Universität Flensburg

Doctoral Thesis

The Role of Norwegian Hydro Storage in Future Renewable Electricity Supply Systems in Germany: Analysis with a Simulation Model

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Summary

Scope

The reality of climate change requires the conversion of energy supply towards renewable energy sources. One important and urgent component of this is the transformation of the electricity system. In Germany wind and solar energy are the main contributors to renewable electricity supply. Both sources are weather-dependent and fluctuating. Their production and the fluctuating electricity demand have to be balanced with flexible capacity. Flexibility is needed on the supply and demand side in different dimensions and time scales in a future sustainable electricity system. Electricity storage will play an important role. In this thesis the benefits of cable capacity between Germany and Norway and new pumped storage capacity in Norway in a 100 % renewable electricity system are explored using a simulation model. The profitability and technical and environmental feasibility of the scheme are analyzed as well. Furthermore, the sensitivity of results to input parameters is evaluated.

Currently pumped storage plants are the most established and cost efficient technology for large-scale storage. The current capacity in Germany is 6.6 GW with a total reservoir capacity of approximately 40 GWh and there are new projects in the planning process. However, the extension potential is limited by environmental restrictions. The electricity system of Norway relies almost completely on hydro power and includes large hydro storage systems. There are approx. 23 GW installed in hydro storage plants and 1.3 GW in pumped storage plants. The total reservoir capacity is 84.3 TWh. Extending those hydro storage plants with new production and pumping capacity and connecting them to Germany could be a storage option with comparably low costs and low environmental impact.

There are many different assessments of the timing and amount of necessary storage capacity in renewable electricity systems. Those assessments depend on assumptions for electricity demand and for amount and distribution of renewable capacity. Values for necessary storage capacity for Germany in the existing research range from 50 GW

(Sachverständigenrat für Umweltfragen, 2011, storage in Norway) to 115 GW (VDE, 2012) when no other dispatchable capacity is available, and assuming no curtailment of renewable production. The necessary storage volume is estimated between 22 TWh (Sachverständigenrat für Umweltfragen, 2011) and 29 TWh (Nitsch et al., 2012).

The potential for new pumped storage plants in Germany is disputed. Views differ between assuming significant further potential (Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien, 2009) and expecting no noteworthy increase of pumped storage plants (VDE, 2009). New projects face environmental concerns and public resistance. Currently projects with a total capacity of 3.15 GW and storage volume of 25.21 GWh are in the planning phase. Additionally planned capacity of 690 MW in Austria and Luxembourg would be connected to the German electricity system. Investment costs for new plants are estimated to be 1000 to 1150 €/kW. For pumped storage potential in Norway only the expansion of existing storage plants is discussed as new large hydro storage schemes are not acceptable to the Norwegian society. Estimations range from 10 GW to 30 GW additional potential that can be realized with acceptable environmental impact. Estimated costs are between 250 and 400 €/kW. Costs are lower in Norway than in Germany because no new reservoirs are needed. In the Alps there is a larger geological potential than in Germany but there are also environmental concerns. In Austria projects with more than 5 GW of capacity are currently planned. In Switzerland 6 GW of new capacity are planned to be installed by 2020. Costs in Switzerland are assumed to be 800 to 1600 €/kW. Other storage options are compressed air energy storage, batteries and the conversion of electricity to hydrogen or methane.

The installation of new pumped storage plants in Norway will have environmental impacts. However, impacts are smaller than for new plants because existing, regulated reservoirs will be used instead of building new reservoirs. New production and pumping capacity will lead to increased water level fluctuations. This can potentially cause stranding of species, erosion and can weaken the ice cover in winter. According to Solvang et al. (2012) water level changes below 13 cm/h will not lead to stranding of salmon.

The extension of pumped storage capacity and increased connection to continental Europe and the UK is discussed controversially in Norway. Potential income on foreign power markets and improved domestic security of supply are seen as benefits of the scheme. Concerns exist about the development of the traditionally low Norwegian electricity price and impacts on environment and landscape.

Methodology

renpass (Renewable Energy Pathways Simulation System) is a simulation model that was built at the Center for Sustainable Energy Systems at the University of Flensburg to analyze electricity systems with a high share of fluctuating renewable energy sources. It models the operation of the electricity system. The configuration of grid, generation and storage plants is determined by the user. Other parameters like weather data, primary energy resource prices, and electricity demand can be varied as well. With each scenario one year is simulated in hourly or 15-minute time steps. The model outputs include time series for the utilization of grid, production and storage plants, electricity price and storage filling levels. The renpass version used for this thesis includes all countries bordering the Baltic Sea and Norway. Germany can be divided in up to 18 onshore and three offshore regions. renpass is an open source model distributed under the public license GNU GPL 3.

The simulation of renpass is based on the concept of residual load. The positive or negative difference between load and the noncontrollable renewable electricity production is defined as residual load and has to be balanced by flexible generation and storage plants. The dispatch of those plants is determined by the merit order, which ranks the plants according to their marginal cost of production. The dispatch is first carried out in each model region. Afterwards power is exchanged via fixed transmission capacity between the regions with the aim of decreasing the total costs of production. The power exchange is simulated with a heuristic iteration. After the exchange, remaining excess electricity is matched with storage plants. That means in renpass only excess renewable production at zero marginal cost is stored.

The hydro power system is represented in very high resolution in renpass. Hydro storage plants and their connected reservoirs are modeled individually. For each plant the available production and pumping capacity in each time step is determined by the installed capacity and the filling levels of upper and lower reservoir. In reality the concept of water value is used for the operation of hydro power plants. Individual bidding by operators and price forecasting cannot be simulated with renpass. Instead the merit order of the hydro production is determined by a generic indicator based on the current reservoir filling level and the sum of inflow over the next week. The bidding price of each plant is derived statistically by relating the merit order indicator to the Nordic power prices of 2012. The merit order of pumps is based on the relative filling level of their connected reservoirs. After the dispatch in each time step, the filling level of each reservoir is updated with natural inflow and water used for production and pumping is added and subtracted.

For this thesis different scenarios for a 100 % renewable electricity system were calculated. While the main focus is on Norway and Germany, which is divided in 5 regions, all scenarios include Sweden and Denmark as well. For all countries load data from 2011 is used. For the grid connections between the model regions twice the existing capacity is assumed. The renewable scenario for Germany is based on Nitsch et al. (2012) but the installed capacity has been increased by 25 %. The main scenarios differ in the connection capacity between Germany and Norway and additional pumped storage capacity in Norway. Both parameters are varied in steps of 10 GW from zero to 50 GW for a total of 36 combinations. The sensitivity of results to input parameters has been tested by varying the grid capacity in Germany, renewable energy capacity in Germany and Norway, weather data for hydro inflow, wind speed and solar radiation, storage capacity in Germany and the scarcity price for electricity.

Results

The analyzed scenarios contain many assumptions about the development of input parameters. All those assumptions influence the results. This is why it is very important to explore the extent to which different parameters change the results. In this thesis this is taken into account by sensitivity analysis. Still it has to be kept in mind that the results of the simulations cannot be separated from the input parameters. Furthermore, models can only be a very simple image of reality, and the operation of individual hydro storage plants in the Norwegian energy system can only be roughly approximated with renpass. However, the results indicate trends for the whole system and can serve as examples for the impacts on individual plants and reservoirs.

The most beneficial combination of cable capacity between Germany and Norway and additional pumped storage capacity in Norway was found by comparing the sum of total consumer costs and investment costs for cable and pumped storage installations of the analyzed scenarios. This sum is displayed in figure 1 for all cable and pumped storage scenarios. Among all the simulated combinations the economically most beneficial is the installation of 10 GW cable capacity between Germany and Norway and 10 GW additional pumped storage capacity in Norway. For higher capacity the additional investment costs are not offset by further reductions of consumer costs. In the current market framework the installation of this favorable amount of capacity is not profitable for private investors. The new installations have short-term and seasonal effects on reservoir filling levels in Norway. In general fluctuations increase, but in a scenario with 10 GW cable and 10 GW pumped storage capacity they remain well within environmentally acceptable limits. The results are very sensitive to assumptions for amount and distribution of

renewable capacity and storage capacity. Also the value of security of supply, expressed in the scarcity price of electricity, has large influence on the benefits of additional storage capacity.

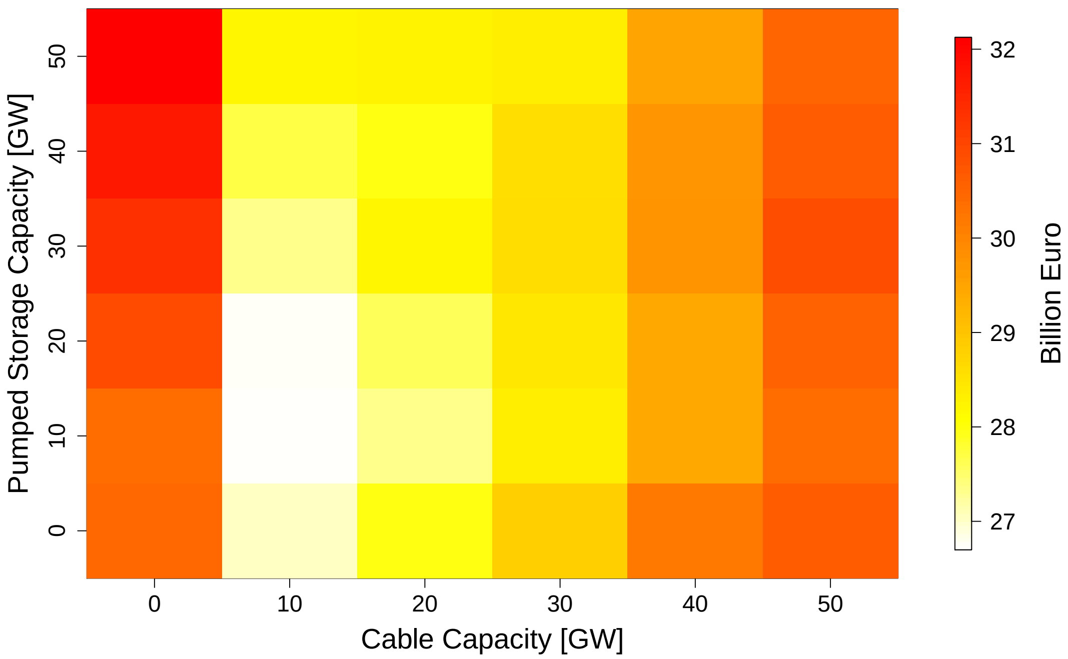

FIGURE 1: Sum of consumer costs and investment annuity for different cable and pumped storage capacities

Challenges for the implementation of the proposed scheme will be the establishment of investment incentives and securing public and political support in Norway. If those barriers are overcome, storage in Norway will be an important contribution to renewable electricity supply in Europe at low costs and with low environmental impact. With accelerating climate change there is no time to loose in transforming the energy system to renewable sources. The first new cables between Germany and Norway and the first new pumped storage plants in Norway bring high benefits to the energy system. Furthermore, those first investments could be profitable for private investors. The optimal total capacity of different flexibility options needs to be reevaluated as the transformation evolves and more knowledge about the costs and potential of the different alternatives becomes available.

Acknowledgements

I am grateful to my supervisors Olav Hohmeyer and Götz Hofmann for reviewing my thesis and for providing me with advice and encouragement along the way.

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Gesine Bökenkamp
Düsseldorf, October 2014

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Abbreviations

CAES	Compressed Air Energy Storage
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CSES	Center for Sustainable Energy Systems
CWE	Central-Western European market coupling
DSM	Demand Side Management
DWD	Deutscher Wetterdienst - The German Weather Service
EEG	Erneuerbare-Energien-Gesetz - Renewable Energy Law
ENTSO-E	European Network of Transmission System Operators for Electricity
FINO	Forschungsplattformen in Nord- und Ostsee - Research Platforms in the North Sea and the Baltic Sea
FNF	Forum for Natur og Friluftsliv - a forum of regional nature and environmental organizations in Norway
GNU GPL	GNU General Public License
ITVC	Interim Tight Volume Coupling
NOK	Norwegian Kroner
NTC	Net Transfer Capacity
NTNU	Norges Teknisk-Naturvitenskapelige Universitet - Norwegian University of Science and Technology
NVE	Norges Vassdrags- og Energiedirektorat - Norwegian Water Resources and Energy Directorate
PSP	Pumped Storage Plant
PTG	Power to Gas Storage
SRU	Sachverständigenrat für Umweltfragen - German Advisory Council on the Environment
TSO	Transmission System Operator
UBA	Umweltbundesamt - German Federal Environmental Agency
VDE	Verband der Elektrotechnik Elektronik Informationstechnik - Association for Electrical, Electronic and Information Technologies
WWF	World Wide Fund for Nature

Chapter 1

Purpose of the thesis

1.1 Problem Outline

The human effect on the climate that causes global climate change is one of the greatest environmental problems of our times. According to the Intergovernmental Panel on Climate Change the warming of the climate system is "unequivocal" (Intergovernmental Panel on Climate Change, 2007, p. 30). In Germany approx. 84 % of the 936 million tons of CO_2 equivalent emitted in 2012 stem from the conversion and use of energy (Bundesministerium für Wirtschaft und Technologie, 2014). In order to restrict climate change to bearable levels - sadly even this will not be possible for all people anymore – a complete change of the way energy is produced and consumed is needed. This transformation has to involve the electricity, heat and transport sectors. Because of the long investment cycles in electricity production it is imperative that the transformation towards alternative sources of electricity is initiated immediately. The production of electricity in Germany accounted 2010 for 305 million t CO_2 emissions (Icha, 2013, p. 15). The objective has to be that electricity production is based to 100 % on renewable energy sources. Nuclear energy is not a sustainable option because of the dangerous nuclear waste and the high risks inherent in this form of electricity production. The sequestration and storage of CO_2, commonly called carbon capture and storage (CCS), from fossil power plants can also not be considered sustainable because it relies not only on depleting energy sources but also on limited storage capacity. The available storage capacity can be utilized more sustainably by storing CO_2 from biomass plants or storing energy in the form of hydrogen or methane. In the following the focus will be on future renewable electricity production systems.

The German government has set a goal of achieving 35 % of renewable electricity production by 2020. This share is to increase further to 50 % in 2030 and 80 % 2050

(Bundesregierung, 2010, p. 4f). This goal is embedded in European goals as set in the directive 2009/28/EC on renewable energy. This directive sets targets for all member states so that the European Union as a whole will reach a share of 20 % of energy consumption supplied by renewable sources by 2020 (European Communities, 2009). Renewable electricity production in Germany has developed dynamically since the beginning of the 90's when the first feed-in tariff was introduced in the Feed-in Act (Bundesministerium für Umwelt, 2012, p. 33). In 2013 renewable electricity production (including conventional hydro power) reached 153 TWh, approximately 24 % of total electricity production (Bundesministerium für Wirtschaft und Technologie, 2014).

The main contributing sources in Germany are wind and solar energy. It can be assumed that wind and solar energy will also be main contributors to a 100 % renewable electricity system. Both sources are weather-dependent and have by nature different characteristics than conventional power plants. Due to the weather-dependency, power production from wind and solar energy is fluctuating and not perfectly predictable. The fluctuations happen on different time-scales from seconds and minutes to seasonal variations. In order to equalize supply and demand of electricity at all times, flexibility is needed in the system to balance the fluctuations from wind and solar production as well as the accustomed demand fluctuations.

The flexibility can be provided on the demand or the supply side. Demand response of consumers will be an important component but not sufficient by itself. Flexible production plants with fast ramping capabilities are needed as well. Storage plants can provide flexibility both on the demand and the supply side. When the production from wind and solar energy exceeds demand for a significant amount of time storage plants are needed to absorb the excess energy and store it for later use.

The fluctuations from renewable electricity production happen on different time scales. Thus storage options for different time scales are needed. For large scale storage only two technologies are available at present. Those are pumped hydro storage and compressed air energy storage (CAES) plants. Compressed air energy storage has so far not been implemented as a pure storage plant. The existing plants use natural gas for reheating the compressed air. Pumped hydro storage is a far more mature technology that is widely used and is operated economically in different dimensions. Investment costs for PHS are lower than for CAES. For the future chemical electricity storage in the form of methane or hydrogen has been proposed. This technology could potentially open up a large storage capacity. However, implementation costs are higher than for PHS or CAES and the efficiency is lower, especially in the power-to-gas-to-power cycle. For the transformation of the electricity system pumped hydro storage is forseeably the most accessible and cost-efficient option. In future electricity systems likely a diversity of storage options will be applied. For a more detailed description of storage options and their costs see section 2.3.

In Germany 6.22 GW of pumped hydro storage plants and 0.37 GW of storage plants without pumping capacity are currently in operation (Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien, 2009, p. 26). The total storage volume is 40 GWh (see e.g. Sachverständigenrat für Umweltfragen, 2011, p. 157). Additionally hydro storage plants in other countries are used to balance the German electricity market. German energy suppliers have shares or long-term electricity supply contracts in hydro storage plants in Luxembourg and Austria. Some of them are moreover connected directly to the German grid, part of the German reserve capacity or operate according to the requirements of the German grid. Those plants account for 3.3 GW production capacity and 1.6 GW pumping capacity (Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien, 2009, p. 28). With the objective to extend the storage capacity, several projects are being proposed at the moment in Germany as well as in the plants operating for German suppliers in neighboring countries. Those extensions could increase the production capacity to 13 GW and the pumping capacity to 10 GW (Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien, 2009, p. 28). It is uncertain however, if the plans will be realized, among other reasons because some of the more concrete projects are met with fierce public resistance. And looking at the total potential, pumped storage plants in Germany will not be able to fulfill the storage needs of future renewable electricity systems. Especially the Alpine region is suited for pumped storage plants and there is a potential for storage extension. However, like in Germany, building new pumped storage plants will most likely involve building new reservoirs. This means a considerable environmental intervention and consequently will encounter opposition. It is therefore debatable if future storage demand can be met in Germany and its Southern neighbors alone.

There is another hydro storage option that is being discussed only recently (e.g. Sachverständigenrat für Umweltfragen (2011), Ess et al. (2012), Bakken et al. (2011)). Norway's electricity system relies almost completely on hydro energy. Most of it is produced from storage plants that often form part of cascade storage systems with different altitude levels. This provides very good pumped storage conditions. At the beginning of 2012 Norway had an installed hydro power production capacity of 30 GW (Olje- og Energidepartementet, 2012, p. 25). The storage volume is 84.3 TWh (Nord Pool Spot, 2013e). The major advantage of using the Norwegian system for storage is that storage capacity can be increased within the existing system without building new reservoirs. The environmental impact will therefore be smaller than with other options. Furthermore, the expansion potential in Norway is far larger than in the Alpine region (see e.g. Solvang et al., 2012). The Norwegian hydro power system can be connected comparably easily to the German system via sea cable. It will connect to Northern Germany where the potential for wind energy is higher than in the South. The advantage, compared to storage in Southern Germany or the Alps, is that the transmission of excess electricity to the storage will not additionally burden the grid between north and south Germany, already heavily used in times of high wind energy production. In Sweden there is also a large hydro storage volume of approx. 34 TWh (Nord Pool Spot, 2013f) but it is smaller than in Norway. Since in Sweden hydro power plants are often located in rivers, the Norwegian system seems more suited for increasing pumped storage capacity. The use of storage plants in other countries is only considered in few sustainable energy scenarios for Germany. Ess et al. (2012) consider only indirect storage in Norway without the expansion of storage capacity. New pumped storage in Norway is simulated in Sachverständigenrat für Umweltfragen (2011) but the Norwegian system is modeled rather roughly without representation of single storage plants. There is a need for a simulation of 100 % renewable electricity supply where both systems are modeled in technical detail. To close this gap the focus in the following will be on the possibilities of connecting the Norwegian storage potential with the German electricity system in the context of 100 % renewable supply.

1.2 Research Questions

From the understanding of the problem several research questions were derived to be answered in the course of the thesis.

1. Which cable capacity between Germany and Norway is beneficial for a 100 % renewable system in Germany and Norway?
2. Which new pumped storage capacity in Norway is beneficial for a 100 % renewable system in Germany and Norway?
3. Are the new installations economically feasible under the current market framework?
4. What are the impacts on reservoir filling levels?
5. Which cable ramping capabilities are needed?
6. Influence of competing storage systems
   (a) How does the operation and economic performance of the storage plants change with competition from hydro storage plants in Germany?
   (b) How in case of CAES in Germany?

(c) How in case of power to gas storage in Germany?

Questions one and two are of technical and economic nature looking at the benefit of transmission capacity between Germany and Norway and additional storage capacity in Norway. For this purpose benefit is defined from a societal point of view. Installations are assumed to be beneficial when cost reductions for the whole system are greater than investment costs.

In the third research question the economic feasibility of new cable connections and new pumped storage plants in Norway are in the focus. This will be analyzed by comparing the annual revenues with the investment cost annuity of the installations in different scenario runs.

More rapid changes to the reservoir filling levels will be among the main environmental impacts of a different operating scheme and of the installation of new capacity. This will be analyzed in detail to answer research question four.

The dynamic characteristics of the cable connection restrict the dynamic response of the Norwegian storage plants to the German system. This will be the focus of research question five. Currently the subsea cables in the North Sea and the Baltic Sea are operated with fixed maximum ramps that do not allow a fast turn of the cable flow.

Future energy systems will rely on different options for energy storage. At the moment it is not clear how those options will compete in the market. In the thesis the competition between Norwegian storage plants and three storage options in Germany will be analyzed with regard to question six.

1.3 Sensitivities

The sensitivity of the results to changing determining parameters will be analyzed. The main influencing parameters are assumed to be the development of the transmission grid in Germany, weather conditions determining the hydro inflow as well as wind and solar energy production, and expansion of installed renewable capacity in Germany and Norway.

1.4 Methodology

The analysis has been conducted by developing and using the simulation model renpass (Renewable Energy Pathways Simulation System). renpass has been developed at the

University of Flensburg, Center for Sustainable Energy Systems (CSES). It is a bottom-up simulation model for electricity supply with high spatial and time resolution. The main focus is on balancing fluctuating residual load with flexible production and storage capacities. The complete model code and database as well as two manuals for the installation and application of the model can be found on the enclosed CD.

In renpass a number of different parameters can be varied for the simulations. For the analysis of the proposed research questions mainly the installed transmission capacity between Germany and Norway and the installed storage capacity in Norway will be varied.

The development of renpass is a joint project of researchers at the University of Flensburg. Mainly Frauke Wiese and I have contributed to the model. Frauke Wiese developed the structure of the model and the exchange algorithm. The modeling of hydro and storage plants in renpass is my work and will be described in detail in this thesis. While each of us had core areas of development, part of the work was carried out in close cooperation. Frank Höfken, Clemens Wingenbach, and Justus Riedlinger have contributed with their master's theses to the model development (Höfken (2012), Wingenbach (2012), Riedlinger (2013)). The extension of the model from Germany and Norway to the whole Baltic region was accomplished in the seminar 'Modeling Sustainable Energy Systems of the Baltic Sea Region' in the Master Course Energy and Environmental Management at the University of Flensburg (Bernhardi et al., 2012).

Chapter 2

Background Information

2.1 Power Systems in Germany and Norway

The power systems in Germany and Norway and possible benefits of combining them will be in the focus of this thesis. The power systems in the two countries are very different from each other. In the following both systems will be described in comparison.

2.1.1 Electricity Demand

In Germany total electricity demand in 2011 was 607 TWh (Bundesministerium für Wirtschaft und Technologie, 2014). In Norway 114 TWh were consumed in 2011 (Statistics Norway, 2013a). In relation to 5.06 million inhabitants of Norway (Statistics Norway, 2013b, status 1.4.2013, end of 2011: 4.93 million) compared to 80.5 million in Germany (Statistisches Bundesamt, 2013a, status 9/2012, 2011: 80.3 million) the electricity demand in Norway seems quite high. Electricity consumption per capita was approx. 23.1 MWh in Norway in 2011 and thus much higher than in Germany where approx. 7.5 MWh per capita were used. The share of electricity in end energy consumption is larger in Norway, it made up approx. 50 % of total end energy consumption and approx. 70 % of stationary end energy consumption in 2011 (Olje- og Energidepartementet, 2012, p. 35f). In Germany electricity only accounts for 21.1 % of end energy demand (Bundesministerium für Wirtschaft und Technologie, 2014). There are several reasons for that. Most of them come back to the fact that electricity production is less costly in Norway due to the abundant hydro resource and electricity prices are consequently lower. This attracted especially energy-intensive industries like aluminum production. In Norway electricity is also used for heating far more than in Germany. A survey from 2006 shows that 98 % of the households in Norway have electric heating equipment, commonly in combination with wood heating (Norwegian Ministry of Petroleum and Energy, 2008, p. 43). Geographic and cultural differences also play a role in causing the difference in electricity consumption.

The seasonal trend of energy demand is more pronounced in Norway. The use of electricity for heating and the more distinct difference of daylight hours between summer and winter in Norway are reasons for that. In figure 2.1 the time series of energy demand in Germany and Norway are shown.

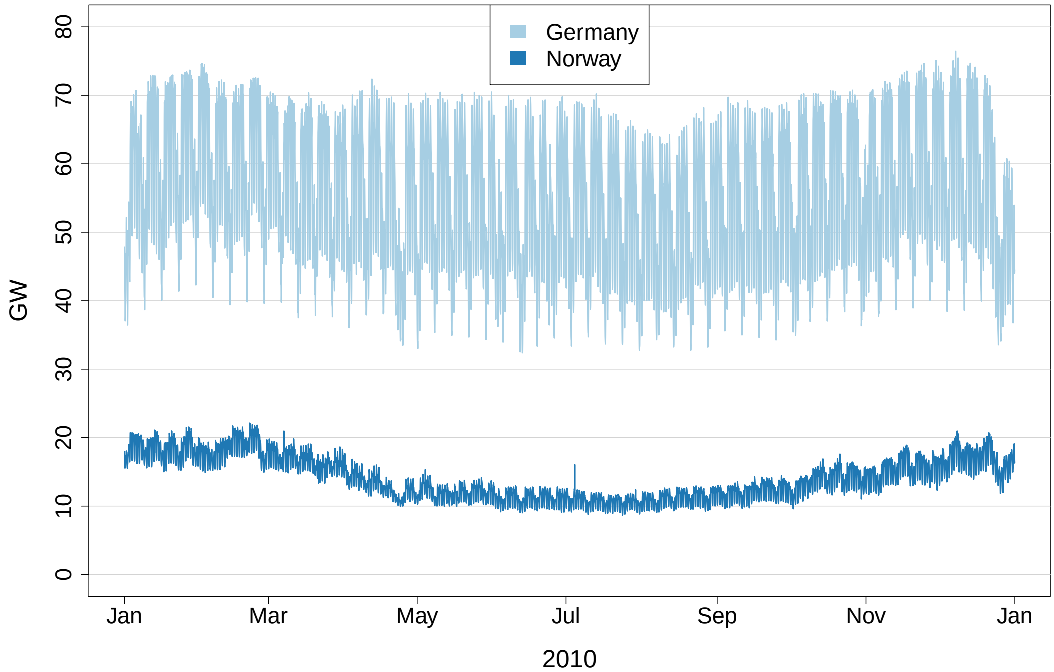

FIGURE 2.1: Demand in Germany and Norway, 2010, source: European Network of Transmission System Operators for Electricity (2013)

Figure 2.2 shows historic data for annual sums of energy demand in Germany and Norway. In both countries the energy demand has grown over the last decades. Energy demand in Germany in 2012 was 15 % higher than in 1993. In Norway the value for 2012 was almost 16 % higher than in 1993.

2.1.2 Electricity Production

Energy Sources

The electricity production sources are very different in Germany and Norway. The Norwegian electricity production is based to 95 % on hydro power (Olje- og Energidepartementet, 2012, p. 24). The German system on the other hand is quite diverse and relies

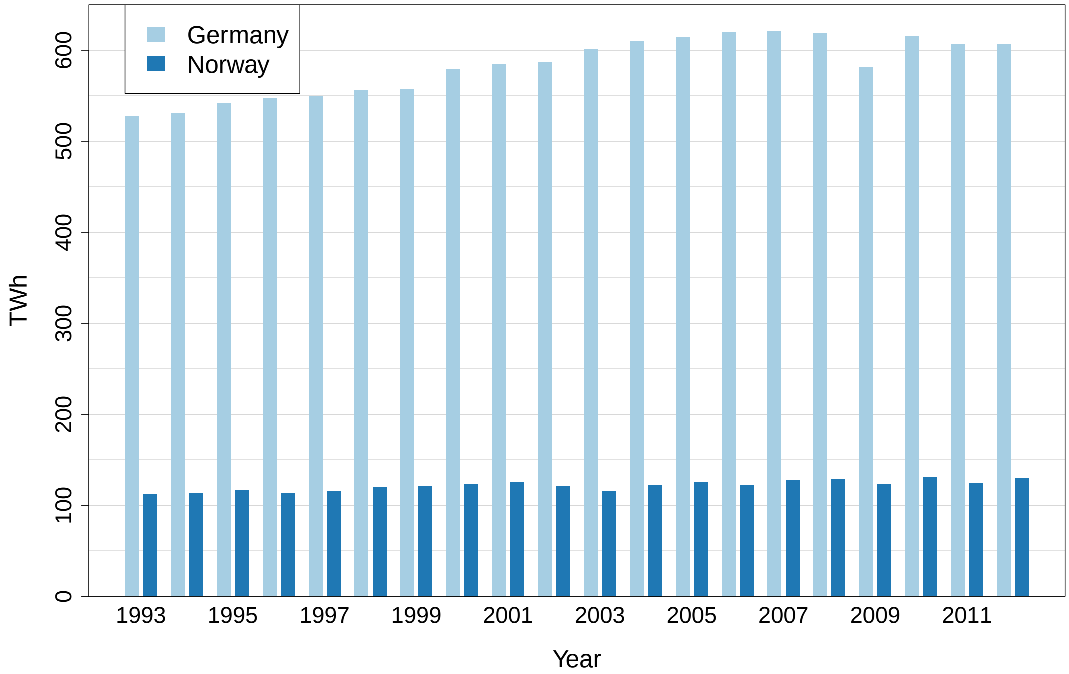

FIGURE 2.2: Development of demand in Germany and Norway, source: Bundesministerium für Wirtschaft und Technologie (2014), Statistics Norway (2013a)

on several different energy sources. Thermal power plants are the dominant production type. Figure 2.3 shows the shares of the power production sources in Germany.

The total installed electricity production capacity in Norway is 31.8 GW (2011), compared to approx. 24 GW peak demand, with an average annual production of 127 TWh in the last ten years (Olje- og Energidepartementet, 2012, p. 24f). The majority of the capacity, 30.2 GW, is installed in 1393 hydro power plants (2011). There are also 1.13 GW thermal power plants (+ 0.3 GW cold reserve) for the use of natural gas, biomass, and waste but they are very little used. In Germany 175 GW were installed in 2011 (Bundesministerium für Wirtschaft und Technologie, 2014) while peak demand was approx. 80 GW. Of the installed production capacity 98 GW were conventional thermal power plants. Power production in 2011 was 613 TWh. In the past the relation of production to installed capacity was lower in Norway than in Germany. That means that on average the power plants in Norway operate with lower full-load hours. This is still true when looking only at the conventional thermal power plants in Germany, as to say the old part of the system. The fundamental difference is that in a hydro-based system, like the Norwegian, the incoming hydro resource is the restricting factor while in a thermal system the installed capacity constrains the production. As Norges Vassdrags- og Energidirektorat (2011b, p. 5) put it, the Norwegian system is energy-dimensioned.

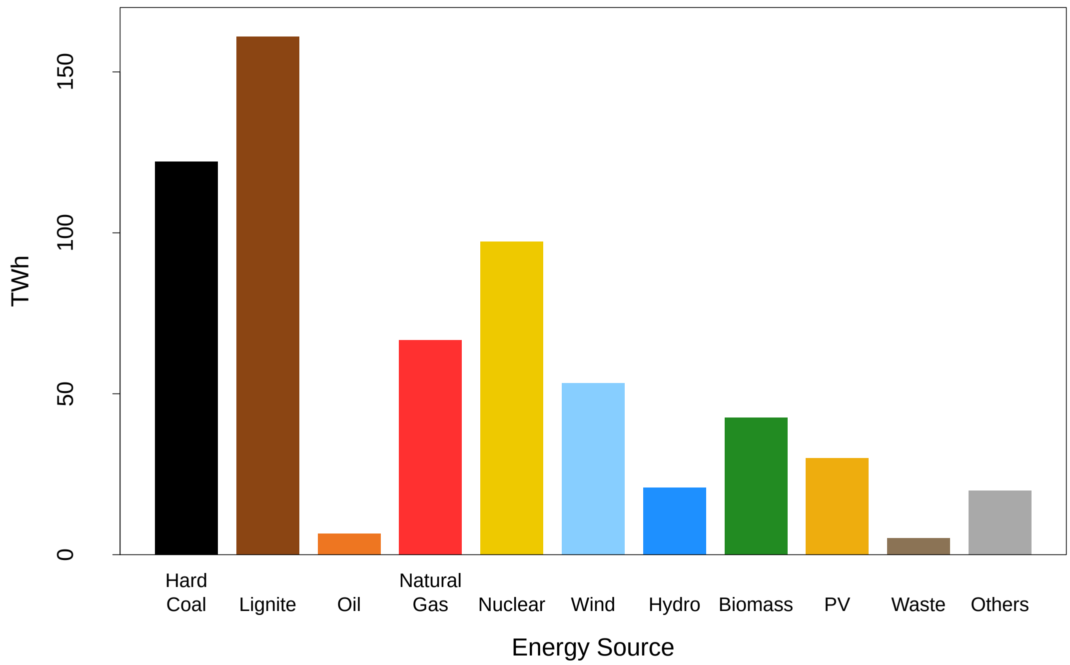

FIGURE 2.3: Electricity production sources in Germany, 2013 (Source: Bundesministerium für Wirtschaft und Technologie (2014))

The situation in Germany however has changed due to increased shares of renewable electricity production. Wind and solar plants are also restricted by the fluctuating energy source.

The Norwegian hydro power system was mainly installed in the 70s and 80s with large hydro projects. Since the 90s very little new capacity was built. Investment since then has mainly been directed towards refurbishment and upgrading. Figure 2.4 shows the development of hydro power capacity.

Table 2.1 summarizes the main indicators for comparing the German and Norwegian electricity systems.

Norwegian Hydro System

The Norwegian hydro system consists of interconnected reservoirs and hydro power plants. According to data from Norges Vassdrags- og Energiedirektorat (NVE), the Norwegian regulator for energy and water, there are approx. 23 GW installed in storage plants and 1.3 GW in pumped storage plants (Norges Vassdrags- og Energidirektorat, 2010b). Additionally there is pumping capacity of 81 MW in locations without production capacity. This is only used for transfering water into the hydro production system. Run-of-river plants without storage capacity account for 4.8 GW. Those figures do not

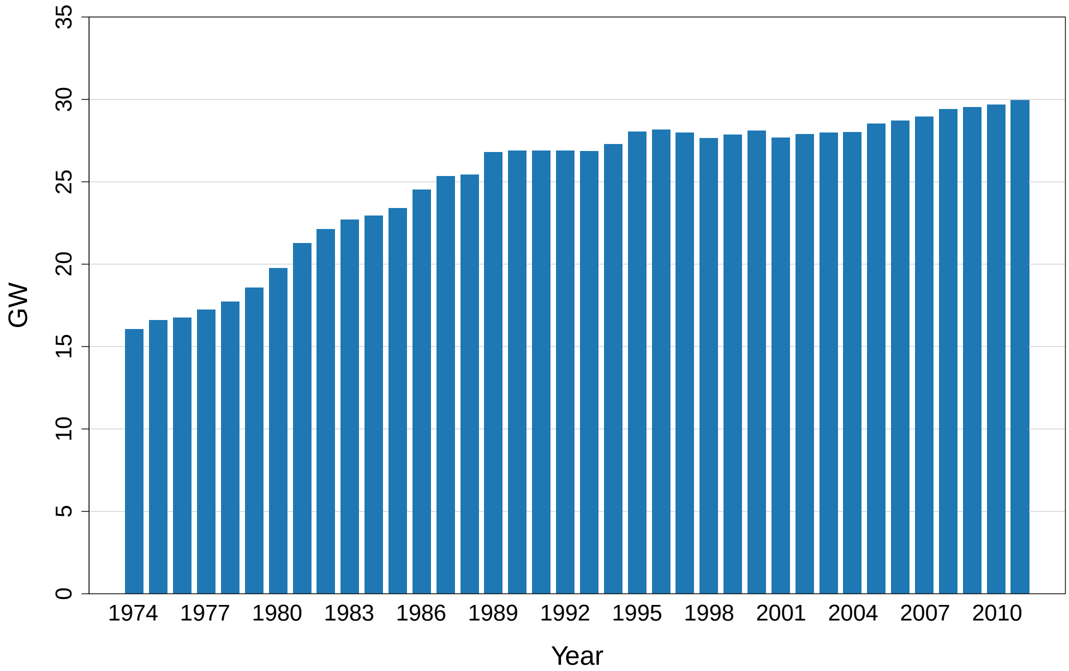

FIGURE 2.4: Development of hydro power capacity in Norway, source: Statistics Norway (2013a)

Indicator	**Germany**	**Norway**
Inhabitants 2011 (million)	80.3	4.9
Electricity demand 2011 (TWh)	603	114
Electricity demand per capita (TWh)	7.5	23.1
Peak demand (GW)	80	24
Share of electricity in end energy demand (%)	21	50
Electricity sources	diverse, approx. 60 % fossil	95 % hydro
Electricity production capacity	98 GW conventional and 77 GW renewable	31.8 GW
System design	capacity-dimensioned	energy-dimensioned

TABLE 2.1: Indicators for the German and Norwegian electricity system

correspond exactly to installed capacity from Olje- og Energidepartementet (2012) but they are quite close, differing only by approx. 5 %. Differences may be caused by the date of publication and the representation of the data.

The total reservoir capacity is 84.3 TWh (Nord Pool Spot, 2013e). The large storage capacity is used to balance the seasonal trend of the natural inflow which is in contrast to the seasonal variation of demand. The largest reservoir is Blåsjø with a capacity of 7.8 TWh (Statkraft, 2010). The natural inflow is highest during the times of snow-melt in late spring and early summer. After that, inflow is only brought in by rainfall. During the winter most of the precipitation falls in form of snow so that there is very little inflow to the reservoirs. The fallen snow forms the so-called snow reservoir which again turns to inflow during snow-melt. Fig 2.5 shows the seasonal pattern of the reservoir filling levels for Norway. The numbers show the longtime median of relative filling levels.

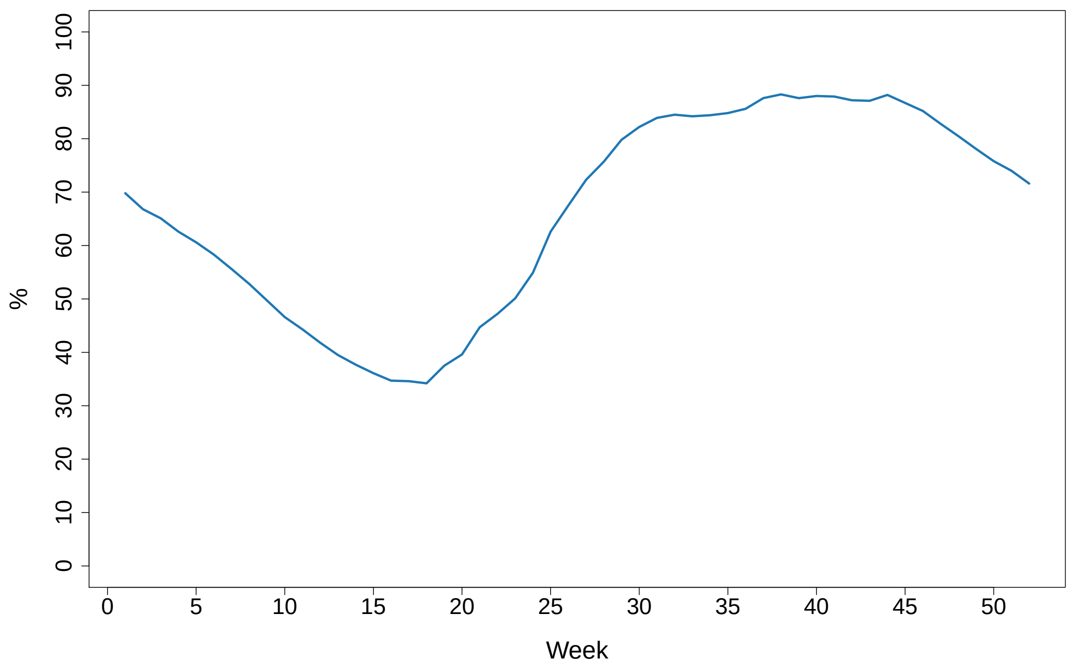

FIGURE 2.5: Seasonal curve of filling level, source: Norges Vassdrags- og Energidirektorat (2011a)

During the last 20 years the annual inflow to the Norwegian power plants has varied by as much as 60 TWh between years (Olje- og Energidepartementet, 2012, p. 24). The largest reservoirs in the system are also used for multi-year regulation to balance the differences between the years.

Renewable Energy

While the Norwegian production system will not change in structure in the forseeable future, Germany is at the beginning of a complete structural transformation towards a renewable energy system. Accordingly the current shares of production are just a snapshot that will change in the coming years. In the wake of the German Energiewende, the transformation towards a non-fossil, sustainable energy system, Germany will expand its renewable energy production capacity significantly. Also the use and transmission of energy will change. Figure 2.6 shows the development of renewable electricity production in Germany since 1990. Scenarios for the expansion of renewable capacity will be described in chapter 7 as a basis for the simulation scenario.

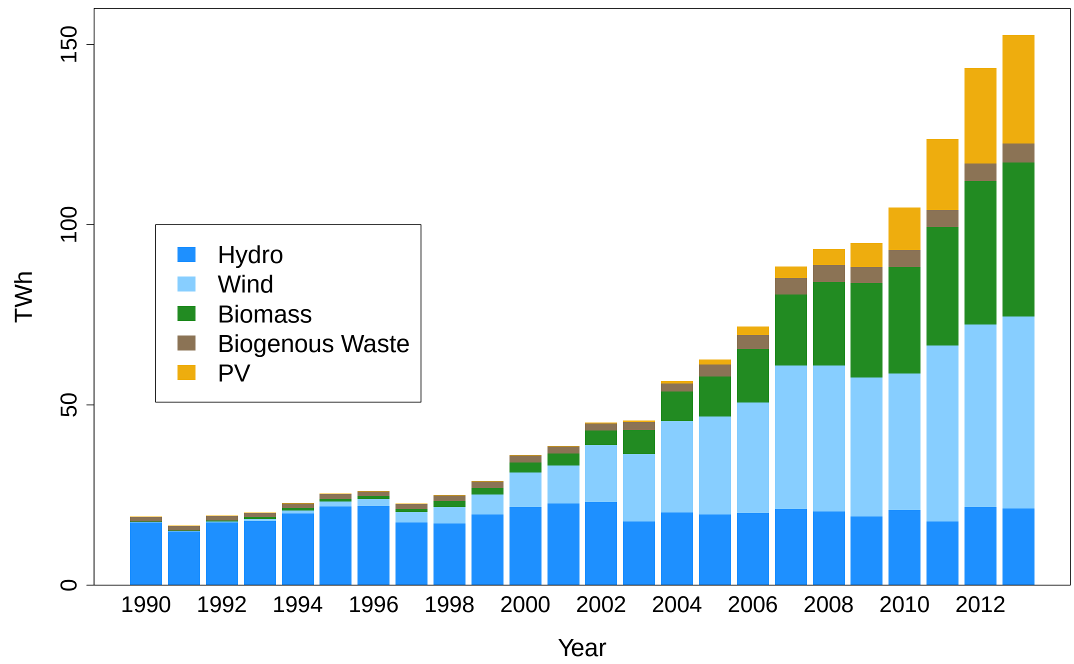

FIGURE 2.6: Renewable electricity production in Germany, source: Bundesministerium für Wirtschaft und Technologie (2014)

Norway has also plans for expanding other renewable energy production besides hydro power. This includes onshore and offshore wind energy production and the use of biomass. In 2009 there were 146 MW_{el} of bioenergy installed in Norway. The power production was 411 GWh while heat production from biomass was 3291 GWh (Norheim et al., 2011, p. 8). By the end of 2011 512 MW of wind power were installed in Norway producing 1310 GWh in 2011 (Olje- og Energidepartementet, 2012, p. 28). Norway has good wind energy resources with average wind speeds in well exposed coastal areas reaching 7-9 m/s (Olje- og Energidepartementet, 2012, p. 28). Waagaard et al. (2008, p. 5) estimate potential wind installations by 2025 between 5800 and 7150 MW. The estimated production would be between 17.4 TWh and 21.5 TWh. In order to promote renewable electricity expansion Norway joined the Swedish market for green certificates in 2012 (Norges Vassdrags- og Energidirektorat, 2013a). The total renewable electricity production in Norway and Sweden is supposed to increase to 26.4 TWh by 2020. The certificate system is intended to operate until 2035.

2.1.3 Electricity Grid

In Germany the high voltage electricity grid is divided into four control areas that are owned and operated separately by private companies. The high voltage grid was unbundled according to EU legislation on the common European electricity market which requires that the operation of the grid is separated from electricity production and trade. The Norwegian high voltage grid is owned and operated by the public company Statnett. Germany has a total grid capacity of more than 15 GW to neighboring countries (European Network of Transmission System Operators for Electricity (2010b), sum of lower NTC values). Norway is less centrally located. It is quite well connected to Sweden (3500 - 3800 MW) and Denmark (950 - 1000 MW) (European Network of Transmission System Operators for Electricity, 2010b). There is also a subsea cable to the Netherlands (700 MW) and small connection capacity to Finland and Russia. An interconnector to Germany with 1400 MW is planned to be commissioned by 2018 (Statnett, 2011a, p. 19). A subsea cable to Great Britain with 1400 MW is planned by 2020. Both projects have received licenses from the Norwegian Ministry of Petroleum and Energy on October 13, 2014 (Norwegian Ministry of Petroleum and Energy, 2014). A new subsea interconnector of 700 MW between Norway and Denmark (Skagerrak 4) is planned to be in operation by 2014. A new connection to Sweden (South-West-Link) of 1400 MW is intended to be built by 2020. NorNed 2, a second cable to the Netherlands, is also considered (Statnett, 2008, p. 34f).

In Germany as well as in Norway grid extension is necessary. In Germany due to the transformation of the energy sector towards renewable energy and to the unbundling of the electricity sector, electricity production is increasingly located near the resources and not necessarily near the consumption. Especially the grid connection between the centers of wind energy production in the North and the centers of consumption in the South needs to be reinforced. The construction of overhead lines often leads to resistance of concerned residents. A participative process of establishing a grid development plan has been started in 2011 in Germany and will be renewed every year (TenneT, 2013b). In Norway the grid needs to be enhanced as well. Most hydro power is produced in western Norway and Nordland, a county in the north, while in eastern Norway the consumption is higher than the production. Consequently power generally flows from the west to the east and from the north to the south. According to Statnett, for increased connection between Norway and other countries beyond the Skagerrak 4 cable, further reinforcement and expansion of the grid is necessary (Statnett, 2011b).

As electricity production varies with hydro inflow so does the im- and export balance of Norway. Norway has traditionally been a net exporter of electricity. However, since the mid 90s consumption has risen faster than production and Norway tends to rely more on imports than before (Olje- og Energidepartementet, 2012, p. 57). Germany has been an exporter of electricity in the last decade. In contrast to what has been expected at the shut-down of seven nuclear power plants in 2011, this trend has not changed since then. Figure 2.7 shows the development of net exports for Germany and Norway.

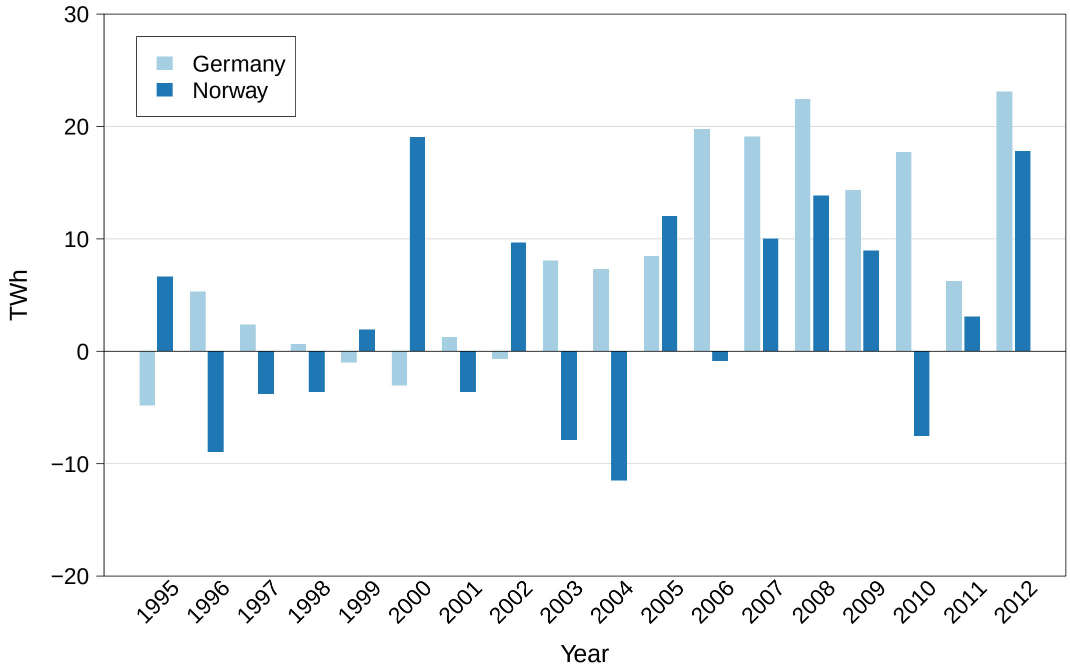

FIGURE 2.7: Development of net export in Germany and Norway, source: Bundesministerium für Wirtschaft und Technologie (2014), Statistics Norway (2013a)

2.1.4 Market Framework

Norway is part of the common Nordic electricity market, together with Sweden, Finland and Denmark. In 2010 Estonia and in 2012 Lithuania joined the Nordic market (Nord Pool Spot, 2013b). The Latvian bidding area was launched in June 2013. Power is traded at the power exchange Nordpool. In 2010 74 % of the Nordic power production was traded on the Nord Pool Spot market (Olje- og Energidepartementet, 2012, p. 52). The Nordic market is split in different market areas that can have different electricity prices in case of grid bottlenecks. Norway is currently split into five price areas (Nord Pool Spot, 2013c).

Germany is part of the market area Germany/Austria that belongs to the central-western European market coupling (CWE). The CWE is a cooperation of TSO's and power exchanges to couple the markets of the Netherlands, Belgium, Luxembourg, France, Germany, and Austria and was launched in 2010 (APX Power Spot Exchange, 2013). Market coupling means that the grid between market areas is used efficiently and differing prices between areas reflect the congestion of the grid. Working towards a common European market, the Nordic and the central European power market are increasingly integrated, with an Interim Tight Volume Coupling (ITVC) between Germany and the Nordic region since 2010 and between the Netherlands and the Nordic region since 2011 (TenneT, 2013a). The volume coupling ensures that bids between the areas are aggregated to an optimal volume for each connecting cable or line.

Electricity prices in Norway are generally lower than in Germany. Figure 2.8 shows prices of 2012 for Germany and for the Nordic price region NO2, which is the area around Kristiansand in south-west Norway. In the Nordic market there is only a system price for the whole market area, not for Norway. NO2 was chosen because is represents the region where cables to Germany will most likely connect. It can be seen that prices in Norway tend to vary less. However, upwards price hikes can be seen in both areas. Negative prices that do occur in Germany do not happen in Norway because of the higher flexibility in the hydro system.

In figure 2.9 for more details only the prices of November 2012 are shown. It can be seen that the daily price fluctuations are more pronounced in the German market. At the beginning of the month this leads to lower prices in Germany during the night and higher prices during the day. This pattern is the basis for arbitrage trading on the NorNed cable between Norway and the Netherlands.

In Germany after the privatization large energy companies were formed that now dominate the production and trading of electricity. In Norway on the other hand approx. 90 % of the energy production capacity is publicly owned, by the state, counties or communities (Olje- og Energidepartementet, 2012, p. 20). Furthermore, new licenses for hydro power resources are only granted to public enterprises.

2.2 Storage in Renewable Energy Systems

The transformation of the electricity system towards renewable energy will most likely lead to a dominating share of wind and solar power production in Germany. Those energy

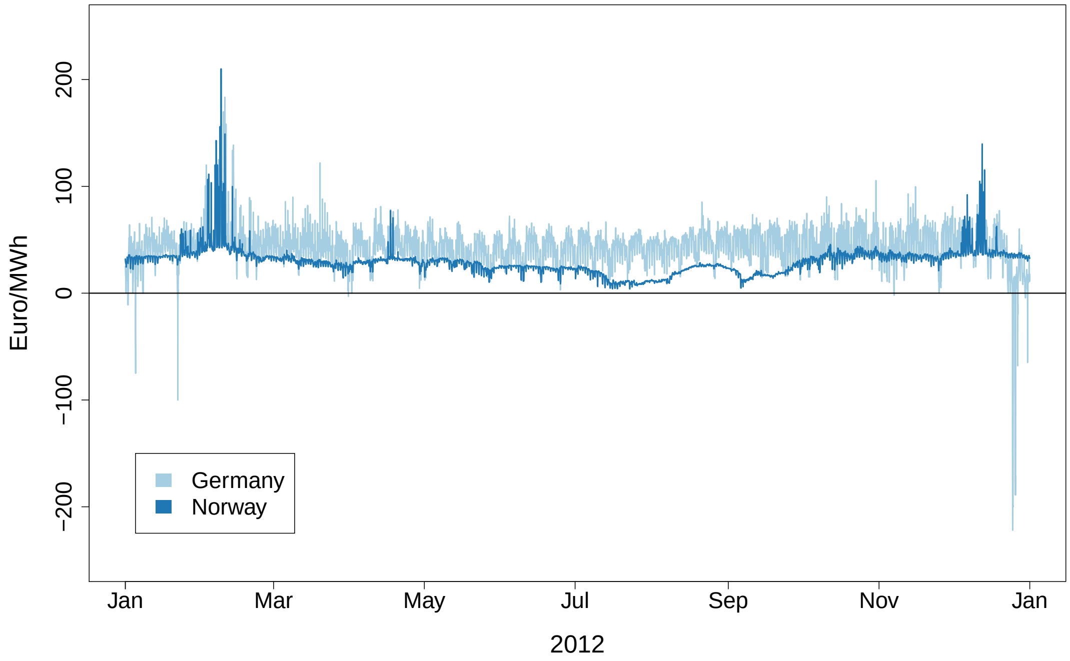

FIGURE 2.8: Electricity prices in Germany and Norway, 2012, source: EEX (2013), Nord Pool Spot (2013a)

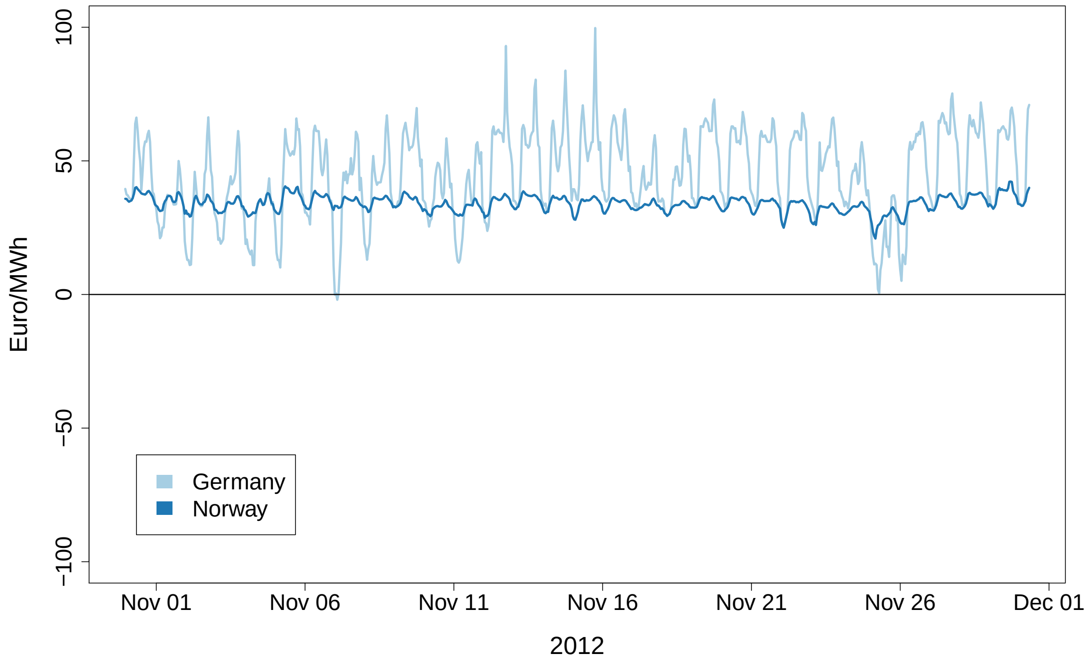

FIGURE 2.9: Electricity prices in Germany and Norway, November 2012, source: EEX (2013), Nord Pool Spot (2013a)

sources are by nature fluctuating and not dispatchable. It is widely consensual that such a system will need much flexibility on the supply and demand side and that storage systems will play an important role. According to Deutsche Energie-Agentur (2010a, p. 14) the extension of storage capacity is of vital importance to integrate renewable energy production. However, the needed dimensions are not clear at all at the moment and research results to the extent and time frame of storage demand differ significantly (see also Nitsch et al., 2012, p. 200).

2.2.1 Benefits of Storage

There is a variety of electricity storage technologies that can operate on different time scales from minutes to days and weeks. Storage systems are currently used in day-to-day electricity supply in diverse applications.

One important application of large-scale storage system is load-shifting. That means that in times of low power demand power is stored and in times of high power demand power is produced, thus the demand curve is flattened. The price difference between those times is the financial incentive for the storage operator. In the short to medium term, when there is still a significant share of conventional thermal capacity, this has the effect that the production hours of traditional base load power plants are increased while the production of peak load power plants can be substituted by the storage system. On the up side this enables thermal power plants at base to medium load to operate more often at maximum capacity where the efficiency is highest and avoid inefficient starts and stops (see Bullough et al. (2004, p. 2), Sterner et al. (2010b, p. 54, p. 105)). On the down side this means in practice often replacing fuels with lower CO_2 emissions (e.g. natural gas) by fuels with higher CO_2 emissions (hard coal and lignite). In a system with a high share of renewable energy the residual demand, demand minus fluctuating renewable production, rather than the demand will be the relevant variable for storage operation. Increasingly the stored energy will be excess renewable production that can be saved that way. Sterner et al. (2010b, p. 54) showed that pumped storage systems can contribute significantly to reducing curtailment of renewable electricity production and reducing the demand for conventional peak capacity. Sioshansi et al. (2009) analyze that load-shifting storage operation leads to consumer surplus gains by reducing peak electricity prices. (p. 14f) This will not be offset by higher base load prices because the quantity of consumed electricity is lower during those times. For generators a loss of producer surplus is assumed but the net welfare effect is expected to be positive. The same effect is simulated by Sterner et al. (2010b, p. 54).

Additionally, on a more technical level, storage systems can, depending on the technology, contribute to system stability by participating in voltage and frequency control, supplying reactive power, and rebuilding grid frenquency and voltage through their black start capabilities (see for example Bousseau et al. (2006, p. 23), Sterner et al. (2010b, p. 126)).

2.2.2 Alternatives to Storage

The need for storage depends on several factors in the development of the energy system. Electricity storage systems fulfill two functions in balancing supply and demand. They can absorb excess electricity when it is not needed and supply electricity when it is needed. For both situations there are alternatives. Flexible demand side management (DSM) also works on both sides towards balancing demand and supply, in principle like a storage system. On the demand side additional grid capacity can access distant load when there is too much electricity production. Likewise the demand can be increased flexibly by converting electricity to heat or fuel. On the supply side there is the possibility of reducing supply by curtailing renewable production when the energy cannot be used. To increase the supply fast-ramping dispatchable production plants can be used to fill the gaps between demand and supply. All those options can partly substitute each other.

Pieper and Rubel (2010, p. 6) assume that conventional back-up capacity will be important in the coming years to integrate renewable energy but that it is neither sustainable nor by its own sufficient in the long-term. The potential contribution of demand side management is debated. Pieper and Rubel (2010) consider it to be limited. Concerning the interrelation of storage and grid Leuthold and Sauer (2010, p. 24) state that storage systems are no competitive alternative to grid extension. The same conclusion is found by VDE (2009, p. 129f) for short and long transmission distances, even under favorable storage assumptions. VDE (2012, p. 134) reproduces those findings, showing furthermore that the application of storage systems for reducing costs of electricity supply does not significantly reduce the grid load. Alonso et al. (2011, p. 330ff) point out that higher ratios of renewable production to demand will lead to lower storage capacity at the cost of production curtailment. Only very high ratios will achieve complete demand coverage without storage systems (p. 326).

It can be concluded that all options will be needed to some extent because the different technologies have different characteristics that make them suitable for different applications. Accordingly they can complement each other in future renewable systems. For that reason all alternatives should be explored further. The contribution and specific application of the different technologies will be the results of their competitiveness on future markets or the effect of political support schemes and will take shape as the transformation progresses. The aim of this thesis is to map out the possibilities of using Norwegian hydro storage in more detail.

2.2.3 Storage Demand

There are diverse opinions on when and to what extent more storage capacity is needed in Germany and Europe. Sterner et al. (2010a) state that storage systems will be needed earliest when a share of 30 % renewable production in the grid is reached, with optimal electricity transmission when the share is 40 %. VDE (2012, p. 141) report likewise that up to a share of renewable production of 40 % additional storage plants are not imperative. The balance of demand and supply can until then be secured with flexible thermal power plants and minor curtailment of renewable production. Storage plants will until that point mainly be operated to optimize the production of thermal power plants and will not reduce CO_2 emissions. A similar conclusion is drawn by Agora Energiewende (2014, p. 86ff) who state that in the next 10 to 20 years, with a share of renewable electricity of 40 % to 60 %, additional electricity storage is not beneficial because investment costs outweigh the decrease of total production costs. VDE (2009, p. 142) concludes that the application of storage systems is reasonable in three cases:

- when more than 15 % of renewable production cannot be used
- when no grid extension is possible
- when the spread between high and low electricity prices is frequently above 3 ct/kWh.

As described before, the storage plants in Germany are currently dimensioned for some hours of storing or producing electricity. Sterner et al. (2010b, p. 54) indicate that in future there will be increasing balancing need within a day, but also within a month or a season. They conclude that in the medium term there is demand for storage for hours and days and in the long term also for storage for weeks and across seasons (p. 133).

A first estimate for storage demand can be found by looking at the amount of renewable energy that cannot be integrated in the electricity system. However, it has to be differentiated if the excess energy is due to lack of demand or caused by grid restrictions. Excess electricity that is purely due to a mismatch of supply and demand can be determined by looking at the residual load in future energy scenarios. The residual load is found by subtracting the non-dispatchable renewable energy production from the load. Of course the resulting values are driven by the assumptions on the development of demand and renewable capacity.

Saint-Drenan et al. (2009) simulated the effects of the renewable energy scenario for 2020 presented by the German Renewable Energy Federation (Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien, 2009). They calculate that the peak of residual load is 20 GW lower than the peak load (p. 33). During 84 hours of the year renewable electricity production is assumed to be higher than demand (p. 35).

Deutsche Energie-Agentur (2010a, p. 146) expect 7 GWh excess electricity in 2020 and 2.8 TWh in 2030, assuming increasing demand. In case of decreasing electricity demand likewise only a small amount of excess electricity is expected until 2020 but a significant increase to 12 TWh in 2030 (p. 144). The analysis is based on renewable expansion according to Bundesministerium für Umwelt (2009), a share of combined heat and power (CHP) plants of 25 % by 2020 and today's storage capacity. It has to be noted that this study assumes an extension of the lifetime of nuclear power plants by 20 years. This has most likely influenced the derivation of the renewable excess production due to the limited ramping capabilities of the nuclear power plants.

In the Leitstudie 2011 (Nitsch et al., 2012, p. 96) the storage demand for scenario 2011 B and a renewable share of approx. 85 % in 2050 is estimated to 16 TWh/a. This is the total stored energy and not the needed storage volume. The demand is assumed to increase to 70 TWh when approaching a 100 % renewable supply. Those figures roughly conform to estimations of VDE (2012, p. 142), who point out that by aiming for 100 % renewable electricity production the storage demand triples compared to a system with 80 % renewable production.

VDE (2012, p. 52/53) analyzed residual load for different scenarios and states that increasing shares of renewable electricity will only reduce the maximum residual load to a small extent while the minimum residual load is decreased significantly to large negative values. In the simulations VDE (2012, p. 53) found that a 100 % renewable electricity scenario (based on Nitsch et al., 2010) reduces the maximum residual load from 76.7 GW in the reference case (based on 2010) to 67.1 GW in the 100 % scenario and the minimum from 30.4 GW to -80.8 GW. The mean was reduced from 56.8 GW to 1.6 GW while the standard deviation increased from 7.8 GW to 26.8 GW. Those results indicate that fluctuating renewable electricity will increasingly lead to excess electricity while there are still times with little or no renewable production. Those gaps are caused by meteorological conditions and can be closed only to a certain extent by increasing the installed capacities. The efforts to reduce positive residual load will on the other hand lead to increased overproduction. Any remaining positive residual load has to be supplied by dispatchable production or storage plants. VDE (2012, p. 52) notes that remaining thermal power plants and possible new storage plants have to guarantee the

	VDE (2012)	**Sachverständigenrat für Umweltfragen (2011)**	**Nitsch et al. (2012)**
Excess electricity (GW)	80.8		
Storage demand (GW)	69 (long-term), 46 (short-term)	50	
Total stored energy (TWh)			70
Storage demand (TWh)	28.5 (long-term), 0.2 (short-term)	22	

Table 2.2: Estimations for storage demand in 100 % renewable electricity scenarios

security of supply. In order to prevent curtailing renewable production storage capacity would have to be increased drastically (p. 53).

VDE (2012) determine total storage demand to balance the residual load in a 100 % renewable scenario, when no other dispatchable capacity is available, and assuming no curtailment of renewable production. The authors differentiate between short-term (approx. 5 h capacity) and long-term storage. The total demand for short-term storage is calculated to 46 GW and 197 GWh (p. 53). For long-term storage a demand for 69 GW and 28.5 TWh is estimated.

Sachverständigenrat für Umweltfragen (2011) also analyzed a 100 % renewable electricity supply. A self-supply scenario for Germany led to stored energy of 50 TWh and 34 TWh production from storage while there are still 53 TWh of unused electricity (p. 161f). The autarky restriction was relaxed for a scenario that includes also Norway and Denmark and permits 15 % exchange relating to energy demand but still requests that the annual total of energy demand is produced within each country. This scenario reduces the stored energy in Germany to 5.7 TWh and the production from storage to 4.3 TWh. Furthermore, the excess energy can be reduced to 0.8 TWh. This is achieved partly by connecting energy systems with less parallelity in load and renewable production and partly by importing the storage service from Norway where storage systems can be installed at lower costs. The needed storage capacity in Norway is approx. 50 GW (p. 164). The maximum needed storage volume is 22 TWh, a figure rather similar to the estimations for long term storage of VDE (2012), as described before.

Table 2.2 summarizes the estimations for storage demand in a 100 % renewable electricity scenario. It has to be kept in mind that the figures are not directly comparable because of the different underlying assumptions in the different sources.

2.2.4 Storage Operation

In the simulations of VDE (2012, p. 80) it was shown that in combination with thermal capacity not all of the available storage capacity is used. Short term storage with a capacity of 36 GW and 184 GWh is employed. For the long-term storage it can be seen that the needed capacity for filling the storage is with 68.3 GW higher than the capacity needed for producing electricity from storage with 41.7 GW. The employed long-term storage volume is 26 TWh. Additionally 41.7 GW of thermal power plants are included. Short term storage is used in the range of days and weeks while long-term storage is used as a seasonal and annual storage with the highest filling level during summer. The short-term storage reaches approx. 500 full-load hours for loading and un-loading the storage respectively (p. 82). The long-term storage reaches approx. 1600 h for loading the storage and approx. 1000 h for unloading. VDE (2012, p. 59) note that long-term storage options, due to an assumed efficiency of 40 % and below, are only used when the capacities of short-term storage and flexible power plants are exhausted. That means short-term storage will replace long-term storage as much as possible. With increasing shares of fluctuating renewable production long-term storage options gain more operating hours.

Ess et al. (2012) investigate indirect electricity storage in Norway. Indirect storage means that electricity transmitted from Germany to Norway is used directly to substitute local production from hydro storage plans. Thus instead of using the electricity for pumping, the operating turbines are stopped and the water is saved for later production. The remaining economically viable connection capacity between Germany and Scandinavia is estimated to 7 to 12 GW (p. 59).

The storage plants in Germany are operated not only on the power market but also on the control reserve market, often for secondary control reserve (VDE, 2009, p. 25). Hence the development of control reserve demand has to be considered when looking at future storage demand. Pumped storage plants can supply reserve capacity as spinning reserve, without having to produce electricity (Nitsch et al., 2012, p. 200). Thereby they can contribute to reduce the conventional must-run capacity and make room for renewable energy. There are different assumptions on the demand for control reserve in a renewable energy system. VDE (2009) argues that increasing fluctuating production increases the demand for control reserve, while increased European market integration lowers it (p. 17). Nitsch et al. (2012) on the other hand expect a significant increase (especially for minute reserve) only until 2020 and afterwards only a slight increase and even a decrease until 2050 caused by improved forecasting of wind and pv production (p. 188). Sterner et al. (2010b) also expect that in the long term control reserve demand will be slightly lower than today, assuming progress in forecasting accuracy (p. 69).

They conclude that the importance of the control reserve market for storage systems will relatively decline while the shifting of (residual) load will become more important. Gatzen (2008, p. 50, cited in Sachverständigenrat für Umweltfragen (2011)) points out that the German control reserve market is small and revenues are uncertain so that for a profitable operation of storage plants the power market is crucial. Conversely Hinüber (2012, p. 8) from Trianel expects a significant contribution to the profitability of a plant from secondary reserve markets.

2.3 Storage Potential

2.3.1 Pumped Storage Potential in Germany

The installations of pumped storage plants is restricted by geographical conditions. There are different assessments of the unexploited storage potential in Germany. Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien (2009, p. 26) assumes a significant but yet unknown potential for the installation of new pumped storage plants. Czisch (2005, p. 111) claims that a maximum potential cannot be given because the potential in Germany is not restricted by technical and geographical conditions, but rather by environmental and economic circumstances. Steffen (2012, p. 420) assume that up to 4.7 GW of additional pumped hydro storage capacity could be installed in the coming years. On the other hand several studies expect the potential in Germany to be rather limited. Sterner et al. (2010b, p. 116) estimate the potential for new pumped storage plants in Germany to be very low due to topographic conditions and the environmental intrusion such projects entail. The same is concluded by Sachverständigenrat für Umweltfragen (2011, p. 157). Also VDE (2009, p. 46) expect no noteworthy increase of pumped storage plants, likewise Oertel (2008, p. 36).

There is the possibility of modernizing and repowering existing pumped storage plants. The capacity of old plants can be raised by increasing the hydraulic and electric efficiency, increasing the maximum flow or increasing the storage volume (Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien, 2009, p. 26). At the Waldeck II plant the capacity has been increased by 9 % (E.ON Wasserkraft, 2006). This was achieved by renovating all the components and installing a new, improved runner. Also the reservoirs were rehabilitated. Another option is to upgrade existing storage plants with new pumps to pumped storage plants (Sterner et al., 2010b, p. 116). However, most of the large storage plants in Germany are already equipped with pumping capacity.

Project	**Capacity** (MW)	**Storage volume** (GWh)
Atdorf	1400	> 13.00
Nethe	390	2.34
Schmalwasser	1000	6.00
Jochenstein	300	3.50
Blautal	60	0.37
Sum	**3150**	**25.21**

Table 2.3: Pumped storage projects in Germany

Several new pumped storage projects are being proposed and discussed at the moment. One of the most concrete is the Atdorf project in the Black Forest, developed by Schluchseewerk, the operator of several large pumped storage plants in the region (Römer, 2012). The planned new pumped storage plant would have a capacity of 1400 MW and a storage volume of more than 13 GWh (Römer, 2012, p. 14). The project is currently in the approval process. Only after that a decision on whether to realize the project will be taken.

Trianel, a cooperation of utilities, is also considering pumped storage projects to be installed after 2020 (Sewckow, 2013, p. 5). According to Trianel (2013c) approx. 2000 MW of storage plants could be implemented in North Rhine-Westphalia and Thuringia. In the area of Weserbergland a concrete project is planned in the form of the storage plant Nethe (Trianel, 2013a). The capacity of the plant would be 390 MW with a storage volume of 2.34 GWh for six hours of production. This project is currently in the regional planning process, the first step of the approval process. Another concrete project is Schmalwasser in Thuringia where the application for a regional planning procedure has been filed in April 2013 (Trianel, 2013b). The storage plant is planned with a capacity of 1000 MW and storage volume for six hours of production. A possible new storage site at the Rursee was dropped due to percieved lack of political support.

In Jochenstein, Bavaria a storage plant with a capacity of 300 MW and a storage volume of 3.5 GWh is planned (Donaukraftwerk Jochenstein AG, 2013). The project Riedl has completed the regional planning procedure and entered the planning approval procedure in September 2012.

The utilities of Ulm/Neu-Ulm are developing a project in Blautal (Blautopfstadt Blaubeuren et al., 2013). The planned capacity is 60 MW and the storage volume 370 MWh. The project is in the regional planning process. The pumped storage projects in Germany are summarized in table 2.3.

According to Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien (2009, p. 27) some of the storage expansion projects which are developed in the alpine region south of Germany will operate directly for the German system. This includes the increase of capacity in the pumped storage plant Vianden in Luxembourg by 200 MW, of which at least 100 MW will operate in the German grid, the expansion of the pumped storage plant Kühtai by 140 MW and the new plant Kops II, both in Austria, with a capacity of 450 MW.

In total the described projects sum up to 3150 MW in Germany and 690 MW in Luxembourg and Austria.

The last new pumped storage plant built in Germany was Goldisthal in 2003. Sterner et al. (2010b, p. 116) cite investment costs for that project of 620 million Euro. With a capacity of 1060 MW the specific costs are 585 €/kW. Hinüber (2012, p. 9) assumes pumped storage costs of 1000 €/kW for a model calculation. Total investment costs of the Atdorf project are estimated to 1.6 billion €, that is 1143 €/kW (Römer, 2012, p. 14). The storage costs are estimated by Landinger (2010, p. 38) to 3 ct/kWh for short-term storage in the range of hours and 10 ct/kWh for long-term storage in the range of weeks. This does not include the costs for buying the stored electricity. Storage operators note that the profitability of new pumped storage plants is uncertain for the future because the spread of electricity prices is not high enough at the moment (see Hinüber (2012) and Römer (2012)).

2.3.2 Pumped Storage Potential in Norway

As described before Norway has a large hydro system. In this section the potential of expanding the current system to include a higher storage capacity is described. Completely new sites for hydro storage plants are not considered. Norway still has unexploited potential for new hydro power plants but it is regarded as highly unlikely that any new large hydro plants are installed in the forseeable future due to environmental and social reasons. However, the existing hydro system is offering much expansion potential that is comparably easy to access so that new schemes seem unnecessary.

Bakken et al. (2011, p. i) conclude that it is possible for Norway to install 10 GW hydro power capacity by 2030 to deliver flexibility to Europe. However, they identified the grid situation in Norway, the development of feasible business models and political acceptance in Norway (see section 2.4.2) as possible barriers to the scheme (p. iii).

Statkraft, the largest power producer in Norway, has analyzed the potential for increasing the capacity of its hydro power plants. The results of this internal study were reported in several presentations for example by Egeland (2011a). The determining factors for the increase of pumped storage capacity are the acceptable water level change and the duration of time that can be pumped or produced. Water level change that is too fast will negatively affect the species in the reservoirs. Higher installed turbine and pump capacity will drain the reservoirs faster, so the longer the storage volume is supposed to last, the lower the potential for installed capacity. Depending on those parameters the extension potential varies between 1.5 GW with a duration of 60 days and 0.01 m/h water level change and 85 GW with 24 hours duration and 0.5 m/h water level change (p. 9). Water level change of 0.1 m/h seems to be in an acceptable range (see also Solvang et al., 2012, p. 71). This leads to 30 GW of capacity for 24 hours, 16 GW for seven days and 2.6 GW for 60 days. Those values are the result of a first estimation and not based on detailed studies of possible locations.

The Norwegian energy and hydro regulator (NVE) has made an assessment of costs and potential of pumped storage plants in Norway (Norges Vassdrags- og Energidirektorat, 2011b). Looking at all hydro power plants in Norway they identified over 100 power plants which are situated between two regulated reservoirs. Of those, 17 current locations are connected to two regulated reservoirs with more than 100 mio m^3 capacity (p. 9). Those locations were selected as potentially suitable sites because it is assumed that in reservoirs with a volume of 100 mio m^3 capacity the environmental effects of installing additional storage capacity are rather small. For four of those plants a detailed cost analysis was carried out by consultants from Vattenfall Power Consultant (Aamot et al., 2011). Those are Trollfjord, Lassajavrre, Fagervollan, and Blåfalli V. Calculated costs range from 500 €/kW for larger plants to 2500 €/kW for small plants (Norges Vassdrags- og Energidirektorat, 2011b, p. 13).

Based on those costs the necessary price difference for pumped storage plants is estimated to approx. 2.5 ct/kWh (20 oere/kWh) (Norges Vassdrags- og Energidirektorat, 2011b, p. 13). In this calculation it is assumed that a storage plant with a cycle efficiency of 80 % is either pumping or producing in 75 % of the time. Financing is assumed for 20 years with 6.5 % interest and operating costs at 1 % of investment per year.

The potential of extending the current hydro power scheme in Norway has also been analyzed by Solvang et al. (2012). 19 different alternatives at seven locations in southern Norway were analyzed. All extensions are within the current regulatory regime of the storage reservoirs. Two different scenarios for new pumped storage installations were developed. The capacity of the individual power plants was set so that the water level change in the connected reservoirs does not exceed 13 cm/h, except for two cases with 14 cm/h. According to Solvang et al. (2012, p. 71), research on the stranding of salmon in rivers indicates that the water level in reservoirs should not change faster than 13 cm/h. The first scenario includes 12 power plants with 11.2 GW total capacity (p. 70). The second scenario includes seven larger power plants with 13.6 GW total capacity (p.

71). Furthermore, in a third scenario it was shown that the output of analyzed hydro systems can be increased by 18.2 GW without water level changes exceeding 14 cm/h. Of that 2.8 GW is pure production capacity without the possibility for pumping (p. 71). Capacity can be further increased to a total of 20 GW by including more locations in southern and northern Norway (p. 72).

For estimating the costs of additional pumped storage capacity in Norway there is a detailed handbook published by the NVE (Norges Vassdrags- og Energidirektorat, 2010a). Based on that Solvang et al. (2012) calculated a simplified cost estimate for the pumped storage projects they investigated. Cost data were scaled up to reflect price levels of 2011. The interest rate of financing is assumed to 6.5 %. The costs range from approx. 250 €/kW (1924 NOK/kW) to approx. 400 €/kW (3200 NOK/kW) (p. 82). While the total average is approx. 330 €/kW (approx. 2600 NOK/kW), it is higher for pumped storage plants with approx. 370 €/kW (2900 NOK/kW) than for storage plants with approx. 290 €/kW (2300 NOK/kW). Those costs seem relatively low. However, it has to be kept in mind, that no completely new storage plants are being proposed but only additional pumping and production capacity at existing plants.

Expected costs can also be derived from the concession application that was provided by Sira-Kvina Kraftselskap for the extension of the Tonstad power plant (Sira-Kvina Kraftselskap, 2007). For the new power plant with 960 MW total investment costs of 2.7 billion (10^9) NOK were estimated (p. 17). This translates to approx. 360 €/kW. Approximately half of that are costs for building and construction works, 20 % for the technical equipment, 17 % for electrotechnical equipment and 13 % for planning, administration and financing.

2.3.3 Pumped Storage Potential in the Alps

When looking at pumped storage potential in Europe the alpine region is often mentioned for good topographic conditions. Indeed the pumped storage capacity in Austria and Switzerland is larger than in Germany and new capacity is planned. However, according to Landinger (2010, p. 29), as in Germany, it is very difficult to build new reservoirs because of environmental constraints and public opposition.

In Austria 3.7 GW of hydro storage and 3.8 GW of pumped storage plants are installed and 1.9 GW of new pumped storage capacity are expected until 2020 (Ess et al., 2012, p. 31). The storage capacity in Austria is 3200 GWh (Energie-Control Austria, 2013). According to Tretter et al. (2010, p. 23) 5 GW new capacity (compared to 2009) are planned alone in the regions of Carinthia, Salzburg and Tyrol. Additionally there are projects in other regions.

Country	**Pumped storage potential** (GW)	**Investment costs** (€/kW)
Germany (planned projects)	3.15 + 0.69 (neighbors)	1000 - 1143
Austria (planned projects)	> 5	n/a
Switzerland (planned projects)	6	800 - 1600
Norway	20 - 30	250 - 400

Table 2.4: Pumped storage potential

In Switzerland 8.1 GW of hydro storage plants and 1.8 GW pumped storage capacity are installed (Ess et al., 2012, p. 31/34). The storage capacity is 8770 GWh (Bundesamt für Energie, 2012a). Until 2020 another 6 GW are expected to be installed. Projects with a sum of 4 GW are already in planning or construction phase. According to Rechsteiner (2006, p. 54) many of the new projects are modifications of existing plants where new capacity is added between existing reservoirs, rather than building completely new ones.

In Switzerland investment costs of 800 - 1600 Euro/kW (1000 to 2000 CHF/kW) are expected for pumped storage plants (Bundesamt für Energie, 2012b, p. 33).

Table 2.4 summarizes the pumped storage potential in Germany, the Alps and Norway. Comparing those figures to the storage demand of 50 to 70 GW (see table 2.2) it is obvious that no region alone will be able to meet the demand but rather all available options are needed. Still Norway has by far the largest potential at the lowest costs.

2.3.4 Potential of Other Storage Technologies

Pumped storage plants are a well established technology and currently the most cost-effective way of storing electricity. However, there are other technologies which are in the development phase that could become valuable options for the future. This section gives a short overview on the potential.

Compressed air energy storage (CAES) in its diabatic variety has been used since the late 70's in Huntorf (Crotogino, 2003, p. 6). Another plant is installed in McIntosh, Alabama/USA. The two existing plants have diabatic air storages and electricity production is supplemented with natural gas (Crotogino et al., 2001, p. 1). Adiabatic CAES, where the heat from the compression of the air is stored and no additional fuel is needed, is not yet in commercial operation. An adiabatic demonstration plant in Germany is currently in the planning phase (RWE Power, 2010). The aim is to build a plant with 90 MW by 2016 to 2018 (Moser, 2012, p. 8). Adiabatic CAES plants are expected to reach a round-trip efficiency of 67-69 % (VDE, 2012, p. 27).

The potential of CAES is mainly determined by the availability of salt formations to form caverns for storing the compressed air. VDE (2009, p. 51) estimate the potential to be favorable, especially along the north-western European coastlines. Ehlers (2005) has analyzed the potential in the North German Plain. In a first rough assessment he identified well suitable locations with a storage volume of 461 to 1910 GWh (p. 76) and suitable locations with a storage volume of 425 to 1763 GWh (p. 80). According to Deutsche Energie-Agentur (2010a, p. 64f) there are potential salt caverns in Germany for several CAES plants with 200 MW each. They point out however that there may be conflicting use of the caverns for storing natural gas, CO_2 or hydrogen. When creating caverns the saline water needs to be disposed of, so distance to shore has to be kept in mind.

VDE (2009, p. 53) estimate costs for CAES plants to be in a similar range of > 600 Euro/kW as for pumped storage plants. However, this regards the conventional diabatic CAES, for adiabatic plants investment costs are assumed to be 20-30 % higher. Additionally for the salt cavern another 20 % of the plant investment costs need to be calculated.

Chemical storage in batteries is at the moment mainly used for small-scale applications but their operation as a large-scale storage is also technically possible (Deutsche Energie-Agentur, 2010a, p. 67f). While fast reaction and high efficiency recommend this storage type, the main disadvantage are the high costs. Also the environmental impact of the production and disposal of batteries needs to be considered. According to Oertel (2008, p. 104) batteries are still too expensive to be used for large-scale applications. VDE (2009, p. 87) estimate costs of 300 €/kWh in the coming years.

Recently the concept of power to gas has received much attention. Hereby power is used to generate hydrogen via electrolysis. Either the hydrogen is stored or used as a fuel or it is converted with the addition of CO_2 to methane. Methane can be directly fed into the natural gas infrastructure. According to Sterner et al. (2010c, p. 10) the existing natural gas grid has a storage capacity of 220 TWh thermal energy. This high storage capacity is the main advantage of the concept. Disadvantages so far are the high costs and low efficiency of the process, especially considering power-to-gas-to-power. VDE (2012, p. 27) state 25-45 % as the round-trip efficiency. However, hydrogen and methane are valuable fuels that can be used for a variety of applications in the heat and transport sector. That would be a more favorable utilization than reconversion to electricity.

2.4 Other Aspects of Large-Scale Pumped Storage Schemes

2.4.1 Environmental Impacts

In this section the environmental implications of the proposed scheme of installing new pumped storage capacity in Norway shall be highlighted. This refers to the upgrade of existing plants with new pumping and production capacity and not to the construction of new storage reservoirs. The new equipment will be installed in caverns in mountain rock and connected to existing regulated reservoirs via tunnels. There is hence very little visual intrusion after the construction phase. Also there is little effect on the rivers which naturally connect the reservoirs and which are often regulated actively.

The environmental impacts during the construction of the storage plant are comparable to the effect of other power plant constructions. Solvang et al. (2012, p. 72) do not consider the potential erosion and sediment supply to the reservoirs and river systems a major environmental impact. Another environmental concern is the disposal of excavation material from the construction of the tunnels and caverns.

Solvang et al. (2012, p. 73f) also describe the environmental effects of the operation phase. Increased capacity for producing and pumping power will in many cases lead to higher erosion. However, increased flow rates in the reservoirs can also have positive effects such as a better mixing and transport of nutrients. In times of high production the water temperature in the downstream reservoirs will be reduced. This leads to reduced growth of most species. The effect is opposite in the upstream reservoir. When water is pumped to a higher reservoir species could be transferred beyond their natural range. This could disturb the biodiversity. Faster and more frequent water level changes will hamper the formation of the ice cover of reservoirs. This can be a danger to traffic and also affect the behavior of fish. Also during the summer the less predictable water level changes will impact the recreational use of the reservoirs.

As Solvang et al. (2012) point out, existing reservoirs are no natural eco-systems but already heavily affected and regulated by human activity. This makes it difficult to evaluate further interference to the reservoirs.

The expected environmental impacts from a new pumped storage plant with 960 MW in Tonstad in the Sira-Kvina power system are described in Sira-Kvina Kraftselskap (2007). The changed flow patterns will likely result in increased erosion in the connected reservoirs, especially in the smallest one (p. 20). However, the erosion is expected to subside with time. The consequences for ice cover of the reservoir are only assumed to be slightly negative for two of the connected reservoirs and insignificant for the smallest one (p. 21). Slightly negative to medium negative impacts on fish and their prey are predicted

(p. 21). Also for the landscape and outdoor activities slightly negative to medium negative consequences are expected (p. 21). This is mainly due to the construction phase and fluctuating water levels during operation.

The environmental impact on the reservoirs depends largely on the size and shape (Solvang et al., 2012, p. 73f). Norges Vassdrags- og Energidirektorat (2011b) refer to a research project that studied the environmental effects of increased ramping of hydro power plants (final report: Bakken Pedersen and Sollibråten, 2001). During that research project characteristics of reservoirs that determine their suitability for pumped storage were analyzed (Norges Vassdrags- og Energidirektorat, 2011b, p. 8). Potentially small environmental effects are expected in reservoirs with the following attributes:

- regulated water level difference of more than 10 m
- volume of more than 100 mio m^3
- depth of more than 10 m
- steep sides
- evenly deep
- no debris
- little sediment input from the catchment area.

Conversely large environmental effects are expected for reservoirs with:

- regulated water level difference of less than 2 m
- volume of less than 20 mio m^3
- depth of less than 10 m
- gently sloping sides
- shallow thresholds
- a lot of fine debris
- a lot of sediment input from the catchment area.

More installed capacity is generally expected to increase the variation in water levels. As mentioned before, according to Solvang et al. (2012, p. 70f) water level changes below 13 cm/h should be slow enough to prevent the stranding of salmon.

2.4.2 Social and Political Dimensions

The extension of pumped storage capacity and increased connection to continental Europe and UK is discussed controversially in Norway. Norges Vassdrags- og Energidirektorat (2011b, p. 5) lists the income that can be gained on foreign power markets, income from the sale of regulation services, a better utilization of the Norwegian grid and improved domestic security of supply as possible benefits for Norway. Also the electricity sector in Norway expects new business opportunities from the scheme (Gullberg, 2013, p. 619).

However, there are also adversaries in the Norwegian society. The industry in Norway has been relying on inexpensive electricity supply. They fear that by increasing the connection between Norway and its neighbors the electricity price will increase. By threatening with the loss of jobs as a result of increased electricity prices they have roped the trade unions into their cause (Midttun and Ruohonen, 2012, p. 15f). However, especially the energy-intensive industry is also sensitive to price spikes in dry inflow years in Norway. This would be alleviated with increased connection capacity. Norway is an exporter of oil and gas and an important supplier of Europe. The petroleum industry has a stake in promoting gas fired power plants rather than hydro storage as the flexible complement to renewable electricity production (Midttun and Ruohonen, 2012, p. 15f).

The Forum for Natur og Friluftsliv (FNF), a forum of regional nature and environmental organizations in Norway, published a statement that is very critical towards Norway becoming a green battery due to the perceived impact on the environment and the landscape S(Lund, 2011). However, the FNF seems to interpret the green battery concept as an extension of wind and hydro electricity generation capacity in Norway for the purpose of electricity export. This is different from the export of flexibility and storage services and would lead to higher impacts than the scheme proposed in this thesis. All in all the environmental movement in Norway has not yet found a clear position on the conflict between nature conservation and climate-friendly renewable energy development (Gullberg, 2013, p. 620).

The current Minister of Petroleum and Energy Tord Lien, member of the Progress Party, has been in office since October 2013. It remains to be seen whether he will support the green battery concept. The former Minister of Petroleum and Energy Ola Borton Moe, member of the Center Party, was critical towards increased overseas connections (Midttun and Ruohonen, 2012, p. 13). The general public is concerned about increased electricity prices, though less than the industry, and also about the environmental and scenic impact of new power plants and overhead lines. The construction of new overhead lines in Norway faces fierce public resistance, a prominent example being the Hardanger Fjord line (Egeland, 2011b, p. 3f).

In June 2013 a joint Norwegian-German declaration for a long-term collaboration to promote renewables and climate protection was signed by more than 20 organizations from

Norway and Germany (Piria and Junge, 2013). The signatories include for example Energi Norway, Greenpeace Norway, WWF Norway, WWF Germany, Agora Energiewende, Bundesverband Erneuerbare Energien, TenneT and 50Hertz.

In conclusion there are concerns in both countries but increasingly the benefits of connection are appreciated.

Chapter 3

General Description of the Simulation Model renpass

3.1 Overview of Model Structure

renpass (Renewable Energy Pathways Simulation System) is a simulation model that was built to analyze electricity systems with a high share of fluctuating renewable energy sources. It is a dispatch model, that means the operation of generation and storage plants is modeled. The assumed capacity and siting of production and storage plants and grid infrastructure are input to the model, to be determined by the user. Those assumptions can be varied for simulating different scenarios. renpass is a bottom-up model with high spatial resolution and hourly or 15-minute time steps.

Different options for balancing fluctuating renewable production can be analyzed and compared with renpass. The utilization of production and storage plants as well as grid connections can be simulated. The output of the model includes in addition to the production and storage data also prices and storage filling levels. All results can be generated in 15-minute or hourly resolution. The influence of the renewable mix and the location of renewable production can be evaluated as well as the influence of other parameters like weather conditions, primary energy resource prices, and electricity demand.

renpass can cover different geographical areas. Germany, Norway and the Baltic countries Poland, Lithuania, Latvia, Estonia, Finland, Sweden, and Denmark are implemented in the renpass version used for this thesis. For Germany and Norway existing power production plants are modeled in detail while for the other countries a more generic approach is implemented. Germany is implemented with the highest regional detail. It can be split into 18 onshore regions and three offshore regions. The regional division of Germany is based on the regions introduced in a regional model for electricity transmission, developed by the transmission system operators (Amprion et al., 2009). In the simulations for this thesis Germany, Norway, Denmark and Sweden are included and Germany is split into five regions. Grid restrictions are represented in renpass by a limited transmission capacity between the model regions.

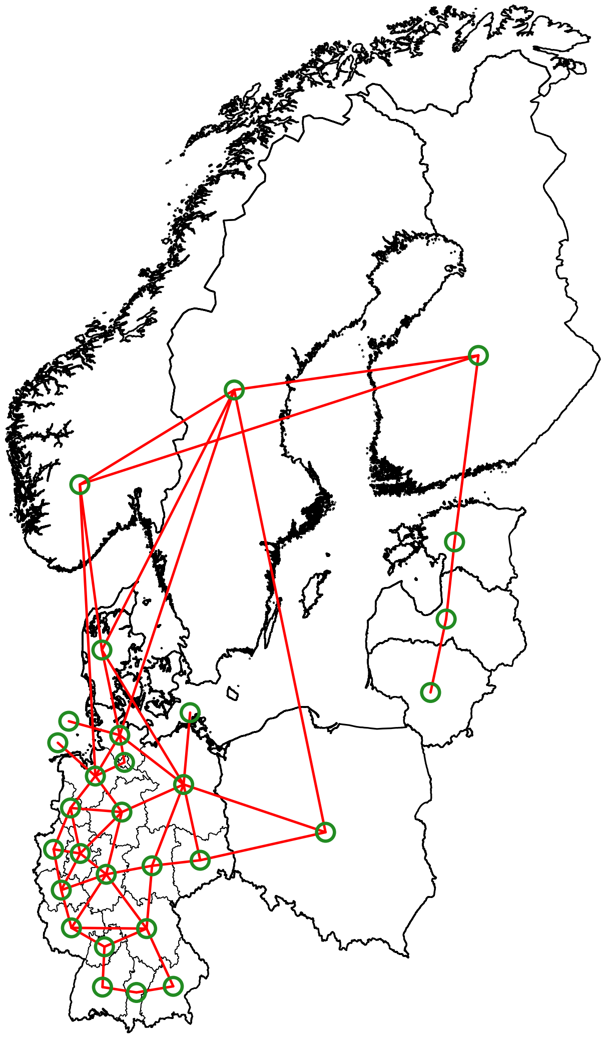

FIGURE 3.1: Schema of model regions and transmission lines

renpass has been developed using only open source software. This is necessary for the model itself to be open source. The input data and the results are stored in a MySQL database. MySQL is a widely used open source database system (Oracle Corporation, 2013). The simulations are processed in R. R is a free software environment, originally developed for statistical computing (R Development Core Team, 2011). It is available under the terms of the Free Software Foundation's GNU General Public License (Free Software Foundation, 2007). R and MySQL communicate directly via an interface that is supplied by the RMySQL package (James and DebRoy, 2011). renpass is distributed under the public license GNU GPL 3.

3.2 Main Modeling Concepts

3.2.1 Residual Load

The concept of residual load is central for renewable electricity systems and is also very important in the renpass simulations. The residual load contains the load and the weather dependent renewable production, like wind and solar electricity. Some run-of-river plants can be regulated to a certain extent. However, according to Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien (2009, p. 26) only approx. 14 % of the total run-of-river capacity in Germany can be regulated. This effect is neglected in the modeling in renpass and electricity from run-of-river plants is treated like wind and solar production. The electricity from those sources should be used as much as possible while it is produced because the primary energy source cannot be stored. Therefore power plants using weather dependent renewable sources are often called must-run capacity.

The residual load is defined by the following equation:

$$\begin{aligned} RL &= L - \sum(MR) \\ \sum(MR) &= W + S + R \end{aligned} \tag{3.1}$$

L	Load (MW)
MR	Renewable must-run production (MW)
W	Wind energy (MW)
S	Solar energy (MW)
R	Run-of-river energy (MW)

Residual load is accordingly the remaining load that has to be covered by dispatchable plants. When renewable must-run production exceeds the load, the residual load becomes negative. That means that too much electricity is being produced at that moment. Either electricity has to be stored or demand or supply has to be adjusted. Those adjustments can be carried out by flexible loads that can be increased or by curtailing electricity production.

The shape and level of residual load is determined by the load curve and the renewable production curves. Figure 3.2 shows the simulated demand and fluctuating renewable production for Germany in January. The resulting residual load is shown in figure 3.3.

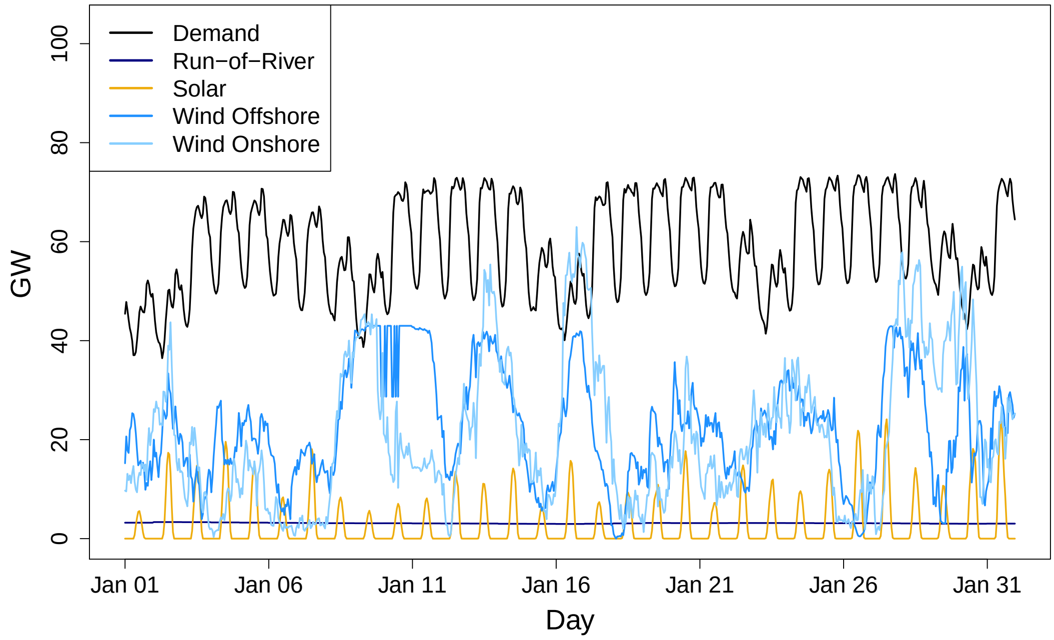

FIGURE 3.2: Demand and renewable production in Germany, simulation for 2050.

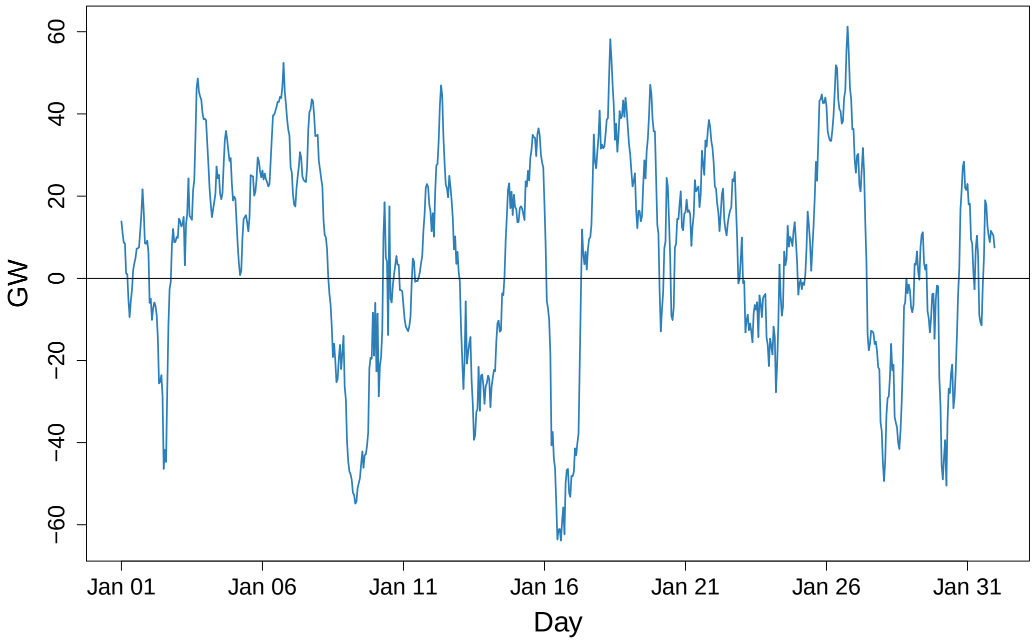

FIGURE 3.3: Residual load in Germany, simulation for 2050.

After the residual load is calculated in renpass, the operation of dispatchable power plants is determined.

3.2.2 Merit Order and Dispatch

In renpass, like in today's power market, the dispatch of production plants is based on the marginal production costs. In the merit order, production plants are sorted by their marginal costs, in increasing order. The plants are dispatched in that order until the demand is fulfilled. The last power plant that is needed to fulfill the demand, determines the price of power. Figure 3.4 shows the merit order of dispatchable power plants.

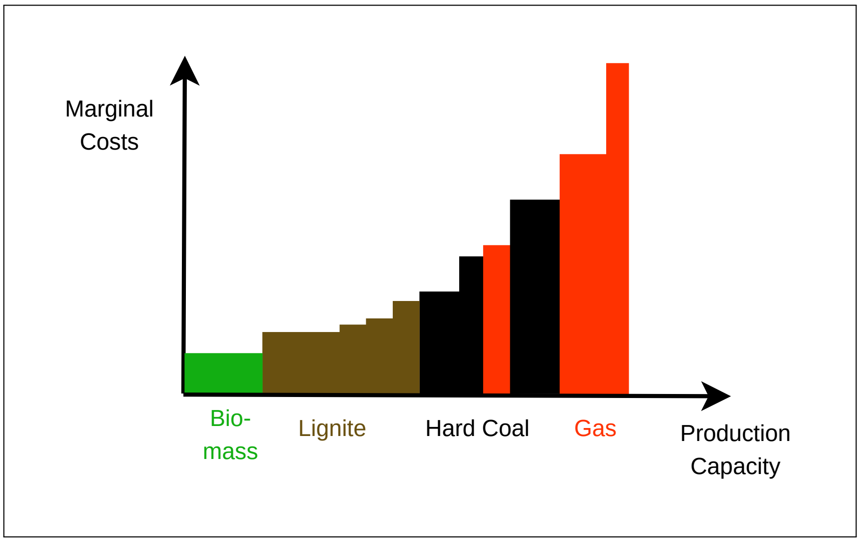

FIGURE 3.4: Merit order, adapted from Wiese et al. (2014)

Fluctuating renewable energy sources have marginal costs that are close to zero. Consequently, when available, they will be used before all other power plants. In renpass this is not implemented by including the renewable sources in the merit order but by calculating the residual load before the dispatch as explained above. Both approaches are equivalent and will have the same outcome. Figure 3.5 shows how a merit order including fluctuating renewable electricity would look like.

In situations when the electricity production capacity is not sufficient to cover the demand the electricity price is determined by the scarcity price. This price is set arbitrarily to express the value of security of supply. It should reflect the costs of alternative options to match supply and demand which are not included in the simulation. The standard setting for this thesis is shown in equation 3.2. The shortage price is set to the marginal costs of the most expensive power plant plus a shortage surcharge that is proportional

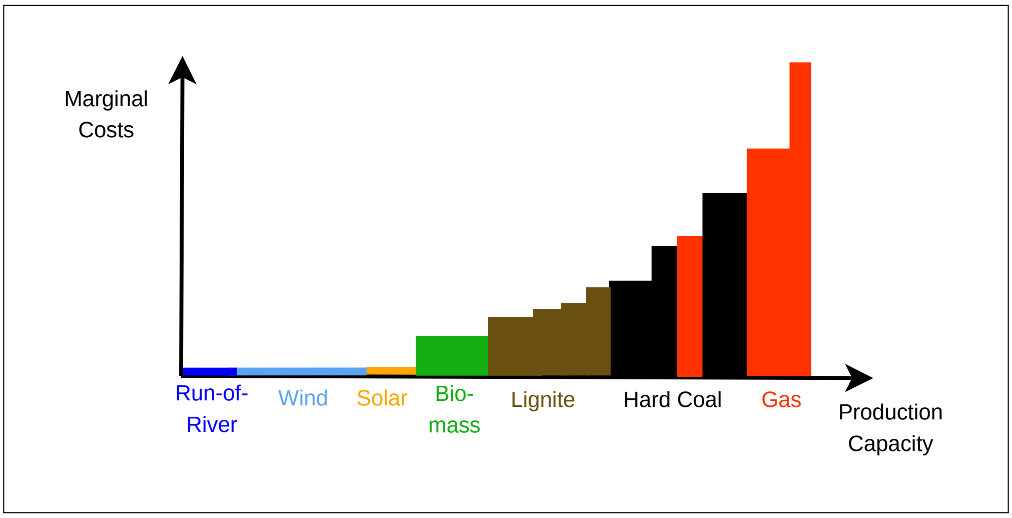

FIGURE 3.5: Merit order, including fluctuating renewable sources, adapted from Wiese et al. (2014)

to the supply gap. Assuming the last power plant in the merit order has marginal costs of 100 €/MWh a supply gap of 500 MW leads to a price of 150 €/MWh.

$$P_{shortage} = MC + OD/10 \tag{3.2}$$

$P_{shortage}$	Shortage price (€/MWh)
MC	Marginal costs of the most expensive production unit (€/MWh)
OD	Over-demand, supply gap

Because of the high influence the scarcity price has on prices and hence on revenues and economic benefits this setting will be varied in the sensitivity analysis as described in section 7.5.

3.2.3 Exchange

In every time step of the simulation the residual load is supplied in two stages. In the first stage the residual load is matched with the merit order of dispatchable production plants within each region in order to fulfill the demand without exchange between the regions. This can lead to very different outcomes in the different regions. In some regions with large renewable capacity and little demand residual load will be negative, that means there is excess electricity. In renpass the price in those regions will be zero. Negative prices are not implemented in renpass. In other regions there could be a situation where residual load cannot be met by production capacity within the region. In that case there is excess demand and the price is set to the scarcity price. In the regions where demand can be met by production plants the price will be set by the marginal power plant leading to different prices in those regions as well. At the end of the first dispatch stage excess production, excess demand and power price are identified for each region.

In the second dispatch stage power will be exchanged between the regions in order to minimize total costs of production. When the transmission capacity is sufficient the prices in all regions should end up on the same level. By equalizing the prices also the excess electricity and excess demand is being matched. The power exchange is approached with a heuristic iteration. The number of iteration loops can be chosen by the user. More iteration loops lead to a better result, however at the expense of computing time. Robust results can be achieved with a few thousand loops. The simulations for this thesis are set to 3000 iteration loops. For each iteration step first two neighboring regions are chosen randomly and then the power exchange on the connecting grid is chosen randomly within the limit of available capacity. The power exchange can be positive or negative, that means that the direction of flow is chosen randomly too. If the exchange of one iteration step does not increase total marginal costs, as defined by the sum of price times produced quantity of dispatchable plants over all regions, it will be included into the point of departure for the next iteration. The process stops after the predefined number of iteration steps or if no improvement has been achieved for a certain number of iterations.

After the second stage of dispatch excess production, excess demand and power price are redefined for each region. A price difference between two regions indicates that the grid capacity has restricted the flow. That means in that time step there is a grid bottleneck. Excess demand can be caused by grid bottlenecks or by excess demand over the whole model area. The excess production after the power exchange cannot be clearly assigned to specific regions anymore, because it could have been transferred between regions by the exchange algorithm. Hence the sum of excess production over all regions is a more meaningful indicator than the figure for every region.

3.2.4 Operation of Storage Plants

In the dispatch and exchange steps the residual load is matched with production capacity. The storage of power is not considered in those steps. This is based on the consideration that demand from power consumers should take priority over demand from storage plants. Whenever possible, renewable production should be matched with demand because then the power can be used without the conversion losses that occur in storage plants.

Hence the storage of power comes after the power exchange. In the renpass model power storage is modeled from a technical point of view. Storage plants only store excess power that comes at zero price. Buying power at a positive price for arbitrage trading is not considered. The storage of electricity happens in two steps, similar to the supply of demand. In the first step excess electricity of each region is stored in available storage plants within the region. After that there is a second power exchange routine, analogous to the first power exchange described in section 3.2.3. In this case remaining excess electricity is transferred to be matched with remaining storage capacity. Again this is carried out with a heuristic iteration that stops when either all excess electricity is stored, all storage capacity is used up or after a defined number of iteration loops.

Chapter 4

Modeling of Hydro Power Plants in renpass

4.1 Model of Hydro Storage Plants

4.1.1 Characteristics of Storage Plants

Hydro storage plants consist of one or more hydro turbines connected to a reservoir. The altitude difference between the reservoir and the plant is called head. It determines the energy content of the storage. Some storage plants also have a downstream reservoir that collects the water efflux from the storage plant. In case of a pumped storage plant two reservoirs on different levels are connected by a turbine and a pump, often combined into a reversible turbine.

In Germany pumped storage plants are often built with an artificial upper reservoir that does not have any natural inflow. Those are pure storage plants without natural production. In contrast to that, in the Norwegian system all reservoirs have natural inflow. Figure 4.1 shows the basic principle of storing energy in pumped hydro storage plants.

4.1.2 Hydro Inflow

The amount and timing of hydro inflow to hydro power plants is a very complex process that has to be simplified for the model. Based on the morphology of the terrain each reservoir has a catchment area. All precipitation onto that area will end up in the reservoir at some point in time. In renpass the annual amount of inflow into each

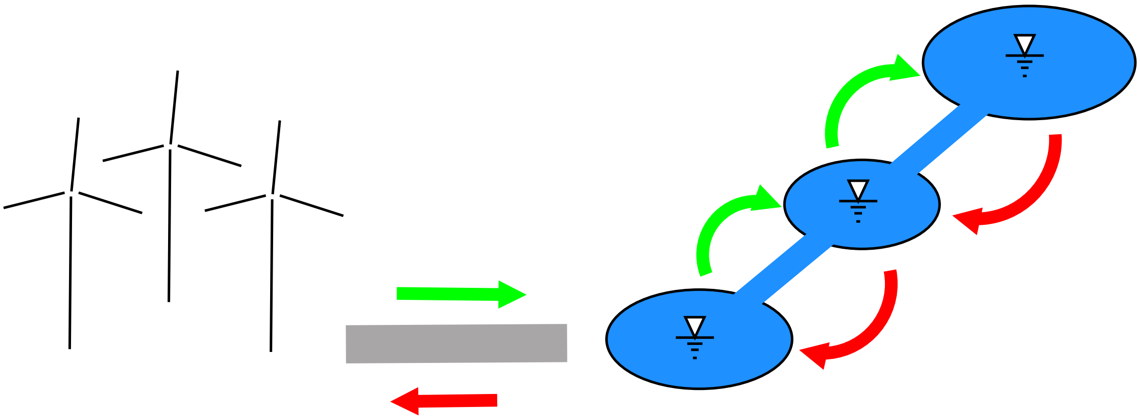

FIGURE 4.1: Schema of storage plants

individual reservoir is specified in the database. The same normalized inflow curve is used for the inflow pattern for all reservoirs. This is an acceptable approach as the inflow is driven by the seasonal pattern of precipitation and snow melt and is thus similar for most reservoirs.

Besides the inflow to reservoirs, which is called regulated inflow, there is inflow that does not flow into a reservoir but directly to the power plant. This is unregulated inflow that can be used for production but cannot be stored. The sources of regulated and unregulated inflow are the same. In the renpass simulations the unregulated inflow is always used for production. This part of the power production is virtually separated from the dispatchable operation and treated as must-run production. After passing the turbine the unregulated inflow will take the same way as the regulated efflux from production into a reservoir, a river or the fjord.

4.1.3 Available Capacity

The operation of storage plants always depends on the water levels in the reservoirs. As shown in equation 4.1 in renpass the available production and pumping capacity is restricted by the installed capacity, the filling level of the upstream reservoir and the filling level of the downstream reservoir.

$$C_{\mathrm{av}} = min(C_{\mathrm{inst}}, R_{\mathrm{up}}, R_{\mathrm{down}}) \tag{4.1}$$

All values in the equation are given in MW.

$C_{\mathbf{av}}$	available production/pumping capacity
$C_{\mathbf{inst}}$	installed production/pumping capacity
$R_{\mathbf{up}}$	restriction of upstream reservoir
$R_{\mathbf{down}}$	restriction of downstream reservoir

To determine the restriction from the upstream reservoir for power production, for every storage plant the sum of water in all upstream reservoirs is converted into MW per time unit of the simulation. The downstream restriction is calculated analogously. In that case available storage space is the restriction and the difference between maximum filling level and current filling level is converted into MW. The power production is restricted by the downstream storage space in order not to spill water that cannot be stored. However, at snow melt when all reservoirs tend to be rather full this restriction can limit the production unduly. In order to prevent that, there is a second condition added. If the upstream reservoir is full, power production will not be limited by storage space of the downstream reservoir. The reasoning behind this is the following: If the upstream reservoir is full and no power can be produced because of downstream restrictions, water will be spilled upstream in the following time steps. In that situation it is preferable to use the water for power production and accept spilling downstream.

For pumping mode the restrictions are opposite. The upstream restriction is the available storage space in the upper reservoir. The restriction of the lower reservoir is the available water for pumping.

For power plants with more than one connected reservoir the values for the reservoirs are added. In case of reservoirs with more than one connected production unit, e.g. when different units of a plant are modeled separately, the values for the reservoir are divided between the units based on installed capacity.

4.1.4 Filling Level Update

After the dispatch and the storage of one time step are completed, the filling levels of the storage reservoirs are updated. Several variables will influence the new filling level of each reservoir. The new filling level is calculated as shown in equation 4.2.

$$fil_{\text{new}} = fil_{\text{old}} + prod_{\text{up}} - prod_{\text{down}} + pump_{\text{down}} \\ -pump_{\text{up}} + inflow + prod_{\text{river}} + prod_{\text{ror}} \tag{4.2}$$

All values in the equation are given in million m^3.

$fil_{\mathbf{new}}$	filling level after the simulation of the time step
$fil_{\mathbf{old}}$	filling level before the simulation of the time step
$prod_{\mathbf{up}}$	upstream production
$prod_{\mathbf{down}}$	downstream production
$pump_{\mathbf{up}}$	upstream pumping
$pump_{\mathbf{down}}$	downstream pumping
$inflow$	inflow into the reservoir
$prod_{\mathbf{river}}$	production of upstream power plants, which is not channeled directly to the reservoir but through a river
$prod_{\mathbf{ror}}$	production of upstream run-of-river plants

For every reservoir the production of upstream and downstream power plants and upstream and downstream pumps is recorded separately. Then the inflow for every time step is added to the filling levels. Additionally water from the production of upstream storage plants, which is first released into a river but ends up in the reservoir, and upstream run-of-river plants is added to the reservoirs.

If changes to the filling level cause reservoirs to be filled above their maximum capacity, this excess water is assumed to spill from the reservoir. If there is another reservoir downstream the spilled water is added to the filling level of that reservoir. If that reservoir also cannot hold the spilled water, it is then added to the next downstream reservoir and so on. Whenever there is no downstream reservoir the spilled water leaves the system. After five spillage routines, the process stops because very few reservoirs have more than five levels below them and the amount of water that could still be added to downstream reservoirs is very low. This remaining spillage also leaves the system. The amount of spillage that happens during the year is an indicator of how well the hydro system is operated in the model. As little water as possible should be spilled.

For the filling level update the relation between reservoirs and storage plants needs to take into account multiple connections as well. The transferred water of a unit with more than one connected reservoir is divided based on the filling level of the reservoirs. For a reservoir with more than one connected storage plant the transferred water of the plants is added.

4.2 Dispatch of Storage Plants

4.2.1 Comparison of Different Algorithms

For hydro power plants, the costs of production cannot be determined fundamentally because there is no price for the energy source. In the operation of hydro power plants the concept of water value is used (see Dueholm and Ravn, 2004). The water value is the opportunity value of the water stored in the reservoir. It depends on the amount of water that is stored, a forecast of the inflow and the expectations for the electricity price. In the modeling in renpass individual bidding by operators and price forecasting cannot be simulated. Instead a method of ranking the hydro power plants to a merit order had to be found that corresponds to individual decisions and ensures an overall reasonable utilization of the hydro resource.

The ranking of the hydro storage plants has to be based on an indicator that reflects the hydro resource availability of the single power plant. Here both the total annual inflow to the power plant and the momentarily available storage level have to be considered. Different rules for the operation are conceivable that include short-term and long-term hydro availability to different degrees:

- Use plants with relatively fuller storage reservoir first.
- Use plants with relatively emptier downstream reservoir first.
- Use plants with more annual inflow per installed capacity first.
- Use plants with reservoirs that are in danger of spilling water first.

In test simulations the following indicators were evaluated:

- **filling level in upper and lower reservoir**: The relative filling levels of upper and lower reservoir are combined, so that higher upstream filling levels and lower downstream filling levels prioritize the plant.
- **filling level transformed into hours of energy production**: The storage content of the upper reservoir is converted into potential hours of production with the energy factor and the installed capacity of the plant. Plants with higher production hours are used first.
- **inflow per installed capacity**: The sum of annual inflow for each plant is related to the maximum usable water volume in one time step. Plants with a higher value are used first.
- **forecast of spillage based on filling level, inflow and maximum storage capacity**: This is described in more detail in section 4.2.2.

Indicator	Variants	Impacts	End filling level (bio m^3)
Filling level	-	neglects inflow and capacity	18.5
Filling level in terms of hours of production	-	neglects inflow	22.5
Inflow per installed capacity	flow into upper reservoir, flow into all upstream reservoirs	neglects filling level	15.0 - 21.5
Spillage forecast	forecast horizon 4 h to 7 d	combination of inflow and filling level	23.7 - 25.1
Seasonal rules	different for snow melt, 4 seasons	not suited for all power plants	22.6 - 23.5

Table 4.1: Hydro merit order algorithm tests

- **a combination of several indicators depending on the time of year**.

The results of the test simulations are shown in table 4.1. There are two main objectives for the algorithm. The first is to reproduce a realistic seasonal filling level curve as shown in figure 2.5. The second is to generate enough power from hydro power plants to cover demand. The algorithm for ordering the hydro power plants directly affects the filling level of the reservoirs. As a measure for the quality of the algorithm the filling level in all reservoirs in Germany and Norway at the end of the year is shown in the table. Ideally this value will reach the filling level at the beginning of the year of 49 billion m^3. However, the simulations in table 4.1 do not include any part-load operation and other variations that have impact on the results as described below. The combination of different measures will lead to the aspired results.

The best results could be achieved with the forecast of spillage. The details of the algorithm will be described in section 4.2.2.

Other parameters that determine the production of the storage plants can be varied as well. One important influencing factor is the extent to which the power plants operate in part-load. In renpass most hydro power plants are modeled as one unit even though they quite often consist of several units. In reality those smaller units will not run in parallel but will be dispatched separately. For example one unit could be running while the other is turned off. Furthermore, hydro power plants reach the highest efficiency not at full power output but around 85 % of rated capacity (Asscociates, 2011, p. 16). So there are several reasons why the simulations should consider part-load operation of hydro power plants.

The following indicators for determining the level of power output for each plant were evaluated:

- **fixed part-load for every plant**: Relative power output is set to a certain level for all plants in all time steps.
- **filling level within boundaries**: The relative power output is determined for each plant in each time step. It is set to the relative filling level but is confined to a fixed range, even if the filling level is higher or lower.
- **power demand**: The ratio of power demand in each time step and peak demand determines the level of power output for each plant.
- **filling level and inflow forecast**: The sum of current reservoir content and forecast inflow in relation to the reservoir capacity sets the part-load level for each plant in every time step.

Table 4.2 shows the results of the part load variations. The rules for part load directly affect the production of the power plants, hence the hydro power production is shown as a measure of the outcome. The objective is to generate enough power so that the demand is covered. A production level of 90 to 100 TWh is needed for that purpose.

Indicator	**Variants**	**Impacts**	**Hydro production**(TWh)
Fixed part load	70 %	all plants treated alike	95
Filling level within boundaries	between 20 % - 40 % and 70 % - 100 %	min and max production level	76 - 78
Power demand	-	even distribution of production	90 - 99
Filling level and inflow forecast	between 20 % and 70 %, forecast 12 - 24 h	includes foresight	87 - 98

Table 4.2: Part load algorithm tests

The overall best results could be achieved with a flexible power output between 20 % and 70 % of installed capacity, depending on the filling level and a forecast for the inflow. This is described in detail in section 4.2.2.

Figure 4.2 shows an overview of 100 simulated test scenarios. It includes the filling level at the end of the year and the hydro power production as the main objectives of the test simulations. There is an obvious and intuitive relationship between filling level and production. In general the higher the production the lower the filling level at the end of the year. However, it can be seen that some dots are farther out on the x-axis and the y-axis than others. That means those test settings do better on both result measures than others. Some have to sacrifice less of one objective for an advance on the other. The aim of the test simulations was to find the best suited algorithm.

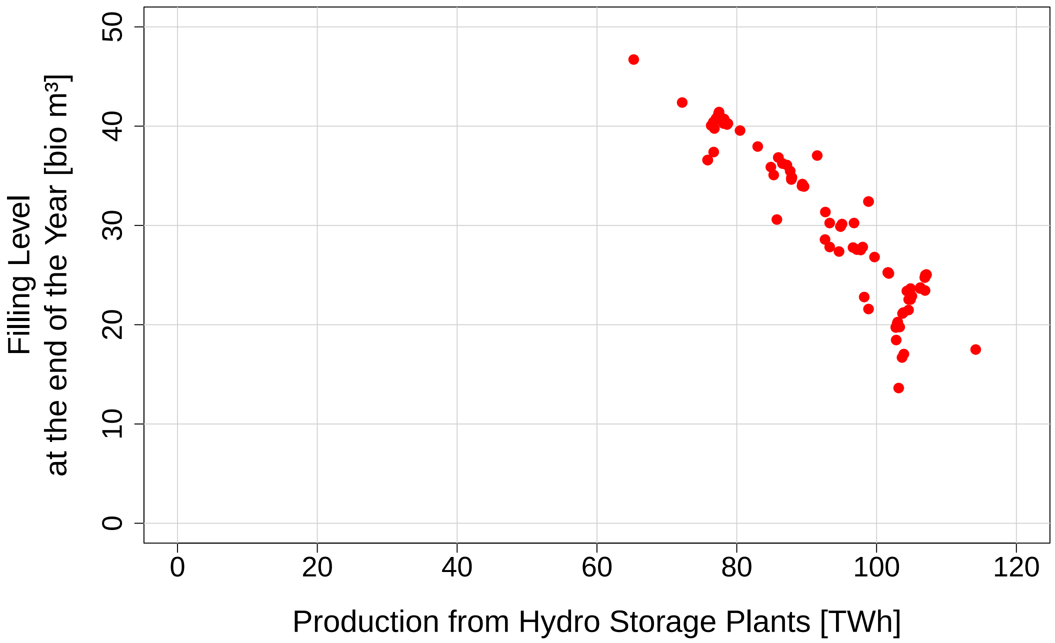

FIGURE 4.2: Filling level at the end of the year and production from hydro storage plants in the simulation tests

4.2.2 Merit Order and Pricing

In the simulations of renpass the forecast of spillage for each storage plant is used as the indicator for arranging the storage plants in the merit order. The forecast of spillage is found by adding the sum of inflow for the next week to the current filling level and subtracting the maximum storage capacity, see equation 4.3. The results improved with the forecast horizon but with decreasing effect. A time frame of one week seems to be a sensible compromise between calculating time and results. If the value is positive, water will spill within the next week when no water is used for power production. If the value is zero the incoming inflow fits exactly and if the value is negative there is still storage capacity left above the inflow of the coming week.

$$spill = fil + \sum_{t}^{t\,+\,1\text{ week}} inflow - fil_{\max} \tag{4.3}$$

$spill$	forecast spillage for each reservoir (mio m^3)
fil	filling level (mio m^3)
t	time step
$inflow$	inflow to the reservoir (mio m^3)
$fil_{\mathbf{max}}$	maximum storage capacity (mio m^3)

The forecast spillage is transformed into energy because the lost energy is the more meaningful indicator to compare different reservoirs. For each storage plant the forecast of spillage for upper and lower reservoir is taken into account. For that purpose the forecast spillage of the reservoirs is related to the storage plants. The value for reservoirs with more than one connected storage plant is divided. When several reservoirs are connected to the same plant the values are added. This is analogous to the allocation of available water for production. The final indicator, the forecast spillage per plant, is then found by equation 4.4. This is a purely theoretical indicator. It is used only as an intermediary for determining the order of operation for the storage plants, and eventually the opportunity costs, and has no physical relation.

$$spillage_{\text{plant}} = spill_{\text{up}} - 1.2 * spill_{\text{low}} \tag{4.4}$$

$spillage_{\mathbf{plant}}$	final ranking indicator, forecast of spillage for each plant
$spill_{\mathbf{up}}$	forecast of spillage for the upper reservoir
$spill_{\mathbf{low}}$	forecast of spillage for the lower reservoir

The forecast of spillage of the lower reservoir is subtracted from the value of the upper reservoir because it works in the opposite direction. When the upper reservoir is in danger of spilling the plant should produce. When the lower reservoir is in danger of spilling the plant should not produce. The factor of 1.2 is included to give a slightly higher weight to the lower reservoir. The ranking of the plants can be exemplified with the four cases shown in table 4.3 that indicate the results of equation 4.4 in each situation.

The weighting of the lower reservoir determines the order between the cases 2 and 3. In the second case both reservoirs are rather empty. In the third case both reservoirs are in danger of spilling. The second case is favored because it will not lead to any spillage. In any case the production is restricted by the available water in the upper

Ranking	**Upper reservoir**	**Lower reservoir**	**Total forecast spillage per plant**
1	full, positive spillage forecast	empty, negative spillage forecast	very high
2	empty, negative spillage forecast	empty, negative spillage forecast	positive
3	full, positive spillage forecast	full, positive spillage forecast	negative
4	empty, negative spillage forecast	full, positive spillage forecast	very low

Table 4.3: Ranking of hydro plants

reservoir. When the upper reservoir is rather empty, the production will be limited. The test simulations showed better results with the algorithm that includes the weighting of the lower reservoir with the factor 1.2.

The level of power output is based on the current relative filling level of the upstream reservoir and the relative inflow for the next 12 hours. The sum of both values determines the level of production as a percentage of power output. However, relative power output of the plants does not vary between 0 and 100 % but it is confined to the range of 20 % to 70 %. When the upstream reservoir of a power plant is full, the part-load settings are dropped and the power plant operates at full capacity.

In the dispatch of power plants the merit order is reflected in terms of production costs in €/MWh. In the renpass simulations there is no price forecast to determine the water value for the hydro power plants. Instead day-ahead electricity prices for 2012 from the power exchange Nord Pool Spot (Nord Pool Spot, 2013a) are taken. Those prices currently determine the value of the hydro resource. Price projections up to 2050 are inherently uncertain. This approach is based on the basic premise that the energy market will be similar to today's market. Also it is assumed that hydro power plants are price takers and that the competitors, that determine the range of prices, will still be the same. Hydro power plants will still have higher (opportunity) costs than wind and solar power plants and they will still have lower costs than gas fired power plants which could be the main competitor in supplying flexible capacity. Assuming a similar bidding strategy than today seems a feasible approximation.

From scenario runs data on the forecast spillage per plant can be collected. These data are then related to the Nordic system price for 2012 based on the quantiles, which give the boundaries between shares of the data. The relation is converse: high values for forecast spillage per plant have to result in low price bids and vice versa. Figure 4.3 shows the data points for specific quantiles. The 5 % data pair, for example, indicates that 5 % of spillage data are lower than the x-value and 5 % of the price data are higher than the y-value.

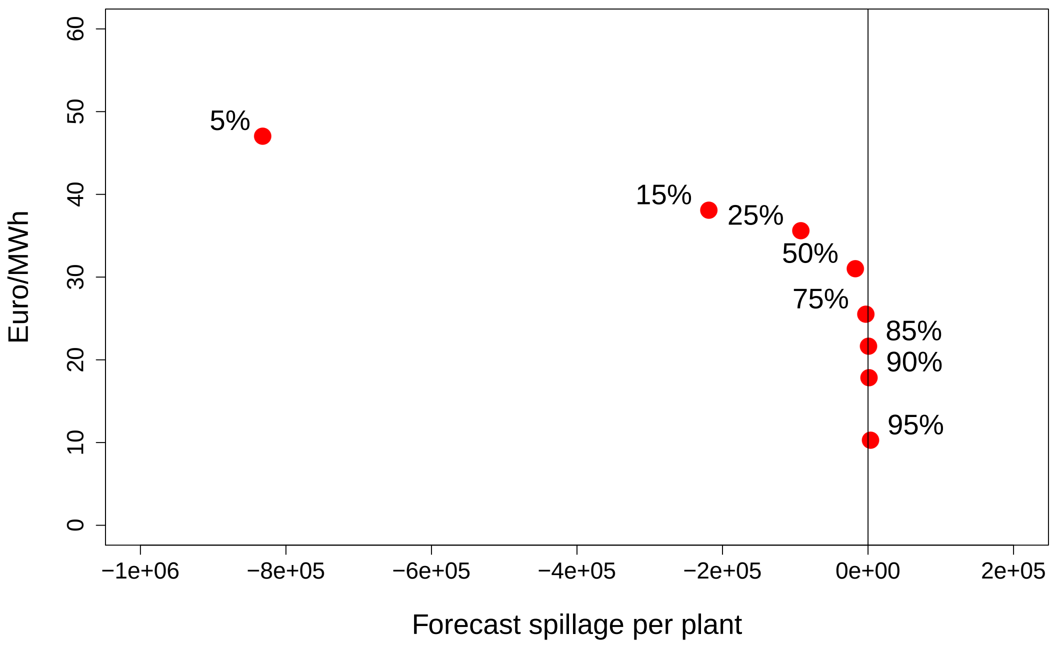

FIGURE 4.3: Relation between forecast spillage per plant and price bid for hydro storage plants

Those data points are used for the calculation of the price bids for all hydro power plants. For every value of forecast spillage per plant a price bid is determined by interpolating linearly between the two nearest values. A floor for the price bids is set to 5 €/MWh and the highest possible price bid is 60 €/MWh. This range covers more than 97 % of the hourly Nordic system prices in 2012.

4.2.3 Operation of Pumps

Throughout the whole model the operation of pumps is regarded from a technical rather than a market perspective. The disptach of pumps is based only on a technical indicator as well, without any reference to prices. The pumps only absorb excess electricity that comes at zero price as explained in section 3.2.4. Pumps are ordered by the relative filling level of their upper reservoir. By pumping, water is transported from the lower to the upper reservoir. Those pumps that have little water in the upper reservoir and thus still much storage space should be used first. On the other hand pumps with an upper reservoir which is already quite full should be at the end of the merit order. The filling level of the lower reservoir is also included in the dispatch as the available capacity is restricted by the installed capacity and the filling levels of the upper and lower reservoir as described in section 4.1.3.

4.3 Additional Pumped Storage Capacity

In addition to the pumped storage capacity that already exists today, more pumped storage capacity can be included in the renpass scenarios. For this thesis the modeling of new storage plants is based on specific projects. Those projects that can be included in the scenarios are listed in the model database. They are attributed with all the characteristics that existing storage plants also have, like installed capacity and head. The order of the projects in the database determines also the order in which the storage plants are included in the scenarios. For each scenario new storage plants are included as far as needed to satisfy the total storage capacity per region, specified by the user. There is no limited lifetime for the existing storage plants. Rather it is assumed that hydro storage plants once built will not be decommissioned but will be renovated as needed to keep them in operation. The new pumped storage plants and the order in which they are included in the simulations are described in section 6.4.

4.4 Model of Run-of-River Plants

In Germany and Norway run-of-river plants are modeled individually. The production curve is based on flow data. The flow data are used to model the seasonal pattern of run-of-river production and the difference between different weather years. This is dealt with differently for Germany and Norway and will be described separately in the next two sections. For all other countries the run-of-river production is modeled as constant production over the whole year. The production from run-of-river plants is considered as must-run production and subtracted from the load to determine the residual load as described in section 3.2.1.

4.4.1 Run-of-River Plants in Germany

For the production from run-of-river plants in Germany a value for capacity utilization is assumed based on production data of run-of-river plants since 2002 from Statistisches Bundesamt (2013b). It varies between 45 % and 65 % with 55 % as the medium value and is linked to the scenario parameter of the weather year. The production curve is based on level meter measurements in several rivers. Each run-of-river plant is assigned to a level meter based on the location.

The level data are transformed into production mathematically so that for each plant the minimum production is 0, the maximum is the installed capacity of the plant and the capacity utilization is the determined value. The production of the single plants is then aggregated for the dispatch regions. Figure 4.4 shows the exemplary simulation of run-of-river production in Germany for 2050.

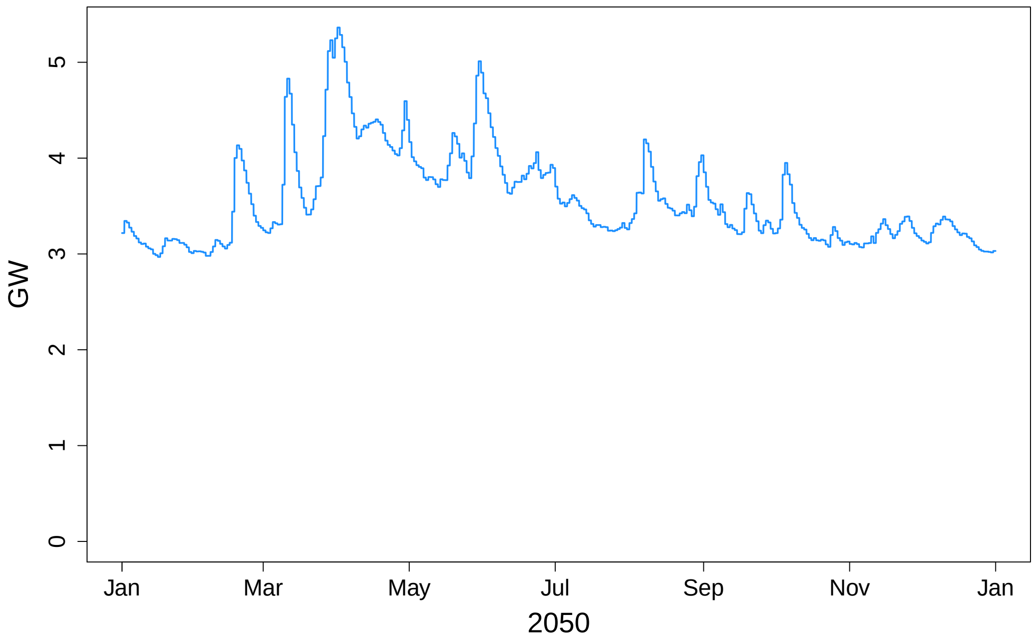

FIGURE 4.4: Run-of-river electricity production in Germany, exemplary simulation for 2050

4.4.2 Run-of-River Plants in Norway

Inflow data for Norway are normalized to the annual inflow of a medium inflow year. To model the production of run-of-river plants in Norway for each plant the normalized inflow curve is scaled to the total annual inflow. The normalization of the inflow data is described in section 6.3. The inflow is converted into electricity production with the energy yield per m^3 of each plant. The energy yield depends on the head of the plant and the efficiency. Inflow that would lead to a corresponding electricity production above the installed production capacity cannot be used. In that case the production has to be cut-off at installed capacity. In figure 4.5 the simulated run-of-river production for Norway is shown.

The hydro system of Norway is very complex and interconnected. The water efflux from run-of-river plants will flow to other run-of-river plants and also into the reservoirs of

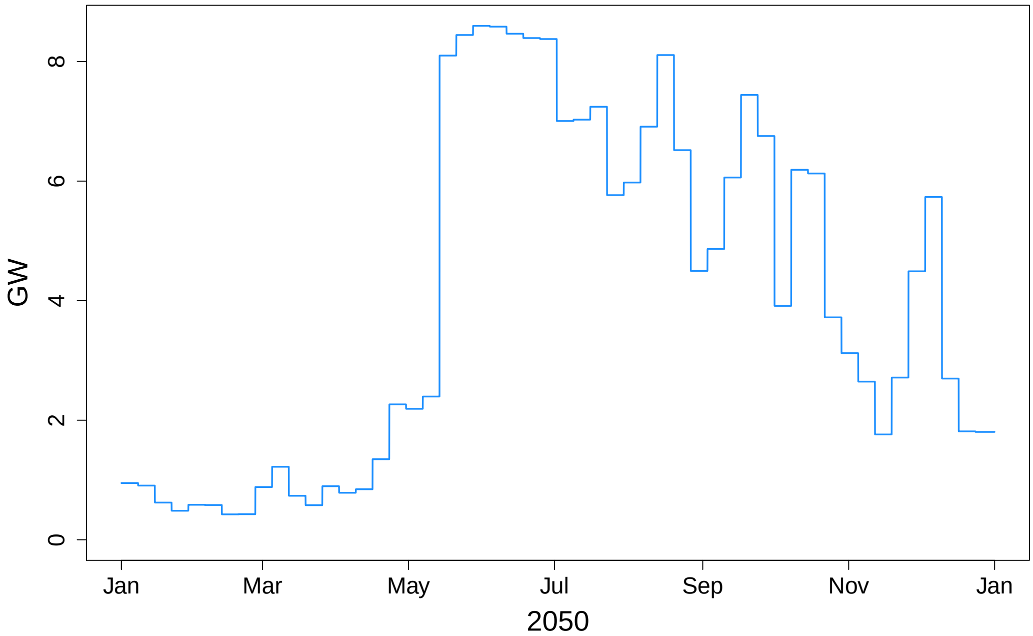

FIGURE 4.5: Run-of-river electricity production in Norway, simulation with current capacity

storage plants. As the amount of production is determined directly for run-of-river plants inflow to the run-of-river plants from storage plants can be disregarded in the model. The opposite case, inflow from run-of-river plants to storage reservoirs, however needs to be considered. For every run-of-river plant the next downstream reservoir, if there is one, is determined from the database. All inflow to the run-of-river plant is then passed through to the reservoir and will be included when determining the reservoir filling levels.

Chapter 5

General Input Data for renpass

5.1 Load Data

For the modeling of the electricity system, data on electricity demand are crucial. ENTSO-E (European Network of Transmission System Operators for Electricity) publishes load data for many countries in Europe. For all countries included in renpass, load data are taken from European Network of Transmission System Operators for Electricity (2013). The data include load from all installations connected to the network and network losses. Consumption from pumped storage plants and other storage plants is excluded. The load data do not represent the total consumption of the countries but only the part that is supplied via the electricity grid. The share represented is between 80 % and 100 % and differs between countries (European Network of Transmission System Operators for Electricity, 2010a). For Germany approx. 91 % of the total demand are included in the data. Currently load data for the years 2010 and 2011 can be used for the modeling as for those years load data are available for all countries included in renpass.

For Germany load data of the grid control areas are published by the four transmission system operators. However, those data sets differ in what is included in the data and how they were derived. In order to get a consistent set, also for Germany load data from the ENTSO-E were used. To derive load data for the 21 modeling regions in Germany the load curve is scaled for each region. Different indicators, including inhabitants and gross domestic product, were tested using the load data from the transmission system operators. The best indicator for dividing the load onto the four control areas was derived from Amprion et al. (2009). The paper includes regional distribution of production and load and the resulting load flows on the high voltage grid for four different grid situations combining high and low wind energy production and high and low electricity load. Taking the mean share of load in these four situations for each region as an indicator showed the best results. This was accordingly used for the division of load onto the 18 onshore modeling regions.

5.2 Weather Data

Weather data are needed to simulate the electricity production from the weather dependent wind, solar and run-of-river power plants. Data on wind speed, solar radiation and hydro inflow is used for the simulations. Inflow data for the hydro power production are described in chapter 6. In renpass the weather years 1998, 2003, and 2010 can be selected.

The German Weather Service (DWD) provides weather data for Germany via the Web-based Weather Request and Distribution System Webverdis (Deutscher Wetterdienst, 2013). For 62 weather stations data are available free of charge. Data from more stations can be purchased. Wind speed data from five free weather stations are used for the simulations. Data on solar radiation from 38 weather stations was purchased by the University of Flensburg (Deutscher Wetterdienst Klima- und Umweltberatung, 2012).

In German waters, offshore wind measurements are collected on the FINO offshore platforms 1, 2 and 3 (Forschungs- und Entwicklungszentrum Fachhochschule Kiel GmbH, 2013). FINO 1 in the North Sea off Lower Saxony operates since 2003. FINO 2 was constructed 2007 in the Baltic Sea. FINO 3 operates since 2009 in the North sea off Schleswig-Holstein. Wind speed data for 2010 from these three stations are included in the renpass database (Bundesamt für Seeschifffahrt und Hydrographie, 2013). For the calculation of offshore wind energy production these data are supplemented with data from onshore weather stations near the coast in order to better simulate distributed production at different locations.

Norwegian weather data are publicly available from the Norwegian Meteorological Institute via the platform eKlima (Norwegian Meteorological Institute, 2013). For use in renpass wind speed data from five weather stations for the years 1998, 2003 and 2010 were selected. For the year 2010 additionally wind speed measurements from one offshore platform are used. No irradiation data for Norway are available in renpass as solar power is not expected to play a large role in Norwegian energy supply.

Figure 5.1 shows a comparison of the three weather years for wind speed, solar radiation, and hydro inflow based on data from the German weather stations and Norwegian inflow data. For clarity the mean of each data series is normalized to the medium year. That means the medium year among the three weather years 1998, 2003, 2010 is represented as 1.0 for each data series and the mean of the other years relative to that.

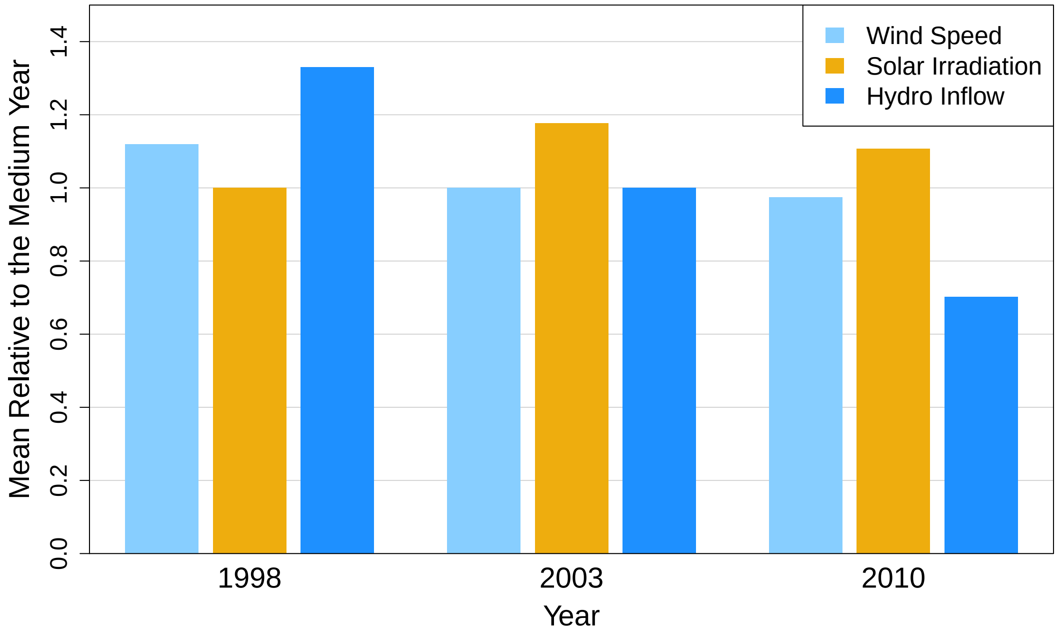

FIGURE 5.1: Comparison of model weather years

Data on hydro inflow are not available for the weather years used in renpass. Data from earlier years are used and attached to the model weather years. This is described in detail in section 6.3.

For the other countries data on wind speed and solar irradiation from five stations for each country were provided by Meteo Group (Meteo Group Deutschland GmbH, 2012).

5.3 Renewable Plant Data

In Germany all renewable energy plants that were installed in the framework of the renewable energy act (Energie-Einspeise-Gesetz, EEG) have to be recorded and published by the transmission system operators (TSOs). However, TSOs use different data formats, the publication is often delayed and data quality is partly poor. The German Section of the International Solar Energy Society (Deutsche Gesellschaft für Sonnenenergie e.V.) has voluntarily undertaken to collect, process, verify and combine the data to visualize the use of renewable resources in Germany in the EnergyMap. A register with more than one million renewable energy plants is available for download (Deutsche Gesellschaft für Sonnenenergie e.V., 2013). It contains the EEG plants with information on installed capacity, renewable energy technology, and location. From this register the installed capacity for each model region was derived by relating each plant to the appropriate region and aggegrating the capacity per region and energy source. Information on plants that are not installed in the framework of the EEG are not in the database. This applies to larger plants that are not supported by the feed-in tariff and older plants that were in operation before the EEG regime started. The older renewable energy plants are mainly hydro power plants. The data sources for hydro power plants are described in chapter 6. For wind and solar energy plants the EnergyMap should be a good representation of the installed capacity.

5.4 Grid Data

Data on the European transmission grid between countries can be collected directly from ENTSO-E (European Network of Transmission System Operators for Electricity, 2010b). ENTSO-E publishes a matrix with net transfer capacities (NTC). Net transfer capacities are assessed in a harmonized way and give the maximum exchange capacity between countries, taking into account interdependencies between the grid on different borders of a country. NTC values are specified for summer and winter, the most recent matrices being summer 2010 and winter 2010-2011. The values also differ according to the direction of the flow. For each border the overall lowest values were taken.

For grid connections within Germany no net transfer capacities are published. To derive grid capacity between regions a grid map was used (Schnug, 2006). By layering the grid map over a map with the model regions, the number of electric circuits between two regions can be counted and their voltage can be read. From the number of circuits the transfer capacity in MW can be calculated as follows (based on Deutsche Energie-Agentur, 2010b, p. 271):

$$C = \frac{n * I_{max} * U * \sqrt{3} * f}{1000} \tag{5.1}$$

C transfer capacity (MW)

n number of circuits between two regions

$\mathbf{I}_{max}$ maximum amperage, 2720 A: According to Deutsche Energie-Agentur (2010b, p. 291) existing overhead lines are usually designed to allow amperage up to 2720 A per circuit.

U voltage of the line in kV, in Germany usually 220 kV or 380 kV

f utilization factor 0.7: This factor is used to account for n-1 security in the whole electric grid.

Chapter 6

Input Data for Hydro Modeling

6.1 Hydro Storage Plants

All existing pumped storage plants in Germany are included in the renpass database. Table 6.1 shows the plants with their parameters and data sources. In total the production capacity is 6886 MW and the pumping capacity is 6178 MW.

Name	**Turbine capacity** (MW)	**Pump capacity** (MW)	**Head** (m)	**Start-up**	**Sources**
Bleiloch	80	36	44	1932	Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien (2009, p. 25), Vattenfall Europe Generation (2013b)
Erzhausen	220	220	300	1964	E.ON Kraftwerke (2013), Statkraft (2013), TenneT (2012)
Finnentrop Rönkhausen	140	140	277	1969	Mark E (2013)
Geesthacht	120	93	80	1958	Vattenfall Europe Generation (2013c), Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien (2009, p. 25), Köppke (2012, p. 38)

Name	**Turbine capacity** (MW)	**Pump capacity** (MW)	**Head** (m)	**Start-up**	**Sources**
Glems	90	68	283	1964	EnBW Kraftwerke AG (2013a), Giesecke and Mosonyi (2005, p. 100)
Goldisthal	1060	1110	302	2004	Vattenfall Europe Generation (2013d), Giesecke and Mosonyi (2005, p. 664)
Häusern	144	100	200	1931	Schluchseewerk (2013c)
Happurg	160	126	200	1955	E.ON Kraftwerke (2013), Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien (2009, p. 25)
Herdecke	153	153	150	1989	RWE Power (2013)
Hohenwarte	380	372	56	1942	Vattenfall Europe Generation (2006), Vattenfall Europe Generation (2013e), Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien (2009, p. 25), Bundesnetzagentur (2013)
Langenprozelten	168	154	300	1976	E.ON Kraftwerke (2013), Rhein-Main-Donau AG (2013)
Leitzachwerk	93	82	128	1983	Stadtwerke München (2010, p. 14f)
Markersbach	1050	1140	288	1979	Vattenfall Europe Generation (2013f)
Niederwartha	40	40	288	1930	Vattenfall Europe Generation (2013g), Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien (2009, p. 25)
Reisach	105	84	179	1955	GDF Suez (2013)
Säckingen	352	352	400	1967	Schluchseewerk (2013a)

Name	Turbine capacity (MW)	Pump capacity (MW)	Head (m)	Start-up	Sources
Schwarzenbachwerk	46	20	357	1926	EnBW (2011), Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien (2009, p. 25)
Tanzmühle	35	25	122	1959	GDF Suez (2013)
Waldeck	620	576	280	1932	E.ON Kraftwerke (2013), Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien (2009, p. 25)
Waldshut	158	80	160	1951	Schluchseewerk (2013d)
Wehr	992	980	625	1976	Schluchseewerk (2013b)
Wendefurth	80	72	126	1967	Vattenfall Europe Generation (2008), Bundesverband Erneuerbare Energie e.V. and Agentur für Erneuerbare Energien (2009, p. 25)
Witznau	220	128	250	1943	Schluchseewerk (2013e)

Table 6.1: Pumped storage plants in Germany

Also the German hydro storage plants without pumping capacity as shown in table 6.2 are included in the model.

Data on Norwegian hydro storage plants are published by the Norwegian regulator NVE (Norges Vassdrags- og Energidirektorat, 2010b). There are 434 storage plants with a total capacity of 23.4 GW and 9 pumped storage plants with a total capacity of 1.3 GW included in the renpass database. Furthermore there are 19 pumping plants without turbine capacity. The sum of production capacity is 24.7 GW and the sum of pumping capacity is 1.4 GW.

In figures 6.1 and 6.2 storage plants in Norway are displayed by their size category and discharge. Discharge indicates the course of the water after leaving the power plant. It can either flow into a downstream reservoir, a river or the fjord. Water that is let out into a river could also flow into a downstream reservoir eventually. This is not depicted

Name	Installed capacity (MW)	Head (m)	Start-up	Sources
Eckertal	0.3	48	1997	Harzwasserwerke (2008, p. 14)
Granetal	0.18	57	1972	Harzwasserwerke (2008, p. 16)
Heimbach	16	110	1905	RWE (2005)
Helminghausen	1	3	1924	E.ON Kraftwerke (2013)
Hemfurth	20	3	1915	E.ON Kraftwerke (2013)
Hohenwarte	3	56	1959	Vattenfall Europe Generation (2006)
Kleine Kinzig	0.58	3	1985	Wasserversorgung Kleine Kinzig (2011)
Murgwerk	22	145	1918	EnBW (2011)
Niederdruckwerk	2.4	6.75	1918	EnBW (2011)
Obermaubach	0.65	7	1969	RWE Innogy (2013d), RWE Innogy (2013f), Wasserverband Eifel-Rur (2010), Ohrem and Ohrem (2012)
Odertalsperre	4.88	60	1934	Harzwasserwerke (2008, p. 13)
Okertal	4.41	80	1956	Harzwasserwerke (2008, p. 15)
Olef	1.45	52	1959	RWE Innogy (2013d), RWE Innogy (2013f), Ohrem and Ohrem (2012)
Ortenberg Lißberg	1.5	65	1923	Oberhessische Versorgungs- und Verkehrsgesellschaft mbH (2013), Wikipedia (2013b)
RADAG Rheinkraftwerk	84	9.16	1933	RADAG (2009)
Raumünzachwerk	0.55	68	1923	EnBW (2011)
Roßhaupten	45.5	35.4	1954	E.ON Kraftwerke (2013), Bundesministerium für Wirtschaft und Arbeit (2003, p. 5-23)
Schwammenauel	14	65	1959	RWE Innogy (2013d), RWE Innogy (2013f), Ohrem and Ohrem (2012)
Soesetal	1.28	54	1932	Harzwasserwerke (2008, p. 12)
Speicherseekraftwerk	1.3	3.5	1951	E.ON Kraftwerke (2013)
Walchensee	124	200	1924	E.ON Wasserkraft (2011)
Warmatsgund	4.72	374	1992	Gemeindewerke Oberstdorf (2013), Tourismus Oberstdorf (2010)

TABLE 6.2: Hydro storage plants in Germany

in the figures. Figure 6.1 shows the number of plants per category and figure 6.2 shows the sum of installed capacity.

Figure 6.1 illustrates that there is a large number of small hydro power plants in Norway. However, as can be seen in figure 6.2 the largest share of capacity is installed in plants between 131 MW and 250 MW. Noteworthy is also that in the category of plants with more than 500 MW most of the installed capacity is equipped with a lower reservoir.

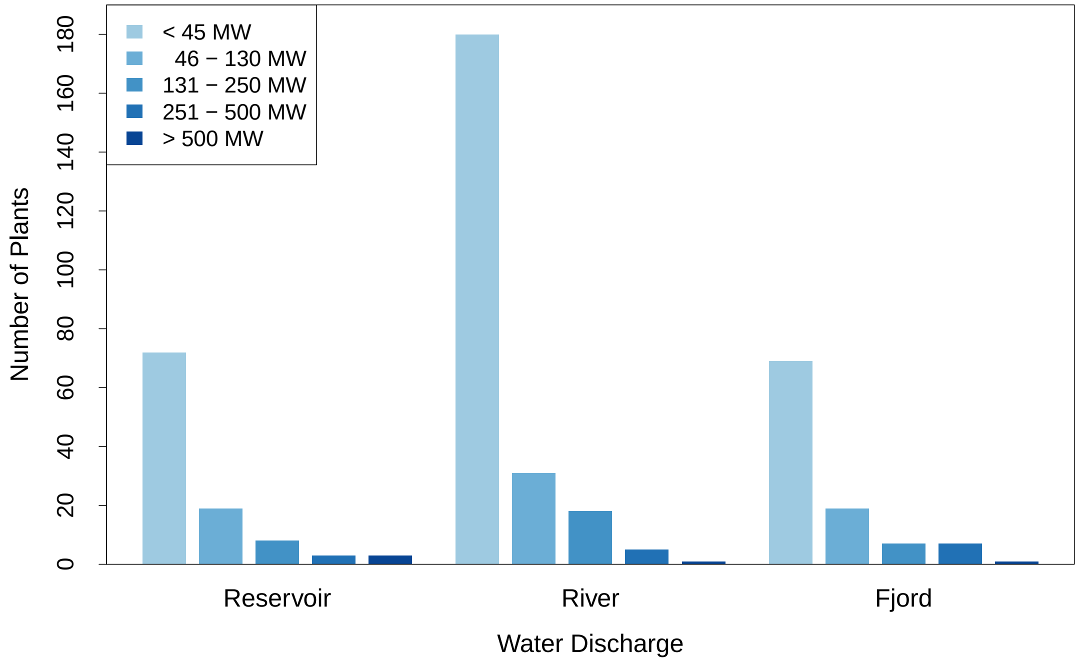

FIGURE 6.1: Number per size and discharge category of storage plants in Norway

The Swedish hydro storage capacity is 10.8 GW and the pumped storage capacity 108 MW (Ess et al., 2012, p. 29). This capacity is modeled in renpass with four generic storage plants of equal size. For the storage volume a factor of 70 MWh/MW is assumed. For Denmark no storage plants are included in the simulations.

6.2 Reservoirs

In order to model the operation of the storage plants, knowledge on the storage reservoirs is crucial. For each hydro storage plant the connected upper and lower reservoirs are recorded in the model database. There are storage plants with more than one upper or lower reservoir and also reservoirs with more than one connected plant. For Germany this information was collected together with information on the storage plants. For each reservoir data on the storage volume and the amount of natural inflow are necessary for

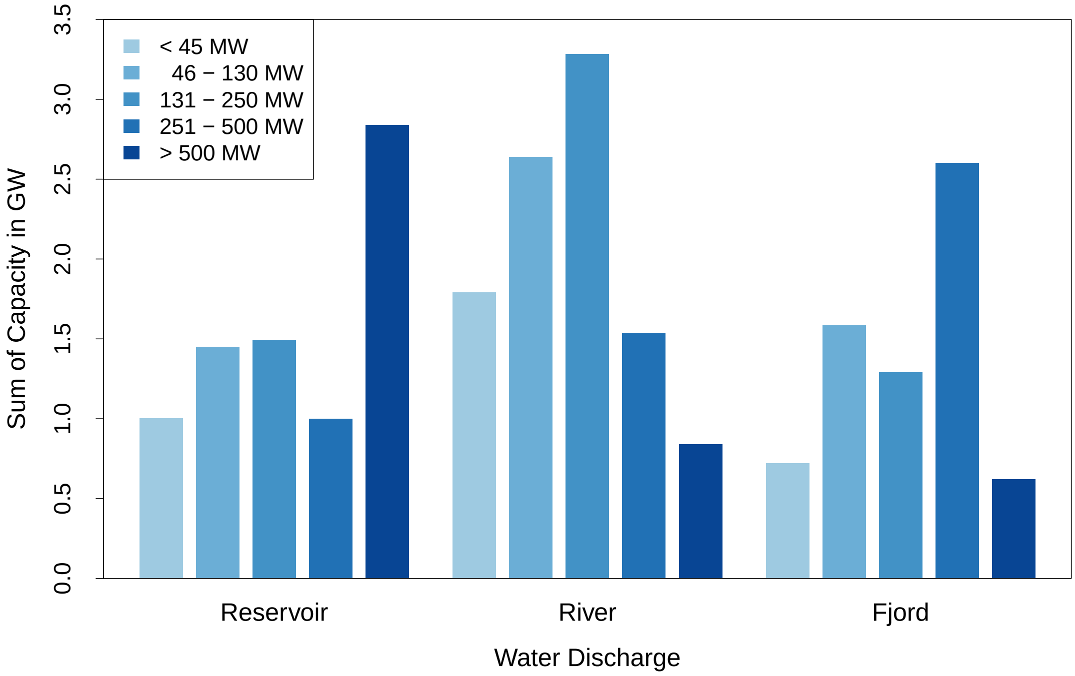

FIGURE 6.2: Sum of capacity per size and discharge category of storage plants in Norway

the modeling. Additional relevant data on the surface area and the water level boundaries could not be collected for every reservoir. Table 6.3 shows the German reservoirs with their attributes and data sources.

Most German pumped storage plants are constructed as pure storage plants. They often have an artificial upper reservoir without natural inflow. According to Heimerl (2005) only 25 % of the produced energy from pumped storage plants in Germany originates from natural inflow. In some cases the lower reservoir is connected to a river (personal communication with Wolfgang Bogenrieder, February 2012). That means that water is flowing through the lower reservoir. However, this does not affect the water level and thus has no impact on the operation of the plant.

Name	**Storage volume** (mio m^3)	**Inflow** (mio m^3)	**Sources**
Affolderner See	7.6	0	Quaißer (2011a)
Albbecken	2.2	0	Quaißer (2011b)
Aubecken	2.17	0	Schluchseewerk (2013d)
Ausgleichsbecken Forbach	0.2	420	EnBW Kraftwerke AG (2012, p. 16), inflow calculated from production
Bleilochtalsperre	215	0	Vattenfall Europe Generation (2013b)

Name	**Storage volume** (mio m^3)	**Inflow** (mio m^3)	**Sources**
Burgkhammer	5.64	0	Vattenfall Europe Generation (2013b)
Diemelsee	19.9	340	Quaißer (2011c), inflow calculated from production
Eckertalsperre	13.3	3.4	Harzwasserwerke (2008)
Edersee	199.3	650	Quaißer (2011d), Wikipedia (2013a)
Eggbergbecken	2.1	73.5	Schluchseewerk (2013a), inflow calculated from production
Eichicht	5.21	0	Vattenfall Europe Generation (2006)
Erzhausen Oberbecken	1.618	0	Statkraft (2013)
Erzhausen Unterbecken	1.516	0	Statkraft (2013)
Forggensee	165	2198	Quaißer (2011e)
Geesthacht Oberbecken	3.8	0	Vattenfall Europe Generation (2013c)
Glems Oberbecken	0.9	0	EnBW Kraftwerke AG (2013a)
Glems Unterbecken	1.2	0	EnBW Kraftwerke AG (2013a)
Glingetalsperre	0.95	0	Mark E (2013)
Goldisthal Oberbecken	12	0	Vattenfall Europe Generation (2013d)
Goldisthal Oberes Schwarzatal	17.7	0	Vattenfall Europe Generation (2013d)
Granetalsperre	46	5	Harzwasserwerke (2008)
Happurg Oberbecken	1.8	0	Quaißer (2011f)
Happurger Stausee	1.3	0	Quaißer (2011f)
Hengsteysee	3.3	0	Quaißer (2012)
Herdecke Oberbecken	0.59	0	RWE Power (2013)
Hillersbach	0.16	30	Wikipedia (2013c), inflow calculated from production
Hirzenhain	0.04	7.5	Wikipedia (2013c), inflow calculated from production
Hohenwarte II Oberbecken	3.28	0	Vattenfall Europe Generation (2013e)
Hohenwarte Stausee	182	0	Vattenfall Europe Generation (2006)
Hornbergbecken	4.4	0	Schluchseewerk (2013b)
Ismaninger Speichersee	11	606	Quaißer (2011j), inflow calculated from production
Kainzmuehlspeicher	1	0	Quaißer (2011g)
Kirschbaumwasen	0.35	225	Keller (2012, p. 153), inflow calculated from production
Kochelsee	184.7	0	Wasserwirtschaftsamt Weilheim (2012)
Langenprotzelten Oberbecken	1.863	0	Quaißer (2011h)

Name	Storage volume (mio m^3)	Inflow (mio m^3)	Sources
Langenprotzelten Unterbecken	1.863	0	Quaißer (2011h)
Leitzachwerk Unterbecken	2	0	Stadtwerke München (2010)
Markersbach Oberbecken	6.5	0	Vattenfall Europe Generation (2013f)
Markersbach Unterbecken	7.7	0	Vattenfall Europe Generation (2013f)
Mettmabecken	1.7	0	Quaißer (2011i)
Niederwartha Oberbecken	2.9	0	Vattenfall Europe Generation (2013g)
Niederwartha Unterbecken	2.5	0	Vattenfall Europe Generation (2013g)
Odertalstausee	30.6	44	Harzwasserwerke (2008)
Okertalsperre	47.4	64	Harzwasserwerke (2008)
Oleftalsperre	19.3	33	Wasserverband Eifel-Rur (2013b)
Rabenleite	1.5	0	GDF Suez (2013)
Rheinstauraum Waldshut	1	0	Schluchseewerk (2013d)
Rheinstauraum Ryburg-Schwörstadt	0.9	0	Schluchseewerk (2013a)
Rheinstauraum Säckingen	1	0	Schluchseewerk (2013a)
Roenkhausen Oberbecken	0.95	0	Mark E (2013)
Rurtalsperre	203	157	Wasserverband Eifel-Rur (2013a), inflow calculated from production
Sammelbecken Erbersbronn	0.02	12	Keller (2012, p. 153), inflow calculated from production
Schluchsee	108	88.7	Schluchseewerk (2013c), Turtur (2002, p. 7)
Schwarzabecken	1.29	0	Schluchseewerk (2013c)
Schwarzenbachstausee	14	0	Keller (2012, p. 153)
Seehamer See	2	0	Stadtwerke München (2010)
Sösetalsperre	22.5	11.7	Harzwasserwerke (2008)
Stausee Obermaubach	1.65	376.5	Wasserverband Eifel-Rur (2010)
Talsperre Kleine Kinzig	13	15	Wasserversorgung Kleine Kinzig (2011), inflow adjusted to represent medium inflow
Trausnitzspeicher	1.5	0	GDF Suez (2013)
Urfttalsperre	45.51	168	Wasserverband Eifel-Rur (2013c)
Walchensee	110	612	E.ON Wasserkraft (2011), inflow calculated from production
Waldeck 1 Oberbecken	0.74	0	Quaißer (2011a)
Waldeck 2 Oberbecken	4.4	0	Quaißer (2011a)

Name	Storage volume (mio m^3)	Inflow (mio m^3)	Sources
Warmatsgund Oberbecken	0.03	15	Tourismus Oberstdorf (2010), inflow calculated from production
Wehrabecken	4.1	0	Schluchseewerk (2013b)
Wendefurth Oberbecken	1.97	0	Vattenfall Europe Generation (2008)
Wendefurth Unterbecken	9.2	0	Quaißer (2011k)
Witznaubecken	1.35	0	Schluchseewerk (2013d)

Table 6.3: Reservoirs in Germany

Information on Norwegian hydro reservoirs is included in the data set provided by NVE (Norges Vassdrags- og Energidirektorat, 2010b). There are 903 reservoirs in the database. It includes the surface area of the reservoirs, the regulated water levels, and the storage volume in million m^3. There is furthermore a connection to a list of inflow fields that form the catchment areas and feed the reservoirs. For each inflow field the area and the annual inflow is given. From those figures and the connection to the reservoirs the sum of annual inflow to each reservoir can be derived.

6.3 Inflow Curve

The German inflow curve is derived from data from the German hydrological yearbook. They are published in different sections by the environmental agencies of the federal states and contain flow and water level measurements from a large number of level meters in German rivers. For the inflow to the storage plants the level meter Rheinfelden, located in the upper part of the river Rhein, from LUBW Landesanstalt für Umwelt (2009) was selected. A level meter from south-western Germany was chosen as most hydro storage plants are located in that area. Figure 6.3 shows the discharge curve of Rheinfelden from the year 2006. The level meter data are described in more detail in section 6.5. Flow data from the level meter Rheinfelden were normalized so that the annual flow adds up to one. This curve is then multiplied by the amount of annual inflow for each reservoir. As described above in Germany only the storage plants without pumping and some of the pumped storage plants have natural inflow.

The inflow curve of Norwegian reservoirs is based on inflow data that were kindly provided by the Norwegian University of Science and Technology (NTNU) and SINTEF Energy Research (Norwegian University of Science and Technology and SINTEF Energy

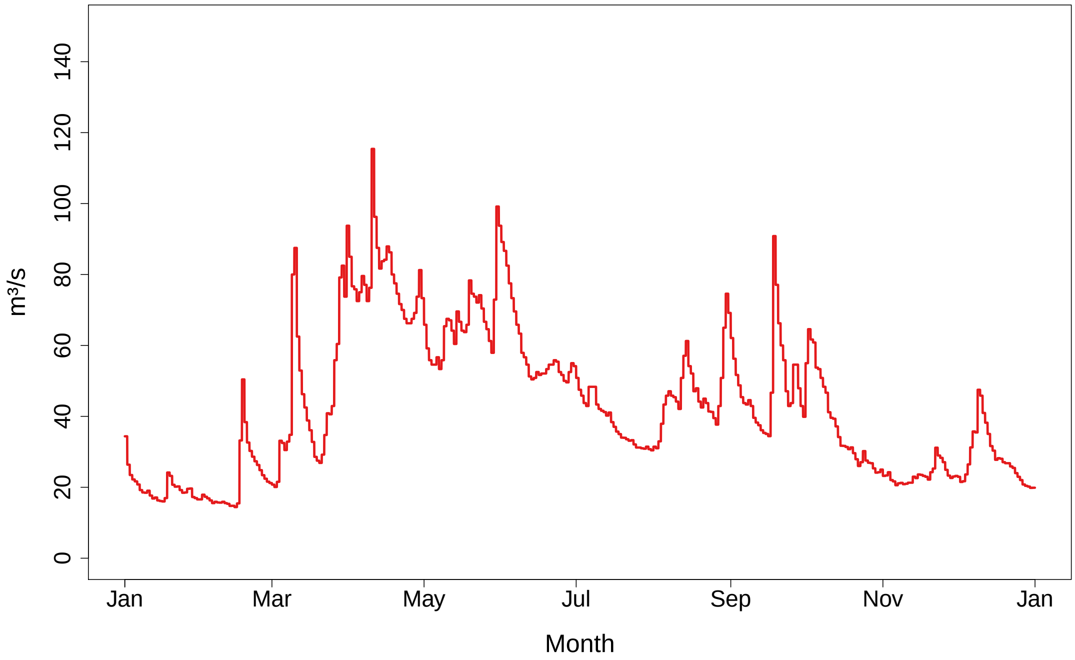

FIGURE 6.3: Inflow curve for Germany

Research, 2010). They contain weekly inflow in GWh for the years 1951 to 1990. For the modeling in renpass three years were selected: the year with the lowest total inflow (1969), the year with the highest total inflow (1990) and a medium year (1979). In the historic data there is an increasing trend of total inflow over the years. This is due to the exploitation of new catchment areas. For that reason a year with total annual inflow slightly above the historic average was selected as the medium inflow year for the renpass scenarios. The weekly figures have been equally distributed for hourly or quarter hourly inflow throughout the week. For the simulations the pattern of the inflow curves as well as the relative annual sums are used. All three years were scaled to the sum of the medium inflow year. For each reservoir the inflow curve is multiplied with the sum of annual inflow. That means that when the medium year is selected for the modeling, every reservoir has exactly the sum of annual inflow given in the database as the multiplying factor, the inflow curve, adds up to one over the whole year. For the low inflow year every reservoir receives 70 % of the indicated sum and for the high inflow year 133 %. The distribution of the annual inflow throughout the year is determined by the form of the respective curve. The inflow curve is not differentiated regionally but the same curve is used for all reservoirs in Norway. It is also used for unregulated inflow directly to the power plants. Figure 6.4 shows the inflow curves for Norway.

In renpass the weather years 1998, 2003 and 2010 are used. For those years no inflow data are available. The inflow years 1969, 1979 and 1990 were assigned to the model years

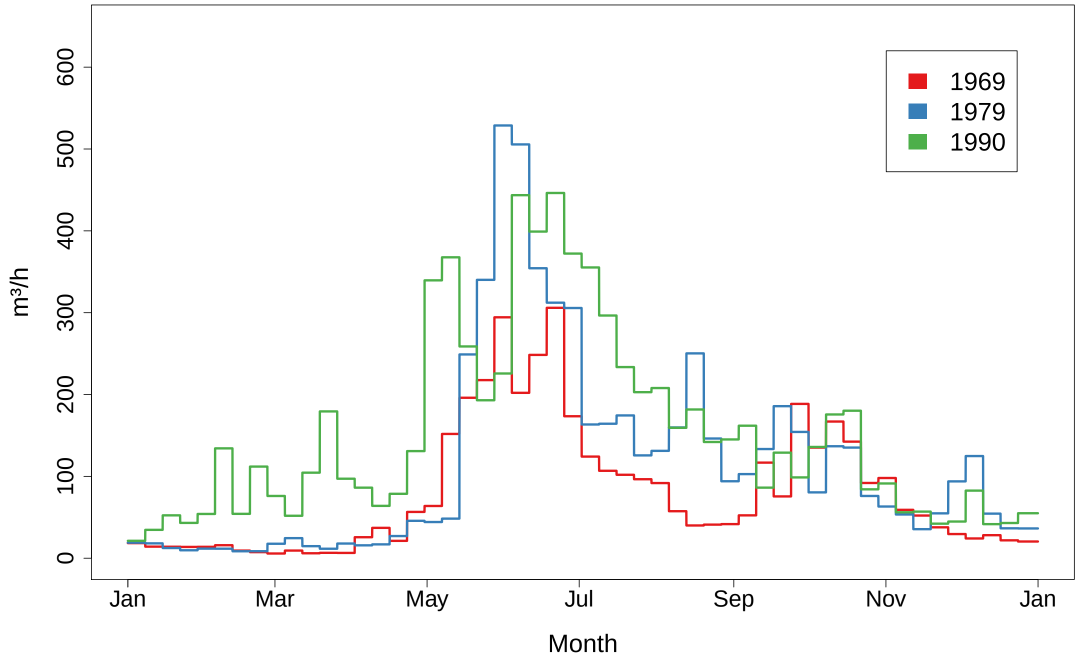

FIGURE 6.4: Inflow years in Norway (Source: Norwegian University of Science and Technology and SINTEF Energy Research (2010))

based on filling level data for the model years from Norges Vassdrags- og Energidirektorat (2013b).

6.4 New Pumped Storage Plants

For the extension of pumped storage plants in Norway potential projects with a total capacity of 50 GW are included in the database. The selection of projects is based on Norges Vassdrags- og Energidirektorat (2011b), Solvang et al. (2012) and own assumptions.

Table 6.4 shows the potential new pumped storage capacity with their location, total capacity, number of plants the capacity is divided between, investment costs, upper and lower reservoir, and source. The priority of the projects was determined by costs, where available, induced filling level change and source. In addition to project propositions found in literature other locations are included based on own assumptions. The suggested projects are located in large hydro schemes. The adopted capacity roughly corresponds to typical plant sizes. For those projects no cost estimation was available. Investment costs of 550 €/kW were assumed. This value is in the upper range of costs for the other projects found in literature as cited in table 6.4. The plants were ordered based on assumptions on their suitability.

Location	**Capacity** (MW)	**No. Plants**	**Costs** (€/kW)	**Upper Reservoir**	**Lower Reservoir**	**Source**
Tysso	700	1	269	Langevatn	Ringedalsvatn	Solvang et al. (2012)
Holen	1000	1	360	Uravatn	Bossvatn	Solvang et al. (2012)
Kvilldal	2400	2	361	Blasjoe	Suldalsvatn	Solvang et al. (2012)
Tonstad	1400	1	417	Nesjen	Sirdalsvatn	Solvang et al. (2012)
Fagervollan	1450	1	422	Trolldalsvatnet	Nedre Fager-vollvatnet	Norges Vassdrags- og Energidirektorat (2011b)
Tinnsjoe	2000	2	472	Moesvatn	Tinnsjoe	Solvang et al. (2012)
Tinnsjoe	2400	2	472	Kallhovd	Tinnsjoe	Solvang et al. (2012)
Lassajavrre	1200	1	519	Ábojávri	Lássajávri	Norges Vassdrags- og Energidirektorat (2011b)
Blaafalli V	1000	1	544	Midtbotnvatnet	Blådalsvatnet	Norges Vassdrags- og Energidirektorat (2011b)
Trollfjord	450	1	678	Botnvatnet	Trollfjordvatnet	Norges Vassdrags- og Energidirektorat (2011b)
Tysso	300	1	269	Langevatn	Ringedalsvatn	based on Solvang et al. (2012)
Kvilldal	500	1	361	Sandsavatn	Suldalsvatn	based on Solvang et al. (2012)
Kvilldal	600	1	361	Blasjoe	Suldalsvatn	based on Solvang et al. (2012)
Tonstad	1300	1	417	Homstoelvatn	Sirdalsvatn	based on Solvang et al. (2012)
Tonstad	4100	3	417	Homstoelvatn	Sirdalsvatn	own assumptions
Tinnsjoe	800	1	472	Moesvatn	Tinnsjoe	based on Solvang et al. (2012)
Tinnsjoe	800	1	472	Kallhovd	Tinnsjoe	based on Solvang et al. (2012)

Location	Capacity (MW)	No. Plants	Costs (€/kW)	Upper Reservoir	Lower Reservoir	Source
Vatnedalsvatn	200	1	NA	Uravatn	Vatnedalsvatn	based on Solvang et al. (2012)
Solhom	3200	3	550	Nesjen	Homstoelvatn	own assumptions
Saurdal	2000	2	550	Blaasjoe	Lauvastoelvatnet	own assumptions
Holen	2200	2	550	Vatndalsvatnet	Botsvatn	own assumptions
Songa	2000	2	550	Songavatnet	Totak	own assumptions
Novle	2000	2	550	Votna	Valldalsvatnet	own assumptions
Kjela	2000	2	550	Totak	Bordalsvatn	own assumptions
Fjone	1500	2	550	Napevatnet	Nisser	own assumptions
Finndoela	1500	2	550	Oeysaevatn	Fyresvatnet	own assumptions
Usta	1500	2	550	Roedungen	Ustevatn	own assumptions
Aurland	1500	2	550	Vetlebotvatnet	Fretheimsdals-vatnet	own assumptions
Aurland	1500	2	550	Nyhellervatnet	Vetlebotvatnet	own assumptions
Litjfossen	1500	2	550	Innerdalsvatnet	Falningsjoen	own assumptions
Roeldal	1000	1	550	Valldalsvatnet	Roeldalsvatnet	own assumptions
Nes	1000	1	550	Ustevatn	Kroederen	own assumptions
Lio	1000	1	550	Byrtevatn	Bandak	own assumptions
Suldal	1000	1	550	Roeldalsvatnet	Suldalsvatn	own assumptions
Tokke	1000	1	550	Vinjevatn	Bandak	own assumptions
Vinje	1000	1	550	Totak	Vinjevatn	own assumptions

Table 6.4: Additional pumped storage capacity in Norway

6.5 Run-of-River Plants

For the compilation of German run-of-river plants several different sources were used. Information on run-of-river plants which operate in the framework of the EEG was taken from the energyMap plant register (Deutsche Gesellschaft für Sonnenenergie e.V., 2013). Data on older and larger run-of-river plants were collected from Bundesministerium für Wirtschaft und Arbeit (2003, p. 5-1ff). The two sources were compared and consolidated and further complemented with information from large operators of run-of-river plants from the following sources: Elektrizitätswerk Aach (2013), EnBW Kraftwerke AG (2013b), E.ON Kraftwerke (2013), GDF Suez (2013), Harzwasserwerke (2008), Rhein-Main-Donau AG (2013), RWE Innogy (2013f), RWE Innogy (2013e), RWE Innogy (2013b), RWE Innogy (2013d), RWE Innogy (2013c), RWE Innogy (2013a), Vattenfall Europe Generation (2013a), Vattenfall Europe Generation (2013f), Waller (2007)

In total there are 8546 German run-of-river power plants in the renpass database. The capacity sums up to 4494 MW.

For the production of the German run-of-river plants flow data from different sections of the German hydrological yearbook are used. Data from 40 level meters are stored in the renpass database. They are collected from Bayerisches Landesamt für Umwelt (2009), LUBW Landesanstalt für Umwelt (2009), Niedersächsischer Landesbetrieb für Wasserwirtschaft (2010), and Bundesanstalt für Gewässerkunde (2013). The most comprehensive data set could be collected for the year 2006, so this year was selected as the base year of the inflow. Each run-of-river plant is related to a specific level meter. Larger plants from Bundesministerium für Wirtschaft und Arbeit (2003, p. 5-1ff), for which information on the exact location within a river is available, were assigned to a level meter according to the location and river system. Smaller plants were assigned based on their model region with one level meter per region.

The information on Norwegian run-of-river plants is included in the hydro power plant data set provided by Norges Vassdrags- og Energidirektorat (2010b).

For the production of the Norwegian run-of-river plants the same inflow curves from Norwegian University of Science and Technology and SINTEF Energy Research (2010) are used as for the storage plants in Norway, see section 6.3. For the Norwegian run-of-river plants the total annual inflow is given in the data set. In some cases the information on total annual inflow is missing. For those plants the annual inflow was approximated by converting data on average production 1970 to 1999 with the energy yield factors to annual inflow.

For all other countries run-of-river plants are not modeled individually but only with the total capacity per region. The capacity is a scenario parameter that can be adjusted by the user of the model.

Chapter 7

Scenarios

7.1 Scenario Assumptions

The simulations will analyze a 100 % renewable electricity system in the year 2050. The choice of year is somewhat arbitrary. It serves as an example for modeling a system that can be developed in the mid to long term. The development of the scenarios is based on some basic assumptions for the future. It is presumed that the European integration of the electricity markets is intensified with increased grid connections and that national self-supply or even autarchy is not pursued. On the other hand a completely potential-based concentration of electricity supply is not anticipated either. Instead a geographically and technologically diverse supply structure is considered to be most resilient and secure.

For scenario simulations with renpass a large number of parameters can be varied. The analysis is concentrated on a few main parameters that are assumed to have the largest effect on the outcome with regard to the research questions. All the other parameters are kept constant so that conclusions can be drawn ceteris paribus. In this section the setting and variation of input parameters will be described.

A number of parameters set the frame for the scenarios. They are displayed in table 7.1 and stay the same in all calculated scenarios. All simulations are carried out for one year in hourly time steps. Germany and Norway are in the focus of the analysis. Sweden and Denmark are included in the scenarios for a better representation of energy exchange in the area. Germany is divided into five regions. The regions cover the North-West, East, Rhine-Ruhr area, South-West and South-East of Germany. A map with the simulation area and the division of Germany can be found in figure 8.1 in chapter 8.

Parameter	Setting
Time frame	1 year
Time step	1 hour
Area	Germany, Norway, Sweden, Denmark
Division of Germany	5 regions

Table 7.1: Parameter settings

Cable	Connected countries	Grid loss (%)	Source
Interconnexion France-Angleterre	Britain - France	1.17	RTE and National Grid (2011)
BritNed	Britain - the Netherlands	3	BritNed (2013)
Baltic Cable	Germany - Sweden	2.4	Emcc (2012)
NorNed	the Netherlands - Norway	4	Kramer (2013, p. 4)
Kontek	Germany - Denmark	2.5	50Hertz Transmission (2012, p.4)
Skagerrak	Norway - Denmark	3.6	50Hertz Transmission (2012, p.4)

Table 7.2: Loss factor of DC cables

Other parameters that are expected to have little impact on the results are kept constant as well. The grid loss is assumed to 3 % for each connection. That means that 3 % of the electricity is lost both on the sea cables and on onshore connections between two dispatch regions. Current transmission losses within Germany are estimated to approx. 5 % of transferred electricity by 50Hertz Transmission et al. (2012, p. 39) based on 2009 data. In renpass the total loss depends on the number of regions the electricity crosses. With five regions in Germany it can be assumed that mostly one or two borders will be crossed resulting in 3 % or 6 % loss. This seems to fit well with the loss data for Germany. The loss factor of existing DC cables is indicated in table 7.2. According to those figures also the sea cable connections are represented quite well with a grid loss of 3 %.

The parameters for the development of electricity demand, grid, storage capacity, and renewable energy capacity are specified per region, resp. between two regions. Load data from the year 2011 are used for the simulations. The total electricity demand is kept constant in all scenarios. The assumptions for grid, storage and renewable energy capacity will be described in the following sections.

Connection	**Capacity** (GW)
Germany - Denmark	5
Germany - Sweden	1.2
Denmark - Sweden	3.28
Norway - Sweden	9.89
Norway - Denmark	3.3
Germany - Norway	0 - 50

TABLE 7.3: Grid connection scenario

7.2 Grid Scenario

In renpass the scenario for grid development is set differently for grid connections between countries and within Germany. For international connections the capacity for each connection is specified. The grid capacity between Germany and Norway is varied for the analysis between 0 and 50 GW. The grid connections to Sweden and Denmark are assumed to be twice the current capacity which includes the existing and planned connections. The planned interconnector Skagerrak 4 between Norway and Denmark and South-West-Link between Norway and Sweden are included in the current capacity as well as the planned upgrading and extension of the connection between Germany and Denmark-West with 1 GW (European Network of Transmission System Operators for Electricity, 2012, p. 122f). Table 7.3 shows the grid scenario for international connections.

For the grid within Germany the development is determined by a factor that applies to all connection lines. For the simulations this factor is set to 200 %, that means that, as for international connections, all connection lines are assumed to have twice the current capacity.

A test simulation was run to gain information on how severe the restriction of the simulated grid scenario is. For that purpose a simulation with unlimited grid capacity was carried out. The simulated unrestricted electricity transmission was then related to the proposed grid scenario with limited transmission capacity. Table 7.4 shows in the first column the maximum flow between regions in either direction which was simulated without grid restriction. The second column indicates in how many hours during the year, given as percentage, the unlimited transmission was not higher than the fixed transmission capacity of the proposed grid scenario. During those hours the electricity flow would not be restricted by the transmission capacity in the scenario simulations. This figure is an indicator of the degree of constraint the grid scenario puts on a specific grid connection. For the connection between Germany and Norway the share of hours where transmission

Connection	Max flow (GW)	Share within grid scenario (% of hours)
North-West - North-East	96	78
North-West - West	75	98
North-East - West	53	30
North-East - South-East	52	48
West - South-West	45	99
West - South-East	68	74
South-West - South-East	43	94
North-West - Denmark	71	63
North-East - Denmark	75	40
Germany - Sweden	71	19
Denmark - Sweden	96	64
Norway - Sweden	83	80
Norway - Denmark	73	65
Germany - Norway	81	73

Table 7.4: Results without grid restriction

is below 10 GW is displayed. The share of hours within the restriction differs considerably between different connection lines. It can be seen that the assumed doubling of grid capacity will result in virtually unlimited flows in some cases, for example between North-West and West Germany and between West and South-West Germany. On the other hand transmission between the North-East and West and between Germany and Sweden will be severely restricted by the grid capacity in the simulated scenarios.

For the sensitivity analysis different grid development pathways for the grid in Germany are simulated. The variations range from the current grid to a tripling of grid capacity for each connection.

7.3 Storage Scenario

The storage capacity in Norway is in the focus of the analysis. It is varied in the range between the existing capacity and the addition of 50 GW new pumped storage capacity. For the additional pumped storage plants it is assumed that reversible turbines are installed that have the same capacity in pumping and turbine mode.

For the main scenarios the storage capacity in Germany is kept at the current level. For the sensitivity analysis different scenarios for storage extension in Germany are simulated. Three different technology pathways are explored separately. In the pumped storage scenario capacity in Germany is increased by 3.15 GW. This includes the planned pumped storage projects Atdorf with 1.4 GW, Nethe with 0.39 GW, Schmalwasser with 1 GW, Jochenstein with 0.3 GW and Blautal with 60 MW. The total proposed storage volume of the projects is 25.21 GWh. The impact of compressed air energy storage is analyzed with an scenario that includes 10 GW compressed air energy storage. This capacity was chosen to match the additional pumped storage capacity in Norway included in the scenario. The storage volume is set to 240 GWh, which enables 24 hours of full-load operation. The third pathway includes power to gas infrastructure, also with a capacity of 10 GW. The storage reservoir in this case is the natural gas grid. The storage volume is assumed to 220 TWh based on Sterner et al. (2010c).

For Sweden in addition to the current pumped storage capacity of 0.1 GW the storage plants with 10.8 GW capacity are assumed to be equipped with pumps as well so that a total pumped storage capacity of 10.9 GW is reached. In Denmark no storage capacity is assumed. For both countries the storage capacity is kept the same in all scenarios.

7.4 Renewable Energy Scenario

7.4.1 Germany

There exists a number of scenarios for the development of the electricity system in Germany. Many of them address the transition towards renewable energies. Among the most notable publications are Nitsch et al. (2012), also referred to as the annually updated lead study, the special report presented by the Council of Environmental Advisors (Sachverständigenrat für Umweltfragen, 2011) and scenarios presented by the German Environmental Agency (Umweltbundesamt, 2010). However, only Sachverständigenrat für Umweltfragen (2011) and Umweltbundesamt (2010) feature scenarios with 100 % renewable electricity supply. Nonetheless Nitsch et al. (2012) is included here because it is widely distributed and often referred to in other publications. Nitsch et al. (2012) present three main scenarios with 80 % greenhouse gas emission reduction by 2050. For comparison Scenario 2011 B is selected because among the three main scenarios it contains the highest renewable generation capacity.

Sachverständigenrat für Umweltfragen (2011) simulated different cost-effective scenarios for 100 % renewable electricity supply in Europe that vary in electricity demand and degree of self-supply. For comparison scenario 2.1.a is selected. This scenario includes Germany, Denmark and Norway with self-supply while 15 % of electricity consumption can be exchanged throughout the year.

Technology	Sachverständigenrat für Umweltfragen (2011) (GW)	Nitsch et al. (2012) (GW)	Umweltbundesamt (2010) (GW)
Offshore wind	73.2	34.5	45
Onshore wind	39.5	54.3	60
PV	40.9	79	120
Biomass	4.9	10.4	23
Geothermal	0	3.4	6.4
Run-of-river	4.1	5.2	5.2

Table 7.5: Installed renewable energy capacity in literature scenarios for Germany

Umweltbundesamt (2010) developed three scenarios for Germany with different characteristics. The main scenario has a regional focus and is based to a large extent on regional self-supply. Additionally there is a centralized scenario with large-scale power production and increased international power exchange. The third one is a local autarchy scenario.

The three reports of Nitsch et al. (2012), Sachverständigenrat für Umweltfragen (2011), and Umweltbundesamt (2010) present quite different views on future electricity supply. While Sachverständigenrat für Umweltfragen (2011) assume stable or increasing electricity demand for their scenarios, Umweltbundesamt (2010, p. 22) assumes lower demand for electricity of 468 TWh in 2050. The Scenario B of Nitsch et al. (2012, p. 59) includes electricity demand of 635 TWh. This is covered by renewable electricity production, conventional electricity production and imports.

The structure of renewable electricity supply is quite diverse among the studies as well. Sachverständigenrat für Umweltfragen (2011, p. 94) expect the largest share of installed capacity to be in offshore wind energy plants. Limited further growth is assumed for onshore wind energy and solar power plants. Umweltbundesamt (2010) on the other hand expects very high solar energy capacity and also a high share of onshore wind energy while offshore wind energy has less significance. Nitsch et al. (2012) expect the smallest offshore wind energy capacity. Table 7.5 summarizes the three scenarios in terms of installed capacity.

The most even distribution of capacity between the technologies can be found in the scenario developed by Nitsch et al. (2012). For that reason the renewable energy capacity from this source is taken as the basis of the main scenario simulations for this thesis. The impact of different technology shares is explored in a sensitivity analysis with two scenarios based on Sachverständigenrat für Umweltfragen (2011) and Umweltbundesamt (2010).

Technology	**Base case** based on Nitsch et al. (2012) (GW)	**Variation 1** based on Sachverständigenrat für Umweltfragen (2011) (GW)	**Variation 2** based on Umweltbundesamt (2010) (GW)
Offshore wind	43	88.5	44.4
Onshore wind	68	47.8	59.2
PV	100	49.5	118.4
Biomass	26	5.8	22.7
Geothermal	4	0	6.3
Run-of-river	6.5	5	5.1

Table 7.6: Simulated scenarios for renewable energy capacity in Germany

The renewable electricity production calculated by Nitsch et al. (2012, p. 316) for scenario B is 460 TWh. Simulating the renewable electricity production based on capacity from Nitsch et al. (2012) with renpass leads to a similar quantity. This is not enough electricity to cover the assumed demand of 485 TWh. Furthermore, when there is a high share of fluctuating renewable energy the sum of production needs to be higher than the demand for a stable system. Alonso et al. (2011, p. 338) state that the ratio of renewable production to demand should be over 1.1 and estimate a reasonable value to around 1.3. For that reason the capacity of each technology was increased by roughly 25 % for the simulations.

For biomass the capacity is set differently. The generating capacity and electricity production from biomass assumed by Nitsch et al. (2012) lead to approximately 5700 full load hours. However, in a 100 % renewable electricity system, based to a large extent on fluctuating generation, available power will be the limiting factor not energy. The storage capability of the available biomass is hence better utilized in more flexible production with higher installed capacity. Based on that argument the biomass generating capacity is doubled but the available biomass is not increased. This will strengthen the use of biomass as peaking capacity with fewer full load hours. Table 7.6 shows the resulting capacity per technology for the year 2050 in Germany.

The renewable energy scenario for Germany is changed in the sensitivity analysis with the objective to model the impact of different total installed capacity and different shares of technology. The two variations are based on Sachverständigenrat für Umweltfragen (2011) and Umweltbundesamt (2010). For this purpose both renewable scenarios as shown in table 7.5 were scaled so that the sum of generated electricity is the same as in the base scenario. The variation is in the distribution of the different renewable technologies. The resulting capacity can also be seen in table 7.6.

Scenario	**Onshore** (GW)	**Offshore** (GW)
Base case	0	0
Offshore	0	10
On- & Offshore	10	5

Table 7.7: Scenarios for wind energy capacity in Norway

Technology	**Sweden** (GW)	**Denmark**(GW)
Offshore wind	4	3.5
Onshore wind	12	6.5
PV	0.03	0.02
Biomass	48	3.3
Geothermal	0	0
Run-of-river	11.65	0.01

Table 7.8: Scenario for renewable energy capacity in Sweden and Denmark

7.4.2 Norway

In Norway in addition to the existing hydro power capacity 4.2 GW run-of-river capacity and 3.4 GW biomass capacity are included in the main scenarios. For the sensitivity analysis also onshore and offshore wind energy plants in Norway are simulated. Those scenarios are displayed in table 7.7.

7.4.3 Sweden and Denmark

For Sweden and Denmark the renewable energy scenario is based on economic potential for renewable electricity production estimated by Trieb (2006, p. 43). The installed capacity of the different technologies is scaled with the objective that Sweden and Denmark are able to cover their own electricity demand and losses from energy transmission and storage. To allow moreover for the temporal mismatch of supply and demand the electricity production is approx. 25 % higher than the demand. The assumed capacities for Sweden and Denmark are shown in table 7.8. Those figures are not varied in the scenarios.

7.5 Scenario Overview

For the main analysis only the cable capacity between Germany and Norway and the additional pumped storage capacity in Norway are changed. Both cable capacity and pumped storage capacity are varied in steps of 10 GW from 0 to 50 GW. With six variations each, there are a total of 36 combinations that were simulated. Additionally two scenarios with 5 GW and 15 GW cable connection and 10 GW additional pumped storage capacity in Norway were calculated to get a closer look at a promising range of installed capacity. For the 38 main scenarios all other parameters are kept constant.

In addition to the main scenarios the influence of several other parameters was tested in a sensitivity analysis. For that purpose the grid capacity between Germany and Norway and the storage capacity in Norway were kept constant. From the analysis of the main scenarios, as described in detail in chapter 8, the most beneficial combination arose to be at 10 GW grid connection and 10 GW additional storage capacity. This scenario was hence simulated with varying influencing parameters. Table 7.9 shows the analyzed variations.

The setting of the scarcity price was analyzed with three variations. In the first alternative the electricity price is set to 600 €/MWh whenever the demand cannot be fully covered. For the other two alternatives the scarcity price is calculated according to equation 3.2 as in the base case but with a different factor for the demand gap. In the second variation the factor is set to 5. This leads to higher shortage prices than in the base case. In the third variation the factor is set to 20 leading to lower shortage prices.

7.6 Analysis of Residual Load

From the fluctuating renewable electricity production of a specific renewable energy scenario, the need for flexible capacity can be deducted by analyzing the residual load curve. Figure 7.1 shows the residual load in the whole region in two different representations. It is based on the scenario assumptions for the base scenarios as described in section 7.4.1 with load of 2011 and renewable capacity adapted from Nitsch et al. (2012) and Trieb (2006). The red line shows the sum of residual load duration curves from the eight model regions. That means that for example the highest residual load of each region is added even though they might not occur at the same time. This residual load curve would have to be balanced if each region was supplied separately without exchange between regions. The blue line shows the combined residual load of all regions. For this line renewable production and load from the whole area are subtracted before sorting for the duration curve. The difference between the two lines is caused by the fact that the duration curves of the regions are not simultaneous. The non-concurrency of load and productions curves smoothens the residual load duration curve compared to the addition of single regions. However, the peak residual load can only be lowered very slightly by connecting the regions. The peak occurs at times with high load and/or low

Number	**Scenario parameter**	**Setting**
1	Grid in Germany	status-quo 2012
2	Grid in Germany	triple
3	Hydro inflow	high
4	Hydro inflow	low
5	Renewable energy scenario Germany	adapted from Sachverständigenrat für Umweltfragen (2011)
6	Renewable energy scenario Germany	adapted from Umweltbundesamt (2010)
7	Renewable energy scenario Norway	offshore
8	Renewable energy scenario Norway	offshore & onshore
9	Weather year	1998
10	Weather year	2003
11	Storage extension Germany	pumped storage
12	Storage extension Germany	compressed air energy storage
13	Storage extension Germany	power to gas
14	Scarcity price	fixed at 600
15	Scarcity price	factor 5
16	Scarcity price	factor 20

Table 7.9: Scenarios for sensitivity analysis

fluctuating renewable electricity generation. Apparently the spatial correlation of those circumstances is high and they will often happen at the same time across the regions. The minimum of residual load on the other hand, which indicates the excess production, can be increased considerably. The times of high renewable production seem to be less correlated across the regions. With unrestricted transmission the temporal differences in residual load can be fully exploited leaving the more even blue line to be balanced by flexible capacity. With limited grid capacity between regions the relevant residual load will be somewhere between the blue and the red line. The sum of residual load of the whole region is positive. This imbalance is covered by hydro storage plants with natural hydro inflow and biomass production.

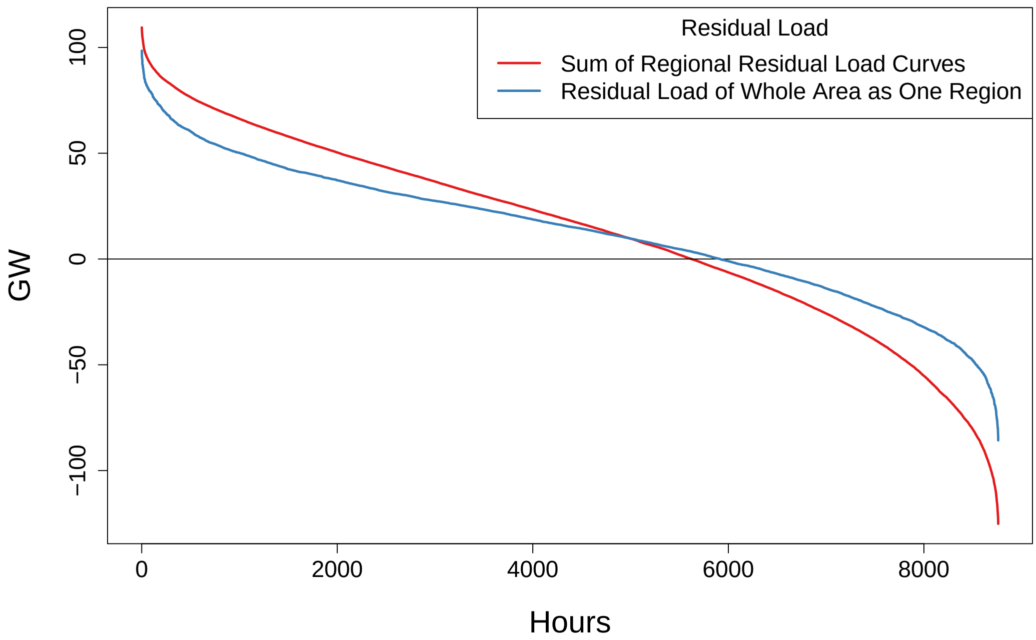

FIGURE 7.1: Residual load in the whole region

From the residual load curve the need for flexible capacity as well as the amount of energy that needs to be produced and absorbed to balance demand and supply can be read. The peak of residual load for all regions is between 99 GW and 110 GW, the minimum between -125 GW and -86 GW. However, the system does not necessarily need to be dimensioned to those figures. Especially with regard to negative residual load, it will not be optimal to store all the produced excess energy up to the minimum of residual load. A trade-off needs to be found between costs of storage capacity and costs of lost renewable production. At the steep end of the duration curve sacrificing a small amount of renewable electricity production will lead to a large reduction of needed storage capacity. Also on the production side it can be assumed that some balancing can be done by load shifting or load shedding which is not considered in this thesis.

	Sum of regions		**Whole area**	
	GW	GWh	GW	GWh
Maximum	109.5	0	98.5	0
- highest 10 h	103.5	26.3	91.7	24.4
- highest 100 h	91.4	544.3	78.3	573.5
- lowest 100 h	-96.0	-962.2	-59.4	-804.9
- lowest 10 h	-116.2	-40.3	-76.6	-39.0
Minimum	-125.2	0	-85.8	0

Table 7.10: Analysis of residual load duration, needed capacity in GW, curtailed energy in GWh

Technology	**Installed capacity** (GW)
Biomass	80.7
Hydro storage	23.7
Pumped storage	18.8
Sum generation	**123.2**
Sum storage	**18.8**

Table 7.11: Base of dispatchable generation and storage capacity in all scenarios

Table 7.10 shows the maximum and minimum of residual load as the sum of all regions and combined for the whole area. It is also shown how the peaks can be reduced when some of the highest or lowest values of the residual load curve are dismissed. In each case the amount of energy that could not be supplied or stored as a result of the under-dimensioning is indicated. It can be seen that the need for capacity can be reduced considerably when only a few hours are excluded. This effect is slightly stronger for needed storage capacity because for the lowest values the duration curve is a bit steeper than at the positive end. The effect is likewise stronger for the residual load of the whole region compared to the sum of regions. The amount of energy that cannot be supplied or stored is comparably small because of the steepness of the cropped parts.

Table 7.11 shows the generation and storage capacity that is included in all scenarios. It is obvious that there is an imbalance of generation and storage capacity. While there are several technologies for generating electricity only pumped storage plants can be used for storing electricity. The pumped storage plants generally have a similar generation and pumping capacity. However, the hydro storage plants and to some extent also the biomass plants are restricted by the availability of the energy resource. That means that the installed generation capacity is not always available for use. This restriction is less severe in reality where plant are operated based on forecasts and the installed capacity will mostly be available at times of peak load.

Additionally the pumped storage capacity in Norway is increased by up to 50 GW in the scenario variations. Also for the sensitivity analysis storage capacity in Germany is increased by up to 10 GW.

The fluctuating curve of the residual load calls for flexible operation of the dispatchable generation and storage units. The gradients of the residual load are largely symmetrical so that up and down ramping is needed in equal measure. The absolute highest gradient from one hour to the next is 39 GW. However, more than 50 % of hourly changes are below 5 GW with the mean at 5.8 GW. The gradient is higher than 20 GW in only 167 hours.

In figure 7.2 the variation of residual load for the whole modeling area in January is shown. The need for production alternates with the need for storage. Over the course of the whole year the residual load switches 631 times between positive and negative values. The largest continuous positive residual demand is 7.6 TWh with a mean of 569 GWh. For negative residual load the maximum is 2.5 TWh with a mean of 204 GWh. This gives an indication of the needed storage volume.

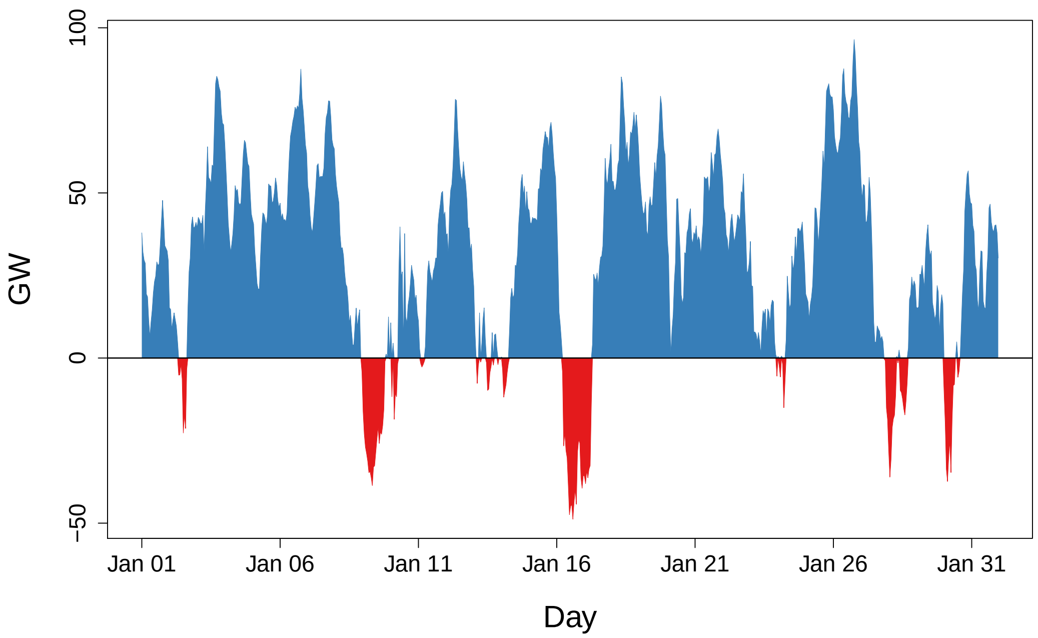

FIGURE 7.2: Residual load variation in January, whole modeling region

Figure 7.3 shows the residual load duration curve for Germany for the three renewable energy scenarios included in the simulations, see section 7.4.1. All three scenarios contain the same load data. They differ only in the renewable energy production. It can be seen that the residual load based on Umweltbundesamt (2010) (UBA) is very similar to the base case. However, this does not mean that the residual load is similar in every time step, the sequence of the shown values could still be quite different. The minimum residual load is significantly lower than in the base case, the lowest value of all three scenarios. The maximum residual load is only slightly lower than in the base case. The scenario based on Sachverständigenrat für Umweltfragen (2011) (SRU) on the other hand results in a residual load duration curve that is slightly different from the others. In this case the renewable production is higher so that there is less residual energy demand and more excess energy. The minimum of the residual load is lower than in the base case and maximum is higher.

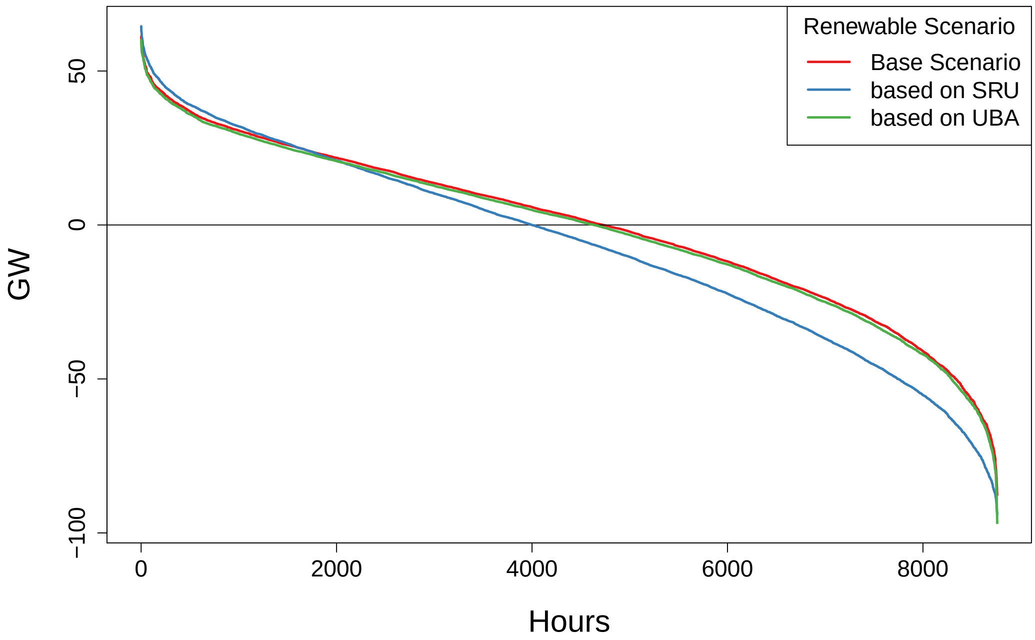

FIGURE 7.3: Residual load in Germany for different renewable energy scenarios

Chapter 8

Results

In this chapter the results of the simulations will be analyzed. Section 8.1 focuses on utilization, benefits, and profitability of connection capacity between Germany and Norway and electricity transmission within Germany. Utilization, benefits and profitability of additional pumped storage capacity in Norway will be described in section 8.2. Those two sections will answer the research questions to the most beneficial cable and pumped storage capacity and the economic feasibility of the installations. The impact of the proposed scheme on reservoir filling levels is examined in section 8.3. The sensitivity of the derived results to competing storage systems in Germany is analyzed in section 8.4 and the sensitivity to other input parameters is analyzed in section 8.5. The complete output data from the scenario simulations can be found in the database named `results` which is stored on the enclosed CD.

8.1 Cable Connection between Norway and Germany

8.1.1 Utilization of Cable Connection

The simulations show the amount and direction of flow for each transmission line and time step. Figure 8.1 gives a first overview on the net balance of transmission. The arrows show the net import transported via each line for a scenario with 10 GW cable capacity between Germany and Norway and 10 GW new pumped storage capacity in Norway. High power flows out of North-Western Germany can be observed. The largest net transmission of 102 TWh appears from North-Western Germany to the Rhine-Ruhr area in the West of Germany. Besides the Rhine-Ruhr area also the South-West of Germany is net importer. The flows within Germany are determined to a large extent by the assumptions for the distribution of renewable production capacity. For onshore installations this is based on the distribution of currently installed capacity. Together with offshore wind energy capacity this leads to excess electricity in the North of Germany and shortage in the West and South as can be observed from figure 8.1. The general pattern of exchange within Germany does not change significantly with different cable capacity between Germany and Norway and pumped storage capacity in Norway as described in more detail in section 8.1.5. With 10 GW cable capacity considerable net transmission of 22 TWh from north Germany to Norway can be noted. In the following the transmission between Germany and Norway for different connection capacity will be analyzed in detail.

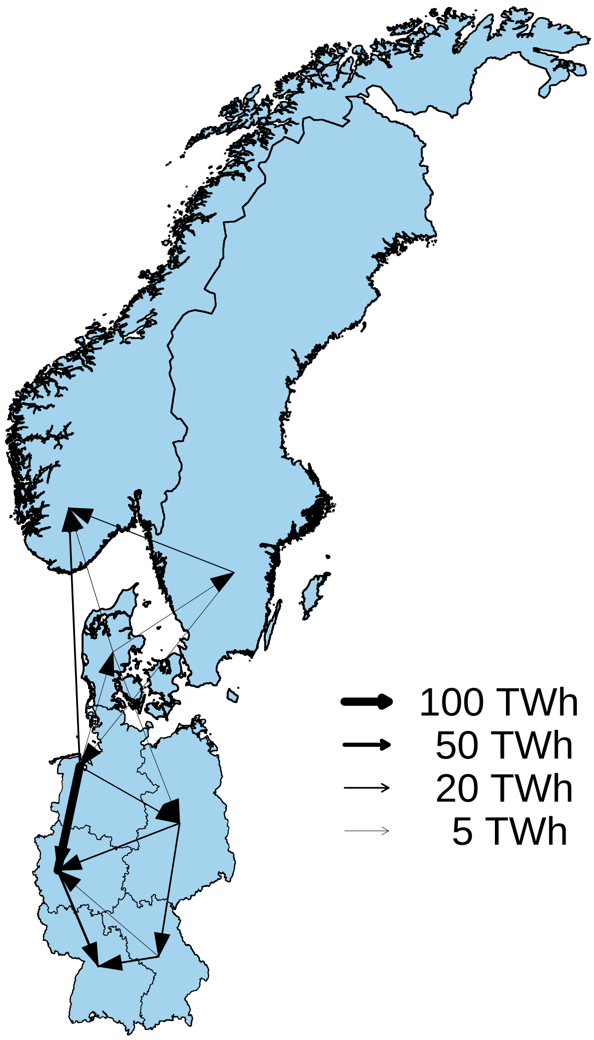

FIGURE 8.1: Net total transmission for one year, scenario with 10 GW cable to Norway and 10 GW new pumped storage

Figure 8.2 shows the the duration curve of power flow between Germany and Norway in different scenarios. For a duration curve the time series data is ordered by magnitude and not chronologically. This way different curves can be compared more easily. The sign of the flow specifies the direction. Positive values indicate power flow from Germany to Norway. Negative values indicate power flow from Norway to Germany. The scenarios in figure 8.2 differ only by the cable capacity between Germany and Norway. No pumped storage expansion in Norway is assumed.

It can be seen that the exchange is not balanced. More power is transmitted from Germany to Norway. The cable connection of 10 GW operates with ca. 4924 full load hours corresponding to 56.2 % utilization while 20 GW reach only 3283 hours or 37.5 %. This goes down to 1319 full load hours or 15.1 % for 50 GW. Only with a capacity of 10 GW the cable is operating at full capacity for a significant amount of time. On the other hand, there are very few hours with no power flow, ranging from 475 h for 10 GW to 1731 h with 50 GW cable capacity. Apparently the storage service is concentrated to fewer hours with higher connection capacity

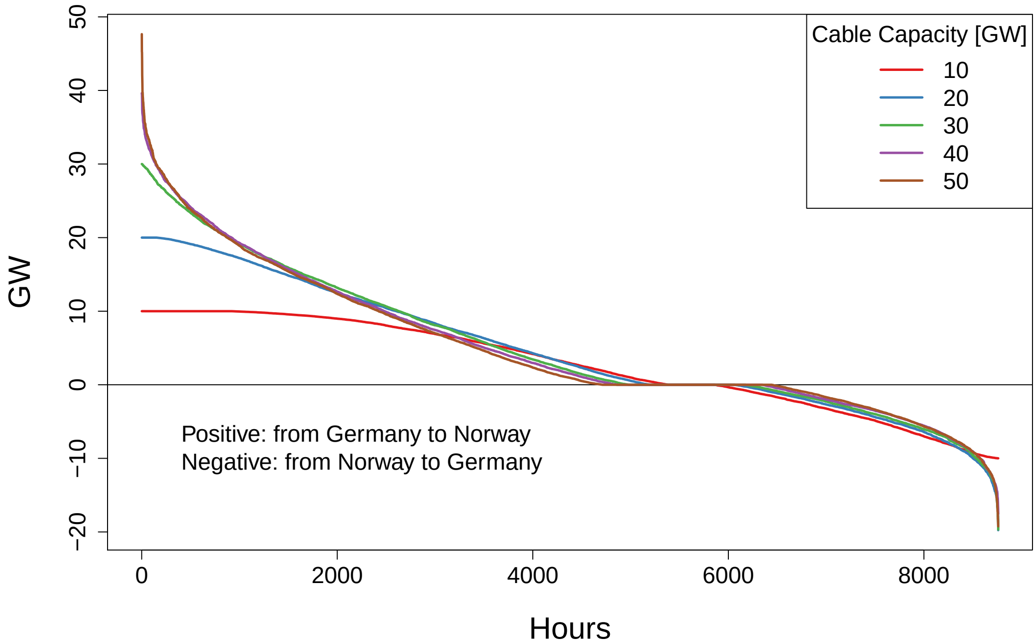

FIGURE 8.2: Duration curve of power exchange between Germany and Norway, no new pumped storage plants in Norway

Figure 8.3 shows the corresponding diagram with the difference of 30 GW new pumped storage capacity in Norway. In general the utilization of the cable connection increases compared to figure 8.2. The full-load hours of 10 GW capacity increase to 5378 h or 61.4 % utilization. The connection with 20 GW now reaches 3712 hours or 42.4 % utilization. Obviously increasing the possibilities for storage in Norway raises the exchange of power. This is completely reasonable because the current Norwegian system, with

24 GW peak load and ca. 30 GW production capacity, is limited in absorbing and exporting power. With the existing system cable connection capacity of more than 20 GW can only be supported for a limited amount of time. On the other hand with 30 GW additional pumped storage capacity the flexibilities of the Norwegian system for absorbing and producing power are greatly increased.

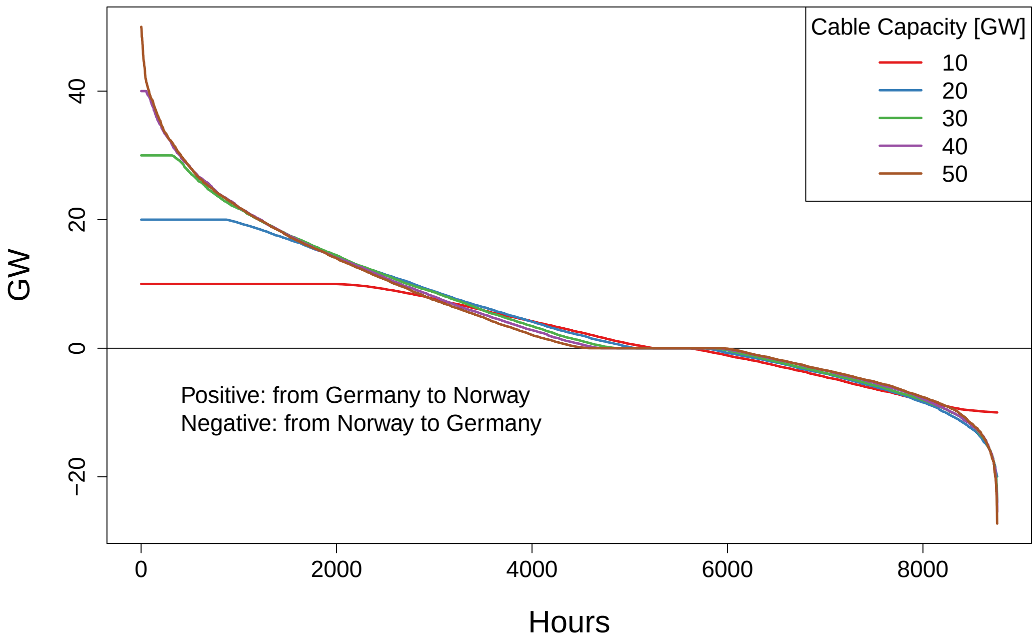

FIGURE 8.3: Duration curve of power exchange between Germany and Norway, 30 GW new pumped storage plants in Norway

The sum of transmitted electricity over the whole year can be seen in figure 8.4. It increases with higher cable capacity. The marginal change decreases however. This follows the law of diminishing marginal utility. The exchange also increases with new pumped storage capacity in Norway but the effect is small compared to the effect of cable capacity.

Figures 8.2 and 8.3 showed that the exchange between Germany and Norway is not balanced. More electricity is transmitted from Germany to Norway than vice versa. The net export from Germany to Norway varies between 20 TWh and 50 TWh in the different scenarios. The exchange in each direction is aggregated for different cable capacity and 10 GW new pumped storage capacity in figure 8.5. It can be seen that the exchange from Germany to Norway increases with more cable capacity while the flow in the other direction decreases. Accordingly the imbalance increases further with more cable capacity.

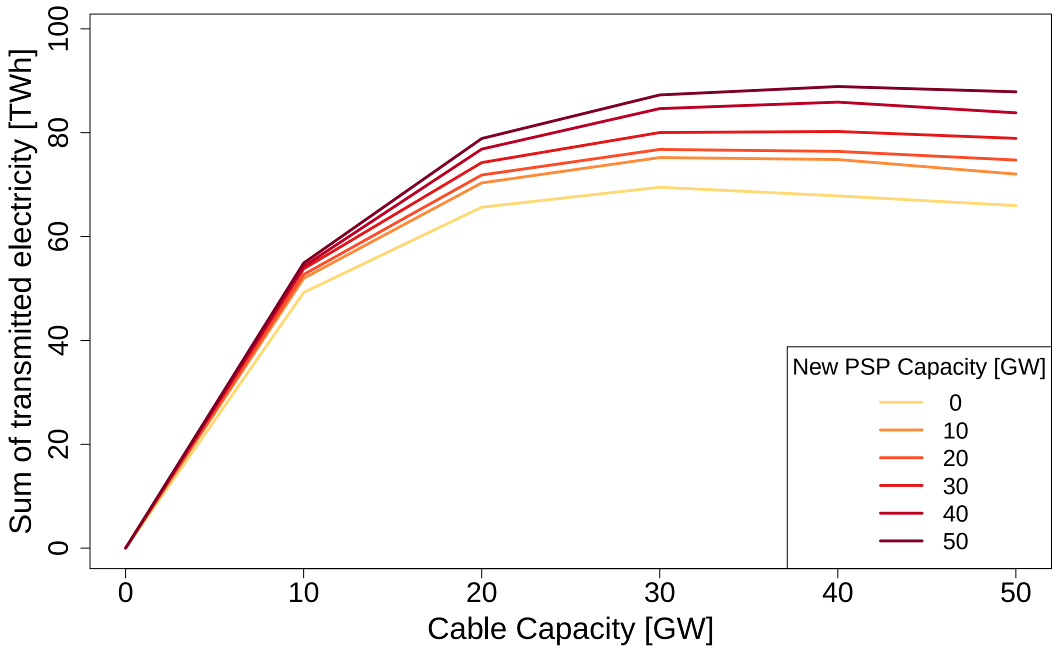

FIGURE 8.4: Total power exchange per year between Germany and Norway for different cable and pumped storage plant (PSP) capacities

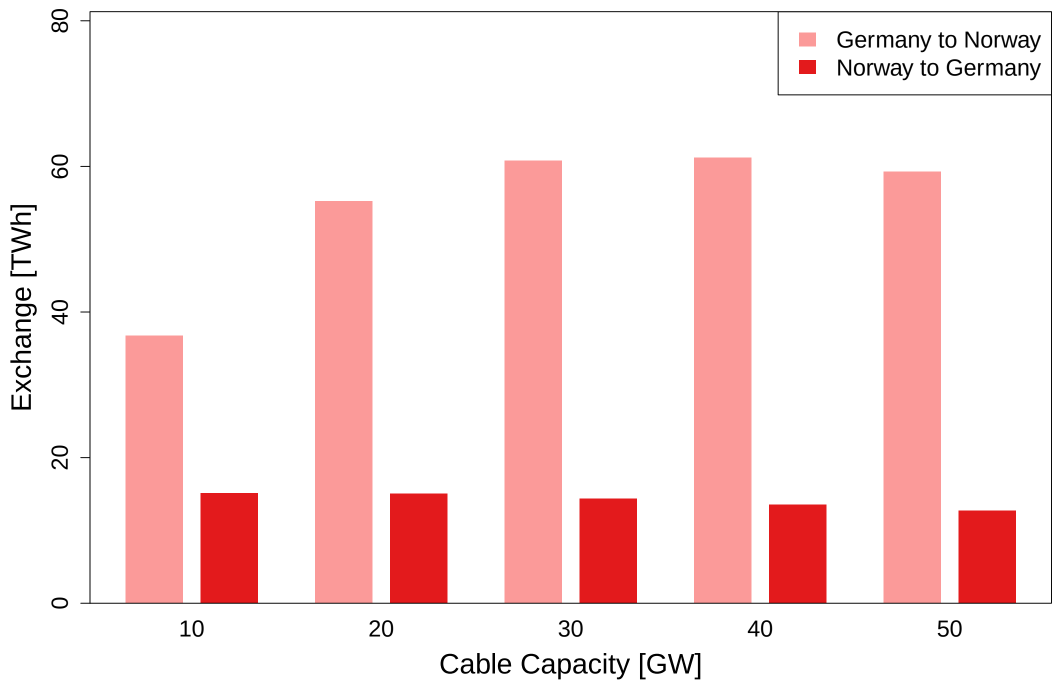

FIGURE 8.5: Total exchange per direction between Germany and Norway, 10 GW new pumped storage in Norway

When looking at the value of the transmitted electricity the situation is different. In figure 8.6 the specific value of the exchanged electricity in both directions is displayed. The electricity is valued at the price of the region it is transferred to. The electricity transmitted from Norway to Germany has a much higher specific value than the electricity transmitted from Germany to Norway. Hence the total value of transmitted electricity is from Norway to Germany is more than double that from Germany to Norway even though the amount is much smaller. Electricity flows from Norway to Germany during times of supply shortage in Germany leading to high electricity prices. This electricity is more valuable than the electricity flowing from Germany to Norway. Germany exports mainly excess electricity from renewable sources at low or zero price. This shows that dispatchable electricity production has a higher value than non-dispatchable production.

Figure 8.6 also shows that the specific value of the electricity transmission from Germany to Norway decreases with increased cable capacity. This is due to the price effect of the cable connection. The flow on the cable will lower the price in the importing region and thus the specific value of the transmitted electricity. The specific value of electricity import to Germany is quite stable. Apparently the price effect of the cable is larger in Norway than in Germany. The reason for that could be that the Norwegian electricity system is much smaller than the German. The total value of exchange decreases in both directions with increased cable connection. For exchange from Germany to Norway there is a decrease despite the increase in the amount of exchange. The decrease in specific value can obviously not be compensated by increased exchange.

Figure 8.7 displays the variations of exchange over time. The figure shows the daily average of transmitted electricity. The represented scenario contains 10 GW cable capacity and 10 GW new pumped storage capacity. A seasonal trend of electricity flow can be observed. Electricity is exported from Germany to Norway mainly in spring, fall and winter. During summer the flow tends to be more balanced. This is however not enough to compensate the trend of the rest of the year and the total imbalance of exchange is more than 20 TWh for the whole year. The seasonality seems to correspond to wind energy production in Germany.

A closer look is displayed in figure 8.8 that shows hourly cable flow in the first week of January. It can be seen that the flow on the cable changes quite frequently. Section 8.1.2 takes a closer look at the cable ramp rates.

To summarize, the simulated exchange is not balanced with more electricity transmitted from Germany to Norway. When the value of the exported electricity is considered the situation is reversed. A seasonal trend of power flow can be observed that is driven by the seasonal trend of renewable electricity production in Germany.

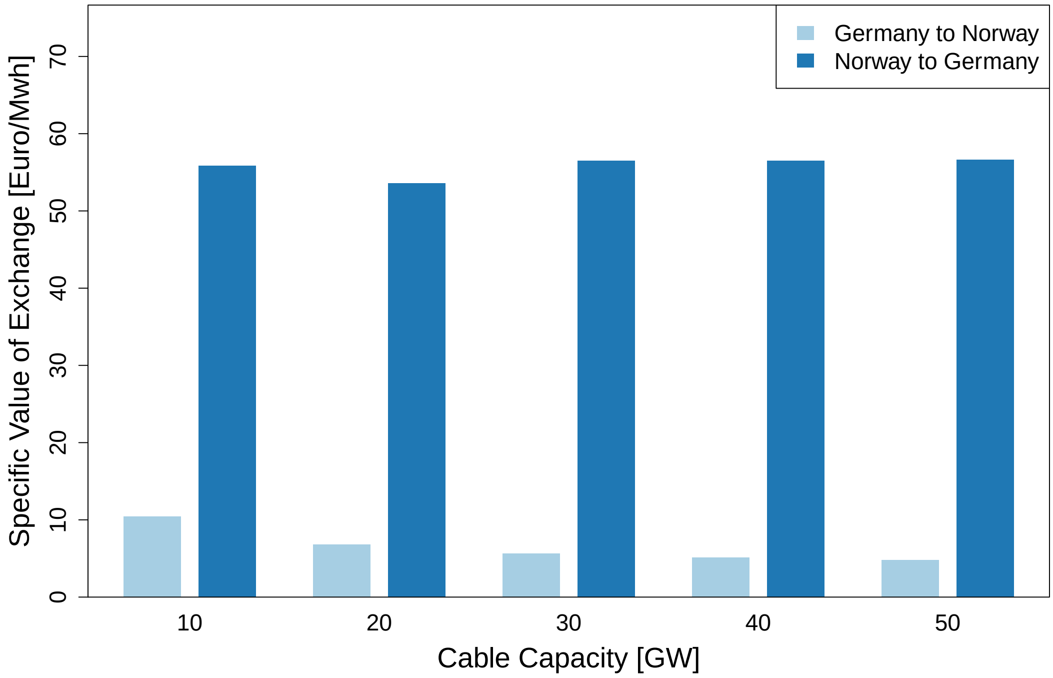

FIGURE 8.6: Specific value of exchange per direction between Germany and Norway, 10 GW new pumped storage in Norway

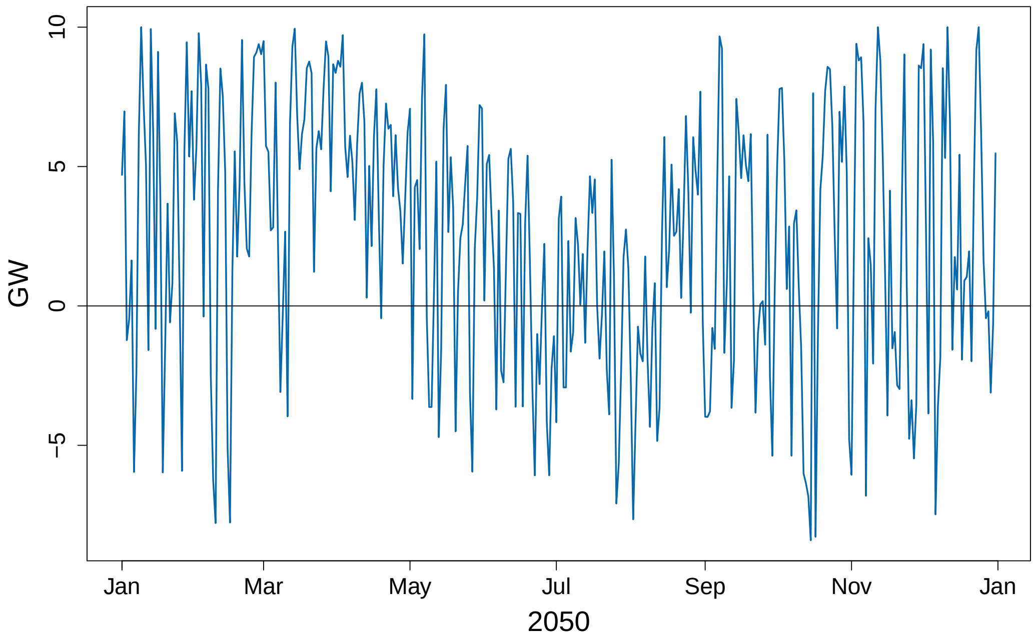

FIGURE 8.7: Daily mean of exchange, 10 GW cable capacity and 10 GW new pumped storage

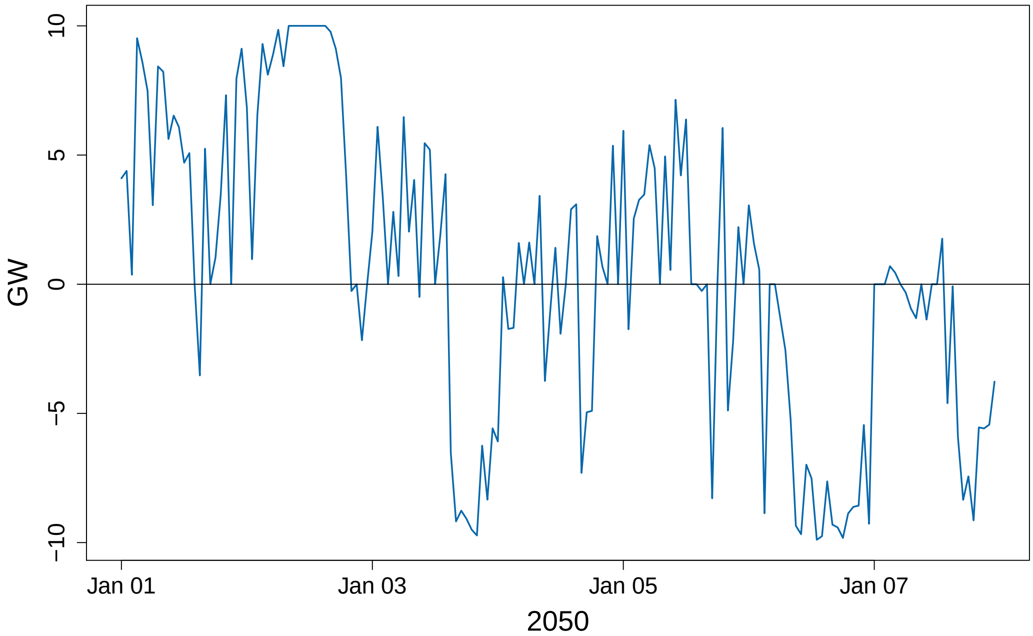

FIGURE 8.8: Exchange in first week of January, 10 GW cable capacity and 10 GW new pumped storage

8.1.2 Cable Ramp Rates

Figure 8.9 shows hourly ramp rates of 10 GW cable capacity between Germany and Norway. For a more detailed view only one week at the beginning of May is displayed. In this week high cable ramp rates can be observed. In some hours the ramp is higher than the capacity of 10 GW. That means that the cable was turned from full-load to the opposite direction of flow from one hour to the next. This is a very high ramp but it occurs only rarely in the simulations.

Figure 8.10 shows the duration curve of cable ramps for different scenarios. All scenarios include 10 GW new pumped storage in Norway. The relative ramp rates decrease with higher cable capacity. It can be seen that in most hours the hourly ramp rate is less than 50 % of the capacity. Currently on all cables between the Nordic region and the continental grid the ramp rate is restricted to 600 MW per hour (Nord Pool Spot, 2013d). In absolute terms the ramp rates are much higher on the simulated cable connection. However, relative to the installed capacity the restriction of 600 MW means 85 % for the NorNed cable, 100 % for the Baltic cable between Germany and Sweden and 100 % for the Kontek cable between Germany and Denmark. A relative ramp rate of more than 85 % per hour happens in the simulations only in 316 hours or 3.6 % of time for the

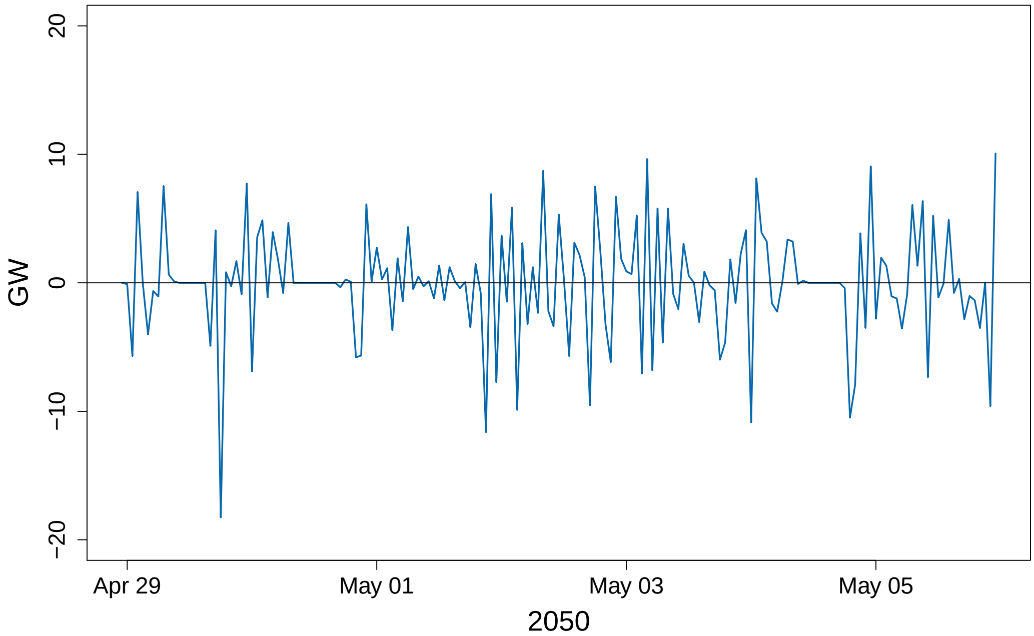

FIGURE 8.9: Cable ramp, one week in May, 10 GW cable capacity and 10 GW new pumped storage

scenario with 10 GW cable capacity. With 20 GW cable capacity the relative ramp rate is higher than 85 % only for 26 hours. For 30 GW and above it does not occur at all.

To conclude, the operation of the proposed connection scheme is, relative to capacity, for the largest part within today's technical limits. If the remaining situations were constrained by the cable limits this would only change the overall operation minimally. The connection of cable capacity in the range of 10 to 30 GW will certainly require the onshore grid at both ends of the cable to be enforced. Within this enforcement it should be possible to enable ramp rates of 85 % of installed capacity per hour.

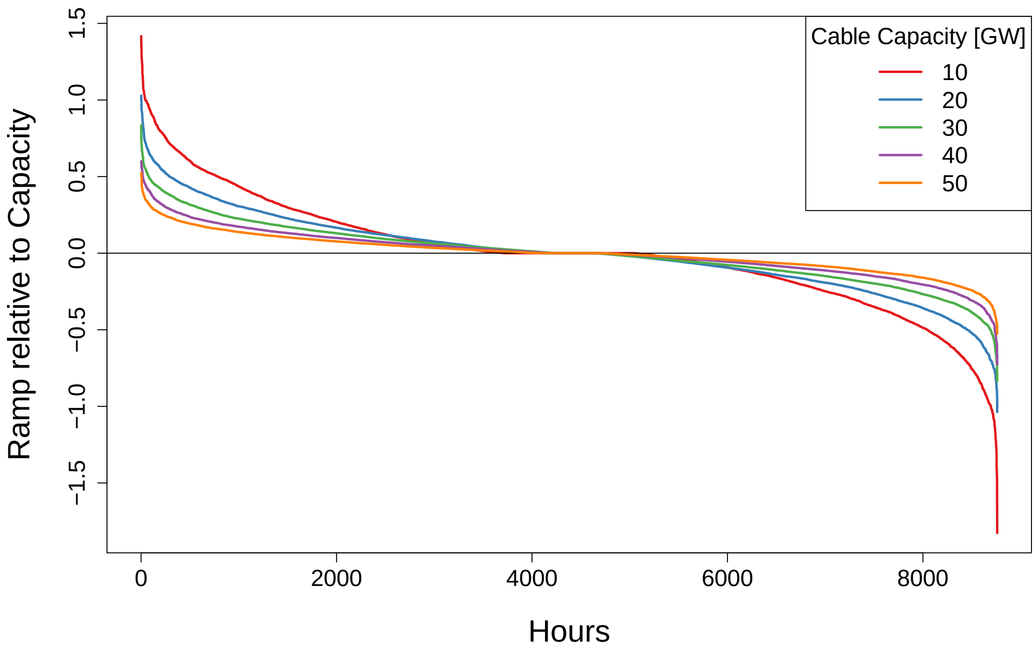

FIGURE 8.10: Duration of cable ramp rates, 10 GW new pumped storage

8.1.3 Economic Benefits of Cable Connection

In figure 8.11 the effect of cable and pumped storage capacity on the amount of unserved demand in Germany is shown. The unserved demand in Germany during the whole year is aggregated for each scenario. In all analyzed scenarios the demand cannot be completely covered. However, significant levels of unserved demand occur only in few hours during the year. Connection to Norway of 10 GW is highly effective in reducing the unserved demand. This effect is even stronger when 10 GW additional pumped storage capacity are installed in Norway. More cable and pumped storage capacity has only little additional effect. For a cable connection of more than 10 GW and less than 30 GW additional pumped storage capacity the unserved demand slightly increases again. Apparently the increase in power exchange is not able to further reduce the unserved demand. On the contrary higher transmission losses increase it. The same effect is visible for additional pumped storage plants. For a cable capacity of 10 GW the demand can be served best with 20 GW additional pumped storage in Norway as higher pumped storage capacity increases the conversion losses but does not further reduce unserved demand. This is different for higher cable capacity that allows the additional pumped storage plants to be utilized more effectively. The lowest gap in serving the demand can be observed with 30 GW cable connection and 50 GW additional pumped storage capacity.

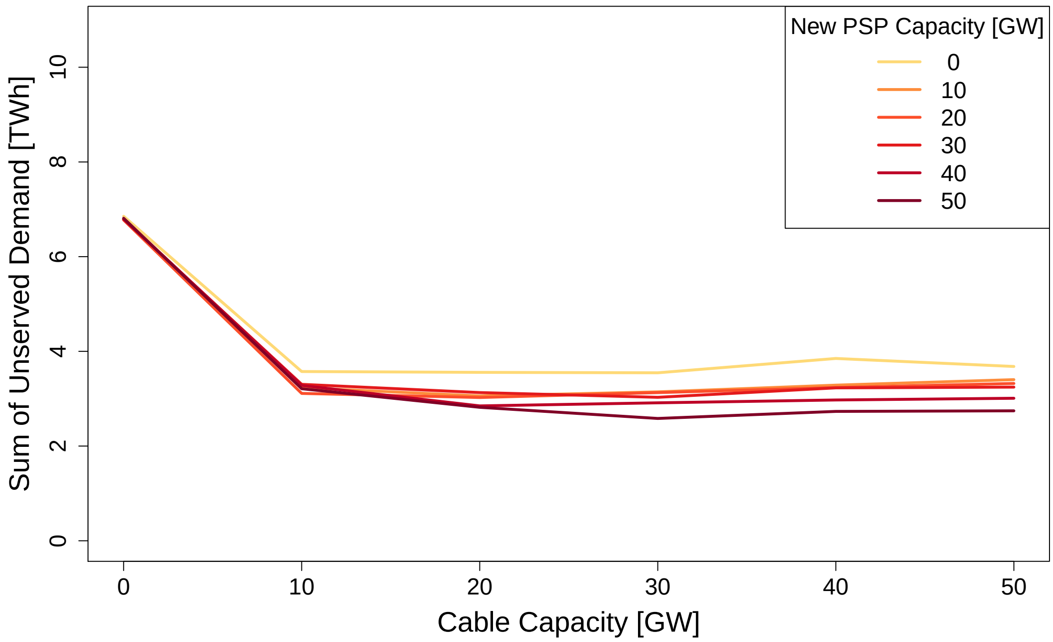

FIGURE 8.11: Unserved demand in Germany for different cable and pumped storage plant (PSP) capacity

In figure 8.12 the effect on the curtailment of renewable production in Germany is shown. The connection to Norway and the installation of additional pumped storage capacity significantly reduces the curtailment of renewable electricity. Additional pumped storage capacity is effective even without a cable to Norway because Germany and Norway are already connected via Denmark and Sweden.

The effect of the cable connection on the electricity price in Norway is shown in figure 8.13. The displayed scenarios include 10 GW additional pumped storage capacity in Norway. Two trends can be observed. On the one hand for almost three quarters of the year the prices in Norway are lowered with increased cable capacity to Germany. The number of hours with zero or very low price increases. However, there are also more hours with higher prices. The maximum price of the year initially increases from 0 to 10 GW cable but decreases again for higher connection capacity. For more than 20 GW there is only little additional effect.

Figure 8.14 shows the price effect in Germany. The average price of the five German regions is displayed. Price peaks in Germany are much higher than in Norway. This is caused by electricity scarcity leading to high scarcity prices. Price effects are of similar magnitude as in Norway but they are not as discernible in the figure due to the larger scale. The extent of time with high prices is reduced due to the connection to Norway. The maximum price is initially reduced but increases again with more than 20 GW

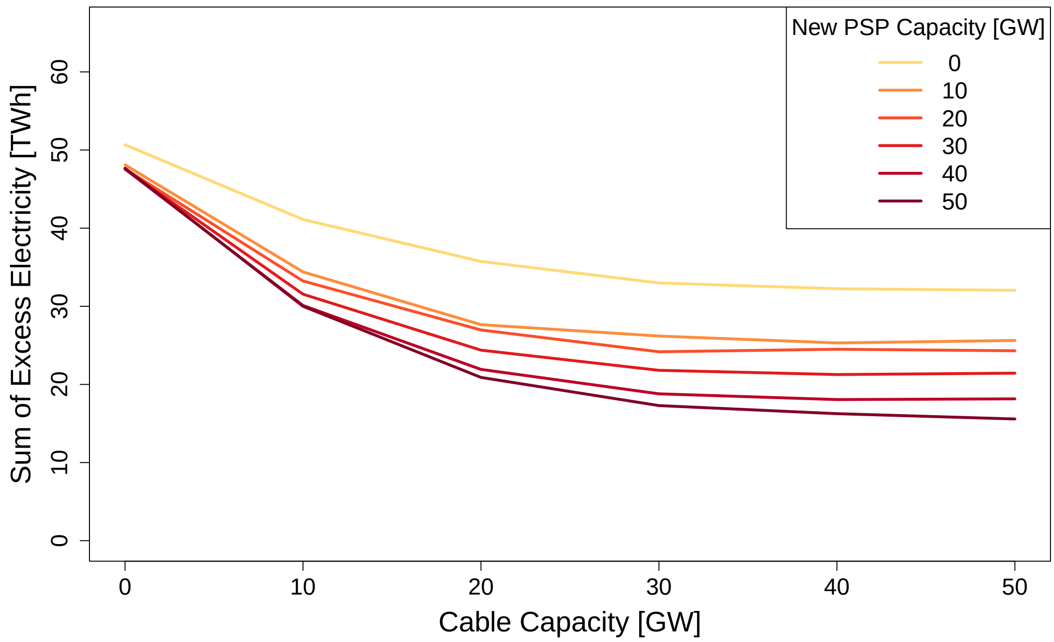

FIGURE 8.12: Excess electricity in Germany for different cable and pumped storage plant (PSP) capacity

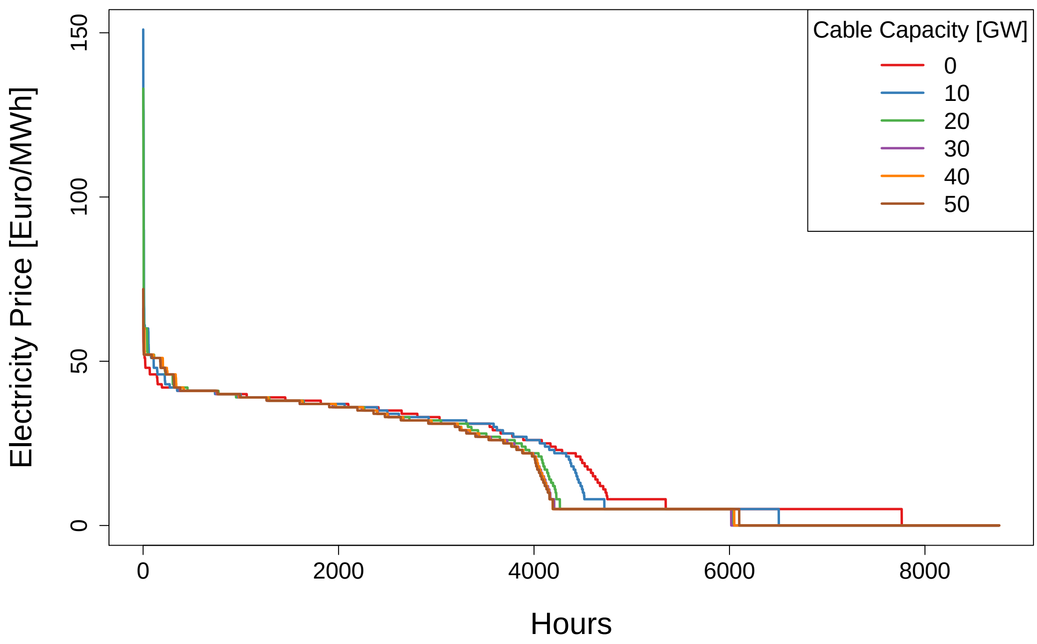

FIGURE 8.13: Electricity prices in Norway for different cable connection scenarios, 10 GW new pumped storage in Norway

connection capacity. At the lower end of the duration curve increased prices can be observed. Above 10 GW cable capacity no significant further changes can be seen.

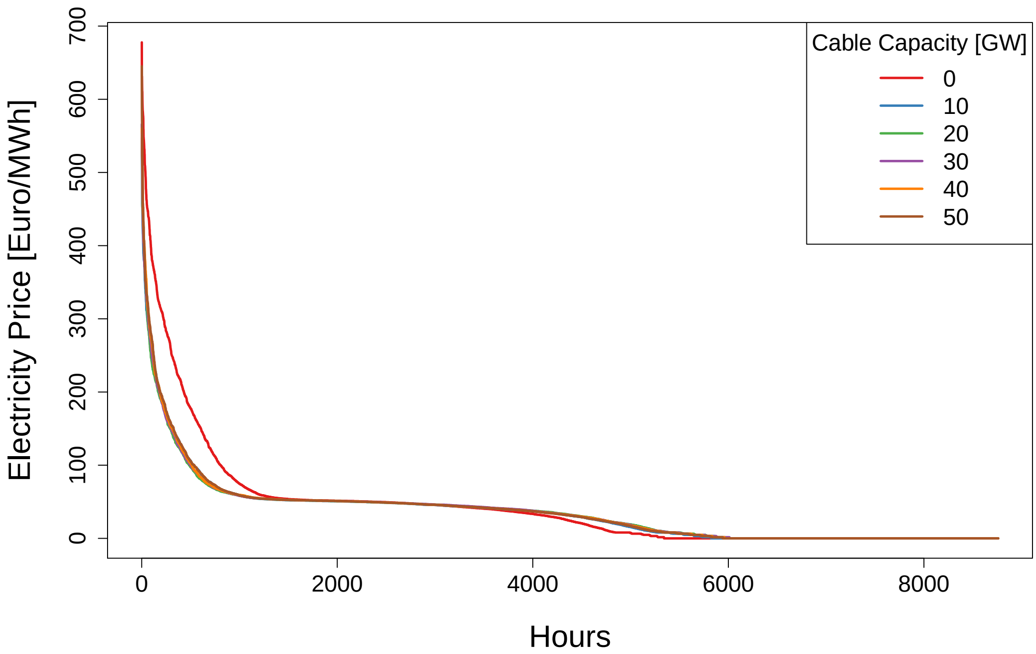

FIGURE 8.14: Electricity prices in Germany for different cable connection scenarios, 10 GW new pumped storage in Norway

In the following the economic benefit of the cable connection to Norway will be analyzed. The economic benefit is defined as the difference in total consumer costs of all model regions between a scenario without cable connection and a scenario with cable connection as shown in equation 8.1.

$$B = \sum_{r}^{R}(P * Q) - \sum_{r}^{R}(P_{\text{cable}} * Q) \tag{8.1}$$

B	benefit
P	price without cable connection
P_{cable}	price with cable connection
Q	demand
$r...R$	regions

The benefits should be evaluated in relation to the costs of cable connection. Here it is assumed that investment costs are the dominant cost component. All other costs are disregarded in the calculations. The investment costs of oversea cables are estimated to

1054 €/kW based on Statnett's concession application for a connection between Germany and Norway (Statnett, 2010, p. 25). For comparison to the benefit of one year of operation the cable annuity is calculated according to equation 8.2 with 35 years and 8 % interest rate. The period of 35 years was selected based on the period for fiscal depreciation of high voltage cables (Bundesministerium der Finanzen, 1995). The interest rate of 8 % approximately matches the equity return for investment in grid infrastructure determined by the Germany regulator. Since 2014 it is set to 9.05 % for new installations and 7.14 % for old installations (Bundesnetzagentur, 2011).

$$a = C_{\text{invest}} \frac{i(1+i)^n}{(1+i)^n - 1} \tag{8.2}$$

a	annuity
$C_{\textbf{invest}}$	investment costs
i	interest rate
n	number of years

Figure 8.15 shows costs reduction and investment annuity for different cable connection and pumped storage capacity. This illustrates the decreasing marginal benefit for higher cable connection capacity. With no additional pumped storage capacity (blue line) the costs reductions are higher than the cable investment annuity for cable capacity up to 40 GW. Still a cable capacity of 10 GW seems to be the best options because higher capacities do not further reduce the costs while the investment costs increase. For pumped storage capacity of more than 10 GW more electricity is transmitted and cost reduction is higher than investment annuity for all analyzed cable capacity. However, also for 10 to 20 GW additional pumped storage capacity (green and red line) 10 GW cable capacity is most beneficial because costs do not decrease significantly with more connection capacity and so the difference to the investment annuity gets smaller. Even for additional pumped storage capacity of 30 to 50 GW the decrease of costs above 10 GW cable capacity is smaller than the increase in investment annuity so that the most favorable options is still 10 GW cable capacity. With 4.2 billion € the difference between cost reductions and cable investment annuity is highest with 20 GW pumped storage plants and cable capacity of 10 GW.

From this figure only the most beneficial cable capacity for a specific pumped storage installation can be deducted not the overall best combination of pumped storage and cable capacity because the investment costs of the pumped storage plants are not taken into account.

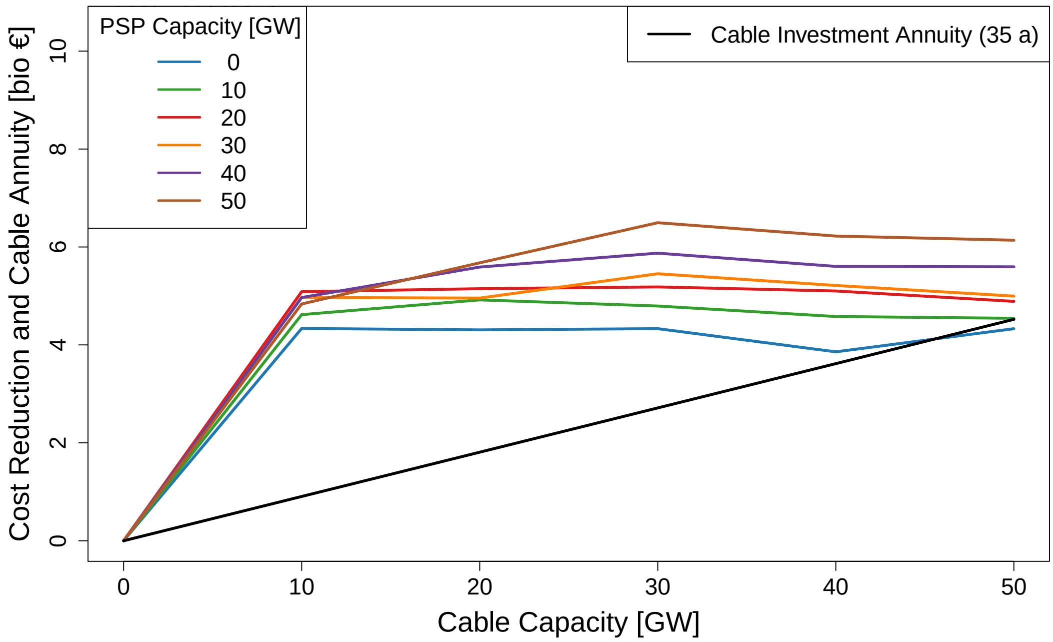

FIGURE 8.15: Cost reduction in relation to cable investment annuity for different cable and pumped storage plant (PSP) capacity

8.1.4 Profitability of Cable Connection

The consumer benefit does not factor into private investment decisions. The revenues that can be earned with a cable connection between two market areas are determined by the congestion rent. The congestion rent is calculated as cable flow times price difference between the areas after the exchange as shown in equation 8.3 (Nord Pool Spot, 2011).

$$R = (P_{\text{region A}} - P_{\text{region B}}) * F_{\text{B to A}} \tag{8.3}$$

R congestion rent
P electricity price
F power flow

The price difference between the regions and thus the specific congestion rent decreases as the connection capacity increases. When transmission equalizes the prices in both regions the congestion rent falls to zero. The reduction in specific rent can only be compensated with increased power flow. However, with diminishing marginal increase of power flow, it can be expected that the congestion rent tends to decline with higher connection capacity.

Figure 8.16 shows the cable revenues and the cable investment annuity. In none of the simulated scenarios are revenues sufficient to cover the investment annuity.

The prospects for profitability will be better the smaller the total connection capacity. Figure 8.17 shows additional scenarios with cable connection of 5 GW and 15 GW. They include 10 GW new pumped storage in Norway. While 5 GW connection capacity is not profitable either, the revenues at least come close to the investment annuity. The gap in this case is 22 million €.

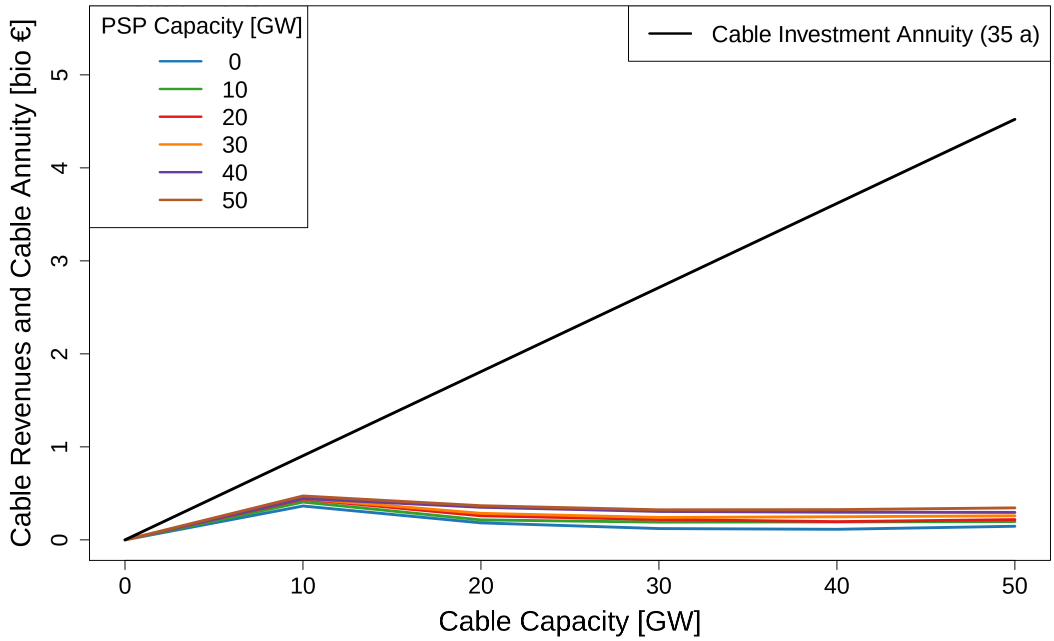

FIGURE 8.16: Cable revenues and cable investment annuity for cable and pumped storage plant (PSP) capacity

Comparing social benefits shown in section 8.1.3 and private revenues of cable connection, the lack of investment incentives becomes obvious. Investments in the range that would be beneficial cannot be financed through congestion rent revenues. Other schemes of funding are needed.

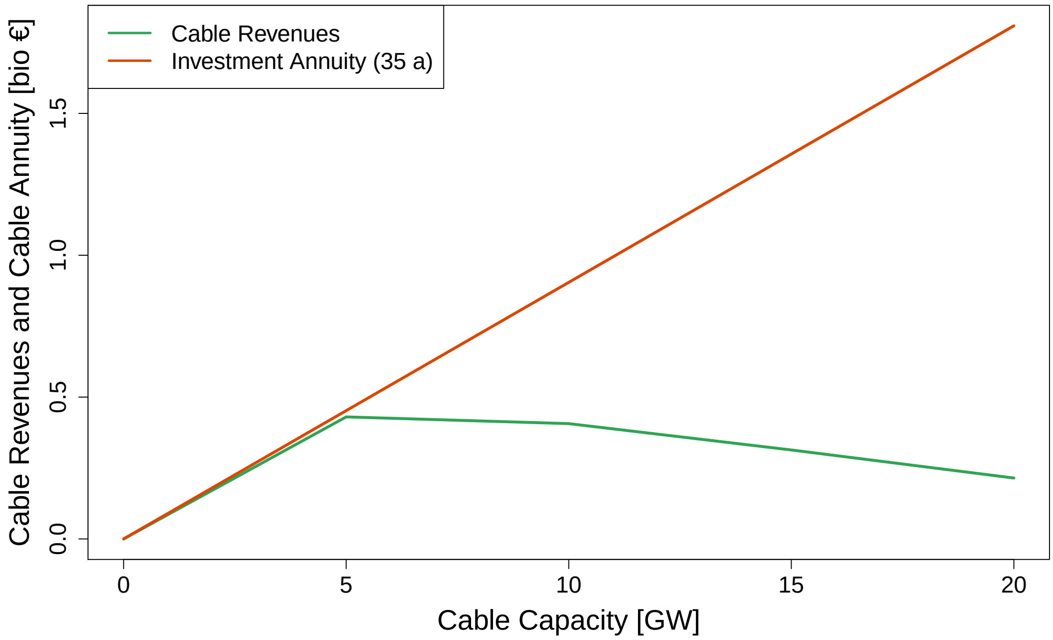

FIGURE 8.17: Cable revenues and cable investment annuity, 10 GW new pumped storage in Norway

8.1.5 Power Exchange within Germany

In this section the effect that connection to Norway has on the power exchange within Germany will be analyzed. Figure 8.18 shows the power exchange between the North-West and the East of Germany for different cable capacity scenarios. It can be seen that the effect of increased cable connection to Norway is limited. The peak flows on the cable, and thus the needed capacity, are not reduced. The power flow from the North-West to the East decreases with more connection capacity to Norway. One reason could be that excess electricity is redirected to Norway instead of to Eastern Germany. On the other hand flow from the East to the North-West is increased because excess electricity from Eastern Germany can be transmitted to Norway via the North-West of Germany. The variation of pumped storage capacity in Norway has no significant effect on transmission.

The power exchange between North-West and Western Germany is shown in figure 8.19. It can be seen that the power exchange between those regions is very imbalanced with more than 8000 hours of flow from the North-West to the West. This is caused by the assumptions for regional distribution of renewable production and load. In the calculated scenarios onshore and offshore wind energy production is concentrated in the North of Germany while a lot of power demand is located in the West. Again the peak flows are not reduced with cable connection to Norway. Also there is little impact on the

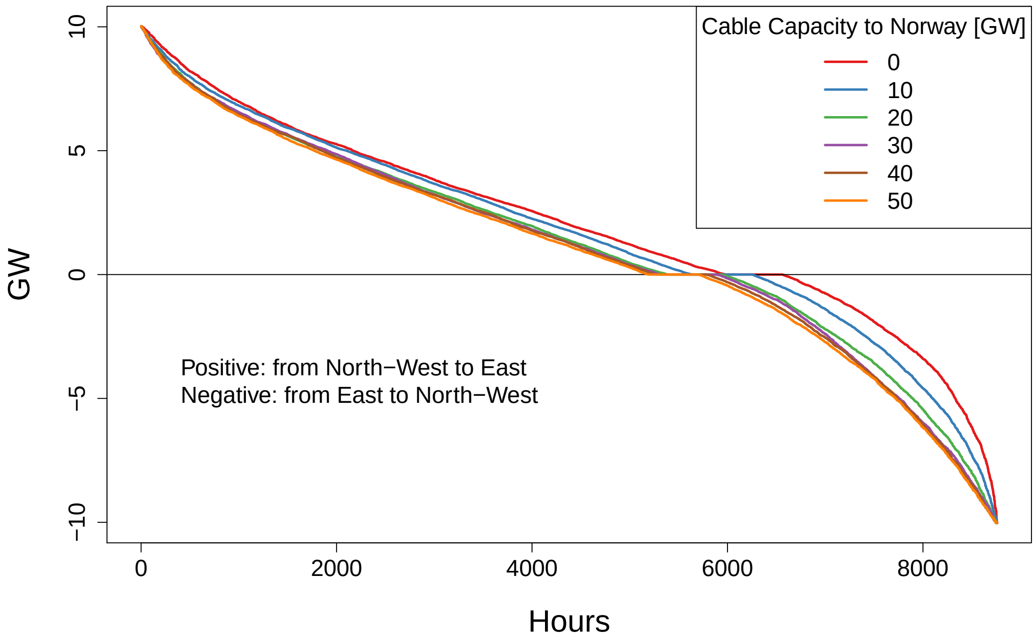

FIGURE 8.18: Duration of exchange between North-Western and Eastern Germany, 10 GW new pumped storage in Norway

exchange from the West to the North-West as well as on the balance of exchange. The power flow from the North-West to the West is reduced by the connection to Norway as in case of Eastern Germany because excess electricity can be redirected to Norway. This effect may be somewhat exaggerated in the renpass simulations because excess electricity is transferred randomly into other regions while in reality excess production would be curtailed without causing additional power flow.

The same effect of connection to Norway can still be observed between the West and the South-West of Germany as shown in figure 8.20. Also here the power flow to the South-West is reduced due to increased cable connection while there is no change to the power flow from the South-West to the West.

It can be concluded that the cable connection to Norway has only limited effect on the power exchange within Germany compared to a scenario without it. Increased connection to Norway is beneficial for the energy system but it will likely not reduce the need for grid extension and enforcement in Germany. The reason is that mainly excess electricity production from Northern Germany, that would otherwise have to be curtailed, is transmitted to Norway. On the other hand, at times of power shortage in the West and South of Germany high transmission capacity is still needed to transfer either renewable production from the North of Germany or stored electricity from Norway. If storage in Norway was compared with large-scale storage in the Alpine region the outcome could

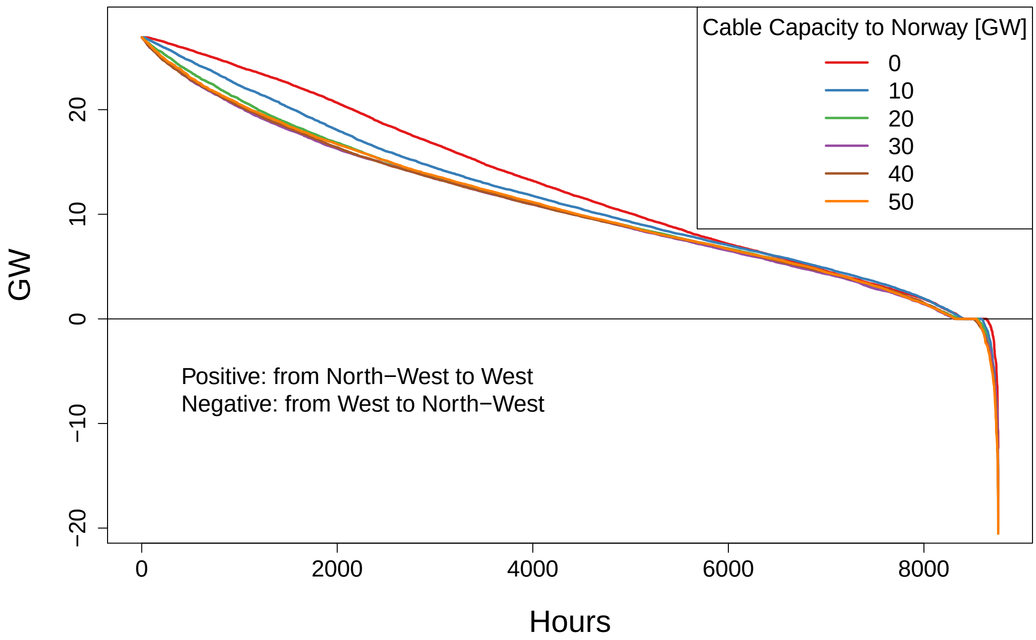

FIGURE 8.19: Duration of exchange between North-Western and Western Germany, 10 GW new pumped storage in Norway

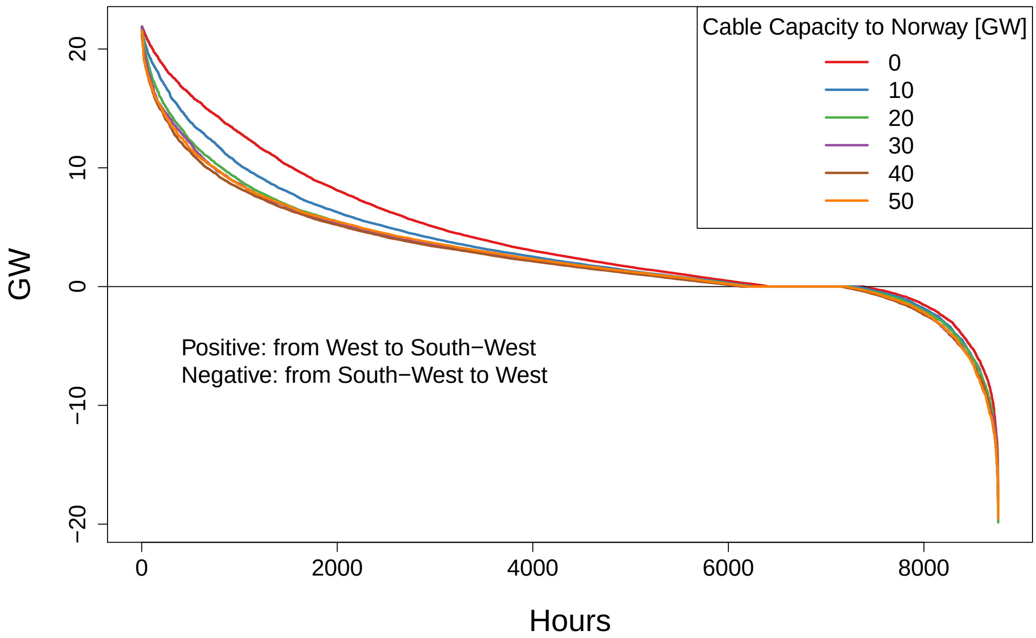

FIGURE 8.20: Duration of exchange between Western and South-Western Germany, 10 GW new pumped storage in Norway

be different. In that case it might be expected that storage in Norway leads to the lower grid demand.

8.2 Operation of Pumped Storage Plants

8.2.1 Utilization of Pumped Storage Plants

This section analyzes how pumped storage plants are operated. Figure 8.21 shows the duration curve of electricity production and electricity pumping of hydro storage plants in Norway for six different scenarios. All scenarios include 10 GW cable capacity between Germany and Norway and differ only in the additional pumped storage capacity in Norway. In the scenario with zero additional pumped storage capacity, the operation of the currently existing hydro storage plants of 23.4 GW and pumped storage plants of 1.3 GW are simulated. The additional capacity is assumed to be equal for operating and pumping mode respectively.

It can be seen that electricity production increases with newly installed capacity but there is only little effect beyond 10 GW additional capacity. The maximum of simultaneously utilized capacity is below 30 GW in all scenarios and thus much lower than the total installed capacity especially in scenarios with 30 and 40 GW additional pumped storage capacity. However, one cannot automatically conclude that the new capacity is superfluous. As explained earlier, the operation is limited by the hydro resource that has to be used where it is collected and the power production cannot be reallocated to other power plants. The Norwegian hydro system is designed for distributed production in many hydro plants that often run below their installed capacity and reach on average only around 4000 full load hours. Section 8.2.4 looks in detail at the operation of the new plants. It also has to be kept in mind that the electricity production of the Norwegian hydro storage plants is always limited by the domestic load and the connection capacity. In scenarios with cable capacity to Germany of 10 GW it can therefore be expected that additional pumped storage capacity of more than 20 GW has only little effect on the production.

The operation of pumps increases steeply with the installation of 10 GW additional capacity, beyond that, as for the turbine mode, there is little effect. In general the utilization hours are lower in pumping mode than in production mode. That is to be expected because the electricity production includes both reconversion of pumped water and direct production from natural inflow that supplies the Norwegian electricity demand. The simulated pumping capacity is very little utilized with very steep duration curves. Full-load hours decrease from 1693 h without additional pumped storage capacity to 292 h with 50 GW additional capacity.

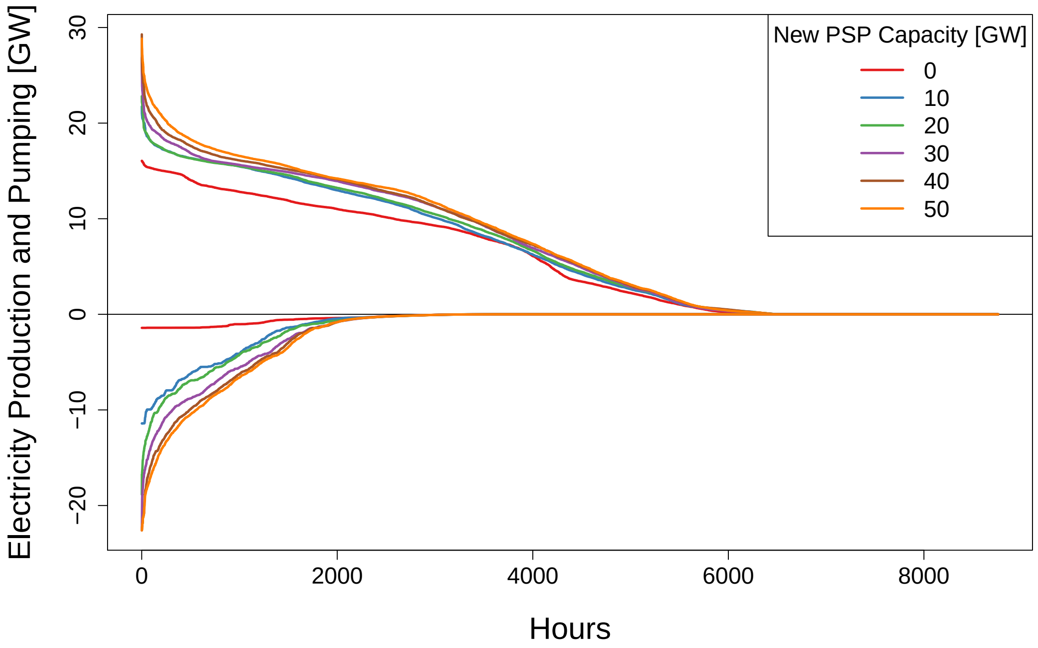

FIGURE 8.21: Duration curve of production and pumping from hydro storage plants in Norway, 10 GW cable capacity

The effect of the cable capacity between Germany and Norway can be seen in figure 8.22. All scenarios include 10 GW new pumped storage capacity. The increase of cable capacity has evidently more effect on the pumping operation than on the power production. The reason for this is the net export from Germany to Norway that either substitutes power production in Norway or is used for pumping.

The dispatchable hydro storage plants produce electricity when it is needed. The daily mean of hydro production and residual load for the whole area are shown in figure 8.23. It shows that the dispatch of the plants in the model is working properly and the production from hydro storage plants follows the residual load. However, even in the scenario with 50 GW cable capacity and 50 GW new pumped storage the residual load can only be covered partly by production from hydro storage plants. The simulated pumped storage plants alone are not sufficient to supply the needed flexible capacity. Other options are needed to fill in the remaining gaps. In the simulated scenarios also biomass plants are included for that purpose.

A closer look can be taken in figure 8.24 which shows hourly production of hydro storage plants and biomass plants. Hydro storage plants closely follow the residual load. The combined production from hydro and biomass plants is sufficient to cover the residual

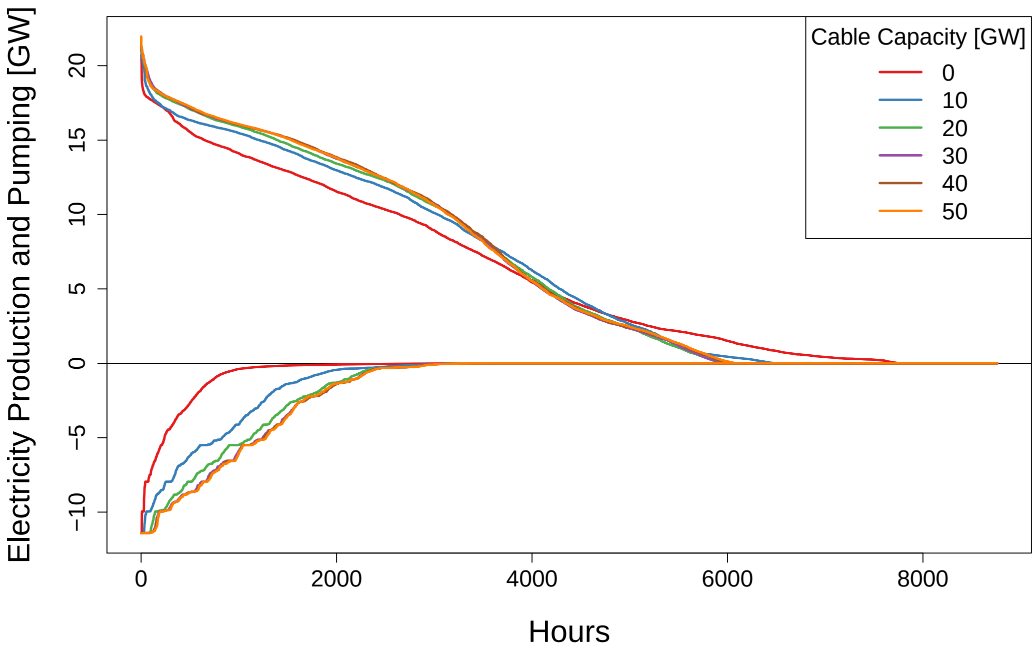

FIGURE 8.22: Duration of production and pumping for hydro storage plants in Norway, 10 GW new pumped storage capacity

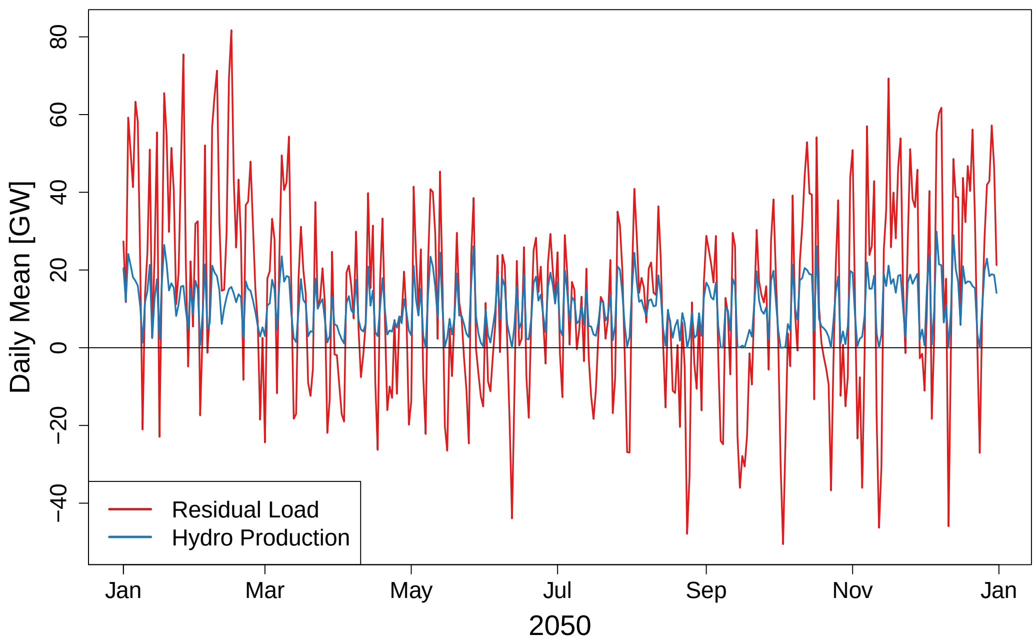

FIGURE 8.23: Daily hydro production and residual load of the whole area, 50 GW cable capacity, 50 GW new pumped storage

load. The production is slightly higher than the residual load because the loss from electricity transmission has to be covered as well.

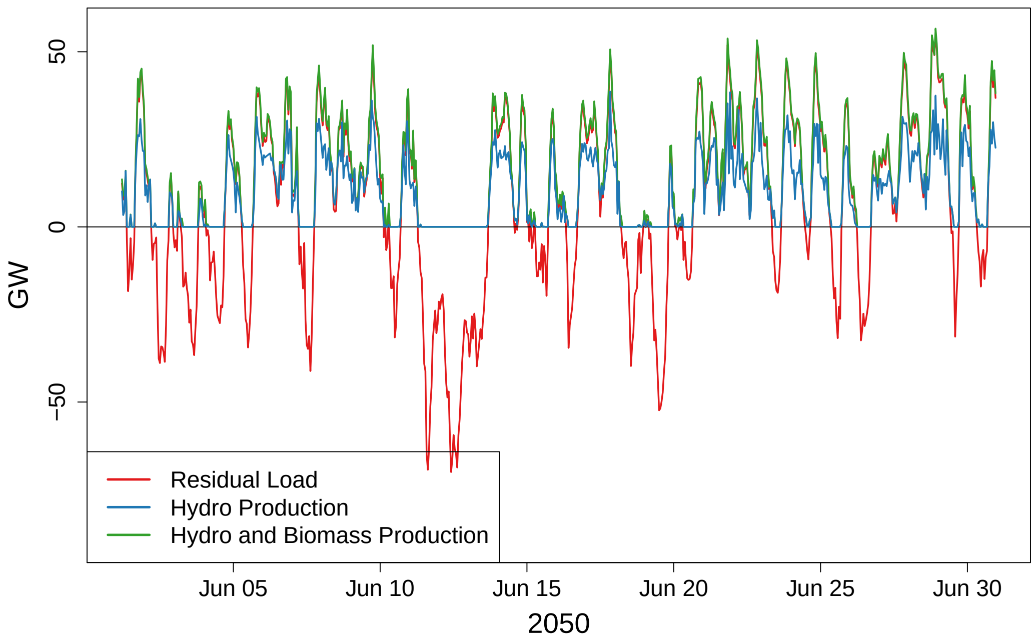

FIGURE 8.24: Hourly hydro and biomass production and residual load of the whole area, 50 GW cable capacity, 50 GW new pumped storage

Similarly the pumping of electricity is driven by the overproduction or excess electricity as shown in figure 8.25 for the whole area. In a scenario with 50 GW cable capacity and 50 GW new storage capacity most of the excess electricity can be absorbed by pumping. In summer and fall there are peaks of excess production that cannot be pumped even though the installed capacity would be sufficient. Apparently the hydro resource is limiting the pumping during times when reservoirs tend to be full. When the upper reservoir of a pumped storage plant is full the pumping capacity is not available.

Figure 8.26 shows the same data for a scenario with 10 GW cable capacity and 10 GW new pumped storage capacity. In that case only a small share of the excess electricity can be absorbed by pumping.

Hourly electricity production and pumping in Norway is shown in figure 8.27. Seasonal trends are more pronounced in the operation of the Norwegian plants. It can be seen that the pumping of electricity occurs mainly during spring and early summer with infrequent peaks during fall. While the amount of electricity pumped is lower than the produced electricity the installed pumping capacity is completely utilized at times while the sum of hydro production is always well below installed capacity. This means the pumping of

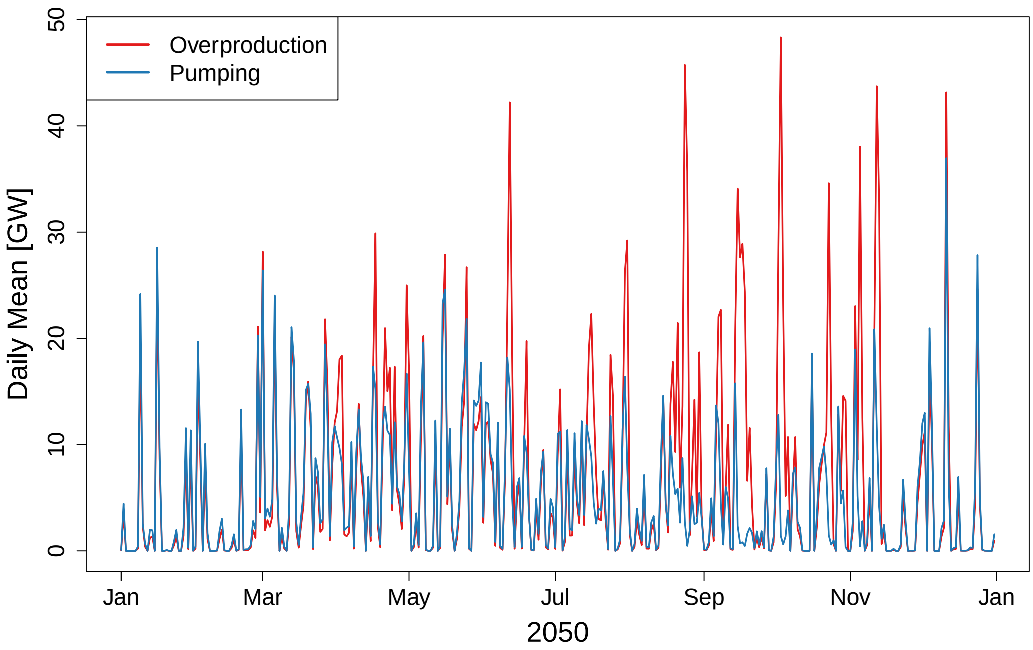

FIGURE 8.25: Daily renewable overproduction and pumping of the whole area, 50 GW cable capacity, 50 GW new pumped storage

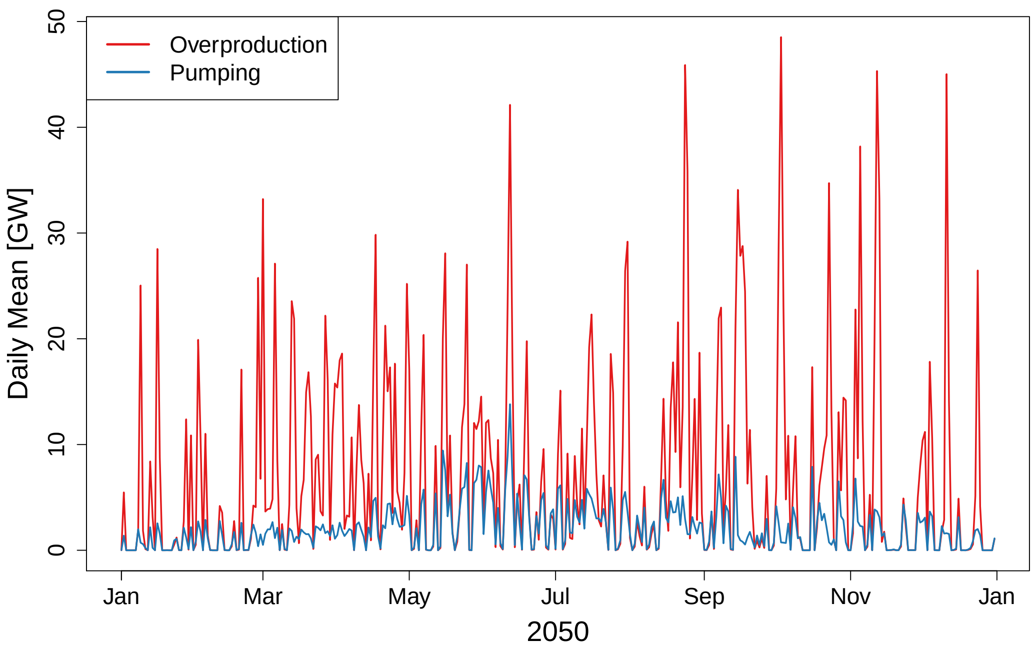

FIGURE 8.26: Daily renewable overproduction and pumping of the whole area, 10 GW cable capacity, 10 GW new pumped storage

electricity is concentrated to fewer hours with higher peaks while the production is more even throughout the year.

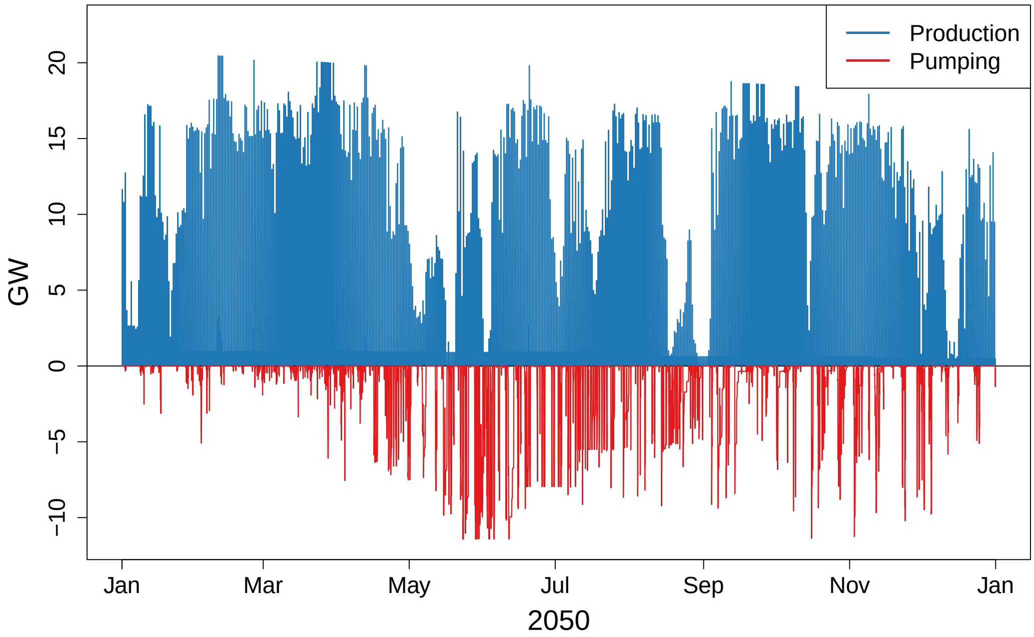

FIGURE 8.27: Hydro production and pumping in Norway, 10 GW cable capacity, 10 GW new pumped storage

8.2.2 Economic Benefits of new Pumped Storage Capacity

In section 8.1.3 the effect of cable capacity between Germany and Norway on the electricity price in Norway and Germany is shown. In this section the effect of additional pumped storage plants in Norway will be presented. Figure 8.28 shows the price duration curve in Norway for different pumped storage scenarios. In all scenarios the cable capacity is 30 GW. The effect of additional pumped storage capacity is clearly noticeable. While the hours with zero price are reduced, for almost half of the year the price is lowered by the additional pumped storage. The highest price of the year is reduced significantly from 133 €/MWh with current pumped storage capacity to 64 €/MWh with 50 GW additional pumped storage.

The price effect in Germany is shown in figure 8.29. The effect from additional pumped storage capacity in Norway is smaller than that of cable connection capacity as shown in figure 8.14. However, it can be seen that the steep end of high prices is lowered with additional pumped storage capacity.

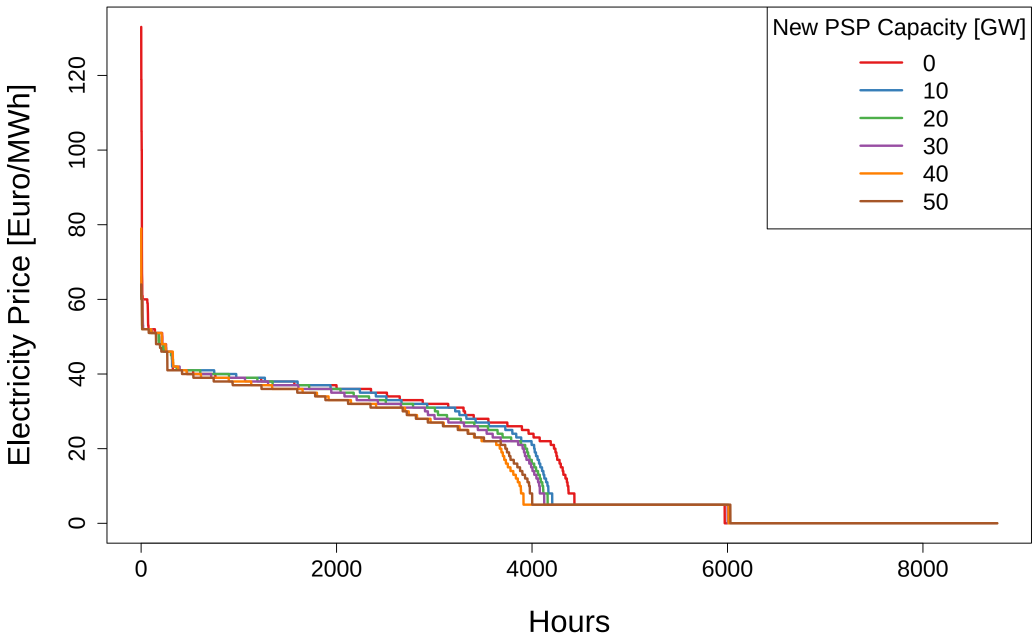

FIGURE 8.28: Electricity prices in Norway for different pumped storage scenarios, 30 GW cable capacity

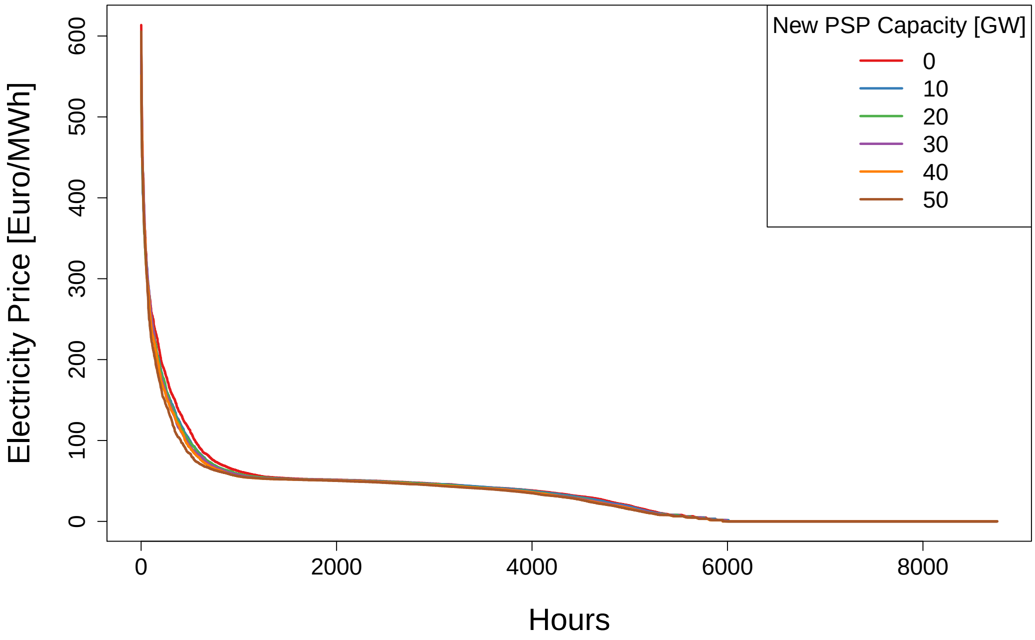

FIGURE 8.29: Electricity prices in Germany for different pumped storage scenarios, 30 GW cable capacity

The impact of new pumped storage capacity on the excess and shortage of electricity was shown in section 8.1.3. In figure 8.30 the costs reductions in the whole area from additional pumped storage capacity and the corresponding investment annuity are shown. The annuity is based on the investment costs for specific projects and is therefore not linear. The economic benefits of new pumped storage plants in Norway change with the cable capacity between Germany and Norway. Additional pumped storage capacity of 10 GW leads to cost reductions higher than the investment annuity already without cable connection to Germany. This is due to cost reductions in Norway, Sweden and Denmark but also in Germany which is indirectly connected to the new pumped storage capacity. For higher pumped storage capacity the benefits will only outweigh the investment annuity if there is sufficient grid capacity between Germany and Norway. At least 10 GW cable capacity is needed for pumped storage investment of 20 GW and more. For 10 GW and 20 GW cable connection pumped storage capacity up to 20 GW is beneficial. With 30 GW and 40 GW cable capacity benefits are higher than investment annuity for all analyzed pumped storage capacity. The highest net benefit can be found with 10 GW pumped storage capacity. On the other hand the net benefit increases again with 50 GW pumped storage capacity and most likely would continue to increase with higher capacity above that.

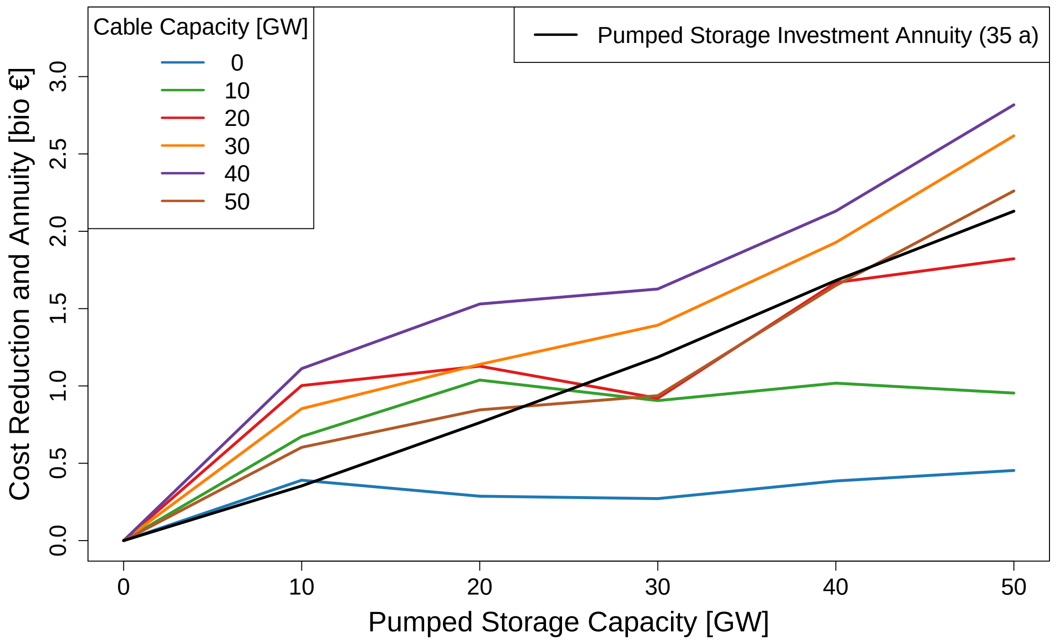

FIGURE 8.30: Pumped storage cost reduction and investment annuity for different cable and pumped storage plant (PSP) capacity

8.2.3 Favorable Combination of Cable and Pumped Storage Capacity

From figure 8.30 only the most beneficial pumped storage scenario for a specific cable connection capacity can be concluded as the investment costs of the cable are not taken into account. The total costs of the scheme are compared in figure 8.31. The color of the rectangles indicates the level of costs. Included in the figure are the investment annuity for additional cable and pumped storage capacity and the sum of consumer costs in each scenario. As more cable and pumped storage capacity is included in the scenarios the investment annuity increases and the consumer costs decrease. The most beneficial investment is reached when further investment costs are not outweighed by the achieved reduction of consumer costs. The investment costs for all other infrastructure such as wind energy plants and other grid connection lines are not included here. Those costs can be disregarded for the analysis because they are the same for all the simulated scenarios. Accordingly the costs shown here are not the total costs of the system and the values can only be used for comparing the different scenarios.

The lowest sum of consumer costs and investment cost annuity can be found with 10 GW cable connection and 10 GW additional pumped storage capacity. Higher capacity of cable connection and pumped storage plants will still reduce operation costs but those reductions do not outweigh the additional investment annuity.

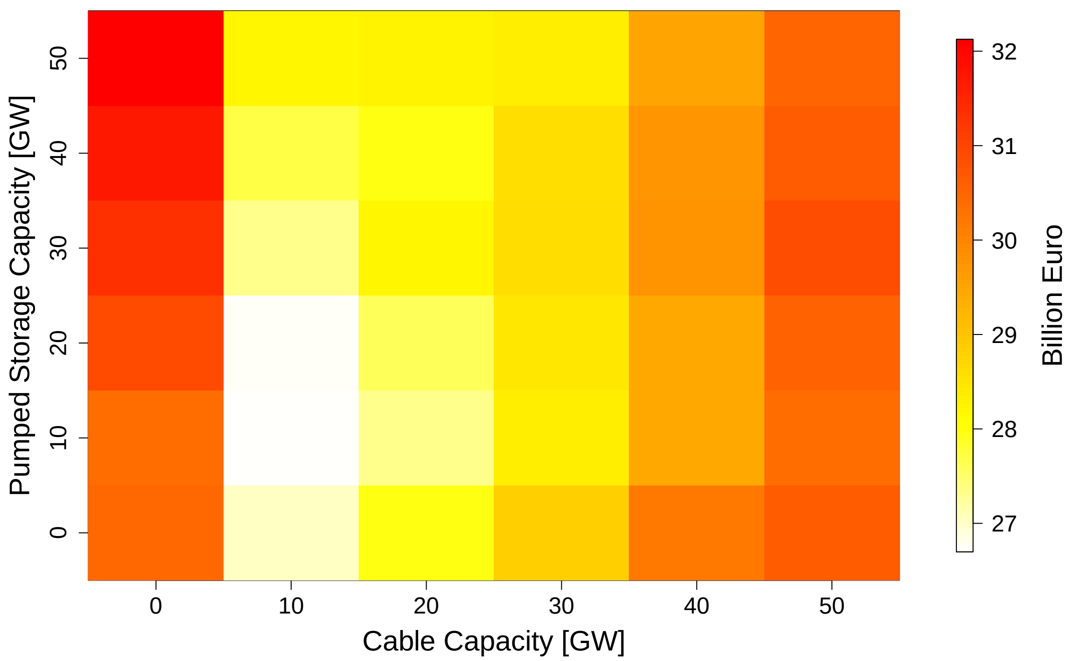

FIGURE 8.31: Sum of consumer costs and investment annuity for different cable and pumped storage capacities

8.2.4 Profitability of New Pumped Storage Capacity

General Development

The economic considerations of the operators of pumped storage plants will be presented in this section. Figure 8.32 shows the investment annuity for additional pumped storage capacity in Norway, calculated based on equation 8.2, and the additional revenues. The difference in revenues from electricity production of all hydro storage plants in Norway compared to a scenario without new pumped storage capacity is displayed. As in case of the cable investment the additional revenues are smaller than the investment annuity. That means that even though increased pumped storage capacity is beneficial for the whole energy system, the additional revenues from selling electricity are not sufficient to trigger the needed investment. However, this representation shows only the development of the whole market. If new plants gain market share from existing plants their individual profitability will be better than suggested by figure 8.32.

For the operation of the pumped storage plants only the pumping of excess energy at zero price is simulated in renpass. Neither arbitrage trading nor revenues from the control reserve market are included in the revenues shown in figure 8.32. Both of those additional revenue sources could improve the profitability of the additional pumped storage capacity.

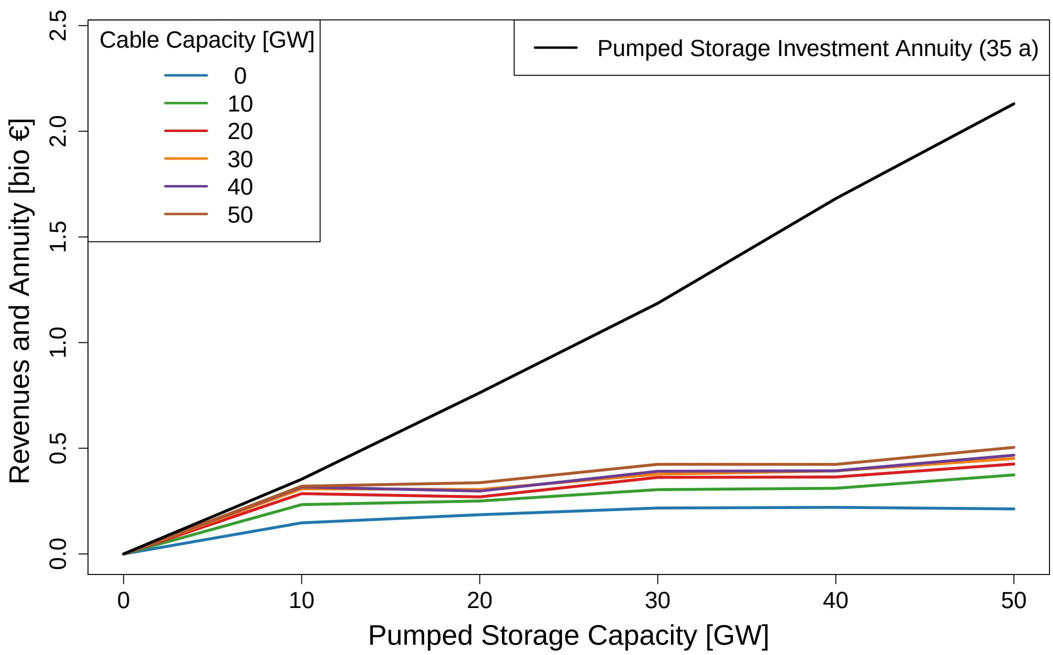

FIGURE 8.32: Revenues and investment annuity for hydro storage plants in Norway for different cable and pumped storage plant (PSP) capacity

As an example the duration of electricity production from the existing power plants in the Sira-Kvina hydro power system is shown in figure 8.33 for different cable connection scenarios. Sira-Kvina is a hydro power system in Southern Norway (Sira-Kvina Kraftselskap, 2000). It consists of seven power plants with a total capacity of 1.76 GW. The power plants are connected to nine main reservoirs on several different height levels. Total storage capacity sums up to 5.6 TWh. Sira-Kvina is one of the hydro storage systems that would be suitable for the extension of capacity. A concession application for a new plant of 960 MW was filed (Sira-Kvina Kraftselskap, 2007) but the project is currently on hold.

The duration curve of production becomes steeper with more connection capacity between Germany and Norway. The sum of production only varies between 4.1 TWh and 4.4 TWh with the highest power production in a scenario with cable connection of 10 GW. However, the number of hours when the plant is not in operation rises with increasing cable capacity and the production of electricity is concentrated in fewer hours with higher operating levels.

The shape of the duration curve is partly influenced by the unit commitment algorithm for hydro storage plants in renpass. In order to ensure an even use of the hydro resource, storage plants will only run above 70 % of their installed capacity in certain situations so that hours with more than 1250 MW of production are very few.

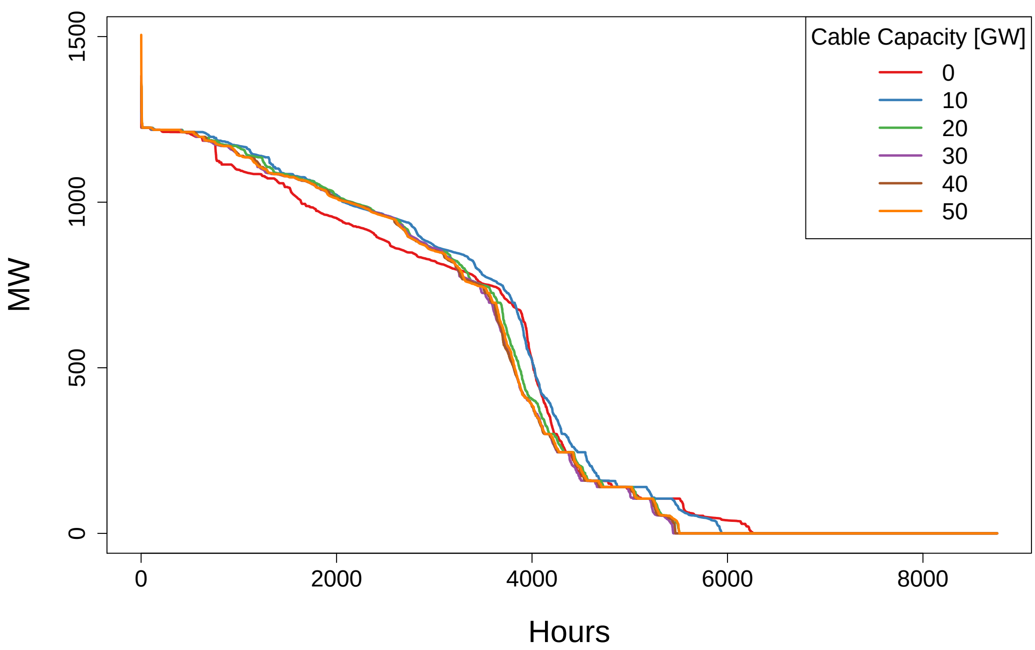

FIGURE 8.33: Production of Sira-Kvina power plants for different cable capacities, no new pumped storage capacity

The duration curves of electricity production in the existing power plants in Sira-Kvina are shown in figure 8.34 for different scenarios with varying additional pumped storage capacity. All scenarios include 30 GW cable capacity between Germany and Norway. As expected the electricity production of the already existing plants decreases from 4.1 TWh to 3 TWh as more pumped storage capacity is included in the Norwegian electricity system.

The total annual revenues from electricity production in the existing Sira-Kvina power system increase as 10 GW cable connection to Norway are included. For higher cable capacity the revenues stabilize or decrease slightly. The addition of new pumped storage capacity on the other hand has a significantly decreasing effect.

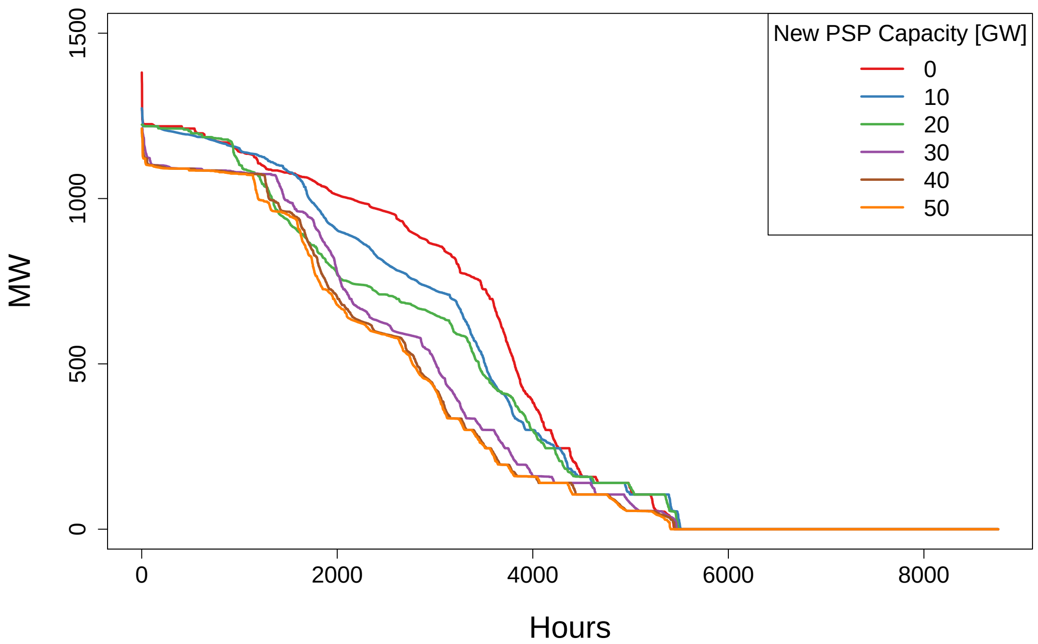

Figure 8.34: Production of Sira-Kvina power plants for different new pumped storage capacities, 30 GW cable capacity

The profitability of the newly included pumped storage plants in Norway is influenced by the cable connection to Germany and the total additional pumped storage capacity. In the analyzed scenarios up to 53 individual pumped storage plants with a total capacity of 50 GW are included. Figure 8.35 shows the number of profitable plants for each scenario. Plants are profitable when the investment annuity can be covered with the annual revenues. Of the 53 plants seven reach profitability in some of the scenarios. In no scenario more than five plants are profitable. The maximum profitable capacity is 3100 MW. In the most beneficial scenario with 10 GW cable capacity and 10 GW additional pumped storage capacity, only 1700 MW are profitable. There is a tendency that more plants are profitable with increased cable capacity to Germany. One would expect the profitability of individual plants to decrease as more pumped storage capacity is added and this can be seen in the figure to some extent. On the other hand with more pumped storage capacity more plants are included and the potential for profitable plants is broader. Four smaller plants which are only included in the scenarios with 20 and 30 GW additional pumped storage reach profitability in some scenarios while larger ones that are included earlier do not. This increases the number of profitable plants for 20 and 30 GW additional pumped storage plants but not the sum of profitable capacity. Still, the general tendency is that plants are less profitable the more pumped storage capacity is included.

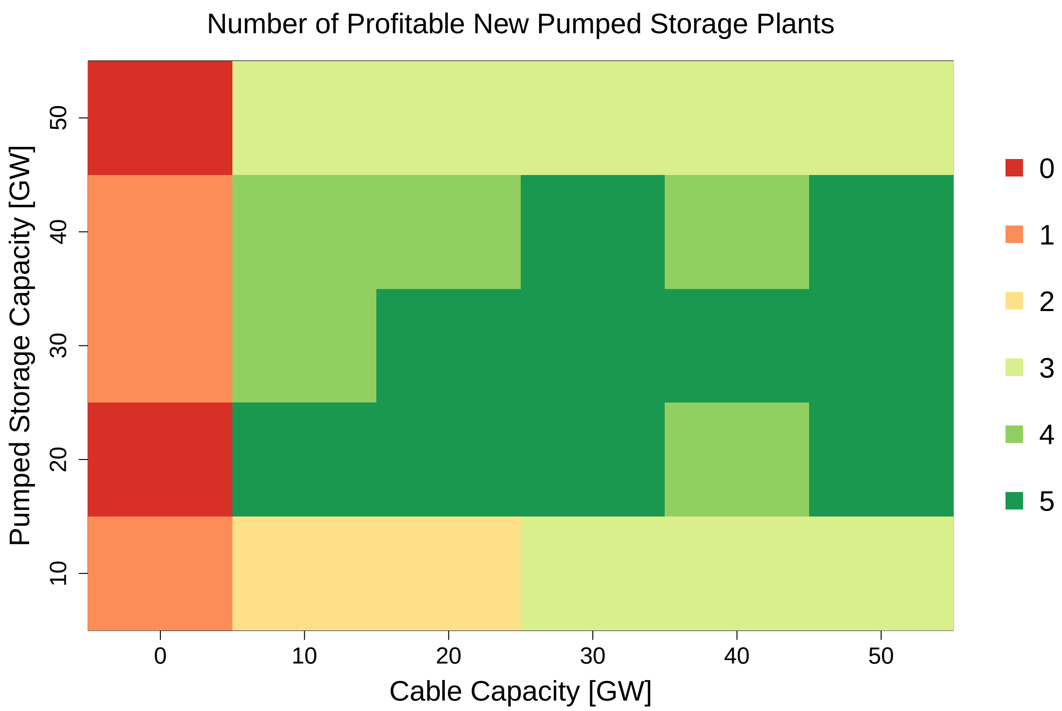

FIGURE 8.35: Number of profitable new pumped storage plants for different cable and new pumped storage capacities

To conclude additional revenues of the whole market are not sufficient to finance the investment in 10 GW new pumped storage capacity but some individual plants reach profitability in specific scenarios.

Case Studies of Individual Plants

Obviously the profitability depends not only on the layout of the system but also on the specific costs and the size of the plant. The situation of three new pumped storage plants in the scenarios shall be analyzed in more detail. Figure 8.36 shows the revenues and the investment annuity of a new pumped storage plant in Tonstad. For the new plant 1400 MW installed capacity and specific costs of 417 €/kW are assumed based on Solvang et al. (2012). This leads to investment costs of 583.8 million € and for a time span of 35 years and 8 % interest rate the investment annuity is 50 million €.

The annual revenues of the plant increase slightly with cable capacity to Germany and decrease considerably with increased pumped storage capacity. Only for additional pumped storage capacity of 10 GW the revenues increase significantly with increased cable capacity. The plant is only profitable for more than 20 GW cable capacity and less than 20 GW additional pumped storage capacity.

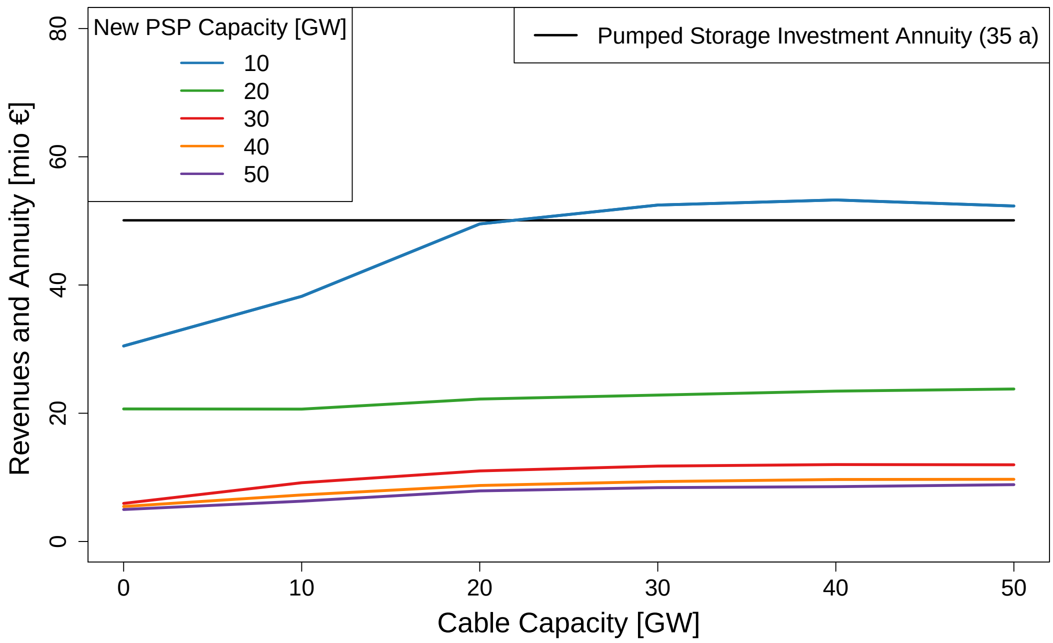

Figure 8.36: Profitability of new pumped storage plant in Tonstad for different cable and new pumped storage capacities

In order to track the drivers of the plant revenues, the annual power production and the average value of the produced electricity of the new plant are shown in figures 8.37 and 8.38. The figure that shows the production looks similar to the figure showing the revenues. Apparently the amount of production is very influential for the revenues. With increased cable capacity the production of the plant increases, especially for pumped storage capacity of 10 GW. The annual production is lower the more pumped storage capacity is included in the scenarios and the increase caused by additional cable capacity is smaller.

The value of produced electricity on the other hand decreases both with cable capacity and pumped storage capacity. For 10 GW and 20 GW additional pumped storage capacity prices do not decrease further for more than 10 GW cable capacity. The decrease is larger with higher pumped storage capacity and continues for cable capacity above 10 GW. Both the development of electricity production and of the value of produced electricity drive the revenues of the plant so that profitability is only reached with more than 20 GW cable connection and less than 20 GW additional pumped storage capacity as shown in figure 8.36.

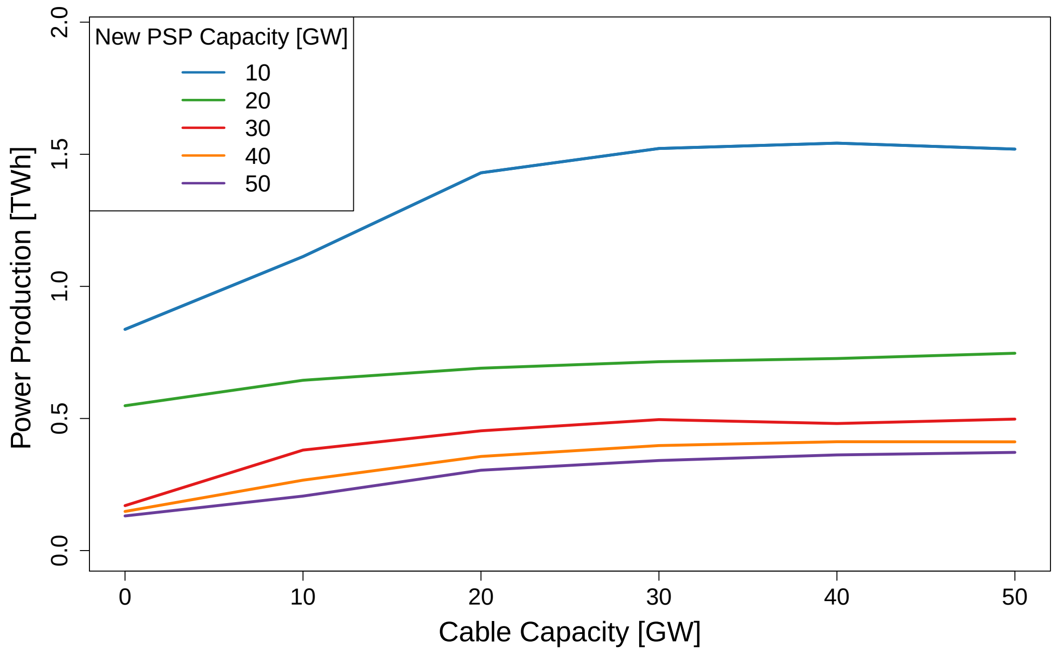

FIGURE 8.37: Production of new pumped storage plant in Tonstad for different cable and new pumped storage capacities

In figure 8.39 the revenues and annuity of a new pumped storage plant in Kvilldal in the power system Ulla-Førre are shown. The new plant is siumulated with 1200 MW capacity. Investment costs are assumed to 433.2 million € based on Solvang et al. (2012) leading to an investment annuity of 37.2 million €. It can be seen that, as in case of Tonstad, revenues increase with cable capacity and decrease with additional pumped storage capacity. However, different from Tonstad in none of the analyzed scenarios revenues are sufficient to cover the annuity.

In the simulated scenarios in total four new pumped storage plants in Kvilldal are analyzed. The first two plants are added in scenarios with 10 GW new pumped storage capacity. Two more plants are included in scenarios with 20 GW additional pumped storage capacity. The third extension in Kvilldal is analyzed in figure 8.40. This is a relatively small plant of 500 MW. All Kvilldal extensions are assumed to have the same specific investment costs of 361 €/kW leading in this case to total investment costs of 180.5 million € and investment annuity of 15.5 million €. It is striking that even though

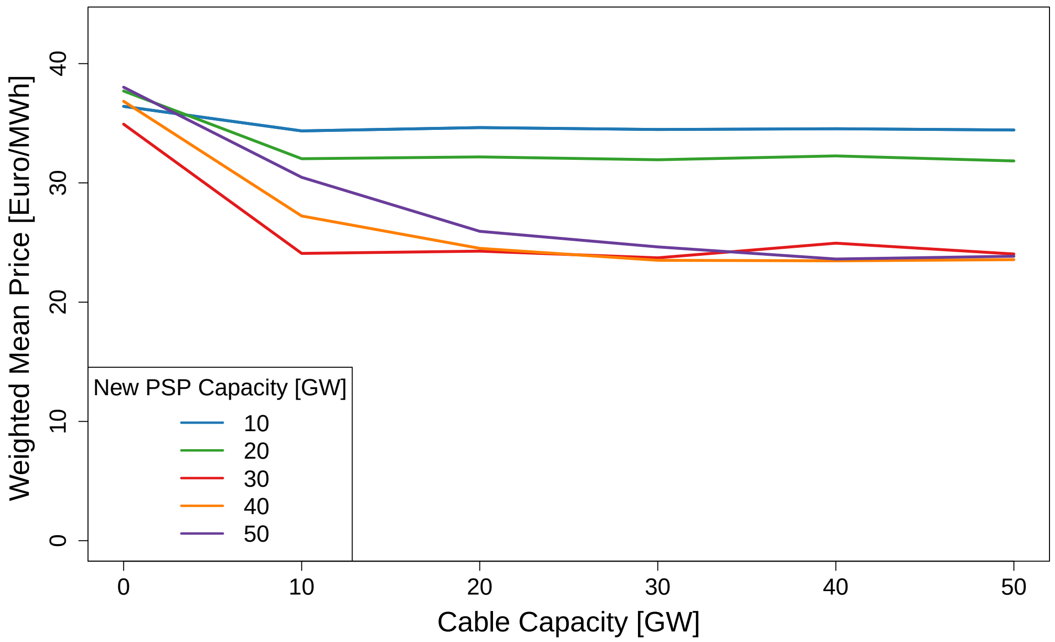

FIGURE 8.38: Average value of produced electricity of new pumped storage plant in Tonstad for different cable and new pumped storage capacities

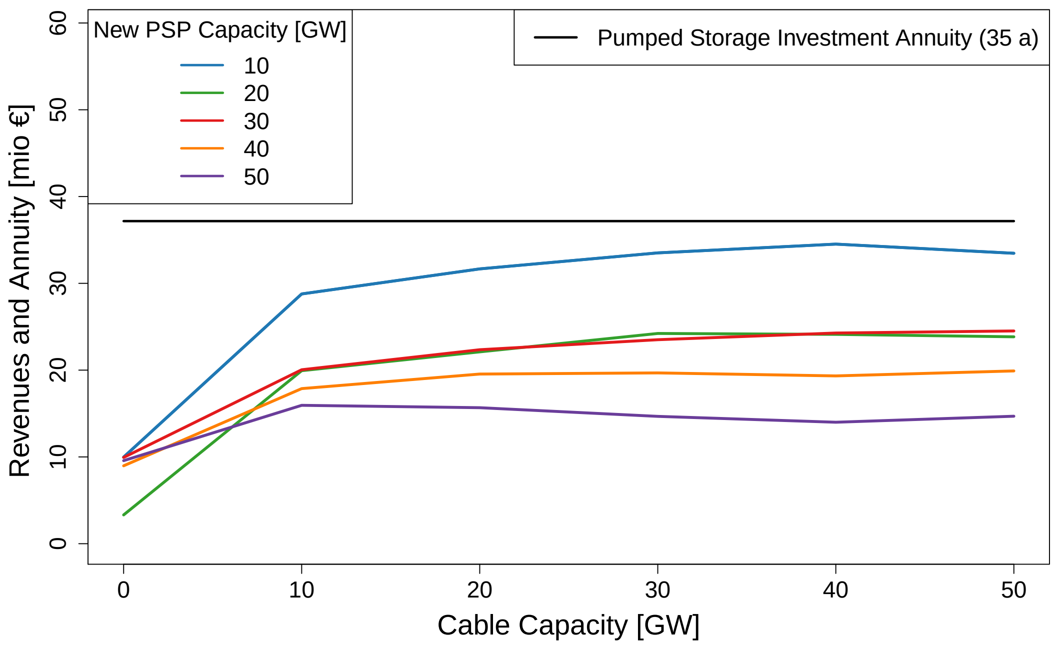

FIGURE 8.39: Profitability of first new pumped storage plant in Kvilldal for different cable and new pumped storage capacities

the third Kvilldal extension has the same specific investment costs and is added later, in contrast to the first it reaches profitability in some scenarios. That means that this plant should actually be build before Kvilldal 1.

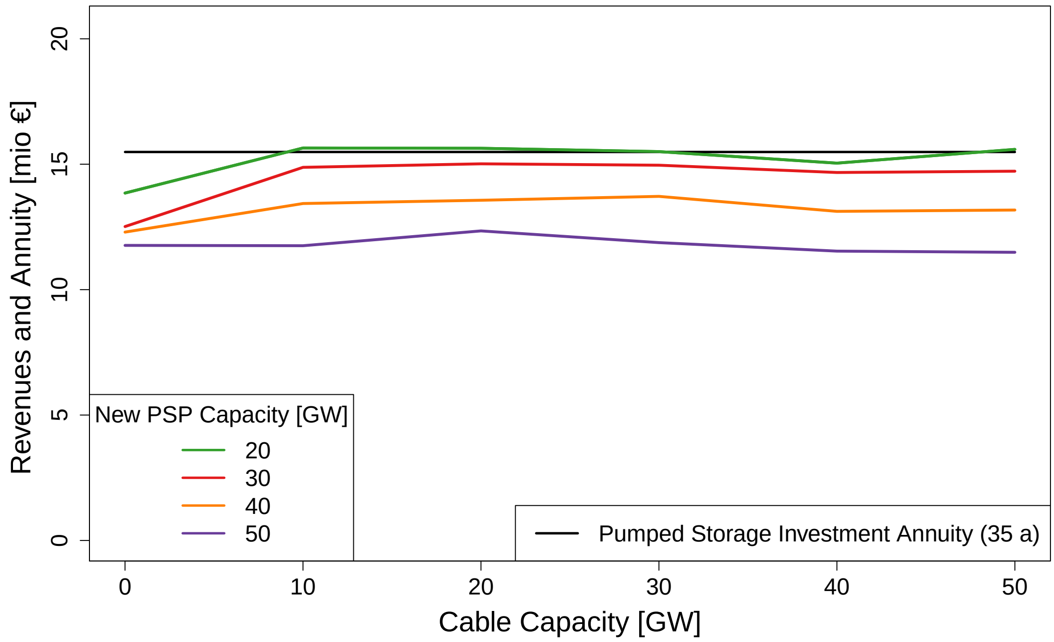

FIGURE 8.40: Profitability of third new pumped storage plant in Kvilldal for different cable and new pumped storage capacities

Figure 8.41 shows the utilization of both plants for the scenarios that include them. For both plants the full-load hours are very low. There is however a clear difference between the two plants. The full-load hours of the smaller plant Kvilldal 3 are significantly higher than those of the larger plant Kvilldal 1. This can explain the better profitability of the smaller plant.

It was shown that a new power plant at Tonstad in the Sira-Kvina system is profitable in scenarios with more than 20 GW cable capacity and less than 20 GW additional pumped storage capacity. A new large power plant at Kvilldal in the Ulla-Førre system does not reach profitability in any of the analyzed scenarios even though specific investment costs are lower than for Tonstad. A smaller plant in Kvilldal, which is connected to the same reservoirs and has the same specific costs as the large one, has higher full-load hours and attains profitability in some scenarios. Apparently smaller plants have a better chance for profitable operation than larger plants connected to the same reservoirs. This is an indication that several smaller pumped storage plants in various hydro systems are more favorable than a few large plants.

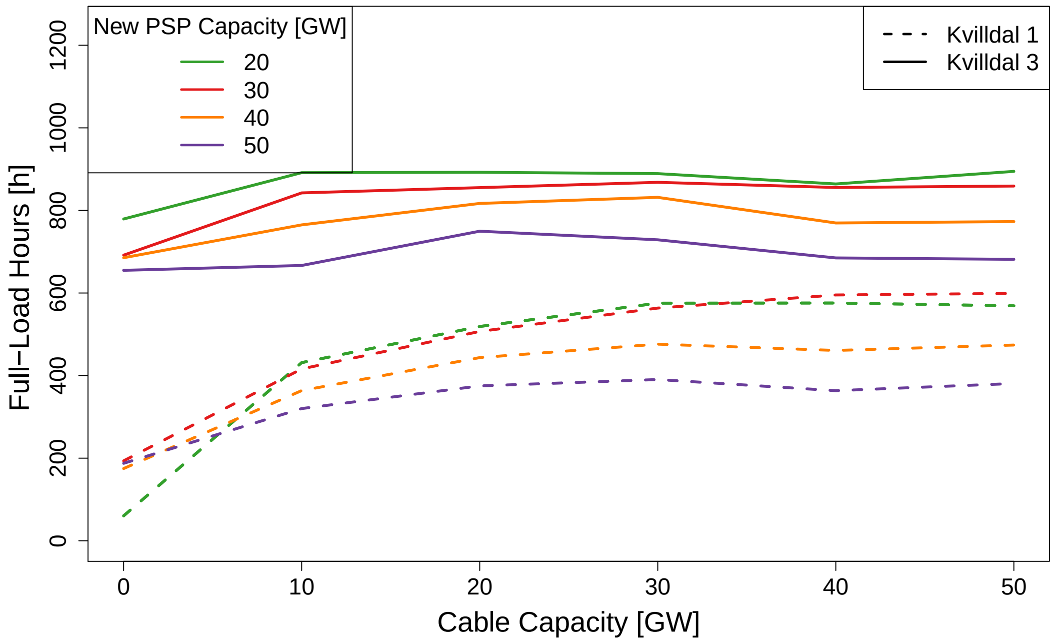

FIGURE 8.41: Full-load hours of new pumped storage plants in Kvilldal for different cable and new pumped storage capacities

Additional Sources of Income

The revenues analyzed here are only the income from the energy market. Additionally the pumped storage plants can operate on the control reserve market. As the new plants are very little utilized there is available capacity that can be provided to the control reserve market without sacrificing revenues from the energy market. As explained in section 2.2.4 there are different assumptions on the demand for control reserve in a 100 % renewable electricity system. Likewise the price levels of control reserve in a renewable system are uncertain. Currently primary control reserve is mainly supplied by conventional power plants while secondary control reserve and minute reserve is supplied by conventional power plants and pumped storage plants. In a renewable electricity system the contribution of the conventional power plants has to be supplied by renewable power plants or pumped storage plants. This will change the prices of the control reserve.

The highest full-load hours of the new pumped storage plant in Kvilldal 1 with 1200 MW are 800 h in the scenario with 10 GW additional pumped storage capacity and 40 GW cable capacity. This is equal to a mean utilization of 9.1 % or 110 MW. On average at least 1090 MW is hence available for positive control reserve and 110 MW for negative control reserve. The gap to profitability ranges between 2.65 million € and 28.2 million € between the scenarios. If only 200 MW were made available for control reserve during half of the year the capacity price would have to be 32.2 €/MW per hour to close the largest gap and only 3 €/MW per hour to close the smallest gap. Those prices are below current average capacity prices for control reserve in Germany, see for example first week of July (50Hertz Transmission et al., 2013). For most of the other pumped storage extensions the gap to profitability is larger than for Kvilldal 1 with the largest at 52 million €. Also in this case closing the gap with revenues from the control reserve market seems possible. However, while it could be possible for each of the new plants not all of them can simultaneously gain sufficient income from the control reserve market.

Shifting electricity from low price hours to high price hours is the business model of the pumped storage plants in Germany today. In the renpass simulations the storage plants pump only excess electricity at zero marginal cost. In a 100 % renewable system there will be very few production sources with positive marginal costs. In the analyzed scenarios those are only hydro power plants and biomass plants. There is hardly any reason why electricity produced from hydro storage plants should be used for pumping. As hydro power plants are very flexible and can be stopped and started rapidly the production should be stopped rather than storing the electricity with conversion loss. The case is similar for electricity production from biomass plants. It can be expected that in a 100 % renewable system biomass plants are designed for flexible production so that they can also be stopped and started quite fast. For this kind of operation biomass needs to be stored in the form of primary energy. The biogas plants are assumed to be equipped with a gas storage that allows the power production to run independently from the biogas production. On the other hand if biomass plants are used for combined heat and power production there could be situations where the produced power has to be stored in order to ensure the heat production. Nonetheless in general it can be assumed that the potential revenues from arbitrage storage are lower in a 100 % renewable electricity system and will not provide a significant contribution to profitability.

It was shown that the revenues from selling power on the energy market lead to profitability only for some new pumped storage plants in very specific system configurations. Supplementary income from the control reserve market can close the gap to profitability but not for all plants simultaneously. Arbitrage storage on the other hand will be less relevant in a 100 % renewable electricity system with a large share of fluctuating generation. All these considerations are based on the assumption that today's markets largely continue within their current framework.

8.2.5 Pumped Storage in Germany

The duration curves of electricity production and pumping from existing hydro storage plants and pumped storage plants in Germany are shown in figure 8.42. The scenarios vary in cable capacity and include no additional pumped storage capacity. The total electricity production varies between 6.5 TWh in the scenario without cable capacity to Norway and 6.3 TWh in case of 10 GW. The pumping of electricity decreases a little from 3.2 TWh without cable capacity to 2.8 TWh for cable capacity above 10 GW. The cable connection has thus only small influence on the sum of electricity production and pumping in German hydro storage plants. Also the shape of duration is only slightly affected by leveling out somewhat with increased cable capacity to Norway.

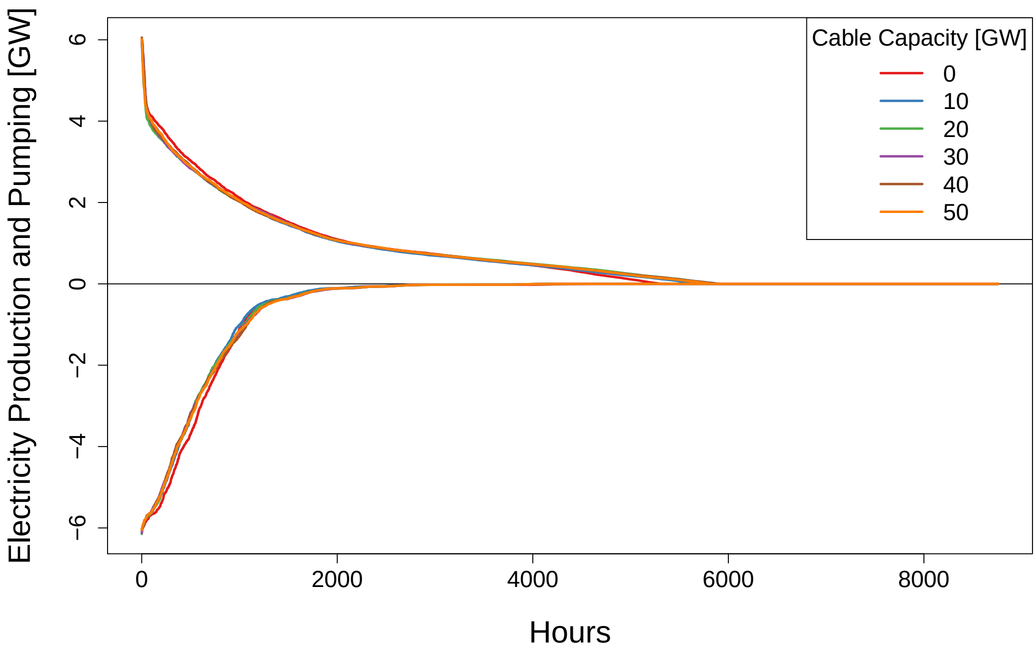

FIGURE 8.42: Duration of production and pumping from hydro storage plants in Germany, no new pumped storage capacity

The effect of increasing the pumped storage capacity in Norway is even smaller. In scenarios with 10 GW cable connection between Germany and Norway the sum of electricity production varies between 6.3 TWh and 6.1 TWh and the shape of the duration curve is not noticeably changed. The sum of pumping varies between 2.86 TWh and 2.88 TWh. The case is very similar for scenarios that include more cable capacity to Norway. Apparently the hydro storage plants in Germany are operated quite independently from indirect storage possibilities accessed through a cable connection to Norway and also from additional pumped storage capacity in Norway.

As an example figure 8.43 shows the revenues of the Goldisthal pumped storage plant for different cable and pumped storage scenarios. Goldisthal was built in 2004 in Eastern Germany and has a capacity of 1060 MW. The addition of 10 GW cable capacity between Germany and Norway has a considerable decreasing effect on the revenues of Goldisthal. Any further cable capacity increase does not have any significant effect. The additional pumped storage capacity does not change the revenues when there is no cable connection to Norway. With increased cable connection a small decreasing effect from additional pumped storage capacity becomes apparent.

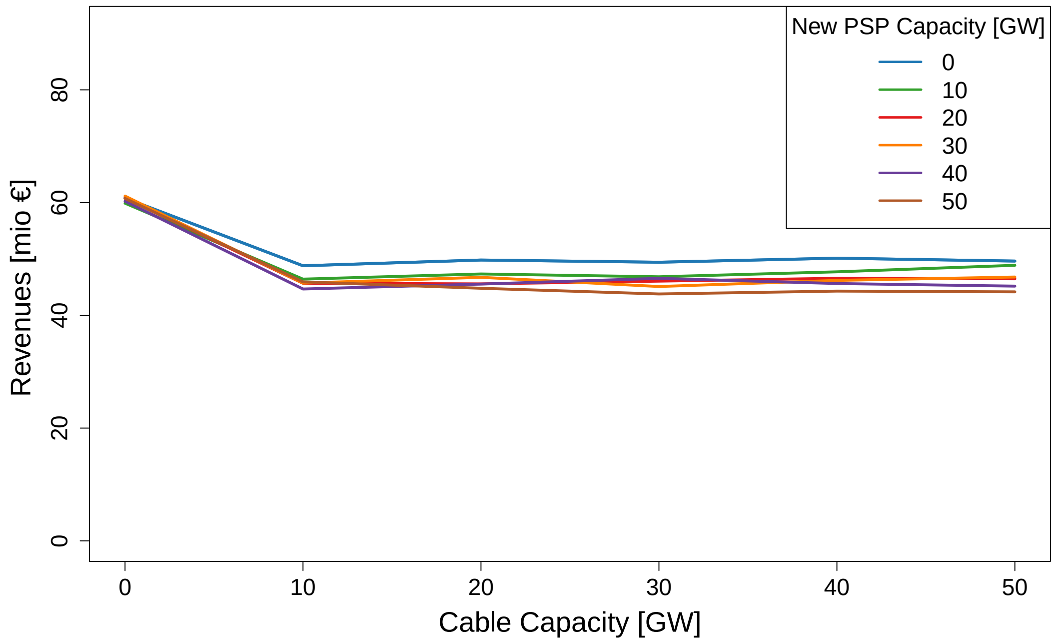

FIGURE 8.43: Revenues of Goldisthal pumped storage plant for different cable and pumped storage plant (PSP) capacity

8.3 Impacts on Reservoirs

8.3.1 Filling Levels throughout the Year

The connection of the German and Norwegian electricity systems and the installation of new pumped storage capacity will impact the levels of the storage reservoirs. Figure 8.44 shows the sum of Norwegian storage reservoirs for different scenarios for cable capacity between Germany and Norway. No new storage capacity is included in the scenarios.

Due to the imbalance of electricity exchange, with more electricity flowing from Germany to Norway, more cable capacity leads to higher reservoir filling levels. The seasonal trend of power exchange is also visible in the impact on reservoir levels. The highest difference can be seen in spring, before the snow melt, when the reservoir levels draw down less than they do without cable connection. Towards summer the difference is reduced when the exchange is more balanced. In fall and winter the net electricity transmission from Germany to Norway leads to higher reservoir levels compared to the scenario without cable connection. The effect of 10 GW cable connection is clearly visible. More cable capacity has less additional effect. This corresponds to the reduced effect of cable capacity beyond 10 GW on the transmission of electricity.

Besides the seasonal changes to reservoir filling levels, there are short-term effects. The levels of the reservoirs fluctuate more with cable connection to Germany. The fluctuations seem to increase only little with more than 10 GW connected capacity.

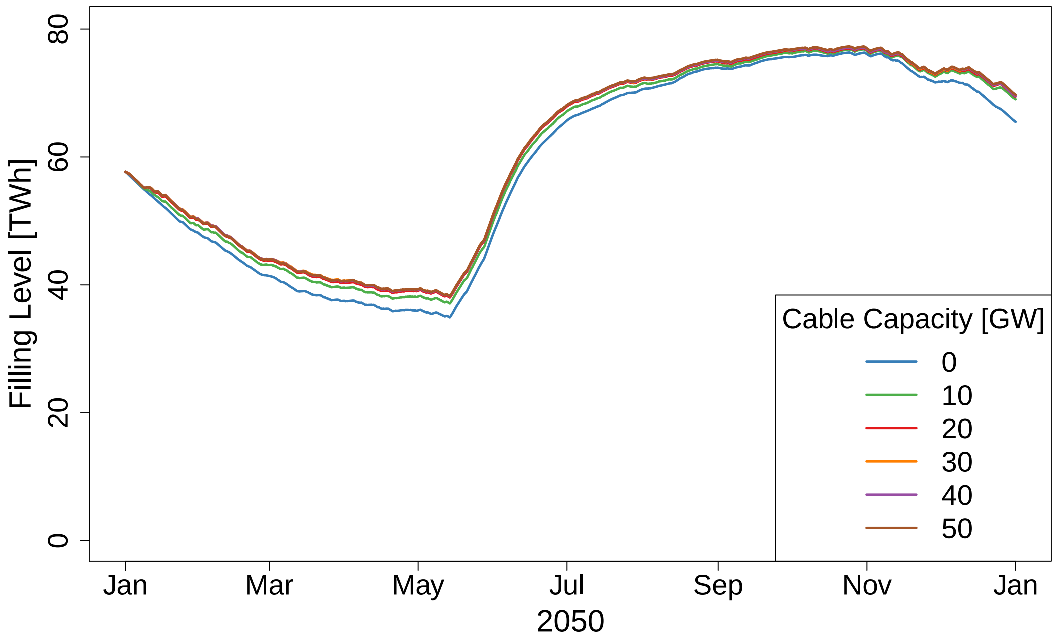

FIGURE 8.44: Impacts of cable capacity on filling level curve in Norway, no new pumped storage

Two reservoirs shall be looked at in detail to get a clearer picture of the specific effects. In figure 8.45 the reservoir filling level for the reservoir Roskreppfjorden is shown during the course of the year. This reservoir is part of the large hydro power system Sira-Kvina in Southern Norway. It has a storage capacity of 695 million m^3 or 1.5 TWh (Norges Vassdrags- og Energidirektorat, 2010b). The reservoir is located at the highest level of Sira-Kvina. The water level is regulated between 890 and 929 m height above sea level (Sira-Kvina Kraftselskap, 2000, p. 38). For Roskreppfjorden the seasonal effect is obvious. The cable connection leads to higher water level in spring and summer and lower water level in fall. The largest change can be seen between 0 and 10 GW cable capacity. The reservoir level is lowest in the fall for 10 GW capacity. More cable connection generally leads to a higher reservoir level also in the fall. An increase in fluctuations can be observed, mainly in the winter, but the difference seems quite limited.

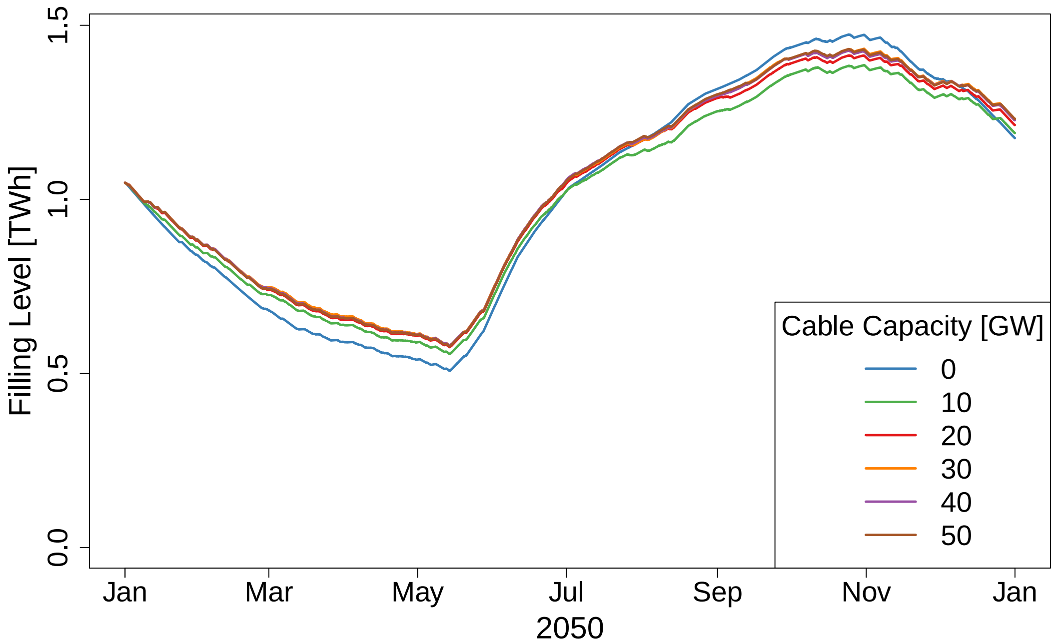

FIGURE 8.45: Impacts of cable connection on the reservoir Roskreppfjorden, no new pumped storage

In figure 8.46 a reservoir from the medium altitude level of Sira-Kvina is displayed. Nesjen, also called Kvifjorden, has a storage capacity of 275 million m^3 or 0.5 TWh (Norges Vassdrags- og Energidirektorat, 2010b) and is regulated between 677 and 715 m height above sea level (Sira-Kvina Kraftselskap, 2000). Also in this case with increased cable connection the water level is higher in winter and spring and increases faster during snow melt. That leads to a full reservoir in August, earlier than without cable connection. As a result it can be expected that water is spilled during summer.

Figures 8.45 and 8.46 are examples that show changes that more cable connection capacity can cause to individual reservoirs. The filling levels of specific reservoirs cannot be reproduced exactly with the model.

The changes in filling levels with new cable capacity are caused by changed operation of the existing plants. In the following the changes caused by new pumped storage capacity will be analyzed. In figure 8.47 the effect of new pumped storage capacity on the filling level of all Norwegian reservoirs is shown. The displayed scenarios include a cable connection capacity of 20 GW. Additional pumped storage capacity leads to lower

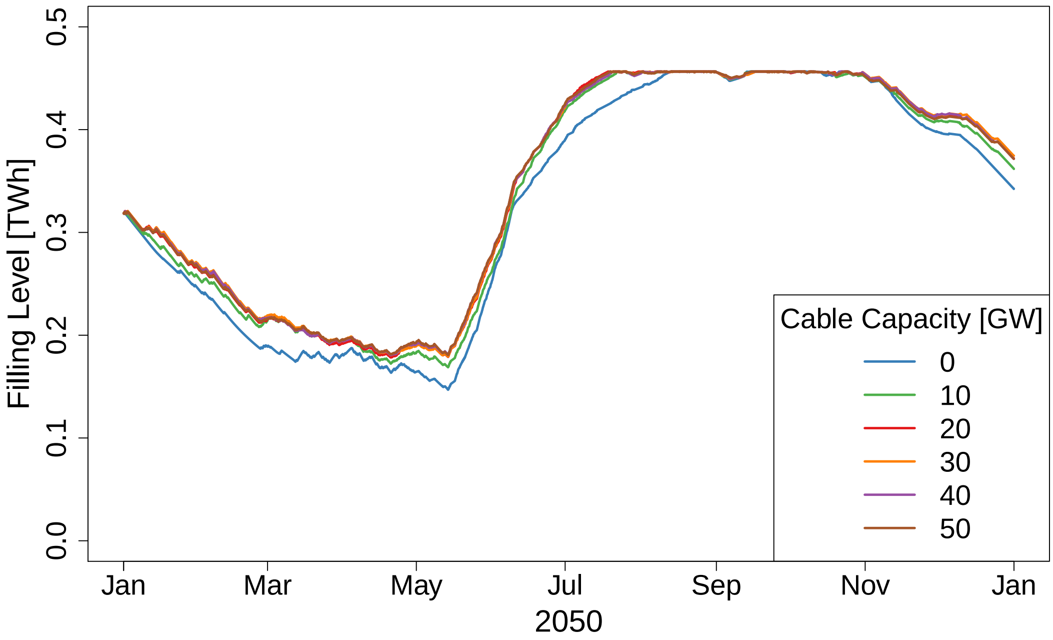

FIGURE 8.46: Impacts of cable connection on the reservoir Nesjen, no new pumped storage

reservoir levels before the snow melt and higher reservoir levels in late summer and fall. This is opposite to the effect of increased cable connection, which is however included in all the scenarios shown in the figure. The short-term fluctuations can be seen in all the curves. They are caused by the cable connection of 20 GW and do not seem to increase much further with more pumped storage capacity.

A similar picture can be observed for Roskreppfjorden in figure 8.48. More pumped storage capacity leads to higher filling levels in in summer and fall. The effect during winter and spring is rather small. The scenario with 10 GW new pumped storage capacity includes a new power plant of 1.4 GW in Tonstad in the Sira-Kvina system. In the scenario with 20 GW extension another 5.4 GW in Tonstad are included. This explains the higher effect between the 10 GW and 20 GW scenario. The 30 GW scenario additionally includes 3.2 GW in Solhom, directly below Nesjen reservoir.

The figure looks quite different for the reservoir Nesjen. Increased pumped storage capacity in the scenarios leads to the water level hitting the lower and upper regulated water levels. This is caused by the stepwise optimization in renpass. In real operation the power plants would be run more smoothly to prevent such extreme reservoir filling levels. This figure shows the shortcoming of renpass in simulating individual curves for some reservoirs.

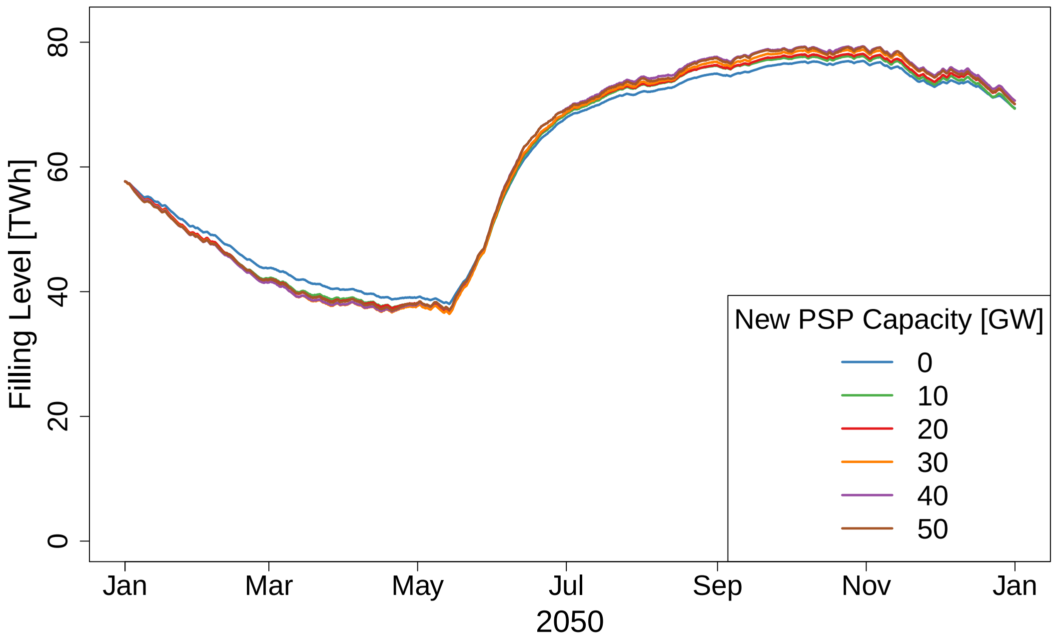

FIGURE 8.47: Impacts of new pumped storage capacity on filling level curve in Norway, 20 GW cable capacity

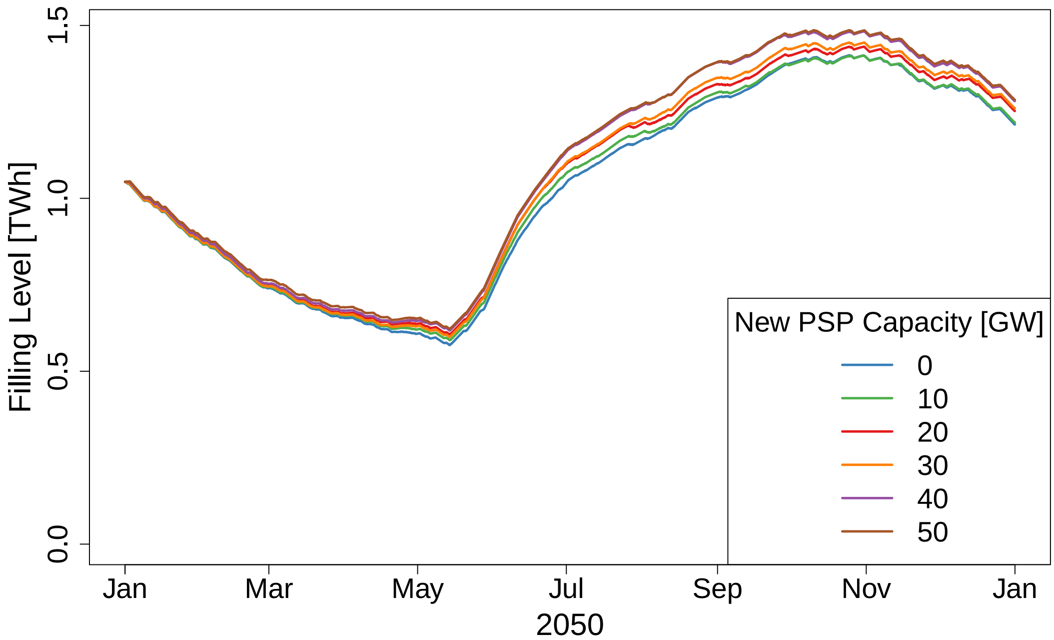

FIGURE 8.48: Impacts of new pumped storage capacity on the reservoir Roskreppfjorden, 20 GW cable capacity

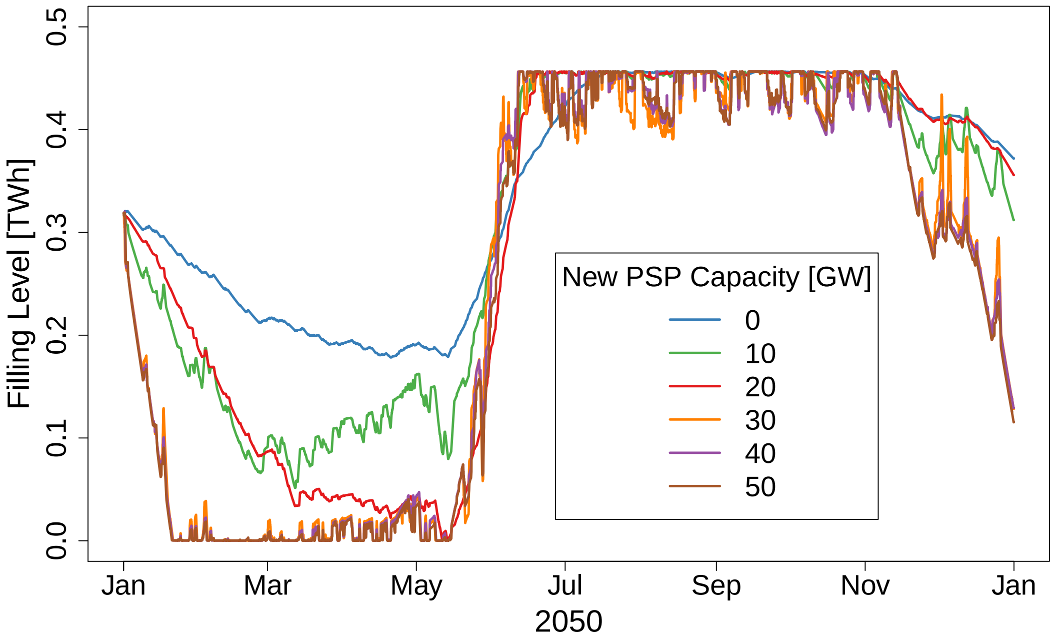

Figure 8.49: Impacts of new pumped storage plant (PSP) capacity on the reservoir Nesjen, 20 GW cable capacity

In summary it can be said that in general additional cable capacity leads to higher reservoir levels in spring and fall and similar or, in some cases, lower levels in summer. Additional pumped storage capacity leads to lower reservoir levels in spring and higher levels in summer. The combination of cable and pumped storage capacity is shifting the reservoir levels upward throughout the whole year.

8.3.2 Rate of Change of Filling Levels

One of the main environmental concerns about the installation of additional pumped storage capacity is the impact on water levels and the rate of change. As related before Solvang et al. (2012) assume that water level changes below 13 cm/h are environmentally acceptable. (p. 70f) Figure 8.50 shows the duration of the rate of water level change for the reservoir Svartevatn for varying pumped storage capacity. All scenarios include 20 GW cable capacity between Germany and Norway. Positive water level change means net inflow to the reservoir and negative water level changes means net outflow. Svartevatn is the largest reservoir in the Sira-Kvina system. It is located at the top of the Sira cascade and has a storage volume of 1398 million m^3 or 727 GWh (Norges Vassdrags- og Energidirektorat, 2010b). As can be expected for such a large reservoir water level changes are quite small with not more than 2 cm/hour. The highest value of water level change is increased only very little by additional pumped storage capacity. On the contrary for most of the time the rate of water level change is reduced. No additional pumped storage capacity is connected directly to Svartevatn and apparently the new installations reduce the needed capacity from Duge power plant below Svartevatn and consequently the rates of water level change.

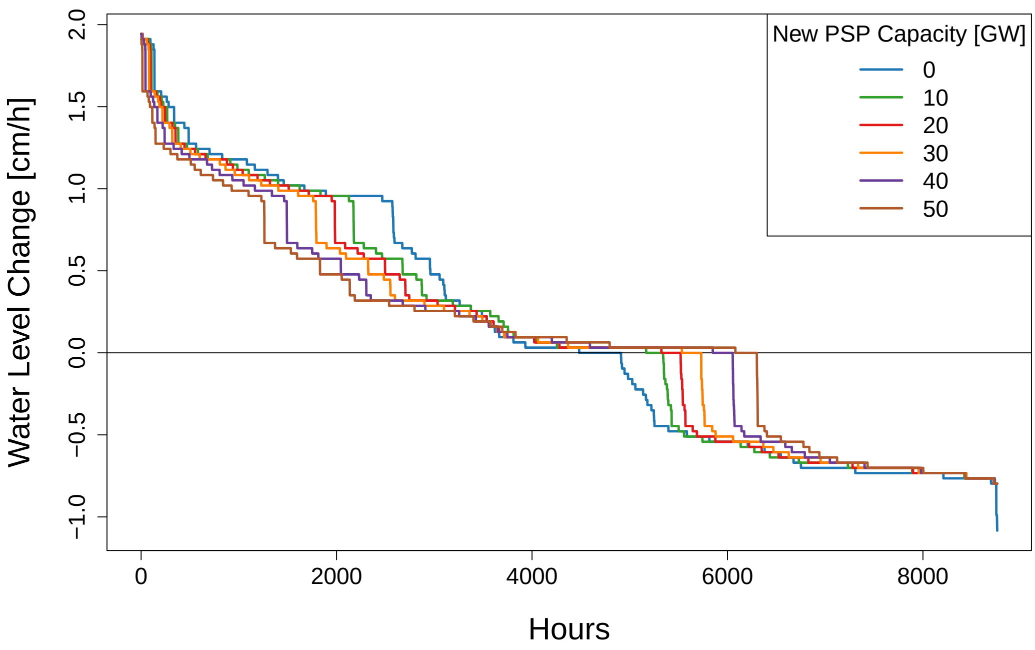

FIGURE 8.50: Impacts of new pumped storage plant (PSP) capacity on water level change of the reservoir Svartevatn, 20 GW cable capacity

Figure 8.51 shows the duration of the rate of water level change for the reservoir Nesjen. All scenarios include 20 GW cable capacity between Germany and Norway and varying pumped storage capacity. As could already be seen in the filling level curves in figure 8.49 the installation of additional pumped storage capacity has a significant impact and raises the maximum water level change. Up to 20 GW additional pumped storage, that means 6.8 GW new capacity in Tonstad, the maximum water level change is only raised to 6.5 cm/h and thus in an environmentally acceptable range. New storage capacity of 3.2 GW directly below Nesjen is included in scenarios with more than 20 GW total new pumped storage capacity. That increases the water level change to almost 50 cm/hour. This rate of water level change can cause environmental problems. None of the new plants causes high water level changes by itself but when all plants are operated in parallel the resulting rate of change can be outside acceptable limits. However, the limit of 13 cm/h is only exceeded in 659 hours in the scenario with 30 GW additional pumped storage capacity and even less frequently in the scenarios with 40 GW and 50 GW. Restricting the operation of power plants in those hours would only moderately impact the annual results.

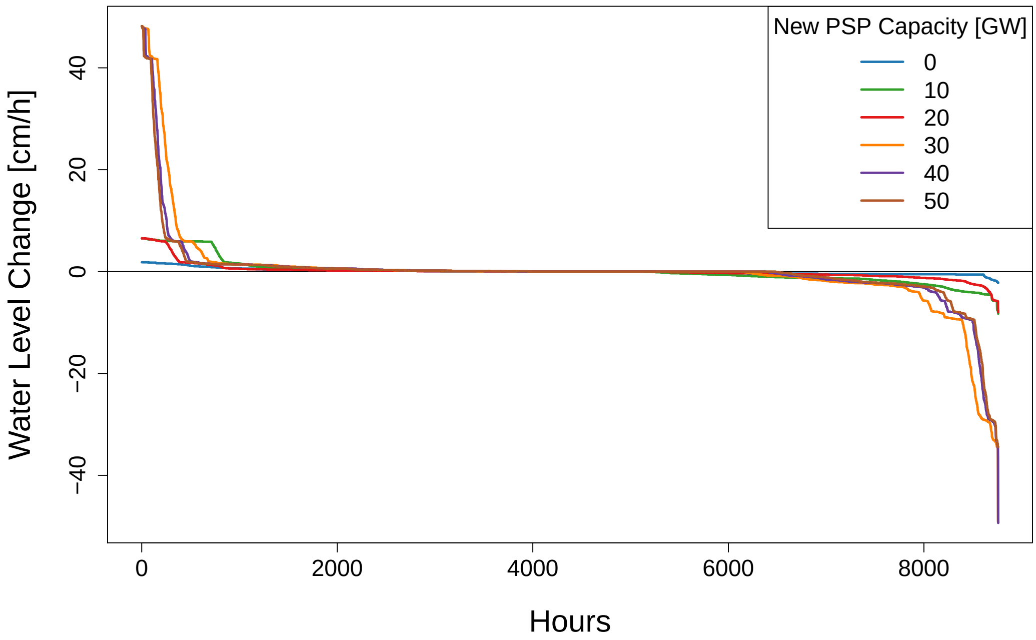

FIGURE 8.51: Impacts of new pumped storage capacity on water level change of the reservoir Nesjen, 20 GW cable capacity

As explained before renpass can give indications on the impact of the proposed scheme on storage plants and reservoirs but cannot do a detailed plant scheduling. It can be assumed that in reality operation of the power plants would be optimized across the whole power plant system as well as across the year and the impacts on the reservoirs would be smaller than they appear in the renpass simulations. That means that the shown results can be regarded as the upper limit of expectable impacts.

8.4 Extension of Storage Plants in Germany

In three alternative scenarios the sensitivity of the main results from the previous sections to the extension of storage capacity in Germany will be analyzed. The alternative storage scenarios consider three different storage extensions in Germany, as described in section 7.3. The first alternative includes planned pumped storage plants (PSP) with a total capacity of 3.15 GW and 25.37 GWh storage volume. The second variation includes instead 10 GW compressed air energy storage (CAES) with 240 GWh storage volume. In the third alternative 10 GW of power-to-gas-to-power storage (PTG) are connected to the natural gas grid with 220 TWh storage volume. All alternative storage scenarios contain 10 GW cable connection between Germany and Norway and 10 GW additional pumped storage capacity in Norway.

8.4.1 Operation of New Storage Plants in Germany

In this section the operation of alternative storage technologies in Germany shall be examined. Figure 8.52 shows the annual sum of electricity produced and stored in storage plants in Germany. Production and storage is divided into hydro storage plants and alternative storage technologies. In the CAES scenario this is only compressed air energy storage and in the PTG scenario only power to gas. The electricity production from hydro storage plants includes production from natural hydro inflow. Accordingly the production is higher than the storage of electricity. The sum of stored electricity increases with added storage capacity. In the scenarios including CAES and PTG plants the operation of the hydro storage plants is partly substituted. As can be expected the PTG plants store the largest amount of electricity because of the large storage volume.

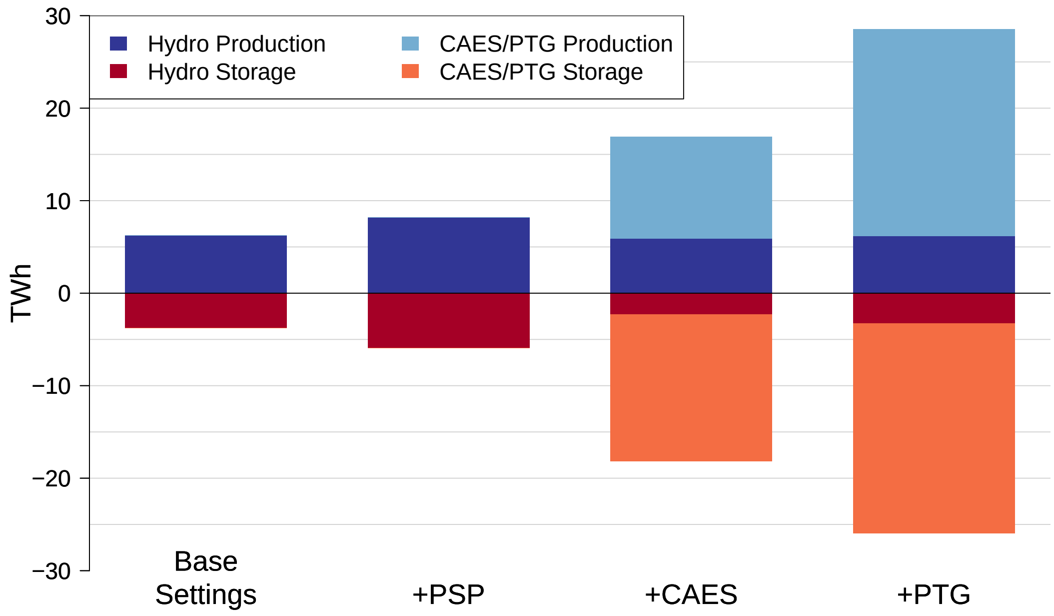

FIGURE 8.52: Sums of power production and storage in Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

In figure 8.53 the duration curves of operation are shown. Electricity production from storage plants of all technologies is displayed on the positive axis and electricity storage on the negative axis. For better comparison the duration curves are displayed above each other. In chronological order times of production and storage alternate. In all scenarios the maximum capacity of production and storage is used only during a few hours. The total hours of production are roughly the same in all four scenarios but in the CAES and PTG scenarios the utilized capacity is much higher. The total production from all storage plants is 6.2 TWh in the base case, 8.2 TWh in the PSP scenario, 16.9 TWh in the CAES scenario and 28.5 TWh in the PTG scenario. Total hours of storage increase in the alternative scenarios. Seemingly the PTG plants have the highest availability or in other words are least restricted by filling levels. The total stored electricity increases from 3.8 TWh in the base case to 5.9 TWh in the PSP scenario, 18.2 TWh in the CAES scenario, and 26.0 TWh in the PTG scenario. The difference between production and storage reflects the natural inflow to hydro storage plants, conversion losses and the change of filling levels between the beginning and end of the year.

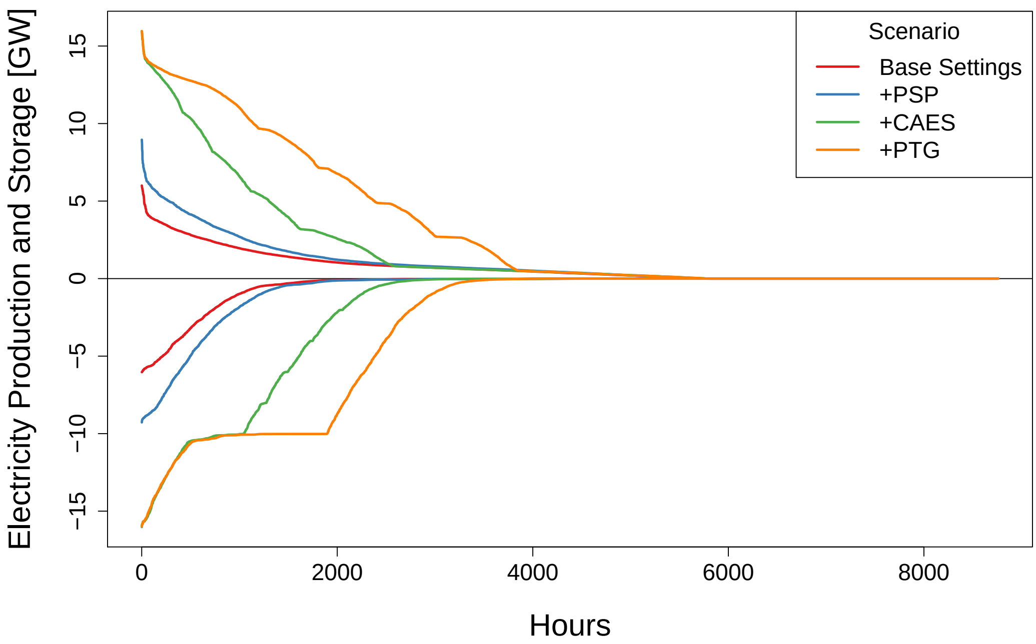

FIGURE 8.53: Duration of electricity production and storage in Germany for the base case and alternative storage scenarios, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

Figure 8.54 shows the operation of the compressed air energy storage (CAES) in Germany throughout the course of the year. The scenario includes production and storage capacity of 10 GW CAES. The daily mean of electricity production and electricity storage is displayed. The storage is used fairly evenly throughout the year. In total 11 TWh electricity are produced and 15.88 TWh are stored. The electricity production capacity is only fully utilized during 63 hours of the year and there are 1102 full-load hours of operation. The storage capacity on the other hand is fully utilized for more than 900 hours of the year and reaches 1588 full-load hours.

Figure 8.55 shows the operation of the power to gas plants (PTG). Also in this case the daily mean of power production and storage is shown. The installed capacity is the same as for the CAES plant. Especially the production capacity but also the storage capacity of the power to gas plants is used more than that of the CAES plants. Obviously the

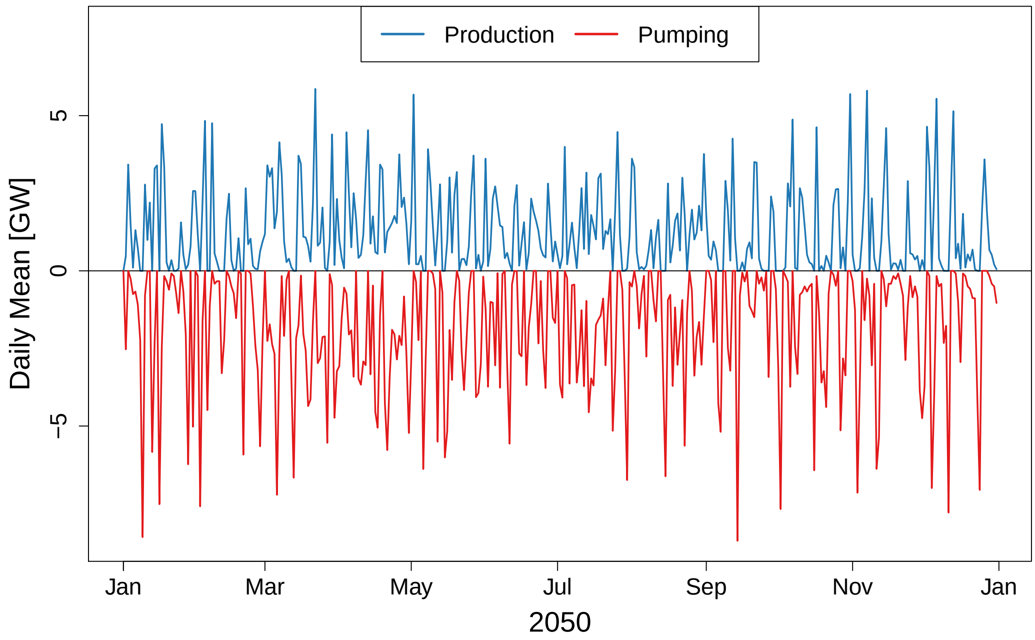

Figure 8.54: Daily mean of electricity production and storage of CAES in Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

production of the CAES plants is restricted by the filling level of the storage. Due to the large gas storage of the power to gas plant the filling level of the storage does not restrict the operation. The total electricity production is 22.37 TWh and the storage of electricity is 22.7 TWh. The full-load hours of electricity production are with 2237 hours significantly higher than in case of the CAES plant. The full production capacity is used in 660 hours. Full-load hours of storage are with 2271 in the same range but the full storage capacity is used during 1750 hours and hence much more often than the production capacity.

Short-term hourly operation of the CAES plants is shown in figure 8.56. It can be seen that the operation of the plant is quite fluctuating. Within the week of November shown in the figure the plant switches quite often between electricity production and storage. The figure shows the sum for all German regions so it is possible that times of production and storage overlap.

The hourly operation of the power to gas plants shown in figure 8.57 is vaguely similar to that of the CAES plants. The time of electricity storage in the middle of the week lasts longer for the PTG plant. This is very likely due to the larger storage capacity compared to that of the CAES plants. Also the times of production last longer at a higher capacity. Small pumping peaks like in figure 8.56 cannot be seen for the PTG plants. It is possible that pumped storage plants assume that task in the PTG scenario.

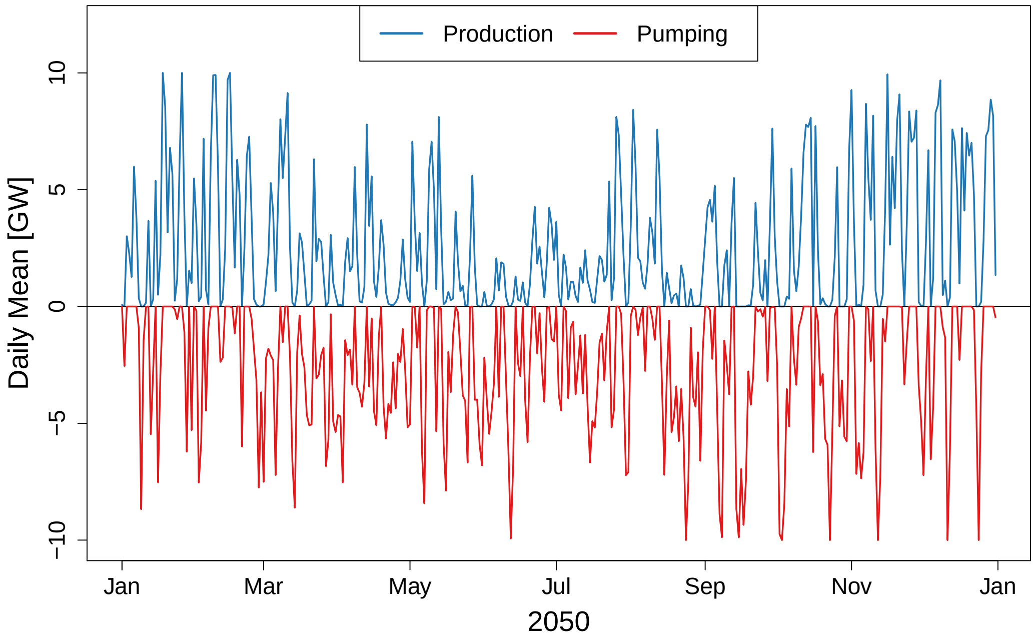

FIGURE 8.55: Daily mean of electricity production and storage of power to gas plants in Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

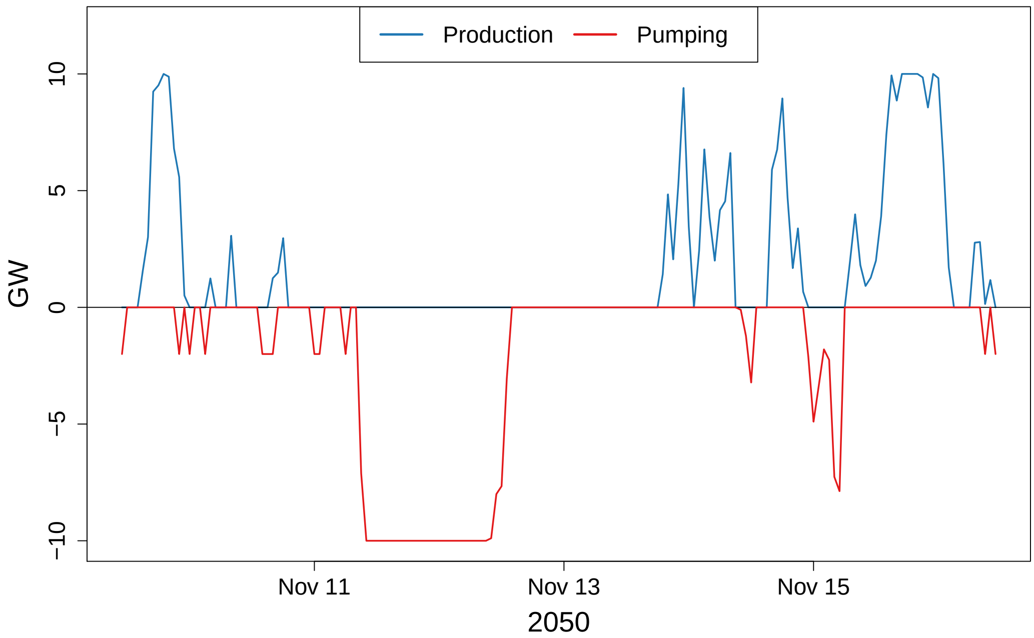

FIGURE 8.56: Electricity production and storage of CAES in Germany, one week in November, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

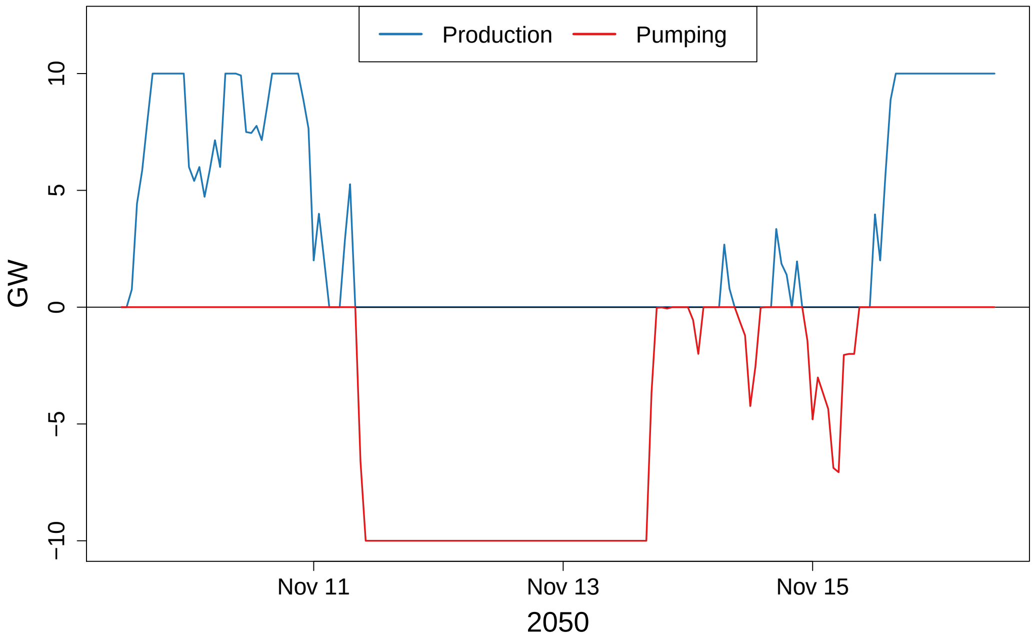

FIGURE 8.57: Electricity production and storage of power to gas plants in Germany, one week in November, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

The compressed air energy storage plant and the power to gas storage plant have the same capacity for power production and storage but very different storage volume. Figure 8.58 shows the hourly filling level of the CAES plant. It fluctuates between zero and the maximum storage capacity of 240 GWh.

The gas storage has a capacity of 220 TWh, almost ten times as much as the compressed air storage. The difference can be seen in figure 8.59 which shows the filling level of the gas storage. The short-term fluctuations are similar to that of the CAES storage but they are hardly visible on the scale of the large storage. The dominating trend in this case is that the filling level is reduced throughout the year by almost 24 TWh. Production and storage of electricity seemed very balanced in the operation of the power to gas storage. However, the efficiency of the operation is very low. It was assumed to be 36 % for the whole cycle. That means that 64 % of the electricity is lost. This results in the net reduction of the filling level. Draining the gas infrastructure in this way is not possible for a time frame of several years and it would not happen in real operation of a power to gas storage. This is caused by the renpass algorithm. In renpass there is no optimization of the whole year that would ensure the balanced operation of storage plants. A result as shown in figure 8.59 could be prevented by starting the simulations with an empty gas storage. The value of the net withdrawal from the gas storage has to be taken into account when the benefit and revenues of the power to gas storage are evaluated.

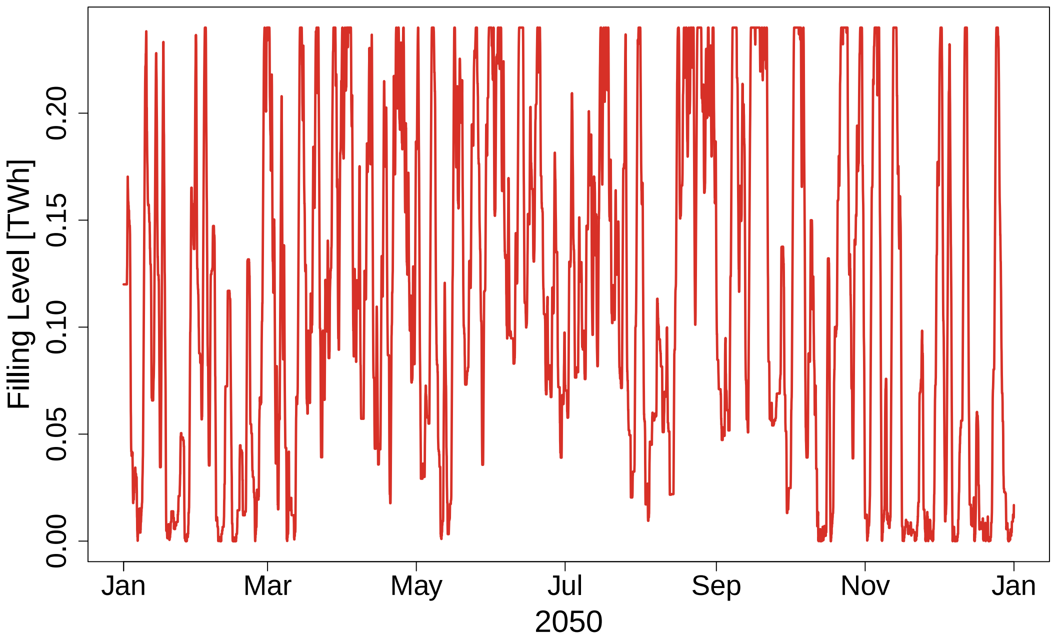

FIGURE 8.58: Filling level of compressed air energy storage in Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

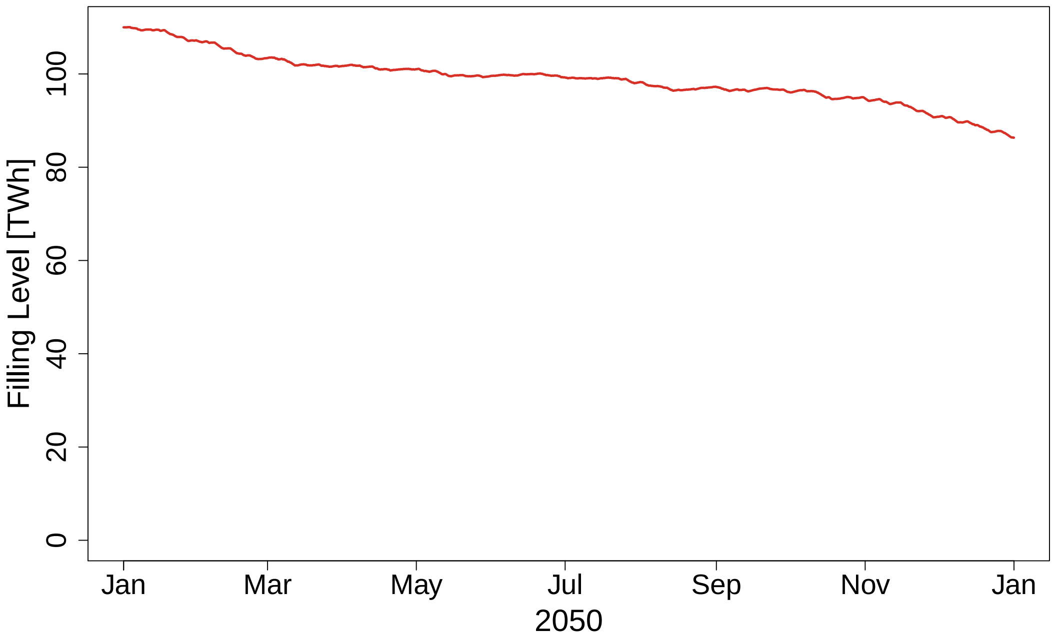

FIGURE 8.59: Filling level of power to gas storage in Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

In the following costs and revenues of the additional storage plants in Germany will be compared. Table 8.1 shows the capacity and cost assumptions of the plants.

Storage	**Capacity** (GW)	**Investment Costs** (bio €)	**Source for Cost Assumption**
Atdorf	1.4	1.6	Römer (2012, p. 14)
Blautal	0.06	0.09	Thierer (2013)
Nethe	0.39	0.45	average of other pumped storage plants
Riedl	0.3	0.35	Donaukraftwerk Jochenstein AG (2013)
Schmalwasser	1	1.15	average of other pumped storage plants
Compressed air energy storage	10	16.98	VDE (2012, p. 43)
Power to gas	10	14.5	Kloess (2013, p. 5)

Table 8.1: Capacity and cost assumptions for additional storage plants in Germany

Figure 8.60 shows the investment annuity and the revenues of the new storage plants in Germany. The investment annuity is calculated according to equation 8.2 with 8 % interest rate and a time frame of 35 years. The total revenues from electricity production are displayed as well as the share of revenues that can be attributed to the net withdrawal from the storage over the course of the year. To determine this amount the net storage reduction is valued at the average electricity price of the scenario weighted with the electricity production from the respective storage plant. This part of revenues would have to be foregone in order to reach a balanced filling level throughout the year. Taking that into account, none of the analyzed storage plants is profitable in the simulated scenarios. For the PTG plant with large storage volume the revenues from storage withdrawal are significant. Without this income the revenues are less than 30 % of the investment annuity.

It can be concluded that electricity storage in Germany increases with new storage capacity. The greatest effect is caused by the power to gas storage which has the highest storage volume. None of the new plants is profitable. The simulations lead to an unfeasible net reduction of the gas storage of almost 24 TWh throughout the year. This is caused by the model algorithm and has to be considered in the evaluation of results.

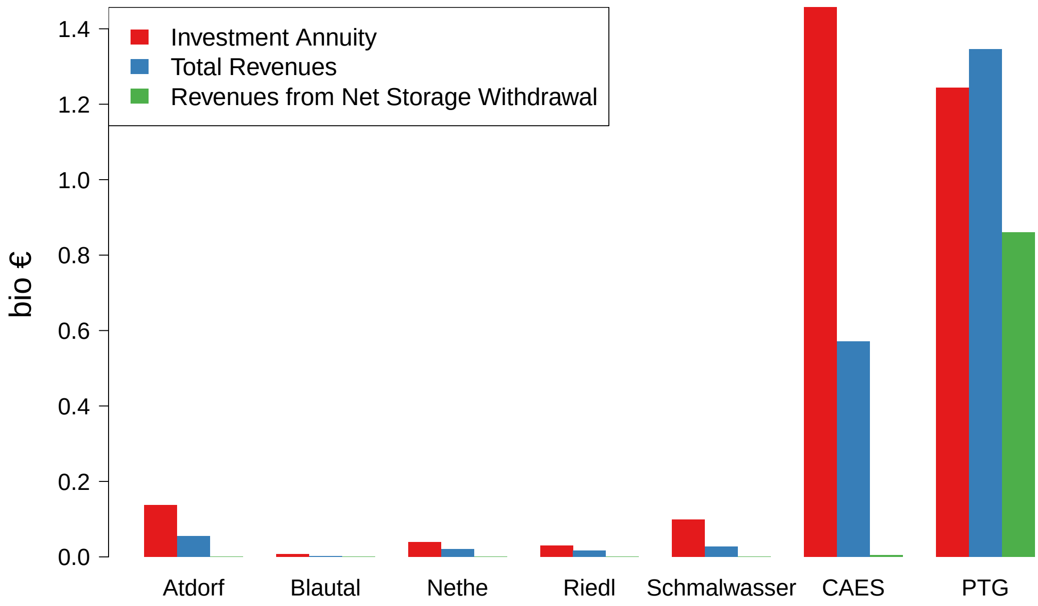

FIGURE 8.60: Revenues and investment annuity of storage plants in Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

8.4.2 Effect on Storage in Norway

Utilization

Figure 8.61 shows the duration curve of exchange on the cable between Germany and Norway for the base case and three alternative storage scenarios. In all scenarios the cable capacity is 10 GW and 10 GW additional pumped storage capacity in Norway are assumed.

The effect of additional storage plants in Germany on the operation of the cable between Germany and Norway is rather small. The sum of transmitted electricity from Germany to Norway is roughly the same in all the shown scenarios. In case of the CAES and PTG scenario hours with high cable utilization are reduced while hours with low cable utilization up to around 2 GW are increased. The flow from Norway to Germany is reduced significantly in the PTG scenario from 15.2 TWh in the base case to 11.3 TWh. Also in the CAES scenario there is a decrease to 13.9 TWh. It seems that the absorbtion of electricity by the Norwegian system and pumped storage plants is not affected by storage competitors in Germany. The production of electricity in Norway and export to Germany on the other hand is reduced as the CAES and PTG plants enter the system while the new pumped storage plants in Germany with significantly smaller capacity have little impact. In the PTG scenario the Norwegian production is partly substituted by the additional energy that stems from the net reduction of filling level of the PTG plants. The total transmitted electricity is largest in the PSP scenario with 52.6 TWh compared to 52.0 TWh in the base case and smallest in the PTG scenario with 48.1 TWh.

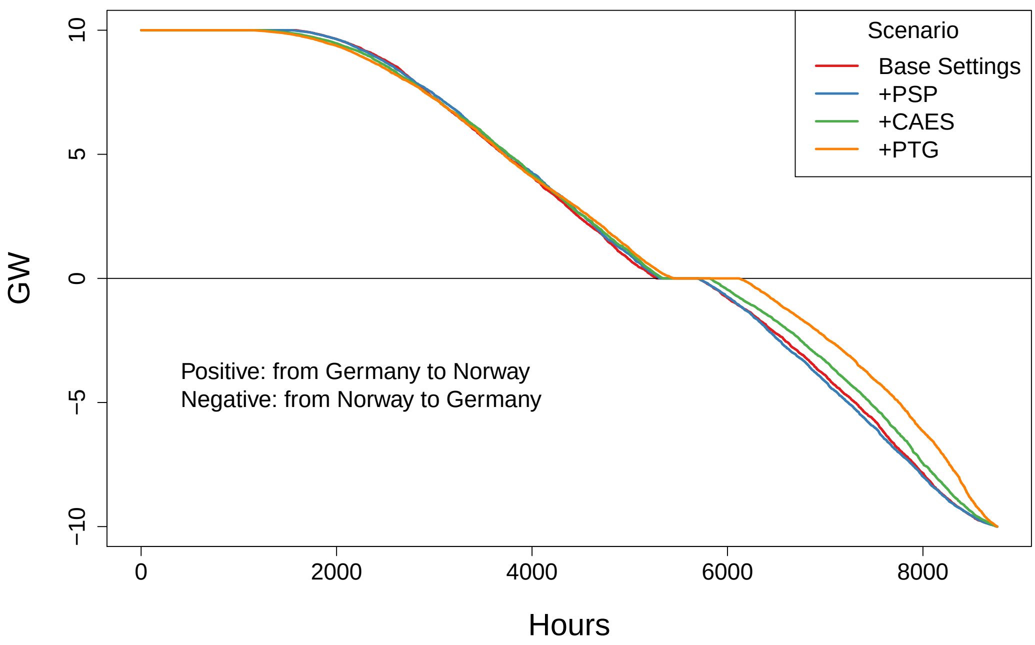

FIGURE 8.61: Duration of exchange between Germany and Norway for different storage scenarios for Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

Looking at the duration curves of electricity production and pumping in figure 8.62 the effect on the electricity production is smaller than expected. The electricity production from hydro storage plants in Norway is reduced only by 2.2 TWh in the PTG scenario and 1.7 TWh in the CAES scenario compared to the base case. Production is not changed significantly in the PSP scenario. The pumping of electricity in Norway is reduced in all scenarios compared to the base case. The strongest effect can be seen in the PTG scenario with a reduction from 8.7 TWh in the base case to 7.5 TWh. This does not correspond to the changes of cable utilization. While the total transmission to Norway hardly changes the share that pumping has in the absorbtion of electricity is reduced. It is possible that due to the reduced electricity production and consequently higher filling levels the availability of the pumps is lower in the alternative storage scenarios.

Economic Effects

The annual sum of unserved demand in the whole area is shown in figure 8.63. The unserved demand is reduced in all the alternative scenarios. The highest effect can be

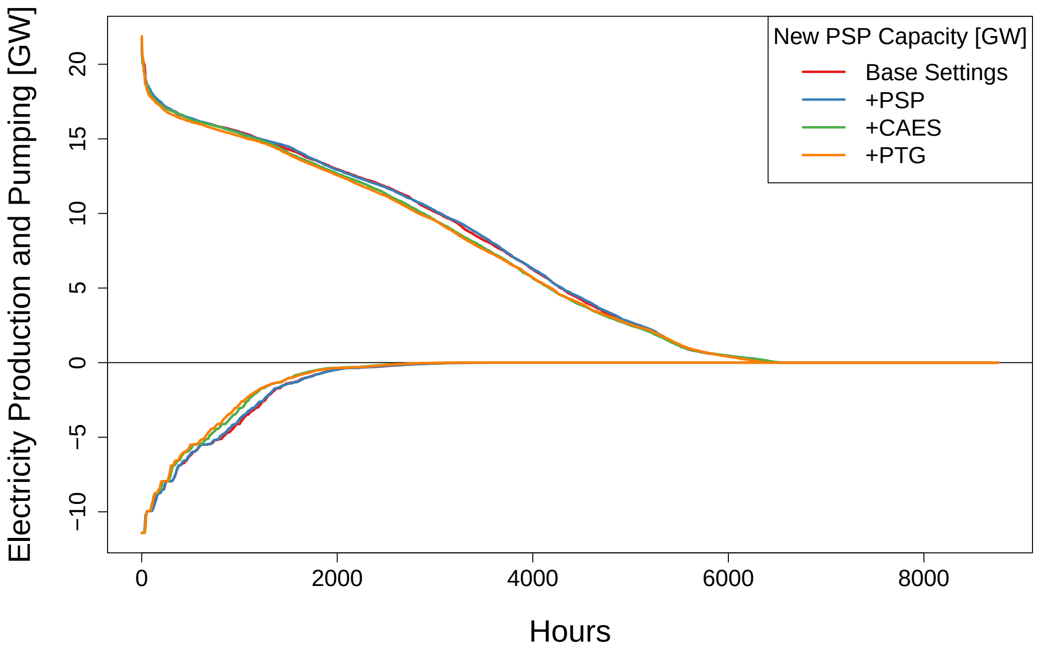

FIGURE 8.62: Duration of electricity production and pumping in Norway for different storage scenarios for Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

seen in the PTG scenario and the smallest in the PSP scenario. The effect of the PTG and CAES scenario are partly caused by the net reduction of filling levels which brings additional energy into the system.

Figure 8.64 shows the annual sum of excess electricity in the different storage scenarios. Also in this case all scenarios with additional storage capacity in Germany reduce the excess electricity compared to the base case. Again the largest effect can be seen in the PTG scenario.

The average annual electricity price of the whole area is shown in figure 8.65. The addition of pumped storage capacity in Germany has no significant effect. The CAES scenario decreases the average price from 30.7 €/MWh to 28.1 €/MWh. In the PTG scenario the average electricity price is lowest with 25.7 €/MWh. The price decrease and the resulting decrease in consumer costs have to be seen in relation to the investment costs for the additional storage capacity which are not included in the simulation of a predetermined system with renpass. With current cost assumptions the total system costs would presumably be a lot higher when CAES or PTG plants are included. Along with the average electricity price the average price difference between Germany and Norway decreases from 13.6 €/MWh to 11.8 €/MWh in the PTG scenario. Together

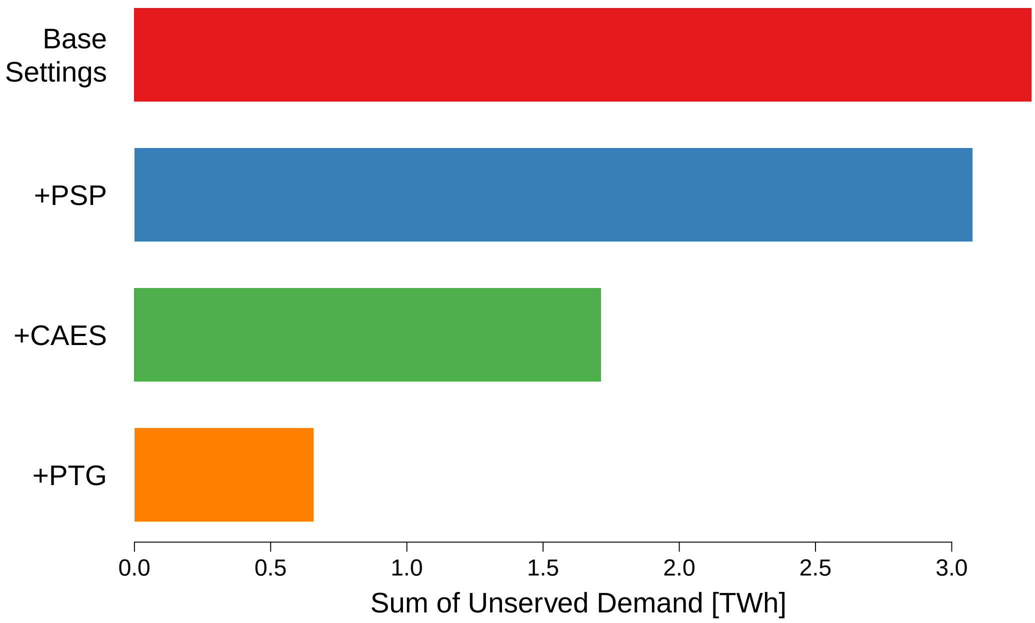

FIGURE 8.63: Unserved demand for different storage scenarios for Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

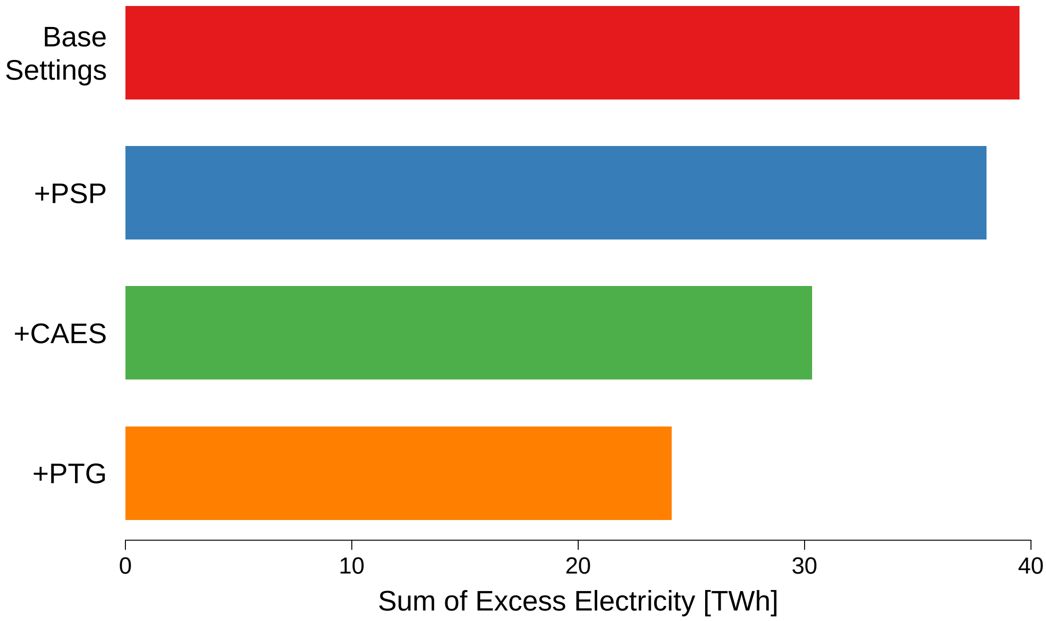

FIGURE 8.64: Excess electricity for different storage scenarios for Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

with the reduced electricity transmission this explains the strong decrease in revenues in the PTG scenario.

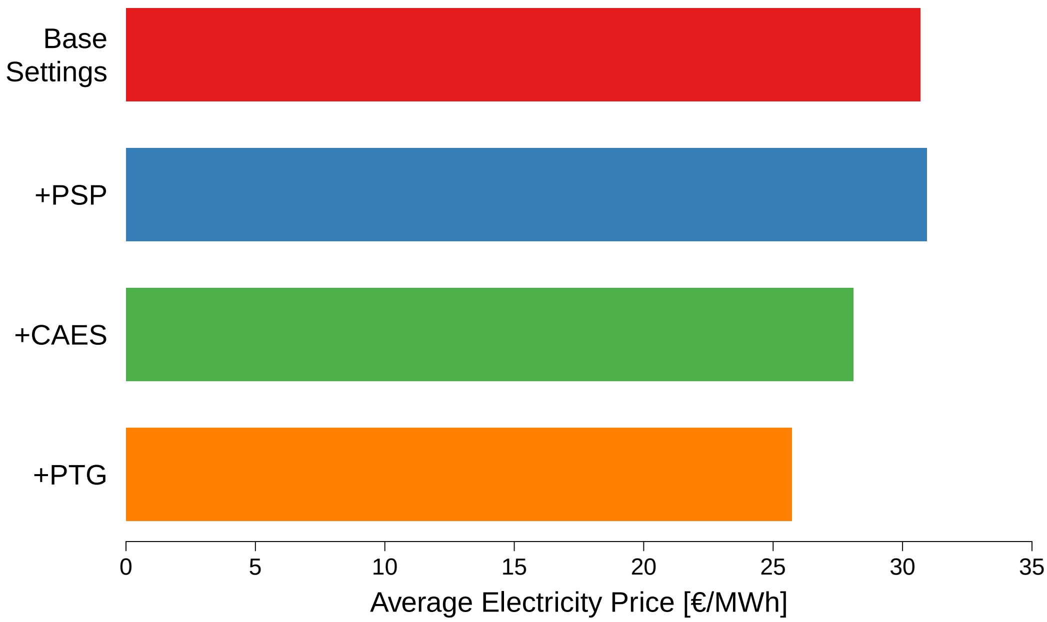

FIGURE 8.65: Average electricity price for the whole area for different storage scenarios for Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

This effect can also be seen in figure 8.66 which shows the duration curves of the electricity price in Norway for the base case and the storage alternatives. All the alternative storage scenarios reduce the the price peaks. The largest effect is caused by the PTG capacity which reduces the peak from 150 €/MWh to 50 €/MWh. Apart from the few peak hours the price is increased in the PSP scenario and decreased in the PTG and CAES scenarios.

Revenues

Figure 8.67 shows the annual revenues from congestion rent on the 10 GW cable between Germany and Norway for the base case and the alternative storage scenarios. Revenues increase when new pumped storage (PSP) plants are installed in Germany but decrease significantly in the power to gas (PTG) scenario and slightly in the compressed air energy storage (CAES) scenario. The impact of the storage alternatives on revenues is larger than on the sum of transmitted electricity. Consequently also the impact on the price difference between Germany and Norway is an important driver.

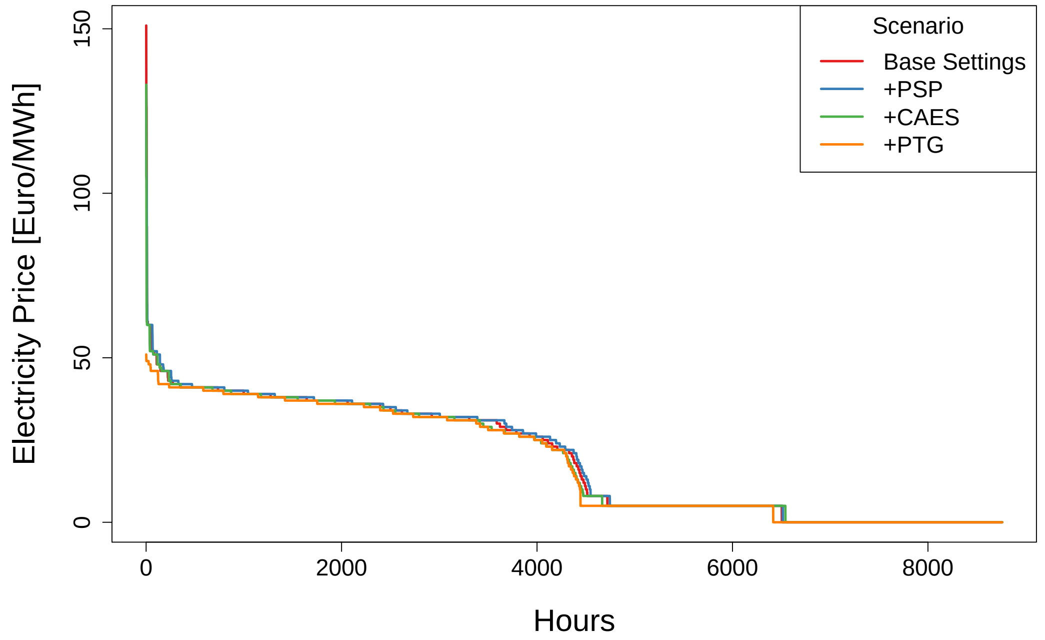

FIGURE 8.66: Duration of electricity price in Norway for different storage scenarios for Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

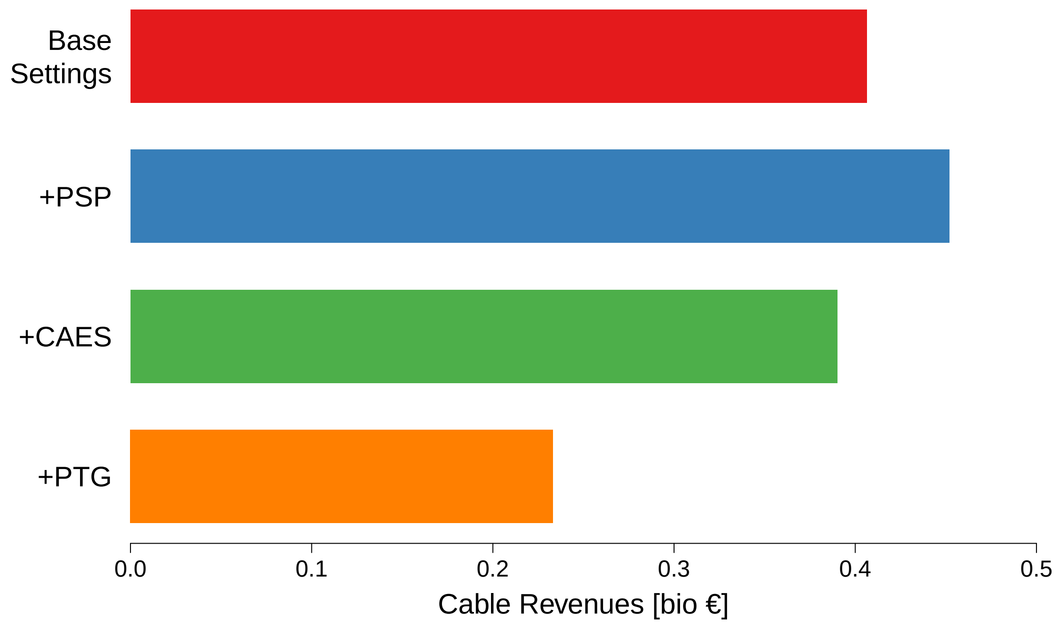

FIGURE 8.67: Cable revenues of 10 GW connection between Germany and Norway for different storage scenarios for Germany, 10 GW additional pumped storage capacity in Norway

The average electricity price clearly determines the revenues of the pumped storage plants. The revenues from electricity production in Norwegian storage plants are shown in figure 8.68. Following the electricity price the revenues increase in the PSP scenario, and decrease in the PTG and CAES scenarios.

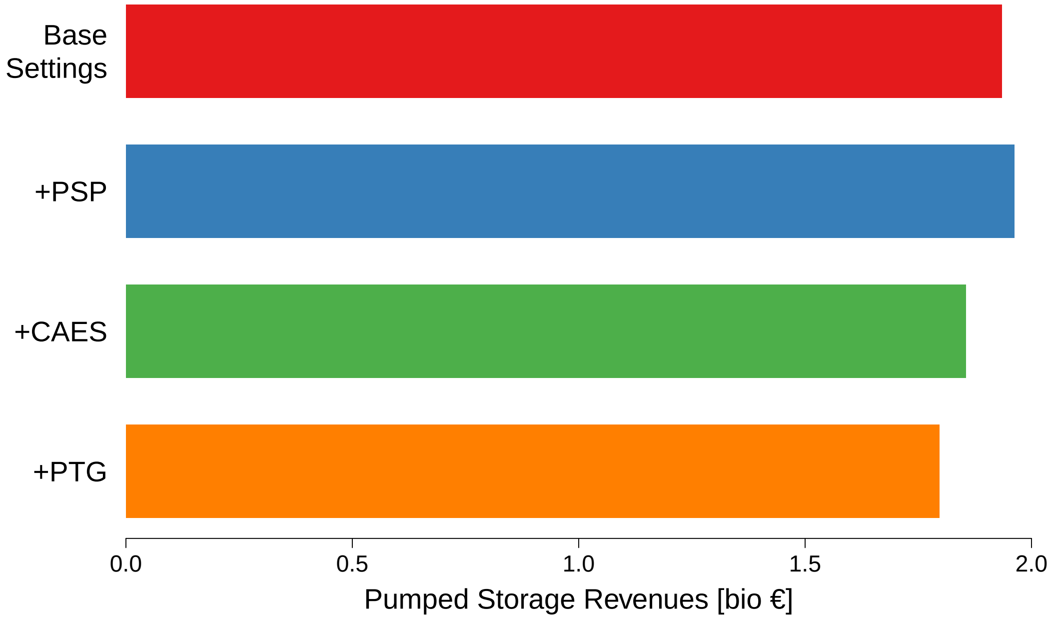

FIGURE 8.68: Norwegian pumped storage revenues for different storage scenarios for Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

In the base scenario with 10 GW cable capacity and 10 GW additional pumped storage capacity two new pumped storage plants with a total capacity of 1700 MW are profitable. In all the storage variations the same two plants remain profitable but the annual revenues of the plants decrease. The power to gas storage in Germany has the largest impact and decreases the revenues of all the new pumped storage plants. The revenues are on average 14 % lower than in the base case. In case of pumped storage and compressed air energy storage in Germany the results are ambiguous. The overall effect of pumped storage capacity in Germany on the revenues is smaller and for six of nine new plants revenues increase slightly. On average there is an increase of 0.7 %. The situation is similar in the CAES scenario with an average increase of 2 %.

Economic Benefits

The economic benefits of the cable between Germany and Norway and the additional pumped storage capacity in Norway are shown in figure 8.69 for the different storage scenarios for Germany. The economic benefits decrease as additional storage capacity is included in the German system. The effect of additional pumped storage capacity in Germany is only very small. With the power to gas scheme the benefits are reduced significantly. In this scenario the cost reductions are lower than the investment annuity of cable and pumped storage plants.

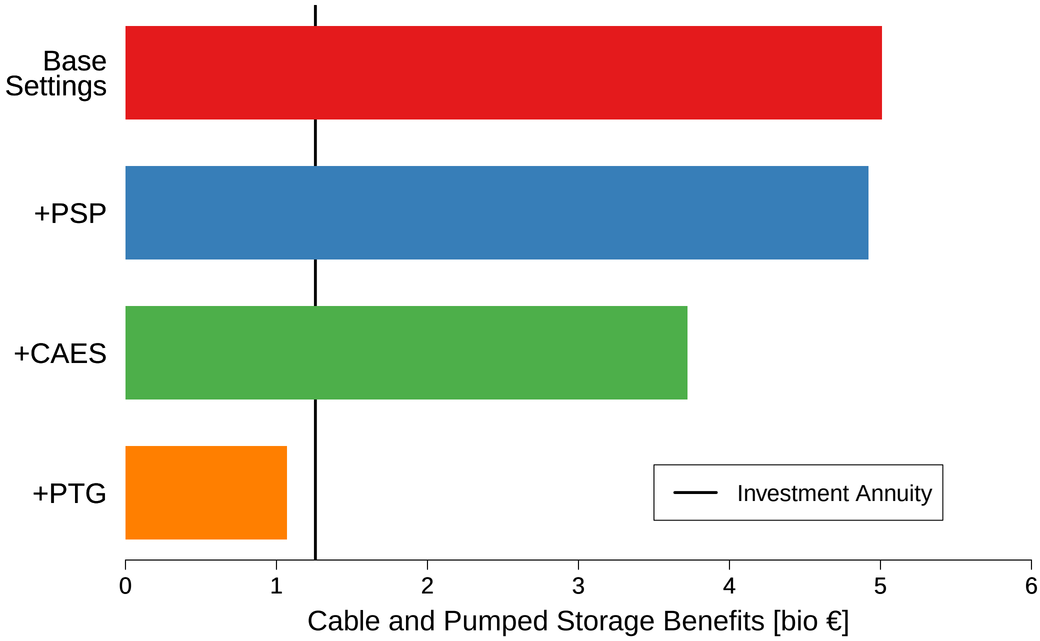

FIGURE 8.69: Economic benefit of cable and new pumped storage capacity for different storage scenarios for Germany, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

Summing up, additional storage capacity in Germany substitutes electricity transmission from Norway to Germany, in case of power to gas partly with the extra energy withdrawn from the gas storage. The revenues of the cable connection are reduced. The revenues of additional pumped storage capacity in Norway are also reduced but less so. The economic benefits of additional cable and pumped storage capacity are smaller when storage capacity in Germany is already included in the system. This perspective analyzes only the effect of existing storage capacity on storage in Norway. It does not include the investment costs of different storage options and does not provide a comparison of storage technologies. If the power to gas technology is pursued in Germany other storage options may be less relevant but total system costs will likely be much higher.

8.5 Sensitivity of the Results

8.5.1 Profitability of Cable Connection

In this section the sensitivity of the main results to changing input parameters will be analyzed. All variations contain the most beneficial capacity combination from the main scenarios with 10 GW cable capacity between Germany and Norway and 10 GW additional pumped storage capacity in Norway. Figure 8.70 shows the duration of electricity exchange between Germany and Norway with varying parameter settings. An overview of the sensitivity scenarios can be found in section 7.5. All scenarios include 10 GW cable capacity to Norway and 10 GW additional pumped storage capacity in Norway. Figure 8.70 shows only those parameters that significantly affect the electricity exchange.

Wind energy expansion in Norway considerably influences the electricity exchange. In the scenario with onshore and offshore wind energy installations 51 TWh additional electricity are produced in Norway. The total transmitted electricity is slightly lower than in the base case but the transmission from Germany to Norway is reduced and the transmission from Norway to Germany is increased. In result the exchange is far more balanced with net transmission of 1.8 TWh from Norway to Germany. The impact of a scenario with only offshore wind electricity production of 42 TWh is similar but less pronounced. In that case the net exchange is 1.4 TWh from Germany to Norway.

The exchange is influenced in the same direction when a year with high hydro inflow is simulated. This scenario is based on inflow data of 1990 and the total annual inflow is 133 % of the base scenario. Similar to the scenarios with wind energy capacity in Norway also in this case additional energy is added to the Norwegian system. Furthermore, the hydro inflow influences the operation of the German run-of-river plants and raises their utilization from 55 % to 65 %. The total electricity transmission is only a little lower than in the base case but the exchange is more balanced with net transmission from Germany to Norway of 16.6 TWh compared to 21.6 TWh in the base case.

As explained in section 5.2 weather data of 1998 leads to higher wind energy production and lower solar energy production than in the base case based on 2010. In sum the electricity generation from fluctuating renewable energy sources increases by 50 TWh. This leads to increased transmission from Germany to Norway and reduced transmission from Norway to Germany. The imbalance of exchange is increased to 32 TWh net transmission to Norway while the total transmission is only increased by 1.9 TWh.

The renewable energy scenario based on Sachverständigenrat für Umweltfragen (2011) leads to a different supply structure in Germany. The total production from fluctuating renewable sources is almost 100 TWh higher than in the base case. Also the structure and distribution of production is different. This leads to a higher utilization of the cable connection than in any other scenario. The transmission in both directions is increased leading to a total transmission that is almost 30 % higher than in the base case. The imbalance of exchange on the other hand is reduced slightly. That means that the impact on the transmission from Norway to Germany is larger than on the other flow direction.

When the grid in Germany is not expanded as in the base scenario but kept at today's capacity the electricity transmission to Norway is increased by 2.5 TWh or 7 %. The transmission from Norway to Germany is only slightly reduced. As transmission is more restricted in Germany the electricity generated in Northern Germany cannot be transported to the South and is transmitted to Norway instead for storage. This restriction also reduces the high power flows from Norway to Germany as the electricity cannot be forwarded to the South of Germany.

Limiting the biomass capacity in the whole region to half compared to the base case decreases the electricity production from biomass from 111.5 TWh to 92.4 TWh even though the amount of available biomass remains the same. Production in Germany is reduced most severely from 73.0 TWh to 46.1 TWh. Apparently in Germany the installed biomass capacity is of more importance than the available primary energy. As a result of the changing production the transmission of electricity from Germany to Norway is slightly reduced from 36.8 TWh to 34.6 TWh. The transmission from Norway to Germany on the other hand is increased from 15.2 TWh to 22.5 TWh. This reduces the imbalance to 12 TWh net transmission from Germany to Norway. The biomass production in Germany is missing especially at times when there is a shortage of fluctuating renewable electricity supply. Consequently far more electricity has to be imported from Norway to fill the gaps.

The renewable scenario based on Sachverständigenrat für Umweltfragen (2011) leads to a much higher electricity transmission than in all the other scenarios. However, not only the amount of transmission increases but also the price spread between the countries. Figure 8.71 shows the duration of the price difference between the Northern German price region and Norway for the base case and the scenario based on Sachverständigenrat für Umweltfragen (2011). A positive difference indicates that the price is higher in Northern Germany while a negative difference shows higher prices in Norway. The price spread is dominated by those hours when the demand cannot be met in Northern Germany and consequently prices rise very high. With over 1800 hours this occurs more often in the scenario based on Sachverständigenrat für Umweltfragen (2011) than in the base case.

In the scenario adapted from Sachverständigenrat für Umweltfragen (2011) the production from fluctuating renewable energy sources is higher but total electricity production is similar to the base case. The supply structure is hence quite different. There is less

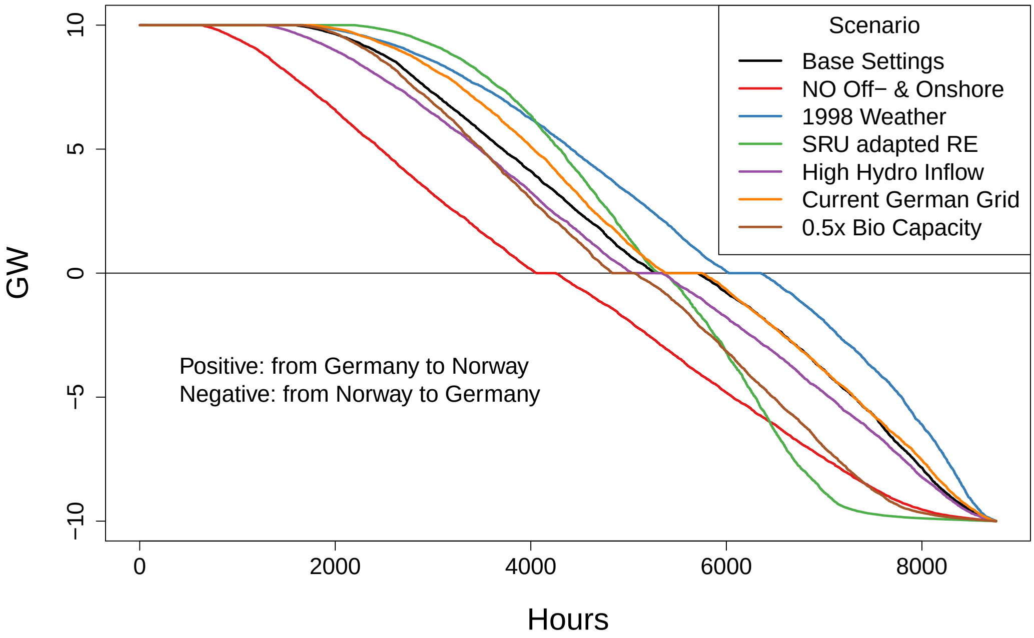

FIGURE 8.70: Sensitivity of the duration of electricity exchange between Germany and Norway to different parameters, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

production from dispatchable sources. Especially the biomass capacity is much lower. As a result the amount of unserved demand and also the amount of curtailed renewable production is higher than in the base case. This leads to a higher average price spread between Northern Germany and Norway.

As both the amount of transmission and the price spread increase also the cable revenues are considerably higher than in the other scenarios. The simulated annual revenues are 4.7 billion € and clearly above the investment annuity of 0.9 billion €. In this scenario cable connection of 10 GW is highly profitable.

Also in case of reduced biomass capacity the total transmission is higher than in the base case. The missing capacity increases the electricity price in Germany and hence the price spread between Germany and Norway. This leads to cable revenues of 1.7 billion € and thus to a profitable cable connection. This variation shows the relevance of the system configuration, especially the amount of flexible capacity for the profitability of additional installations.

Figure 8.72 shows the cable revenues for other parameter variations. Only parameters that significantly impact the cables revenues are shown. For easier comparison the black line indicates the level of revenues in the base case. In the scenario based on Sachverständigenrat für Umweltfragen (2011) and in the scenario with reduced biomass capacity

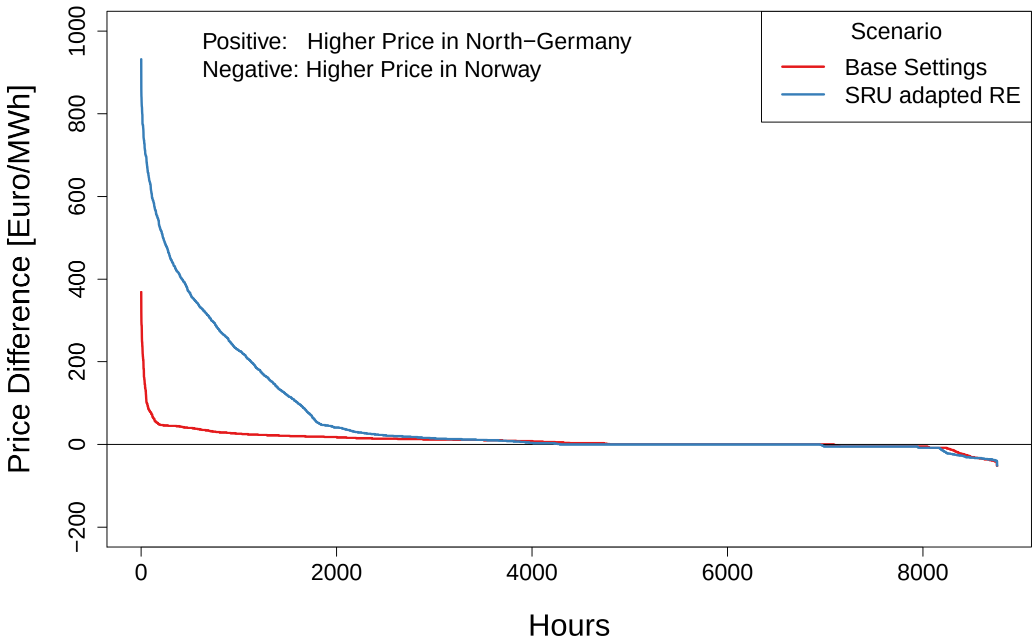

FIGURE 8.71: Duration of price spread between Northern Germany and Norway, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

revenues are many times higher than in the other scenarios are therefore not included in the figure. None of the other parameter variations lead to profitability of the cable connection as revenues are lower than the investment annuity of 0.9 billion €.

When the grid within Germany is not extended the transmission to Norway increases. Also the price spread increases slightly because the balancing of prices within Germany is restricted. Both factors lead to higher cable revenues.

Increasing the biomass capacity by factor 1.5 compared to the base case with the same amount of available biomass increases the flexibility of the system. Consequently it will rely less on the exchange for balancing. Transmission between Germany and Norway is reduced compared to the base case. Also the price spread that can be reaped is reduced. This leads to the lowest cable revenues of all the analyzed variations and again underlines the significance of other flexible capacity for the profitability.

The extension of wind energy capacity in Norway leads to higher revenues from the cable connection. While the total exchange is reduced when additional wind energy is produced in Norway the flow-weighted price difference increases. More electricity can be exported to Germany when the prices are high.

As explained above using 1998 weather data for simulations increases the renewable production. This reduces the price peaks in Northern Germany and the price difference at times when the price in Germany is higher. This cannot be compensated by the slightly increased transmission and the revenues of the cable are lower than in the base case. With weather data of 2003 the fluctuating renewable production is also higher than in the base case but not as high as with 1998 data. Accordingly also in this case the price spread on the cable is reduced but less so. However, the total transmission on the cable is lower than in the base case so that the resulting revenues are reduced further than with 1998 weather data.

The shortage price sets the electricity price at times when the demand cannot be met. In the base case the shortage price is set according to formula 3.2 with a shortage factor of ten. In the first variation a fixed shortage price of 600 €/MWh is set whenever the demand cannot be supplied completely in a region. For the second variation the shortage price is calculated as in the base case but with a shortage factor of 5 that results in higher shortage prices. The third variation uses a shortage factor of 20 that leads to lower shortage prices. The setting of the shortage price has direct influence on the mean price difference between Germany and Norway. Also the transmission is affected but only very little. Fixed shortage prices and lower shortage prices lead to a reduction in the mean electricity price in Northern Germany and consequently the price spread on the cable. Higher shortage prices increase the electricity price and the price spread. As a result the revenues of the cable decrease with fixed and lower shortage prices and increase with higher shortage prices. It can be concluded that the value that is assigned to security of supply has a large influence on the value of the installations in the electricity system.

The renewable scenario based on Umweltbundesamt (2010) is more similar to the base case than the variation based on Sachverständigenrat für Umweltfragen (2011). Compared to the base case the production from offshore wind and solar plants is higher and the onshore wind electricity production is lower. The total fluctuating renewable electricity production is with 451 TWh ca. 2 % lower than in the base case. The transmission on the cable is only slightly higher than in the base case. The price spread on the other hand is increased significantly. This leads to cable revenues that are well higher than in the base case.

The profitability is determined by the ratio of revenues and cost annuity. The annuity in turn is influenced by the assumptions for interest rate and depreciation period. In the following the impact of interest rate and depreciation period will be analyzed. Figure 8.73 shows the cable revenues and the annuity calculated with the base case of 8 % interest rate and two variations. All scenarios include 10 GW additional pumped storage capacity in Norway. The interest rate clearly influences the annuity. When it is lowered to 6 % cable capacity of 5 GW becomes profitable. For 10 GW cable capacity however

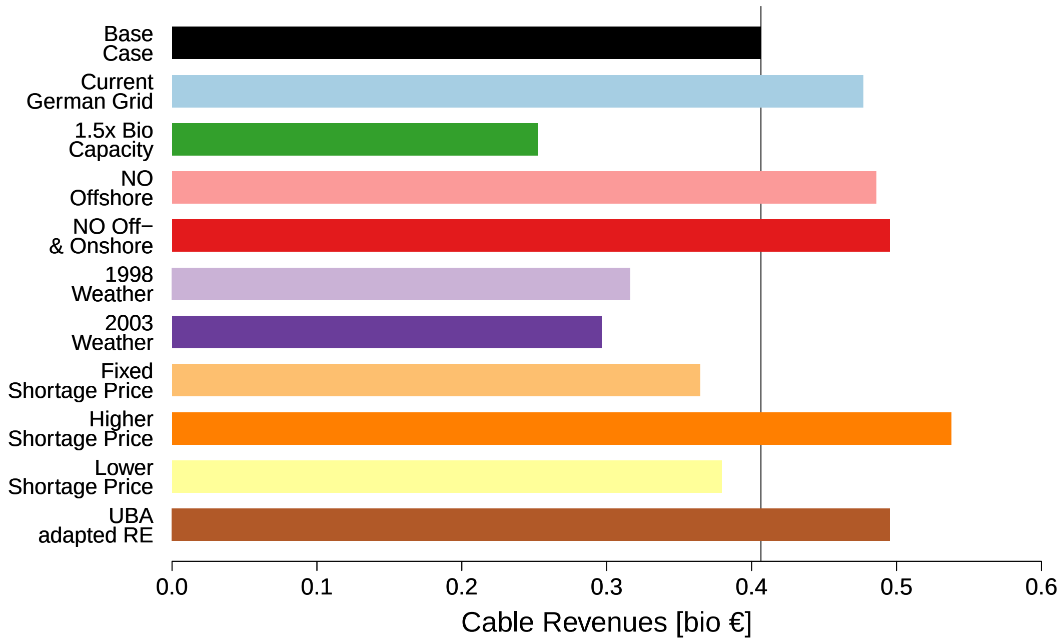

FIGURE 8.72: Sensitivity of the cable revenues to different parameters, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

the gap between revenues and annuity is too large. Also with different assumptions for interest rate this investment is not profitable.

In figure 8.74 the depreciation period is varied from the base case of 35 years. When the depreciation period is increased to 45 years 5 GW cable capacity comes quite close to profitability. The gap between revenues and annuity is reduced to 5 million €. Again the variation is inconsequential for cable capacity of 10 GW.

It can be concluded that the transmission of electricity between Germany and Norway is most affected wind energy production in Norway which leads to a more balanced exchange and the renewable scenario based on Sachverständigenrat für Umweltfragen (2011) which increases the exchange in both directions and highly increases the cable revenues. Cable revenues are also increased by reduced biomass capacity and a higher scarcity price for electricity. They are reduced most by higher biomass capacity. A variation of interest rate and depreciation period does not affect the profitability of 10 GW cable capacity.

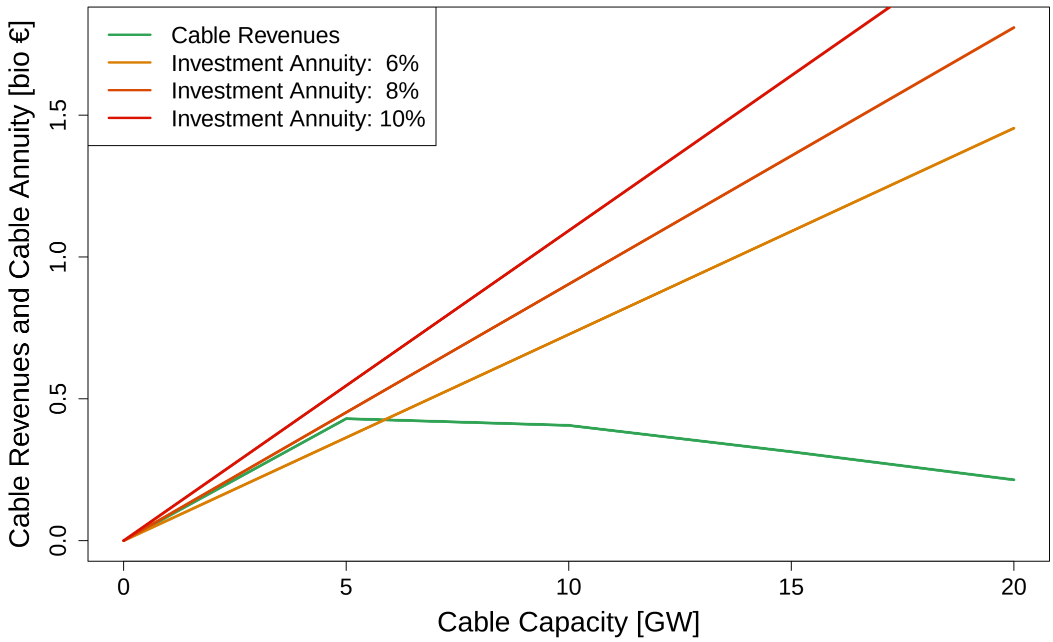

FIGURE 8.73: Cable revenues and cable investment annuity with different interest rates, 10 GW new pumped storage in Norway

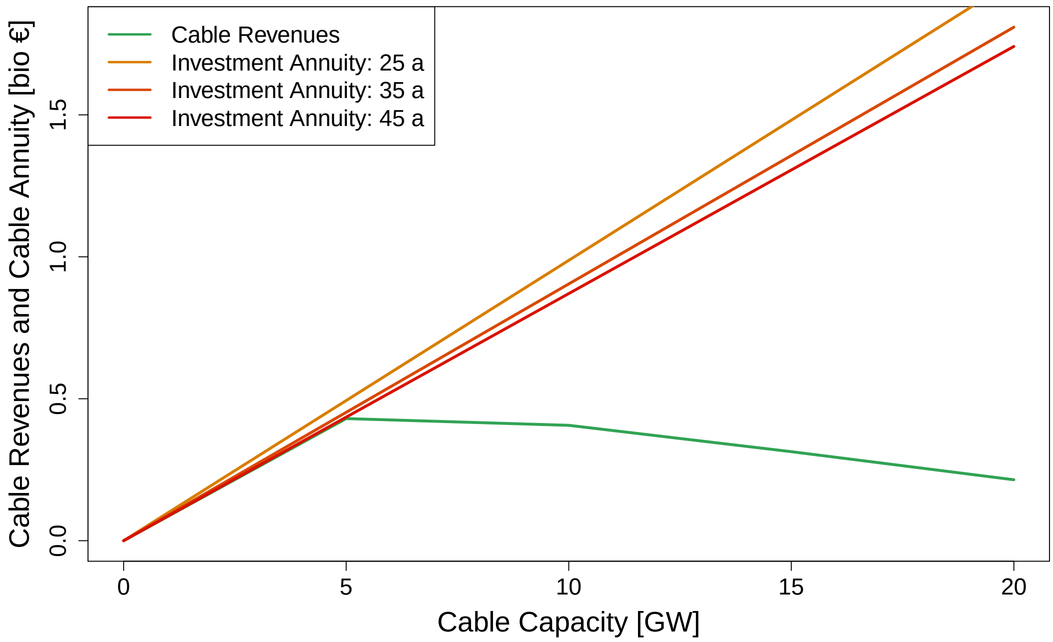

FIGURE 8.74: Cable revenues and cable investment annuity with different depreciation periods, 10 GW new pumped storage in Norway

8.5.2 Profitability of New Pumped Storage

Figure 8.75 shows the duration of electricity production from hydro storage plants in Norway for the base case and selected parameter variations. All scenarios include 10 GW cable capacity between Norway and Germany and 10 GW additional pumped storage capacity in Norway.

The amount and pattern of hydro inflow in Norway influences the electricity production from hydro storage plants. However, contrary to what might be expected the production from hydro storage plants in Norway decreases with high hydro inflow and increases with low hydro inflow. It has to be kept in mind that the inflow affects not only the storage reservoirs but also the production from run-of-river plants in Norway and Germany. The change of the non-controllable run-of-river production is compensated by the hydro storage plants. This will strengthen the effect on the filling levels as can be seen in section 8.5.3.

In the scenario based on 1998 weather data the increased electricity transmission from Germany to Norway and reduced transmission from Norway to Germany leads to a lower electricity production in hydro storage plants.

When additional wind energy is produced in Norway the production from hydro storage plants is reduced. Also it can be observed that the duration curve becomes somewhat steeper. It seems that the reduced production leads to a better use of the hydro resource so that a high hydro production capacity is available for a longer period than in the base case.

The renewable scenario based on Sachverständigenrat für Umweltfragen (2011) leads to slightly increased production in Norwegian hydro storage plants. More noticeable is the effect on the production curve which is steeper than in the base case. This corresponds to the duration curve of exchange between Norway and Germany which is steeper than in the base case as well.

The reduction of biomass capacity also leads to a reduced electricity production from biomass plants. This is compensated by the hydro storage plants in Norway which produce 12 % more electricity than in the base case.

In figure 8.76 the duration curve of pumping in Norwegian pumped storage plants is shown for selected parameter variations. As could be seen in figure 8.75 high hydro inflow reduces the hydro power production in Norway. Both factors lead to higher reservoir filling levels. This reduces the availability of pumping capacity and consequently pumping in Norway is 20 % lower than in the base case.

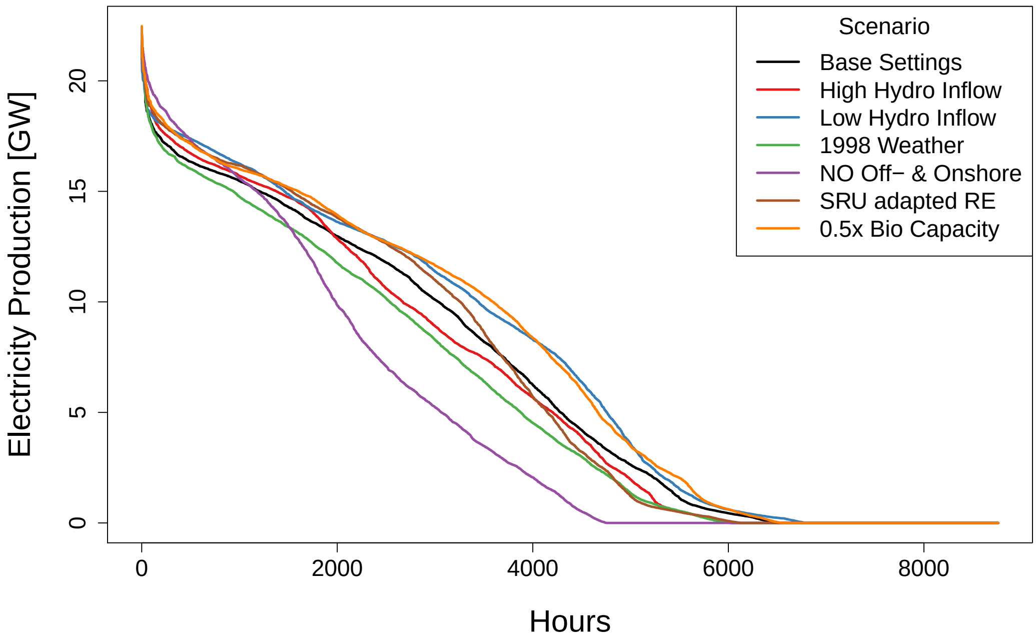

FIGURE 8.75: Duration of electricity production from hydro storage plants in Norway for different scenarios, 10 GW new pumped storage in Norway

Weather data of 1998 also leads to lower electricity production from hydro storage plants in Norway. Like in case of high hydro inflow this reduces the available pumping capacity, however the effect is much smaller. With weather data of 1998 pumping is 6 % lower than in the base case.

Not surprisingly when additional wind energy is produced in Norway the amount of electricity that is being pumped increases. In the scenario with wind onshore and wind offshore production in Norway it is more than 30 % higher than in the base case.

Also the renewable scenario based on Sachverständigenrat für Umweltfragen (2011) leads to more pumping in Norway. In this case it is roughly 15 % higher than in the base case. The increased renewable energy production in Germany leads to increased transmission to Norway and ultimately to increased pumping.

In figure 8.77 the revenues from hydro storage plants in Norway are shown for the base case and selected sensitivity scenarios. Only the parameters with significant impact on revenues are shown. The figure shows the total revenues from all hydro storage plants in Norway and not the difference to a scenario without additional pumped storage capacity as figure 8.32. The revenues can consequently not be related to the investment annuity for additional pumped storage capacity of 10 GW but rather should be compared to the base case to show the sensitivity to different parameters. The black line marks the

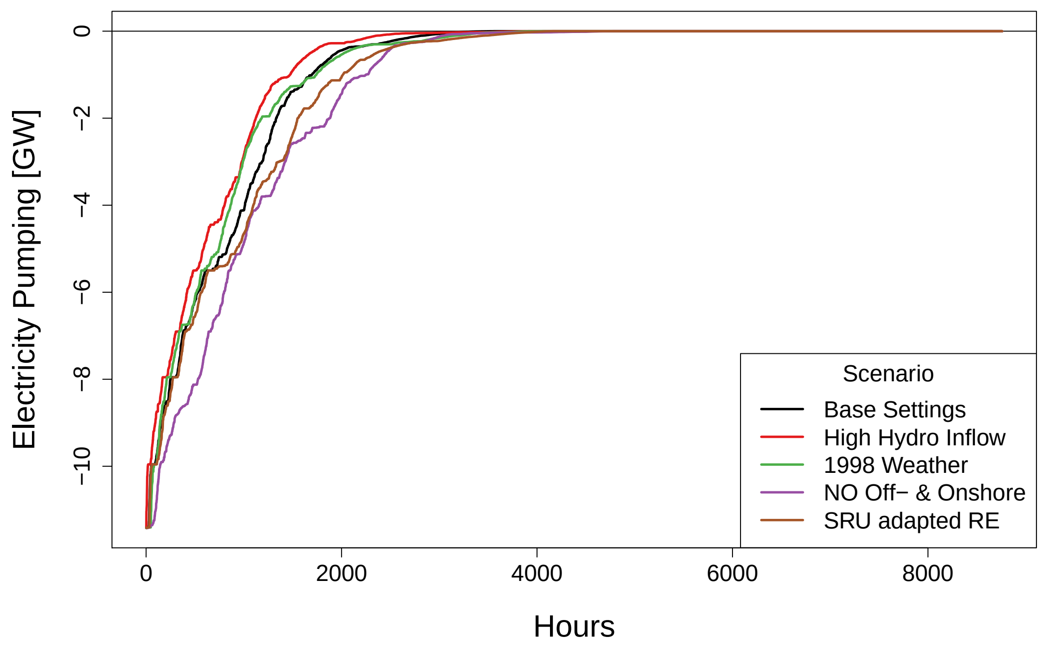

FIGURE 8.76: Duration of electricity pumping in Norway for different scenarios, 10 GW new pumped storage in Norway

level of revenues in the base case. The revenues are driven by the amount of produced electricity and the electricity price that can be earned.

The installed biomass capacity affects the electricity production in hydro storage plants. Production increases with lower biomass capacity and decreases with higher biomass capacity. Likewise the price increases with lower biomass capacity and decreases with higher biomass capacity. In both cases the effect of the reduced biomass capacity is stronger. This leads to significantly increased revenues when the biomass capacity is reduced and slightly lower revenues when it is increased.

As shown above the production from hydro storage plants decreases with high inflow and vice versa. The change of the price that can be earned works in the same direction. Ultimately the revenues of pumped storage plants are significantly affected. There is a strong decrease in case of high hydro inflow and a strong increase in case of low hydro inflow.

When wind energy production in Norway is included in the simulations the production from hydro storage plants and the electricity price are reduced. This results in significantly lower revenues for the hydro storage plants. The scenarios with wind energy production in Norway show the lowest revenues of all analyzed variations.

Weather data of 1998 leads to 12 % less electricity production from hydro storage plants in Norway than in the base case. Due to the increased transmission from Germany to Norway also the average electricity price in Norway is lowered. Both factors lead to lower revenues for hydro storage plants.

With the renewable scenario based on Sachverständigenrat für Umweltfragen (2011) the production from hydro storage plants in Norway slightly increases. Due to increased times of unmet demand the average electricity price for hydro storage production is considerably higher than in the base case. This combines to increased pumped storage revenues.

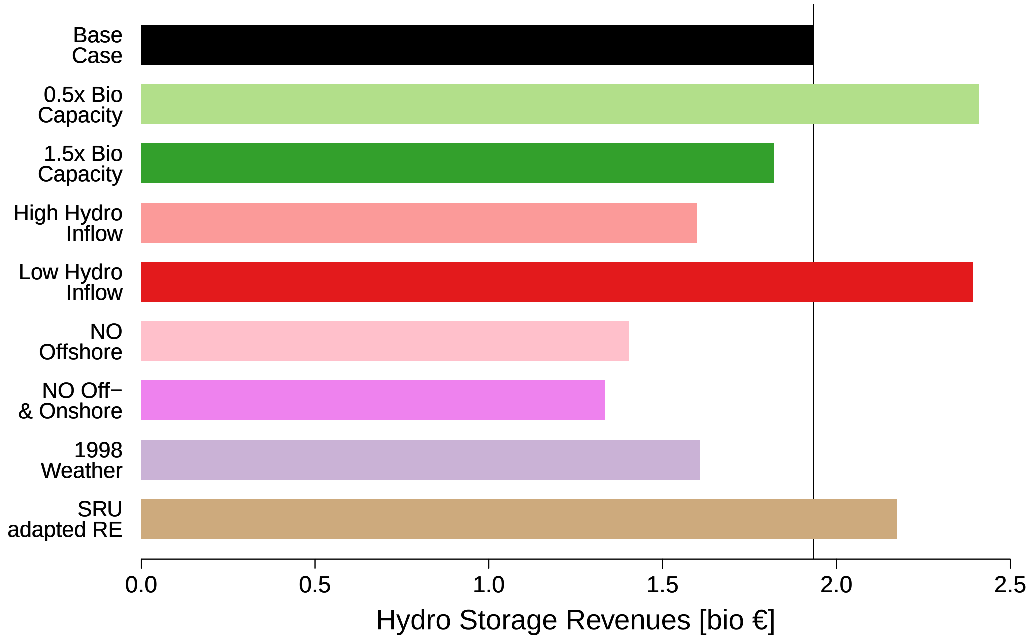

FIGURE 8.77: Sensitivity of the hydro storage revenues to different parameters, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

For the profitability of the pumped storage capacity the interest rate and depreciation period are important as well. Figure 8.78 shows the pumped storage revenues and the investment annuity with different interest rates. The interest rate distinctly influences the annuity but for the case of 10 GW pumped storage capacity the annuity is higher than revenues even with a low interest rate of 6 %. The profitability of 5 GW additional pumped storage capacity has not been analyzed. The interest rate will likely be crucial for the profitability in that case.

In figure 8.79 the annuity is calculated with varying depreciation periods. It can be seen that the effect is smaller than that of the interest rate and in none of the variations the revenues of 10 GW additional pumped storage capacity are close to the annuity.

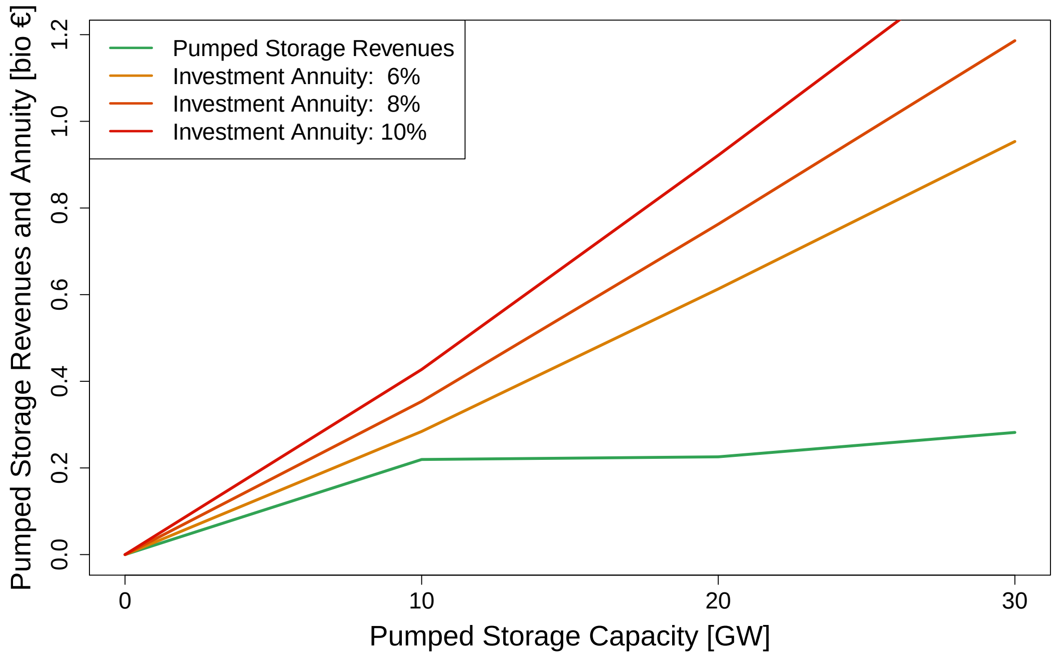

Figure 8.78: Additional pumped storage revenues and pumped storage investment annuity with different interest rates, 10 GW cable capacity between Germany and Norway

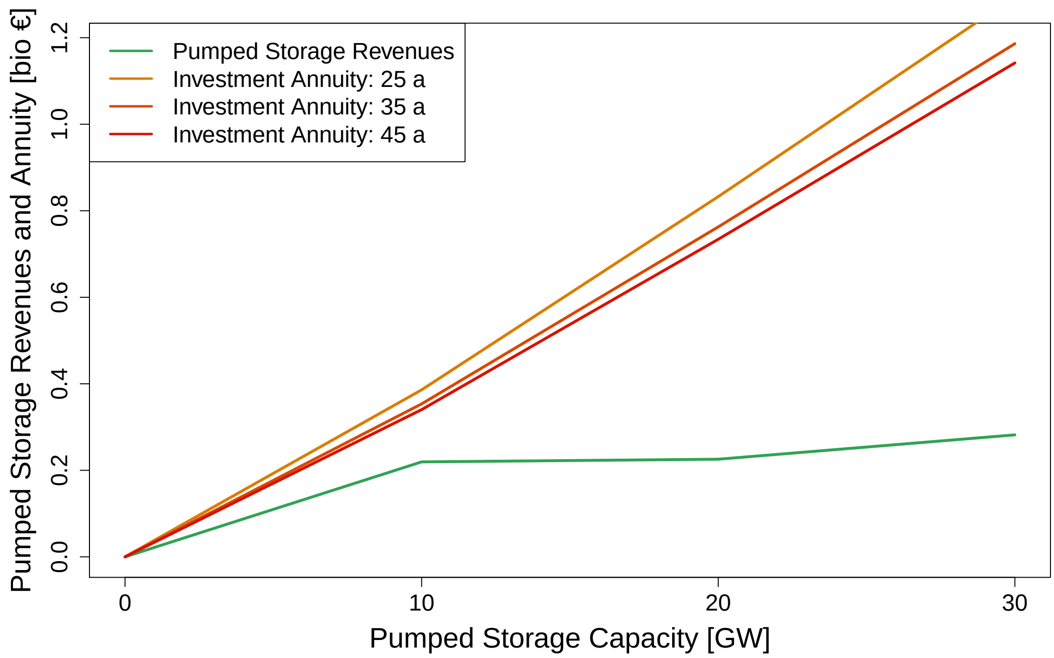

Figure 8.79: Additional pumped storage revenues and pumped storage investment annuity with different depreciation periods, 10 GW cable capacity between Germany and Norway

Figure 8.80 shows consumer costs reductions from the combination of 10 GW cable capacity between Germany and Norway and 10 GW additional pumped storage capacity compared to a scenario without cable and pumped storage capacity. The base case and the parameter variations with the highest influence are displayed. The black line shows the investment annuity for the cable and pumped storage capacity, calculated with 8 % interest rate and 35 years depreciation period. For all variations the cost reductions are higher than the investment annuity. The benefits of the storage scheme are a measure for the necessity of the capacity for the electricity system.

In the scenario with half the biomass capacity compared to the base case there is less flexible capacity in the system. In that case additional storage capacity in Norway is especially valuable. Consumer cost reductions more than triple compared to the base case. In years with low hydro inflow the operational range of the hydro storage plants is reduced. In that case the flexibility from the cable connection to Germany and additional pumped storage capacity in Norway is more beneficial than in average inflow years. When wind energy capacity in Norway is increased there is more fluctuating electricity production that has to be balanced. That increases the value of the cable and pumped storage capacity.

The scenarios with weather data from the years 1998 and 2003 lead to more electricity production from fluctuating renewable sources in Germany. This leads to a higher export to Norway but not to a higher total utilization of the cable. In case of 2003 weather the total transmission is even reduced compared to the base case. The utilization of production and pumping capacity in Norway is reduced in the 1998 scenario and only slightly increased in the 2003 scenario. The combination of those factors leads to lower cost reduction from cable and pumped storage capacity than in the base case. However, in both scenarios the cost reduction is still higher than the investment annuity.

The scarcity price of electricity or the value of security of supply is a very important parameter for the benefits of flexible capacity. It can be seen that the three variations of the scarcity price lead to very different levels of consumer cost reduction. The higher the value of security of supply, the higher are the benefits of additional cable and pumped storage capacity but all three scenarios lead to cost reduction that is higher than the investment annuity for the installed capacity.

The renewable scenario based on Sachverständigenrat für Umweltfragen (2011) shows the highest consumer cost reduction of all analyzed variations. In this scenario the share of fluctuating production is higher than in the base case. Therefore there is a greater need for flexible capacity. This causes increased electricity transmission between Germany and Norway and increased utilization of production and pumping capacity in Norway. Both factors lead to the high level of cost reduction. The scenario based on Umweltbundesamt

(2010) also leads to higher cost reduction than in the base case but the effect is much smaller. Both utilization of the cable and utilization of the production and pumping capacity in Norway are slightly higher. There is also a notable increase in the average price spread between Germany and Norway. This raises the cost reduction that can be gained with the cable and pumped storage capacity.

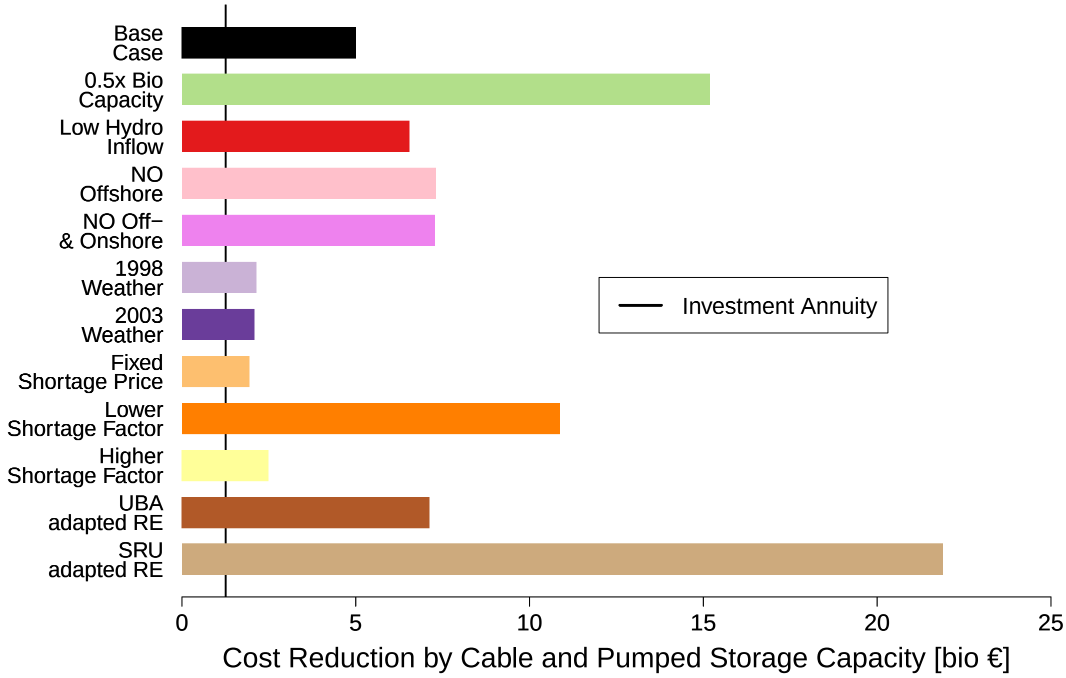

FIGURE 8.80: Consumer benefit of 10 GW cable between Germany and Norway and 10 GW additional pumped storage capacity in Norway for different parameter variations

The interest rate and depreciation period used for calculating the investment annuity of cable and pumped storage capacity influence the benefits of the installations. The interest rate is varied between 2 % and 10 %. When the interest rate for the investment is below 7 % more pumped storage capacity is beneficial. The favorable combination in that case is 10 GW cable capacity and 20 GW additional pumped storage capacity in Norway. For 6 % interest rate the advantage of more pumped storage capacity is quite small. It increases with decreasing interest rate but there is no further shift to yet more capacity. The effect of varied interest rate on pumped storage capacity is larger because the specific investment costs are only approx. half of the investment for cable capacity. That means that additional investment can be outweighed more easily by reduction of consumer costs. The variation of the depreciation period between 25 and 40 years does not change the favorable combination of cable and pumped storage capacity.

To summarize the production in hydro storage plants in Norway is increased most by low hydro inflow and lower biomass capacity and reduced most by wind energy production in Norway. The same pattern can be observed for the revenues of hydro storage plants. The pumping of electricity is increased most by wind energy production in Norway and reduced most by high hydro inflow. The variation of interest rate and depreciation period does not affect the profitability of the analyzed pumped storage capacity. The consumer cost reduction that can be achieved with cable connection between Germany and Norway and additional pumped storage capacity in Norway increases with the renewable scenario based on Sachverständigenrat für Umweltfragen (2011), reduced biomass capacity and a higher scarcity price of electricity. When a lower value is attributed to security of supply, cost reduction from storage in Norway decreases. The consumer cost reduction is larger than the investment annuity for cable and pumped storage capacity in all analyzed scenarios.

8.5.3 Filling Levels

Figure 8.81 shows the impact of sensitivity parameters on the filling level of the Norwegian reservoirs. Only some of the varied parameters significantly influence the filling levels. The scarcity price of electricity and and amount of grid extension in Germany have virtually no impact and are not shown in the figure. Also the two alternative renewable scenarios for Germany are not shown. The scenario based on Umweltbundesamt (2010) does not change the filling level curve and the renewable scenario based on Sachverständigenrat für Umweltfragen (2011) has only very little impact.

Not surprisingly the filing level is distinctly influenced by the hydro inflow. The high hydro inflow is based on data from 1990 and the total inflow is 133 % of the base case. The low hydro inflow is based on data from 1969 and the total inflow is 70 % of the base case. The distribution of inflow throughout the year is different in all three cases but the general seasonal pattern is similar.

The effect of the renewable extension scenarios for Norway is very similar. Both lead to higher filling levels because of the additional energy that is added to the electricity system. The increase is especially noticeable in winter, spring and early summer. In late summer and fall the difference is smallest. This is caused by the seasonal pattern of wind energy production. In the scenario that includes onshore and offshore wind energy capacity the filling levels are slightly higher in spring compared to the scenario with only offshore capacity but the difference is small.

The simulations with weather data from the year 1998 leads to higher renewable production in Germany and more electricity transmission from Germany to Norway. As a results this leads to higher filling levels than in the base case but the difference is smaller than for the other variations. Using weather data of 2003 shows a lower transmission from Germany to Norway than in the base case. This leads to slightly lower filling levels for most of the year.

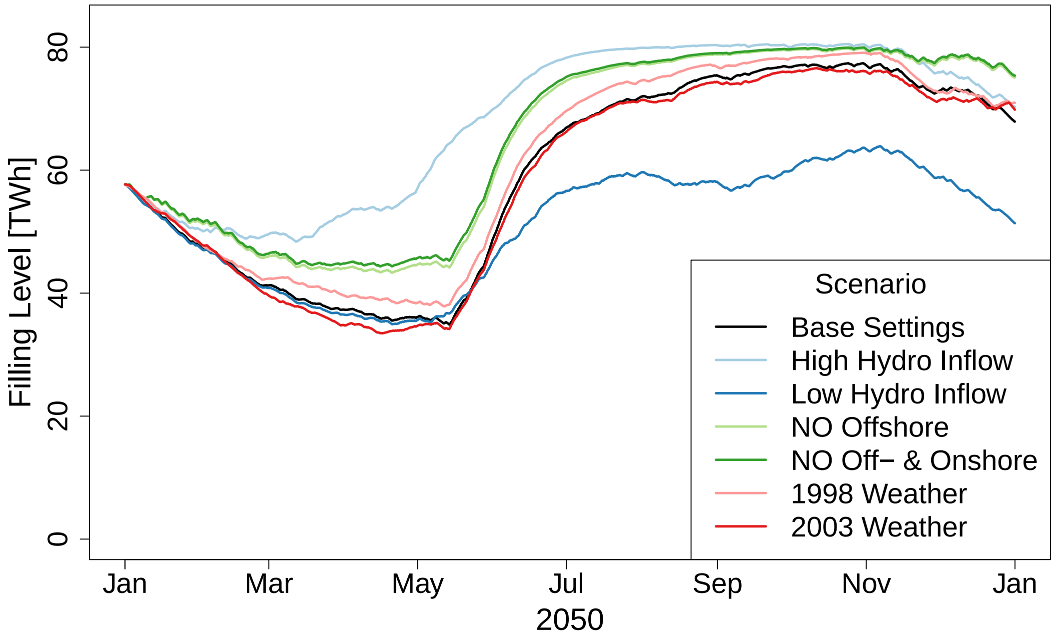

FIGURE 8.81: Sensitivity of the reservoir filling levels to different parameters, 10 GW cable capacity and 10 GW additional pumped storage capacity in Norway

Chapter 9

Conclusions

9.1 Main Findings

All the results of the simulations have to be assessed in light of the assumptions for input parameters, especially for renewable and storage capacity. On that basis it can be concluded that among all the simulated cable and pumped storage combinations the economically most beneficial is the installation of 10 GW cable capacity between Germany and Norway and 10 GW additional pumped storage capacity in Norway. For higher capacity the additional investment costs are not offset by further reductions of consumer costs. The simulations are not designed to find the necessary capacity for covering the load at all times. Shortage of electricity is allowed but will be penalized with a high shortage price. This is based on the assumption that at high prices certain consumers will prefer to reduce their load. A forced complete load coverage would lead to higher capacity than arises from this analysis.

Under the current market framework the installation of this favorable amount of capacity is not profitable for private investors. A different market framework or additional financial incentives are needed to stimulate such investment. This is further discussed in section 9.2.2.

The new installations have short-term and seasonal effects on reservoir filling levels in Norway. Those are different for each individual reservoir. In general fluctuations increase but in a scenario with 10 GW cable and 10 GW pumped storage capacity they remain well within environmentally acceptable limits. The cable connection increases the filling level in spring and winter. During summer it is lowered for some reservoirs but the collective filling level is very similar to the case without cable connection. Additional pumped storage capacity leads to lower filling levels before the snow melt and higher filling levels during summer and fall. This evens out throughout the course of the year. Then combination of cable and pumped storage capacity is shifting the filling levels upward throughout the whole year.

The simulated ramp rates of the cable connection show relative values that are in some hours higher than today's operational limits. However, with a cable capacity of 10 GW the hourly ramp is only higher than 85 % of installed capacity in 3.6 % of time. Restricting the operation in those situations would affect the system only very little. In order to connect such large cable capacity to the onshore grid in both countries most likely grid enforcement is needed. However, in any case the transformation of the electricity system towards renewable energy sources and the resulting changes in supply and demand structure will require a transformed grid structure so that necessary grid extension cannot be attributed only to connection of interconnector capacity.

The impact of other storage technologies on the discovered results has been analyzed. This does not constitute a comparison of different storage technologies and does not provide any conclusion on the possible contribution of different storage technologies to a sustainable electricity system. Such an analysis would have to be based on the potential, costs, environmental and social impacts of different options. The purpose of the sensitivity analysis was to show the impact of a different competitive environment on the benefits and profitability of storage in Norway. The revenues of cable connection and pumped storage plants in Norway decrease as additional storage capacity in Germany is included in the simulations. The greatest effect is caused by the power to gas storage which has the largest storage capacity of all analyzed options. This is however partly due to unfeasible net withdrawal from the gas storage that is caused by the model algorithm. It is still beneficial to install 10 GW cable capacity between Germany and Norway and 10 GW additional pumped storage capacity in Norway if pumped storage capacity in Germany is extended or 10 GW compressed air energy storage are build in Germany. If the power to gas technology is pursued with large storage capacity connected to the natural gas infrastructure the benefits of storage in Norway in addition to that are not offset by the investment costs. However, in that case the total system costs will be much higher because of the higher investment costs of the PTG technology compared to storage in Norway.

The sensitivity analysis has shown that renewable capacity in Germany and Norway, biomass capacity, and the scarcity price of electricity have the largest impact on the results. The residual load which is mainly shaped by fluctuating renewable electricity production imposes the need for balancing capacity. With higher renewable capacity and production the need for flexible production capacity can be reduced to some extent but the need for storage capacity and the excess electricity will increase. Demand for flexible capacity can be lowered when the combination of fluctuating production from diverse sources leads to a relatively smooth residual load curve.

A 100 % renewable electricity system needs enough flexible capacity to balance supply and demand at all times. The revenues and benefits of additional flexible capacity depend on how much flexibility is already in the system. The variation of biomass capacity can be taken as an example for any available flexible production capacity. The balancing of the system does not need a specific production or storage technology. It needs a certain capacity for producing and absorbing electricity and a certain storage volume. The choice of technology depends on the potential and costs of different options but also on the environmental and social impacts.

The higher the security of supply is valued the greater the need for and the benefits of flexible capacity. This is a very important parameter. All results from energy modeling are influenced by how this issue is treated. The value of security of supply is determined by the costs caused by electricity outages but also by the costs of other flexibility options like demand response which are not included in the scenarios.

The results for the filling level of Norwegian reservoirs are most influenced by wind energy expansion in Norway and the supply of renewable energy in terms of hydro inflow, wind speed and solar radiation.

9.2 Critical Appraisal

9.2.1 On the significance of energy models

The energy system is very complex with many interacting and interdepending factors. Qualitative analyses can only give insights to a limited extent. In order to examine a larger number of parameters and their interaction quantitative methods are needed. Different kinds of energy models can help come to conclusions about future development and map out potential pathways of the energy system. Models are especially useful to explore the interdependency and sensitivity of different parameters. However, models are only a very simple image of reality and by nature flawed and biased.

Before a model run a multitude of parameters has to be set by the modeler or the model user. It is not possible to make neutral decisions for those settings. Every choice has an impact on the results. The best way to deal with this is to lay open all assumptions and to evaluate the impact they have on the modeling outcome. In this thesis this is taken into account with sensitivity analysis for those parameters that were assumed to have the largest impact on the results.

It has to be kept in mind that the results of model optimization or simulation cannot be separated from the assumptions on input parameters. They always have to be communicated together. Results should also not be reduced to one figure but rather a range of possible outcomes should be opened and assessed.

9.2.2 Shortcomings of the model

renpass simulates the commitment of storage and production plants. The operating costs of the system are minimized in the simulation. The model does not optimize the configuration of the electricity system. That means that the simulated system will not be optimal with regard to total system costs. Also in reality the development of infrastructure and the investment in new capacity is not optimized. Rather it is determined by individual economic and political decisions. This approach allows the model users and the audience of modeling results to apply their own criteria for comparing different pathways. This is more transparent than evaluating and ranking options within the model with only one fixed optimization criterion, usually the total system costs. By leaving the assessment to the user, other important characteristics of energy systems like diversity, resilience, environmental and social impacts can be taken into account.

There are countless possible pathways towards a renewable system that cannot all be simulated due to limited time and computing capacity. Hence from all possible scenarios only a selected few can be compared to find the most favorable option according to the specified criteria.

The operation of the Norwegian hydro storage plants is very complex. The operation and price bids of hydro power plants are based on the water value concept that includes a price forecast. The scheduling and pricing of specific plants can only be roughly approximated with renpass. Consequently also environmental impacts for specific sites cannot be predicted exactly. However, the results indicate trends for the whole system and can serve as examples for the impacts on individual plants and reservoirs. Many different operating algorithms for hydro storage plants were tested. The simulation might be improved if operating rules were differentiated between different types of plants, for example old and new capacity. The relaxation of part-load rules for newly installed pumped storage capacity could be introduced in future model versions.

The scheduling of hydro power plants is based on price expectations. The basic assumption for renpass is that the competitive environment for hydro storage plants will be similar in a renewable electricity system. This premise serves well for simulating the operation of the plants. A price forecast for 2050 cannot be concluded from the simulations. Price projections for such a long time frame are very uncertain. They depend not only on the development of production capacity but also on the market framework which is determined politically and difficult to predict.

9.3 Threats and Opportunities of the Scheme

The presented work has shown that high connection capacity between Germany and Norway and substantial extension of pumped storage capacity in Norway is feasible and beneficial for the electricity system. There are however some obstacles that need to be overcome. One important issue are the investment incentives for cable and pumped storage capacity. Here the situation is different for cable investment and pumped storage investment. The operation of the transmission grid as a natural monopoly is regulated so that investments do not have to be refinanced by the congestion rent. Cable connections that are beneficial for society can be financed as infrastructure projects by the transmission grid operators. Pumped storage plants on the other hand are operated on liberalized markets. Here the missing investment incentives have to be overcome by altering the market framework or providing additional income.

The public and political support in Norway is crucial for the success of the proposed scheme. This is related to the perceived environmental impact of the scheme but there are other concerns beyond that. The Norwegian interests need to be taken very seriously and should be addressed with continuing communication among politicians, researchers and the general public about the objectives, scope and implementation of the scheme.

If those barriers can be overcome storage in Norway will be an important contribution to renewable electricity supply in Europe at low costs and with low environmental impact.

9.4 Outlook and Further Research Need

With accelerating climate change there is no time to loose in transforming the energy system to renewable energy. The first new cables between Germany and Norway and the first new pumped storage plants in Norway bring high benefits to the energy system. Furthermore, those first investments could be profitable for private investors. The optimal total capacity of different flexibility options needs to be reevaluated as the transformation evolves and more knowledge about the costs and potential of the different alternatives becomes available. A closer look should be directed towards the operation and profitability of pumped storage plants from the perspective of private operators. The conversion of the electricity system may call for new market frameworks. The design of those markets and the effect on the profitability of new pumped storage capacity should be analyzed in future research work. Furthermore, besides costs and benefits, the environmental and social impacts of different pathways towards a sustainable electricity supply need to be examined in more detail.

Appendix A

Entity-Relationship Model of Hydro Data

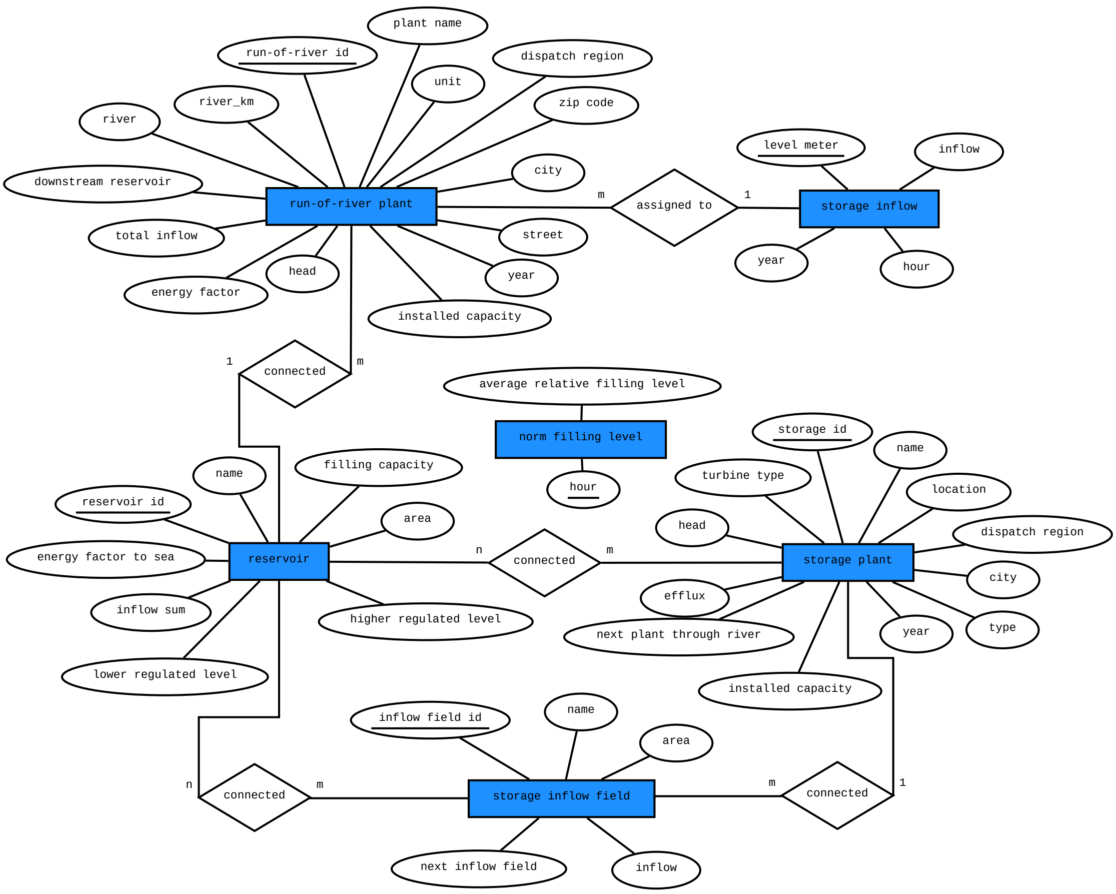

FIGURE A.1: Entity-relationship model of hydro storage system data

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