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Analysis of the impact of large quantities of electricity from photovoltaics on Central European wholesale electricity market prices and its influence on profitability of pump hydro storage power stations

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Univ.Prof. Dipl.-Ing. Dr.techn. Reinhard Haas

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unter der Leitung von

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Danksagung

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Abstract

In recent years, large quantities of renewable electricity, especially from photovoltaics, have influenced wholesale electricity market prices. The result was a decreasing price spread and less operating hours for pump hydro energy power stations, which caused declining revenue.

Therefore, the question in this thesis is to analyze the impact of large quantities of electricity from photovoltaics on Central European wholesale electricity market prices and its influence on profitability of pump hydro storage power stations.

Firstly, electricity prices on an hourly resolution are derived from a linear dispatch model, which represents the electricity market, for changing scenarios with different photovoltaic infeed and CO_2 prices. Afterwards the linear optimization model maximizes the revenue for different scenarios and storage sizes using the derived prices.

The findings demonstrate that an increase of installed photovoltaic capacity in Austria and Germany leads to a reduction of revenue first. However, if the capacity grows further, revenue is expected to rise with higher photovoltaic share. The model shows that the smallest revenue (about 70% compared to the scenario without photovoltaic infeed) occurs at the photovoltaic penetration level between $20GW_{peak}$ and $30GW_{peak}$ due to peak shaving. This correlates with the installed capacity in the base year 2012. Furthermore, higher CO_2 prices are reducing revenue at lower photovoltaic share ($<20GW_{peak}$) and raising revenue at higher photovoltaic levels ($>30GW_{peak}$).

Kurzfassung

Durch die Einspeisung großer Mengen an elektrischer Energie aus erneuerbaren Quellen, vor allem aus Phtovoltaik, wurde der Elektrizitätspreis an der Strombörse maßgeblich beeinflusst. Daraus resultierten kleinere Preisspannen und sinkende Einsatzstunden für Pumpspeicherkraftwerke, welche zu einem Einkommensrückgang führten.

Das Ziel dieser Arbeit ist den Einfluss großer Mengen an Photovoltaikstrom auf dem Elektrizitätsmarkt in Mitteleuropa zu analysieren und in weiterer Folge die Auswirkungen auf das Einkommen von Pumpspeicherkraftwerken zu untersuchen.

Dafür wurde ein lineares Modell zur Abbildung des Elektrizitätsmarktes erstellt, aus dem sich die Strompreise für verschiedene Szenarien mit unterschiedlichen Photovoltaik Anteilen ableiten lassen. Ein weiteres lineares Modell optimiert das Einkommen auf Basis des Strompreises für die Szenarien und für verschiedene Speichergrößen.

Das Ergebnis des Modells zeigt eine Reduktion des Einkommens von Pumpspeicherkraftwerken bei einem Anstieg an installierter Photovoltaik Leistung in Österreich und Deutschland. Jedoch steigt das Einkommen wieder mit weiter zunehmender Photovoltaik Einspeisung. Laut dem Modell liegt der Einkommenstiefpunkt bei 70% des Einkommens ohne Photovoltaik Einspeisung, im Bereich zwischen $20GW_{peak}$ und $30GW_{peak}$, was der installierten Leistung des Jahres 2012 entspricht.

Der steigende CO_2 Preis reduziert das Einkommen bei einer installierten Photovoltaik Leistung kleiner als $20GW_{peak}$. Für eine installierte Leistung größer als $30GW_{peak}$ steigt das Einkommen laut dem Modell bei höheren CO_2 Preisen

Statement of Affirmation

I hereby declare that this Master Thesis was in all parts exclusively prepared on my own, and that other resources or other means (including electronic media and online sources), than those explicitly referred to, have not been utilized.

All implemented fragments of text, employed in a literal and/or analogous manner, have been marked as such.

This thesis was not submitted in the same or in a substantially similar version, not even partially, to another examination board and was not published elsewhere.

Vienna, January 2016 ………………………………………………………..

Andreas Permoser, BSc

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1 Introduction

Power generation from renewable energy sources has increased significantly during the past decade and is expected to increase further to a share of 20% in European energy demand by 2020 (Sensfuß and Ragwitz 2007a). This target was decided by the European Union in Directive 2009/28/EC. The aim for electricity generation is that 34.3% of total electricity demand is provided by renewable energy sources in 2020 (Geth et al. 2015). In 2007 the share of renewable energy sources in electricity production was 14% (Haas et al. 2008). Pumped hydro energy storage (PHES) and hydro energy storage (HES) are representing 99% of storage capacity for electricity worldwide, and so these storages are important to raise the share of renewable energy in electricity production by storing volatile energy sources such as photovoltaics and wind energy.

Operators of pump hydro storage plants are facing a difficult economic situation in Central Europe in the last years since the rising infeed of renewable energies. Decreasing utilization time and price spreads are making the operation uneconomical (Wagner, Mauch, and Corradini 2014). “At the moment, there is nothing to earn with pump hydro storage plants” according to E&M powernews (Schlossarczyk 2013) in Germany. A simulation by energy provider E.ON shows a decrease in revenue about -50% from 2008 to 2015 due to the infeed of electricity from photovoltaic around midday (Harasta 2014). The question in this thesis is how this situation develops if additional photovoltaic capacity is installed.

Pumped storage plants participate in two structurally different markets: the market for scheduled energy (also known as spot market) and the reserve market for balancing energy (Engels et al. 2010). This thesis concentrates on the change of profitability of pump hydro energy storage plants in Austria and Germany at the spot market. The indicator for the profitability of pump hydro energy storage plants is the revenue, which is optimized for several scenarios of different PV infeed and CO_2 prices.

The method of approach is to represent the electricity market for Austria and Germany by a linear dispatch model in MATLAB. The model optimizes the dispatch of all power plants and derives the electricity price on an hourly resolution. The model is used to derive electricity prices for different scenarios of installed photovoltaic capacity and CO_2 prices. The electricity price on an hourly resolution is the input for the linear programming model that optimizes the revenue for pump hydro energy storage plants. The optimization is evaluated for different storage volume sizes.

This thesis starts with an overview on the state of the art of pump hydro storage plants. In the theory part, a report is given that focuses on the economic situation and its influencing indicators. Additionally, information is given about the tasks and the need for PHES in the electricity system, followed by explanations about the price forming progress on the energy stock market. The different types of markets are discussed as well as the formation and influence of negative electricity prices. The final theory part gives an overview about the modelling of electricity prices. Finally, the theory part is followed by a detailed explanation of the applied models.

All assumptions and constraints are explained for the linear dispatch model that derives the electricity price, and also for the revenue optimizing model. The chapter for presentation and analyzation starts with a comparison of the modelled price with the real historic price. Furthermore, the results for optimized revenue at different PV capacity scenarios are displayed and the reasons for this behavior are shown and analyzed. Examples are given among others for the developing of price spread, pump hydro power dispatch and state of capacity of storages. Results for the storage profitability at different CO_2 price levels are presented and interpreted.

The last part analyses the results and deals with the differences in revenue for different storage volumes. The conclusion summarizes and interprets the collected and evaluated results.

2 State of the art and theory about pump hydro storage plants

This chapter informs about the current economic situation of large-scale electricity storage plants in Austria and Germany and their need for the energy system. Moreover, information about the electricity market and its mechanisms is demonstrated. Pumped hydro energy storages (PHES) are representing 99% of storage capacity for electricity worldwide. Other storage technologies such as batteries, power to gas, or compressed air energy storage are increasingly used but still account for a small share worldwide as well as in Europe. Hydro energy storage is the main storage for electrical energy in Austria and Germany. The installed power for PHES in Austria is 3621.84MW ("APG - Installed Capacity" 2015). There are 11 storage projects under construction or planned for the near future with a combined power of 3632MW in Austria. The PHES Tauernmoos with a capacity of 130MW is already under construction (Geth et al. 2015). In Germany the installed PHES power is 6804.7MW. An amount of up to 5280MW of new storage developments is planned to be built in Germany (Geth et al. 2015). It is not specified until when these plants should be built. Governmental and regional targets for renewable energies are also driving the demand for system reserve and an increase of PHES services. A general growing demand for electricity and peak power when renewable energies are not available across Europe is expected. PHES are seen by many developers as contributors to a country's security of supply (Deane, Ó Gallachóir, and McKeogh 2010).

Not every hydro storage plant is able to pump the water to a higher reservoir. Pumped hydro storages are able to refill the basin with water in times when the price is low, for example, during the night or if there is an overflow of electricity in the grid due to a high infeed of renewable energy. The implementation of storage systems is expected to increase because of the rising amount of volatile energy such as photovoltaics (PV) and wind energy. Subsidies for private photovoltaic plants and the aim of the government to reduce CO_2 led to the relatively quick increase in wind power and PV capacity in Austria and Germany. The rising installed PV capacity in Austria is illustrated in Figure 1 and in Germany is shown in Figure 2. Furthermore, wind power plant installations raised considerably but in this thesis the focus is on the impact of photovoltaics energy.

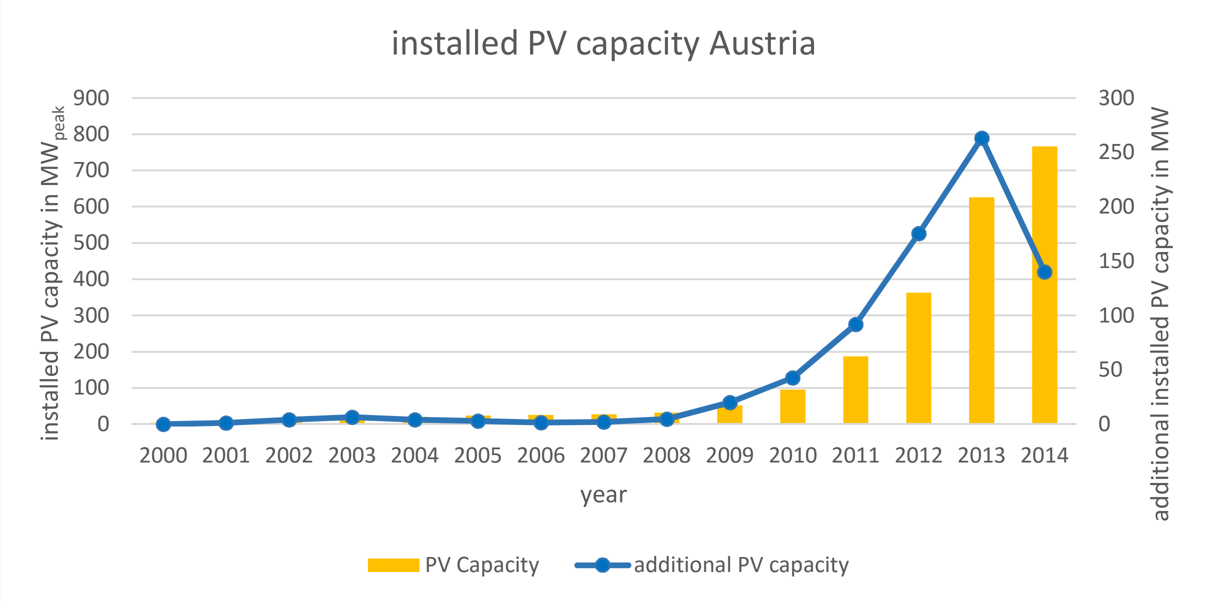

Figure 1: installed PV capacity Austria[1] (own illustration)

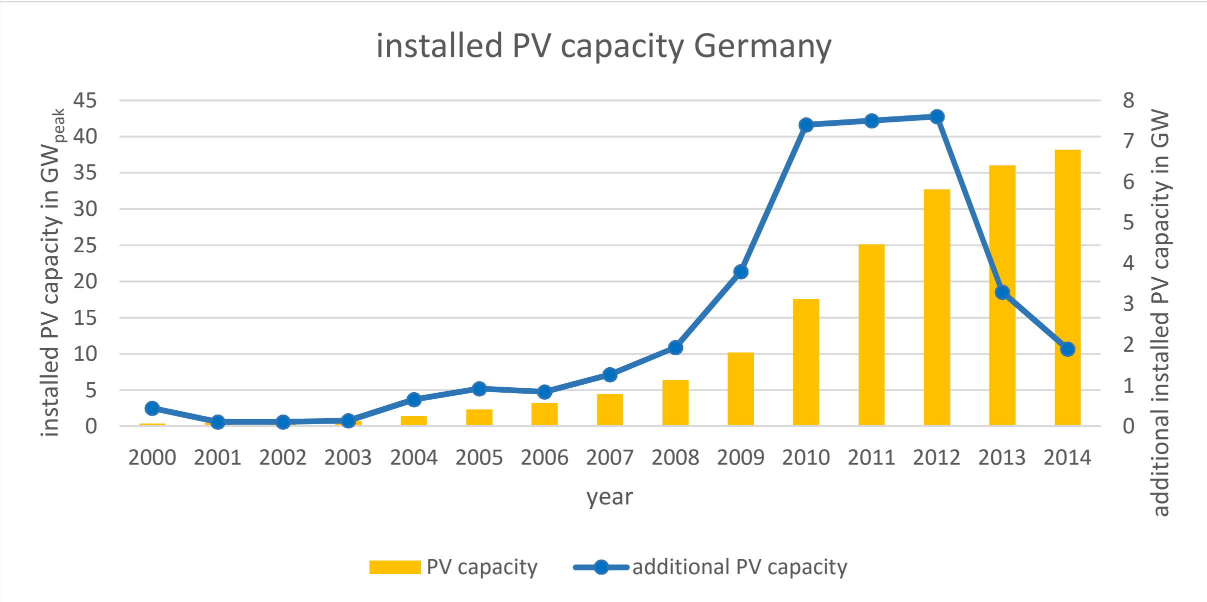

Figure 2: installed PV capacity Germany[2] (own illustration)

2.1 Situation of pump hydro storage plants

The current situation on the electricity market is a challenge for electricity providers because the rising energy infeed of renewables influences the spot market prices (Keles 2013). The result is a lower spot market price. This trend is shown in Figure 3 for the average electricity price on EPEX market in 2007 and 2011. Moreover, the graph not only shows the significant price decrease, it further demonstrates that the price peak at noon is gone. The missing

[1] http://www.pvaustria.at/daten-fakten/grafiken/ (accessed on 05.01.2016)
[2] http://www.pvaustria.at/daten-fakten/grafiken/ (accessed on 05.01.2016)

price peak can be explained by the high PV infeed in these hours. The energy production from photovoltaics increased from 3100GWh in 2007 to 18500GWh in 2011 according to Figure 3 (“Bundesverband Photovoltaic Austria” 2016).

Figure 3 and Figure 4 are illustrating the electricity price situation in the past years. Figure 3 shows the average price in 2007 and 2011. The missing price peak due to the high PV infeed around noon is obvious. Figure 4 displays the course of electricity price for one week in May in the years 2006 and 2013. Here one can see in detail how the average price and the price difference between the highest and lowest prices decreased. The price difference, called spread, shrunk due to the midday infeed of photovoltaic energy. Furthermore, the time period between high and low prices got smaller, so that storages are not able to fill their storage volumes completely and therefore, they are underused (Apel et al., n.d.). The smaller time period can be explained with the rising photovoltaics infeed around noon. This leads to a morning and evening residual peak load. Due to this change, the dispatch of pump hydro energy storages changes that way. Another reason for the smaller price difference is the nuclear exit in Germany. The price level in times of low prices increased, because without nuclear plants, more expensive fossil thermal plants are the price building plants in these hours. On the other side, the peaks are reduced by infeed of renewables (Apel et al., n.d.).

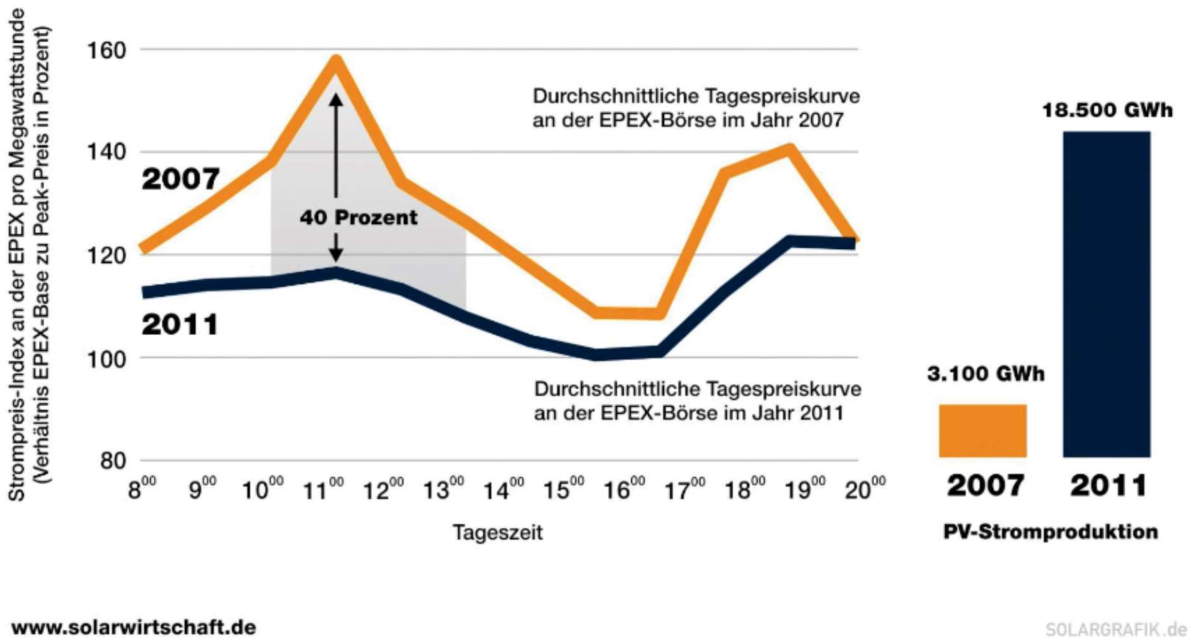

Figure 3: EPEX electricity price 2007 and 2011 (“BSW - Bundesverband Solarwirtschaft e.V.” 2016)

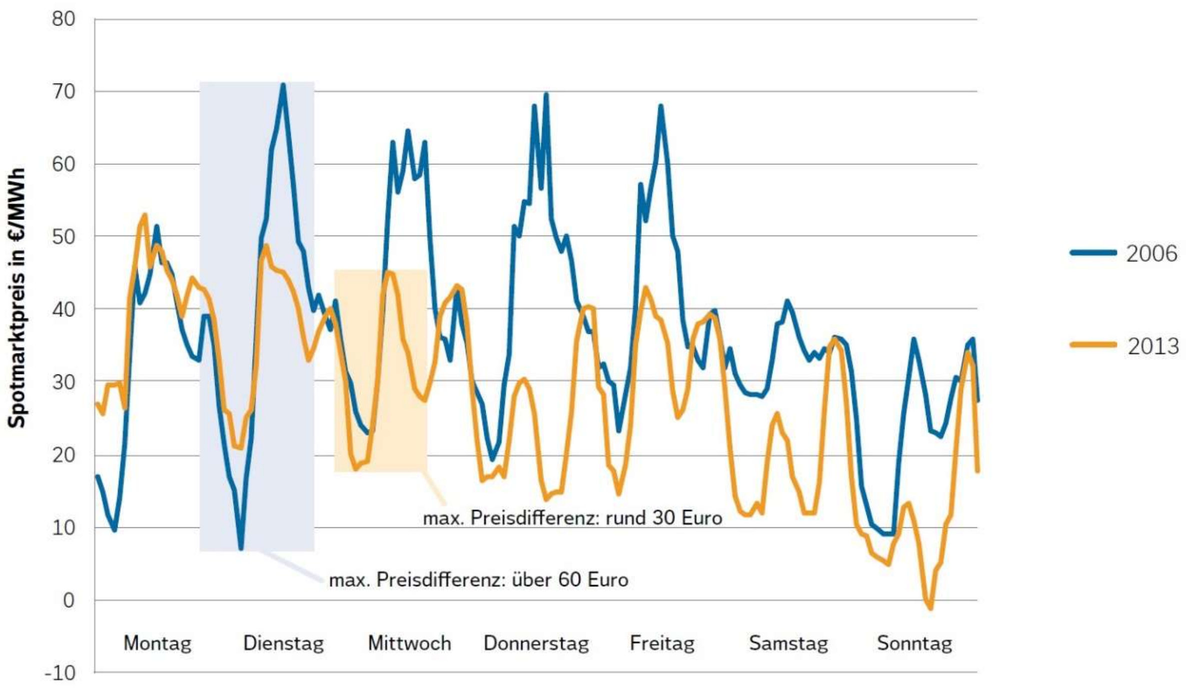

Figure 4: EPEX electricity price 2006 and 2013 for one week in May (Apel et al., n.d.)

2.2 Merit-order effect

The merit order effect can be described as *"the lowering of power prices at the electricity exchange due to an increased supply of renewable energies"* (Appun 2015). It is explained in Figure 5 which illustrates the effect of PV on the market prices of electricity.

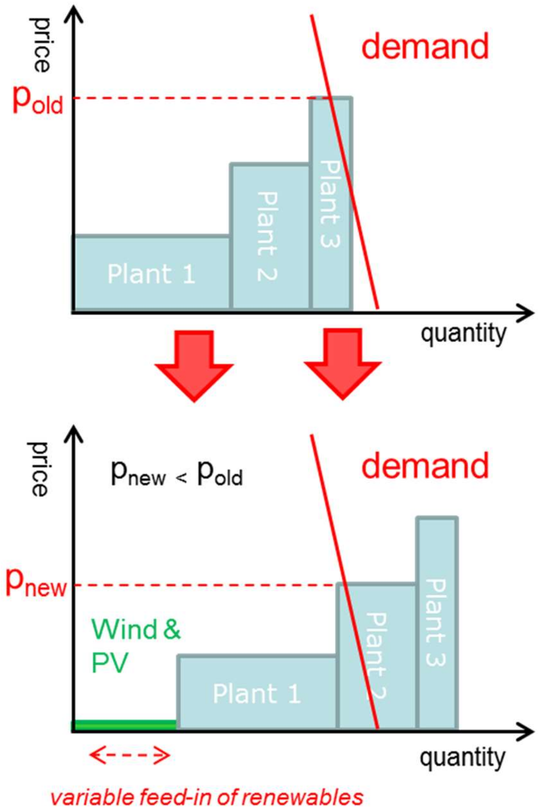

Figure 5: Effect of PV on the market prices of electricity merit order effect (Kloess 2012)

The price for electricity on the spot market is determined by the power plant with the highest marginal costs which is required to cover demand. The merit order sorts power plants in order of their marginal costs for electricity production. The low priced plants are used first for operating. With rising electricity demand, the more expansive plants are operating. Renewable power infeed has legal priority and is placed at the beginning of the pricing scale in the merit order with fictional costs of zero or even negative prices. Renewable energy sources have to be bought by supply companies in advance. The residual load is respectively reduced because of the guaranteed infeed of electricity produced by renewable energies (Sensfuß and Ragwitz 2007b). Therefore, the plants with the highest marginal costs are not needed any more. This leads to a reduction of the spot market price as illustrated in Figure 5. The merit-order for the thermal plants, which is used in the model, is shown in Figure 6. Nuclear power plants are clearly the cheapest thermal plants followed by lignite and coal power plants. Next in the merit order are the different types of gas power plants and after them, the oil firing plants (Moreno, Lopez, and Garcia-Alvarez 2012).

The merit-order changes significantly, if renewable energies are raising infeed. PV, wind and run of river power with fictional costs of zero are shifting the merit-order to the right. If electricity demand is the same as without renewables, the price decreases. Figure 7 shows the merit order including 30GW of renewable infeed. At a demand of 76GW, the price would be about 42€/MWh. In a scenario without infeed of renewable energies like in Figure 6, the price for the same demand would be about 60€/MWh.

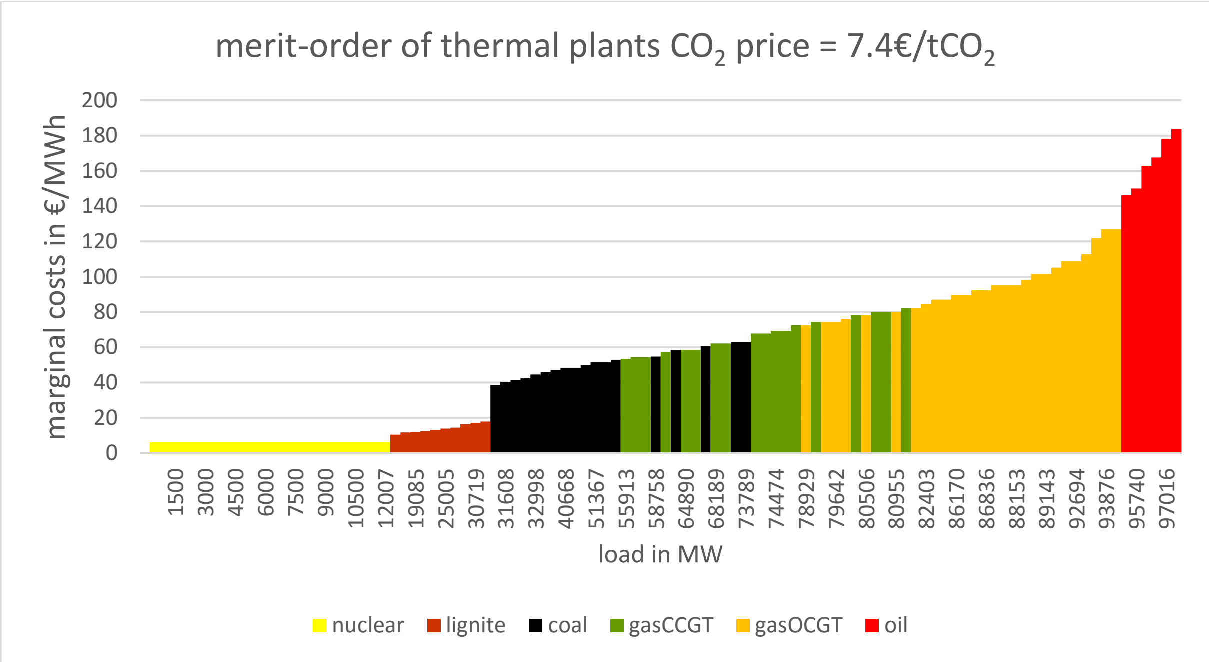

Figure 6: merit-order thermal plants CO_2 price = 7.4€/tCO_2 (own illustration)

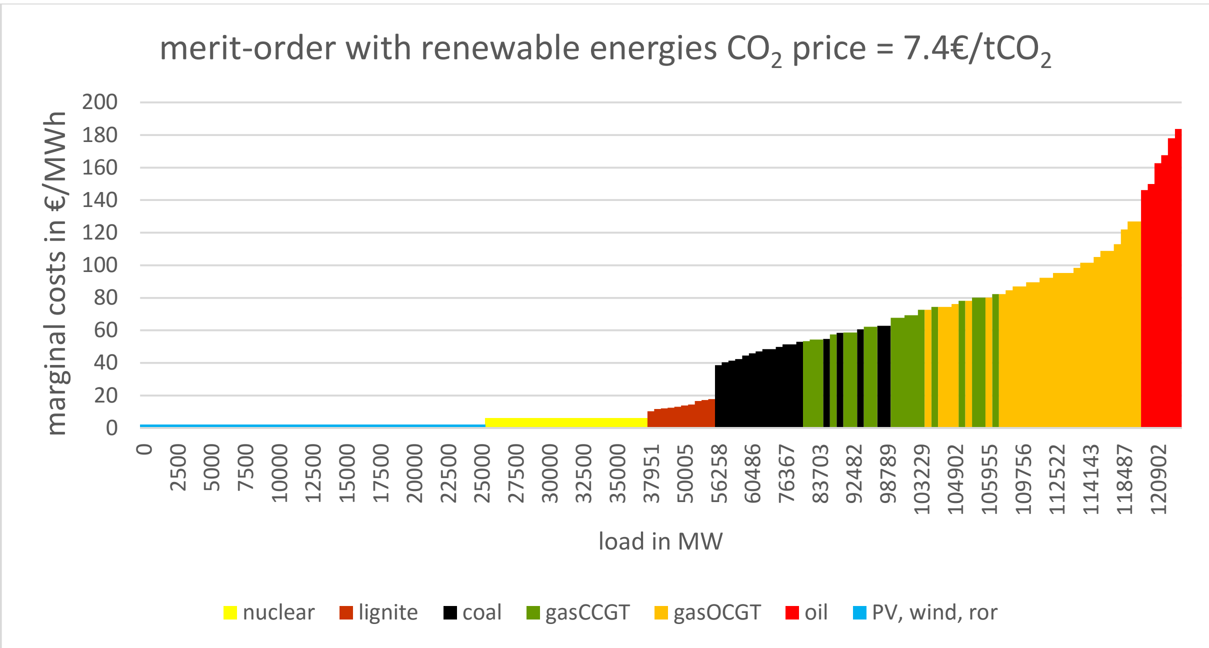

Figure 7: merit-order CO_2 price = 7.4€/tCO_2 (own illustration)

The merit order changes significantly, if the CO_2 price changes. Different types of plants are more or less affected by the CO_2 price. Marginal costs of nuclear plants and renewable energies are not changed by the CO2 price. The merit order for thermal plants is displayed in

Figure 8 for a CO_2 price of 20€/tCO_2 and in Figure 9 for a CO_2 price of 70€/tCO_2. It can be seen that coal and lignite power plants are moving to the right in the merit order and changing the place with gas fired combined cycle gas turbines and also with open cycle gas turbines. This has a major effect on thermal power dispatch and electricity price. Especially if, additionally to a higher CO_2 price, also the infeed of renewable energy would rise.

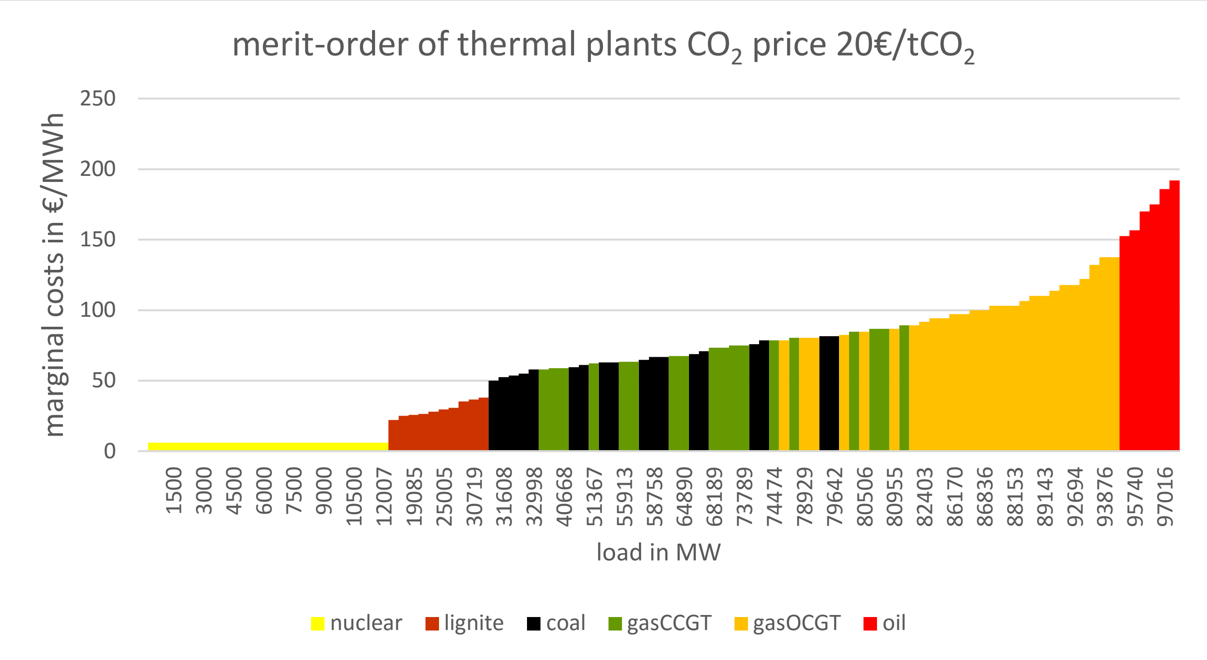

Figure 8: merit-order thermal plants CO_2 price = 20€/tCO_2 (source: own illustration)

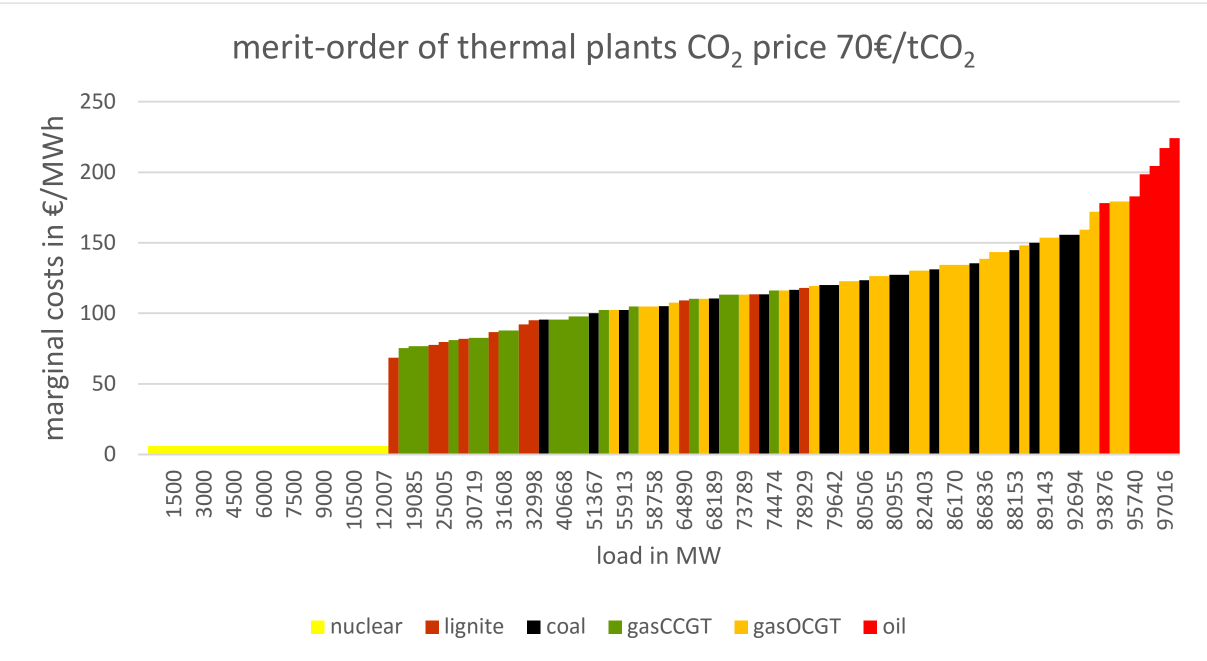

Figure 9: merit-order thermal plants CO_2 price = 70€/tCO_2 (own illustration)

2.3 Change of residual demand situation

The higher infeed of photovoltaic energy affects the residual load in a way shown in Figure 10. “Peak shaving” appears through high PV infeed and reduces profitability of conventional power plants (Harasta 2014). Especially the pump hydro storages are affected by this situation (Asendorpf 2013). Pump hydro storage plants earn their revenue by pumping water up in the storage using cheap electricity during the night hours and producing electricity by turbining in times of peak load with high prices. This price difference is called price spread. Due to the reduction of the peak at noon on sunny days with high PV infeed, the pump hydro storages are needed less often. The number of hours with the opportunity to earn revenue is reduced (Asendorpf 2013). The difference in operation of pump hydro storage power plants is illustrated in Figure 11 and Figure 12. In Figure 11 one can see the operation activity of PHES on 10.08.2011. As described above, there is the pumping activity during the night hours and the turbining activity during the day. The situation differed significantly a year later on 16.09.2012 in Figure 12. The operation activity of PHES changed considerably around noon. Instead of turbining, the pump hydro storages are pumping.

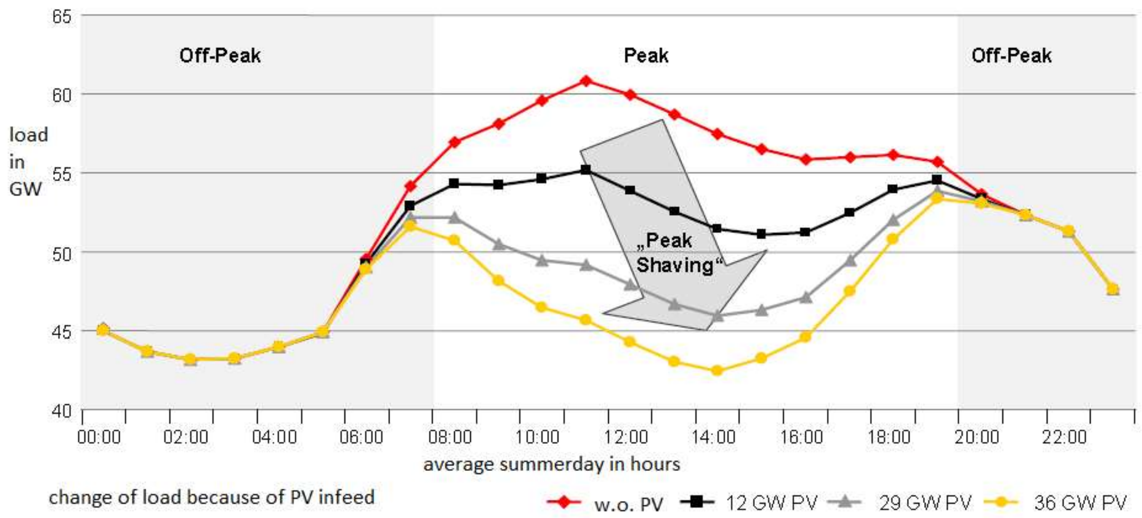

Figure 10: peak shaving of residual load (Harasta 2014)

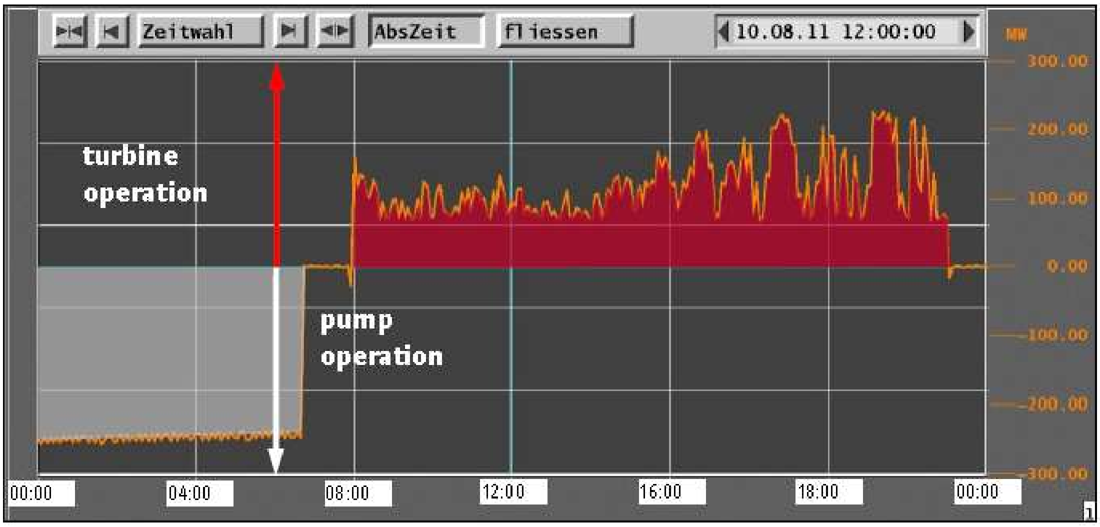

Figure 11: operation activity of PHES on 10.08.2011 (Harasta 2014)

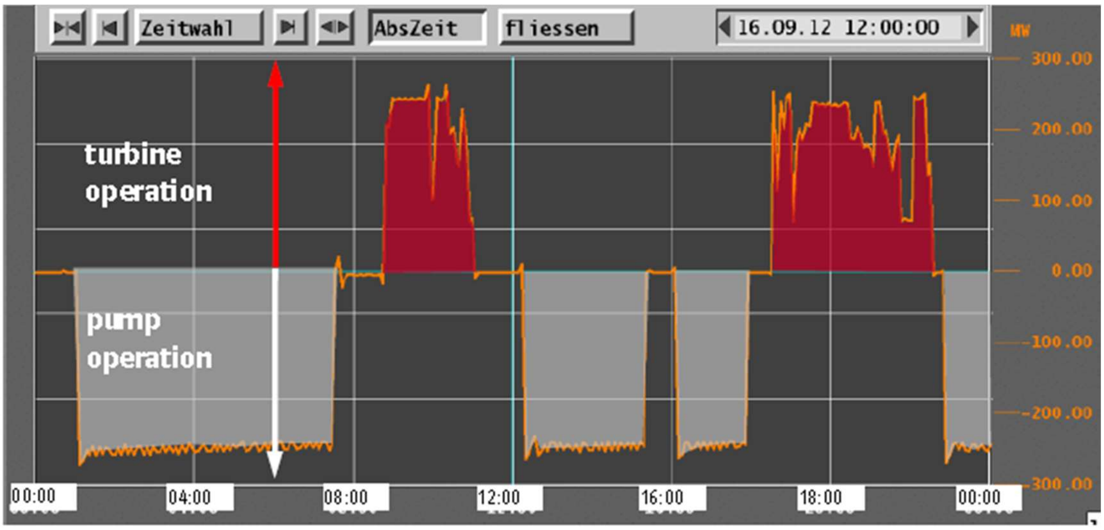

Figure 12: operation activity of PHES on 16.09.2012 (Harasta 2014)

Another important factor in addition to the price is the amount of energy demand. Due to the legal priority of renewable energies, the other power plants are competing for covering the residual load. The amount of residual load decreased with rising infeed of renewables. The histogram on the top left in Figure 13 shows load in classes on the x-axes and the frequencies of occurrences on the y-axes. On the top right in the same figure, the residual load is displayed. It can be seen that the feed in of renewable energies reduces the hours where demand for conventional power plants is higher than 70GW, which mainly affects gas-fired power plants. The histogram at the bottom shows that this trend continues with higher PV infeed. It can also be seen that peak demand > 80GW is hardly affected by this scenario.

Figure 14 illustrates the load and residual load of the Austrian and German electricity system for the whole year 2012. The duration curves show sorted loads over the hours of the year starting with the peak demand. The area between the blue and red line can be interpreted as reduced demand for conventional electricity generation. The value of PV infeed depends on the costs of providing those savings with other technologies which depend on fuel prices, CO_2 prices and conversion efficiencies of existing power plants (Hartner 2015).

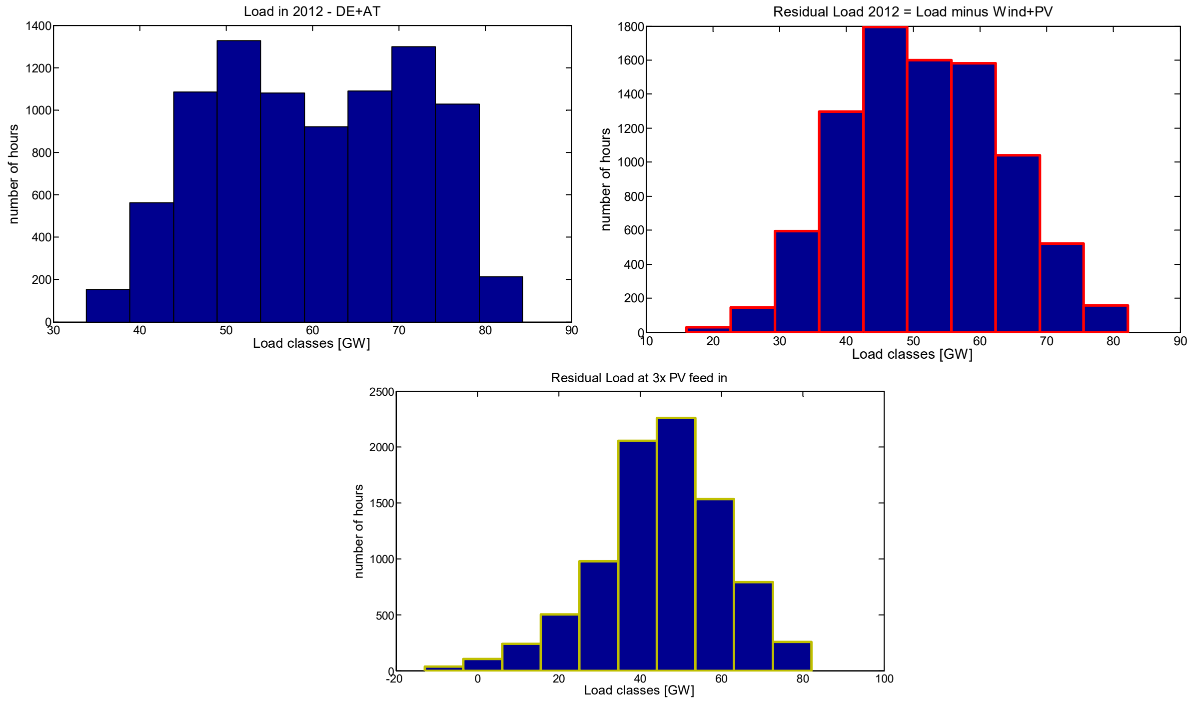

Figure 13: Histogram of load, residual load in 2012 and residual load if the PV feed-in had been 3 times higher than the actual feed-in of PV in 2012 (Hartner 2015)

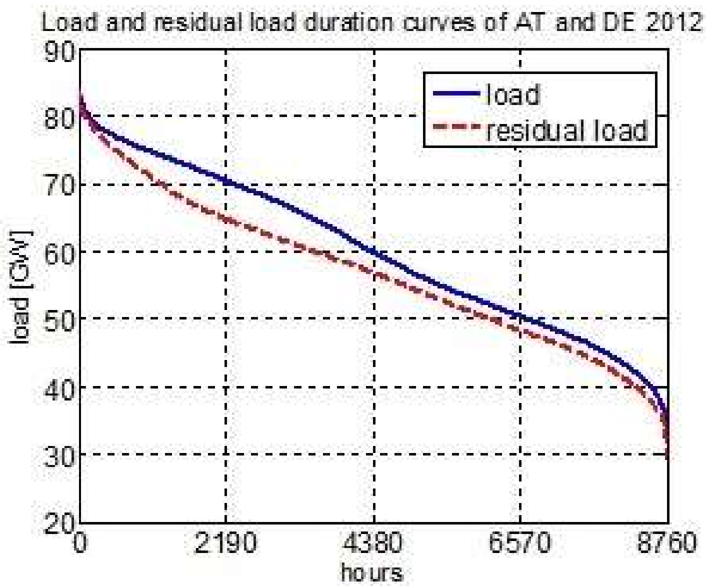

Figure 14: Load and residual load duration curves in 2012 for Austria and Germany (Hartner 2015)

2.4 Economic situation of pump hydro storage plants

Pump hydro storage power plants can earn revenue on two different markets. Firstly, profit on the energy spot market can be earned, as already mentioned, by turbining in times of peak load with high electricity prices. This thesis concentrates on the revenue on the day-ahead market on energy stock exchange. Besides that, profit can be earned with balancing energy, which is not considered in this thesis. Pump hydro storage plants are getting money for reserving balancing energy. Grid operators can access these reserves when there is demand. Due to better prediction because of improving reliable computer models, the power of sluggish coal power plants can be adapted earlier and therefore less profit can be earned for pump hydro storage plants (Asendorpf 2013). The difficulty for the PHES operators is the reduced price spread between pumping and turbining. This price gap makes profit possible. The reduced demand and price peaks are reducing the possible revenue of PHES. Not only the price spread decreased, but also the required amount of peak energy was reduced to the coverage of peak load by photovoltaics around noon (Schlossarczyk 2013). According to a simulation study by E.ON Germany (Harasta 2014), the achievable revenue decreased about 50% from 2008 to 2015 as illustrated in Figure 15 and there is no improvement that can be foreseen under these circumstances (Harasta 2014). However, it is to say that the base year 2008 in this study was a year with higher average prices and higher price peaks than the other years. So this was also a reason for the higher revenue in this year.

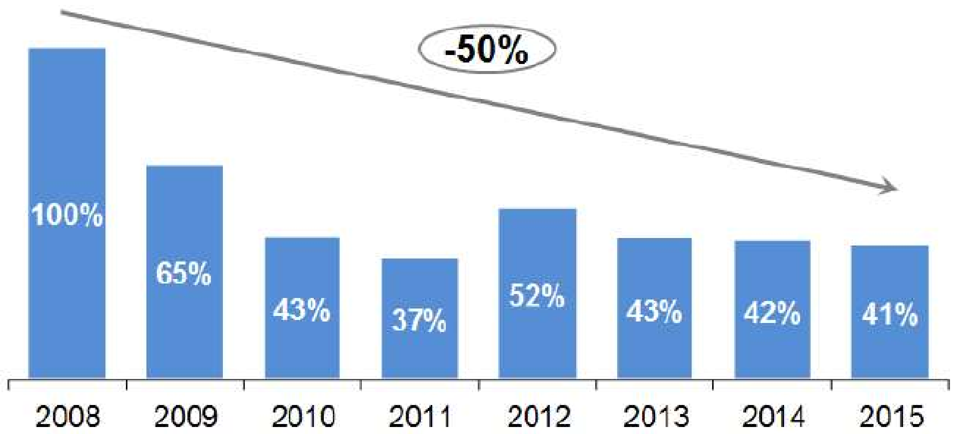

Figure 15: achievable revenue of PHES (Harasta 2014)

Another influence beside the decreasing price spread and smaller residual load, is the increase of grid fee in Germany. In addition to the price for electricity, the pump hydro plant operators have to pay fee for grid usage during pumping operation. So in the current situation, an essential part of the profit derives from covering balancing demand (Wagner, Mauch, and Corradini 2014). Moreover, there is a need of pump hydro storage plants in grids with a rising share of renewable energies. However, apart from that, under the current market conditions, the marginal return is too small for new investments to built new PHES (Hildmann et al. 2014). The nuclear exit in Germany will reduce an essential part of base load. In hours with high load, prices will be determined by gas power plants more often. This would lead to higher price peaks again. So from 2020 on, the fluctuation of electricity price, and so the price spread, may rise again and would change the economic situation for PHES (Schlossarczyk 2013).

2.5 Tasks of pump hydro storage plants

As already mentioned, the most widely established large-scale form of energy storage is hydroelectric pumped storage. Typically, these plants operate on a daily basis charging at night during periods of low demand and low-priced energy and discharging in times of high or peak demand. Hydroelectric plants have typically fast ramp-up and ramp-down rates (Gönen 2012).

The advantages of PHES according to Dandekar and Sharma (2009) are listed below.

- In relation to other quick available peaking units like batteries, PHES have relatively low capital costs compared to other energy storage systems and are thus the cheapest source of peaking energy.
- The PHES schedule is dependable and can pick up load rapidly in a matter of few minutes.
- Such power stations are simply adaptable to automation as well as remote control.
- Hydro power has small effects on environmental pollution compared to fossil fuel burning plants. Besides the dams that have to be built and the included grey energy for the construction, PHES are a valuable part of the power system in reduction of air and water pollution.
- PHES are black start able, this means in cases of a blackout, the grid can be started up again with pump hydro storage plants.

Therefore, the main tasks of PHES are the provision of peak load and the allocation for balancing energy. Both of these tasks require a fast reaction for power adaption. Balancing energy is needed to keep the grid in balance. The amount of produced electricity in one moment has to be equal with the current demand. Imbalances are affecting the grid's frequency of 50Hz. This mismatch is adjusted in three steps of control. The primary, secondary and tertiary control adjusts the imbalance.

2.5.1 Types of control energy

Primary control is need for keeping the gird in balance due to power variabilities. The power has to be available in 30 seconds to prevent a power failure. Primary control happens not in Austria because the European network of grid operators ENTSO-S ("European Network of Transmission System Operators for Electricity") is responsible for this. The needed power comes from more than thousand power plants in Central Europe. They are reacting automatically at power fluctuations. In the APG control area, the primary control power is in a range of +/- 65MW ("APG - Balancing" 2016). PHS would be able to provide primary energy, but because of the need for uninterrupted supply, the conventional "base load" plants are providing primary energy (Tretter, Pauritsch, and Lechner 2010).

The next step to control frequency deviation in the control zone is the secondary control. Its task is to restore the frequency deviation and relieve primary control. It is realized as integral controller, which for example controls the fuel feed at a thermal plant or the flow rate in a hydro plant. Secondary control has to be available in 5 minutes and works in a timer period of 30 seconds to 15 minutes (Havranek 2012). Power is provided by gas power plants and PHES in a range of +/- 200MW ("EEX & EXAA" 2015) ("APG - Balancing" 2016).

Tertiary control is also called minute reserve and is applied for deviations that last longer than 10 minutes. It relieves primary and secondary control and backs the frequency. Tertiary control differs in positive and negative control power. The positive tertiary control power compensates an underproduction of electricity by feeding in electrical energy. Negative tertiary control power is a capacity that is held back in situations with too much energy on the grid or insufficient demand. Energy can also be stored in such situations. Power for tertiary control power is provided by gas power plants and PHES in a range of +280MW/-125MW ("APG - Balancing" 2016). The explained power frequency control is illustrated in Figure 16.

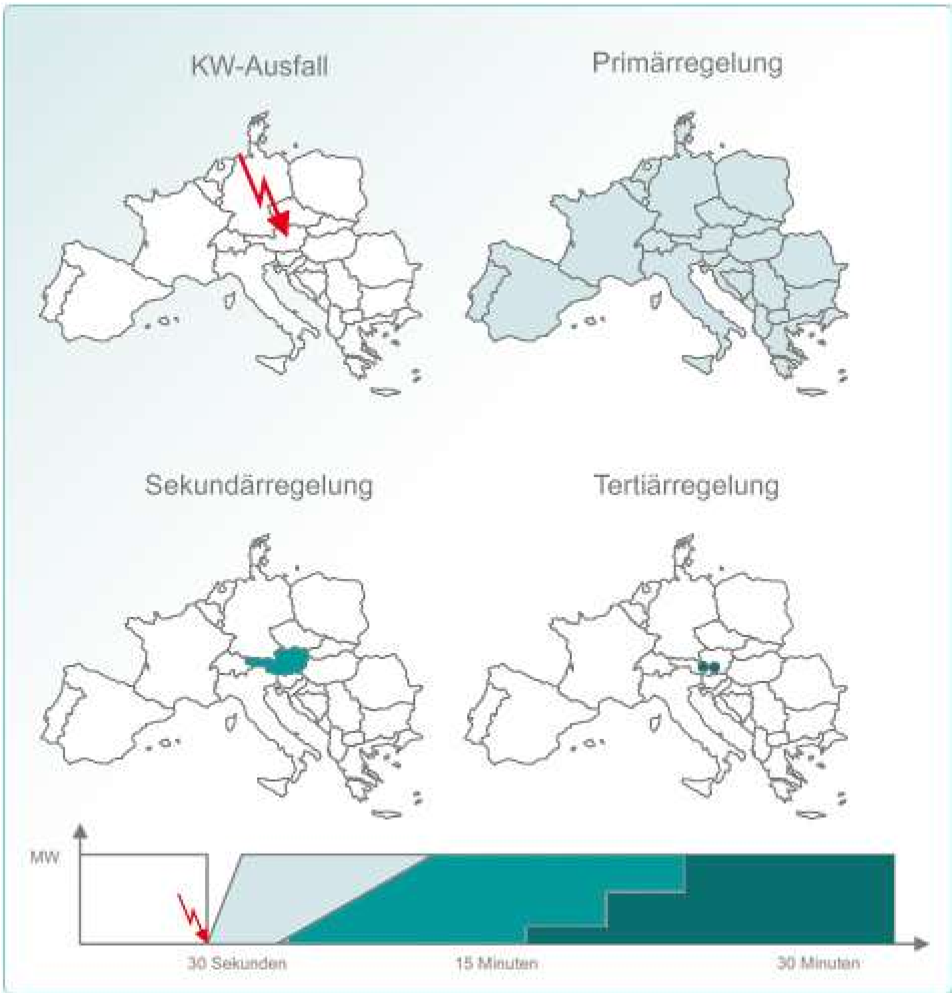

Figure 16: Power frequency control ("E-Control Austria Für Die Regulierung Der Elektrizitäts- Und Erdgaswirtschaft" 2016)

2.5.2 Storage operation dispatch

The generation of storage and pumped storage plants has typical daily, weekly and seasonal patterns. (Burger, Graeber, and Schindlmayr 2007). They are operating as daily-, weekly-, or annunal-reservoir. The determining factors for the operating cycle are the storage volume, the inflow and the withdrawal.

For daily-reservoirs, the inflow is determined by the power plant itself by pumping water up to the reservoir. The storage has the volume for turbining with full power for 4 to 8 hours. It can balance the demand for about one day. Pumping activity happens when electricity price and demand is low and in times of high prices and high demand, the plant is in turbining mode. In the traditional mode of operation, PHES follow a daily operational cycle ("Pumped Storage and Potential Hydropower from Conduits" 2015). The withdrawal is determined by the operation mode of the power plant.

Weekly-reservoirs are similar to daily-reservoirs. They differ in storage volume of about 100 to 200 hours at full turbining power. The pumping activities are happening on weekends, were demand and prices are lower than on weekdays. In addition to the weekly cycle, also a daily operating cycle is possible for weekly-reservoirs.

The volume of the storage of an annual-reservoir compensates the seasonal differences in electricity production. The storage is filled with water from natural infeed like melted snow but also by the power plant itself by pumping. The withdrawal depends on the season and is therefore more stochastic than in the other chases. An annual-reservoir has the volume for turbining with full power for 1500 to 2000 hours (Votruba and Broža 1989). Annual-reservoirs are also able to operate in a daily cycle in addition to the seasonal cycle.

The task of PHES changed in the last years considerably due to the rising infeed of renewable energy. The supply for peak power at noon was the main task, now with the peak of photovoltaics infeed around noon, less peak power is required. The market for control energy gets more important for PHES operators. The reduced revenue on the spot market leads PHES to the control energy market. A future task for earning revenue may be to provide control or balancing energy and earn profit for this performance (Pietroni 2013).

2.6 Formation of prices and market mechanisms on electricity market

2.6.1 Energy stock exchange EEX & EXAA

EXAA Energy Exchange Austria is Austria's leading stock exchange for trading electric energy. The EXAA trades in the Austrian APG (Austrian power grid) control zone as in all of the four German control zones. Together with the EEX European Energy Exchange in Leipzig, these two energy stock exchange markets are responsible for trading energy in Germany and Austria and also other European countries. The energy stock exchange is open for every producer who has got an admission and is willing to sell electric energy on the market. Another way is to authorize an admitted merchant ("EEX & EXAA" 2015). Trading takes place from Monday to Friday except for holidays. Therefore, traded delivery days are the calendar day following the trading day. On Fridays, for example, the products are traded which are actually fulfilled on the following Saturday, Sunday, and Monday.

2.6.2 Day-ahead market

In general, energy stock exchanges provide at least a day-ahead market, where the bids are submitted and the market is cleared on the day before the real dispatch. The day to be scheduled is divided into 24 periods of 60 minutes each. At EXAA the day is scheduled into 96 periods of 15 minutes each to provide better and more flexible management ("Der Viertelstundentakt Der Strombörse EXAA" 2014). Every bidding participant makes a price bid for every generation unit for the whole day. Usually, in the day-ahead market either hourly contracts (for the 24 hours of a day) or block contracts for a number of following hours are being traded. While the stock exchange allows the market participants to balance their portfolio of physical contracts, the bidding firm allows them to bring complete power plant capacities into the auction process. Block contract bidding can either be organised for a certain number of standardised blocks (primary), or for flexible blocks.

2.6.3 Intra-day/Adjustment/Hour-ahead market

Due to the time span of one day or more in case of weekends or holidays between the settling of contracts on the day-ahead market and physical delivery, exchanges offer an intra-day market. Which is sometimes also set as hour-ahead market. This market closes 15 minutes before delivering and enables the participants to improve their balance of physical contracts in the short term.

2.6.4 Balancing services/Real-time market

In order to balance power generation to load at any time during real-time operations, system operators use a balancing or real-time market. After the closure of the spot market, participants can submit bids that specify the prices. They require (offer) to increase/decrease their generation or decrease/increase their consumption for a particular volume immediately. Such balancing services, for which competitive market mechanisms are increasingly wanted for, cover the providing of services like voltage control, frequency response and reactive power support. Some grid operators in Europe have started to acquire the capacities and energy necessary to provide auxiliary services from other companies via published auctions. This currently still fragmented market is expected to become increasingly integrated in the near future.

2.6.5 Trading System

Trading is based on double-sided auctions for every hour of a day. Participants can transmit their bids to the exchange market and can change them via a special Internet software, or by fax as backup solution. All bids are collected in a closed order book and then, at 12:00 a.m., used to calculate the prices. Individual hour contracts are traded with a minimum of 0.1MWh and in steps of 0.1MWh for day-ahead delivery. Participants at least have to state a volume for the bottom and top price limit defined by EEX or EXAA and can add price/volume pairs within the price scale. Specifying the same volume for the bottom and top price limit generates independent bids. At the EXAA the bidding progress is the same, except the minimum size of an order is 1MWh. Participants can add several execution conditions to their bids and they can offer the same quantity of power for sequent hours. These bids are called block bids (Madlener and Kaufmann 2002).

2.6.6 Auction trading

Participants can submit and change their bids until the end of the call phase. The simple bid matching ignores any conditions or grid capacity constraints and results in an initial market clearing price for every hour and trade volumes for every bid. The market clearing price is the price level at the intersection of the aggregated demand and supply curves. The matching of these two curves is shown in Figure 17. If there is no crossing of the two curves, there has to be a second run of bidding to get a market clearing price for the auction.

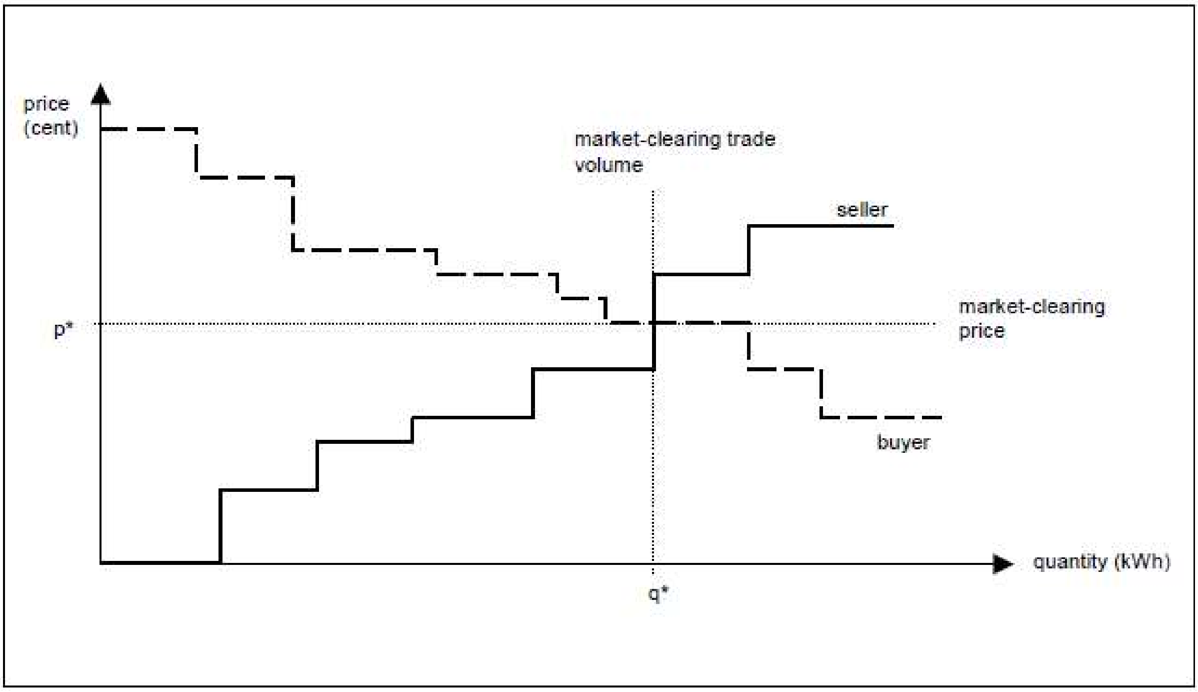

Figure 17: market clearing price / market trade volume (Madlener and Kaufmann 2002)

2.6.7 Pricing Rules

The mentioned pricing as intersection of the aggregated demand and supply curve is the most common pricing rule. The intersection point represents also the maximum trade volume. In Austria at the EXAA, price determination follows an auction algorithm. All products are included for the calculation of the optimal solution. Out of the aggregated demand and supply curves, the system calculates a market clearing balance, considering the boundary condition of arbitrage freedom of all products. This is the point of maximum volume and equals the market clearing price. The fact that bids can be made in 15 min time slots does not affect the formation of prices in contrast to the hourly base. According to the allocation rules, bigger units are queued before smaller units. This means blocks before hours and hours before quarter of an hour ("Der Viertelstundentakt Der Strombörse EXAA" 2014). Figure 18 shows the formation of the market clearing price. If the seller's offer is in balance with the buyer's demand, the price and quantity is set. Additional renewable energy causes a shift of the blue curve in Figure 18 to the right and results in a reduced price.

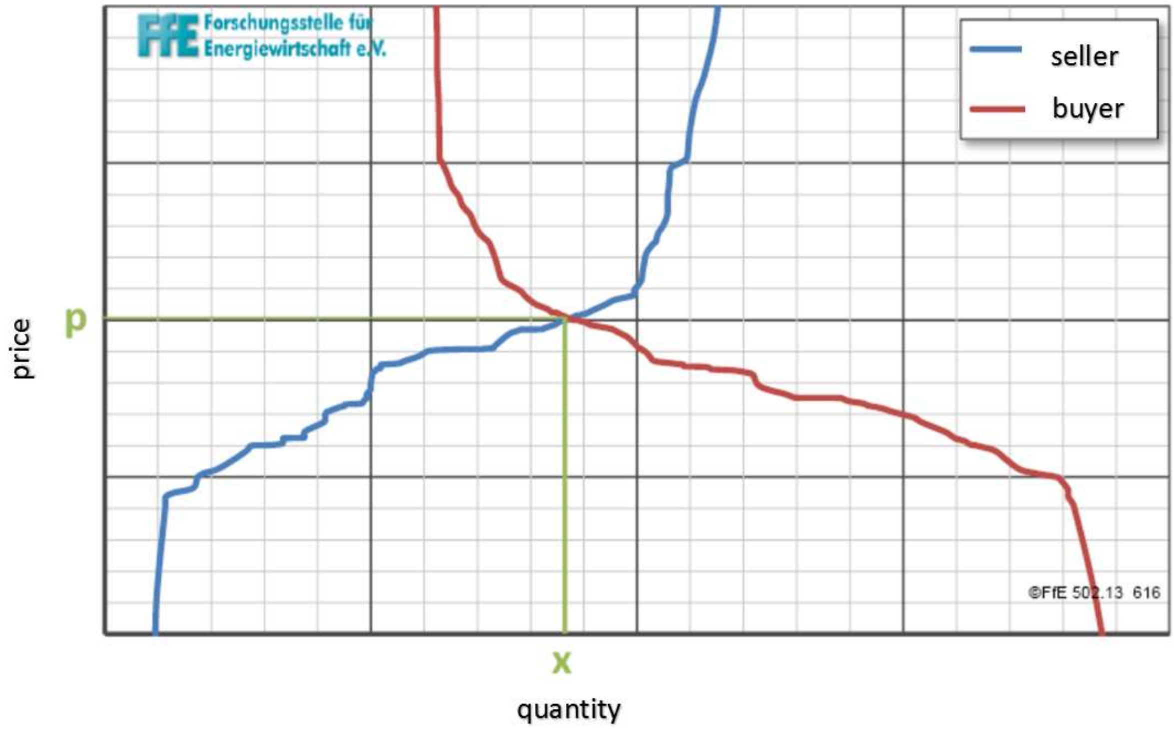

Figure 18: Pricing on the European Energy Exchange EEX (Wirth 2015)

2.6.8 Matching Rules

The auction determines the market clearing price and the decision who is allowed to deliver is made. All bids with a price limit below the market clearing price are executed. The other bids were too high and are kicked out. This mechanism ensures the lowest possible price for electricity (Madlener and Kaufmann 2002).

2.6.9 Negative Prices

The raising infeed of renewable energy leads to a volatile supply of electricity on the market and in the grid. Sometimes there is a constellation of such high infeed coupled with a low electricity demand that the intersection of the demand and supply curve results in a negative price as illustrated in Figure 19.

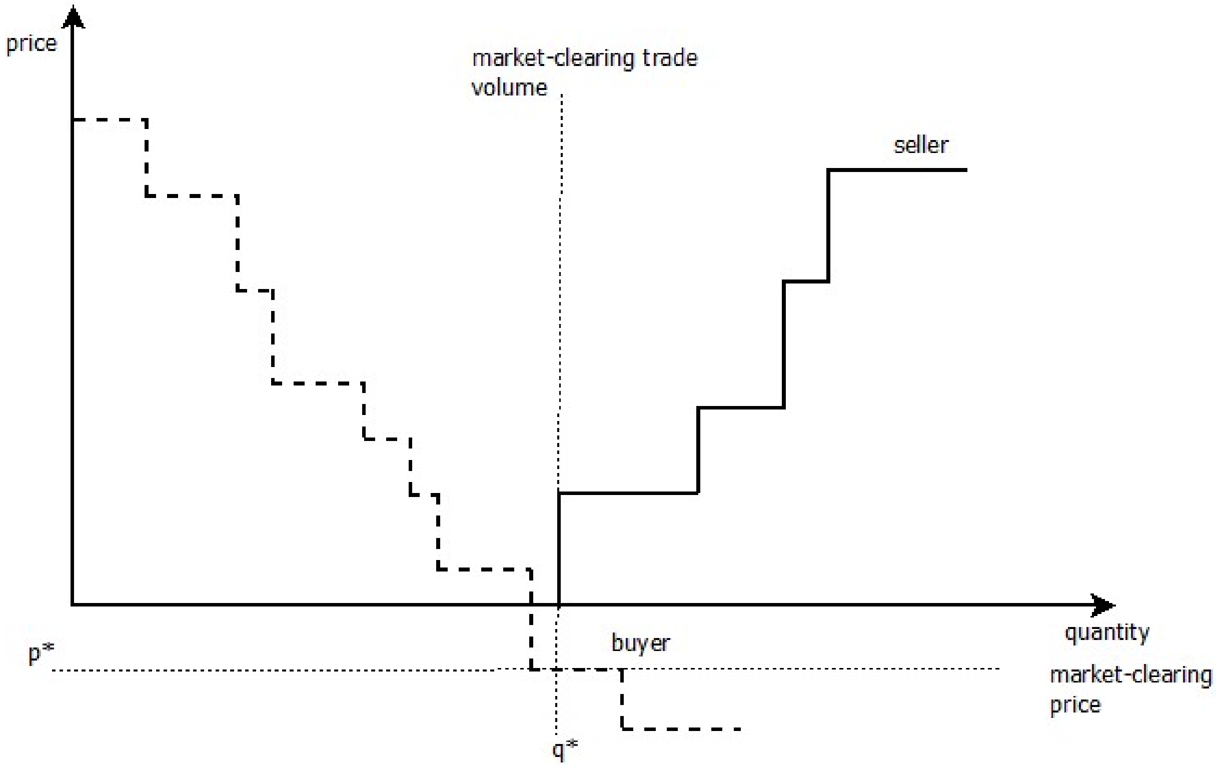

Figure 19: negative market clearing price (own figure)

In the year 2012 the electricity price was negative at EXAA in 50 hours. Commonly the high infeed of renewable energy is made responsible for this situation. However, a closer analysis of the electricity production in Germany in 2013 shows that renewable energy sources never reached more than a 65% share of electricity production. This means that renewable energies never covered complete demand. There are several possible explanations for negative spot market prices. The maximum share of 65% of renewable electricity production means also a share of 35% of other power plants in production. This demonstrates that if the electricity price is negative, thermal plants are still operating and could be switched of. This will have the effect that less quantity of electricity is on the market and the price will rise in these hours. The fact that prevents operators from shutting down thermal plants in hours of high renewable infeed is the financial aspect. The price for shutting down and starting up a thermal power plant is higher than the loss that is made because of the negative electricity price. Consequently, it is less unprofitable for owners to keep the thermal plants operating in hours with a negative price. Figure 20 shows the price limit of different types of thermal plants if the avoided start-up and shut down costs are distributed to several hours. The realization of starting up and shutting down is neglected here (Götz et al. 2014).

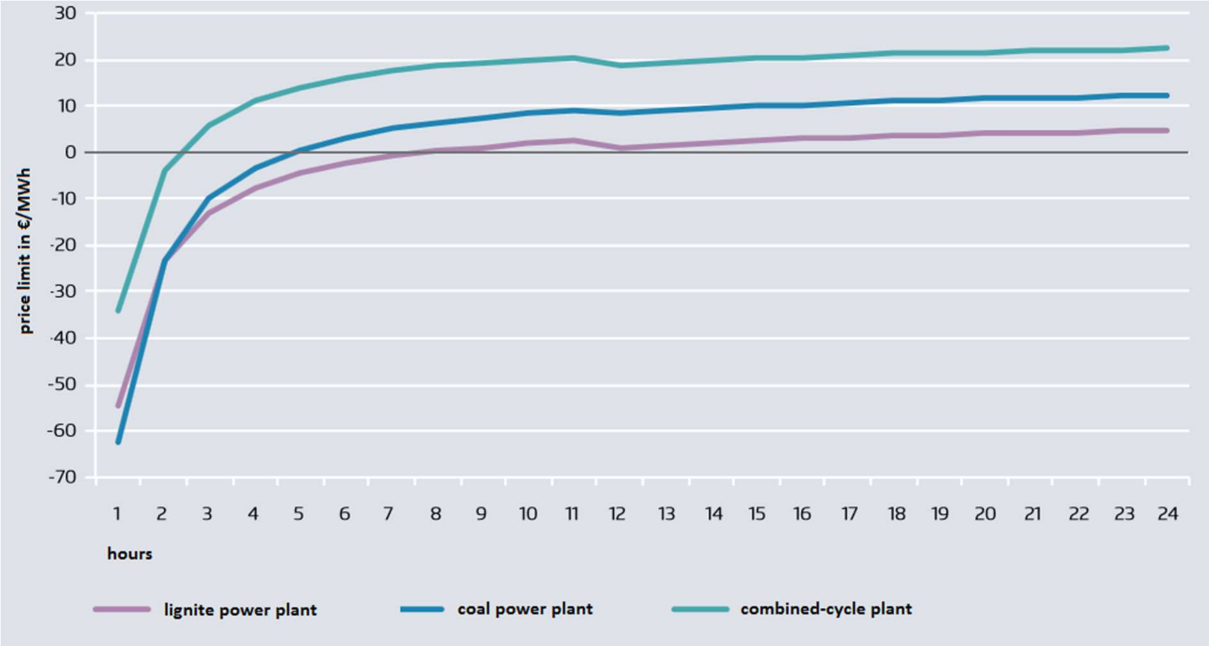

Figure 20: price limit if the avoided shut down and start-up costs are distributed to several hours (Götz et al. 2014)

Therefore, it is not necessarily profitable to shut down thermal plants in case of negative prices. Even not in a period of more hours with a price between 0 and 10 €/MWh. Another reason for keeping the plants in operation can be the need for control energy. The grid stability requires a reserve of short-term available primary control energy. Thermal plants can be operated for example with curbed steam valve. If additional power is needed, the plant can provide more power quickly. This power reserve is needed for situations like the drop out of other plants. Furthermore, there is also a minimum of thermal power that has to be in operation all the time. In the model that is used for this thesis, it is the value of the variable *thermal_min* with the value 10000MW. Thermal plants are always working with this amount of power for system stability reasons. Moreover, the need for heat from thermal plants with cogeneration of heat and power is a reason to keep such plants running during a few hours with negative electricity price. At least there are functional and technical issues that make it hardly possible to shut down thermal plants for a few hours. The biggest functional barrier is possibly the missing flexibility in operation of a thermal plant. Such functions have not been an issue for thermal plants and therefore this necessary flexibility is not implemented in operation. The technical barriers are the physical constraints of processes in thermal plants. All these mentioned issues are reasons for thermal plant operators to keep thermal plants running also during hours with negative prices. The supply of electricity in hours with high infeed of renewables and less additional demand leads to a low or negative price (Götz et al. 2014). Negative prices can be seen as an indicator for the tense situation on the electricity market. Negative prices do not have an immediate effect on the consumer price but in the long run, more often negative wholesale prices will also affect the consumer prices.

2.7 Modelling of electricity prices

There are many different types of models used in the energy sector. According to the task and aim of the model, the corresponding model type is chosen. The fitting type of model is the first step to be successful in the illustration and interpretation of results. This short overview references to the script of the lecture Energy Models and Analysis, that was held at TU Wien in 2014 (Nakicenovic and Haas 2014).

In compliance with the given parameters and constraints, an optimization model tries to find the optimal constellation for the variables by minimizing or maximizing the objective function. This objective function is the core of the model. The optimization model considers all constraints and delivers the optimal solution for the decision variables. The model in this thesis is an optimization model which is realized in MATLAB.

Models in energy economics differ at several characteristics and criteria. The most common criteria are time, data, datasets and perception (Nakicenovic and Haas 2014) (Krey 2006).

The used models for this thesis are optimization models. The first model optimizes the power plant dispatch for minimal system costs. From the optimal dispatch, the electricity price is derived. The second model optimizes the revenue of PHES with the electricity price from the first model as input. The aim of the optimization progress is the minimization or maximization of an objective function under consideration of all constraints and restrictions. For the solution a solver using either linear programming (LP) or non-linear programming (NLP) can be applied. The most used type is still linear programming (LP). This is also the chosen method of this thesis (Krey 2006) (Renner 2014).

3 Linear dispatch model for representation of electricity market and optimization of revenue for hydro storage power plants

The aim of the model is the representation of the spot market electricity price as background for a calculation of maximal revenue of pump hydro storage plants in the countries Austria and Germany. The calculation uses data from Austria and Germany from 2012. The price calculation is based on the coherence

$$price = mc, \tag{1}$$

which means that the electricity price equals the marginal costs of energy production. The electricity producing power plant with the highest marginal cost leads to the price. For the model some simplifications have to be made in order to make a calculation possible in a decent timescale. Firstly, there is the aggregation of thermal power plants and secondly, the calculation of marginal cost is not made for every single thermal plant. Thermal plants with similar characteristics in acquisition to their marginal cost are combined to a bigger plant. This simplification is explained in detail in the chapter Input data. The important aspect is that this aggregation of similar plants has a minor effect on the prices.

Another simplification compared to the real electricity market is the absence of negative prices. The lowest possible price is 0. This situation occurs in 53 hours of 2012 on EXAA. There are two types of demand that the thermal plants have to cover which are the electricity and heat demand of Austria and Germany. The production of electricity is connected with the heat demand in thermal power plants with cogeneration. The optimal dispatch of plants follows the merit order.

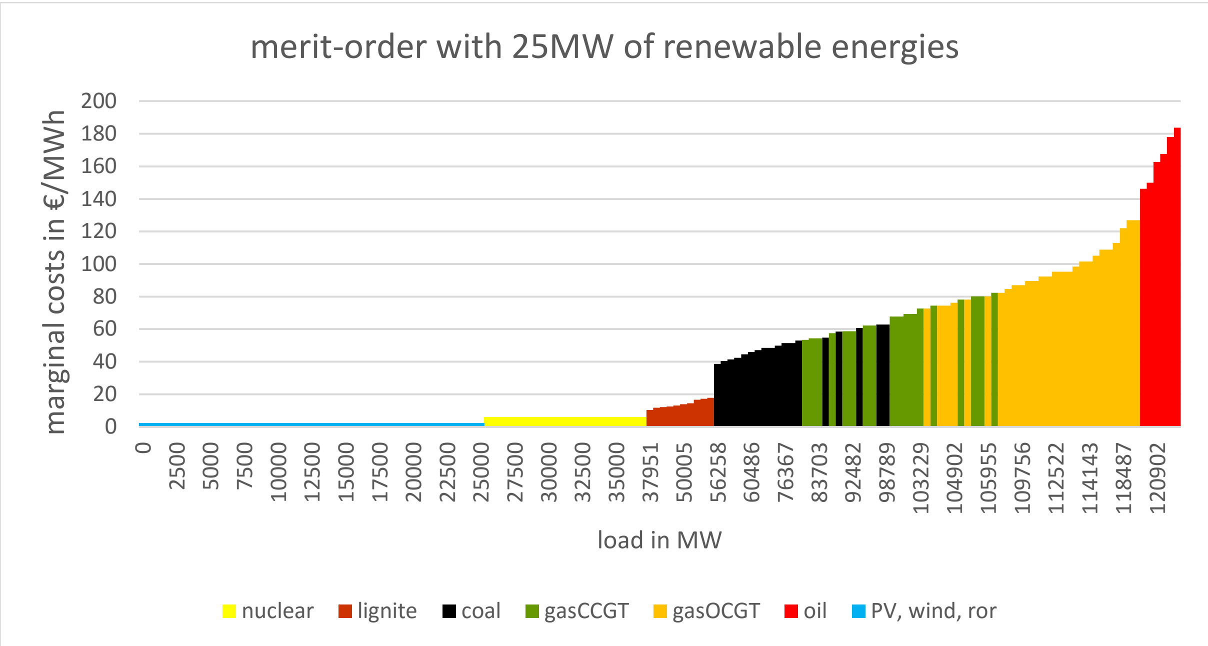

Figure 21: merit-order including 25MW renewable energies (own illustration)

Renewable energies are having fixed compensation rates and feed-in guarantees and so they are first in the merit order. In the model, photovoltaics-, wind-, biomass- and run of river power plants are set with a merit order price mc=0. This means a feed-in guarantee for all of the mentioned plants. The price setting plants are the thermal power plants. They are aggregated to a sum of 80 plants.

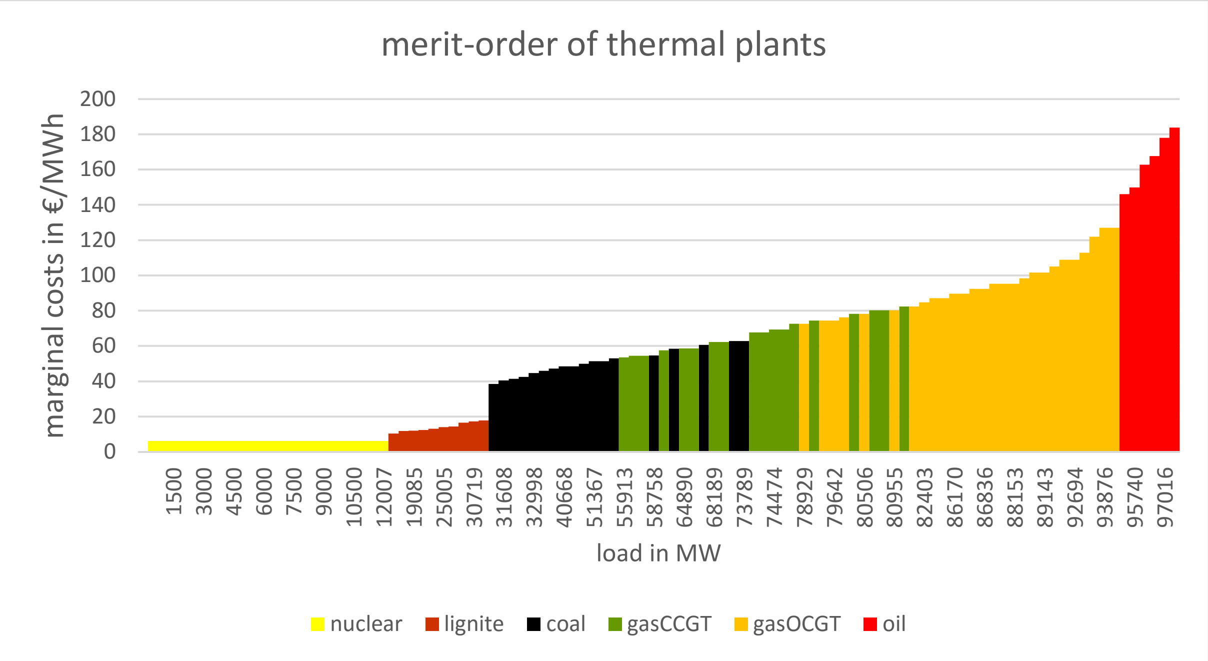

Figure 22: merit-order for thermal plants (own illustration)

3.1 Software

The modelling takes place in MATLAB which is a license responsible software that is specialized for vector and matrix calculations. MATLAB can be expanded by additional toolboxes which are extending the usage of MATLAB. YALMIP is such a toolbox and it is used for the modelling in this theses. YALMIP is a modelling language for advanced modelling and solution of convex and nonconvex optimization problems. It is implemented as a free toolbox for MATLAB. The main motivation for using YALMIP is rapid algorithm development. Moreover, the language is consistent with standard MATLAB syntax, thus making it extremely simple to use for anyone familiar with MATLAB.

One of the central ideas in YALMIP is to concentrate on the language and the higher level algorithms, while relying on external solvers for the actual computations. However, YALMIP also implements internal algorithms for global optimization, mixed integer programming, multiparametric programming, sum-of-squares programming and robust optimization. These algorithms are typically based on the low-level scripting language available in YALMIP, and solve sub-problems using the external solvers (Löfberg 2015). In this thesis the solver Gurobi is used for optimization and version 6.5 is used with a free academic licence. The Gurobi

Optimizer is a commercial optimization solver for a variety of mathematical programming problems, including linear programming (LP), quadratic programming (QP), quadratically constrained programming (QCP), mixed integer linear programming (MILP), mixed-integer quadratic programming (MIQP), and mixed-integer quadratically constrained programming (MIQCP) ("Gurobi Optimizer - Solves All Major Problem Types" 2015). In this model the LP is used for optimization.

The input data has to be calculated from different units to a common unit for calculation. All the input data is measured in MW or MWh. So every value has the factor 10^6 included.

3.2 Input data

For calculation it is important to bring the input data to a common unit. Most of the data is calculated in €, MW and MWh to minimize conversions. Therefore, the results are all related to MW, MWh and €/MWh. The units for the different variables are shown in the section Notation.

Prices for primary energy in €/$MWh_{primary}$, the emission factors in $tCO_2/MWh_{primary}$ and all other input data of the model is taken from the paper "East to West - The Optimal Tilt Angle and Orientation of Photovoltaic Panels from a System Perspective" (Hartner et al. 2015) in "Applied Energy, Volume 160".

primary energy carrier	MATLAB variable	price in [€/$MWh_{primary}$]
Natural Gas	p_gas	29
Coal	p_coal	14
Oil	p_oil	55.5
Lignite	p_lignite	1.5
Uranium	p_uranium	2

Table 1: input data primary energy carrier

emissions of	MATLAB variable	emissions in [$tCO_2/MWh_{primary}$]
Coal	em_coal	400
Natural Gas	em_gas	200
Oil	em_oil	200

Table 2: input data emissions primary energy carrier

plant	fuel	capacity	effectivity	max_ramp	c_ramp	c_start	KWK
plant	*fuel*	*cap*	*eff*	*max_ramp*	*c_ramp*	*c_start*	*KWK*
		[MW]	[%]	[1]	[€/MWh]	[€/MWh]	[1]
'gas1'	'gas'	165	41	1	1,17	9	1
'gas5'	'gas'	686	41	1	1,17	9	1
'gas2'	'gas'	168	40	1	1,17	9	1
'gas6'	'gas'	463	39	1	1,17	9	0
'gas7'	'gas'	241	37	1	1,17	9	0
'gas8'	'gas'	425	36	1	1,17	9	1
'gas3'	'gas'	324	35	1	1,17	9	0
'gas9'	'gas'	1097	35	1	1,17	9	1
'gas10'	'gas'	2204	34	1	1,17	9	1

'gas4'	'gas'	250	33	1	1,17	9	0
'gas11'	'gas'	435	33	1	1,17	9	0
'gas12'	'gas'	358	32	1	1,17	9	0
'gas13'	'gas'	389	28	1	1,17	9	0
'gas14'	'gas'	24	27	1	1,17	9	0
'gasGT4'	'gas'	60	42	1	0,66	2	0
'gasGT5'	'gas'	544	38	1	0,66	2	1
'gasGT6'	'gas'	219	34	1	0,66	2	1
'gasGT1'	'gas'	180	32	1	0,66	2	0
'gasGT7'	'gas'	50	32	1	0,66	2	0
'gasGT8'	'gas'	141	31	1	0,66	2	0
'gasGT2'	'gas'	815	30	1	0,66	2	0
'gasGT9'	'gas'	492	30	1	0,66	2	0
'gasGT10'	'gas'	2049	29	1	0,66	2	1
'gasGT11'	'gas'	304	28	1	0,66	2	0
'gasGT12'	'gas'	1414	25	1	0,66	2	0
'gasGT3'	'gas'	63	24	1	0,66	2	0
'gasGT13'	'gas'	438	24	1	0,66	2	0
'gasGUD9'	'gas'	3460	57	1	0,25	20	1
'gasGUD1'	'gas'	1105	56	1	0,25	20	0
'gasGUD10'	'gas'	2592	56	1	0,25	20	1
'gasGUD11'	'gas'	360	53	1	0,25	20	0
'gasGUD2'	'gas'	347	52	1	0,25	20	0
'gasGUD12'	'gas'	3108	52	1	0,25	20	1
'gasGUD3'	'gas'	220	49	1	0,25	20	0
'gasGUD13'	'gas'	2272	49	1	0,25	20	1
'gasGUD4'	'gas'	190	45	1	0,25	20	0
'gasGUD14'	'gas'	324	45	1	0,25	20	0
'gasGUD5'	'gas'	171	44	1	0,25	20	0
'gasGUD15'	'gas'	517	44	1	0,25	20	1
'gasGUD16'	'gas'	3238	42	1	0,25	20	0
'gasGUD17'	'gas'	700	41	1	0,25	20	0
'gasGUD6'	'gas'	365	39	1	0,25	20	0
'gasGUD7'	'gas'	142	38	1	0,25	20	0
'gasGUD18'	'gas'	206	38	1	0,25	20	0
'gasGUD8'	'gas'	260	37	1	0,25	20	0
'coal4'	'coal'	255	44	0,8	1,3	20	1
'coal5'	'coal'	350	42	0,8	1,3	20	1
'coal6'	'coal'	740	41	0,8	1,3	20	0
'coal7'	'coal'	30	40	0,8	1,3	20	0
'coal8'	'coal'	620	38	0,8	1,3	20	1
'coal9'	'coal'	2488	37	0,8	1,3	20	0
'coal10'	'coal'	4206	36	0,8	1,3	20	0
'coal1'	'coal'	976	35	0,8	1,6	30	0
'coal11'	'coal'	4339	35	0,8	1,6	30	0
'coal12'	'coal'	5384	34	0,8	1,6	30	0

'coal2'	'coal'	168	33	0,8	1,6	30	0
'coal13'	'coal'	3320	33	0,8	1,6	30	0
'coal14'	'coal'	954	32	0,8	1,6	30	0
'coal15'	'coal'	1058	31	0,8	1,6	30	0
'coal16'	'coal'	1380	29	0,8	1,6	30	0
'coal17'	'coal'	1410	28	0,8	1,6	30	0
'coal3'	'coal'	55	27	0,8	1,6	30	0
'coal18'	'coal'	1567	27	0,8	1,6	30	0
'lignite1'	'lignite'	944	43	0,8	1,6	30	0
'lignite2'	'lignite'	6051	38	0,8	1,6	30	0
'lignite3'	'lignite'	83	37	0,8	1,6	30	0
'lignite4'	'lignite'	66	36	0,8	1,6	30	0
'lignite5'	'lignite'	3142	34	0,8	1,6	30	0
'lignite6'	'lignite'	2712	32	0,8	1,6	30	0
'lignite7'	'lignite'	3808	31	0,8	1,6	30	0
'lignite8'	'lignite'	2272	27	0,8	1,6	30	0
'lignite9'	'lignite'	1170	26	0,8	1,6	30	0
'lignite10'	'lignite'	284	25	0,8	1,6	30	0
'oil3'	'oil'	26	39	1	0,66	2	0
'oil4'	'oil'	300	38	1	0,66	2	0
'oil1'	'oil'	162	35	1	0,66	2	0
'oil5'	'oil'	772	34	1	0,66	2	0
'oil6'	'oil'	342	32	1	0,66	2	0
'oil2'	'oil'	152	31	1	0,66	2	0
'uranium1'	'uranium‘	12007	33	0,396	200	30	0

Table 3: input data thermal plants – th_data

3.3 Aggregation of power plants in the model

As already mentioned, the aggregation of similar plants has a minor effect on the prices. This is because of the size of these plants, which were combined for this calculation. For example the 9 nuclear power plants in Germany with a power capacity of about 1400MW each are combined to one nuclear plant with the sum of power for the calculation. The 9 nuclear plants are aggregated and in the model, the same marginal costs for all of them are set. This cannot be done for the type of plants which are responsible for price forming. In the case of coal and lignite power plants, the aggregation is made in smaller parts such that there are more power plants with different marginal costs. This sensitively made aggregation allows summarizing the amount of real power plants for calculation to a reduced number of plants. Therefore, this aggregation leads to a smaller model with appropriate results.

The photovoltaic input in *pv_in_12* is the real PV input for the year 2012. For calculation of prices with higher PV penetration, it is necessary to scale the infeed of electricity from photovoltaics up. Before the upscaling, the annex of photovoltaics power from the beginning of 2012 till the end of 2012 has to be considered. The infeed of photovoltaics electricity for the calculation has to be reduced by the additional installed PV capacity during 2012, so that the PV infeed is related to the amount of installed capacity on 1.1.2012. The installed PV capacity in Austria and Germany at the beginning of 2012 was 25616MW$_{peak}$.[3] In the year 2012 there was an expansion of capacity overall to 33395MW$_{peak}$.[4] This leads to an annex of 7779MW$_{peak}$ in 2012. That is 0,888MW$_{peak}$ of additional PV capacity per hour. The corrected PV infeed is implemented by using the coherence

$$\begin{array}{rcl} installed\ PV\ capacity\ (t) & \cdots & pv\_in\_12(t) \\ installed\ PV\ capacity\ (01.01.2012) & \cdots & pv\_in\_12\_cor\_zubau\ (t) \end{array} \tag{2}$$

The corrected photovoltaic infeed is calculated in *pv_in_12_cor_zubau* for every hour

$$pv\_in\_12\_cor\_zubau\ (t) = \frac{installed\ PV capacity(01.01.2012) * pv\_in\_12(t)}{installed\ PV\ capacity\ (t)} \tag{3}$$

Figure 23 shows the installed photovoltaics capacity in 2012 and it demonstrates that the additionally built PV capacity has a major impact on the infeed. So with the calculation of the corrected PV infeed, conclusions uninfluenced from additional annex during a year can be made.

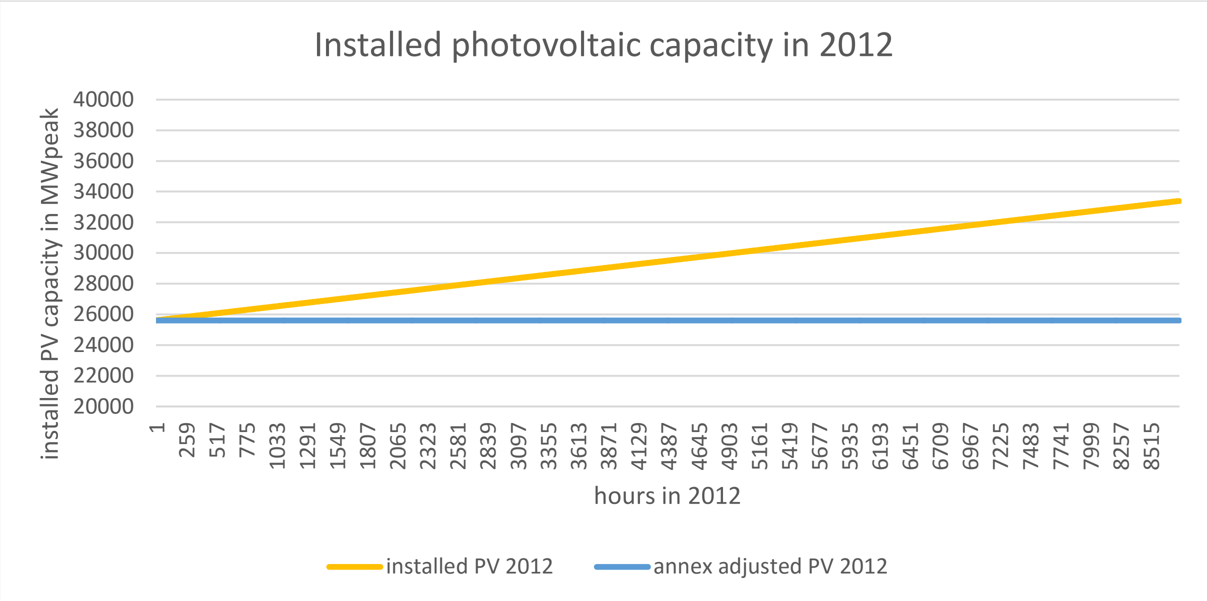

Figure 23: installed PV capacity in 2012 (own illustration)

[3] http://www.pvaustria.at/daten-fakten/grafiken/ (accessed on 05.01.2016)

[4] http://de.statista.com/statistik/daten/studie/13547/umfrage/leistung-durch-solarstrom-in-deutschland-seit-1990/ (accessed on 05.01.2016)

3.3.1 Positive and negative thermal controlling energy

Positive and negative thermal controlling energy (*x_reg_neg_thermal* and *x_reg_neg_thermal*) is required for grid stability. A minimal amount of control power (*d_pos_reg* and *d_neg_reg*) has to be reserved to stabilize the grid. Electrical energy cannot be stored in the grid. Moreover, production and consumption has to be equal every time. As already mentioned, the standard frequency of 50Hz is going to rise or fall in case of too much or insufficient electricity production. Due to the natural fluctuation of consumption and the raising penetration of variable renewable energy sources, the availability of enough control energy is growing. In this model a minimum of 2000MW for positive and negative control power is set. Another value for system stability is the minimal power of thermal plants at every time. The variable *thermal_min* is therefore set to 10000MW.

3.3.2 Waerme_baseload

The value of 1000MW for *Waerme_baseload* represents the heat baseload produced from district heating plants. All-over the year this constant amount of heat is available for heating water and building heating.

3.4 Notation

The following section shows the used variables in the calculation and in the model. The sequence is approximately the same as the variables appear in the calculation starting with the indices.

i	[1]	control variable thermal plants (1 … number of thermal plants)
h	[1]	control variable photovoltaics factor in steps (-3 … 30)
j	[1]	control variable weekly constraints (1 … 52)
t	[h]	number of hours (8760)
t_f	[1]	vector for number of hours (1 … 8760)
t_start	[1]	starting hour (1)
t_stop	[1]	last hour (1)
p_co2	[€/tCO_2]	CO_2 certificate price for 1 ton CO_2 (7.4, 20, 70)
marginalCost(i)	[€/MWh]	marginal costs for electricity production
mc	[€/MWh]	marginal costs for electricity production
thermalPlants	[1]	number of thermal plants

eaf	[1]	energy availability factor (0.8)
x_leistung	[MW]	vector with power capacity of all thermal plants
X	[MW]	matrix with power capacity of all thermal plants
inflows	[MWh]	inflow from hydro power plants
hydroProdMax_hes	[MW]	max. power of hydro energy storage plants
hydroProdMax_phes	[MW]	max. power of pump hydro energy storage plants
hydroProdMax	[MW]	max. power of all hydro energy storage plants
hydroProdMin_hes	[MW]	min. power of hydro energy storage plants
hydroProdMin_phes	[MW]	min. power of pump hydro energy storage plants
hydroProdMin	[MW]	min. power of all hydro energy storage plants
storageLevelMax_hes	[MW]	max. storage level of hydro energy storage plants
storageLevelMax_phes	[MW]	max. storage level of pump hydro energy storage plants
storageLevelMax	[MW]	max. storage level of all hydro energy storage plants
hydroPlants	[1]	number of hydro plants
plants	[1]	number of thermal and hydro plants
PV	[1]	vector for photovoltaic factors
pv_factor	[1]	photovoltaic factor for raising PV share
pv_power_plus	[MW]	additional PV power
x_s_thermal	[MW]	power of thermal plants
x_s_hydro_turb	[MW]	hydro turbining power
x_s_hydro_pump	[MW]	hydro pumping power
ramp_thermal	[MW]	thermal ramping power
x_s_heizkessel	[MW]	power of heat demand
on	[1]	shows if thermal plants are on
up	[1]	shows if thermal plants are starting
down	[1]	shows if thermal plants are stopping
x_reg_pos_thermal	[MW]	positive thermal balancing power
x_reg_neg_thermal	[MW]	negative thermal balancing power

spill	[MW]	spill from hydro power plants
storageLevel	[MWh]	positive thermal balancing power
pv_in_12	[MW]	power of photovoltaic infeed
res_in	[MW]	power infeed of renewable energies
mustrun	[MW]	power infeed of biomass and waste-to-energy plants
inflows	[MWh]	water inflows to storage hydro plants
d_s	[MW]	electricity demand
d_pos_reg	[MW]	necessary positive controlling power
d_neg_reg	[MW]	necessary negative controlling power
Waerme_ges	[TWh]	max. amount of district heating
Waerme_baseload	[MW]	base infeed of heat
d_h	[MW]	heat demand
th_data.eff_h	[1]	heat producing plant efficiency
stromkennzahl	[1]	cogenerate heat and power factor CHP
cap_heizkessel	[MW]	power capacity heat production
eff_heizkessel	[1]	heat production fuel efficiency
mc_heizkessel	[€/MWh]	marginal costs for heat production
KWK_mat	[1]	CHP matrix
thermal_min	[MW]	min. thermal production
ramp_costs	[€/MW]	ramping costs
ramp_max	[€/MW]	limit for ramping costs

3.5 MATLAB code for linear dispatch model for representation of electricity market

The first part of this thesis focuses on the modelling of the electricity market. Out of this linear dispatch model, the electricity price is going to be derived on an hourly base. Main parts of the MATLAB Code were used in “East to West - The Optimal Tilt Angle and Orientation of Photovoltaic Panels from a System Perspective” (Hartner et al. 2015) and adapted to the requirements of this theses.

The course of the electricity price is the most important fragment for the calculation of the pump hydro energy storage (PHES) power plant profitability that is following in the second part of the calculation. A model has to be created that represents the real electricity price market by using historical data from 2012. The model is built to deliver qualitative correct data for different input scenarios whereas the main focus is on different penetration levels of photovoltaics.

In the following section the essential MATLAB Code lines are presented and explained. The necessary input data is imported into the MATLAB workspace with the command *load.* The input data comes from the Energy Economics Group and is the base for all calculations. A request for test purpose checks if the calculation should be made for a certain number of weeks or for one complete year. The variable ‘All_hours” has to be equal to 1 to start the calculation for the complete 8760 hours of one year.

The calculation of the marginal cost is based on the formula

$$mc = \frac{p + e_{CO2} * p_{CO2}}{\eta} \quad (4)$$

p	[€/MWh_{prim}]	fuel price
η	[1]	energy efficiency
p_{CO2}	[€/t CO_2]	CO_2 certificate price for 1 ton CO_2
e_{CO2}	[t CO_2/MWh_{prim}]	CO_2 Emission factor

Input data for all 80 aggregated thermal plants is used to calculate the marginal costs and save them into a vector. The used formula is embedded in a loop for all thermal plants and is realized in the following way in MATLAB code

```
marginalCost(i)=(p_gas+em_gas*p_co2*10^-3)/(th_data.eff(i)/100);
```
(5)

The vector *marginalCosts* is extended for every hour of a year with the operator *kron* to practically make a matrix out of the vector in

```
mc = kron(marginalCost, ones(t, 1));
```
(6)

by using the Kronecker tensor product. Also a matrix is needed to store the available power of each thermal power plant. The vector

```
x_leistung = th_data.cap;
```
(7)

gets the information about the power capacity from the input data file and is afterwards multiplied

```
x_leistung = x_leistung'*eaf;
```
(8)

with the energy availability factor

```
eaf=0.80;
```
(9)

The energy availability factor over a specified period is the ratio of the energy that the available capacity could have produced during this period and the energy that the reference unit power could have produced during the same period.[5] With the command *repmat*,

```
X = repmat(x_leistung,[t,1]);
```
(10)

the vector x_leistung gets copied in the number of t lines and is therefore practically converted to a matrix X as before the vector mc. The amount of produced electricity from hydro power is limited by the inflows and the capacity of the hydro power plants. This information comes from Excel datasheets, gets imported by using the command *xlsread* and stored in the variables *hydroProdMax_hes, hydroProdMax_phes, hydroProdMin_hes, hydroProdMin_phes, storageLevelMax_hes* and *storageLevelMax_phes.* Furthermore, the mentioned maxima and minima of hydro power production and storage levels are merged by using the command *horzcat*

```
hydroProdMax = horzcat(hydroProdMax_hes',hydroProdMax_phes');
```
(11)

```
hydroProdMin = horzcat(hydroProdMin_hes',hydroProdMin_phes')*(-1);
```
(12)

```
storageLevelMax = horzcat(storageLevelMax_hes',storageLevelMax_phes');
```
(13)

which concentrates arrays to a matrix. The number of hydro plants is calculated by the length of the vector *storageLevelMax* in the line

```
hydroPlants = length(storageLevelMax);
```
(14)

In this model, the hydro plants are aggregated to 3 storage power plants and 5 pump hydro storage (PHES) power plants. As outlined above, the hydro production also underlies the same energy availability factor

```
hydroProdMax = hydroProdMax*eaf;
```
(15)

```
hydroProdMin = hydroProdMin*eaf;
```
(16)

[5] https://www.iaea.org/PRIS/Glossary.aspx (accessed on 08.01.2016)

as the thermal power plants. The definition of the decision variables and implementation of the variable photovoltaics penetration will follow in the next section of the calculation. The command *sdpvar* defines variables in YALMIP. The value of the sdp-variables after the optimization progress results out of the optimal value of the objective function. The variables are vectors which are representing the optimal value for every hour of a year and for the different plants. Here is an explanation of all the decision variables:

The power of thermal plants in *x_s_thermal:*

```
x_s_thermal = sdpvar(t, thermalPlants);
```
(17)

The hydro turbining power in *x_s_hydro_turb:*

```
x_s_hydro_turb = sdpvar(t, hydroPlants);
```
(18)

The hydro pumping power in *x_s_hydro_pump:*

```
x_s_hydro_pump = sdpvar(t, hydroPlants);
```
(19)

The power difference between two hours when thermal plants are raising their power output in *ramp_thermal:*

```
ramp_thermal = sdpvar(t, thermalPlants);
```
(20)

The needed power for heat demand *x_s_heizkessel:*

```
x_s_heizkessel = sdpvar (t,1);
```
(21)

The *on, up* and *down* variable shows the starting and stopping of thermal plants. This information is necessary for the calculation of the ramping costs.

```
on = sdpvar(t,thermalPlants);
```
(22)

```
up = sdpvar(t,thermalPlants);
```
(23)

```
down = sdpvar(t,thermalPlants);
```
(24)

x_reg_pos_thermal and x_reg_neg_thermal represent the minimal positive and negative balancing energy from thermal plants needed in every moment.

```
x_reg_pos_thermal= sdpvar(t,thermalPlants);
```
(25)

```
x_reg_neg_thermal= sdpvar(t,thermalPlants);
```
(26)

The amount of water expressed in MWh which is released in every hour by the hydro plants is represented in the variable *spill*:

```
spill = sdpvar(t, hydroPlants);
```
(27)

storageLevel characterizes the amount of water, and therefore energy, in the storage of all hydro power plants expressed in MWh

```
storageLevel = sdpvar(t + 1, hydroPlants);
```
(28)

The adjustable PV input is realized in steps of 10GW

```
pv_power_plus = 10000; %+10GW PV;
```
(29)

in a variety of complete removement of PV capacity by setting the infeed to zero

```
PV=[-3,-2,-1,0,2,3,4,5,6,8,10,12,15,20];
```
(30)

up to additional 200GW$_{peak}$ on installed PV capacity. As mentioned in the chapter Input data, the infeed of photovoltaic energy is reduced by the annual amount of additionally built photovoltaics in *pv_in _12_cor_zubau*. The installed PV capacity in Germany and Austria of 25616,2MWpeak is the cleared value for the whole year 2012. The corrected photovoltaics infeed is saved in *pv_in_12*.

```
pv_in_12(t_start:t_end) = pv_in_12_cor_zubau(t_start:t_end);
```
(31)

In the following command, the mentioned PV factor is implemented by using the coherence

$$\begin{array}{ccc} installed\ PV\ capacity\ (t) & \cdots & pv\_in\_12(t) \\ installed\ PV\ capacity\ (t)\ +\ (10GW\ x\ pv\_factor) & \cdots & pv\_in\_12\_new\ (t) \end{array} \quad (32)$$

$$pv\_in\_12\_new\ (t)\ = \frac{installed\ PV capacity\ (t) + (10GW\ x\ pv\_factor))*pv\_in\_12(t)}{installed\ PV\ capacity\ (t)} \quad (33)$$

This connection is represented in the code line as

```
pv_in_12 =
((pv_inst(t_start:t_end)+kron((pv_factor*pv_power_plus),ones(t,1)))*
pv_in_12(t_start:t_end)')./kron((pv_inst(t_start:t_end)),ones(1,t));
```
(34)

All the renewable energy sources are summarized in *res_in*

```
res_in=
wind_in(t_start:t_end)+ror(t_start:t_end)+pv_in_12(t_start:t_end);
```
(35)

where *ror* stands for run of river powerplant and *wind_in* for the wind power station. In the variable *mustrun*, the always and constant running renewable power plants are merged. These are, for example, biomass and waste-to-energy plants. For the considered regions, the *mustrun* equals 4729MW

```
mustrun=4729;
```
(36)

```
res_in=res_in+mustrun;
```
(37)

For bringing the variable to the fitting matrix dimension, the code line

```
inflows(:,length(inflows(1,:))+1:hydroPlants)=0;
```
(38)

is necessary before the inflows of all hydro plants are set in the next step

```
inflows=inflows(t_start:t_end,:);
```
(39)

In the variable

```
d_s=d_s_ATDE(t_start:t_end);
```
(40)

the energy demand for every hour is set. The necessary positive and negative controlling power rage is set to the values

```
d_pos_reg=2000;
```
(41)

and

```
d_neg_reg=2000;
```
(42)

The need for district heating is in total

```
Waerme_ges= 154
```
(43)

TWh of heat demand. A baseload of 1000MWh is represented in

```
Waerme_baseload=1000;
```
(44)

for every hour of a year. This value is an all-time available heat source. So the heat demand

```
d_h=Waermenachfrage(t_start:t_end)*Waerme_ges*10^6/1000;
```
(45)

equals the *Waermenachfrage* value between 0 and 1 times the total *Waerme_ges*. The efficiency of the heat production is different to the efficiency in electricity production and calculated by

```
th_data.eff_h=(0.88-th_data.eff/100).*th_data.KWK;
```
(46)

where KWK is the ability of the plant to cogenerate heat and power. This ratio is called CHP coefficient and it is the relation between produced electricity and rejected heat.[6]

```
stromkennzahl=(th_data.eff/100)./th_data.eff_h;
```
(47)

Further constants are the maximum capacity of heat production

```
cap_heizkessel=35000;
```
(48)

and the heat productions efficiency

[6] http://www.umweltbundesamt.de/service/glossar/s?tag=Stromkennzahl#alphabar (accessed on 06.01.2016)

```
eff_heizkessel=0.9;
```
(49)

The marginal cost for the heat production results from

```
mc_heizkessel=p_gas/eff_heizkessel;
```
(50)

KWK_mat is a matrix including the CHP coefficient which is necessary for the heat demand constraint later

```
KWK_mat=kron(th_data.KWK'./stromkennzahl',ones(t,1));
```
(51)

The minimum value that thermal plants have to produce for system stability is

```
thermal_min=10000;
```
(52)

Ramping cost are an important factor for the resulting power plant dispatch. In the variable

```
ramp_costs=th_data.c_ramp;
```
(53)

the ramping costs are taken from the input data file. It would be possible to raise the impact of the ramping costs by increasing the factor

```
ramp_c_factor=1;
```
(54)

The limit of the ramping costs is set in ramp_max in the line

```
ramp_max=(th_data.max_ramp.*th_data.cap)';
```
(55)

For correct usage in the program as a matrix with the correct size, the command *kron* in

```
ramp_max=kron(ramp_max,ones(t,1));
```
(56)

is used. The constraints of the model are the restrictions of the decision variables that have to be made for a correct result that represents the real electricity price. In the next section, all of the constraints will be explained for their usage and sence starting with the constraints for the thermal units. The constraint

```
Constraints =
[Constraints, 0 <= x_s_thermal + x_reg_pos_thermal <= X.*on];
```
(57)

regulates the amount of produced electricity from thermal plants between a minimum and a maximum. The minimum power is set to zero and the maximum amount is the installed capacity in X.

The constraints

```
Constraints = [Constraints, up(1,:) >= on(1,:)-on(t,:)];
```
(58)

and

```
Constraints = [Constraints, up(2:t,:) >= on(2:t,:) - on(1:t-1,:)];
```
(59)

are representing the starting of thermal plants. The decision variable *up* characterizes the percentage of plant power which have been started up as a result from the *on* variable. The value of the *up* variable is, as described in constraint

```
Constraints = [Constraints, 0 <= up <= 1];
```
(60)

between 0 to 1. The same procedure made for the shutdown of thermal plants in the constraints

```
Constraints = [Constraints, down(1,:) >= on(t,:)-on(1,:)];
```
(61)

and

```
Constraints = [Constraints, down(2:t,:) >= on(1:t-1,:) - on(2:t,:)];
```
(62)

for the decision variable *down*. The variable *on* is used to decide the value of the *down* variable. If a plant reduces its power, which can be seen in the *on* variable, it is stored in the *down* variable in a range between 0 and 1, regulated by the constraint

```
Constraints = [Constraints, 0 <= down <= 1];
```
(63)

As mentioned in the explanation above, the constraint

```
Constraints = [Constraints, 0 <= on <= 1];
```
(64)

indicates at which level of power output the thermal plants are operating. The range between 0 and 1 specifies the operating status from 0 to 100%. The amount of produced electricity from thermal plants has to be higher than the required minimal positive balancing energy *x_reg_pos_thermal*

```
Constraints = [Constraints, x_s_thermal >= x_reg_pos_thermal*k];
```
(65)

and negative balancing energy *x_reg_neg_thermal*

```
Constraints = [Constraints, x_s_thermal >= x_reg_neg_thermal*(1+k)];
```
(66)

The power difference between two hours when thermal plants are raising their power output in *ramp_thermal* has to be higher than 0:

```
Constraints = [Constraints, ramp_thermal >= 0];
```
(67)

And the exact amount of *ramp_thermal* is restricted by the constraint

```
Constraints = [Constraints,
ramp_thermal(2:t,:) >= x_s_thermal(2:t,:)-x_s_thermal(1:t-1,:)];
```
(68)

The constraint

```
Constraints = [Constraints,
ramp_max(2:t,:) >= x_s_thermal(2:t,:)-x_s_thermal(1:t-1,:)];
```
(69)

limits the maximal raise of *x_s_thermal* for one hour to the next. Otherwise, the thermal power would rise too quickly from one hour to the next. Thermal power plants are having a limit of raising their power per hour. This limit is specified as a percentage of power capacity of the plant. In one hour a plant can only raise its power output about this percentage due to physical bounds. Another restrain for *x_s_thermal* is

```
Constraints =
[Constraints, sum(x_s_thermal(1:t,1:79),2) >= thermal_min];
```
(70)

This illustrates that the power of all thermal plants, except the nuclear plants, has to be higher than *thermal_min* for every hour of a year. Nevertheless, a minimum of running thermal plants is important for the grid's stability. The next constraints are concerning the hydro power plant. Pumping power is limited in constraint

```
Constraints = [Constraints, (0 <= x_s_hydro_pump <= kron(hydroProdMin*(-1),
ones(t, 1))):'pump'];
```
(71)

between 0 and *hydroProdMin*. The factor "-1" negates the hydro production minimum for correct usage in the constraint. The same restrictions are needed for turbining power in

```
Constraints = [Constraints, (0 <= x_s_hydro_turb <= kron(hydroProdMax,
ones(t, 1))):'turb'];
```
(72)

and as well for the storage level in

```
Constraints = [Constraints, (0 <= storageLevel <= kron(storageLevelMax,
ones(t + 1, 1))):'storage'];
```
(73)

The storage level has to be in a range between 0 and the maximum storage level. Furthermore it is necessary to keep the storage in balance. With the following constraint

```
Constraints =[Constraints, storageLevel(2:t+1, :)
== storageLevel(1:t,:) - x_s_hydro_turb/0.88+x_s_hydro_pump*0.88 + inflows
- spill, inflows >= spill >= 0];
```
(74)

the storage level for the next hour is a result of the current storage level discounting, the turbining and pumping activities of the hydro plants. The effectiveness of turbining and pumping is included with the factor 0.88. The water inflows and the water spill is also involved. Additionally to the storage balance, the storage is at the same level at the end of a year as it was at the beginning. This behavior is included in the constraint

```
Constraints =
[Constraints, storageLevel(1, :) == storageLevel(t + 1, :)];
```
(75)

For covering the electricity demand in every moment, a balance of generation and demand is required. The demand constraint

```
Constraints = [Constraints,(sum([x_s_thermal, x_s_hydro_turb,-
                    x_s_hydro_pump], 2) >= d_s -res_in):'p_s']; 
```
(76)

restricts that the sum of thermal produced electricity and hydro power covers the remaining demand. The remaining demand equals the demand *d_s* subtracted by the renewable energy infeed *res_in*. Turbining hydro power is counted positively in opposite to hydro pumping power. The following restrictions are equally right for positive and negative balancing energy. The amount of positive or negative controlling power has to be always produced by thermal plants. This is what the constraints

```
Constraints = [Constraints, sum(x_reg_pos_thermal, 2) >= d_pos_reg];
```
(77)

and

```
Constraints = [Constraints, sum(x_reg_neg_thermal, 2) >= d_neg_reg];
```
(78)

are about. Positive and negative balancing energy *x_reg_pos_thermal* and *x_reg_neg_thermal* must have a positive value, which is ensured by the constraints

```
Constraints = [Constraints, x_reg_pos_thermal >= 0];
```
(79)

and

```
Constraints = [Constraints, x_reg_neg_thermal >= 0];
```
(80)

An additional claim for thermal plants derives from the heat demand. Energy for heating buildings and warm water is required even in summer, so thermal plants with combined heat and power (*KWK*) have to satisfy the constraints

```
Constraints = [Constraints,
x_s_heizkessel+sum(x_s_thermal.*KWK_mat,2)+Waerme_baseload >= d_h];
```
(81)

and

```
Constraints = [Constraints, 0 <= x_s_heizkessel <= cap_heizkessel];
```
(82)

Thermal plants are generating heat and power, the CHP coefficient declares how much heat is produced at a certain level of power in the formula *sum(x_s_thermal.*KWK_mat,2).* The sum of heat from the thermal plants, a boiler (*x_s_heizkessel*) and the heat baseload (*Waerme_baseload*) has to be higher than the heat demand *d_h*. An addition is made to reserve balancing power *x_reg_pos_thermal* and *x_reg_neg_thermal* for one week previously. The next step is the adjustment of the sdp settings. In the command

```
options = sdpsettings('solver', solver, 'verbose', 2);
```
(83)

the “Gurobi” solver is specified and the display level *verbose* is set on the value 2 which stands for the amount of the solving progress that is shown in the MATLAB workspace. In the next step, the objective function is constructed by the sum of costs. The summands for the objective function

```
obj = sum(objSpot)+sum(objramp)+sum(objstart)+sum(objheat)+sum(objstop);
```
(84)

are calculated as the sum of thermal production times the marginal cost

```
objSpot = [x_s_thermal] .* [mc];
```
(85)

the ramping cost for thermal plants

```
objramp = ramp_thermal*(ramp_costs*ramp_c_factor);
```
(86)

the costs for starting

```
objstart = sum(up*(th_data.c_start.*x_leistung'));
```
(87)

and stopping thermal plants

```
objstop = sum(down*((th_data.c_start/3).*x_leistung'));
```
(88)

as well as the heating costs

```
objheat = x_s_heizkessel*mc_heizkessel;
```
(89)

for heat production of thermal plants. The optimization problem is now solved with the command *solvesdp*. The constraints, the objective function and the options are committed to the function in

```
d = solvesdp(Constraints, obj, options);
```
(90)

The value in the objective function *obj* gets minimized to the smallest possible value. The objective function is a main part of the model. All relevant parts for the optimization are summarized there. If the minimum value is reached after a number of iteration by the solver, the result for all decision variables in every hour is complete. The derivation of electricity prices on an hourly resolution happens in

```
p_s = dual(Constraints('p_s'));
```
(91)

The *dual* command is used to extract the dual variable related to the demand constraint (76) (Löfberg 2015). The electricity price is derived on an hourly resolution using the idea of the shadow prices. The results for the optimal solution of the objective function are declared as the shadow prices of the associated constraint (76). The result indicates how much the price changes for one more unit of demand in the constraint (Nakicenovic and Haas 2014).

The results are saved for evaluation in MS EXCEL files with the MATLAB command *xlswrite*.

3.6 MATLAB code for optimization of revenue for pump hydro storage power plants

The second part of the thesis is the optimization of the storage profitability for pump hydro power plants. Main parts of the MATLAB Code were used in the calculations for the paper "East to West - The Optimal Tilt Angle and Orientation of Photovoltaic Panels from a System Perspective" (Hartner et al. 2015) in "Applied Energy, Volume 160".

The storage profitability model is not directly connected with the electricity price calculating model. These two models are separated from each other. The only input data, which is needed, is the price for each hour of one year. Therefore, an input data vector or dataset with 8760 rows is imported by the command

```
load('prices_model.mat');                                  (92)
```

The command

```
l=size(prices,2);                                          (93)
```

evaluates the quantity of data vectors in the 'prices' dataset. For the calculation of different scenarios the loop

```
for i=1:l;                                                 (94)
```

repeats the calculation for each one of the input price vectors. The same procedure is used for different values of storages. Four different values are represented in

```
SOC_all=[4,8,200,2000];                                    (95)
```

The storage value signifies the quantity in MWh. So practically this means for the profitability model with a set for turbining and pumping power of 1MW, that in the case of storage value 8, the storage is empty in 8 hours at full power. So the storage works as a daily-reservoir with values of 4 and 8, as weekly-reservoirs with a value of 200 and as an annual-reservoir-storage with the value 2000. The loop

```
for j=1:4                                                  (96)
```

repeats the calculation for all storage scenarios

```
SOC_Max=SOC_all(j);                                        (97)
```

An electricity price for every hour of one year is now located in the workspace of MATLAB. The model only calculates positive price values because the appointed constraints are prepared that no negative price can result. The storage profitability model makes sure that no prices with negative values are appearing. The values in the workspace were written into the vector

```
price = prices(1:8760,i);                                  (98)
```

and after this the values are being converted to the datatype double

```
p_s = double(price);                                   ( 99 )

p_s(isnan(p_s)) = 0;                                   ( 100 )

p_s(p_s<0) = 0;                                        ( 101 )
```

The next program step defines the required constants and variables: *p_turb* and *p_pump* defines one unit of turbining and pumping. *n_turb* and *n_pump* represents the efficiency of tubining and pumping

```
p_turb=1;                                              ( 102 )

p_pump=1;                                              ( 103 )

n_turb=0.9;                                            ( 104 )

n_pump=0.9;                                            ( 105 )
```

The definition of the decision variables is made with the command "sdpvar". The model calculates the optimal value of these variables. The result can be seen as the optimal, most profitable, dispatch for turbining (*x_s_turb*), pumping (*x_s_pump*) and *SOC* (state of charge).

```
Plants = length(p_turb);                               ( 106 )

x_s_turb = sdpvar(t, plants);                          ( 107 )

x_s_pump = sdpvar(t, plants);                          ( 108 )

SOC = sdpvar(t + 1, plants);                           ( 109 )
```

The storage profitability model does not consider the best economic solution for the energy market. It calculates the most profitable turbining and pumping dispatch by caring only about the following constraints.

The first two constraints are limiting the power of tubining and pumping between 0 and 1. This means that turbining and pumping power can take a value between 0 and 100% on nominal power.

```
Constraints =
[Constraints, 0 <= x_s_pump <= kron(p_pump, ones(t, 1))];     ( 110 )

Constraints =
[Constraints, 0 <= x_s_turb <= kron(p_turb, ones(t, 1))];     ( 111 )
```

The power of all turbines is aggregated in the variable *x_s_turb* respectively in *x_s_pump*. The next two constraints are concerning the storage level. The constraint

```
Constraints =
```

```
[Constraints, 0 <= SOC <= kron(SOC_Max, ones(t + 1, 1))];
```
(112)

is limiting the storage capacity between 0 and 100%. For the calculation of different scenarios it is possible to extend the storage capacity in steps to show the impact of a lager storage. To keep the storage in balance, the constraint

```
Constraints = [Constraints, SOC(2:t+1, :) ==
SOC(1:t,:) - x_s_turb(1:t,:)./n_turb + x_s_pump(1:t,:).*n_pump];
```
(113)

is responsible for the state of charge which changes by turbining and pumping. The formula considers the efficiency rating of the turbine and the turbine in pumping mode. This means the *SOC* after the present hour is a result of the *SOC* in the present hour considering turbining and pumping activities during this hour. The last constraint in the calculation of the storage profitability defines that the *SOC* at the beginning of the calculation is equal the *SOC* at the end of calculation. The constraint

```
Constraints = [Constraints, SOC(1, :) == SOC(t + 1, :)];
```
(114)

makes sure that the storage at the end of the year must have the same level as in the beginning of the year. In between the storage level is optimized by the model for every hour. The course of storage level depends on the volume *SOC_all*. As mentioned previously, the storage can work as daily-, weekly-, or annual-reservoir. In the progress of storage profitability optimization, it is sufficient to represent the storage in a value between 0 and *SOC_Max*. The objective function *obj* is the function that gets optimized. Turbining and pumping power dispatch is multiplied with the corresponding price in each hour. The sum equals the objective

```
obj = -(sum(x_s_turb.*(p_s)- x_s_pump.*(p_s)));
```
(115)

The minus sign is needed for the optimization progress because the YALMIP toolbox and the solver are always minimizing the objective function. The task here is to calculate the highest revenue. So the solution is to negate the objective function. After removing the minus sign, the result is the maximized objective function. In the code line

```
options = sdpsettings('solver', solver, 'verbose', 2);
```
(116)

the settings for the solver are set. The used solver for the optimization is GUROBI 6.50. The real optimization progress takes place in the line

```
d = solvesdp(Constraints, obj, options);
```
(117)

The minimization of the objective variable *obj* starts here. After the optimization, *obj* is transformed in

```
profit=-(double(obj));
```
(118)

from a sdp-variable to a double datatype. The evaluation of the results takes place in MS Excel where the data is transferred by command *xlswrite*. All the data transfer for the different scenarios is summarized in the file “*save_results.m*”.

4 Results

The following results and explanations are based on data from the year 2012. The first part of the model was completed with varying values of installed photovoltaic capacity to derivate electricity prices on an hourly resolution for different PV infeed scenarios. The second part of the model is the optimization of revenue for different storage sizes.

The optimization of both model parts was realized with a personal computer with following specifications and programs:

- Windows 7 (64 Bit)
- Intel Core i7-4720HQ CPU 2,60GHz
- RAM: 16 GB DDR3L
- SSD 256GB
- MATLAB R2015a
- Gurobi Optimizer 6.5
- Yalmip Toolbox

The optimization process for the model that derived the electricity price took up to 7 hours for one PV infeed scenario. Solving all scenarios took about 2 weeks of computer calculation time. A higher amount of random access memory (RAM) would have speed up the process, but the maximum quantity of RAM was installed on the computer.

4.1 The linear dispatch model for derivation of electricity price

The first and lone standing part of the model is the linear dispatch model for electricity price derivation. However, it was not the aim to get completely equal results as they were in reality on EPEX in the year 2012. The model should reproduce a correct consistent characteristic of electricity spot market price. Based on this model, the installed PV capacity can be raised in steps of 10GW or more to get an outlook what could happen to the electricity prices in these cases. The model is explained in detail in the previous chapter and the results are outlined in this chapter. As an example for the result of the price building model, two example price progressions are shown in comparison to the real EPEX price in these hours. Two weeks with different energy market and seasonal conditions were chosen to show the accuracy of the model. The week from Monday 30.01.2012 till Sunday 05.02.2012. Figure 24 is characterized by a seasonally appropriate infeed of Photovoltaic energy and high wind energy infeed in the first three days of the week.

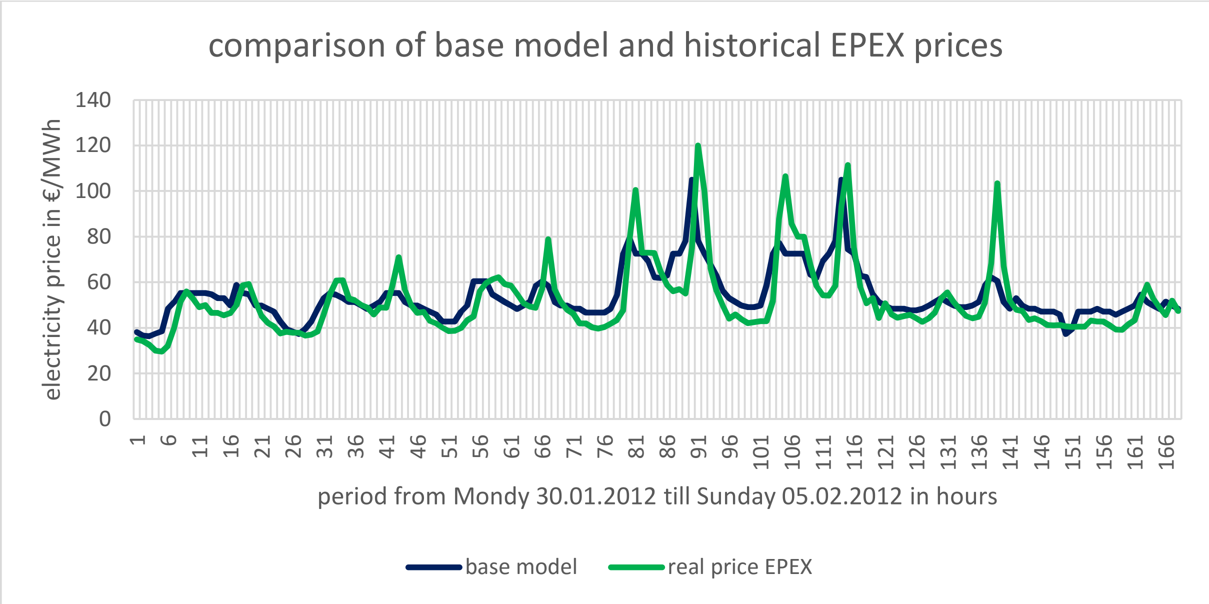

Figure 24: price comparison for February 2012 (own illustration)

The week from Monday 23.07.2012 till Sunday 29.07.2012 in Figure 25 is characterized by high PV infeed every day and low wind energy infeed for the whole week. From the development of electricity prices in these two different weeks can be seen that the model works accurately to get realistic results in other model scenarios. There are several reasons why the model does not match perfectly to reality. The factors with the highest influence are the aggregation of thermal plants, the not exactly fitting of the modelled heat demand and general uncertainties and simplifications that were made.

Another important point is that the heights of price peaks and the lowest points in valleys are not accurate compared to the real historic price. This is a result of many different factors and uncertainties in the model. It has to be mentioned that the exact modelling of the electricity market is a highly complex and difficult issue. The market behavior is not represented in the model. Moreover, in the model simplified representations of technical constraints are made. Besides there are general uncertainties in assumptions and restrictions that were made. Therefore, these inaccuracies in the model lead to differences to real prices.

These interferences from real market prices do not have to be considered because the price spread is similar to reality. The price spread is not the same as in reality but the difference to the real value is not the essential point. This difference is a consequent offset variance. For optimization of the revenue in the next step, the price spread is more important. This offset variance does not matter because it affects all scenarios in the same way and so the difference between revenues is a valid estimation. This means, a valid statement for the development of revenue with changing PV infeed and alternative CO_2 prices can be made. This is the reason why the model works properly for the requirements.

The two displayed weeks are representative for the functionality of the price deriving model. The distribution of real historic prices in comparison to the modelled prices is presented in Figure 26.

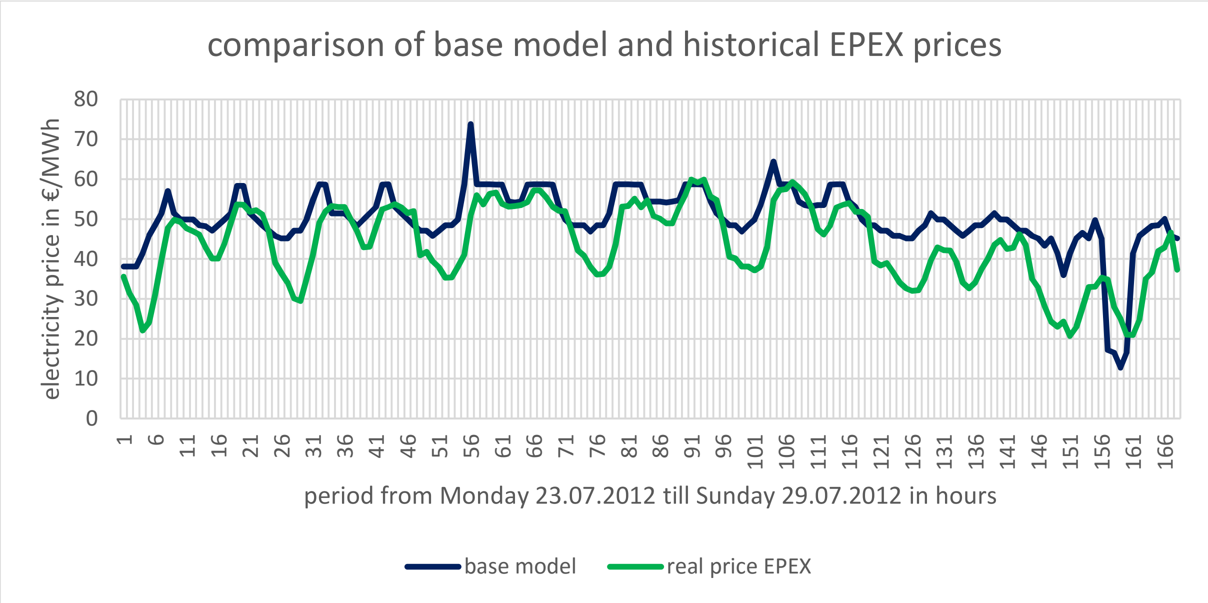

Figure 25: price comparison for July 2012 (own illustration)

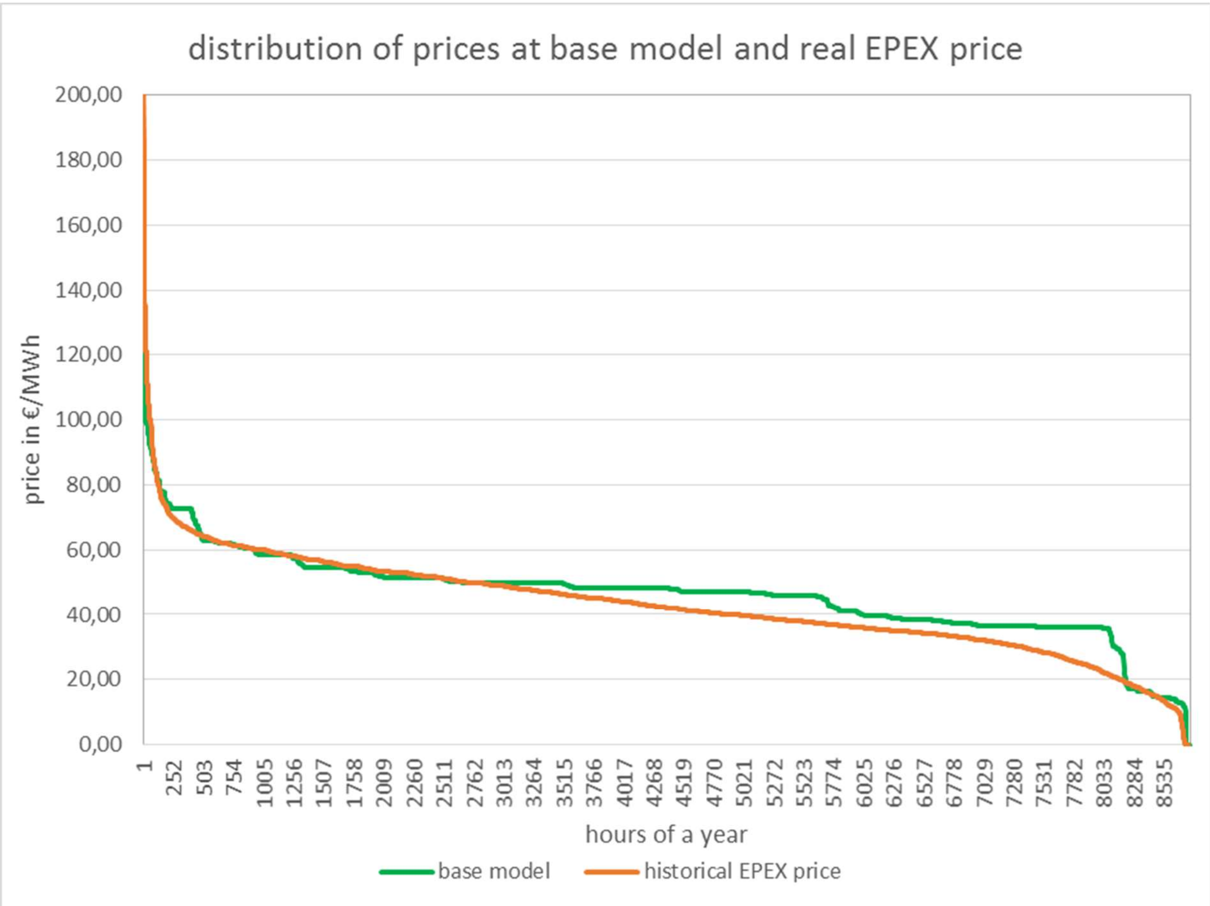

Figure 26: distribution of real and modelled prices in comparison (own illustration)

4.2 Revenue of pump hydro storage plants

The calculation of the revenue for pump hydro storage plants is realized, as mentioned before, with a linear programming optimization model. The input of the model is the electricity price for every hour of a year. Scenarios with different CO_2 prices and diverse storage behavior are considered. For the following graphs, a storage value of 8MWh (daily-reservoir) was chosen in the profitability calculation. The plant in the model has 1MW turbining power which means that the storage is empty in 8 hours (daily-reservoir). This value was chosen because most of the pump hydro storage plants are working as daily-reservoir due to their storage capacity and power. The result of the calculation is the revenue in €/MW for 1 MW turbining power in one year depending on installed PV capacity. The model calculates results from zero PV infeed to additional $200GW_{peak}$ PV infeed.

The relatively high value of additional PV capacity of $200GW_{peak}$ is not realistic for the countries Austria and Germany. In comparison, the net installed power plant capacity in 2015 in Austria is 22.9 GW_{peak} [7] and in Germany 199.2 GW_{peak}.[8] This is in sum 222.1 GW_{peak} of installed power plant capacity. So the installation of $200GW_{peak}$ seems unrealistic at this point, but for demonstration it is interesting to see how this scenario develops.

The optimised revenue is the maximum value that can be reached with an optimal dispatch of pumping and turbining under consideration of all constraints. This section explains how profit develops if PV infeed rises. By increasing installed photovoltaic capacity in the basic model, the developing of the revenue is shown in Figure 27.

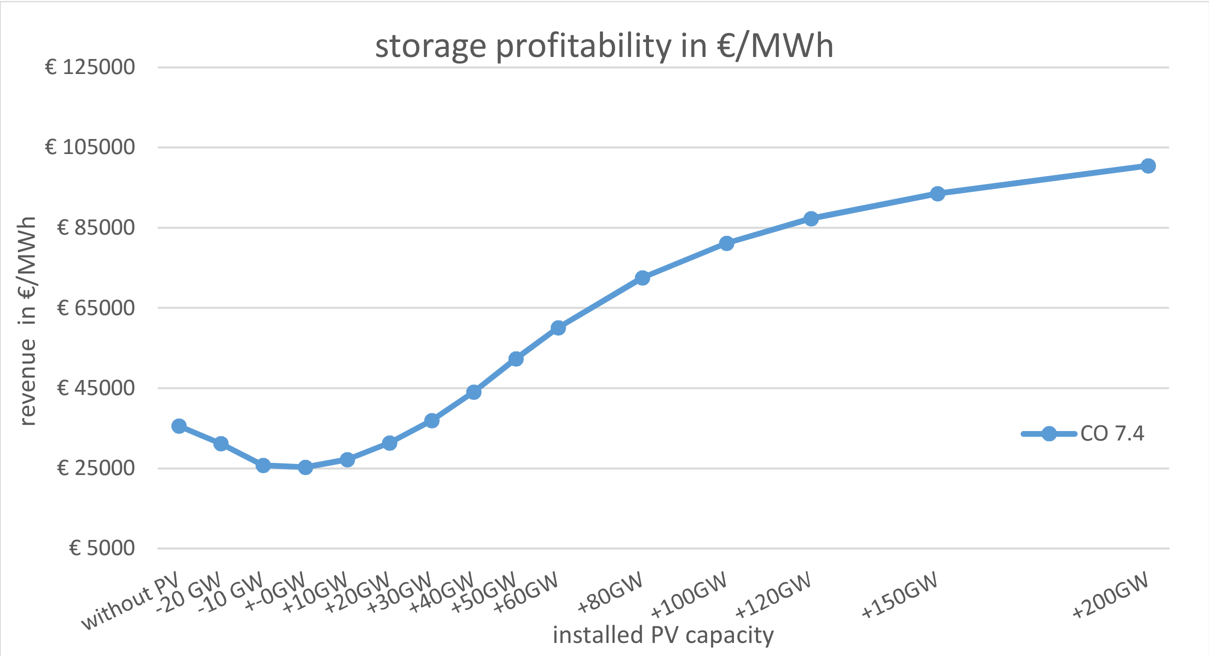

Figure 27: storage profitability with rising PV capacity (own illustration)

[7] https://www.apg.at/de/markt/erzeugung/installierte-leistung (accessed on 06.01.2016)

[8] http://www.bundesnetzagentur.de/cln_1911/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/kraftwerksliste-node.html (accessed on 07.01.2016)

In the case of a daily-reservoir (8 hour storage) the profit is at 25268€ for the base model with PV infeed from the year 2012. This is the lowest point of revenue for pump hydro storage plants. It can be seen that the revenue will increase if PV capacity is reduced and will increase, if PV capacity is expanded. The explanation for this behavior lies in the development of electricity prices, more precisely in the price spread between turbining and pumping of pump hydro storage plants as well as in the amount of produced electricity by PHS. The underlying factor is the infeed of photovoltaic electricity, which affects the price and the amount of pumped and turbined energy.

Profit can be made if PHS are using the price difference between hours with low and high prices. Storages are filled by pumping water up to the storage in times of low prices. In hours of high demand and high prices, PHS are turbining and so producing electricity. This is where the revenue comes from. Figure 28 shows the different price spread for the same period of time. It is obvious that the price spread is higher in case of additional $50GW_{peak}$ installed PV capacity. The hours with electricity prices of zero are rising with higher PV infeed. Especially at noon, a high amount of PV electricity is produced. The high supply of electricity with marginal costs equal to zero leads to the situation shown in Figure 28.

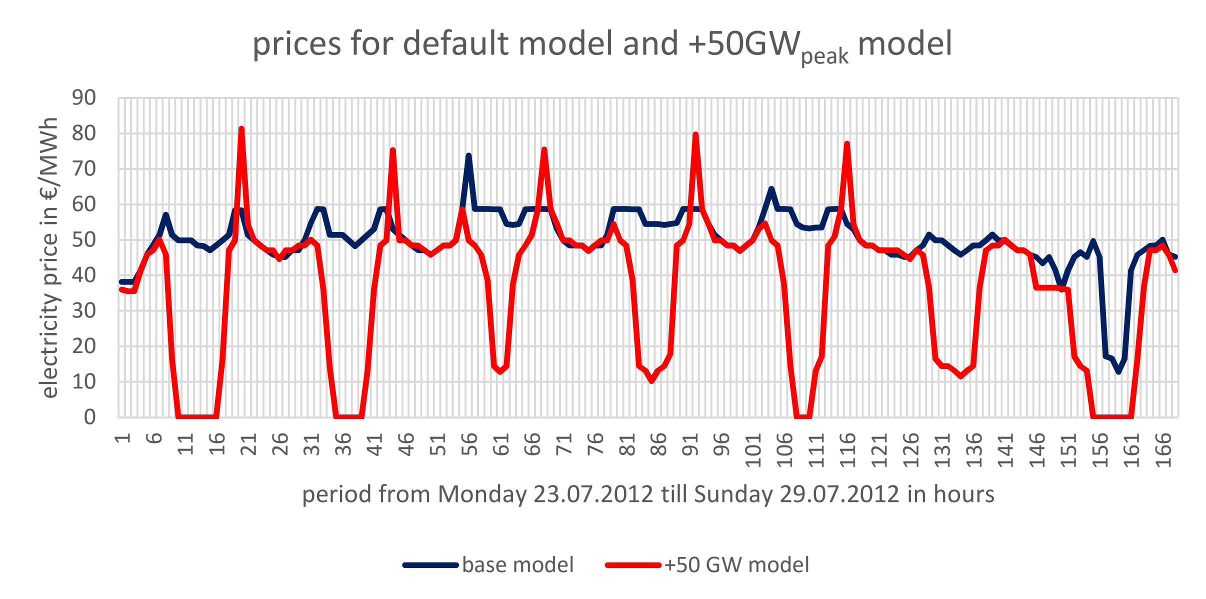

Figure 28: price spread between 0 and $50GW_{peak}$ additionally installed PV capacity (own illustration)

The number of hours with electricity price equal to zero rises continuously with more installed PV capacity. Figure 29 shows how the number of hours with a price of zero develops in the different scenarios. Figure 30 illustrates the course of the price for two days with slightly different PV infeed in detail. The rising number of hours with a price of zero is connected with the higher PV infeed. In the scenario without installed PV, a price peak at noon is visible on the second day. This situation changes with more PV energy on the market. With more and more PV infeed, the price decreases first at noon. With higher penetration level, the price during daylight is constant at zero from 8 p.m. to 20 p.m. in the scenario of $+200GW_{peak}$. This behavior could be reduced if thermal plants shut down for the time of high infeed of renewable energies (Götz et al. 2014). In comparison, Figure 31 demonstrates a winter day with lower PV infeed. The effects on the electricity price are the same as on the summer day in Figure 30. The number of hours is smaller because of lower PV infeed at this time.

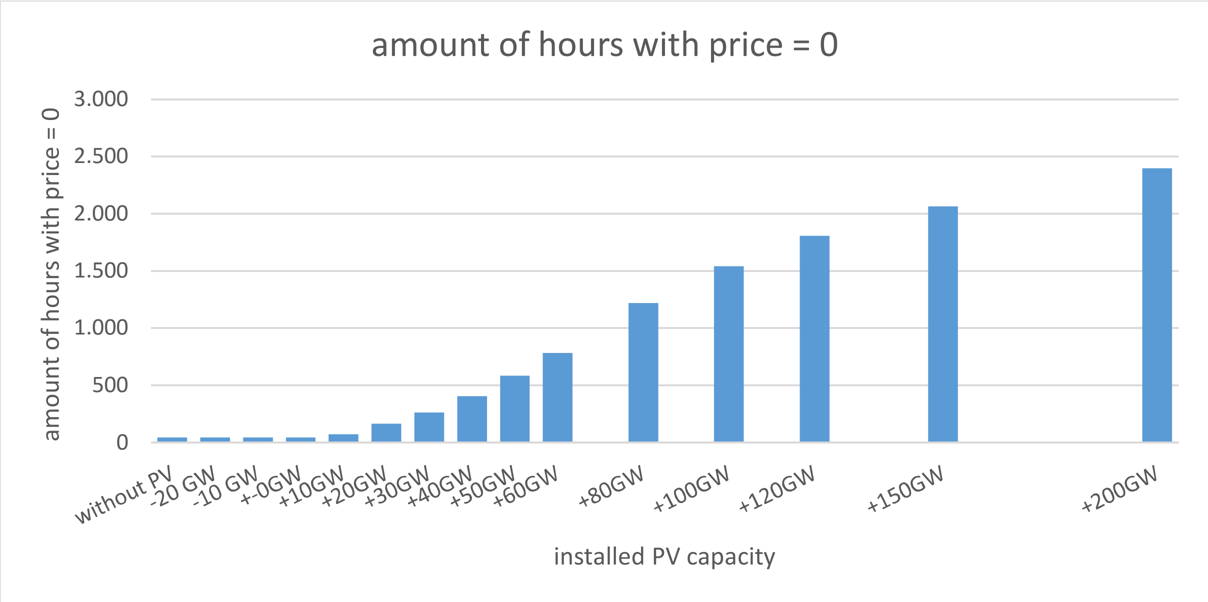

Figure 29: number of hours with electricity price = 0 (own illustration)

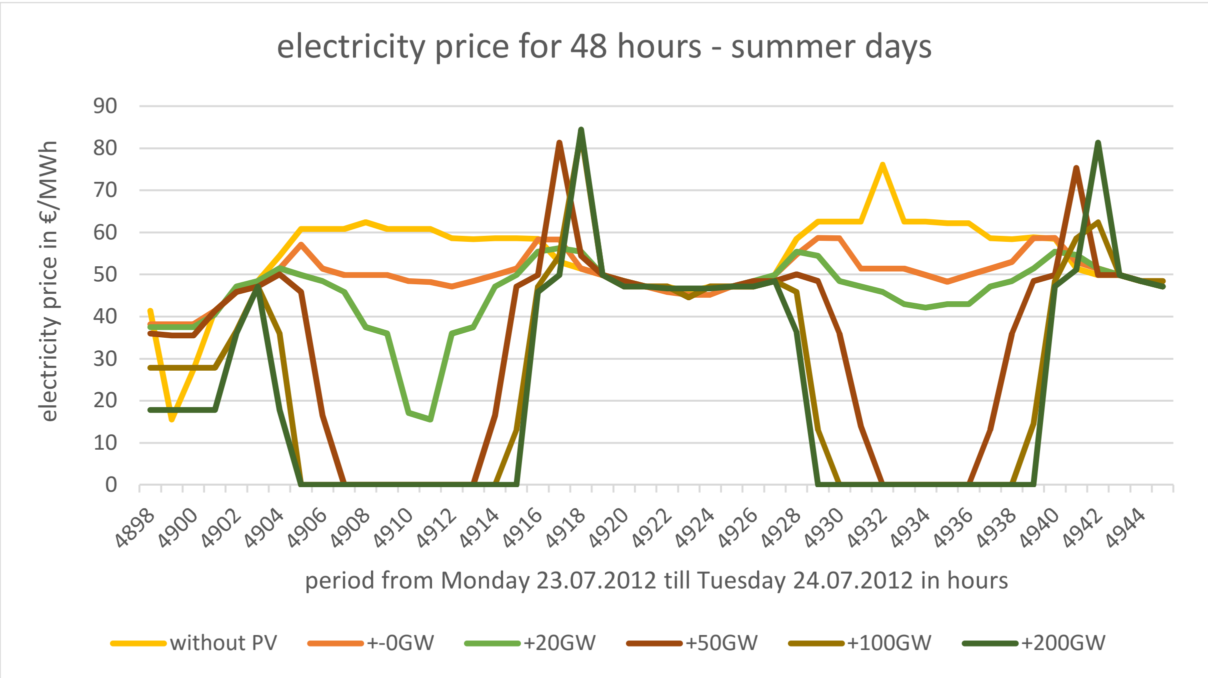

Figure 30: electricity price for 48 hours in different scenarios - summer days (own illustration)

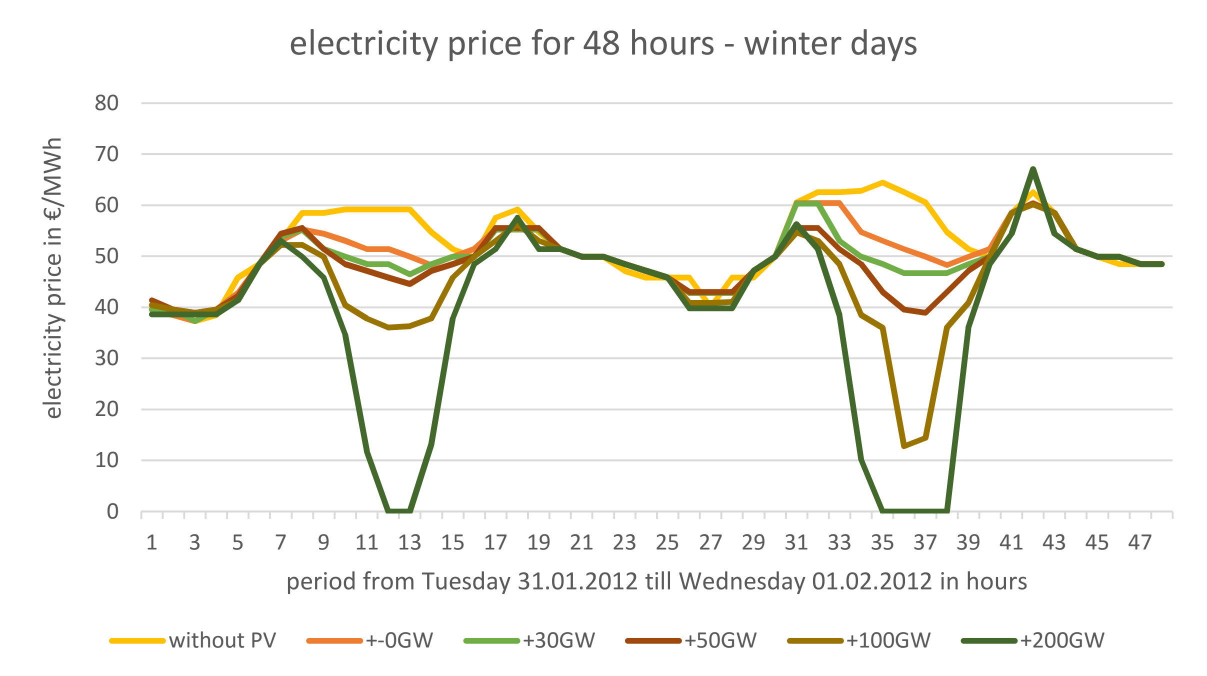

Figure 31: electricity price for 48 hours in different scenarios – winter days (own illustration)

4.3 Calculation of price spread

The price spread is calculated from the price difference between the average price of the 1000 hours with highest prices and the average price of the 1000 hours with the lowest prices. This calculation is illustrated in Figure 32 and Figure 33 using the price period line.

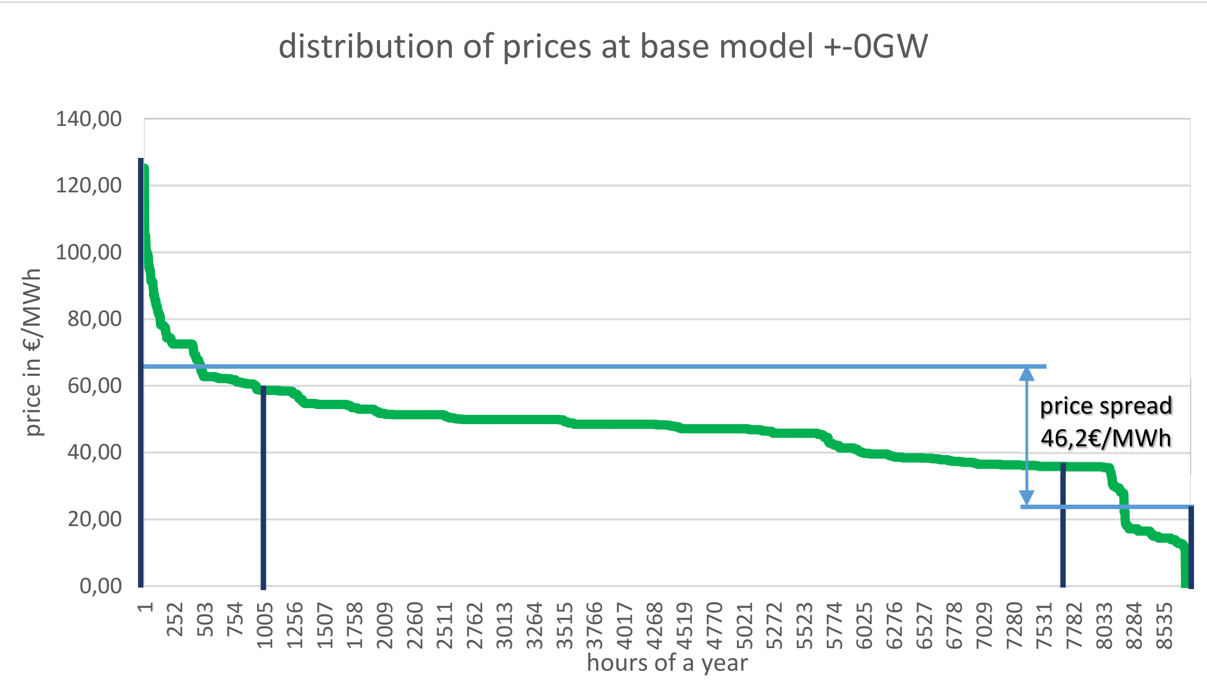

Figure 32: price period line base model (own illustration)

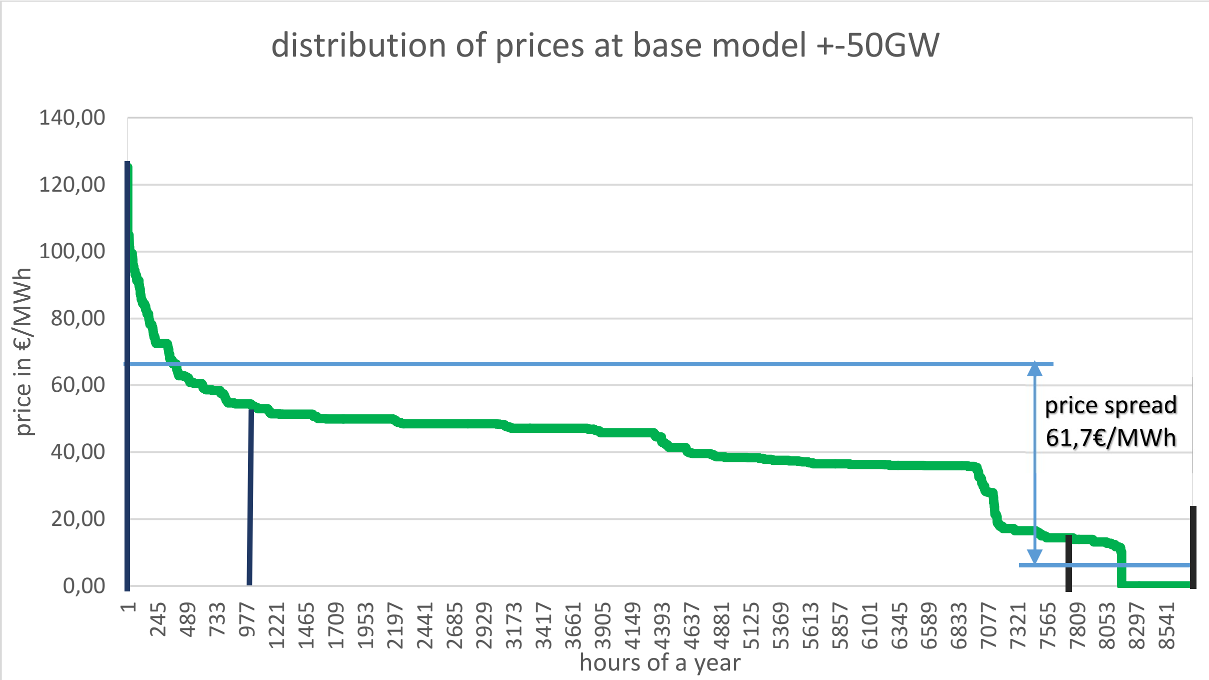

Figure 33: price period line base model for $50GW_{peak}$ scenario (own illustration)

The price spread is an important factor for the revenue. If the spread between the price of pumping and turbining rises, it is understandable that the profit will rise too. The price spread is influenced by the infeed of renewables, especially at higher PV penetration levels. The number of hours where storages are pumping at an electricity price equal to zero is rising. This can be explained with the merit-order. The supply curve moves to the right if PV infeed, with marginal costs equal to zero, is rising. At constant demand, this results in a lower price. According to the model, the amount of hours with electricity price equal to zero is going to rise with higher PV penetration and this leads to a lower average price for the 1000 hours with the lowest prices of the year. On the other side of the price period line are the 1000 hours with the highest prices of a year. The 1000 hours with the highest prices are not as affected by PV infeed as the 1000 hours with the lowest prices. This is because of the steep merit order in the range of power plants with higher marginal costs. Average prices in the higher range are decreasing not as much as the average prices in the lower range of the price period line. The result of price spread for different PV penetration levels is shown in Figure 34, Figure 35 and Figure 36.

Another important factor for the revenue is the quantity of electricity that is produced. A high price spread is one part of the revenue, the other part is the amount turbined energy. How much this is for every PV penetration scenario, is shown in the green curve in Figure 34, Figure 35 and Figure 36.

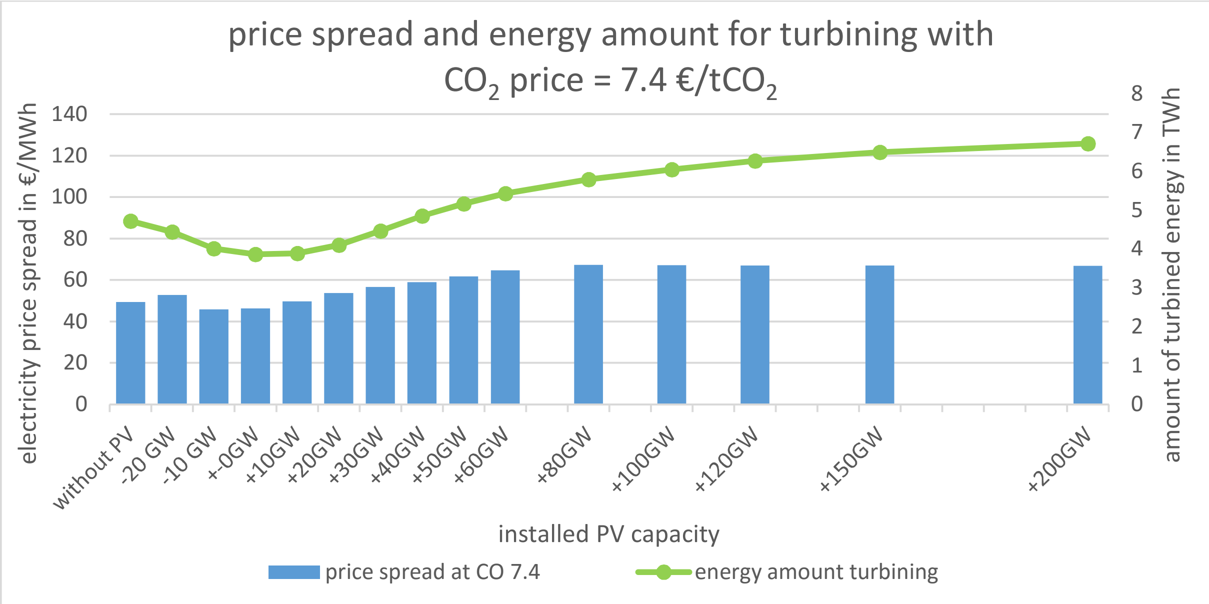

Figure 34: price spread and energy amount for turbining at CO_2 price = 7.4 €/tCO_2 (own illustration)

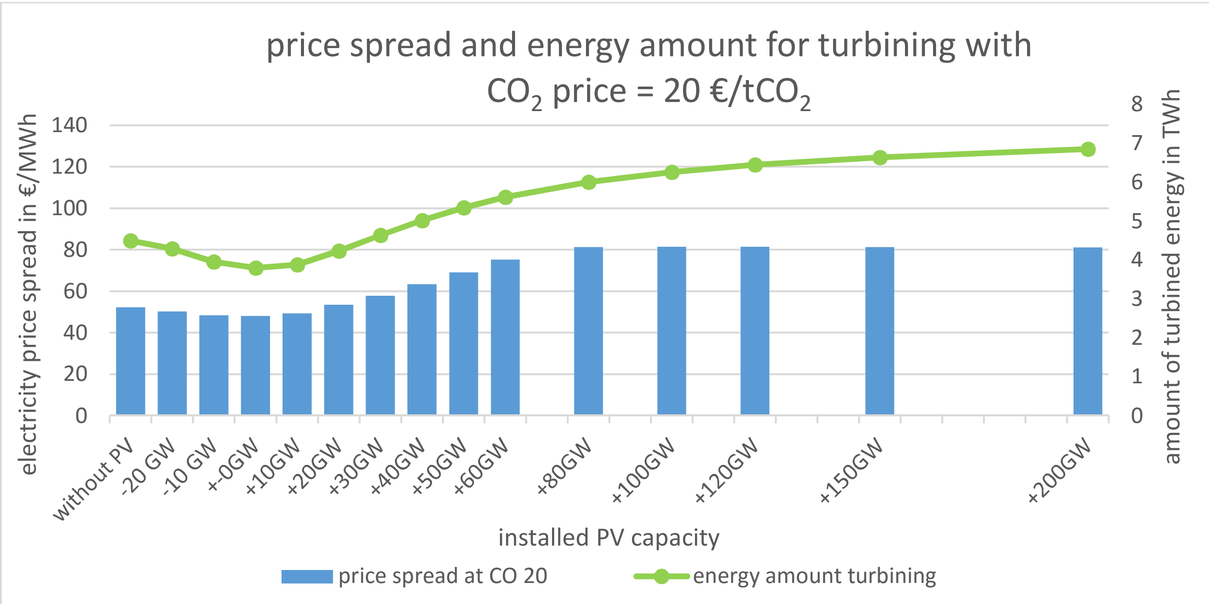

Figure 35: price spread and energy amount for turbining at CO_2 price = 20 €/tCO_2 (own illustration)

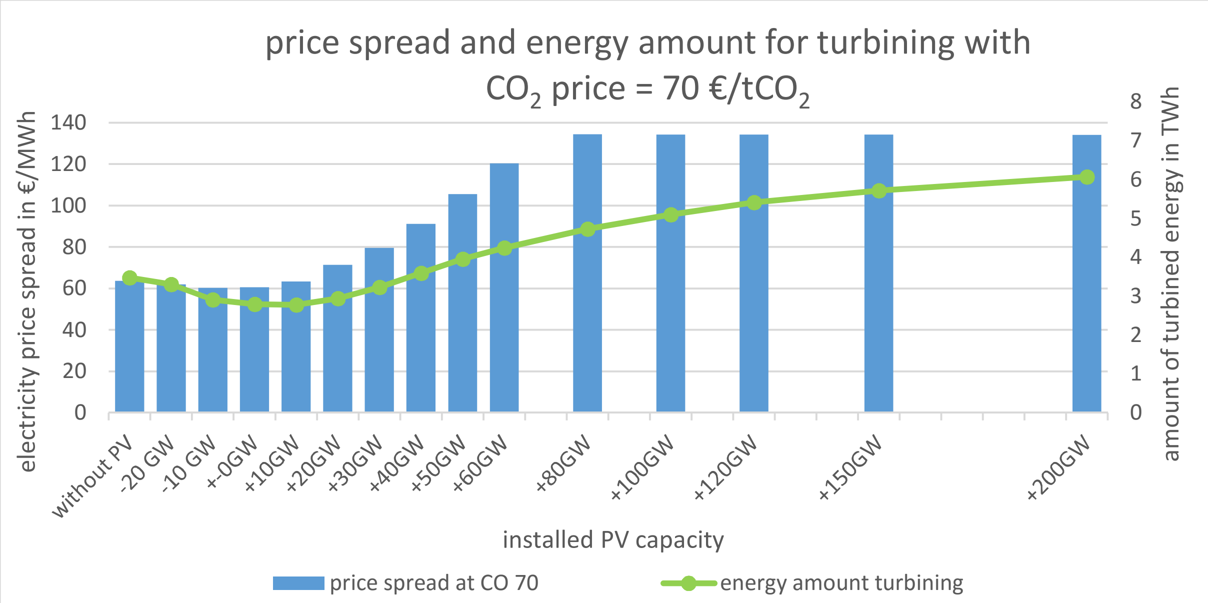

Figure 36: price spread and energy amount for turbining at CO_2 price = 70 €/tCO_2 (own illustration)

4.4 Hydro storage power plant dispatch

The dispatch of hydro storage power plants depends on the mentioned constraints in the model description. The duty is to cover electricity demand by keeping the storage in balance. Additionally there is a minimum pumping power and a maximum turbining power for each hydro power plant. The optimization of the model makes sure that this happens with the lowest possible costs.

Hydro storage power plants without the possibility of pumping water back to the reservoir are not considered in the following figures. Only pump hydro storage power plants (PHS) are considered. As already mentioned, the only input for the hydro storage plants is the natural inflow to the storage reservoir. In opposite to them, the inflow to pump hydro storages is realized by pumping from a lower reservoir to the upper reservoir. There is no inflow from outside to the PHS in the model.

4.4.1 Pump hydro storage plant electricity production

The behavior of turbining and pumping actions for the exemplary period from Monday 23.07.2012 till Thursday 26.07.2012 is compared in Figure 37, Figure 38 and Figure 39 for different levels of PV penetration. Filling their storages through pumping by using electricity with a low price and turbining when there is high demand. This is what makes the profit for pump hydro power stations.

The period of four days in the last week of July 2012 was characterized by PV infeed typical for the season and normal demand for weekdays. Three PV capacity scenarios were chosen to show how PHS energy production develops. The scenario without an infeed of PV energy in Figure 37, the base model with the installed PV capacity from about 25.6GW_{peak} in 2012 in Figure 38 and scenario with additional 50GW_{peak} installed PV capacity in Figure 39. A CO_2 price of 7.4€/tCO_2 for the mentioned scenarios is set. Differences in other CO_2 price scenarios are discussed the following chapter. As expected, it can be argued that in the range from zero to +50GW_{peak} PV infeed, the result is only slightly different at other CO_2 prices. On higher PV penetration level there is a bigger difference in PHS energy production. For a better comparison, the figures for pump hydro production are displayed one after the other on the next page.

The scenario without PV infeed in Figure 37 shows the situation for pump hydro storages before the PV installation boom started, which is described as a typical development in "Wirtschaftliche Situation von Pumpspeicherwerken" (Harasta 2014). You can see the turbining at full power around the hour 12 on every day because of the high demand at noon. This time span of full power lasts up to 4 hours, depending on the volatile wind energy infeed. In the night hours between about 11 p.m. and 6 a.m., the PHS are pumping at almost full power. The need to refill to keep the storage in balance as well as the lower price during the night is the reason for that behavior. So the PHS dispatch works simplified like pumping during the night and turbining at peak load around noon.

The scenario without PV infeed in Figure 38 shows the situation for pump hydro storages as it is demonstrated in the base model. This is the situation at the beginning of 2012 with an installed PV capacity of about 25.6GW_{peak} in Austria and Germany. One can see that the turbining at full power is not at noon any more but it is in hour 8 and hour 19 and time span of full power lasts maximum for one hour. The pumping activities are nearly completely gone. There is no need for a lot of pumping activities because only a relatively small amount of energy was used for turbining. The refilling of storage happens on weekends when demand and electricity prices are low. With the PV infeed at noon, the peak of demand is covered by photovoltaics and there is no need for peak energy from PHS. However, the demand for PHS energy relocates to the morning and evening hours, every day at about 8 a.m. and 7 p.m. (hour 8 and hour 19).

The scenario without PV infeed in Figure 39 shows the situation for pump hydro storages with additional $50GW_{peak}$ of installed PV capacity. This is a relatively high amount because it is twice as much as the installed capacity at the beginning of the base model year 2012. One can see that the turbining activities are still around the hours 8 a.m. and 7 p.m. (hour 8 and hour 19), but the duration increased significantly. This is because there is so much energy stored from pumping during the day, that PHS can provide the grid with electrical energy longer. The biggest difference to the base model scenario is that pumping activities are occurring during the day around noon. There is much more energy from PV available and consequently the electricity price is so low that PHS are refilling their storages by pumping during the day.

In these three figures it can be clearly seen how the amount of turbined energy from PHS develops. It first decreases with rising PV capacity and then, the pump hydro production rises again. Figure 34 shows the progress with the green track. The amount of turbined energy is one major influence factor for revenue of PHS.

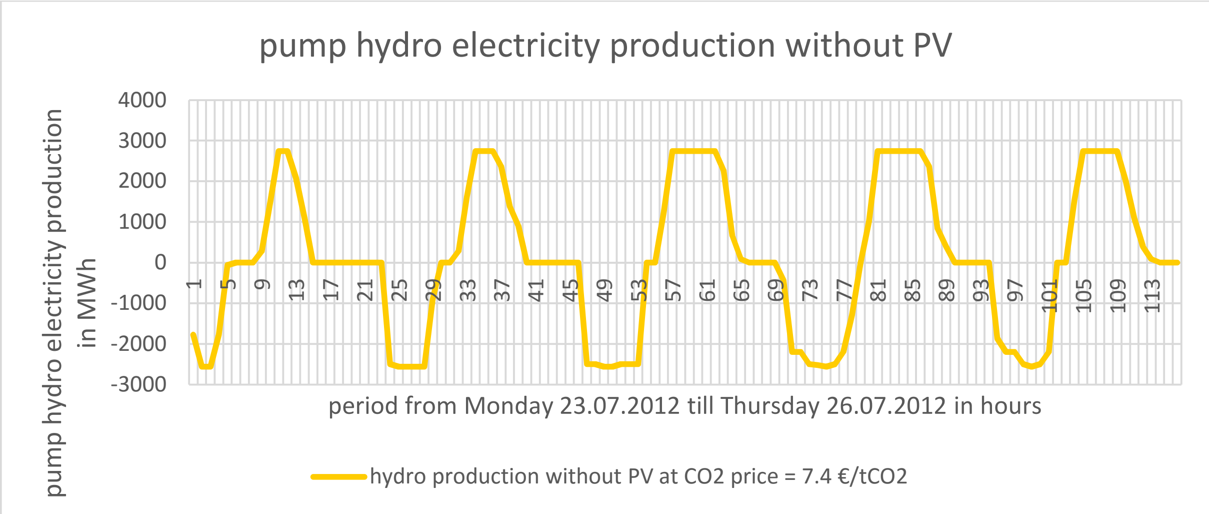

Figure 37: pump hydro electricity production without PV (own illustration)

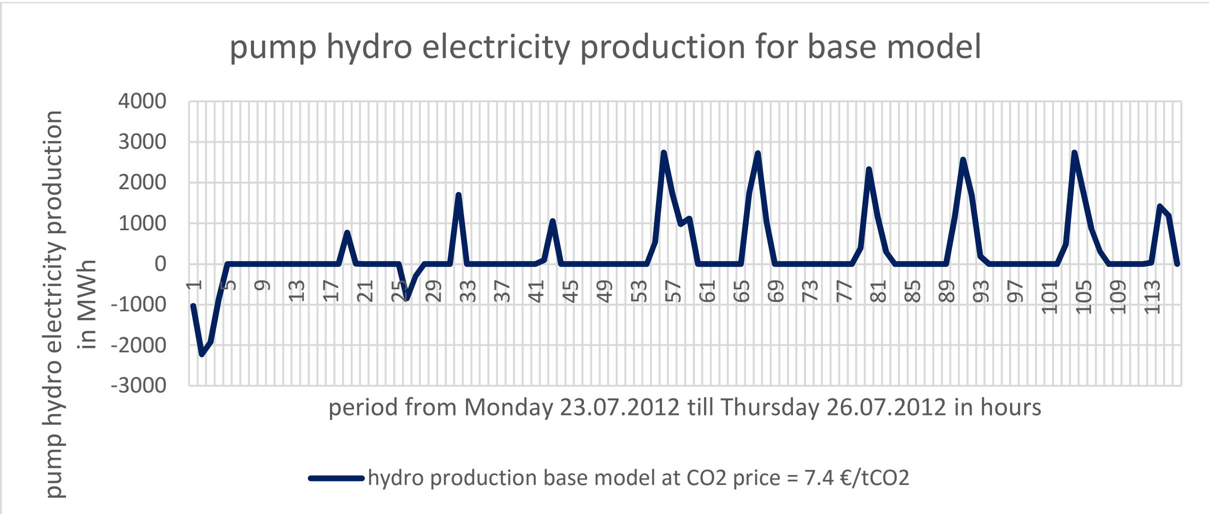

Figure 38: hydro electricity production base model (own illustration)

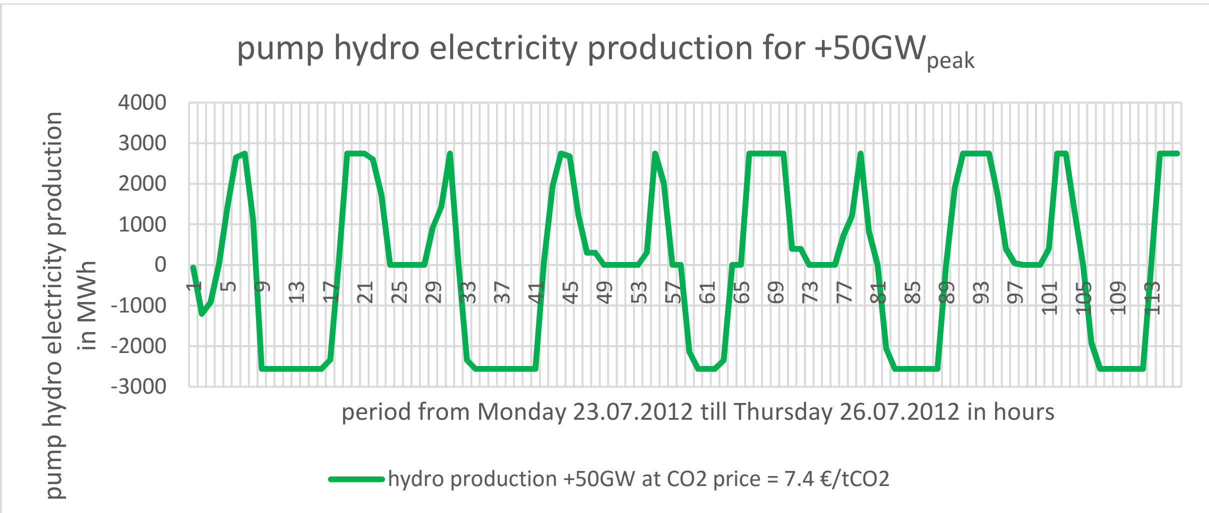

Figure 39: hydro electricity production for +50GW$_{peak}$ additional installed PV capacity (own illustration)

4.4.2 Storage quantity SOC of pump hydro storage plants

As already mentioned, storages can work as daily-, weekly-, or annual reservoir. The storage capacity decides in which cycle the storage operates. Explanations for the electricity production of PHES from the preceding chapters are also valid for the behavior of storage content. The SOC for pump hydro power storages is a direct result of pumping and turbining actions. To illustrate the activities of the storage volume, the same exemplary period from Monday 23.07.2012 till Thursday 26.07.2012 is used. The state of charge (SOC) for the sum of all modelled storages is shown for three PV capacity scenarios. The scenario without an infeed of PV energy in Figure 40, the base model with the installed PV capacity of 2012 (about 25.6GW_{peak}) in Figure 41 and the scenario with additional 50GW_{peak} installed PV capacity in Figure 42. A CO_2 price of 7.4€/tCO_2 is set in the scenarios. Differences to other CO_2 price scenarios are discussed the following chapter. For a better comparison, the figures for storage value of all PHS are presented one after the other on the next page.

The scenario in Figure 40 shows the situation without PV infeed. The storage is filled by pumping during the night from about 12 p.m. to 6 a.m. The PHS operates in turbining mode from about 9 a.m. to 4 p.m. to cover the peak of demand around noon every day.

The scenario in Figure 41 illustrates the base model storage behavior. Turbining happens twice as often as in the case before. Most of the pumping occurs on the weekend when demand and price is low. Obviously it can be argued that there is less volume in hydro energy in the base model scenario than in the other scenarios. This fact is shown with the green line in Figure 34.

In the scenario illustrated in Figure 42, a more often changing dispatch of storage content can be seen. Additional 50GW_{peak} of installed PV capacity are changing the PHS dispatch as already explained above. The state of charge is changing more often than in the other scenarios. This affects the amount of pumped and turbined water. The rising amount of turbined water is one factor of rising revenue for PHS.

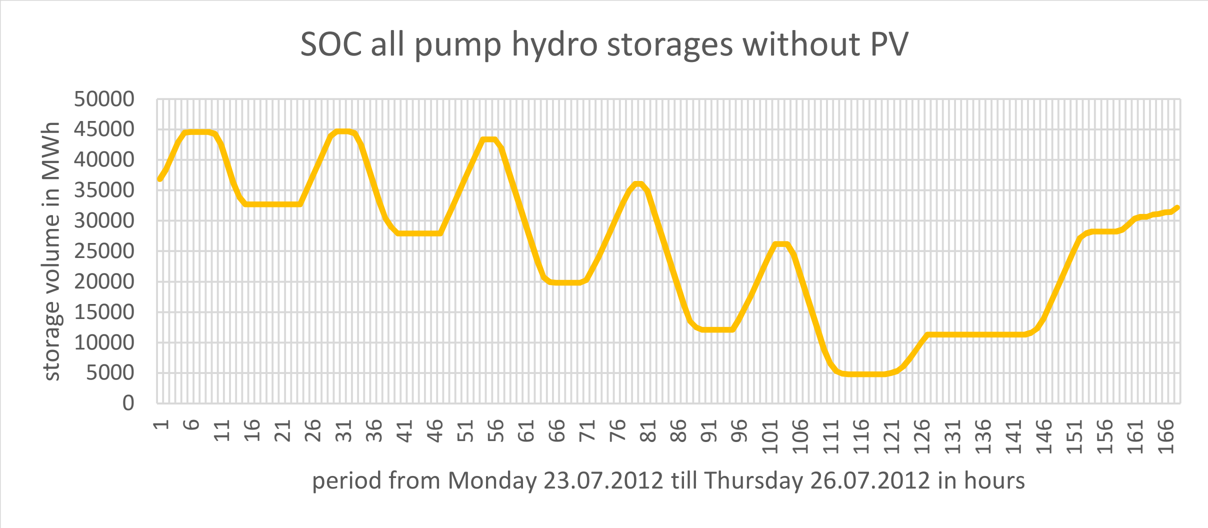

Figure 40: SOC for all storages without PV at CO_2 price = 7.4 €/tCO_2 (own illustration)

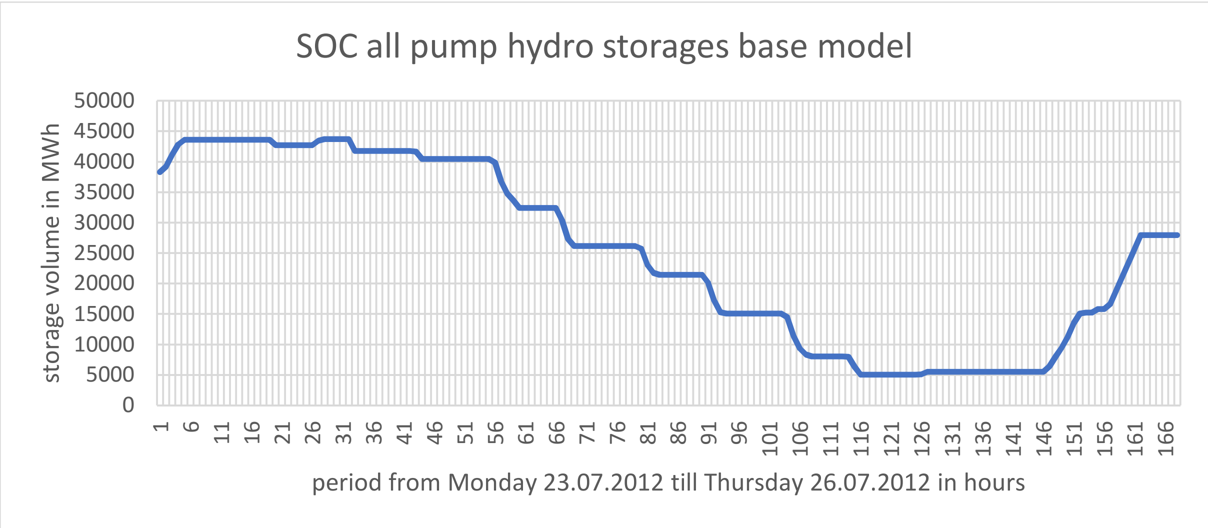

Figure 41: SOC for all storages base model at CO_2 price = 7.4 €/tCO_2 (own illustration)

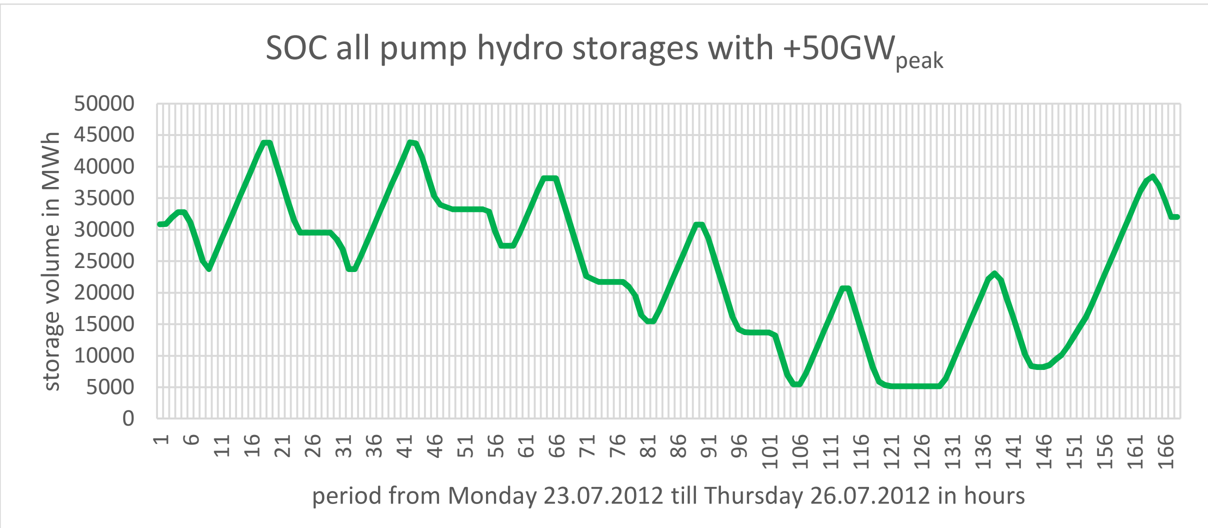

Figure 42: SOC for all storages with +50GW_{peak} at CO_2 price = 7.4 €/tCO_2 (own illustration)

4.5 Thermal dispatch

The production of thermal plants declines with raising PV capacity. The higher amount of PV infeed shifts the merit order, as already described, to the right. This results in a lower electricity price and a lower production of thermal plants at steady demand. Thermal production changes only marginal for different CO_2 prices. The difference in thermal production for rising CO_2 prices is one-hundredth of one per cent. Therefore, the results are presented for one CO_2 price scenario, p_{CO2} = 7.4€/tCO_2. According to the model, electricity production of thermal plants would decrease from 418TWh without PV infeed to 306TWh in the scenario with additional 200GW_{peak} installed PV capacity. This trend can be seen in Figure 43.

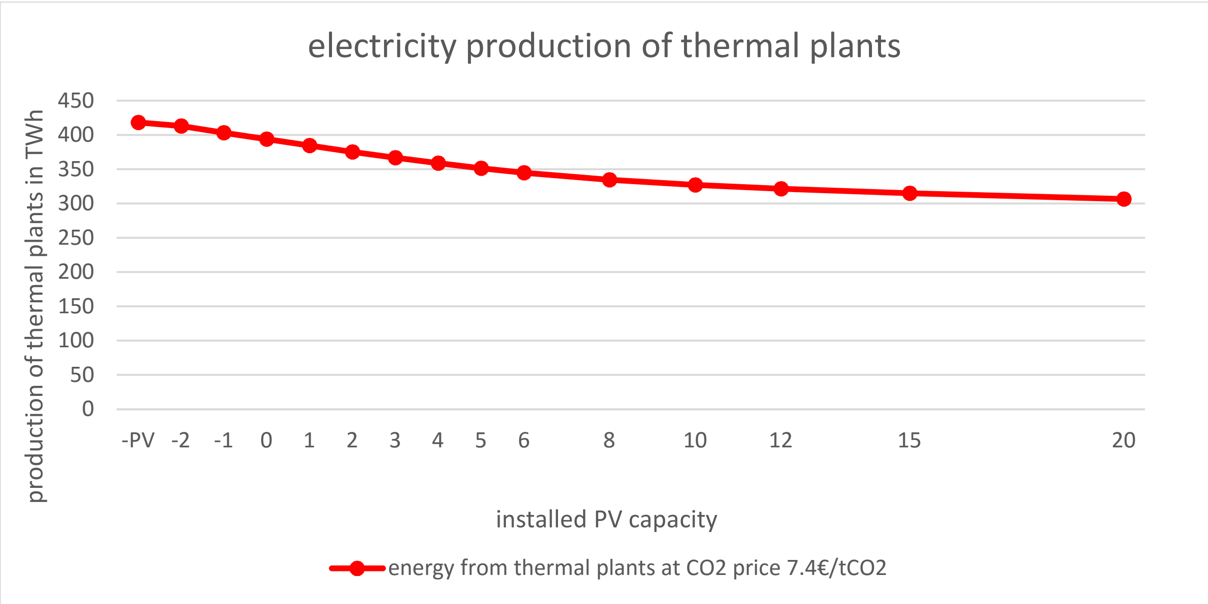

Figure 43 production of thermal plants with rising PV capacity (own illustration)

Figure 44 and Figure 45 are showing a more detailed picture of thermal electricity production in two different time periods of a year. The electricity output of all thermal plants is summarized to one characteristic. A typical summer day is presented Figure 44 and a typical winter day in Figure 45. It is obvious to see that thermal production shrinks if PV infeed rises. A minimum of thermal production is set in the model for several reasons. For example, heat demand and system stability are requiring a minimum of operating thermal plants. In the model this minimum of about 19.5GW is reached when PV infeed is high in summer. In winter, the minimum limit is reached not as often because of less PV infeed.

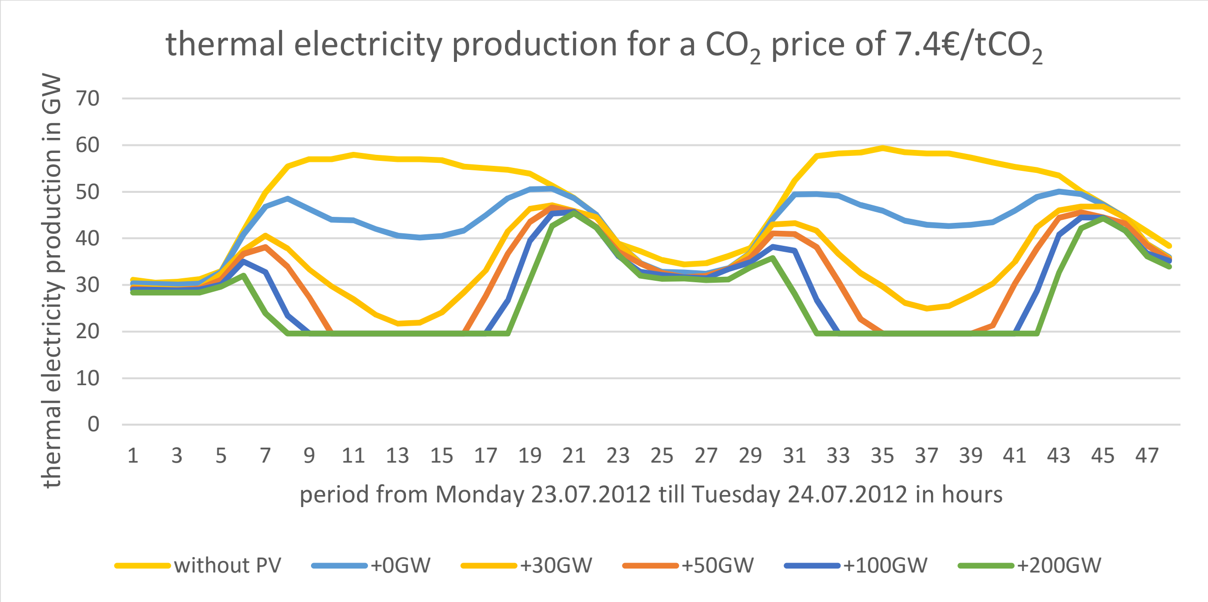

Figure 44 thermal electricity production for 48 hours in different scenarios - summer days (own illustration)

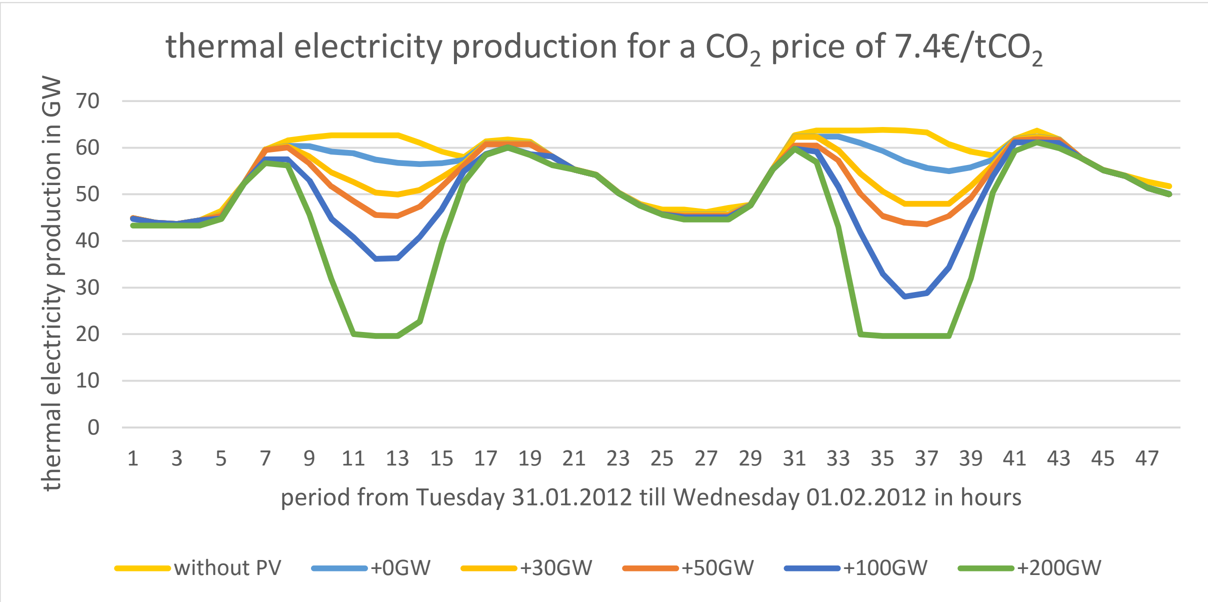

Figure 45 thermal electricity production for 48 hours in different scenarios - winter days (own illustration)

4.6 Results for other CO_2 prices

The results and explanations in chapter Hydro storage power plant dispatch are made for the scenario with a CO_2 price of 7.4€/tCO_2. To show how revenue of pump hydro storage power stations develops with higher CO_2 prices, other scenarios are derived from the model. Different output prices are the result for changing CO_2 prices. The model for optimization gets other input prices and so the storage profitability changes. The explanations in the chapter Hydro storage power plant dispatch are also valid for the other CO_2 price scenarios. A CO_2 price of 20€/tCO_2 and 70€/tCO_2 was chosen for comparison with the situation of a CO_2 price of 7.4€/tCO_2.

Figure 46 shows how the revenue would develop for the mentioned CO_2 prices in different PV penetration scenarios according to the model. In the base model the effect of higher CO_2 prices is minimal. With rising PV capacity, the model predicts an increase in revenue for a CO_2 price of 20€/tCO_2 and 70€/tCO_2. With lower PV capacity than in the base model, the model predicts a different behavior. It comes out that revenue for a CO_2 price of 20€/tCO_2 and 70€/tCO_2 would decrease at lower shares of PV infeed. The chart in Figure 46 shows the declared results.

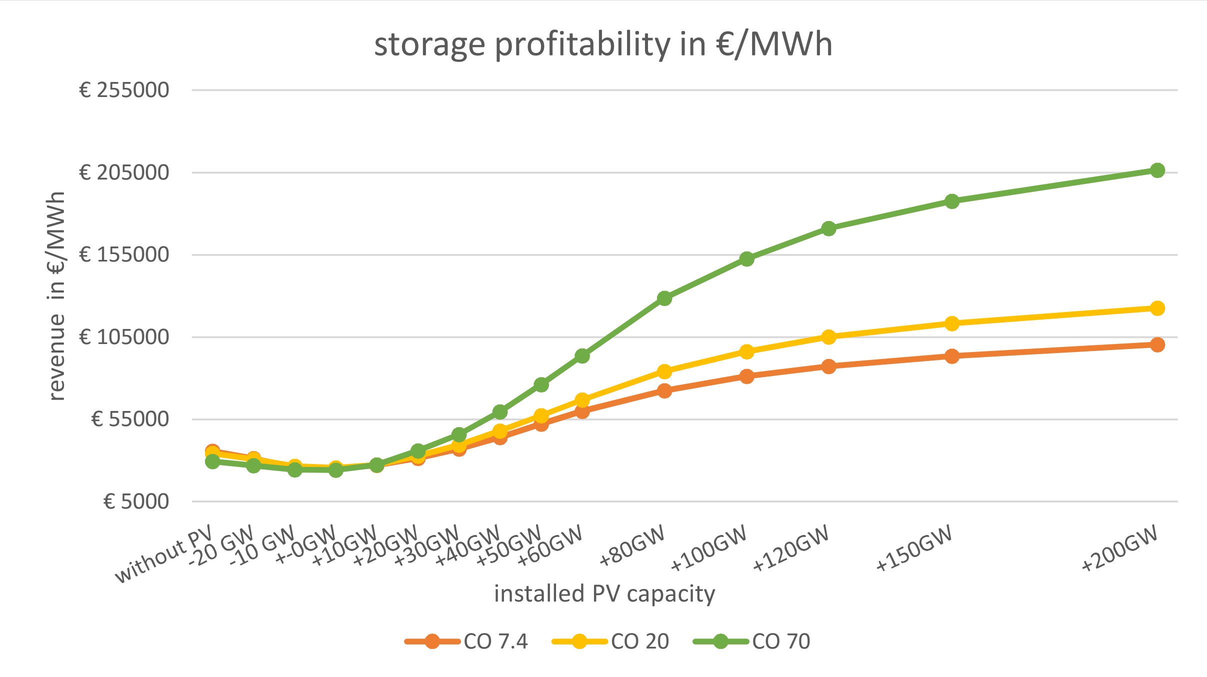

Figure 46: storage profitability with rising PV capacity for different CO_2 prices (own illustration)

This result can be characterized by two factors, the price spread and the amount of turbined energy. Figure 47 shows the price spread for a year in the considered scenarios and Figure 48 illustrates the electrical energy amount that is produced by the pump hydro storage power plants in one year for the considered scenarios. The development of the price spread in case of a CO_2 price of 7.4€/tCO_2 was explained in the chapter Calculation of price spread. The level of the price spread develops differently with other CO_2 prices.

In case of 20€/tCO_2, the scenario in comparison to the case of 7.4€/tCO_2 is similar. The level of price spread is slightly higher at low PV capacity scenarios and considerably larger at scenarios with higher PV capacity. In case of a CO_2 price of 70€/tCO_2, the progression of price spread in comparison to the case of 7.4€/tCO_2 and 20€/tCO_2 is also related. At lower PV share, the spread is marginally higher than in the other cases, but in higher PV capacity scenarios, the spread is significantly higher. The calculated price spreads for the modelled scenarios are shown in Figure 47.

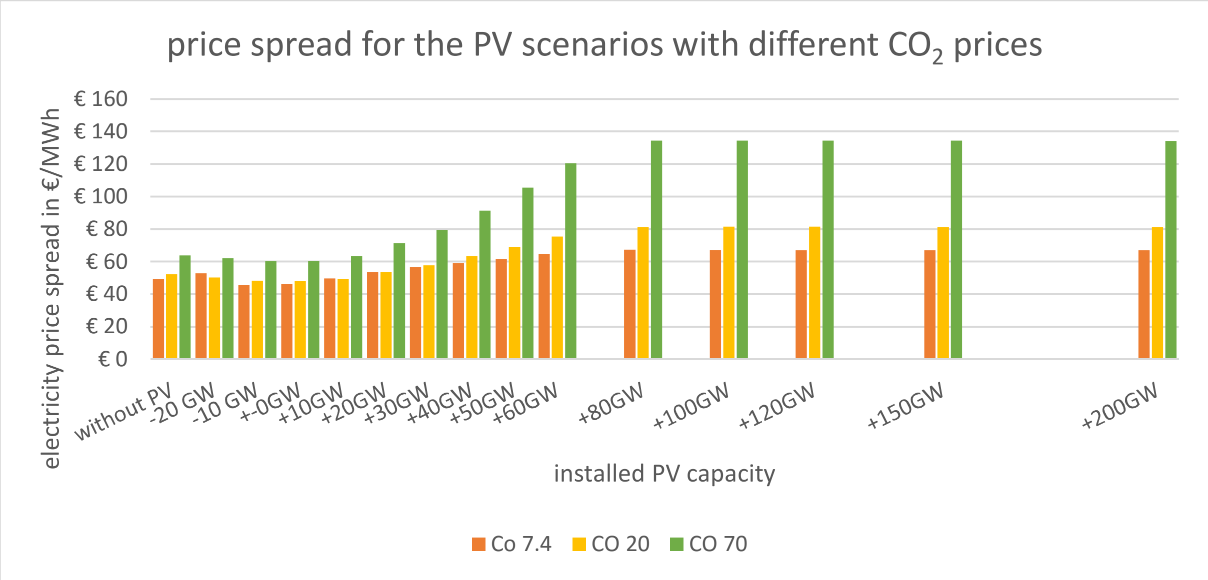

Figure 47: price spread with rising PV capacity for different CO_2 prices (own illustration)

The reason for the differently illustrated price spreads can be found in the changing merit order due to a varying CO_2 price. Due to the marginal costs of thermal plants the electricity price is rising in consequence of a higher CO_2 price. In the merit order, lignite and coal plants are having partly higher costs than combined cycle gas plants at a CO_2 price of 20€/tCO_2 or 70€/tCO_2. The nuclear plants and the renewable energies are not affected by CO_2 price change. As a result of that, the price spread rises with higher CO_2 prices. This effect would get boosted if there was more installed PV capacity. The reason for that is the infeed of electricity with marginal costs equal to zero. This affects the merit order as already mentioned in chapter 2.2. Moreover, price spread cannot get much higher due to the fact that the average minimum of electricity prices in a year cannot get lower than zero. The average maximum of electricity prices does not change considerably in cases of higher amounts of installed PV capacity. The merit order is quite flat in the price forming region. Therefore, the higher and lower average prices cannot change anymore in big steps and so the price spread stays quite constant at high PV penetration levels.

The behavior of price spread is only one part of the reason for the development of revenue at different CO_2 prices. The electricity amount that is produced by PHS in one year develops as presented in Figure 48. The quantity of electric energy that is produced by all pump hydro storage power plants matters for the sum of revenue. The trend in Figure 48 shows how the quantity of electric energy for turbining develops. The quantity decreases with rising CO_2 prices and the progress is nearly the same for different PV infeed scenarios.

As outlined before, the merit order is quite flat in the price forming region at higher CO_2 prices. Lignite and coal power plants are at CO_2 prices of 70€/tCO_2 in the same price region as combined cycle gas plants. This leads to a relatively flat merit order and smaller price differences in the price forming area. Because of this situation, the model decides that it is the optimal dispatch to activate another thermal plant instead of a pump hydro storage plant. This is why the amount of energy through PHS decreases for higher CO_2 prices.

The trend of price spread and the amount of turbined energy leads to the revenue result for different CO_2 prices in Figure 46.

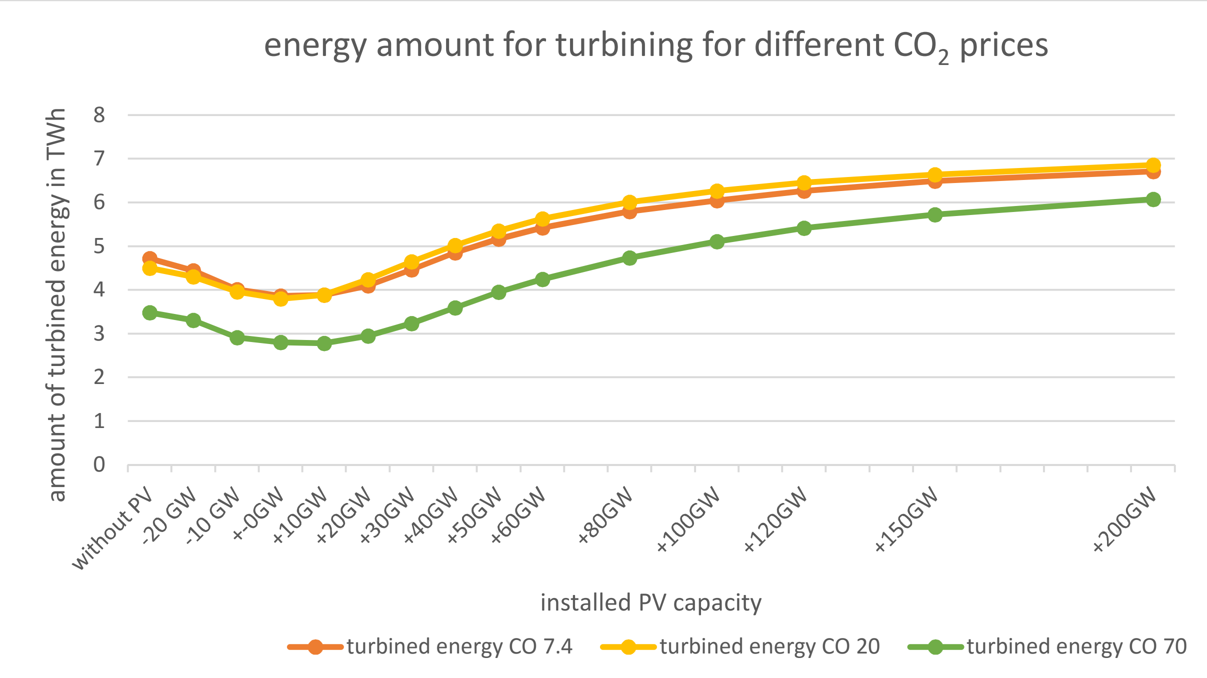

Figure 48: amount of turbined electricity for different CO_2 prices (own illustration)

4.7 Revenue for different storage volumes

The optimization of revenue was done by the model for different sizes of storages. The following figures are based on a CO_2 price of 7.4€/tCO_2. Explanations are valid for other CO_2 price scenarios. As mentioned in chapter 2.5, storages operate in different cycles corresponding to their volume. The proportion between volume and plant power results is a number of hours in which the storage can be discharged. According to this, storages are classified in daily-, weekly-, and annual-reservoirs. In the model, storages with 4 and 8MWh are working as daily-reservoir. A storage of 200MWh operating as weekly-reservoir and a storage with 2000MWh operating as annual-reservoir is used for modelling. A modelled turbine power of 1MW leads to the mentioned number of hours.

Figure 49 displays the revenue for different storage volumes based on a CO_2 price of 7.4€/tCO_2. Four PV capacity scenarios are chosen to show the revenue for different PV infeed and storage volumes. Basically it is clear that a bigger storage volume will earn more revenue than a smaller one because of the larger amount of energy that can be sold. More flexibility in turbining and pumping dispatch is possible because of bigger storage volume. The difference in revenue for changing installed PV capacity was explained in the previous section. Storage profitability is optimized by the model for different storage volumes. The result is shown in Figure 49.

This trend in revenue cannot be interpreted as the best economic solution. There are no construction, operating or service costs included. The difference in revenue for daily reservoirs with 4 and 8 hours of storage capacity occurs because of more available storage volume that can be used. The revenue does not double for two times the storage size. A basic constraint is to cover electricity demand. A daily reservoir settles the interferences for a few hours or one day and therefore contributes to load distribution. With rising storage volume, less amount of energy in relation to full storage volume is moved by pumping and turbining. This is why the optimized revenue develops as shown in Figure 49. Weekly or annual reservoirs can balance longer lasting fluctuations in addition to the daily variability. This leads to a higher revenue. The differences in changing PV capacity scenarios is reasonable in price development.

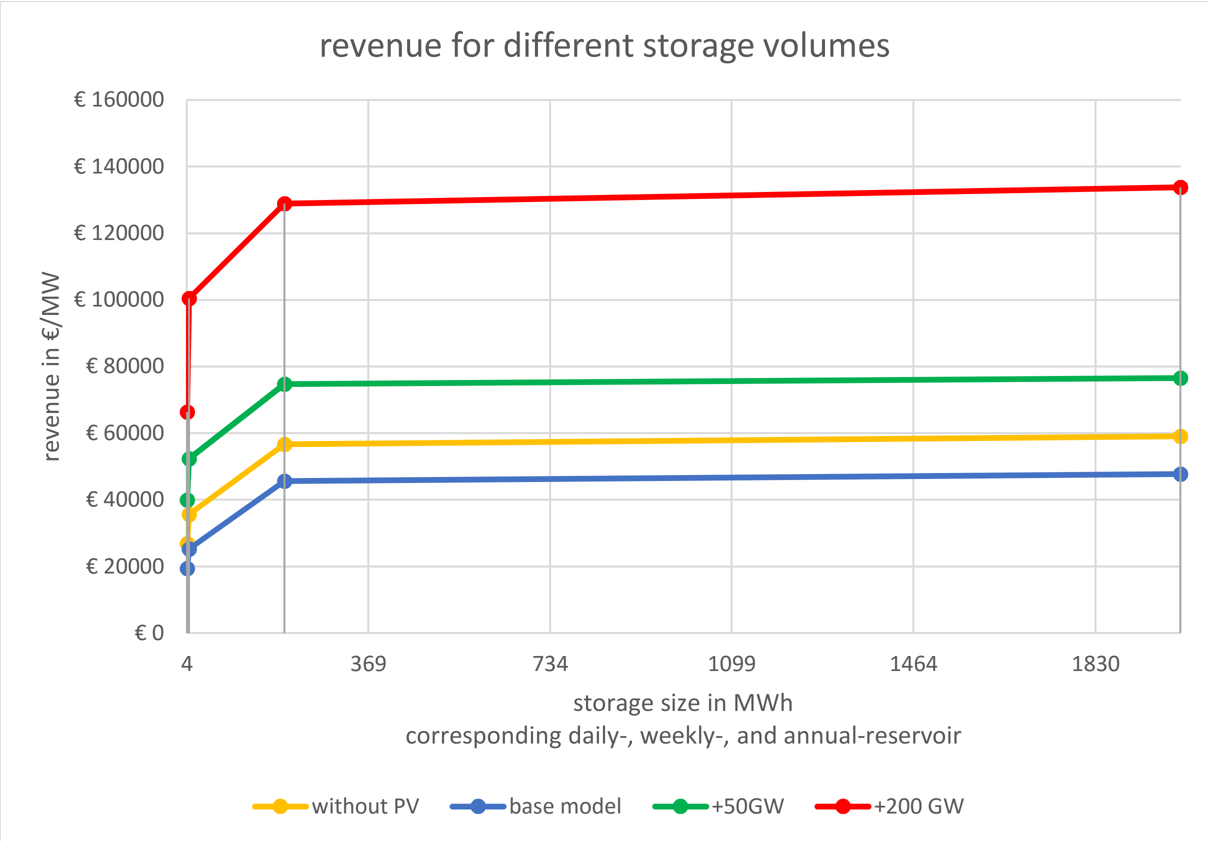

Figure 49: revenue for different storage sizes at CO_2 price = 7.4 €/tCO_2 (own illustration)

5 Conclusion

The method of approach was to build a linear dispatch model that represents the electricity market in Austria and Germany in MATLAB. The electricity price on an hourly resolution is derived from the model. This progress was made for varying installed PV capacity and different CO_2 prices. Using the electricity prices for the different scenarios as input, a second model optimizes the revenue for pump hydro storage plants. The profitability model for revenue optimization applies linear programming. Because of simplified assumptions and general uncertainties in the electricity price generating model, the result is not exactly equal to the real historic prices. This inaccuracy is no problem for the further analysis of results because it can be seen as an offset difference for all scenarios. Therefore, the chosen method and applied models are suitable for this theses.

The core awareness of this thesis is that starting without installed photovoltaic capacity, the revenue for pump hydro power storage plants decreases with raising photovoltaic capacity. Around the photovoltaic infeed level of the base year 2012, revenue reaches its lowest level. With further rising of photovoltaic capacity, revenue increases again.

Different prices for CO_2 emissions from thermal plants are affecting the revenue. The combination of higher CO_2 prices and rising photovoltaic infeed leads to a higher revenue according to the model. In scenarios without photovoltaic infeed, higher CO_2 prices are decreasing the revenue slightly. The price spread of the modelled electricity price and the produced amount of electricity from pump hydro storage power plants are leading to the development of revenue.

The number of hours with an electricity price equal to zero rises with increasing photovoltaic capacity. This is a main reason for the growth of price spread. The average of the highest prices of a year does not change considerably, but the average of the lowest prices of a year is falling because of the high number of hours with an electricity price equal to zero.

Electricity production by thermal plants decreases with rising photovoltaic infeed. Due to the merit order effect, thermal plants are crowded out. This behavior flattens and remains constant at the highest photovoltaic penetration scenarios. Moreover, system stability requires a minimum of operating thermal plants.

The optimization of revenue was done by the model for different storage volumes. Based on the modelled electricity price, revenue is optimized for storage operating as daily-, weekly-, and annual-reservoir. There is a significantly higher revenue between the modelled daily- and weekly-reservoirs. The revenue of the annual-reservoir is only slightly higher, compared to the higher storage volume, as for the weekly-reservoir.

According to the model it is clear that starting at the market situation in 2012, raising installed photovoltaic capacity will increase the revenue of pump hydro storage power plants. A higher CO_2 price would expand this effect and reduce thermal plant dispatch. From the current situation, 200GW_{peak} additional photovoltaic capacity for Austria and Germany is not realistic, but these high infeed scenarios are illustrating an outlook for what could happen.

The results of the models are explaining the decrease in revenue for pump hydro storage plants in the last years. The installed photovoltaic capacity in the last decade raised from zero to the $25GW_{peak}$ at the beginning of 2012. The model depicts that the revenue without PV infeed would be higher than in the base scenario of 2012. This result corresponds with the real historic behavior. This fact and the true assumption of the development of revenue leads to the conclusion that the modelled performance of revenue for pump hydro storage power plants is a valid estimation.

This development of revenue cannot be interpreted as the best economic solution. An analysis of e.g. construction, operating or service costs and much more would be required to get an evaluation for the best economic solution for operating a pump hydro thermal plant. For further explorations of this topic, additional scenarios with other changing circumstances can be analysed.

6 Appendix

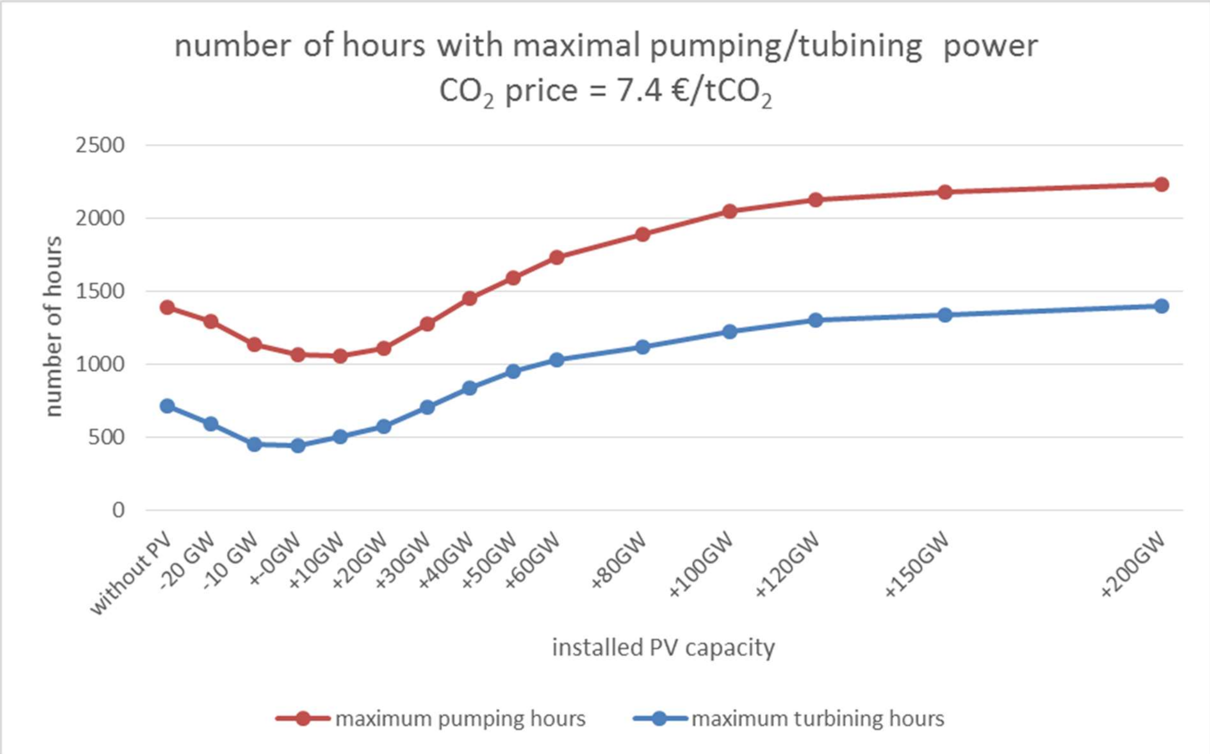

Figure 50: number of hours with maximal pumping/turbining power
at CO_2 price = 7.4 €/tCO_2 (own illustration)

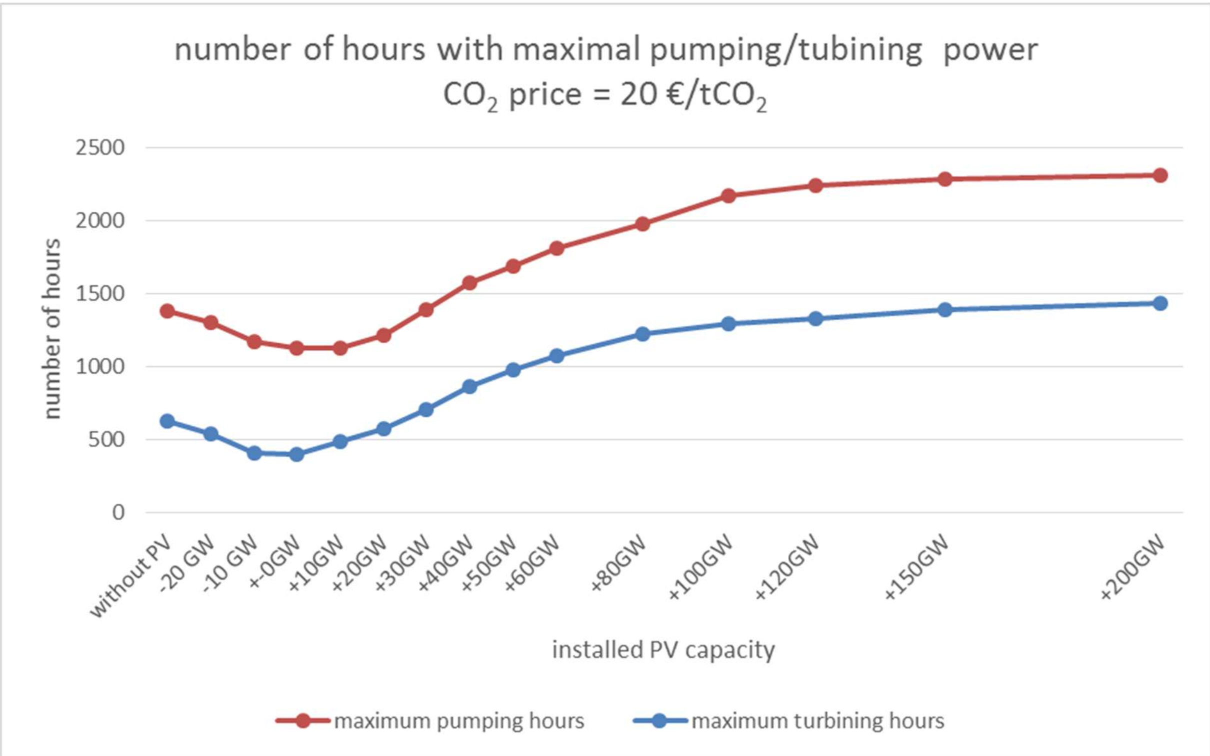

Figure 51: number of hours with maximal pumping/turbining power
at CO_2 price = 20 €/tCO_2 (own illustration)

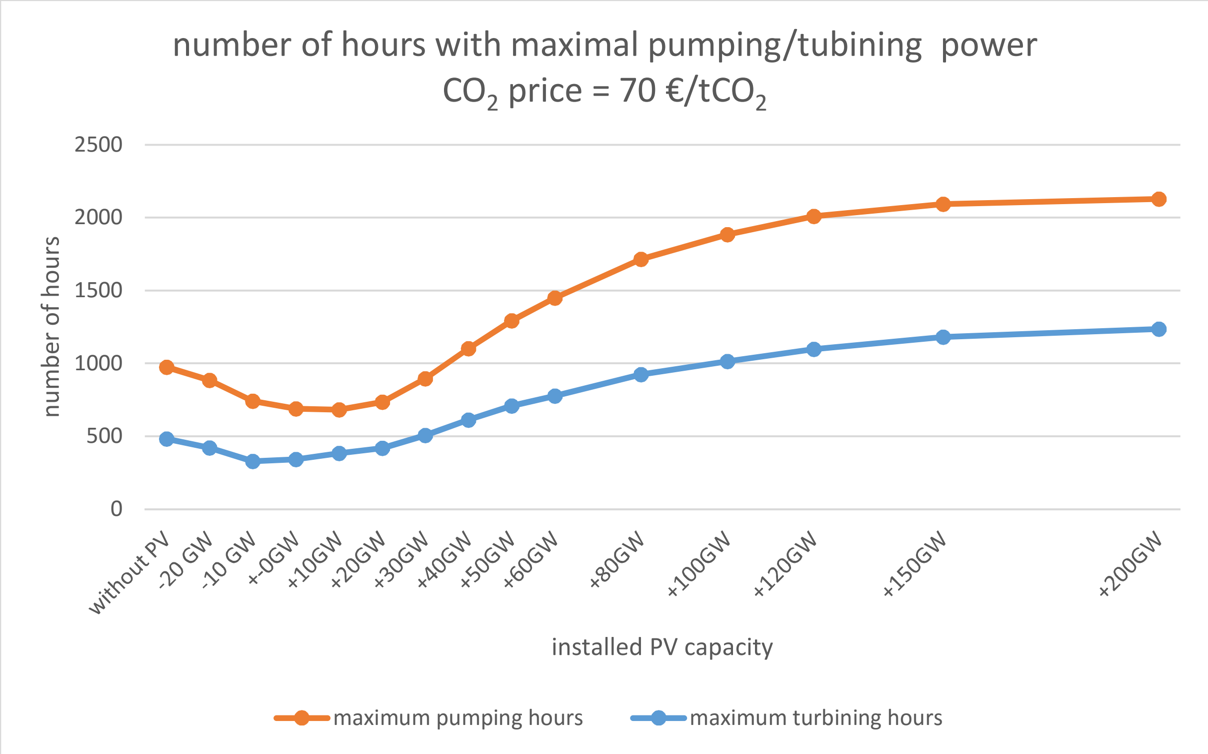

Figure 52: number of hours with maximal pumping/turbining power
at CO_2 price = 70 €/tCO_2 (own illustration)

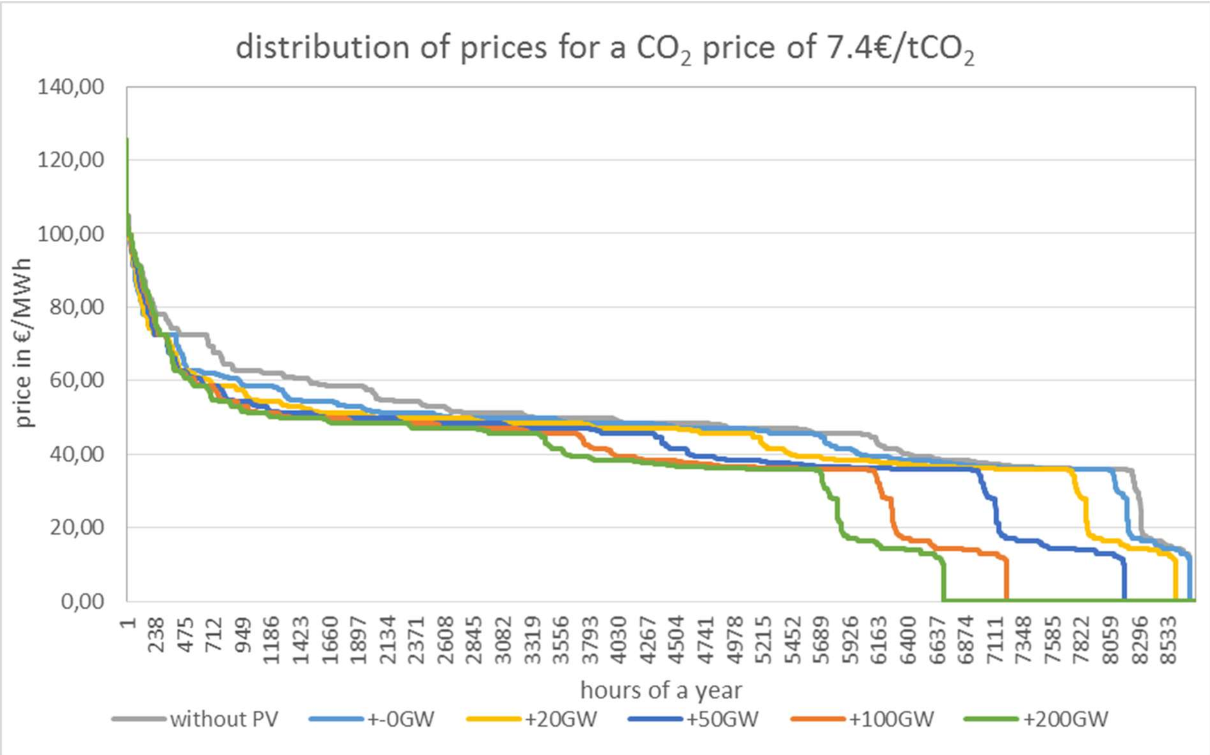

Figure 53: price period line different scenarios
at CO_2 price = 7.4 €/tCO_2 (own illustration)

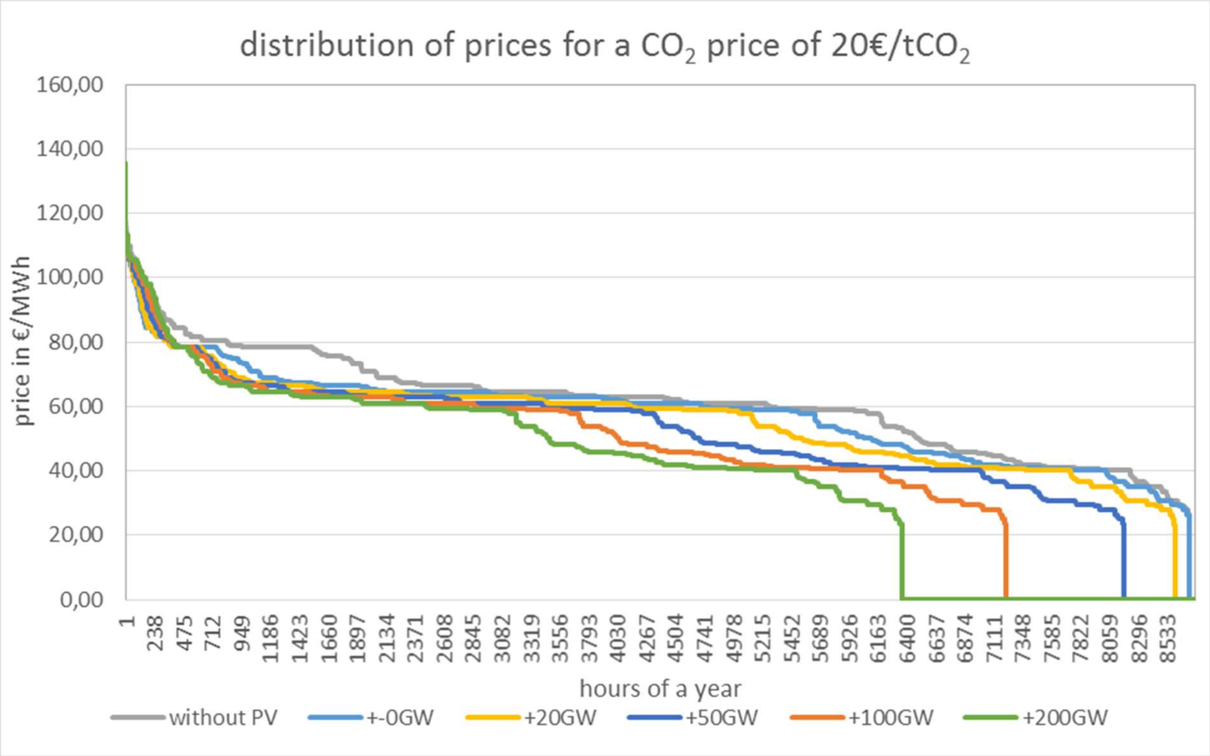

Figure 54: price period line different scenarios at CO_2 price = 20 €/tCO_2 (own illustration)

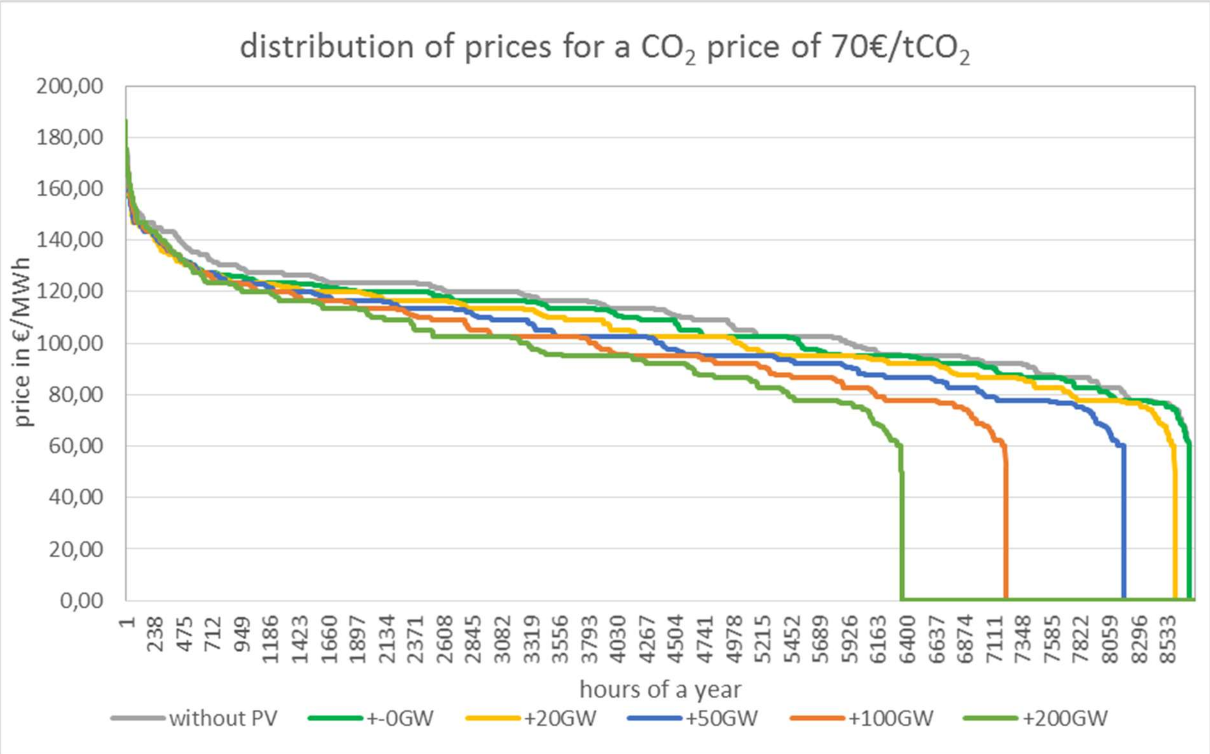

Figure 55: price period line different scenarios at CO_2 price = 70 €/tCO_2 (own illustration)

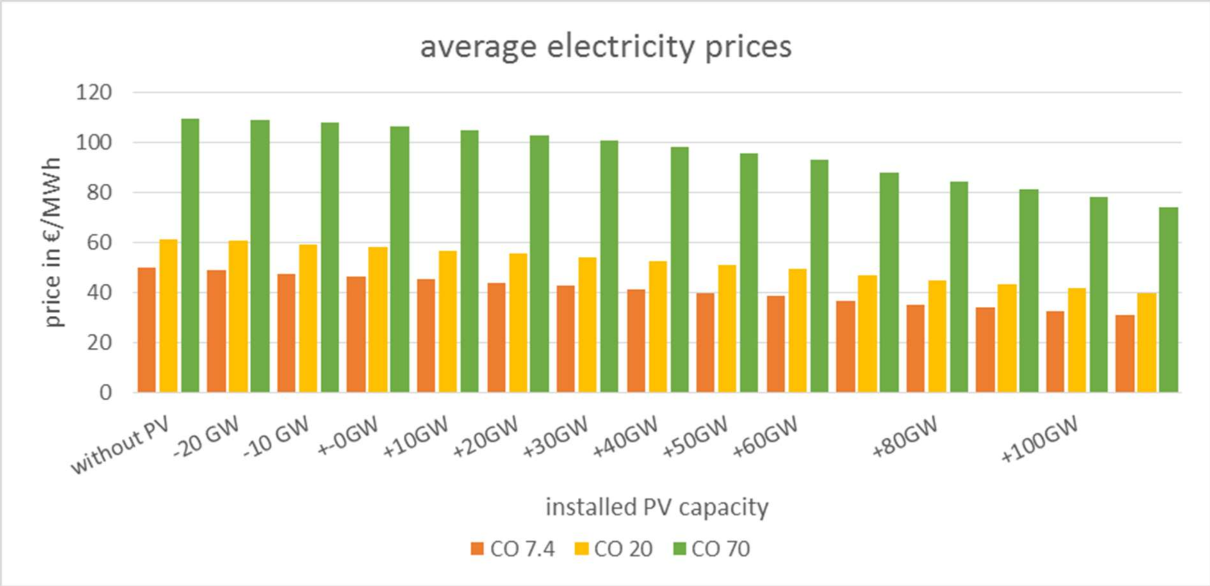

Figure 56: average electricity price for a year in different scenarios (own illustration)

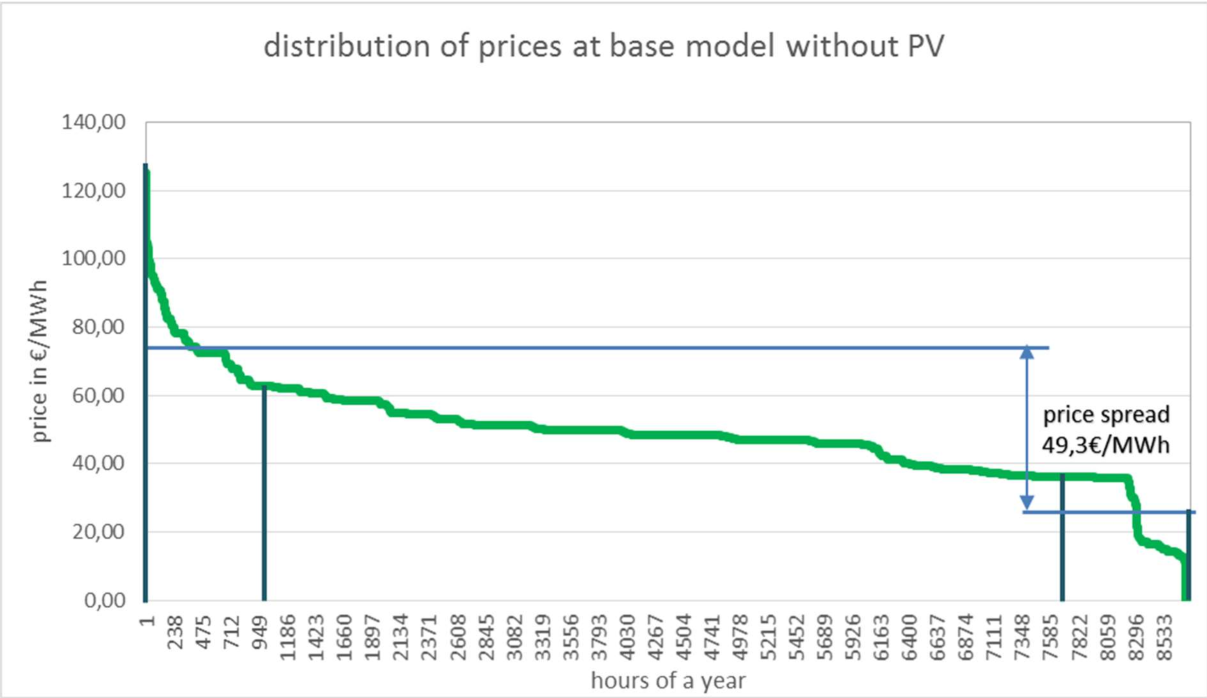

Figure 57: price period line base model for without PV scenario
at CO_2 price = 7.4 €/tCO_2 (own illustration)

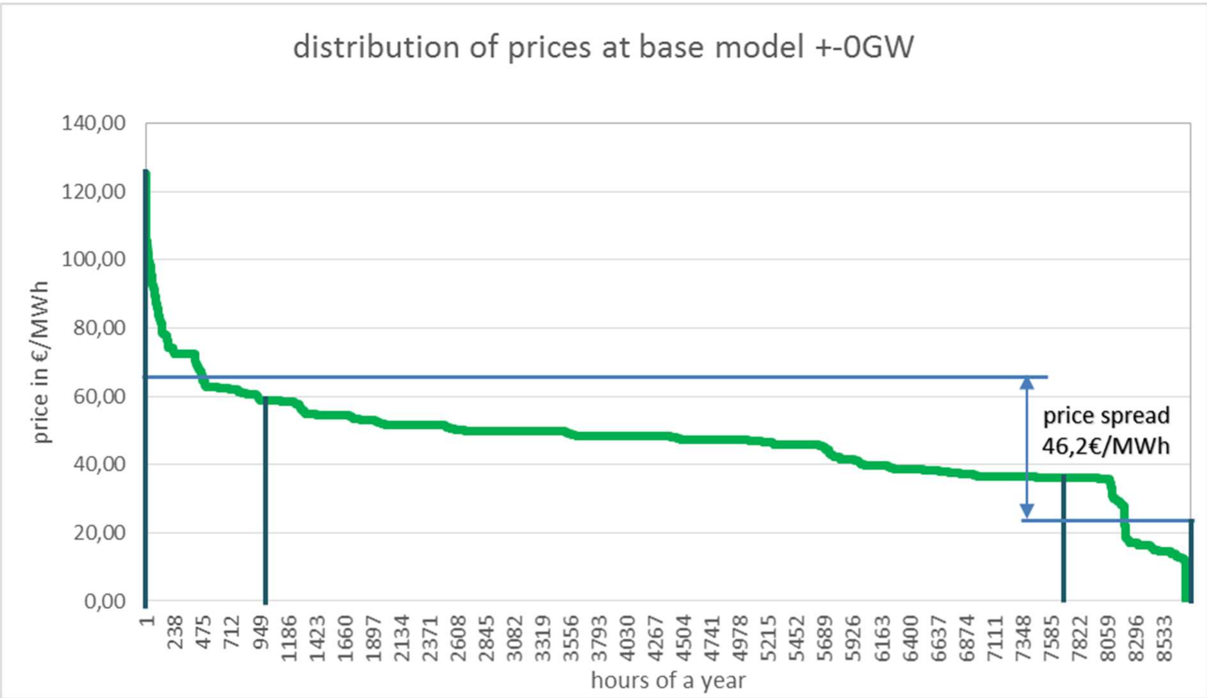

Figure 58: price period line base model for base model
at CO_2 price = 7.4 €/tCO_2 (own illustration)

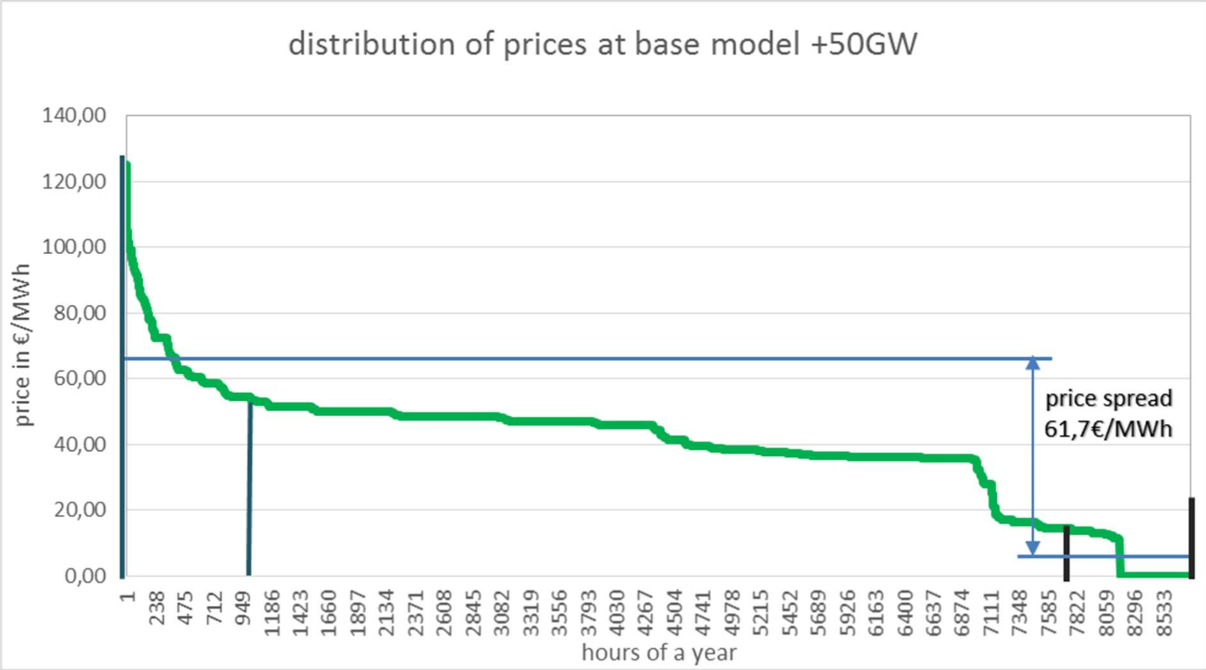

Figure 59: price period line base model for +50GW_{peak} scenario at CO_2 price = 7.4 €/tCO_2 (own illustration)

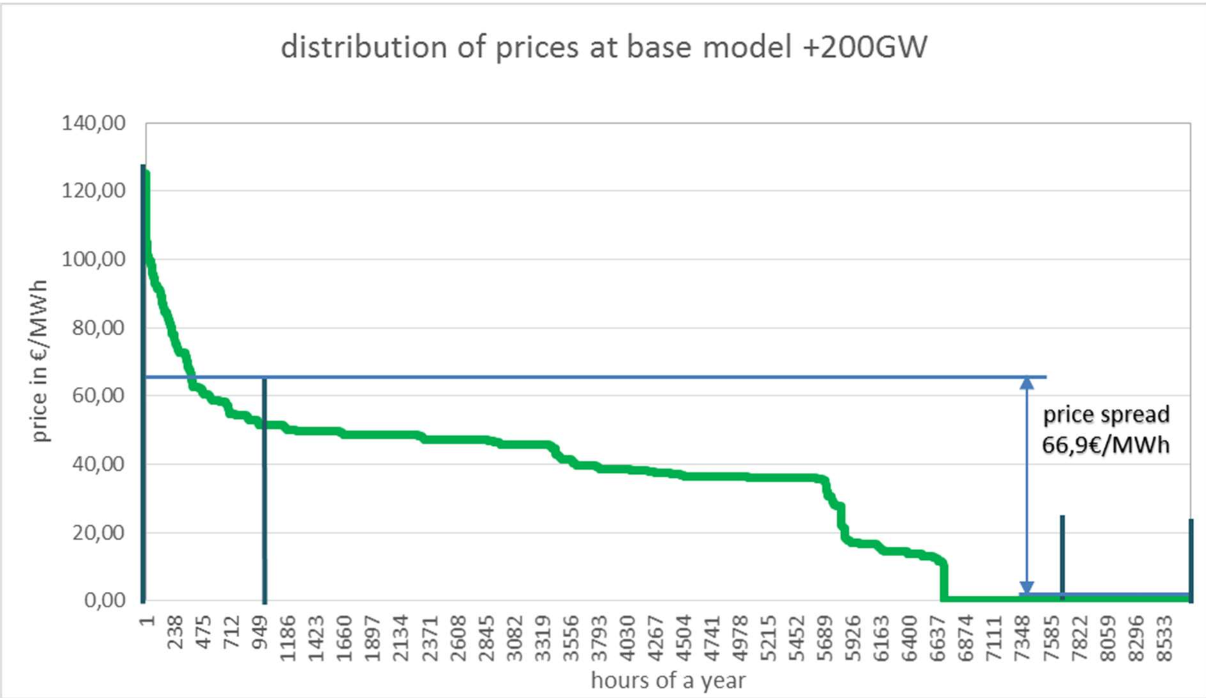

Figure 60: price period line base model for +200GW_{peak} scenario at CO_2 price = 7.4 €/tCO_2 (own illustration)

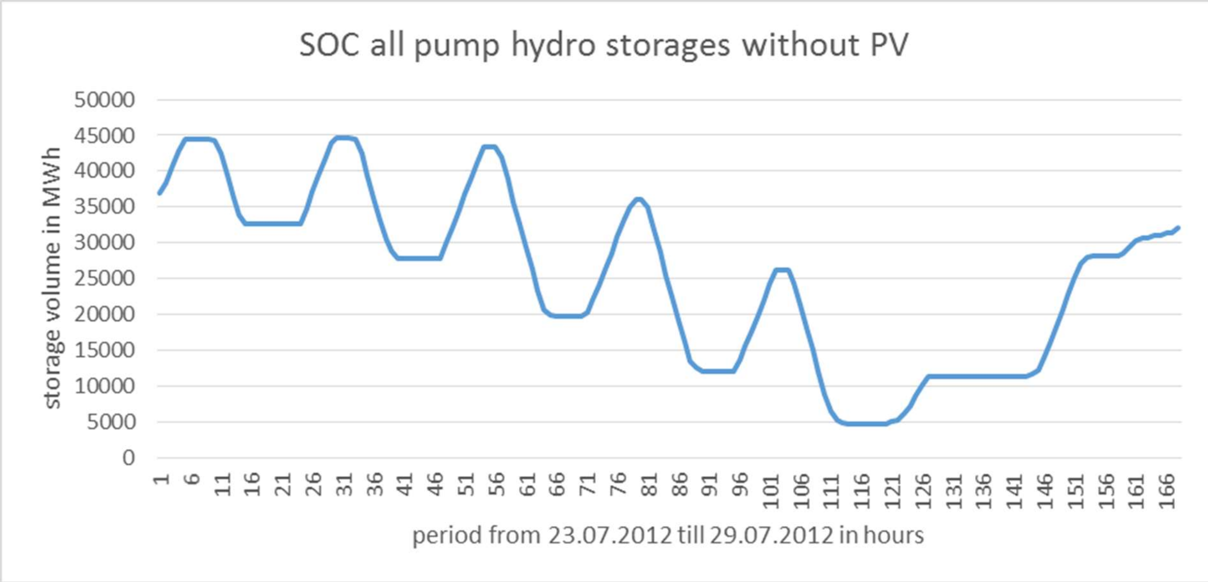

Figure 61: SOC for all pump hydro storages without PV at CO_2 price = 7.4 €/tCO_2 (own illustration)

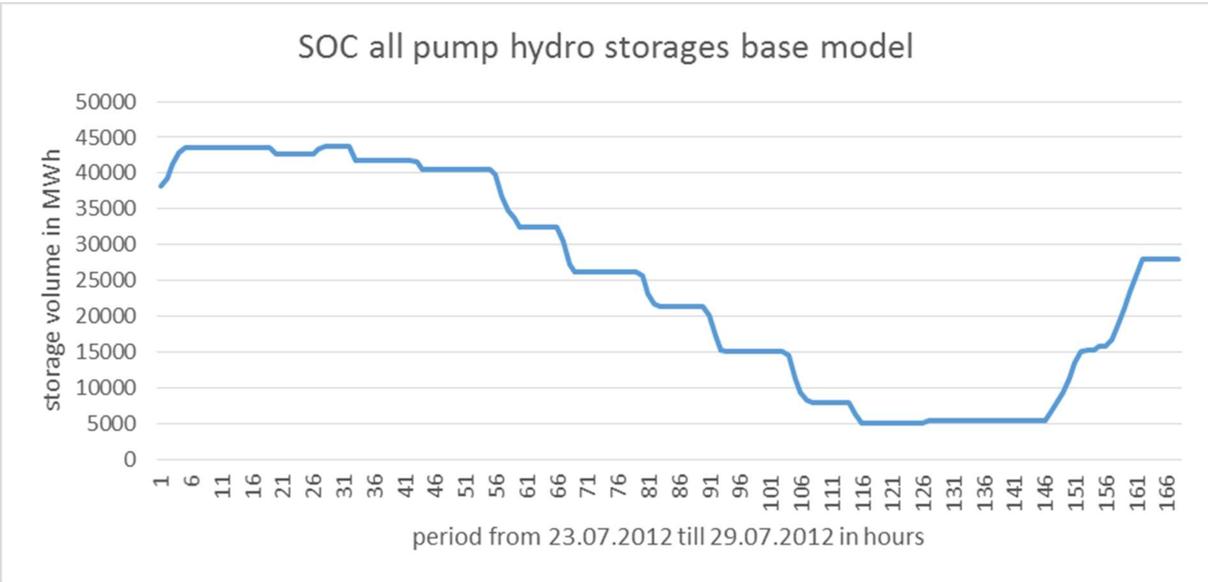

Figure 62: SOC for all pump hydro storages base model at CO_2 price = 7.4 €/tCO_2 (own illustration)

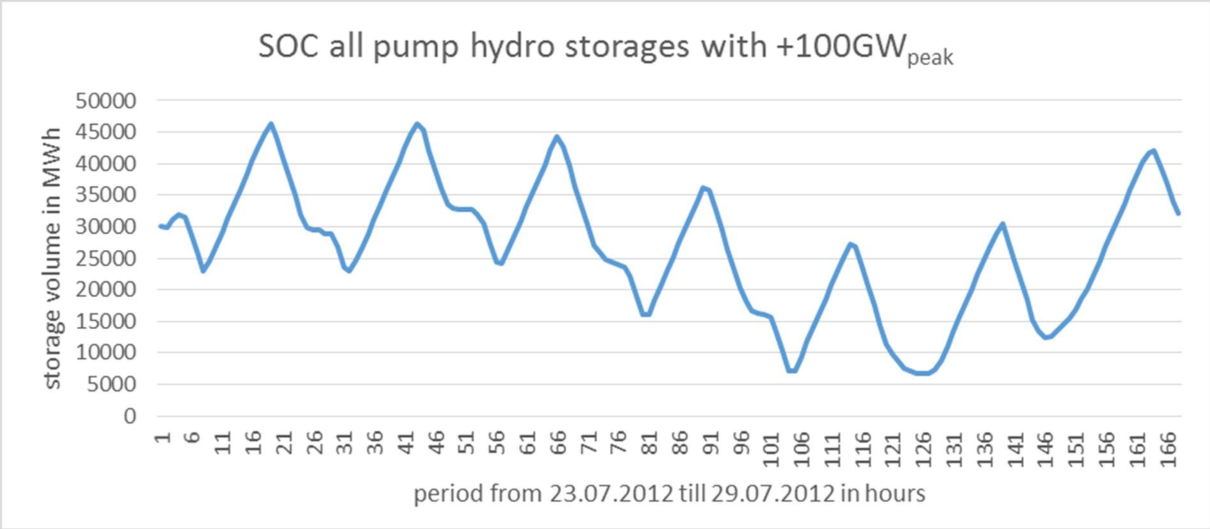

Figure 63: SOC for all pump hydro storages with +100GW$_{peak}$ at CO_2 price = 7.4 €/tCO_2 (own illustration)

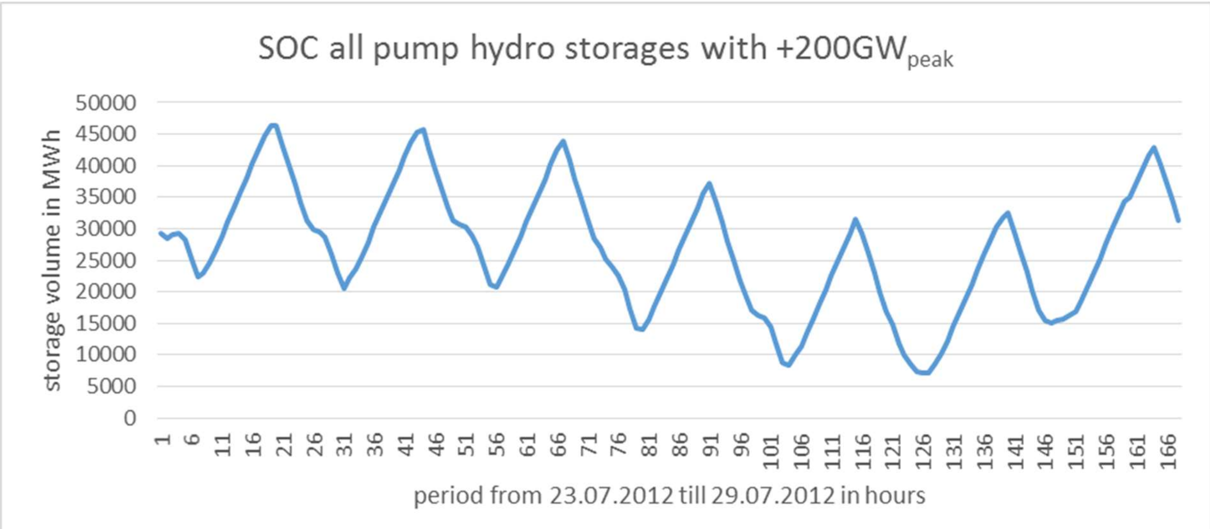

Figure 64: SOC for all pump hydro storages with +200GW$_{peak}$ at CO_2 price = 7.4 €/tCO_2 (own illustration)

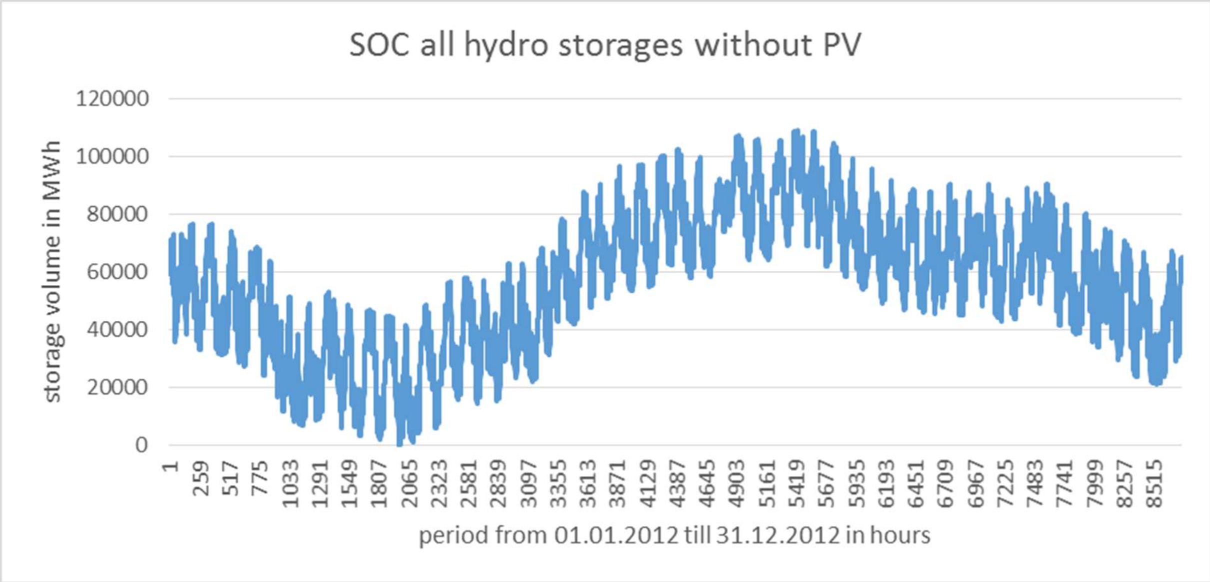

Figure 65: SOC for all storages without PV full year at CO_2 price = 7.4 €/tCO_2 (own illustration)

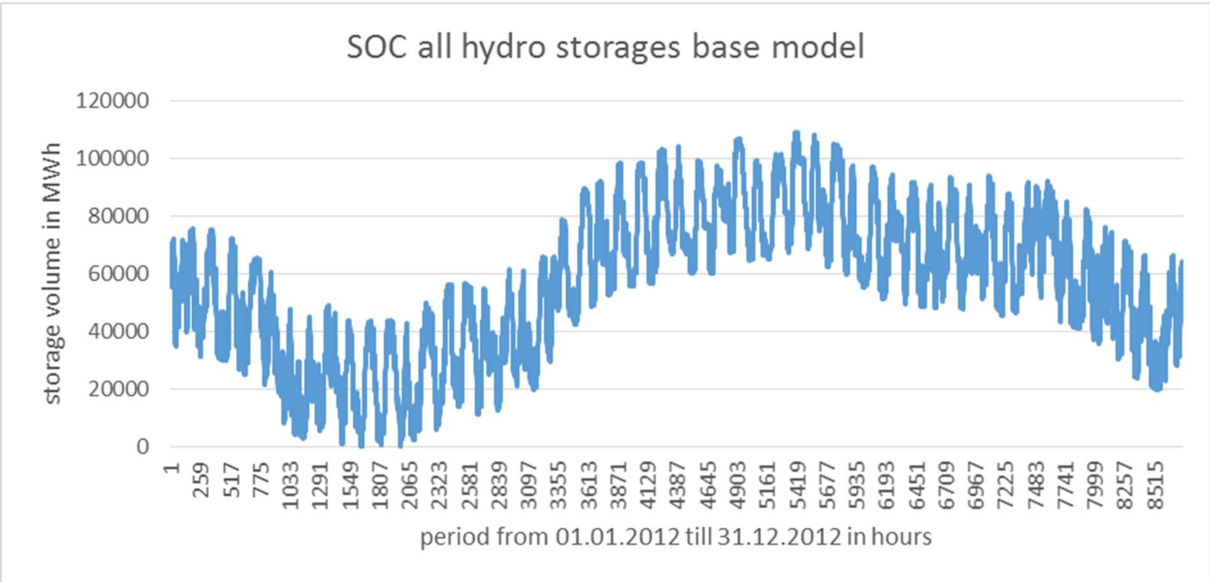

Figure 66: SOC for all storages base model full year at CO_2 price = 7.4 €/tCO_2 (own illustration)

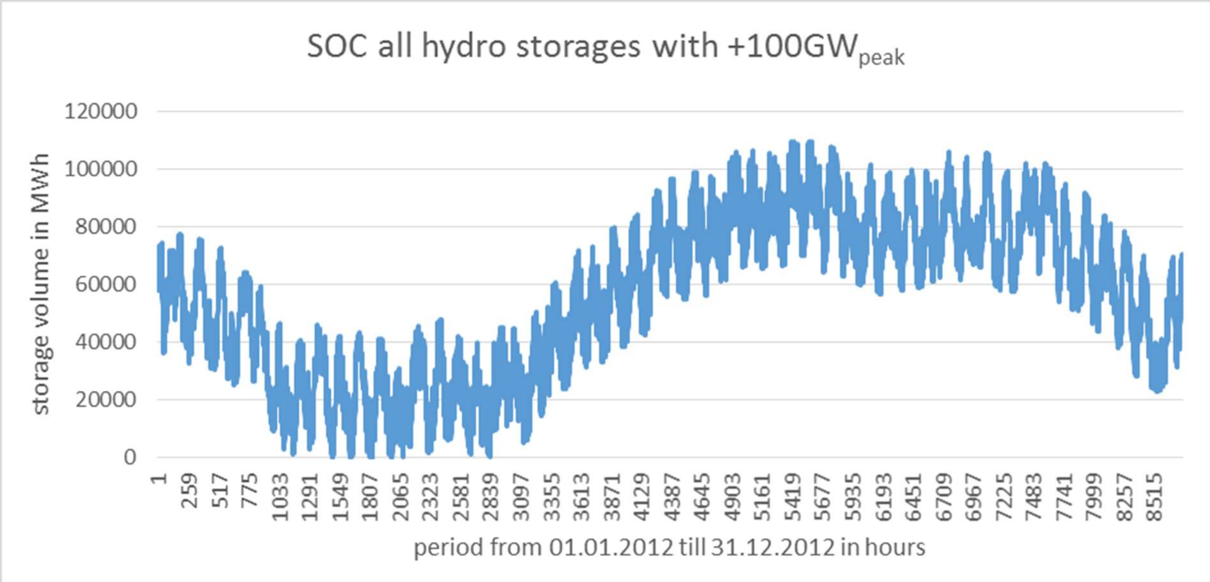

Figure 67: SOC for all hydro storages with +100GW$_{peak}$ full year at CO_2 price = 7.4 €/tCO_2 (own illustration)

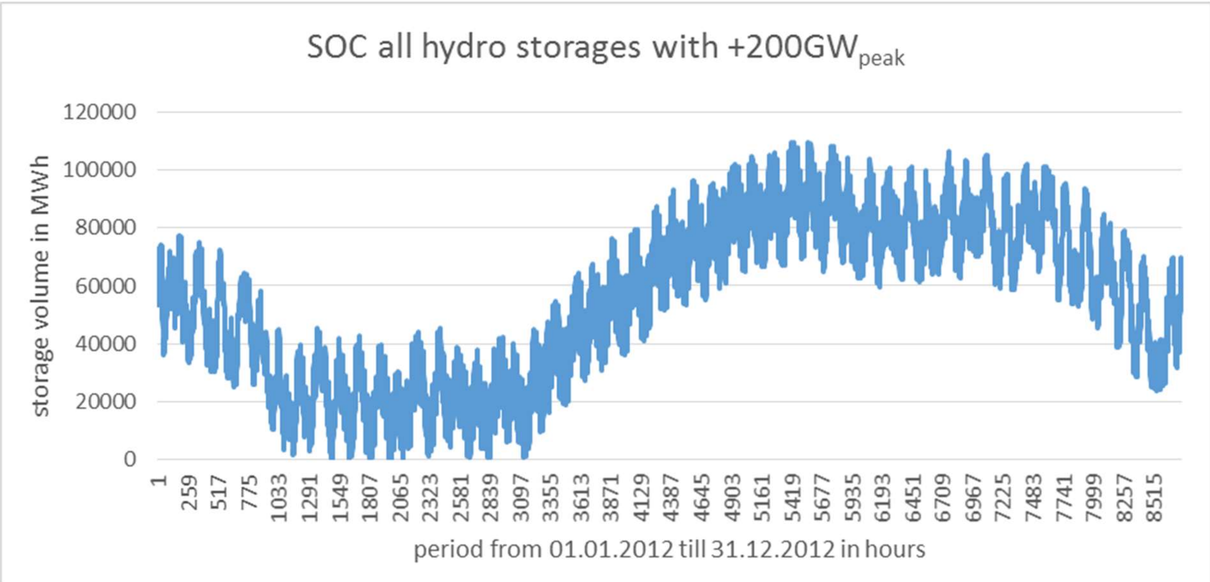

Figure 68: SOC for all hydro storages with +200GW$_{peak}$ full year at CO_2 price = 7.4 €/tCO_2 (own illustration)

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