CCS	1	MWh/MWh	0	tCO2/MWh	0	tCO2/MWh
Light oil	1.569	MWh/barrel	0.47	tCO2/barrel	0.3	tCO2/MWh
Heavy oil	1.49	MWh/barrel	0.52	tCO2/barrel	0.35	tCO2/MWh

Table 6.8: Fuel energy content and emission intensity.

6.3.8 Merit order of the European power system

Figure 6.12 and Figure 6.13 illustrates the merit order of the thermal power plants in S1 and S2/S3 respectively. Renewable plants are all modelled with zero marginal cost and is thus for simplicity not included in the figures (if included it would simply push all thermal plants to the right of the curve).

S1 is, as mentioned in chapter 6.2, based on Vision 2 from ENTSO-E and uses the fuel and CO_2 prices associated with this vison. S2 and S3 is based on Vision 4, and uses the fuel and CO_2 prices associated with this vision.

The merit order curve for S1 is similar to how a conventional merit order curve for electricity production looks like today. Starting with bio and nuclear to the left, followed by lignite, hard coal, gas and oil.

As for S1, the merit order curve for S2 and S3 starts with bio and nuclear power to the left. Gas, however, is found longer to the left than it did in S1. Lignite and coal is on the other hand moved to the right. This reflects the threefold increase in CO_2 price, favoring less CO_2 intensive production. Thus, the marginal cost for gas relative to lignite and hard coal is lower in S2 and S3 than in S1. This shift results in an increased marginal cost at lower capacities for S2 and S3 compared to S1.

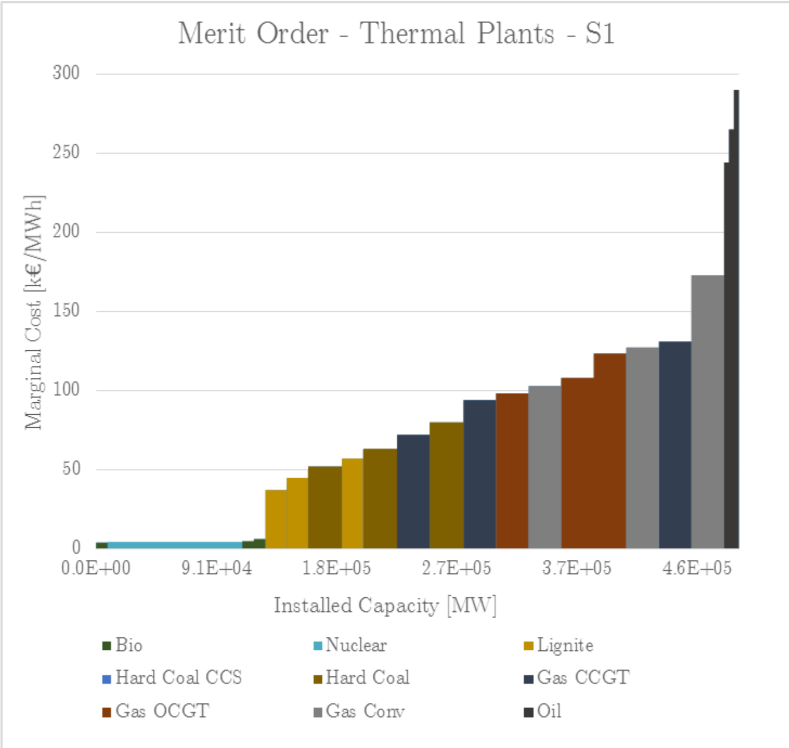

Figure 6.12: Merit order of thermal plants – S1.

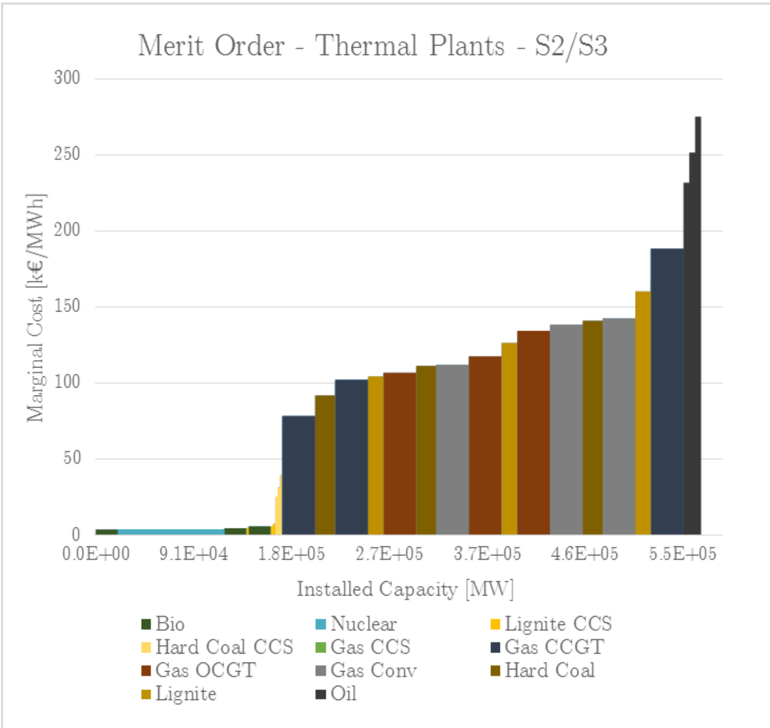

Figure 6.13: Merit order of thermal plants – S2 and S3.

6.3.9 Price segments

The time step resolution used in this model derives from the resolution given from the price segments. The price segments are divided into 60 two hour segments between Monday and Friday and twelve four hour segments on Saturday and Sunday (as seen in Table 6.9). This gives a total resolution of 72 segments per week and 3744 segments per year.

	Price segments						
Hour	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
1-2	1	13	25	37	49	61	67
3-4	2	14	26	38	50		
5-6	3	15	27	39	51	62	68
7-8	4	16	28	40	52		
9-10	5	17	29	41	53	63	69
11-12	6	18	30	42	54		
13-14	7	19	31	43	55	64	70
15-16	8	20	32	44	56		
17-18	9	21	33	45	57	65	71
19-20	10	22	34	46	58		
21-22	11	23	35	47	59	66	72
23-24	12	24	36	48	60		

Table 6.9: Price segments.

6.3.10 Plant costs

Table 6.10 and Table 6.11 shows CAPEX and OPEX related to the different power plants in the system. The values have been gathered from the IEA report Projected Costs of Generating Electricity [19] as well as a report written by VGB PowerTech in 2011 [20]. It should be noted that the CAPEX and OPEX cost will variate depending on the source. The given values should, however, give a good indication of the cost differences between the different technologies. Also, costs are assumed to be the same in all countries for the different plant categories. In reality they would variate due to economic and political differences between the countries. A wighted average cost of captial of 8 percent is used. [21]

Economic life and investment-/operational costs for thermal power plants			
Plant type	**Economic life [yrs]**	**CAPEX [€/kWyr]**	**OPEX [€/kWyr]**
Coal	35	116	20
Coal CCS	35	216	70
Gas Conv	25	64	15
Gas CCGT	25	69	20
Gas OCGT	25	56	19.5
Gas Conv CCS	25	133	40
Gas OCGT CCS	25	112	40
Gas CCGT CCS	25	137	40
Lignite	35	108	28
Lignite CCS	35	209	54
Nuclear	60	214	100
Oil	35	62	17.5

Table 6.10: Economic life and investment-/operational costs for thermal power plants.

Economic life and investment-/operational costs for renewables			
Plant type	**Economic life [yrs]**	**CAPEX [€/kWyr]**	**OPEX [€/kWyr]**
Wind onshore	25	99	22.5
Wind offshore	25	283	90
Solar (PV)	25	219	22.5
Biomass	30	197	14
Hydro	50	145	7.5

Table 6.11: Economic life and investment-/operational costs for renewables.

6.3.11 Cable costs

Table 6.12 shows annualized cable costs for selected cables gathered from the EU project TWENTIES [21]. Please note that since OPEX is considerably smaller than CAPEX, these costs are considered negligible. Thus, the numbers given below only includes CAPEX.

Annualized cable costs – Selected cables					
Cable name	**Between areas**	**Capacity [MW]**	**Length [km]**	**Annualized cable cost per megawatt [€/MWyr]**	**Total annualized cable costs [M€/yr]**
NSN Link	GB–NO	1400	750	83 638	117.1
NORD.LINK	DE–NO	1400	623	55 758	78.1
NorNed	NL–NO	700	580	65 051	45.1

Table 6.12: Annualized cable costs for selected cables. [22] [23] [24] [25]

6.3.12 Limitations

As with all data sets, there are certain limitations. Featured in this section is a brief discussion of the main limitations of the data sets used in this thesis.

As described in chapter 4.2.3, thermal plants can be modelled with startup- and shutdown cost constraints. These attributes can be adjusted in such a way that they also represents the ramp up/down time to a certain degree. Due to computational limits this was not implemented in this thesis. The exclusion of these parameters causes all thermal plants to have the same high flexibility, while in reality the differences are big. In turn this will reward thermal plants with low flexibility such as coal and nuclear to an unrealistically high degree while high flexibility plants such as OCGT and oil will be underutilized. The de facto result of this simplification is an unrealistically high flexibility in the system and an unnatural utilization pattern of the thermal plant fleet.

Energy storage systems like pumped hydro is not included in the model. This could be done by the use of EMPS extensions like ReOpt, but this is beyond the scope of this thesis. The total European pumped hydro capacity was around 45 GW in 2011 [26] An implementation of pumped hydro capacity adjusted to the 2030 ENTSO-E visions would increase the capabilities of the system to handle periods with surplus I-RES production as well as peak demand situations.

7 Methodology

7.1 Profitability of assets

For the comparison between different system assets, marginal profit (MP) and net marginal profit (NMP) calculations are used. Calculated as Euro per installed effect per year, a single aggregated comparable number is given.

Net marginal profit (NMP) for assets is defined as revenues minus all expenses per megawatt of installed capacity per year. Expenses includes production costs as well as annualized CAPEX and OPEX.

Marginal profit (MP) for assets are defined as revenue minus production cost per installed capacity per year.

Missing break-even revenue (MBER) is the extra revenue needed to ensure profitability if the NMP of an asset is negative.

7.1.1 Revenue

Revenue is defined as the amount of money brought in through sales without subtracting any costs. Revenues from power plants (R^p) are calculated as produced volume multiplied with the power price in a given hour. Revenues (R^l) from transmission lines are calculated as the price difference between the two price areas connected by the transmission line multiplied with the transmission volume.

Equation (7.1) and (7.2) are used to calculate the yearly revenues from power plants and transmissions lines.

$$R_{i,m,n}^{p} = \sum_{t=1}^{T} PREF_{m,n,i,t} * KRV_{i,t} \tag{7.1}$$

$R_{i,m,n}^{P}$	:	Total revenue in country i for plant type m and plant number n.
$PREF_{i,m,n,t}$	:	Production for plant type m, plant number n and country i in time period t.

$$R^l_{i,j} = \sum_{t=1}^{T} abs(UTV_{i,j,t} * (KRV_{i,t} - KRV_{j,t})) \tag{7.2}$$

$R^l_{i,j}$	:	Total revenue for the transmission line connecting country *i* and country *j*.
$UTV_{i,j,t}$	:	Transmission between country *i* and *j* in time period *t*.
$KRV_{i,t}$	:	Power price in country *i* in time period *t*.

7.1.2 Missing Break-Even Revenue

An asset has a MBER if the NMP is negative. The MBER is equal to the economical support needed to make an unprofitable asset profitable, and follows Equation (7.3).

$$MBER_{m,n,i} = \begin{cases} 0, & NMP^p_{i,m,n} \geq 0 \\ -NMP_{m,n,i}, & NMP^p_{i,m,n} < 0 \end{cases} \tag{7.3}$$

$MBER_{m,n,i}$	:	Missing break-even revenue for plant type *m* and plant number *n* in country *i*.
$NMP_{i,m,n}$	:	Net marginal profit for plant type *m* and plant number *n* in country *i*.

7.1.3 Expenditures

The expenditures for assets are divided into two parts, the yearly production expenditures and the yearly fixed costs. The production expenditures only occur when producing and is equal to zero if there is no production while the fixed cost occurs regardless of production.

Variable production costs

Production expenditures (C^p) per year for a certain plant is calculated by multiplying the marginal production cost (MC) of that plant with its total yearly production ($PREF^{tot}$), as seen in Equation (7.4). The marginal production cost includes fuel and CO_2 emission costs. Costs related to power transmissions is for simplicity not included due to its low value relative to other costs. Transmission losses are set to 1 % for all lines in the system.

$$C^{p}_{m,n,i} = MC_{m,n} * PREF^{tot}_{m,n,i} \tag{7.4}$$

$C^{p}_{m,n,i}$	:	Production expenditures for plant type *m* and plant number *n* in country *i*.
$MC_{m,n}$	:	Marginal production cost for plant type *m* and plant number *n*.
$PREF^{tot}_{m,n,i}$	:	Total yearly production for for plant type *m* and plant number *n* in country *i*.

Yearly fixed costs

The fixed cost are divided into two parts, CAPEX and OPEX. The CAPEX is considered as a sunk cost[10] while the OPEX can be reduced (e.g. in the case of mothballing[11]) or omitted completely if an asset is decommissioned. OPEX is given as annualized values per megawatt installed capacity and does not require conversion into annual numbers. CAPEX, on the other hand, is given as total investment cost for an asset. To obtain annualized capex cost conversion is needed. The amortization of CAPEX into annual values for each asset is done using a discount rate of 8 % [27] and an individual lifetime for each assets type. This calculation is done as seen in Equation (7.5).

$$A = \frac{r}{1-(1+r)^{-t}} * P_o \tag{7.5}$$

A	:	Annualized investment cost
P_o	:	Total investment cost
r	:	Interest rate
t	:	Economic life of asset

7.1.4 Marginal and net marginal profit

MP and NMP for power plants is calculated as given in Equations (7.6) and (7.7). For transmission lines, Equations (7.8) and (7.9) are used.

[10] A cost that has already been incurred and cannot be recovered.

[11] The preservation of an asset without using it to produce. The asset is kept in working order, so that generation may be restored at a later point.

$$MP^p_{m,n,i} = \left(\frac{R^p - C^p}{CAP^p}\right)_{m,n,i} \quad (7.6)$$

$MP^p_{m,n,i}$	:	Marginal plant profit for plant type *m* and plant number *n* in country *i*.
$R^p_{m,n,i}$	:	Plant revenue for plant type *m* and plant number *n* in country *i*.
$C^p_{m,n,i}$	:	Production expenditures for plant type *m* and plant number *n* in country *i* (see Equation (7.4)).
$CAP^p_{m,n,i}$	:	Plant capacity for plant type *m* and plant number *n* in country *i*.

$$NMP^p_{m,n,i} = MP^p_{m,n,i} - CAPEX^p_m - OPEX^p_{m,n} \quad (7.7)$$

$NMP^p_{m,n,i}$	:	Net marginal plant profit for plant type *m* and plant number *n* in country *i*.
$MP^p_{m,n,i}$	:	Marginal plant profit for plant type *m* and plant number *n* in country *i* (see Equation (7.6)).
$CAPEX^p_m$	:	Annualized capital plant expenditures for plant type *m*.
$OPEX^p_{m,n}$	:	Operational expenditures for plant type *m* and plant number *n*.

$$MP^l_{i,j} = \frac{R^l_{i,j}}{CAP^l_{i,j}} \quad (7.8)$$

$MP^l_{i,j}$	:	Marginal line profit for the line connecting area *i* and *j*.
$R^l_{i,j}$	:	Line revenue for the line connecting area *i* and *j*.
$CAP^l_{i,j}$	:	Line capacity for the line connecting area *i* and *j*.

$$NMP^l_{i,j} = MP^l_{i,j} - CAPEX^l_{i,j} \quad (7.9)$$

$NMP^l_{i,j}$	:	Net marginal line profit for the line connecting area *i* and *j*.
$MP^l_{i,j}$	:	Marginal line profit for the line connecting area i and j (see Equation (7.8)).
$CAPEX^l_{i,j}$	:	Annualized capital line expenditures for the line connecting area *i* and *j*.

8 Results

8.1 Generation

8.1.1 Total generation

Figure 8.1 and Figure 8.2 illustrates the total energy mix for all ENTSO-E countries across all simulated scenarios as well as the production from 2014 for reference.

As can be seen there's a fairly steady decrease in nuclear production moving from 2014 to S3. This makes sense as nuclear power is largely policy driven, and many countries have plans of phasing out nuclear power in favor of other energy sources. Reduction in capacity along with increased supply from other energy sources (especially I-RES) causes nuclear production to drop to around 60 % of 2014 levels in S3.

Compared to 2014, the fossil based production sees an increase in S1 before experiencing heavy declines, dropping 60 % compared to 2014 levels in S3. The increase seen in S1 compared to 2014 is a result of nuclear phase-out as well as a demand increase of around 15 %. In S2 and S3 the increased share from I-RES causes production from fossil sources to drastically decrease.

Examining Figure 8.2 gives further insight as to how the different fossil categories change over the scenarios. Hard coal experiences a slight increase between 2014 and S1 before dropping by over 50 % in S2 and again in S3. Compared to 2014, generation from hard coal is reduced by around 75 % in S3. The reduction from S1 to S2 and S3 is induced by increasing CO_2 price and increased capacity of I-RES. The CO_2 price also drives forth a shift from coal to gas, seeing gas has lower emission intensity than coal. Thus, a 10 % increase in generation from gas power can be observed going from S1 to S2, before dropping 60 % going from S2 to S3. Generation from lignite experiences a decrease in all scenarios compared to 2014 levels. The largest reduction (53 %) is found going from S1 to S2, where CO_2 price is tripled. Generation from lignite power is reduced by 77 % in S3 compared to what it was in 2014. Oil powered generation, being expensive compared to the alternatives, is negligible in all of the simulated scenarios.

As with nuclear, bio power is mostly policy driven. From 2014 to S1, the capacity is increased from 29 to 96 GW. Capacity is further increased to 158 GW in S2 and S3. With high utilization in S1 (84 %) and S2 (80 %), a drop can be observed in S3 (55 %) due to extreme amounts of production from I-RES.

When it comes to renewables, the most notable changes are generation from I-RES which sees around a twofold increase going from 2014 to S1, as well as between the other simulated scenarios. This leads to S3 generation being above eight times than that of 2014, accounting for 58 % of total production. Since both wind and solar irradiance data are model inputs, the changes reflect the increased capacity in the scenarios. As can be seen, wind power is the main contributor within I-RES, accounting for around 70 – 75 % of production. Also, hydro production stays largely the same across all scenarios, mostly due to insignificant changes in capacity.

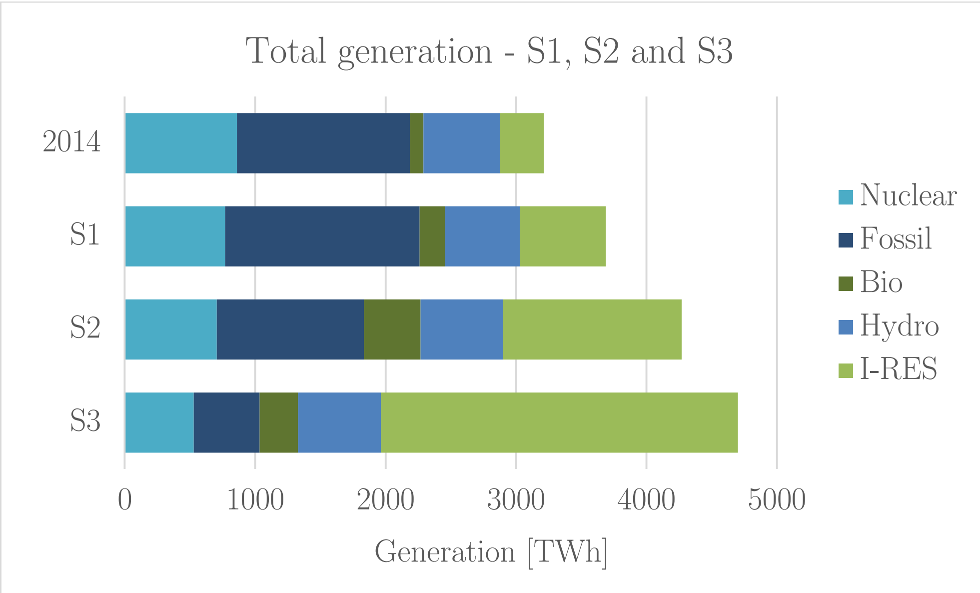

Figure 8.1: Total European generation – 2014, S1, S2 and S3. [1]

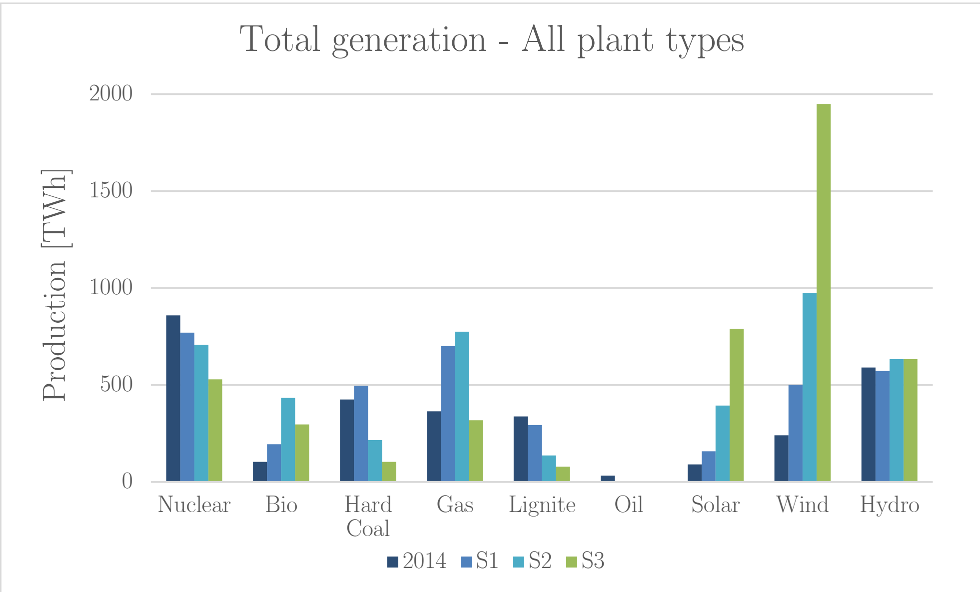

Figure 8.2: Total European generation across all plant types in the system. [1]

8.1.1.1 Germany

As illustrated by Figure 8.3 and Figure 8.4, the general trend in Germany is reduction of fossil production and a large increase in production from I-RES. In S3, fossil based production is reduced by 72 % compared to 2014 levels. Production from RES (mainly I-RES) on the other hand sees an over six fold increase. Also visible is a substantial rise in total production (70 %) going from 2014 to S3.

The distribution across the different energy sources is given in Figure 8.4. The general trend resembles that of Europe as a whole, with a decrease in production from fossil sources (especially hard coal and lignite) and increase from I-RES. As can be observed wind power is the main contributor in both S2 and S3, accounting for as much as 75 % of RES production and 60 % of overall production in S3.

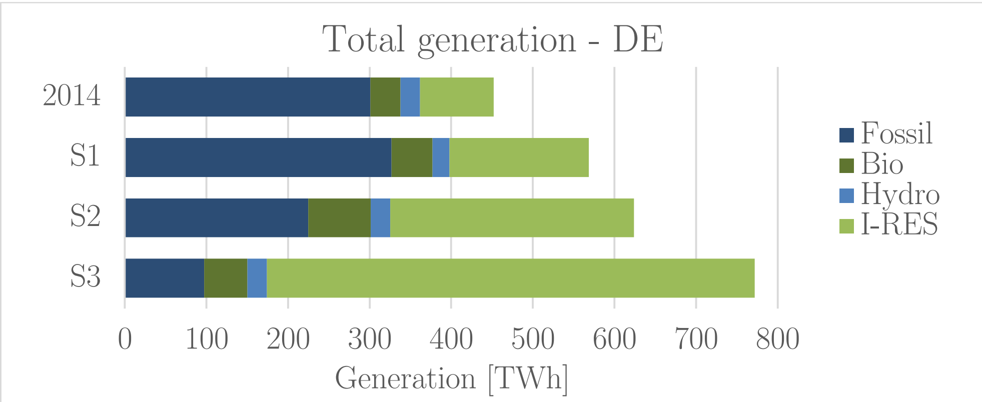

Figure 8.3: Total generation in Germany – 2014, S1, S2 and S3.

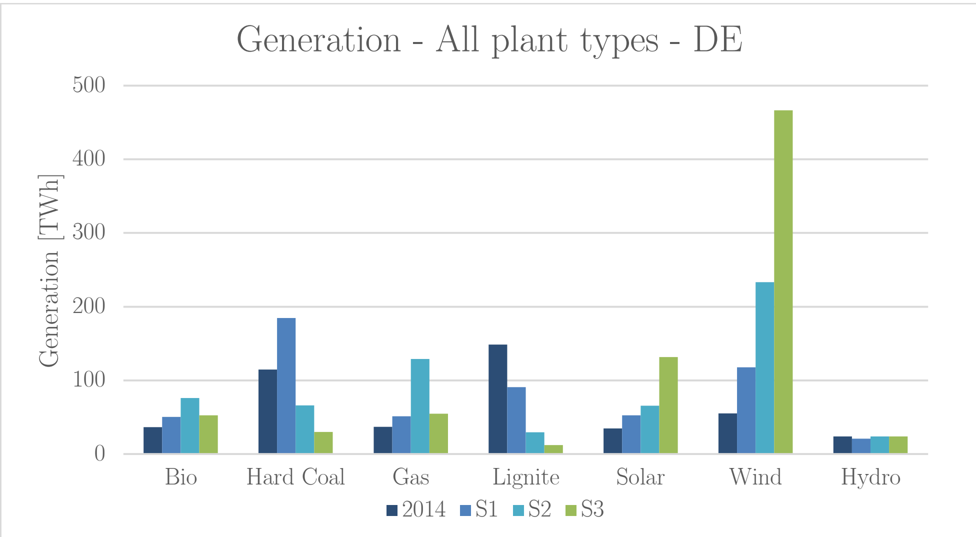

Figure 8.4: Total generation across all plant types in Germany.

8.1.1.2 France

France's main power source is nuclear power. From Figure 8.5 however, it can be seen that production from nuclear power is greatly reduced in favor of production from I-RES. One reason for this is a planned nuclear phase-out which causes installed nuclear capacity to be reduced from 63 to 56 GW between 2014 and S1 and even more, to 40 GW, in S2 and S3. Another reason is, as with most other simulated countries, increased supply of cheap, renewable energy as a result of I-RES expansion. The increase in total production isn't as prominent as for Germany, with a mere 14 % rise in S3 compared to in 2014.

With nuclear power supplying 77 % of total production in 2014, the number is only a mere 30 % in S3. As seen in Figure 8.6 it is largely replaced by solar and wind power which accounts for over 50 % of the total production in S3. Interestingly, wind power surpasses nuclear production in S3, making it France's largest contributor in this scenario.

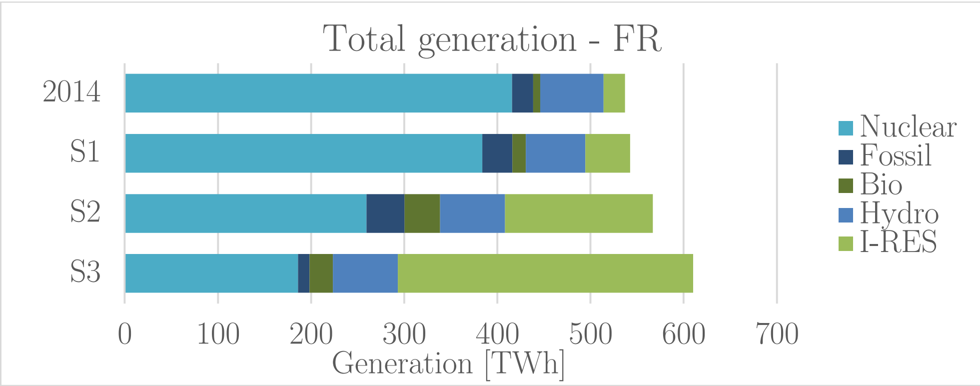

Figure 8.5: Total generation in France – 2014, S1, S2 and S3.

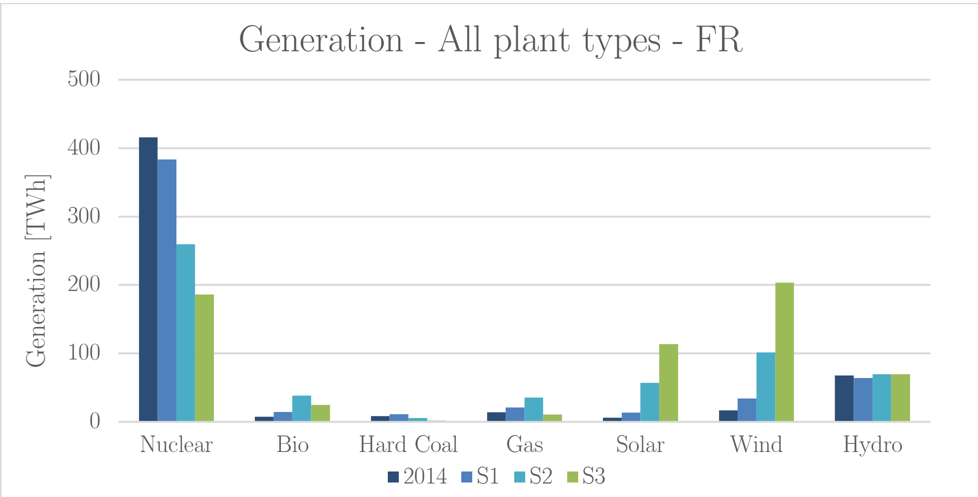

Figure 8.6: Total generation across all plant types in France.

8.1.1.3 Great Britain

As can be seen in Figure 8.7 and Figure 8.8, Great Britain experiences extreme changes when it comes to the generation distribution. Thermal sources (nuclear and fossil) account for 68 and 42 % of the total production in 2014 and S1 respectively. In S2, the number is 20 % while in S3 only 6 %. The changes reflect increased supply from wind power, which in S3 amounts to almost 400 TWh, around 75 % of total production.

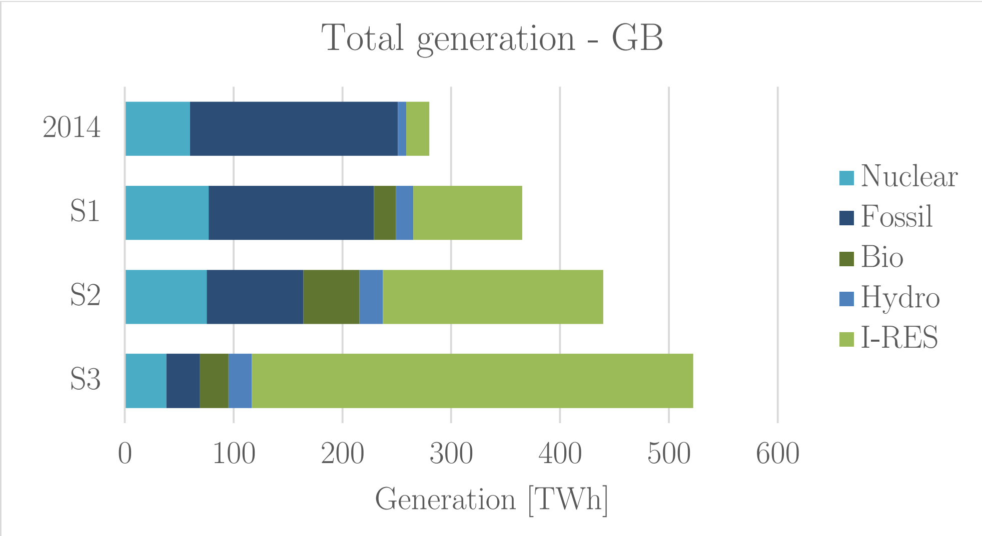

Figure 8.7: Total generation in Great Britain – 2014, S1, S2 and S3.

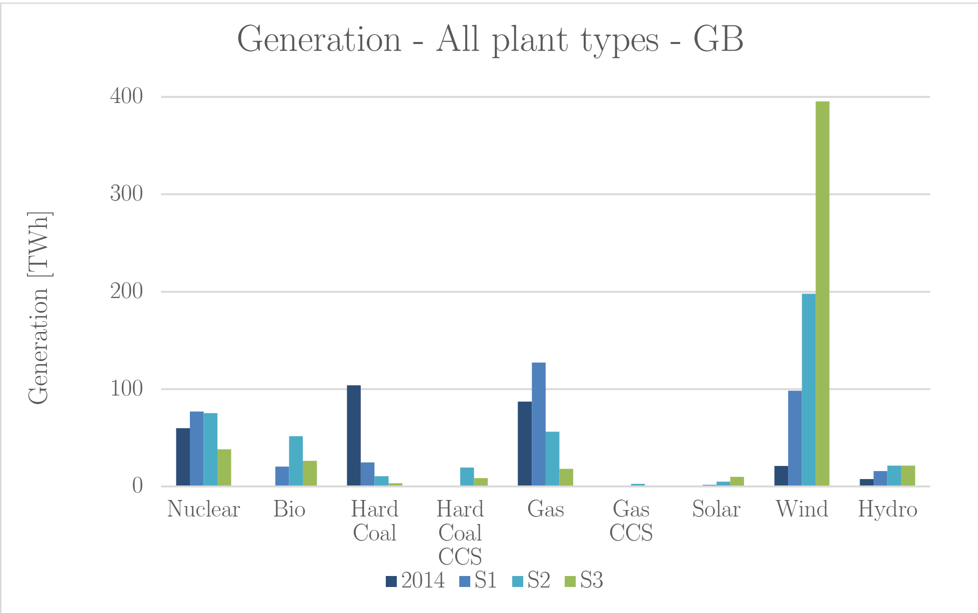

Figure 8.8: Total generation across all plant types in Great Britain.

8.1.1.4 Norway

The Norwegian power production is dominated by hydro. This is further illustrated by Figure 8.9 and Figure 8.10, where hydro power is the main contributor across all scenarios. The hydro production does, however, remain fairly constant. The most prominent changes are found looking at gas and wind power. Gas power, being moderately utilized in 2014, sees a steady decrease up until S3 where there's no production at all. I-RES (which consists solely of wind power) on the other hand experiences the opposite trend, with S3 production amounting to around one third of total production.

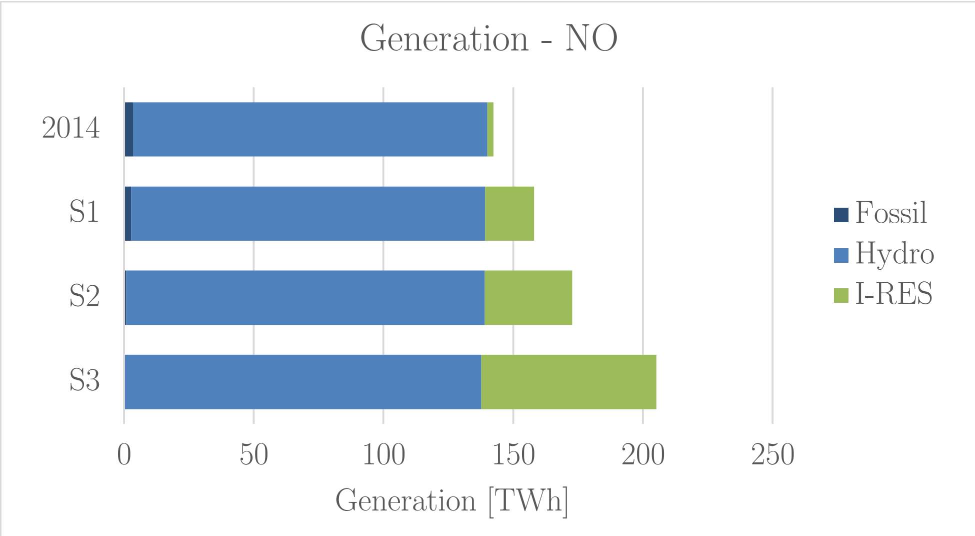

Figure 8.9: Total generation in Norway – 2014, S1, S2 and S3.

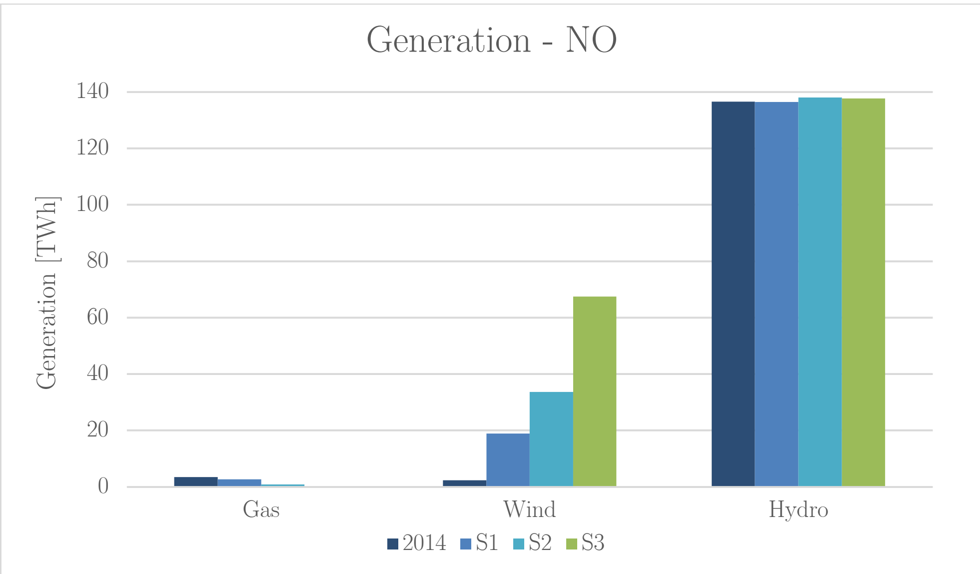

Figure 8.10: Total generation across all plant types in Norway.

8.1.2 RES/I-RES penetration

Figure 8.11 illustrates I-RES (wind and solar) and RES (wind, solar, hydro and bio) penetration in 2014 as well as the simulated scenarios. I-RES penetration in 2014 was around 10 %, while the total RES penetration was around 30 %. Thus, I-RES only accounted for one third of the total RES production. Looking at the scenarios, a clear increase in both RES and I-RES penetration can be observed between S1 and S3. Notably, I-RES has an increased share of the total renewable production with wind and solar accounting for around 75 % of the total RES production in S3.

Compared to the RES penetration levels of 2014 (32 %), penetration levels are at 78 % in S3 with I-RES penetration sitting at 58 %.

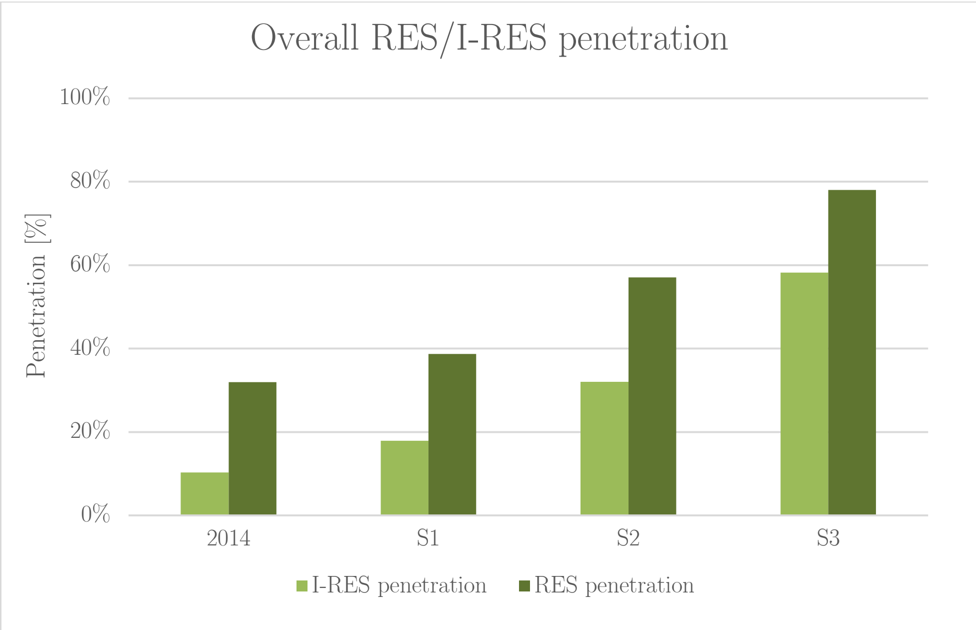

Figure 8.11: RES/I-RES penetration – 2014, S1, S2 and S3.

8.1.3 Dump energy

This section briefly investigates dump energy[12] in S1, S2 and S3. In the simulated system, dump energy occurs in situations where I-RES covers over 100 % of the demand and the interconnections are fully congested, when there is spillage from hydro reservoirs or a combination of the two. In the real world dump energy can also occur in situations where thermal plants, particularly those with a slow ramp

[12] Excess energy that cannot be stored or prevented from generation.

up/down time, are producing excess energy in combination with spikes in the I-RES production or sudden drop in demand. As described in 6.3.12, the low technical resolution of thermal plants in the simulations prevents such situations from occurring in the featured system.

Table 8.1 depicts dump energy in each of the three simulated scenarios. As can be seen, total dump energy in the system is negligible in S1 (0.08 %) and S2 (0.03 %). All of the dump energy seen in S1 originates from hydro spillage in Norway. As generation flexibility in Norway is increased in S2, spillage is reduced from 2.77 to 0.38 TWh. The rest of the spillage in S2 is distributed out among the different I-RES producers in Europe.

The amount of dump energy is massively increased in S3. At 129.1 TWh (almost as much as the entire power demand of Norway), it now accounts for 2.75 % of the total generation. The vast majority of the dump energy in S3 stems from excess I-RES production. In fact, 4.7 % of all I-RES production goes to waste in S3. A large part of the dump energy is split between the major I-RES producers in Europe, namely Great Britain (31.9 TWh), Germany (16.2 TWh) and Spain (14.9 TWh).

The numbers for S3 indicate that strengthening of interconnections from major I-RES producing countries should be done to limit dump energy and reduce overall prices. This will be further assessed in chapter 8.7.

Scenario	S1	S2	S3
Dump energy [TWh]	2.77	1,22	129.1
Percentage of total generation [%]	0.08	0.03	2.75

Table 8.1: Amount of dump energy – S1, S2 and S3.

8.2 Average prices

Figure 8.12 – Figure 8.14 show average prices across Europe for Scenario 1 – 3 (S1 – S3). S1, having the largest share of fossil production among the scenarios, has high prices with a fairly flat overall price picture (ranging from 90 to 120 €/MWh). The highest prices are found in Poland and the Baltic states.

Despite a fairly large increase in I-RES capacity in the system, S2 also experiences relatively high prices (70 to 120 €/MWh). In fact, compared to S1 a price increase can be observed in southeastern Europe. This is likely due to the threefold increase in CO_2 price compared to S1. Some countries do, however, experience a large price drop, most prominently Great Britain and Ireland due to increased wind power capacity.

Examining the prices for S3, extreme changes are found. As can be seen the overall average prices are greatly reduced, with prices ranging from 0 to 90 €/MWh. The highest prices are still found in southeastern Europe, albeit they're substantially lower than in the other two scenarios. In the lower end of the spectrum, the Nordic countries along with the British Isles and the Iberian Peninsula reign, with prices in Norway and Sweden approaching zero.

With I-RES having no marginal cost, it's fairly expected that large capacity increases will contribute to lower prices. However, with triple the CO_2 price in S2 and S3 compared to S1, it's fair to assume that the effect would be somewhat evened out. This is apparent comparing the prices in S1 and S2 where the latter actually sees an increase in large parts of Europe. Thus, the I-RES capacity increase in S2 is not large enough to affect the overall price picture in a considerable way. As was seen earlier, this was not the case for S3, which saw prices plummeting.

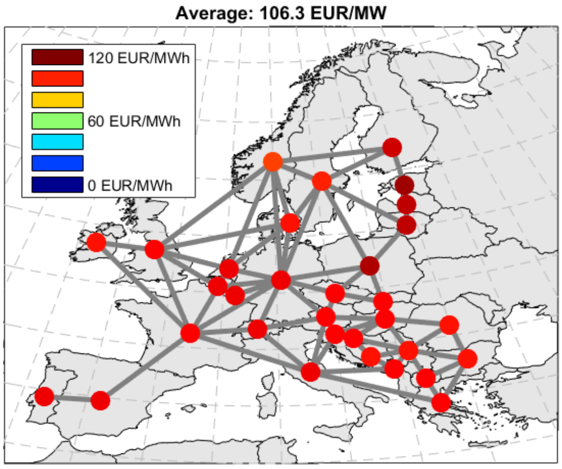

Figure 8.12: Average prices across Europe – S1 – 40 % RES. CO_2 price 31 €/ton.

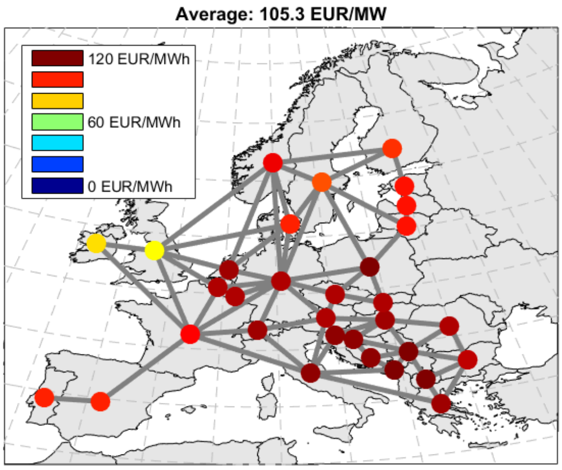

Figure 8.13: Average prices across Europe – S2 – 60 % RES. CO_2 price 93 €/ton.

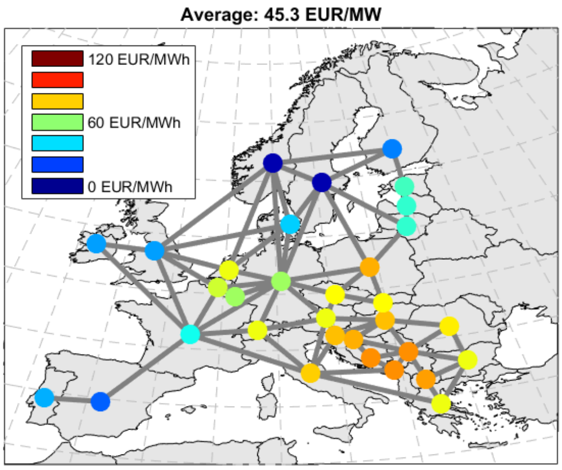

Figure 8.14: Average prices across Europe – S3 – 80 % RES. CO_2 price 93 €/ton.

8.3 Transmissions

When large amounts of cheap energy is introduced in the power system in S2 and S3, it is likely it will increase the strain on certain lines in the system. High-price areas will want to import energy from low-price areas (typically areas with large amounts of RES) to reduce prices. The following section features a look at the European transmissions in the three scenarios as well as a more in-depth look at selected lines in the system.

8.3.1 Line utilization

Figure 8.15 – Figure 8.17 shows line utilization for the different scenarios. As seen, S1 experiences moderate overall utilization. Most prominent are the lines from Norway and Sweden which experiences high utilization due to large amounts of hydro power, but none of the lines are at 100 % utilization.

An increased amount of renewable energy in the system sees total amount of transferred energy rise by 24 % in S2 compared to S1. This leads to increased utilization for most lines in the system, with several lines from Norway, Sweden and Great Britain nearing 100 %. Also observable is a notable increase in utilization for the French lines, while the lines in southeastern Europe still experience a fairly light strain.

Examining S3, even heavier utilization than in S2 can be observed. The overall transfer increase is only around 1.5 %, but several lines, such as the Finnish, experience increased utilization. Also prominent is an increased strain on southeastern Europe.

An increased share of RES in the system increases the line utilization with large amounts of cheap renewable energy being transferred between high- and low-price areas. In all scenarios, the cables from Norway to Great Britain, Netherlands and Germany are among the most utilized, nearing 100 percent in S2 and S3. As possible bottlenecks, these lines will be examined further.

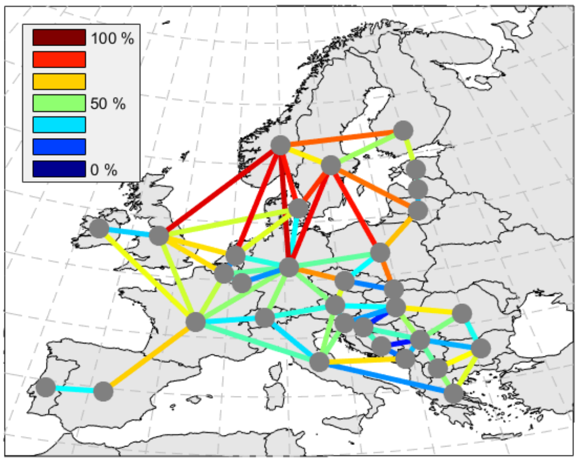

Figure 8.15: Line utilization – S1.

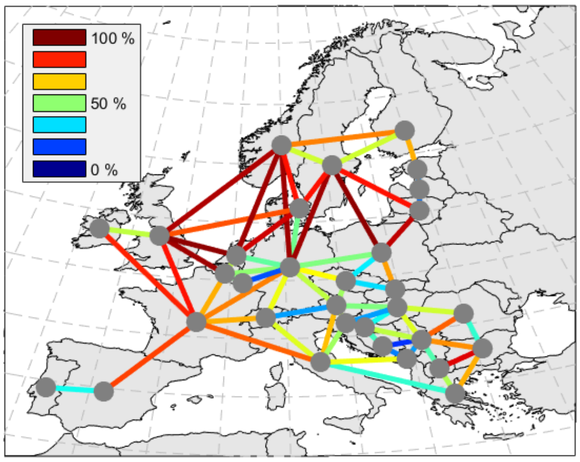

Figure 8.16: Line utilization – S2.

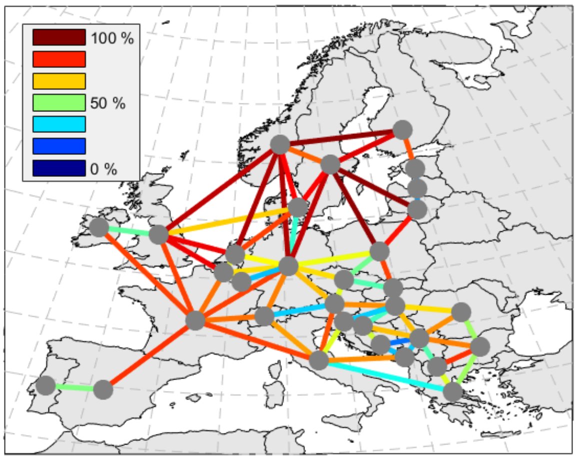

Figure 8.17: Line utilization – S3.

8.3.2 Analysis of lines GB-NO, DE-NO and NL-NO

As seen in the previous section, GB-NO, DE-NO and NL-NO are among the most utilized lines. Presented in Figure 8.18 – Figure 8.20 is the transferred power between the countries in S1, S2 and S3.

Despite having the lowest average price of the four countries, Norway is actually a net importer from all three. This is due to the fact that there are longer periods where the price is higher in Norway, despite the average price difference being fairly low. Figure 8.18 illustrates high congestion rates for the cables, ranging from 81 to 85 %.

Looking at S2, a different distribution is found. While Norway is still net importing from Great Britain (albeit less than in S1), export to Germany and Netherlands is now larger than import by a large margin. Import from Great Britain is expected based on an almost twofold increase in wind power capacity compared to S1. As seen in chapter 8.2 this lead to the lowest average prices in Europe. Congestion rates are also increased quite substantially in S2 compared to S1. DE-NO now has a congestion rate of 98.5 % while GB-NO and NL-NO experiences rates of 91.5 and 94.3 % respectively.

In S3, where all I-RES capacity is doubled compared to S2, things move slightly in the other direction. Although Norway is now a net exporter to all the other three countries, the exported quantity to Germany and Netherlands is reduced compared to in S2. Congestion rates see minor changes, now ranging from 93 to 95 %. DE-NO and NL-NO experiences slight decreases while GB-NO sees a slight increase.

High congestion rates point towards certain lines being bottlenecks in the system. Increasing these lines might lead to more efficient distribution of energy reducing dump energy and prices. Increased line capacities is further investigated in chapter 8.7.

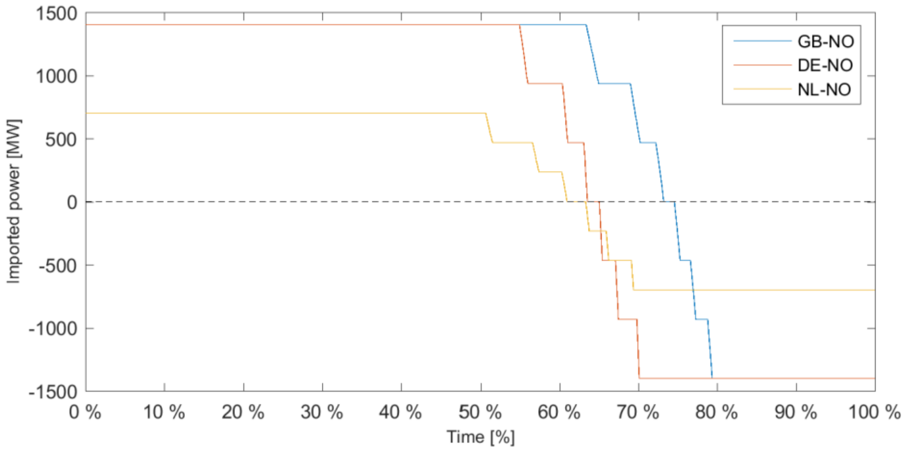

Figure 8.18: Line utilization – GB-NO, DE-NO and NL-NO – S1.

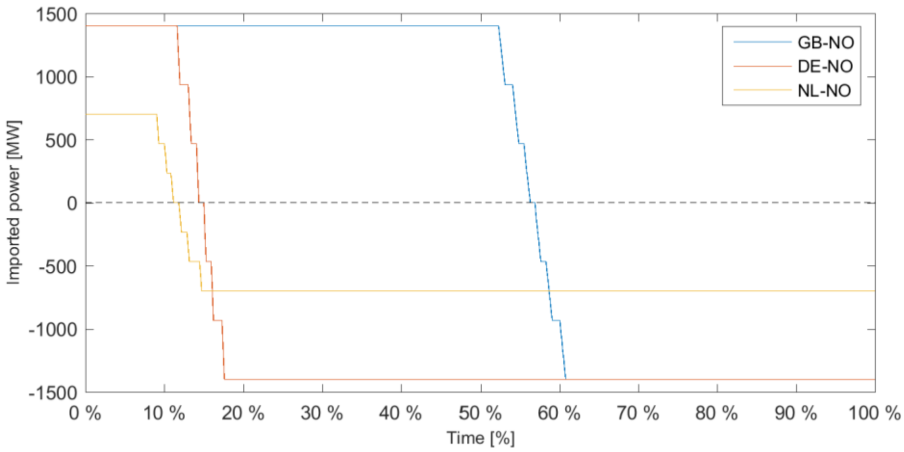

Figure 8.19: Line utilization – GB-NO, DE-NO and NL-NO – S2.

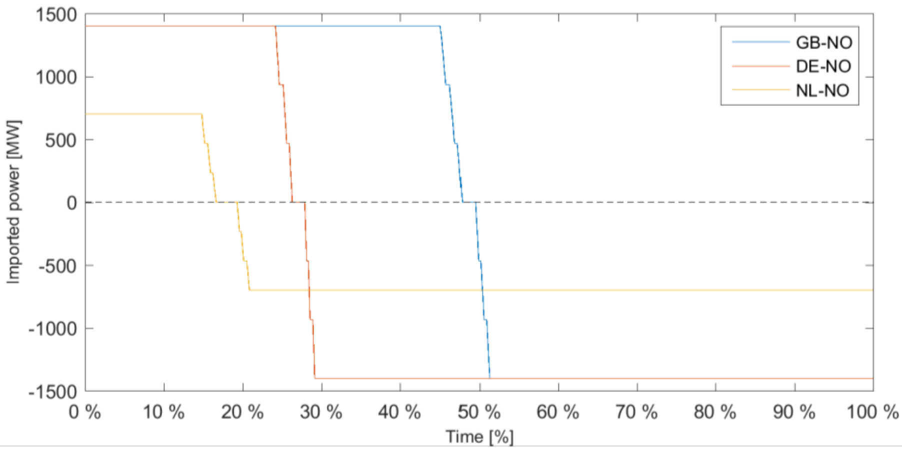

Figure 8.20: Line utilization – GB-NO, DE-NO and NL-NO – S3.

8.4 System adequacy

This section briefly investigates the system adequacy for the three different scenarios. Historically assessing of system adequacy is done by choosing the point with the highest demand for evaluation [28]. The combination of increased I-RES capacity and less conventional fossil power capacity in the system increases the chances of critical situations occurring at times other than at peak demand.

Thus system adequacy investigation is done by examining peak controllable production[13] hours and rationing situations during the year for each scenario. The points and values presented in this section are values extracted from each inflow scenario and not based on mean values. Occurrences of load curtailment and load shedding, described as demand response within this thesis, is based on average values over the 75 inflow scenarios.

Rationing, as described in chapter 4.2, only occurs when the firm demand exceeds the available energy supply. The firm demand is set to 75 % of the total input demand in this model. Meaning that there has to be a 25 % price elastic demand response before rationing occurs. The total rationing is zero in each scenario. There are no occurrences of rationing in the system in any hour for any of the 75 inflow scenarios. Thus, rationing situations will not be further investigated. It can be concluded that the system as it is modelled, will always be able to match the firm demand.

Price elastic demand response (see chapter 4.2.5) occurs when the power prices reaches certain thresholds. The elastic demand is modelled as synthetic power producers with separate marginal costs. The negative elastic demand are divided into 14 producers (i.e. 14 steps with marginal cost ranging from 197 to 2736 k€/MWh) with installed capacity equal to 1.79 % of the total demand in the given time segment. It should be noted that the first synthetic power producer (i.e. the first demand response step) has a lower marginal cost than that of oil power plants, which are the highest cost plants in the system. Thus, this producer is not included when investigating demand response. The rest of the demand response steps occur at power prices above the marginal cost of producing power from oil plants, and is thus a reduction in the elastic demand due to insufficient capacity in the system.

Peak controllable production hours are found at the maximum production points or at the hours with maximum power prices. The maximum production includes production from thermal plants as well as synthetic power production, representing elastic demand.

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[13] Hours with the highest thermal power output.

There is zero demand response above the first demand response level in S1 and S3. Thus, there is no load shedding and the demand, both flexible and firm, can be met by the energy supply throughout all of the inflow scenarios. It should be noted that the model does not include start up-/stop cost nor ramping time, making the system flexibility artificially high. In turn this reduces the amount of required demand response.

Looking at S2, some demand response is found in Norway and Sweden The maximum response is 25 and 17.3 % of the total demand in Norway and Sweden respectively. This occurs on average of 0.0034 % and 0.00013 % (0.30 and 0.01 hours) of the year for these countries respectively – in other words, very rarely. The total average amount of demand response to total firm demand is 0.085 % in Norway and 0.013 % for Sweden.

The general trend for all scenarios is that the generation capabilities of the power system to match the consumption is well met. There is zero rationing and the demand response is almost non-existent except for a few rare cases in Norway and Sweden in S2. This indicates that the scenarios are plausible and applicable to further development of the European power system.

As mentioned earlier, the high level of system adequacy is at least in part due to the low technical resolution of the power plants in the system. An assessment of the generation flexibility with regards to system adequacy is therefore not possible.

8.5 Asset profitability

Examined in the following section is profitability of assets (plants and lines) for all scenarios when accounting for investment and operational costs.

8.5.1 Thermal

Table 8.2 shows the total revenue from the European power system as well as total revenue from thermal power. Most notable is the reduction in total revenue from S1 and S2 to S3, with the revenue in S3 being reduced to 54 and 47 % of what it was in S1 and S2 respectively. From S2 to S3, revenue is reduced by 236.9 billion Euros.

As I-RES capacity in the system increases, the share of revenue from thermal power is reduced. From S1 to S2 the changes are fairly moderate, with revenue from thermal power being reduced by 7.5 billion Euros, equal to an 11 % reduction in the revenue share from thermal power. Comparing S2 and S3, however, extreme changes are observed. Total revenue from thermal power in S3 is reduced by 144.2 billion Euros, a 56 % reduction compared to S2. The revenue share from thermal is also down, albeit only by a moderate 4 percent. This number might perhaps not be as large as expected, but is heavily influenced by the total revenue reduction in the system.

This reduction in revenues can be seen directly when investigating the marginal profit of the different thermal plants.

Total revenue from energy			
Scenario	**Total revenue from power market [G€]**	**Total revenue from thermal power [G€]**	**Share of revenue from thermal power**
S1	392.1	265.4	68 %
S2	449.7	257.9	57 %
S3	212.8	113.7	53 %

Table 8.2: Revenue from energy sales, both overall and from thermal power.

Figure 8.21 and Table 8.3 shows a summary of the net marginal profit and utilization factor for the different thermal categories. For simplicity all plant types within the same category has been added together (e.g. all gas plants, both regular and CCS). A more in-depth look at the different categories is found when assessing specific countries.

A clear trend can be observed looking at net marginal profits going from S1 to S3 with large declines across all categories rendering many unprofitable in S3. In fact, only biomass is still profitable in S3 (and also most profitable in S1 and S2). This is largely due to the fact that biomass is modelled as energy input with low fuel costs and no emissions. In reality this is not necessarily true, as there will be limitation of fuel. Also, classifying biomass as 'carbon neutral' is a source of discussion, seeing there's energy used in the production etc.

Nuclear is very prominent in S1 and S2 with large net marginal profitability. When doubling I-RES capacity going from S2 to S3, nuclear is rendered unprofitable as a result of the large increase in I-RES production. High fuel costs cause gas and oil production to be unprofitable in all scenarios, with oil not being utilized at all in any of them.

Looking at utilization factor, the same trend can be observed. Coal and lignite experience extreme changes in utilization between S1 and S3. Coal utilization is reduced from 74 to 19 percent and lignite from 70 to 18 percent. Large decreases are also found for the other thermal plants, with the biggest drop happening between S2 and S3.

Even though fossil fuel is cheaper in S2 and S3 than in S1 (except for lignite which is unchanged), the two former have triple the CO_2 price. The observed changes for fossil plants going from S1 to S2 seems to be largely affected by the increased CO_2 price (more so than the decreased fuel cost) in combination with increased I-RES capacity. Going from S2 to S3, the change is mainly driven by a large increase in I-RES capacity, seeing as the fuel and CO_2 costs are the same.

Considering the thermal plants without emissions, bio and nuclear, the observed changes is due to increased I-RES capacity alone. Between S1 and S2 there's a 20 percent increase in I-RES penetration, causing a drop in average prices. The price drop is not large enough, however, to affect the marginal profitability of nuclear and bio power substantially. The utilization factor also remains fairly stable in both these scenarios. Between S2 and S3, I-RES capacity is doubled. The resulting increased supply of cheap energy drastically limits profitability of all thermal plants, including nuclear and bio plants. This is reflected in both net marginal profitability and utilization factor.

Looking at net marginal profit and utilization factor, it can be seen that most of the plants are making money in S1, while most (apart from bio) are losing money in S3. Increased I-RES capacity in S3 contributes to lower system prices, causing thermal power plants to be pushed to the right on the merit order curve, thus reducing utilization.

Since firm demand has to be met, thermal plants are a necessity in the system. The fact that all thermal assets apart from bio power loses money in S3 indicates that the current reward system is not equipped to handle extreme increases in I-

RES capacity, and that some form of capacity remuneration mechanisms (CRM) would likely need to be deployed for such a system composition to work.

It should be noted that the utilization factors have been extracted directly from the simulation results, while the net marginal profitability has been calculated based on the results (i.e. investment and operational costs were subtracted post simulation).

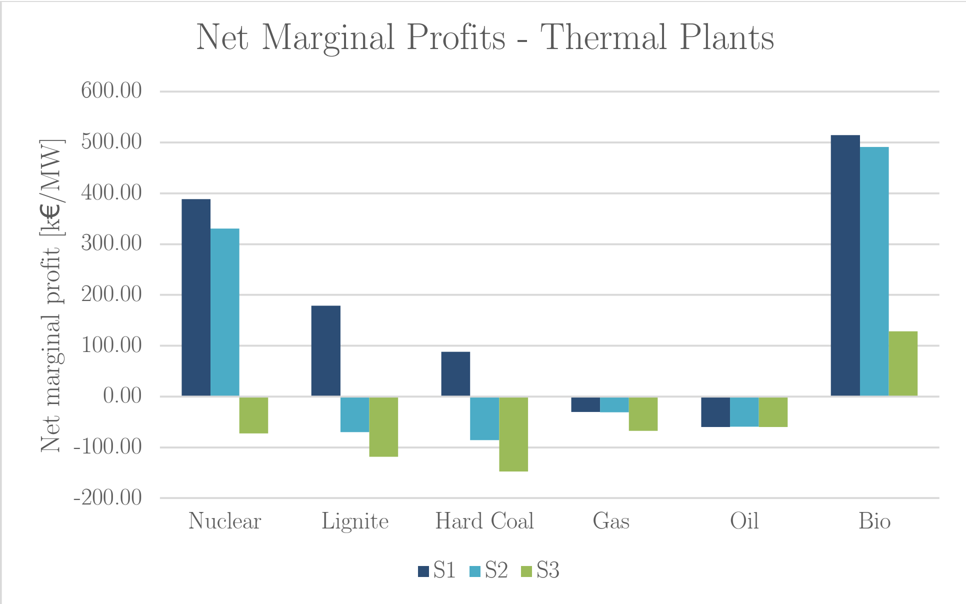


Figure 8.21: Average EU net marginal profit for thermal plants – S1, S2 and S3.

Utilization factor – EU average			
Plant type	**S1**	**S2**	**S3**
Coal	0.74	0.40	0.19
Gas	0.36	0.32	0.13
Lignite	0.70	0.32	0.18
Nuclear	0.86	0.81	0.61
Oil	0.00	0.00	0.00
Bio	0.84	0.80	0.55

Table 8.3: Average EU utilization factor for thermal plants – S1, S2 and S3.

8.5.1.1 Germany

Figure 8.22 and Table 8.4 shows net marginal profit and utilization time for all thermal plants in Germany. With both lignite and hard coal along with bio and combined cycle gas (CCGT) being fairly profitable in S1, only bio and CCGT are still profitable in S2. In S3 CCGT is no longer profitable leaving only bio.

The differences between the scenarios is also reflected in the utilization factors where all fossil plants apart from CCGT have utilization ranging from 6 to 19 percent. CCGT also sees a drastic drop from 52 to 28 percent. While still fairly well utilized, bio also experiences a significant decrease, from 89 to 61 percent. As can be seen, oil is not utilized at all.

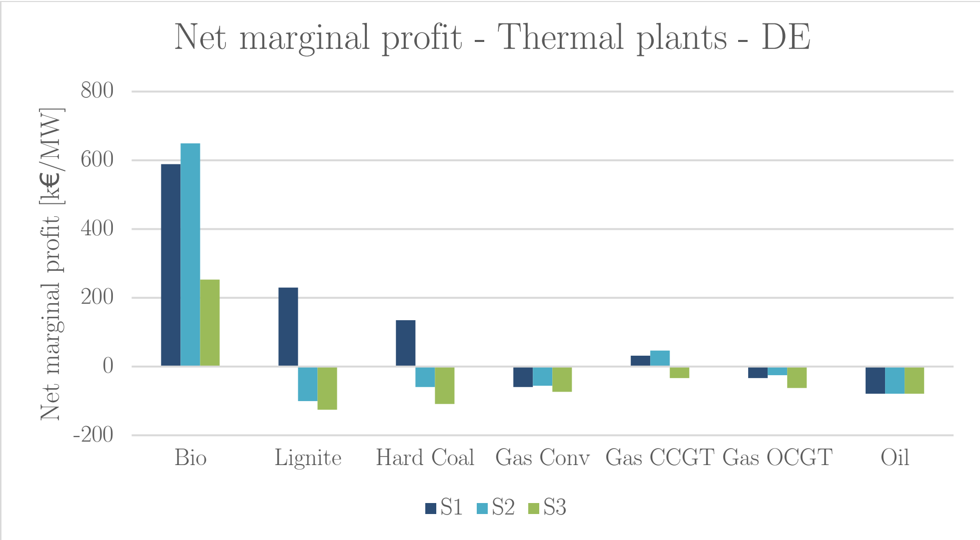


Figure 8.22: Net marginal profit for all thermal plants in Germany – S1, S2 and S3.

Utilization factor – Thermal plants – DE			
Plant type	**S1**	**S2**	**S3**
Bio	0.90	0.89	0.61
Lignite	0.70	0.26	0.11
Hard Coal	0.73	0.41	0.19
Gas Conv	0.19	0.19	0.06
Gas CCGT	0.53	0.52	0.28
Gas OCGT	0.38	0.41	0.14
Oil	0.00	0.00	0.00

Table 8.4: Utilization factor for all thermal plants in Germany – S1, S2 and S3.

8.5.1.2 France

Net marginal profit and utilization factors for all thermal plants in France is given in Figure 8.22 and Table 8.5. With low fuel costs and no emissions, nuclear and bio power are by far the most profitable assets in S1 and S2. With the increased I-RES supply in S3 only bio remains profitable, although it still experiences a large profit drop going from 449 to 65 €/MW. Conventional and open cycle (OCGT) gas power as well as oil is not profitable in any of the three scenarios (the latter is not utilized at all).

Bio power, which is 100 percent utilized in S1, drops to 48 percent utilization in S3. Fossil fueled power sees drastic reduction in utilization, ranging from 0 – 74 percent in S1 but only 0 – 20 percent in S3. Also, nuclear power has a mere 57 percent utilization in S3, which in reality would be way too low for any nuclear power plant, which aim to be running most hours of the year.

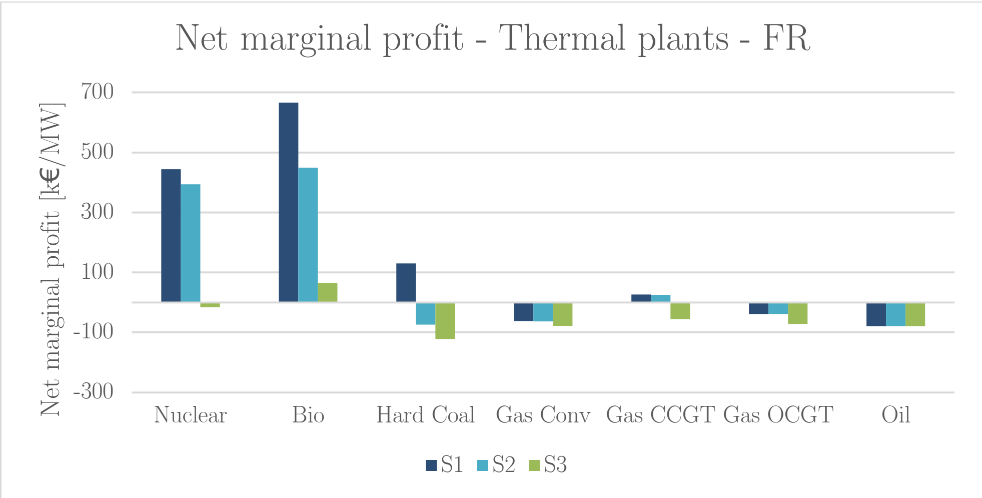


Figure 8.23: Net marginal profit for all thermal plants in France – S1, S2 and S3.

Utilization factor – Thermal plants – FR			
Plant type	**S1**	**S2**	**S3**
Nuclear	0.85	0.80	0.57
Bio	1.00	0.73	0.48
Hard Coal	0.74	0.36	0.12
Gas Conv	0.17	0.16	0.02
Gas CCGT	0.53	0.47	0.20
Gas OCGT	0.36	0.34	0.08
Oil	0.00	0.00	0.00

Table 8.5: Utilization factor for all thermal plants in France – S1, S2 and S3.

8.5.1.3 Great Britain

Britain has large amounts of wind power, even in S1. The installed capacity sees a significant increase between S1 and S2 and a twofold increase between S2 and

S3. Also introduced in S2 and S3 is CCS technology for gas power. Net marginal profit and utilization is given in Figure 8.24 and Table 8.6.

From Figure 8.24 it can be seen that nuclear, bio, hard coal and CCGT are the only profitable thermal assets in S1 (with the two latter being marginally profitable). In S2 this is reduced to only nuclear, bio and the newly introduced hard coal with CCS. The two former experience drastic reductions, with nuclear dropping by 69 % and bio by 46 %. Apart from bio power, with a net marginal profit of 14 k€/MW, no other thermal assets are longer profitable in S3.

While nuclear and bio are the most utilized thermal assets in all scenarios, a significant reduction is seen going from S1 to S3. Nuclear, having a utilization of 35 % in S3 is probably not something that would occur in a real-world scenario. While the CCS assets see decent utilization in S2 (at least compared to the equivalent non-CCS assets), it plunges to very low values in S3 as a result of the vast increase in I-RES capacity.

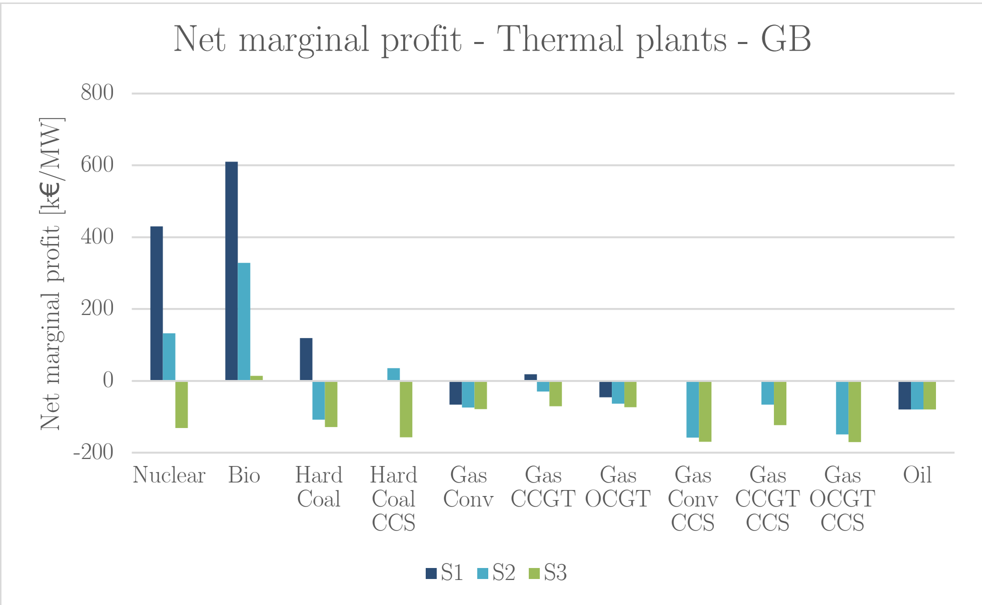


Figure 8.24: Net marginal profit for all thermal plants in Great Britain – S1, S2 and S3.

Utilization factor – Thermal plants – GB			
Plant type	S1	S2	S3
Nuclear	0.85	0.68	0.35
Bio	0.95	0.78	0.40
Hard Coal	0.73	0.21	0.07
Hard Coal CCS	-	0.52	0.23
Gas Conv	0.16	0.06	0.01
Gas CCGT	0.53	0.31	0.12
Gas OCGT	0.33	0.14	0.04
Gas Conv CCS	-	0.16	0.05
Gas CCGT CCS	-	0.36	0.15
Gas OCGT CCS	-	0.27	0.08
Oil	0.00	0.00	0.00

Table 8.6: Utilization factor for all thermal plants in Great Britain – S1, S2 and S3.

8.5.1.4 Norway

Having large amounts of hydro power, Norway's only thermal assets are gas power. Shown in Figure 8.25 and Table 8.7 is the net marginal profit and utilization factor respectively for all gas assets in the Norwegian power system. As can be seen, an increase in net marginal profit occurs between S1 and S2. This reflects higher average prices in S2 compared to S1 as examined in chapter 8.2.

With more hydro and wind power in S2 compared to S1, the utilization of thermal plants is reduced. This also reflects increased availability of renewable power from connecting countries such as Great Britain and Germany. As a result of the twofold increase of I-RES capacity in the European power system going from S2 to S3, no thermal power is utilized in Norway in S3.

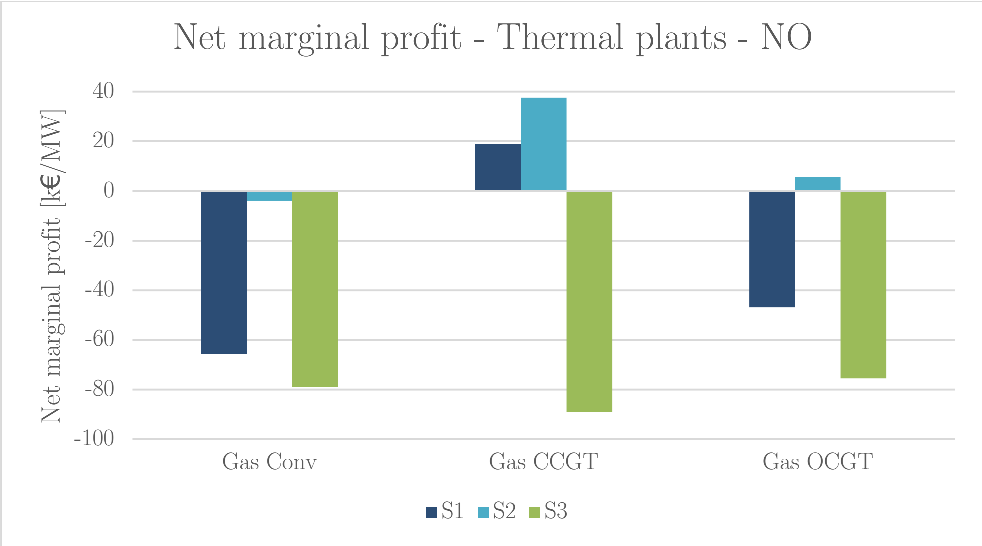


Figure 8.25: Net marginal profit for all thermal plants in Norway – S1, S2 and S3.

Utilization factor – Thermal plants – NO			
Plant type	**S1**	**S2**	**S3**
Gas Conv	0.20	0.01	0.00
Gas CCGT	0.49	0.34	0.00
Gas OCGT	0.41	0.01	0.00

Table 8.7: Utilization factor for all thermal plants in Norway – S1, S2 and S3.

8.5.2 RES

8.5.2.1 Solar and wind

Even though the marginal cost of production from I-RES power approaches zero, significant expenses are associated with investments and operations. Figure 8.26 illustrates the net marginal profit when accounting for these expenses, resulting in I-RES being unprofitable in all scenarios apart from offshore wind in S1 and onshore wind in S1 and S2. As seen, both solar and wind power are unprofitable in S3, with offshore wind being highly unprofitable.

When it comes to hydro power the profitability is high in both S1 and S2, with a slight increase in S2. In S3, hydro is no longer profitable.

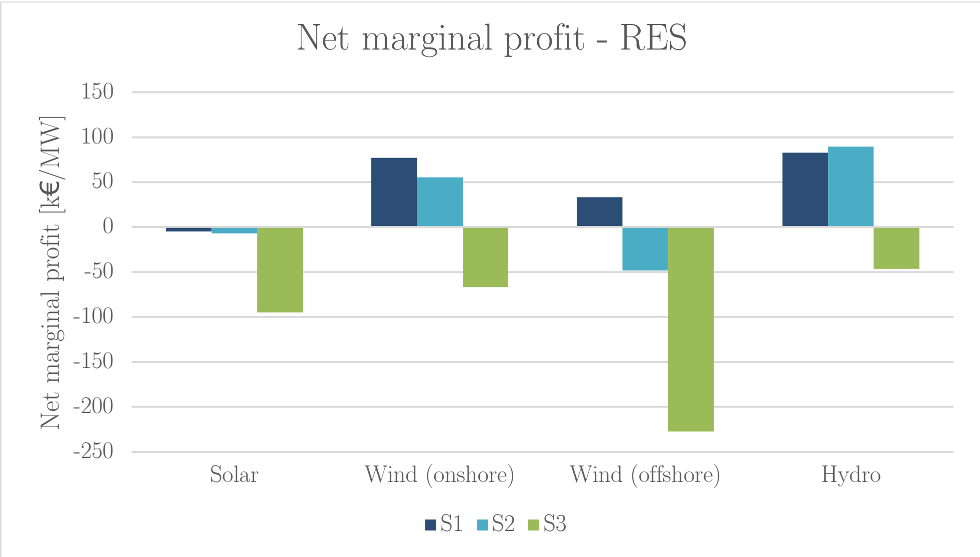


Figure 8.26: Net marginal profit for RES – S1, S2 and S3.

8.5.3 Lines

The line profitability vary greatly depending on the scenario. Figure 8.27 shows net marginal line profit for the lines between Norway and Great Britain, Germany and Netherlands. These lines were chosen because they're among the most utilized lines (as seen in chapter 8.3) and because they connect countries with different energy mixes.

The lines DE-NO and NL-NO experiences similar changes going from S1 to S3, with large increases in net marginal profitability. DE-NO sees a 140 percent increase going from S1 to S2 and an increase of 97 percent between S2 and S3.

The changes for NL-NO are even more extreme with an increase of 164 percent between S1 and S2, while the increase going from S2 to S3 is 137 percent.

GB-NO sees a dramatic increase in net marginal profitability going from S1 to S2, with a more than fourfold increase. From S2 to S3, the profitability decreases by 43 percent going from a profitability of 333 to 188 k€/MW.

As seen from Figure 8.27, DE-NO is the most profitable line in S1, GB-NO in S2 while NL-NO rises to the top in S3. From the figure it is also evident that the average price difference between the examined areas correlate extremely well with the line profitability. The high profitability of lines compared to power plants indicates that investing in lines could be key for future development of the European power system. This will be further assessed in chapter 8.7.

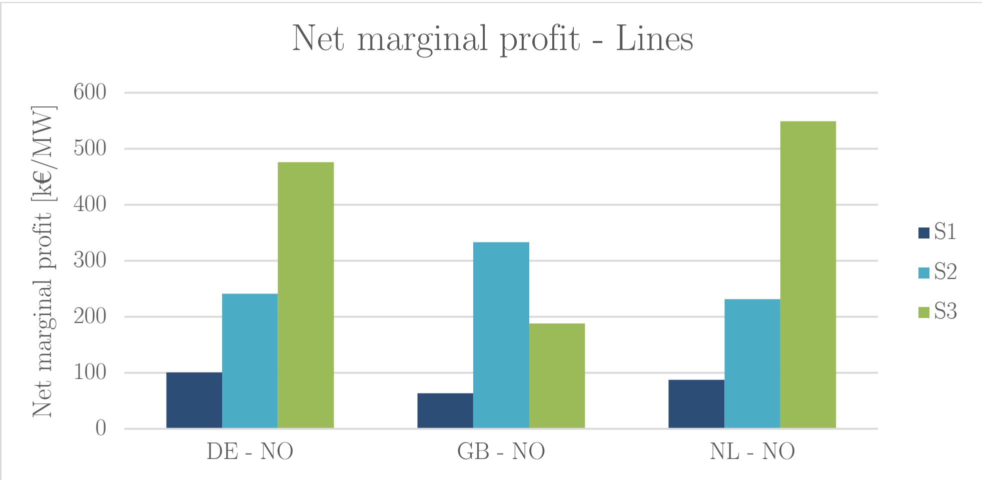


Figure 8.27: Net marginal profit for selected lines – S1, S2 and S3.

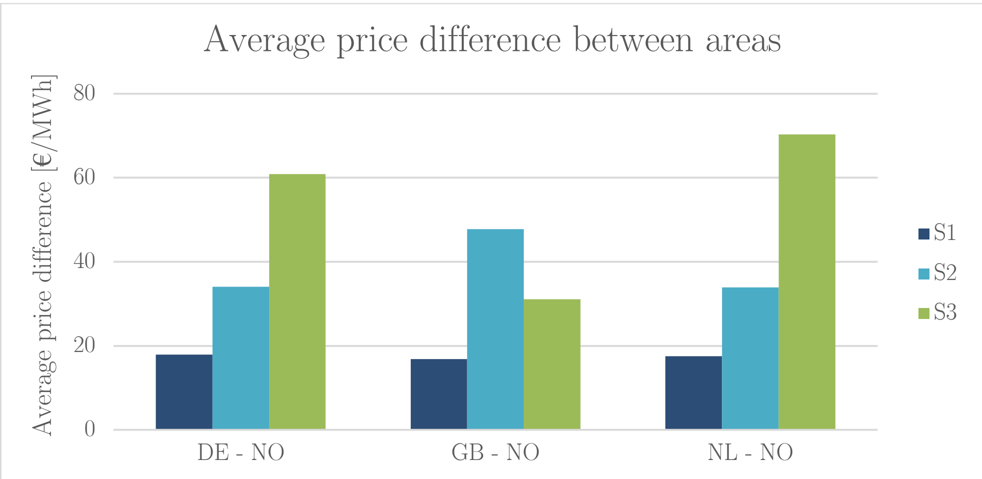


Figure 8.28: Average price difference between examined areas – S1, S2 and S3.

8.6 Revenue from energy and required support

The following section investigates the thermal revenue distribution and the required economical support needed to ensure profitability of assets in the system (referred to as 'missing break-even revenue'). This is typically the needed revenue from the capacity market.

Figure 8.29 illustrates the thermal revenue distribution across Europe with the missing break-even revenue stacked on top. As seen, revenues from most thermal assets decline significantly going from S1 to S3 (this was also examined in section 8.5.1). The only exceptions are gas and bio power, which experiences a slight revenue increase between S1 and S2, before dropping in S3. The increase for gas power in S2 is in large part due to higher CO_2 price compared to S1, favoring gas instead of coal. In S3 revenues decrease as a result of large energy supply from I-RES. Seeing bio power has very low fuel costs and zero emissions, the revenue increase experienced from S1 to S2 is a result of increased capacity. In S3, the increased energy supply from I-RES contributes to reducing revenue from bio power by around 50 %.

As can be observed from Figure 8.29 and Table 8.8, very little support is needed in S1. In fact, only gas and oil requires support. For gas, extra support of around 6 billion Euros is required to break even, amounting to around 7 % of total revenue. Oil, which is not utilized at all, requires 100 % support equaling 0.7 billion Euro. This is equal to the investment- and operating costs associated with oil power.

Increased CO_2 prices make hard coal and lignite unprofitable in S2, causing a fairly large increase in required revenue support. Both now require 17 % support, amounting to 3.4 and 5.3 billion Euros for lignite and hard coal respectively. Gas power, benefitting from the increased carbon price, experiences a revenue increase in S2. Although relative required support is about the same (now 8 %), absolute support is increased from 6 to 8 G€. Total required support for thermal power in S2 equals 26 G€, a threefold increase compared to S1.

As no thermal assets apart from bio are profitable in S3, required support is heavily increased. Illustrated by Table 8.8, it now ranges from 18 % for nuclear power to 40 and 43 % for lignite and hard coal respectively. The total required support for thermal assets sees a 60 % increases compared to S2, going from 26 to 41 G€.

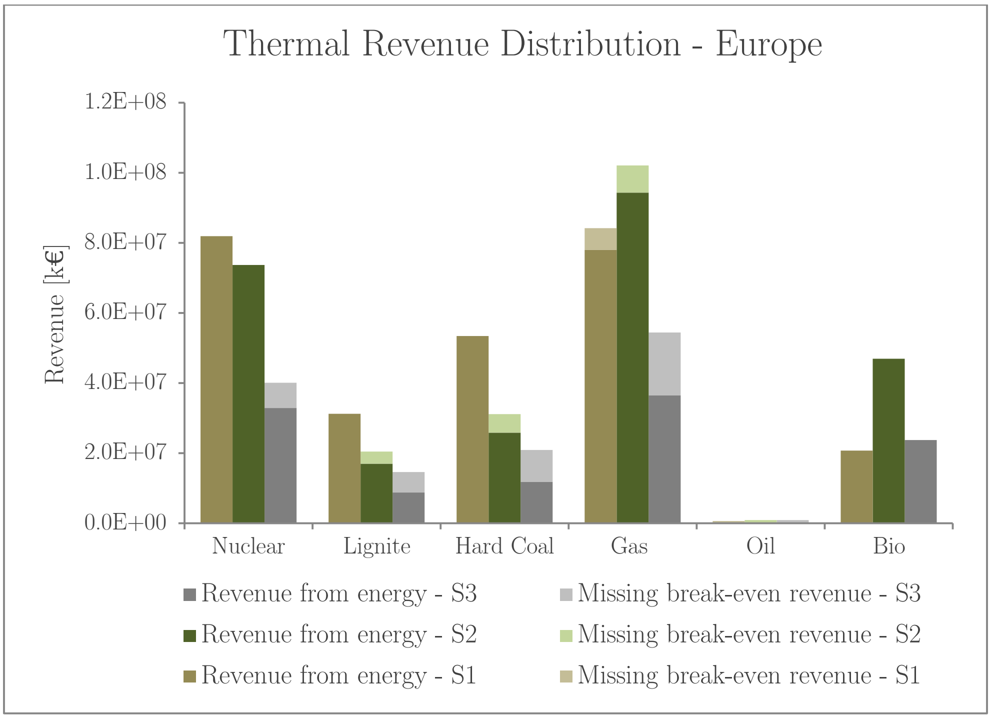


Figure 8.29: Thermal revenue distribution – S1, S2 and S3.

Missing break-even revenue to revenue from sales ratio – Thermal plants			
Type	**S1**	**S2**	**S3**
Nuclear	-	-	0.18
Lignite	-	0.17	0.40
Hard Coal	-	0.17	0.43
Gas	0.07	0.08	0.33
Oil	1.00	1.00	1.00
Bio	-	-	-

Table 8.8: Share of total revenue needed as support for an asset to break even – S1, S2 and S3.

Revenues from energy sales along with missing break-even revenue for RES is shown in Figure 8.30. Table 8.9 shows how much revenue support is needed (if any) for the asset to break even.

In S1, where prices are relatively high, only solar requires a mere 4 % support, equaling 0.7 G€. Between S1 and S2 there's about a twofold increase in I-RES capacity, reflected in increased revenues for all RES categories. This increase does also, however, contribute to lower prices which in turn causes both solar and offshore wind power to require financial support. Offshore wind, which has fairly high investment- and operating costs, now require 14 % support (6 G€). Solar power sees only a minor relative change from 4 to 6 %, but due to the revenue increase the required support is now 2.3 G€. The total revenue support required for RES assets to break even is now 8.3 G€.

With I-RES capacity being doubled compared to S2, S3 is by far the most extreme scenario. Prices are reduced by such a considerable amount that RES revenues from energy sales decrease across all categories. Since capacity has been greatly increased, large amounts of financial support is now required for the assets to break even. As seen in Table 8.9, the required support ranges from 29 % for hydro to 79 % for solar. In total, the RES assets now require a staggering 175 G€ in support, up from 8 G€ in S2.

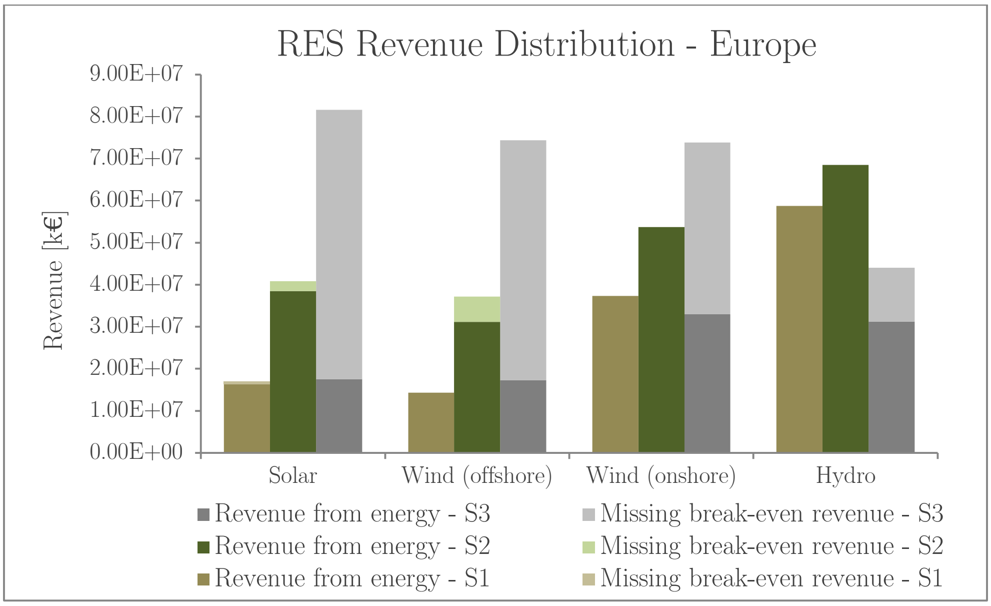


Figure 8.30: RES revenue distribution – S1, S2 and S3

Missing break-even revenue to revenue from sales ratio - RES			
Plant type	**S1**	**S2**	**S3**
Solar	0.04	0.06	0.79
Wind (offshore)	-	0.16	0.77
Wind (onshore)	-	-	0.55
Hydro	-	-	0.29

Table 8.9: Share of total revenue needed as support for an asset to break even – S1, S2 and S3

Table 8.10 summarizes how much revenue support is needed for both thermal and RES assets in the different scenarios. The general picture (as has been discussed in detail previously in this section) is a fairly large increase from S1 to S2 then an extreme increase going from S2 to S3. The numbers indicate several things.

Firstly there is too much fossil capacity installed in S3. Thus, in a scenario such as S3 there would be incentives to reduce the fossil capacity in the system, lowering the required financial support. While nuclear power is also unprofitable, it is mostly policy driven which places it in a unique position compared to the fossil assets.

Secondly, a need for capacity remuneration mechanics (CRM) is underlined. While it is desirable to have large amounts of renewable power in the system, investments would not be incentivized in a system where prices are too low (such as in S3). The large amount of support needed in S3 indicates that support mechanisms, especially for RES, are necessary if high RES penetration levels are to be achieved.

Missing break-even revenue [G€]			
Category	**S1**	**S2**	**S3**
Thermal	6	18	41
RES	0.7	8.3	175
Total	6.7	26.3	216

Table 8.10: Revenue support needed for thermal and RES assets combined.

8.6.1 Thermal revenue distribution – GB

Figure 8.31 illustrates the thermal revenue distribution in Great Britain. Revenues from oil power and gas power with CCS technology is excluded due to their low revenue values compared to the other thermal plants.

In total, the revenue from thermal plants in Great Britain drops from 26 to 7.5 G€ as we go from S1 to S3. As a result, the required economical support increases from 1.9 G€ in S1 to 6.2 G€ in S3.

All fossil assets would require significant financial support to stay profitable in both S2 and S3. In S3, the break-even revenue to revenue from sales ratio is as high as 67 and 59 % for hard coal and gas respectively. As previously seen, oil power is not utilized and would thus require 100 % support. Also, even nuclear power would require around 40 % of the revenues to come from financial support. Looking at the different gas plants, CCGT plants are the most effective and requires the least support. In the other end of the scale, conventional gas power experiences very low utilization thus requiring large amounts of support to stay profitable. In S3, Great Britain would need around 45 % of the thermal revenue to be financial support.

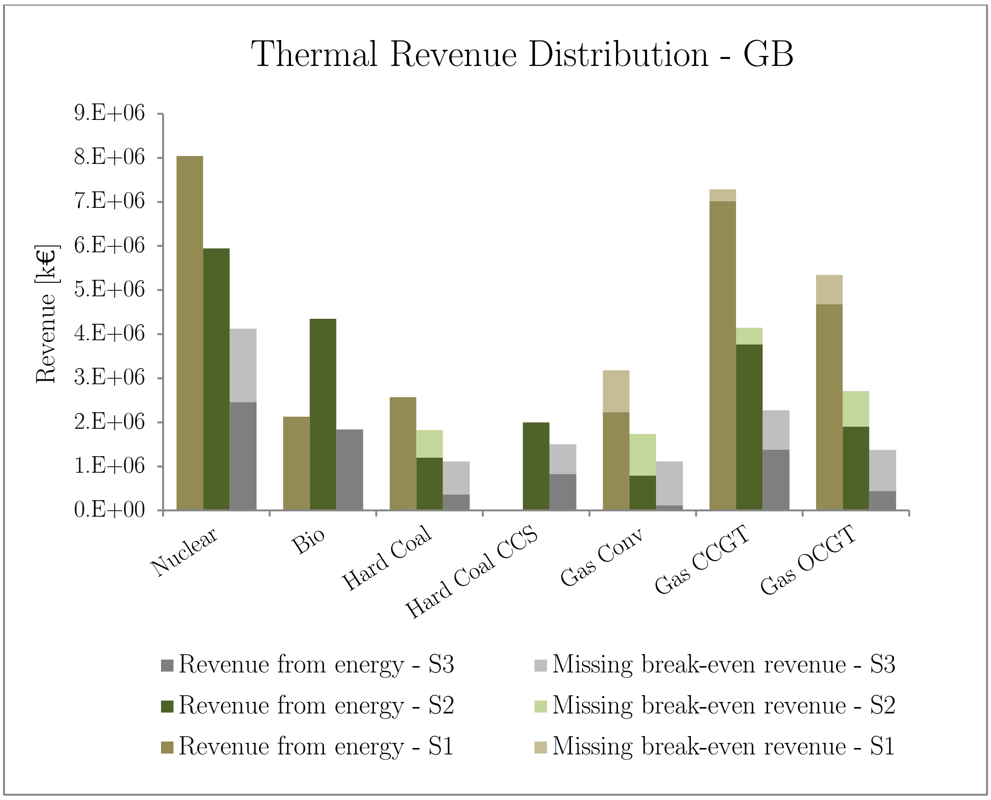


Figure 8.31: Thermal revenue distribution in Great Britain – S1, S2 and S3.

8.6.2 Thermal revenue distribution – DE

The thermal revenue distribution in Germany is illustrated in Figure 8.32. As can be seen, thermal revenue in Germany drops from 40.58 to 16.15 G€ going from S1 to S3. The required economical support thus experiences an eightfold increase, from 0.76 G€ in S1 to 6 G€ in S3.

Overall, the total missing break-even revenue to revenue from sales ratio in S3 is 27 % in S3. This number is a fair bit lower than for Great Britain, albeit still a substantial amount.

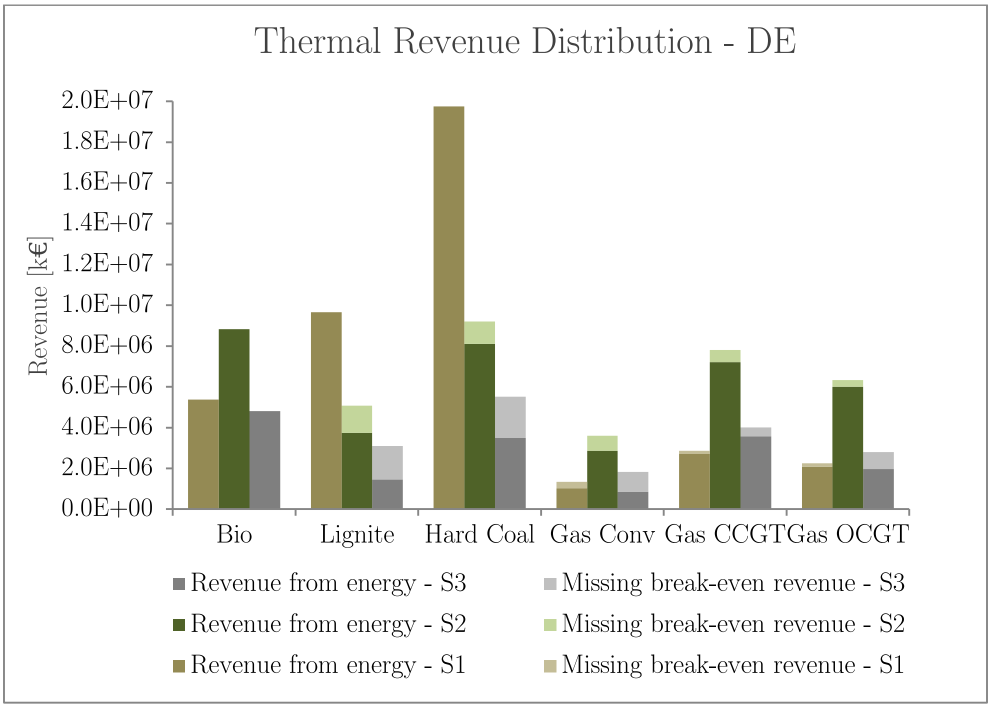


Figure 8.32: Thermal revenue distribution in Germany – S1, S2 and S3.

8.6.3 Thermal revenue distribution – FR

Figure 8.33 illustrates the thermal revenue distribution for France. The upper chart includes all plants, while the lower chart excludes nuclear plants. Please note the different scales.

France's thermal revenue stem largely from nuclear power. The total revenue from thermal plants in S1 is 45.9 G€, while the revenues from nuclear production were 40.8 G€. Thus, nuclear accounts for 88.9 % of the thermal revenues in S1. Going from S1 to S3, nuclear power is no longer profitable. In turn, this leads to reducing nuclear power revenues by 70.8 % compared to S1. While no economic support is needed in S1 and S2, nuclear requires 0.6 G€ in support in S3. In total, France's thermal asset requires support of 1.98 G€ in S3. While all thermal assets apart from bio requires support, the number is significantly lower than for Great Britain and Germany, both in absolute and relative terms.

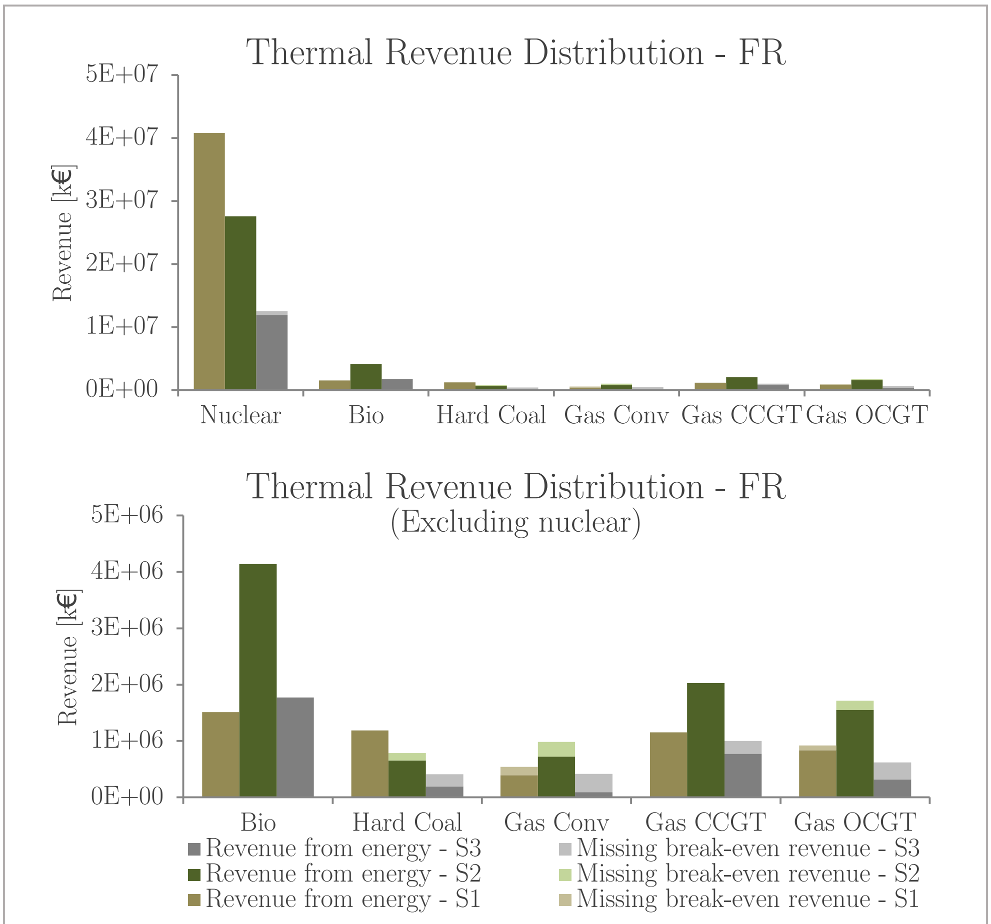


Figure 8.33: Thermal revenue distribution in France – S1, S2 and S3. Please note the different scales.

8.7 Investment analysis of S3

To explore and gain further insight into a system with extreme amounts of renewable energy, investment analyses on S3 is done. The analyses highlights different properties of the power system and aims to gain insight into how the system composition could be altered to better accommodate a reality where most of the energy stem from renewables.

As described in chapter The Scenarios6.2, S3 is based on S2 but with 100 % increase in I-RES capacity. From the performed assessments earlier in this chapter, it could be argued that the system composition of S3 is rather unrealistic. There is an abundance of generation capacity, in particular thermal capacity. Some of the thermal capacity is not utilized at all, not even in peak demand situations, meaning it is not needed to ensure system adequacy. Low utilization combined with low prices renders all thermal plants apart from bio plants unprofitable. Also, excessive amounts of dump energy is present, whereof a large share occurs in countries with highly congested transmission lines.

Based on the above info, it is evident that reducing the amount of thermal capacity in the system could lead to increased utilization and profitability of thermal assets. Large amounts of dump energy combined with the fact that lines are highly profitable point towards increasing line capacities.

The capacity reduction is set to only affect fossil assets, while nuclear and bio capacity will stay the same. When it comes to nuclear power, investment decisions are often driven by policies to a higher degree than profit. Also, as the only profitable thermal asset, bio power capacity will stay the same. As the goal is to achieve significant penetration of renewables, RES capacity is also untouched.

8.7.1 Scenario adjustments

Using an investment module in EMPS (described in chapter 4.4) new scenarios based on the original S3 scenario were created.

For fossil power, the decommissioning tool in the investment module was used. This module requires OPEX input for each examined plant and removes capacity until the MP is greater than the OPEX. Grid reinforcements were done using the investment tool, which increases specified lines until the MP of the line is greater than the CAPEX.

The investment module does not take system adequacy into consideration when reducing or increasing capacities. This was done manually by monitoring rationing and demand response values.

The CAPEX and OPEX values used when altering line- and plant capacities are the same as when calculating NMP (see chapter 6.3.10 and 6.3.11).

Three investment simulations were executed in series (i.e. each of the simulations are based on the previous one). This was mainly done because of computational limitations. The first simulation focused on decommissioning fossil capacity. OPEX for all fossil plants in the system was included resulting in an overall fossil capacity reduction of around 50 %.

The second simulation aimed to increase the previously investigated transmission lines: DE-NO, GB-NO and NL-NO. These lines were among the most utilized and thus increased capacity could prove beneficial to the system as a whole. The simulation resulted in extreme changes, with DE-NO experiencing a twentyfold increase in capacity.

The third simulation used the decommissioning tool once again to reduce fossil capacity. With the increased lines from the previous simulation, this resulted in a further decrease in fossil capacity, albeit only a few percent. Onwards, this third simulation outcome is referred to as Scenario 3.1 (S3.1).

Based on S3.1, two other scenarios were created manually. Line utilization and dump energy in S3.1 indicated that the system could benefit from increasing certain other highly congested lines. Thus, FR-ES, GB-BE, GB-FR and GB-NL were increased by 100 %. These adjustments are referred to as Scenario 3.2 (S3.2).

Transmission capacities for the lines DE-NO, GB-NO and NL-NO is rather extreme in S3.1 and S3.2. Thus, a final scenario was created to bring values down to a slightly more realistic level. This scenario is referred to as Scenario 3.3 (S3.3), and apart from a 50 % reduction of mentioned lines it is identical to S3.2.

Onwards, S3.1 – S3.3 will be examined to highlight the different properties of these scenarios compared to the original S3 scenario.

8.7.2 Fossil power and line capacities

The only changes done to the original S3 scenario through the investment analysis and manual modifications affect fossil power and transmission line capacities. This section features a summary of the investigated scenarios (Table 8.11) as well as their respective fossil power and transmission line capacities (Table 8.12 and Table 8.13).

As seen in Table 8.12, the total fossil capacity in the modified scenarios is reduced by over 50 %. A detailed view of the installed capacity in these scenarios can be found in Appendix A: Generation capacity. Generation from fossil power is reduced, albeit not by considerable amounts factoring in the large capacity reduction. More notably, the fossil revenue is not decreased by a lot, indicating that large amounts of the capacity was not utilized at all. As the average system price decreases going from S3 to S3.3 (see section 8.7.3), this also influences the generation and revenue seen from fossil sources. Lower prices means less generation and in turn lower revenues.

Line capacities for the affected lines are shown in Table 8.13 (the remaining lines are unchanged). Massive line increases are found in S3.1 after running the investment module in EMPS – a total of almost 55 GW increased capacity distributed over the lines DE-NO, GB-NO and NL-NO. With line profitability for these lines being very high in S3, they are increased until they break even in S3.1.

In S3.2 several other lines are doubled while the lines changed in S3.1 stays the same. As can be seen, this is the scenario with the largest total line capacity increase, amounting to over 67 GW.

Having lines as large as DE-NO, GB-NO and NL-NO in scenario S3.1 and S3.2 is most likely fairly unrealistic. Major grid investments in the national grids would most likely also have to be implemented, increasing the overall investment cost of the respective cables. Thus, the capacities for these lines were decreased by around 50 % in S3.3.

Summary of examined scenarios	
Scenario	**Description**
S3	The original S3 scenario.
S3.1	Identical to S3 apart from reduced fossil capacity and increased capacity on lines DE-NO, GB-NO and NL-NO.
S3.2	Identical to S3.1 apart from double capacity on lines BE-GB, FR-GB, FR-GB, GB-NL and ES-FR.
S3.3	Identical to S3.2 apart from reduced capacity (around 50 % decrease) on lines DE-NO, GB-NO and NL-NO.

Table 8.11: Summary of examined scenarios.

Capacity, generation and revenue – Fossil power				
Scenario	**S3**	**S3.1**	**S3.2**	**S3.3**
Fossil Capacity [GW]	403	191		
Fossil generation [TWh]	503	410	403	387
Fossil Revenue [G€]	57.1	50.0	43.1	40.5

Table 8.12: Fossil power capacity, generation and revenue – S3, S3.1, S3.2 and S3.3

	Transmission line capacity [MW]			
	Scenario			
Line	**S3**	**S3.1**	**S3.2**	**S3.3**
DE-NO	1 400	28 415	28 415	15 000
GB-NO	1 400	21 141	21 141	10 000
NL-NO	700	8 780	8 780	4500
BE-GB	2 000	2 000	4 000	4000
FR-GB	4 400	4 400	8 800	8 800
ES-FR	5 000	5 000	10 000	10 000
GB-NL	1 000	1 000	2 000	2 000
Total increase compared to S3	-	54 836	67 236	38 400

Table 8.13: Line capacities for the altered lines – S3, S3.1, S3.2 and S3.3.

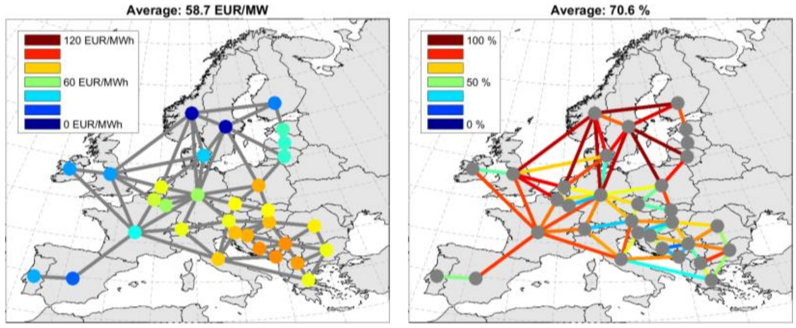
8.7.3 Prices and line utilization

Figure 8.34 – Figure 8.37 shows prices and line utilization for the original (for reference) as well as the modified versions of S3.

Removing fair amounts of fossil power and allowing line investments for the lines DE-NO, GB-NO and NL-NO (as was done in S3.1) leads to prices and utilization as depicted in Figure 8.35. As can be seen, the price alterations are fairly minor. Prices are up in certain areas in southeastern Europe and down others, leading to an average price of 42.4 €/MWh. This is a 2.9 €/MWh reduction compared to the original S3. The enormous increase in capacity for the lines which were opened for investment means the flow between the respective countries is almost free. As seen in the figure, the utilization for these lines is around 50 % while it was close to 100 % in the original S3. Still, high congestion rates are found on other important cables such as the French and British ones, suggesting that reinforcements might also be needed on those lines. High congestion rates are also found on some of the northern cables (such as FI-NO and PO-SE), however most of these have fairly small capacities and are located in a less central part of Europe thus considered to be less important for the system as a whole.

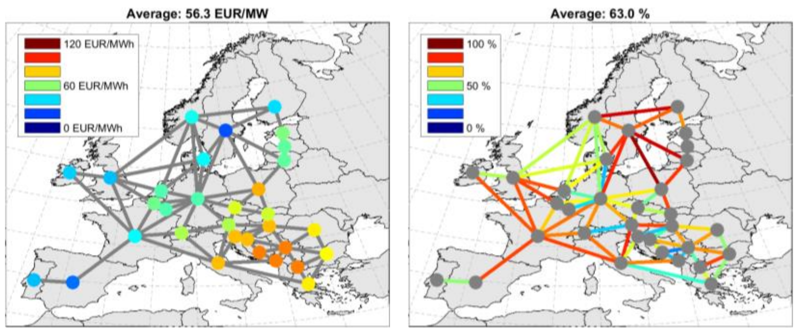
S3.2 saw a doubling in capacity for lines BE-GB, FR-GB, FR-GB, GB-NL and ES-FR. From Figure 8.36 it is evident that prices are decreased, especially in central-/southeastern Europe, and that the strain on the reinforced lines has been reduced. The average price is 42.0 €/MWh, which is a further reduction compared to S3.1.

As a measure to bring line capacities down to more realistic levels, the capacities for DE-NO, GB-NO and NL-NO were cut in half in S3.3. As expected, this increases line utilization for mentioned lines by a substantial amount (see Figure 8.37). The average price, however, is down to 39.8 €/MWh. While high line capacities contribute to evening out prices across Europe, lower capacities means more energy has to be sold in production areas when lines are fully congested. This leads to lower prices in export areas and higher in import areas (less energy is available for import). As seen in the figure, a price reduction is induced in Norway and Great Britain, the latter of which is one of the largest energy producers in Europe. These reductions are large enough to reduce average prices, even though the line reductions causes prices in other areas to rise.



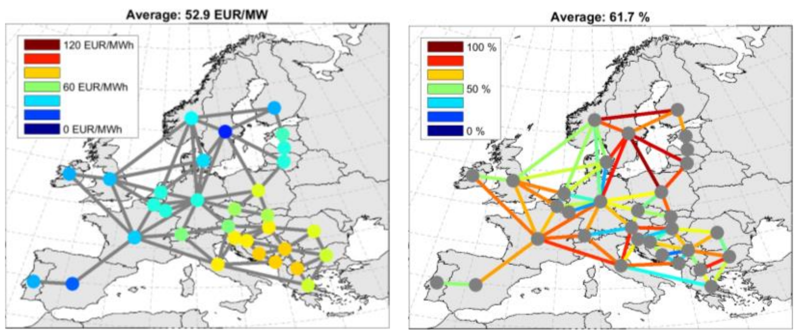
(a) (b)

Figure 8.34: Prices (a) and line utilization (b) – S3.



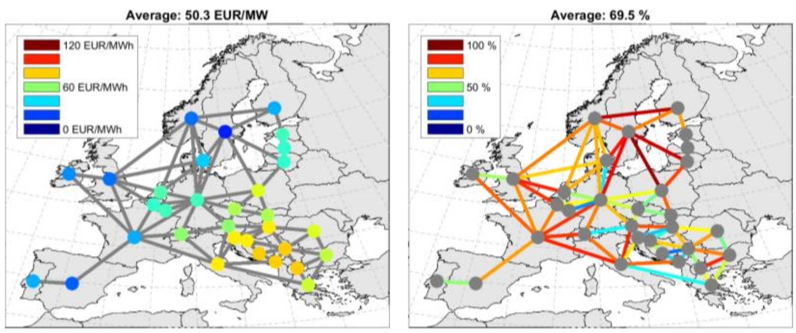
(a) (b)

Figure 8.35: Prices (a) and line utilization (b) – S3.1.



(a) (b)

Figure 8.36: Prices (a) and line utilization (b) – S3.2.



(a) (b)

Figure 8.37: Prices (a) and line utilization (b) – S3.3.

8.7.4 Dump energy

One of the goals with increased line capacities was to reduce the amount of dump energy in the system. Shown in Table 8.14 is the amount of dump energy in the original S3 vision as well as the modified versions. As can be seen, there's a moderate reduction going from the original S3 scenario to S3.1 (where several of the Norwegian lines were increased). The difference between the modified visions, however, is not as big. As an investigative measure, a simulation with unlimited transfer capacity on all lines was run. This resulted in 92 TWh of dump energy. It is thus evident that there are times when the total demand is simply less than the total production (e.g. times with low demand and high I-RES production), resulting in an energy surplus. Taking into account that 92 TWh of dump energy will be present in the system regardless of transfer capacities, the surplus reduction in the modified scenarios become relatively larger.

Of 129 TWh dump energy present in the original S3 vision, only 37 TWh can be removed from the system with the current demand. The presented numbers shows a reduction of 22, 27 and 25 TWh compared to S3, a relative reduction of 59, 73 and 68 % for S3.1, S3.2 and S3.3 respectively.

It is desirable to limit the amount of dump energy as much as possible. With considerable amounts of dump energy being present in all of the scenarios presented in Table 8.14, there are incentives to take extra measures towards reducing these numbers. Grid energy storage using batteries or other methods (something not included in the model used in this thesis) would potentially be effective in systems with large amounts of dump energy. It would allow for energy to be stored when production exceeds consumption and returned to the grid when production falls below consumption.

Total surplus (dump) energy [TWh]			
S3	S3.1	S3.2	S3.3
129	115	110	112

Table 8.14: Total dump energy in the system – S3, S3.1, S3.2 and S3.3.

8.7.5 Thermal asset profitability

8.7.5.1 Net marginal profit

Seen in Figure 8.38, Table 8.16 and Table 8.16 is the net marginal profit, installed capacity and utilization factor for thermal power in S3 – S3.3. While most thermal plants are still unprofitable, some interesting changes can be observed.

Nuclear power has the same installed capacity across all these scenarios. Still, scenarios S3.1 – S3.3 have higher nuclear utilization than S3. In S3.1 nuclear power sees increased profitability compared to S3 (albeit it is still unprofitable). This is likely due to increased utilization and a not too large price drop.

While nuclear utilization is the same in S3.2 and S3.3, there are several changes causing profitability to drop below S3 levels. Firstly, several of France's lines have been doubled. This means more renewable energy from Great Britain and Spain (which was previously dump energy) will be available for import, causing prices to drop even more than between S3 and S3.1. This energy will be favored over nuclear energy, causing nuclear revenues to drop.

Lignite, of which the installed capacity is reduced by 56 % in S3.1 – S3.3 compared to S3, experiences extreme changes in regards to profitability. As seen in Figure 8.38 it is nearly profitable in the three modified scenarios. In large part, this is due to increased utilization (resulting from reduced capacity) – from 18 % in S3 to 34, 41 and 42 % in S3.1, S3.2 and S3.3 respectively. Even though average prices decrease between S3.1 and S3.2 (-3.4 €/MW), the utilization increase (7 %) is large enough to increase the net marginal profit. Going from S3.2 to S3.3 it seems the price decrease (-2.6 €/MW) outweighs the increase in utilization (1 %), causing a minor drop in profitability.

Going from S3 to the modified scenarios (S3.1 – S3.3), hard coal capacity is reduced by 53 %. As a result, utilization is up, ranging from 30 – 36 % in the modified scenarios compared to only 19 % in the original S3 scenario. This causes an increase in net marginal profit, as seen in Figure 8.38. Going from S3.1 to S3.3, the price decrease between the modified scenarios causes revenues to drop and in turn the profitability of the power plants.

Gas power capacity is reduced by just below 50 % in S3.1 – S3.3 compared to S3. In S3.1 the gas power utilization is up to 22 % compared to 13 % in S3. This causes a fairly big increase in net marginal profit. In S3.2 and S3.3 the utilization drops to 19 and 18 % respectively. Combined with reduced power prices, this causes a profitability drop. The profitability in S3.2 and S3.3 is, however, still higher than in S3.

There's almost no oil power capacity left in the modified scenarios (0.8 GW), and practically zero utilization. Apart from a small production increase in S3.1 (causing the profitability increase seen in Figure 8.38), oil production is negligible.

As before, bio power is the only profitable thermal asset. Increased utilization between S3 and S3.1 causes a minor profitability increase. In the following two scenarios (S3.2 and S3.3), the price decrease causes profits to drop.

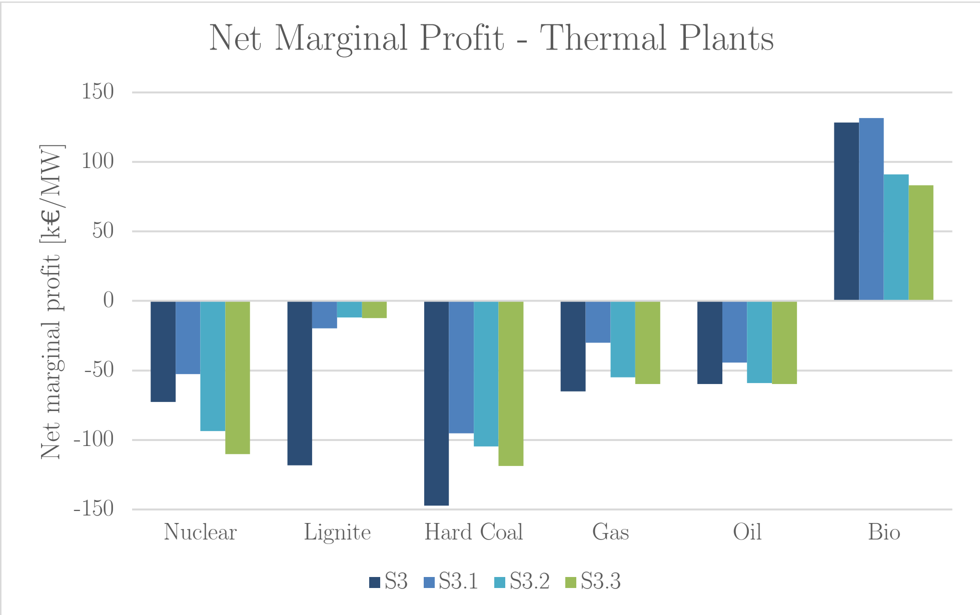


Figure 8.38: Net marginal profit – Thermal plants – S3, S3.1, S3.2 and S3.3.

	Installed capacity - Thermal power [GW]			
	S3	**S3.1**	**S3.2**	**S3.3**
Nuclear	99.3			
Lignite	49.4	21.7		
Hard Coal	61.8	29.1		
Gas	276.0	139.2		
Oil	16.2	0.8		
Bio	62.0			

Table 8.15: Installed thermal power capacity – S3, S3.1, S3.2 and S3.3.

	Utilization factor – Thermal power			
	S3	S3.1	S3.2	S3.3
Nuclear	0.61	0.64	0.64	0.64
Lignite	0.18	0.34	0.41	0.42
Hard Coal	0.19	0.30	0.36	0.34
Gas	0.13	0.22	0.19	0.18
Oil	0.00	0.00	0.00	0.00
Bio	0.55	0.57	0.58	0.59

Table 8.16: Utilization factor – Thermal plants – S3, S3.1, S3.2 and S3.3.

8.7.5.2 Revenue distribution

Figure 8.39 depicts the revenue from energy and missing revenue (if any) required for the asset to break even. Table 8.17 shows how much revenue support is required for thermal assets to break even. Due to low installed capacity and utilization, oil power is not included.

Nuclear power has very low fuel costs and no emission costs. Investment costs, however, are large. Thus, even though the production volume varies, the variable costs related to production are practically negligible compared to the investment costs. Seeing as installed nuclear power capacity is the same for all of the scenarios (S3 – S3.3) the sum of revenue and missing revenue is basically the same. The revenue distribution for nuclear power is closely related to the net marginal profit seen in the previous chapter. Revenue from energy goes up with increased profitability and vice versa for MBER.

As for nuclear, installed bio capacity is the same for all scenarios. As a profitable asset, no revenue support is required, and the revenue is closely related to the net marginal profit already assessed.

For lignite, the revenue distribution is significantly altered as a result of the decreased capacity in the modified scenarios. From requiring around 40 % of the total revenue being support in S3, almost no support is required in S3.1 – S3.3.

Hard coal follows the same trend as lignite. While production volume drops, a lot less support is required in S3.1 – S3.3 than in S3. Whereas 43 % of the total revenue was support in S3, only 23 – 28 % is required in the modified scenarios.

Gas power required around one third of total revenue to be support in S3. In S3.1 this is reduced to 11 %, while in S3.2 and S3.3 it is 23 and 26 % respectively. As seen from the figure, revenue from energy sales is reduced quite substantially in S3.2 and S3.3 compared to S3 and S3.1. This reflects decreased production and lower prices in these two scenarios compared to S3 and S3.1.

As seen in Table 8.17, the combined support required for thermal assets compared to S3 is reduced by 28 G€, a reduction of 68 %. The number rises moderately in S3.2 and S3.3, but is still significantly lower than in S3. Generally, getting rid of excess fossil power is positive for the system as a whole, increasing the profitability of assets and reducing required economical support.

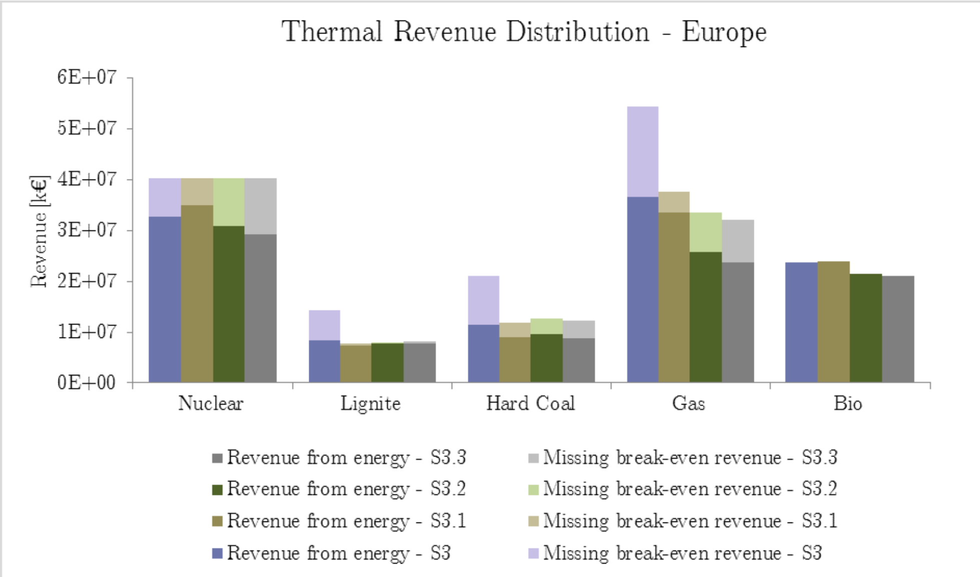


Figure 8.39: Thermal revenue distribution – S3, S3.1, S3.2 and S3.3.

Missing break-even revenue - Thermal [G€]			
S3	**S3.1**	**S3.2**	**S3.3**
41	13	20	23

Table 8.17: Total revenue support needed for thermal assets – S3, S3.1, S3.2 and S3.3.

9 Conclusion

In this master's thesis, three scenarios for the EMPS model have been created and analyzed. The scenarios are based on the Vision 2 («Money Rules») and 4 («Green Revolution») scenarios as described by the Ten Year Network Development Plan released by ENTSO-E in 2014. Scenario 1 (S1) and 2 (S2) are direct adaptations of Vision 2 and 4, while Scenario 3 (S3) is identical to S2 apart from double the amount of installed I-RES capacity. Using the EMPS model, the impacts of having a European power system composed as described by the scenarios is examined. Both an overall evaluation of Europe as well as in-depth looks at high-impact areas such as France, Germany, Great Britain and Norway is given.

Based on the simulation results, an investment analysis of S3 was run. This was done to gain further insight into how the power system could be altered to better accommodate a generation mix consisting largely of renewables. This resulted in three new scenarios based on S3 named S3.1, S3.2 and S3.3. The altered scenarios were then investigated, again assessing system properties such as prices, utilization and asset profitability.

The data collection, creation of data sets, simulations and analysis of the simulation results have given the candidates a thorough and valuable insight into the EMPS model, a deeper understanding of how increased amounts of renewables affects an energy system as well as highlighting some of the future challenges Europe will face regarding alteration of the power system.

As expected, increased amounts of I-RES capacity in the system greatly affects the generation mix. I-RES generation experiences an over fourfold increase going from S1 to S3, having a total generation of above 2700 TWh in S3. The increased I-RES capacity causes total RES penetration to rise quite substantially, sitting at 39, 57 and 78 % for S1, S2 and S3 respectively. As a result, a steady decrease in both fossil and nuclear powered generation is seen, with fossil generation being cut by 66 % and nuclear by around 30 %. The reduced thermal generation is reflected in very low utilization for most thermal plants in S3. This indicates that there's excessive thermal capacity in the system, and that reducing this capacity might be necessary should such an extreme scenario play out.

Large scale integration of RES causes a drop in power prices. Due to changes in fuel- and CO_2 prices, the average power price is fairly similar in S1 (106.3 €/MW) and S2 (105.3 €/MW). In S3, however, the average price plummets to 45.3 €/MW, a 57 % reduction compared to S2. Increased feed-in of renewable energy causes prices to approach zero in some of the largest RES producing countries such as Norway, Sweden and Spain. It should be noted that even though average prices are down in all of the examined countries, the price differences are larger in S3 compared to S1 and S2.

With large amounts of cheap renewable energy being transferred between high- and low-price areas, increased RES production increases utilization of transmission lines. While none of the transmission lines are at 100 % utilization in S1, this changes rapidly going to S2 and S3 where several of the Norwegian and Swedish lines approaches 100 % utilization. Several of the British and French lines also experience high congestion rates in S2 and S3. The high level of congestion for a significant amount of lines in the system suggest that line capacities are too low to properly support a system composition with substantial amounts of I-RES.

The drop in power prices highly affects the profitability of assets. Accounting for investment- and operational costs, no thermal assets apart from bio power is profitable in S3. Thus, even nuclear power is unprofitable. The trend is fairly similar for renewables. Both hydro as well as onshore- and offshore wind power is profitable in S1. In S2, only onshore wind and hydro power remain profitable, while no RES assets are profitable in S3.

The unprofitability of nearly all power plants in S3 indicates that the current reward system is not equipped to handle extreme increases in I-RES capacity, and that some form of capacity remuneration mechanisms would likely need to be deployed for such a system composition to work. Looking at S3, a total of 41 and 175 billion Euros would have to be supported for thermal and RES assets respectively.

For transmission lines the trend is reversed. As price differences are increased going from S1 to S3, so is line profitability. Transmission lines are the most profitable assets in the system by far, incentivizing additional line investments.

The investment analysis caused a reduction in fossil capacity of around 50 %. This is the basis for all the scenarios S3.1 – S3.3. In S3.1, the lines DE-NO, GB-NO and NL-NO increased up until the break-even point. This resulted in line capacities of around 28, 21 and 9 GW for the mentioned lines respectively. S3.2 is identical to S3.1 apart from doubling of other highly congested lines – namely BE-GB, ES-FR, FR-GB and GB-NL. S3.3 is identical to S3.2 apart from bringing the Norwegian lines down to a more realistic level (a reduction of around 50 %).

As expected, line utilization is reduced as line capacities are increased. Increased lines also contribute to lowering the average prices, being 42.2, 42.0 and 39.8 €/MW in S3.1, S3.2 and S3.3 respectively. Even though some line reductions are performed between S3.2 and S3.3, the average price drops by 2.2 €/MW. While high line capacities contribute to evening out prices across Europe, lower capacities means more energy has to be sold in production areas when lines are fully congested. This leads to lower prices in export areas and higher in import areas (less energy is available for import). Because of this, a price reduction is induced in Norway and Great Britain in S3.3, the latter of which is one of the largest energy producers in Europe. These reductions are large enough to reduce average prices, even though the line reductions causes prices in other areas to rise.

Profitability of fossil assets are increased as a result of reduced capacity. However, the general picture is still the same as for S3 as no thermal assets apart from bio are profitable in either of the three modified scenarios. Due to the increased profitability, thermal assets now require less economical support than in S3. In S3.1, 13 billion Euros in support is needed for thermal assets, a reduction of almost 70 % compared to S3. For S3.2 and S3.3 the numbers are 20 and 23 billion Euros respectively. These results indicate that thermal capacity and fossil capacity in particular should be reduced to increase profitability and limit the amount of economical support required.

While the amount of excess (dump) energy is negligible in S1 and S2, it amounted to 129 TWh in S3. Increased transmission capacities contributes to reducing these numbers, being 115, 110 and 112 TWh in S3.1, S3.2 and S3.3 respectively. After running a simulation with unlimited transmission capacities, 92 TWh of dump energy was still present in the system. Thus, it is evident that there are times when the total demand is simply less than the total production, resulting in an energy surplus. Taking this into account, the relative dump energy reduction in the modified scenarios become more significant.

The dump energy present in the high-RES systems examined calls for grid energy storage to be utilized. It would allow for energy to be stored when production exceeds consumption and returned to the grid when production falls below consumption, thus reducing dump energy and increasing the overall utilization of the power system.

10 Further work

A more detailed simulation of the data sets should be done to increase the accuracy and realism of our results. The model is simulated without implementing startup-/shutdown costs and ramp up/down times for any assets. This simplification rewards thermal plants such as nuclear with an unrealistically high flexibility thus reducing the utilization factor of assets that in reality have a higher flexibility, such as open cycle gas plants. Implementing these parameters, especially for thermal plants, would better reward the different assets in relation to their flexibility. This would also increase quality of the system adequacy analysis and give a better insight into how much flexible capacity is needed in the system.

Energy storages is not included in the used model. As a result, large amounts of dump energy is present in the system. An implementation of different storage solutions such as pumped hydro into the model should better accommodate the large share of I-RES generation, theoretically reducing the system dump energy and increase the system adequacy. The EMPS model is, however, known to handle pumping poorly, but this could be examined using ReOpt or other tools and extensions available to the EMPS model.

The significant increase in I-RES generation, especially in S3, results in reduced utilization for conventional power plants. This reduces their revenue from the conventional power market, making many thermal assets unprofitable. In turn this means some of the revenue will have to come from elsewhere in order to stay profitable. Capacity remuneration mechanisms is not modelled in this thesis, but is something that should be implemented in future simulations.

The simulations identified certain transmission bottlenecks. A sensitivity analysis on the respective interconnections should be conducted to establish whether or not they limit the system adequacy.

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Appendix A: Generation capacity

TYNDP 2014 - 2030 Generation capacity [MW] – S1															
Country	Nuclear	Bio	Lignite	Lignite CCS	Hard Coal	Hard Coal CCS	Gas	Gas CCS	Oil	Diverse	Other RES	Hydro	Wind onshore	Wind offshore	Solar
AT	0	1630	0	0	1212	0	10091	0	326	0	0	19506	3290	0	820
BA	0	0	2101	0	0	0	0	0	0	0	0	2053	350	0	0
BE	0	1710	0	0	0	0	11996	0	0	3240	0	1437	2590	2200	4050
BG	1000	0	3300	0	600	0	1563	0	0	0	0	3150	3000	0	2500
CH	1165	230	0	0	0	0	780	0	0	700	0	18644	530	0	600
CZ	5200	411	5800	0	1500	0	3773	0	0	0	389	2521	740	0	2000
DE	0	8800	14867	0	28774	0	15933	0	1197	2430	0	15650	49500	9800	55100
DK	0	260	0	0	2925	0	3211	0	0	0	0	9	4710	2140	1110
EE	0	190	0	0	0	0	329	0	1435	40	0	10	350	0	0
ES	7070	6097	1060	0	3285	310	31590	0	0	10480	1283	23190	35027	723	12000
FI	4890	1700	560	0	2525	0	200	0	1360	2900	0	3740	1850	950	10
FR	56000	2300	0	0	1740	0	6885	0	1753	4200	0	25200	18500	1500	25000
GB	10921	3420	0	0	3831	0	43081	0	504	3670	0	5005	11350	19220	1870
GR	0	380	2856	0	0	0	7007	0	0	0	350	4526	5900	300	4000
HR	0	300	0	0	1200	0	1700	0	200	300	0	2700	1300	0	100
HU	3022	550	491	0	110	0	5097	0	407	720	0	66	750	0	60
IE	0	350	0	0	860	0	3963	0	400	210	0	508	3450	550	20
IT	0	6670	0	0	11375	0	43377	0	2393	610	0	24061	12760	650	24600
LT	1350	340	0	0	0	0	1292	0	188	870	0	1031	500	0	10
LU	0	70	0	0	0	0	375	0	0	600	0	1320	130	0	120
LV	0	230	0	0	0	0	995	0	0	270	0	1602	753	452	10
ME	0	0	720	0	0	0	0	0	0	0	0	785	240	0	0
MK	0	50	485	0	0	0	460	0	0	70	0	1704	0	0	30
NI	0	190	0	0	348	0	1209	0	401	10	0	0	1130	600	0
NL	484	640	0	0	5214	0	13013	0	0	6200	0	203	4000	2000	4000
NO	0	0	0	0	0	0	855	0	0	0	0	37900	2750	0	0
PL	4500	0	6960	0	9211	0	1950	0	0	10380	0	2546	6150	2250	500
PT	0	203	0	0	0	0	4605	0	0	1510	608	9066	5300	0	550
RO	2625	450	2568	0	1899	0	4268	0	0	0	0	7941	5000	0	550
RS	0	0	5644	0	0	0	450	0	0	0	0	4339	450	0	10
SE	8159	5340	0	0	0	0	0	0	660	490	0	16203	6090	160	0
SI	696	0	545	0	159	0	747	0	0	0	0	1901	120	0	435
SK	2880	280	241	0	200	0	1630	0	0	970	0	2576	200	0	600

Table A.1: Generation capacity – S1.

TYNDP 2014 - 2030 Generation capacity – S2															
Country	Nuclear	Bio	Lignite	Lignite CCS	Hard Coal	Hard Coal CCS	Gas	Gas CCS	Oil	Diverse	Other RES	Hydro	Wind onshore	Wind offshore	Solar
AT	0	2650	0	0	970	0	7560	0	326	0	0	21737	5500	0	6500
BA	0	0	1779	322	0	0	390	0	0	0	0	2278	640	0	1900
BE	0	2510	0	0	0	0	11892	0	0	3240	0	1438	5370	4000	6740
BG	2000	0	3300	1000	655	0	1826	0	0	0	0	3400	4000	0	7900
CH	1165	1800	0	0	0	0	1170	0	0	700	0	18994	900	0	4500
CZ	7600	1279	5800	0	1200	0	4500	0	0	0	1211	3057	1250	0	3500
DE	0	13500	13165	0	18523	0	39302	0	1197	3320	0	15950	89500	23600	68800
DK	0	860	0	0	2678	0	3232	0	0	0	0	9	5920	5540	3430
EE	0	400	0	0	0	0	723	0	1400	40	0	20	650	250	100
ES	7070	17000	0	0	1420	1068	41770	0	0	12210	0	30655	47127	1873	58000
FI	6490	2550	700	0	2025	0	3825	0	1360	1950	0	3740	2550	2350	40
FR	40000	9300	0	0	1740	0	12480	0	3750	4200	0	28200	38000	14400	49600
GB	13910	10570	0	0	5818	4284	38005	1180	606	5710	0	5268	18060	42310	5800
GR	0	438	2856	0	0	0	7611	0	0	0	512	4626	7500	300	10900
HR	0	300	0	0	500	500	1700	0	200	300	0	3000	1500	0	100
HU	4152	1040	0	0	110	0	5004	0	407	720	0	100	1000	0	3600
IE	0	1250	0	0	0	0	5943	0	400	210	0	590	5150	1950	50
IT	0	19570	0	0	9879	0	46005	0	5057	2790	0	24761	21100	1000	68500
LT	1350	440	0	0	0	0	2137	0	188	1090	0	1405	1000	0	20
LU	0	60	0	0	0	0	375	0	0	120	0	1344	200	0	120
LV	0	1460	0	0	0	0	995	0	0	270	0	1536	882	598	20
ME	0	0	0	480	0	0	0	0	0	0	20	900	300	0	540
MK	0	20	485	0	0	0	460	0	0	70	0	1704	360	0	1040
NI	0	340	0	0	0	0	1562	0	461	10	0	0	1330	900	0
NL	484	1000	0	0	4621	0	15214	0	0	6200	0	203	6000	6800	9100
NO	0	0	0	0	0	0	855	0	0	0	0	52000	5000	6400	0
PL	6000	5300	7410	4407	4120	0	7130	0	0	5600	0	2656	7300	8300	5300
PT	0	1136	0	0	0	0	4605	0	0	1740	704	10280	6400	0	4550
RO	2625	2800	2568	0	773	527	5700	0	0	0	0	8000	5500	0	9450
RS	0	0	4299	0	0	0	450	0	0	0	0	4939	1000	0	3410
SE	9952	5300	0	0	0	0	0	0	660	10	0	16203	14000	5000	1000
SI	1796	0	545	0	45	114	787	0	170	0	0	1999	240	0	1920
SK	2880	940	241	0	200	0	1630	0	0	970	0	2706	450	0	2420

Table A.2: Generation capacity – S2.

TYNDP 2014 - 2030 Generation capacity – S3															
Country	Nuclear	Bio	Lignite	Lignite CCS	Hard Coal	Hard Coal CCS	Gas	Gas CCS	Oil	Diverse	Other RES	Hydro	Wind onshore	Wind offshore	Solar
AT	0	2650	0	0	970	0	7560	0	326	0	0	21737	11000	0	13000
BA	0	0	1779	322	0	0	390	0	0	0	0	2278	1280	0	3800
BE	0	2510	0	0	0	0	11892	0	0	3240	0	1438	10740	8000	13480
BG	2000	0	3300	1000	655	0	1826	0	0	0	0	3400	8000	0	15800
CH	1165	1800	0	0	0	0	1170	0	0	700	0	18994	1800	0	9000
CZ	7600	1279	5800	0	1200	0	4500	0	0	0	1211	3057	2500	0	7000
DE	0	13500	13165	0	18523	0	39302	0	1197	3320	0	15950	179000	47200	137600
DK	0	860	0	0	2678	0	3232	0	0	0	0	9	11840	11080	6860
EE	0	400	0	0	0	0	723	0	1400	40	0	20	1300	500	200
ES	7070	17000	0	0	1420	1068	41770	0	0	12210	0	30655	94254	3746	116000
FI	6490	2550	700	0	2025	0	3825	0	1360	1950	0	3740	5100	4700	80
FR	40000	9300	0	0	1740	0	12480	0	3750	4200	0	28200	76000	28800	99200
GB	13910	10570	0	0	5818	4284	38005	1180	606	5710	0	5268	36120	84620	11600
GR	0	438	2856	0	0	0	7611	0	0	0	512	4626	15000	600	21800
HR	0	300	0	0	500	500	1700	0	200	300	0	3000	3000	0	200
HU	4152	1040	0	0	110	0	5004	0	407	720	0	100	2000	0	7200
IE	0	1250	0	0	0	0	5943	0	400	210	0	590	10300	3900	100
IT	0	19570	0	0	9879	0	46005	0	5057	2790	0	24761	42200	2000	137000
LT	1350	440	0	0	0	0	2137	0	188	1090	0	1405	2000	0	40
LU	0	60	0	0	0	0	375	0	0	120	0	1344	400	0	240
LV	0	1460	0	0	0	0	995	0	0	270	0	1536	1764	1196	40
ME	0	0	0	480	0	0	0	0	0	0	20	900	600	0	1080
MK	0	20	485	0	0	0	460	0	0	70	0	1704	720	0	2080
NI	0	340	0	0	0	0	1562	0	461	10	0	0	2660	1800	0
NL	484	1000	0	0	4621	0	15214	0	0	6200	0	203	12000	13600	18200
NO	0	0	0	0	0	0	855	0	0	0	0	52000	10000	12800	0
PL	6000	5300	7410	4407	4120	0	7130	0	0	5600	0	2656	14600	16600	10600
PT	0	1136	0	0	0	0	4605	0	0	1740	704	10280	12800	0	9100
RO	2625	2800	2568	0	773	527	5700	0	0	0	0	8000	11000	0	18900
RS	0	0	4299	0	0	0	450	0	0	0	0	4939	2000	0	6820
SE	9952	5300	0	0	0	0	0	0	660	10	0	16203	28000	10000	2000
SI	1796	0	545	0	45	114	787	0	170	0	0	1999	480	0	3840
SK	2880	940	241	0	200	0	1630	0	0	970	0	2706	900	0	4840

Table A 3: Generation capacity – S3.

TYNDP 2014 - 2030 Generation capacity – S3.1, S3.2 and S3.3															
Country	Nuclear	Bio	Lignite	Hard Coal	Gas	Oil	Diverse	Other RES	Hydro	Wind onshore	Wind offshore	Solar	Country	Nuclear	Bio
AT	0	2650	0	323	2520	0	0	0	21737	11000	0	13000	AT	0	2650
BA	0	0	795	0	344	0	0	0	2278	1280	0	3800	BA	0	0
BE	0	2510	0	0	6967	0	3240	0	1438	10740	8000	13480	BE	0	2510
BG	2000	0	1100	218	1012	0	0	0	3400	8000	0	15800	BG	2000	0
CH	1165	1800	0	0	391	0	700	0	18994	1800	0	9000	CH	1165	1800
CZ	7600	1279	145	400	2005	0	0	1211	3057	2500	0	7000	CZ	7600	1279
DE	0	13500	4388	6174	26202	798	3320	0	15950	179000	47200	137600	DE	0	13500
DK	0	860	0	893	2154	0	0	0	9	11840	11080	6860	DK	0	860
EE	0	400	0	0	400		40	0	20	1300	500	200	EE	0	400
ES	7070	17000	0	5	8050	0	12210	0	30655	94254	3746	116000	ES	7070	17000
FI	6490	2550	2	675	2017	0	1950	0	3740	5100	4700	80	FI	6490	2550
FR	40000	9300	0	580	2248	0	4200	0	28200	76000	28800	99200	FR	40000	9300
GB	13910	10570	0	1939	22993	0	5710	0	5268	36120	84620	11600	GB	13910	10570
GR	0	438	961	0	5379	0	0	512	4626	15000	600	21800	GR	0	438
HR	0	300	0	167	756	0	300	0	3000	3000	0	200	HR	0	300
HU	4152	1040	0	37	2032	0	720	0	100	2000	0	7200	HU	4152	1040
IE	0	1250	0	0	1980	0	210	0	590	10300	3900	100	IE	0	1250
IT	0	19570	0	6586	27193	0	2790	0	24761	42200	2000	137000	IT	0	19570
LT	1350	440	0	0	1176	0	1090	0	1405	2000	0	40	LT	1350	440
LU	0	60	0	0	252	0	120	0	1344	400	0	240	LU	0	60
LV	0	1460	0	0	537	0	270	0	1536	1764	1196	40	LV	0	1460
ME	0	0	0	0	0	0	0	20	900	600	0	1080	ME	0	0
MK	0	20	324	0	408	0	70	0	1704	720	0	2080	MK	0	20
NI	0	340	0	0	638	0	10	0	0	2660	1800	0	NI	0	340
NL	484	1000	0	1540	10150	0	6200	0	203	12000	13600	18200	NL	484	1000
NO	0	0	0	0	0	0	0	0	52000	10000	12800	0	NO	0	0
PL	6000	5300	4940	2746	6336	0	5600	0	2656	14600	16600	10600	PL	6000	5300
PT	0	1136	0	0	1360	0	1740	704	10280	12800	0	9100	PT	0	1136
RO	2625	2800	856	258	2525	0	0	0	8000	11000	0	18900	RO	2625	2800
RS	0	0	1716	0	400	0	0	0	4939	2000	0	6820	RS	0	0
SE	9952	5300	0	0	0	0	10	0	16203	28000	10000	2000	SE	9952	5300
SI	1796	0	182	15	348	0	0	0	1999	480	0	3840	SI	1796	0
SK	2880	940	0	67	543	0	970	0	2706	900	0	4840	SK	2880	940

Table A 4: Generation capacity – S3.1, S3.2 and S3.3.

Appendix B: Transmission capacity

Transmission capacity [MW] - Part 1																
Country	AT	BA	BE	BG	CH	CZ	DE	DK	EE	ES	FI	FR	GB	GR	HR	HU
AT	0	0	0	0	2200	1200	7500	0	0	0	0	0	0	0	0	800
BA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	700	0
BE	0	0	0	0	0	0	1000	0	0	0	0	4300	2000	0	0	0
BG	0	0	0	0	0	0	0	0	0	0	0	0	0	400	0	0
CH	2500	0	0	0	0	0	5000	0	0	0	0	4700	0	0	0	0
CZ	1000	0	0	0	0	0	2000	0	0	0	0	0	0	0	0	0
DE	7500	0	1000	0	5000	2600	0	1600	0	0	0	4100	0	0	0	0
DK	0	0	0	0	0	0	3000	1200	0	0	0	0	1400	0	0	0
EE	0	0	0	0	0	0	0	0	0	0	1000	0	0	0	0	0
ES	0	0	0	0	0	0	0	0	0	0	0	5000	0	0	0	0
FI	0	0	0	0	0	0	0	0	1000	0	0	0	0	0	0	0
FR	0	0	2800	0	2800	0	4100	0	0	5000	0	0	4400	0	0	0
GB	0	0	2000	0	0	0	0	1200	0	0	0	4400	0	0	0	0
GR	0	0	0	1400	0	0	0	0	0	0	0	0	0	0	0	0
HR	0	900	0	0	0	0	0	0	0	0	0	0	0	0	0	2000
HU	1200	0	0	0	0	0	0	0	0	0	0	0	0	0	2000	0
IE	0	0	0	0	0	0	0	0	0	0	0	700	1200	0	0	0
IT	1900	0	0	0	5900	0	0	0	0	0	0	4350	0	500	0	0
LT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LU	0	0	700	0	0	0	2300	0	0	0	0	0	0	0	0	0
LV	0	0	0	0	0	0	0	0	1600	0	0	0	0	0	0	0
ME	0	550	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MK	0	0	0	300	0	0	0	0	0	0	0	0	0	685	0	0
NI	0	0	0	0	0	0	0	0	0	0	0	0	500	0	0	0
NL	0	0	2400	0	0	0	5000	1200	0	0	0	0	1000	0	0	0
NO	0	0	0	0	0	0	1400	1700	0	0	100	0	1400	0	0	0
PL	0	0	0	0	0	800	2000	0	0	0	0	0	0	0	0	0
PT	0	0	0	0	0	0	0	0	0	3200	0	0	0	0	0	0
RO	0	0	0	1400	0	0	0	0	0	0	0	0	0	0	0	1300
RS	0	1250	0	1100	0	0	0	0	0	0	0	0	0	0	450	600
SE	0	0	0	0	0	0	1200	740	0	0	3150	0	0	0	0	0
SI	1200	0	0	0	0	0	0	0	0	0	0	0	0	0	1500	1700
SK	0	0	0	0	0	2100	0	0	0	0	0	0	0	0	0	2000

Table B.1: Transmission capacity – Part 1.

Transmission capacity [MW] - Part 2																	
Country	IE	IT	LT	LU	LV	ME	MK	NI	NL	NO	PL	PT	RO	RS	SE	SI	SK
AT	0	1700	0	0	0	0	0	0	0	0	0	0	0	0	0	1200	0
BA	0	0	0	0	0	500	0	0	0	0	0	0	0	1200	0	0	0
BE	0	0	0	700	0	0	0	0	2400	0	0	0	0	0	0	0	0
BG	0	0	0	0	0	0	150	0	0	0	0	0	1500	1000	0	0	0
CH	0	3650	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CZ	0	0	0	0	0	0	0	0	0	0	1800	0	0	0	0	0	1100
DE	0	0	0	2300	0	0	0	0	5000	1400	3000	0	0	0	1200	0	0
DK	0	0	0	0	0	0	0	0	700	1700	0	0	0	0	740	0	0
EE	0	0	0	0	1600	0	0	0	0	0	0	0	0	0	0	0	0
ES	0	0	0	0	0	0	0	0	0	0	0	3200	0	0	0	0	0
FI	0	0	0	0	0	0	0	0	0	100	0	0	0	0	3150	0	0
FR	700	2200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GB	1200	0	0	0	0	0	0	500	1000	1400	0	0	0	0	0	0	0
GR	0	2200	0	0	0	0	845	0	0	0	0	0	0	0	0	0	0
HR	0	0	0	0	0	0	0	0	0	0	0	0	0	350	0	1500	0
HU	0	0	0	0	0	0	0	0	0	0	0	0	1400	700	0	2000	2000
IE	0	0	0	0	0	0	0	1100	0	0	0	0	0	0	0	0	0
IT	0	4000	0	0	0	1000	0	0	0	0	0	0	0	0	0	2400	0
LT	0	0	0	0	1900	0	0	0	0	0	1000	0	0	0	700	0	0
LU	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LV	0	0	2100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ME	0	1000	0	0	0	0	0	0	0	0	0	0	0	1300	0	0	0
MK	0	0	0	0	0	0	0	0	0	0	0	0	0	800	0	0	0
NI	1100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NL	0	0	0	0	0	0	0	0	0	700	0	0	0	0	0	0	0
NO	0	0	0	0	0	0	0	0	700	0	0	0	0	0	3995	0	0
PL	0	0	1000	0	0	0	0	0	0	0	0	0	0	0	600	0	990
PT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RO	0	0	0	0	0	0	0	0	0	0	0	0	0	1300	0	0	0
RS	0	0	0	0	0	1300	640	0	0	0	0	0	1400	0	0	0	0
SE	0	0	700	0	0	0	0	0	0	3695	600	0	0	0	0	0	0
SI	0	1000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SK	0	0	0	0	0	0	0	0	0	0	990	0	0	0	0	0	0

Table B.2: Transmission capacity – Part 2

Appendix C: Annual demand

Country	Annual demand [GWh]	
	Vision 2	Vision 4
AT	75999	93802
BA	16910	18907
BE	96956	106531
BG	39533	35625
CH	66740	80046
CZ	71670	86172
DE	579620	655450
DK	39039	47804
EE	11552	13757
ES	341231	419161
FI	92267	106258
FR	491920	516299
GB	338785	368418
GR	76451	88430
HR	22510	25073
HU	48341	52915
IE	30999	34062
IT	377438	481010
LT	12534	19143
LU	6873	7470
LV	9579	10022
ME	5476	6065
MK	12547	14725
NI	11039	12665
NL	123521	164861
NO	140503	149908
PL	183120	227657
PT	55615	64748
RO	68590	86141
RS	48617	50051
SE	149875	160425
SI	15253	20730
SK	31634	36539

Table C.1: Annual demand.

Appendix D: Reservoir and inflow data

Area	Volume [GWh]	Regulating factor [%]	Inflow Vision 2 [TWh]	Inflow Vision 4 [TWh]
AT	22686.6	50	44.2883	46.7912
BA	1559.2	25	6.2078	6.9128
BE	0.1	5	1.1365	1.6785
BG	676.3	20	3.3899	4.6422
CH	26754.2	67	39.6469	42.6946
CZ	814	20	3.8323	4.6764
DE	2693.5	13	20.9089	23.9242
EE	0.1	5	0.0786	0.1328
ES	23904.4	67	34.6132	57.8427
FI	2974.6	20	14.6889	14.3888
FR	12866.6	20	63.8258	69.6511
GB	2825.1	17	15.9257	21.4709
GR	1229.7	17	7.3037	8.1003
HR	2821	50	5.5435	6.0999
HU	0.1	13	0.2932	0.4386
IE	0.1	14	0.9754	1.1802
IT	20216.3	50	39.8353	44.3483
LT	0.1	13	0.7023	1.3139
LU	0.1	5	0.7722	1.2243
LV	0.1	13	2.758	2.758
ME	0.1	17	1.8821	2.156
MK	790.3	17	4.7137	4.7058
NL	0.1	5	0.795	0.795
NO	107380	80	137.0864	138.3199
PL	0.1	13	3.4625	4.101
PT	2863.9	20	14.1582	15.9611
RO	4530.7	25	18.0365	19.1283
RS	2655.3	20	12.9997	13.5742
SE	46960	67	62.9534	62.4512
SI	1221.1	20	6.0183	6.5356
SK	1389.5	25	5.4511	6.5441

Table D.1: Reservoir and inflow data.