Delft University of Technology

Electricity and Gas: Market Design and Policy Issues
SEN1522

Modelling Assignment: Final Report

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Contents

1 Introduction

The market for electrical energy is a complex structure, which operation is dependent on physical and economical constraints. In order to combat climate change, the electricity sector is seen as a key driver for transitioning towards a low carbon energy supply. However, this transition poses new physical and economical challenges on the operation of the electricity system. In Germany the energy transition (ger. Energiewende) has long been enforced by policy. However, with the last legislation of the law for climate protection (ger: Klimaschutzgesetz), in combination with the law for renewable energy (Erneuerbare Energien Gesetz) the German government has set out once again ambitions target for building up the capacity of renewable energy power plants, particularly focusing on wind and solar pv (Erneuerbare Energien Gesetz 23 n.d.; Klimaschutzgesetz 23 n.d.). In consequence to the upcoming high penetration of renewable energy generation in the German electricity system, calls for policy intervention get louder and measures like bidding zone splits within Germany is discussed in research.Egerer, Weibezahn, and Hermann 2016

The understanding of the economic operation of the electricity market is vital for further investigation of the consequences of shifting towards low carbon energy supply and the impact of policy intervention. The fundamental concept for market driven short term operation is the economic dispatch. The concept economic dispatch incorporates a) the physical constraint that generated power needs to match the demand at every single moment and a) the economic objective of cost minimisation.

In this report a hourly dispatch model is presented for Germany, in order to investigate the physically constrained and economically efficient operation of the electricity system.Moreover, the following additional research questions are under investigation:

1. *What are the consequences in the Germany electricity market regarding the targets for installed renewable capacity in 2030 as stated by latest German latest federal legislation (Klimaschutzgesetz)?*
2. *What impact is generated by bidding zone split of German electricity bidding zone into north and south, taking into account high renewable penetration in prospected 2030 scenario as stated by Klimaschutzgesetz?*

The remainder of this report is structured as follows. Chapter 2 gives insight into the used methodology used for modelling the hourly dispatch and presents the scenarios under investigation. Chapter 3 presents the consequent analysis, followed by a conclusion in chapter 4.

2 Methodology and Scenarios under Investigation

2.1 General Methodology

For optimisation of the economic dispatch problem a linear programming model is used. However, strong assumptions have to be made to assume linearity. More realistic, non-linear, hourly dispatch model is out of the scope of this report.

To follow better the investigation, we need to define the variables and parameters of the model: We divide the electricity generation into conventional generation, performed by generators, that have a certain power output $G_{i,t}$, and the fluctuating renewable energy output PV_t and W_t, for solar pv and wind generation respectively. We take the generation of renewable energy as given, so that we can only influence the generation of conventional power plants as a decision variable. However, each conventional power plant is bound to its minimum and its maximum power output (G_i^{max}, G_i^{min}).

We also introduce energy storage systems in form of battery energy storage system (BESS) and hydro energy storage system (hydro) as a way to compensate for over generation of renewable energy and shifting the produced energy to a possible later timestep. These energy storage systems operate at a maximum energy capacity and a able to charge and discharge at a certain rate.

First of all, the goal is to minimise the total operational costs defined by the power output per conventional generator and its marginal costs mc_i:

$$\min_{G_{i,t}} costs = \sum_{i,t}^{I,T} G_{i,t} \cdot mc_i. \tag{1}$$

where $G_{i,t}$ is the power output of generator i at timestep t. The marginal costs of the generator depend on the efficiency of the generator η_i, its energy carrier (hard coal, lignite, gas etc.) and the price of energy carrier per

thermal energy output $p_{fueltype}^{thermal}$: $mc_i = \frac{1}{\eta_i} * p_{fueltype}^{thermal}$.
The generators power output is bounded by their capacity:

$$s.t. \quad G_i^{min} \leq G_{i,t} \leq G_i^{max} \quad \forall t \in T; \forall i \in I. \tag{2}$$

We define the BESS with the following characteristics:

$$0 \leq SOC_t^{BESS} \leq SOC^{BESS,max} \quad \forall t \in T \tag{3}$$

$$0 \leq discharge_t^{BESS} \leq discharge^{BESS,max} \quad \forall t \in T \tag{4}$$

$$0 \leq charge_t^{BESS} \leq charge^{BESS,max} \quad \forall t \in T \tag{5}$$

$$SOC_t^{BESS} = SOC_{t-1}^{BESS} - discharge_t^{BESS} + charge_t^{BESS} * \eta^{BESS} \quad \forall t \in T. \tag{6}$$

Where equation 6 defines the intertemporal relationship of the state of charge, expressed in energy content of the BESS.[1] The Hydro powered energy storage system is assumed to be operated under analogue conditions.

Naturally, the physical constraint of power equality needs to hold for every timestep t within the optimisation time horizon T:

$$\sum_i^I G_{i,t} + PV_t + W_t + discharge_t^{BESS} + discharge_t^{Hydro} = L_t + charge_t^{BESS} + charge_t^{Hydro} \quad \forall t \in T. \tag{7}$$

Hence, the generators and the energy storage systems must be operated under the condition that the residual load matches with the generation for each timestep. The residual load is the actual load per timestep subtracted by the renewable generation per timestep.
Following this set of constraints, decision variables and the objective function, a (cost-)optimal solution for the economic dispatch problem can be found.

2.2 Scenarios

General assumptions have been made:

- The weather data is taken as deterministic and a priori and as of weather year 2019 for all scenarios. Renewable energy output is emulated with *renewables.ninja*(Stefan Pfenninger n.d.; Pfenninger and Staffell 2016).
- The load is taken as deterministic and known a priori and as of 2015 for all scenarios. Data is oriented on ENTSO-E Transparency ENTSO-E Transparency n.d.[2]
- The fuel prices are assumed to be deterministic and known a priori.[3]
- Renewable energy sources are assumed to bid always at marginal costs equal zero.
- Demand response and flexibility in demand are assumed to be non-existent.
- The power plant portfolio of conventional power plants are as of 2023. Data from *PyPSA/powerplantmatching* Gotzens et al. 2019, Fabian Hofmann, Fabian Gotzens, Jonas Hörsch n.d.).
- The operation of conventional power plants are assumed to be linear.
- Ramp up and ramp down constraints for conventional power plants are neglected.
- Reliability of conventional power plants is assumed to be 100%.
- Grid constraints are neglected.

2.2.1 Baseline

We define the baseline Scenario (Top-index: BASE) as the scenario taking the year 2019 as reference. The load and the generation capacity is taken as of 2019. For the renewable energy generation of onshore wind and solar pv we assume a location in mid-Germany. Offshore wind is neglected. For Baseline scenario we assume Energy Storage capacity to be infinite.

[1] Note here that the SOC (state of charge) is depicted as the actual energy content and not - as usual - in percent of the BESS capacity.
[2] We note that the load for reference year 2019 differs slightly.
[3] Fuel prices are stated in Appendix and follow educated guess.

2.2.2 Renewable Penetration in 2030

The second scenario (Top-index: 2030) depicts the economic dispatch for the planned installed renewable energy capacity in Germany according to latest legislation (KSG) (Erneuerbare Energien Gesetz 23 n.d., Klimaschutzgesetz 23 n.d.):

Table 1: Installed Renewable Capacity in 2030

Renewable Source	Capacity in 2030 [GW]
Solar PV	215
Onshore Wind	115
Offshore Wind	30

- Two thirds of aimed renewable capacity for onshore wind and solar PV is assumed to be in Brandenburg
- The remaining one third of the renewable capacity of onshore wind and solar PV is assumed to be in Bayern.
- The expected offshore wind generation is assumed to be placed in the north sea.

2.2.3 Dispatch for Bidding Zone Split

In the third scenario, we investigate the consequences of a bidding zone split alongside a north-south frontier for Germany. We will hence divide German energy generation and its load into a southern (south-western) and a northern (north-eastern) part. For the bidding zone split we assume the following statements to hold. For background on the assumptions made, please review section A.4 in the appendix.

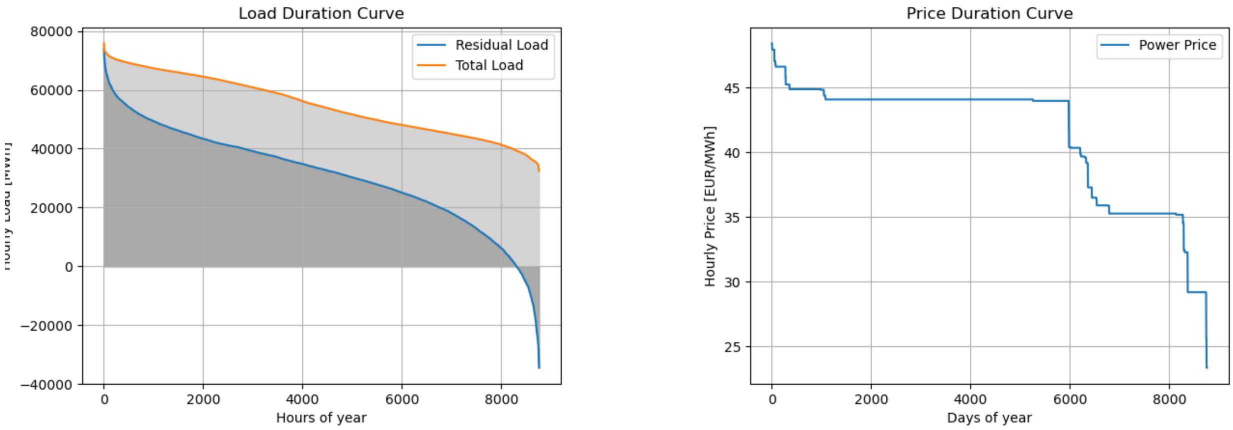
- Two thirds of aimed renewable capacity for onshore wind and solar PV is assumed to be in North - with localisation in Brandenburg
- The aimed renewable capacity for offshore wind is assumed to contribute to North
- The remaining one third of the renewable capacity of onshore wind and solar pv is assumed ot be in South - with localisation in Bayern.
- Two thirds of the total load (as of 2015) is assumed to be demanded in South
- One third of the total load (as of 2015) is assumed to be demanded in North
- Bidding zones are split by federal states:
  - South bidding zone: 'Baden-Württemberg', 'Bayern', 'Hessen', 'Saarland', 'Rheinland-Pfalz', 'Nordrhein-Westfalen'
  - North bidding zone: 'Berlin', 'Hamburg', 'Bremen', 'Schleswig-Holstein', 'Mecklenburg-Vorpommern', 'Niedersachsen', 'Brandenburg', 'Sachsen', 'Sachsen-Anhalt', 'Thüringen'

3 Analysis

The problem stated in chapter 2 is implemented in Python using the PyOMO package (Hart et al. 2017, Fabian Neumann n.d.).

3.1 Baseline

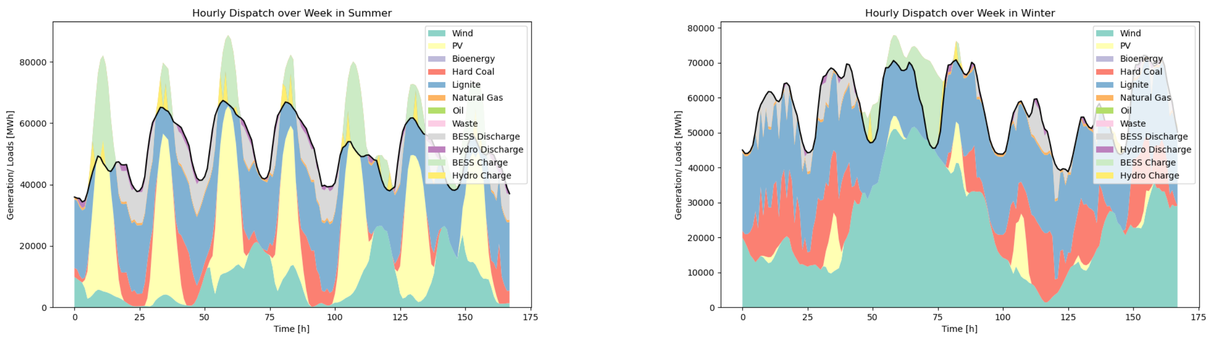
For the Baseline scenario we implement the developed economic dispatch model for one year for the following reference data: First, we investigate the reference load duration curve and the corresponding residual load duration curve, as depicted in figure 3a.[4] We can hence conclude that the load varies from up to 70GW to about 30GW over the course of the year. If we take the residual load, the maximum value remains at a similar level, the average load decreases and there is even negative residual load in some hours of the year, where renewable generation exceeds the load. This is where storage options would preferably charge their energy storages.



(a) Load Duration Curve

(b) Price Duration Curve

Figure 1: Duration Curves in BASE



(a) Hourly Dispatch over Week in Summer BASE

(b) Hourly Dispatch over Week in Winter BASE

Figure 2: Hourly Dispatch BASE

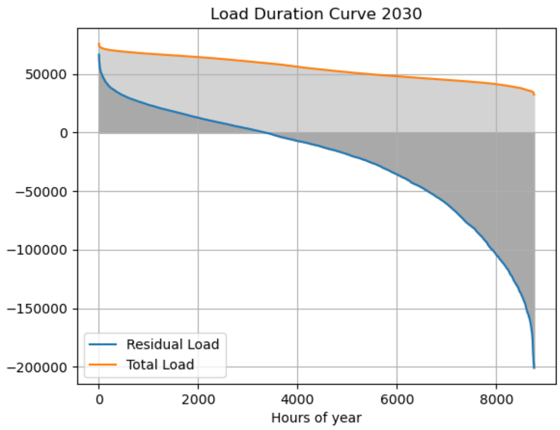
The hourly dispatch of the generators for representative summer week and winter week can be seen in in figure 2. In these hourly dispatch graphic, the load per hour is stated by the black line, where as the generation quantity per energy carrier is stated by coloured surface. For the summer months one can recognise that there is substantial generation of pv solar during the mid-day hours. At these hours some lignite plants are still operating and at the same time BESS and the hydro storage are being charged. Conventional power plants such as lignite, hard coal fill in the generation of low solar incidence. Additionally the energy storage systems discharge to contribute to the load. In winter a similar image is displayed (Figure 2b). Here we have substantial intermittent generation by wind energy. Solar pv only playing a marginal role in the generation portfolio. The residual load is compensated by conventional power plants. We can also see here that the BESS gets charged, even though there is no negative residual load. This may come from the relation that is might be cheaper to produce lignite powered electricity in one timestep, charge it to BESS and then discharge it later on, in order to avoid using other, more expensive, energy carrier. This does not display anticipated behaviour and hence needs further investigation.

Lastly, we look at the prices that emerged from the optimised economic dispatch. Therefore, we use the price duration curve to monitor the occurrences of different price levels over the course of the year. Figure 1b gives insight into the price duration curve of the BASE scenario. We can recognize that prices range from nearly 50EUR/MWh to about 25 EUR/MWh. The prices are determined by the marginal costs of the last generator in operation. The prices are derived as the dual variable of the power equality constraint, as mentioned in equation 7. The price range roughly matches the prices seen in the day ahead market in 2019 for DE-LU bidding zone.

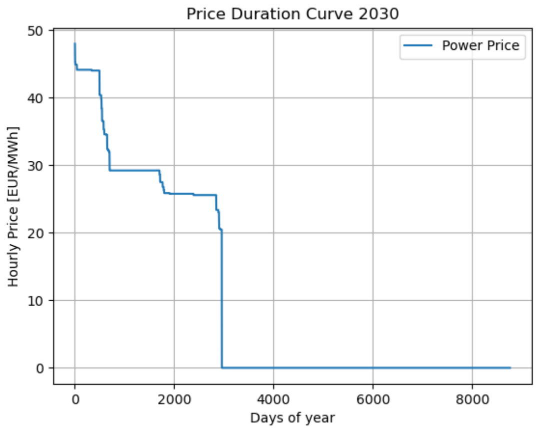
[4]The graphic of load duration is not displayed correctly. Please note that the units on y-axis is in [MW]

3.2 Installed Renewable Capacity Targets 2030

For modelling the renewable capacity targets stated in latest German legislation we increase renewable capacity accordingly. Furthermore, we differentiate the renewable generation spatially. We take that two thirds of installed capacity of wind onshore and solar pv will be in Brandenburg area in northeast Germany, wheres the remaining capacity will be generated in Bayern area in the south of Germany. Additionally offshore capacity will be situated in the German north sea EEZ. This gives us the opportunity to display spatial renewable generation differences. The data for renewable energy generation is produced using "renewables.ninja". Figure 3a already



(a) Load Duration Curve 2030



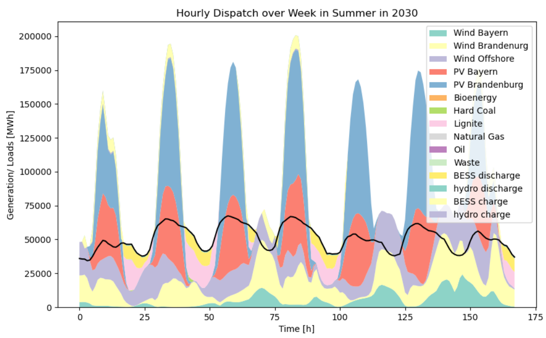
(b) Price Duration Curve 2030

Figure 3: Duration Curves in 2030

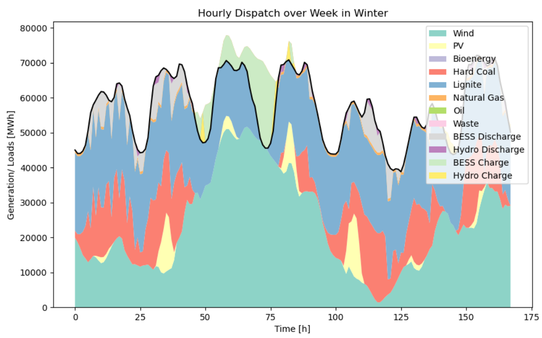
reveals the impact of the substantially higher renewable energy installed capacity in 2030, as demanded by Klimaschutzgesetz. We can recognise that for more than half of the time of the year, generation may exceed the actual load, leading to negative residual load. However, the peak residual load remains still at 50GW, meaning that conventional generation or energy storage system still need to be able to provide that amount of load for at least some hours of the year, when s do not contribute significantly. Moreover, we can see that the residual load reaches up to -200GW. This consequently means that at some hours of the year that the installed renewable power plants generate 200GW excessive power. Given this vast over-generation, the model needs to be adjusted. The power equality is difficult to hold for moments of such high excess generation. Unrealistic storage option would be able to charge up to 200GW. We therefore relax the power equality to power inequality and rewrite constraint 7 as follows in order to account for renewable dispatch and power shedding:

$$\sum_{i}^{I} G_{i,t} + PV_t + W_t + discharge_t^{BESS} + discharge_t^{Hydro} \geq L_t + charge_t^{BESS} + charge_t^{Hydro} \quad \forall t \in T. \tag{8}$$

After optimisation we yield the optimal dispatch, as shown for representative weeks in summer and winter.



(a) Hourly Dispatch over Week in Summer in 2030



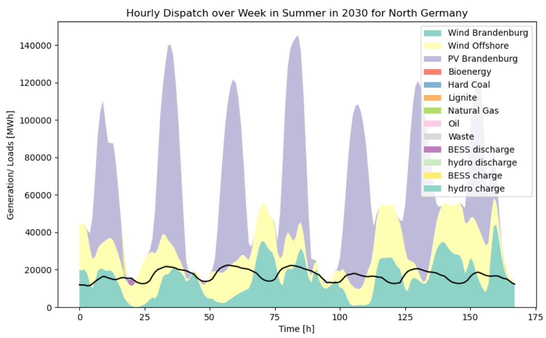
(b) Hourly Dispatch over Week in Winter in 2030

Figure 4: Hourly Dispatch in 2030

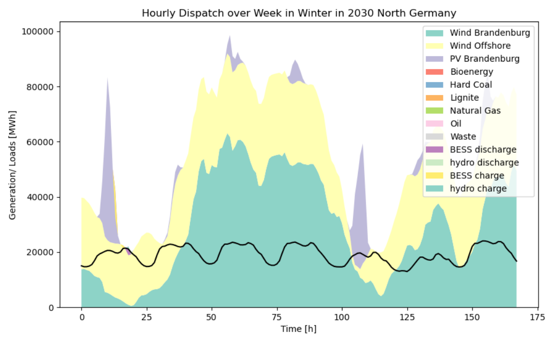
We can recognise the massive over-generation of PV in summer during daytime hours and the over-generation of wind energy in winter. In the summer week, the lower renewable generation during low sun-incidence is majorly compensated by BESS discharge. However, still conventional power plants (lignite) need to fill in some generation gap. For winter a similar conclusion can be drawn. The wind generation however is less repetitive and over-generation exists over longer time periods. This probably leads to less charging possibility of BESS, due to the fact that BESS might be already at full SOC and no further charging is possible. This is an interesting insight and would require further analysis.

3.3 Bidding Zone Split

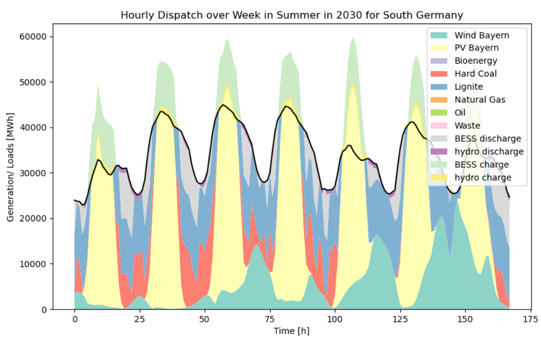
A background on German bidding zone split is pictured in section A.4.Here, an analysis of the hourly dispatch for the split zones of north and south of Germany for the expected renewable capacities in 2030 is delivered. It is assumed, that there is no interaction between the zones. In figure 5 one can recognise that the the split has significant impacts on the generation portfolio in north and south region. As expected the north generates huge amounts of excess renewable energy, whereas the South still needs to compensate the times of low renewable energy generation with conventional power plants. Naturally, this has huge impact on the observed prices as to



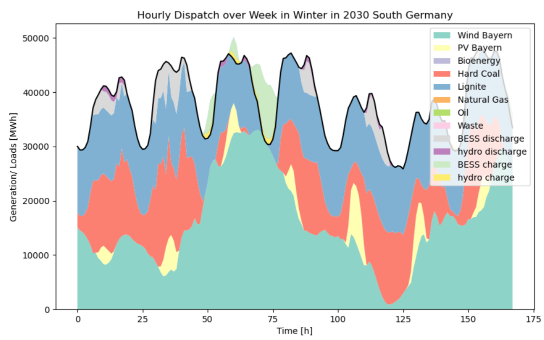
(a) Dispatch Summer 2030 North



(b) Dispatch Summer 2030 North



(c) Dispatch Summer 2030 South



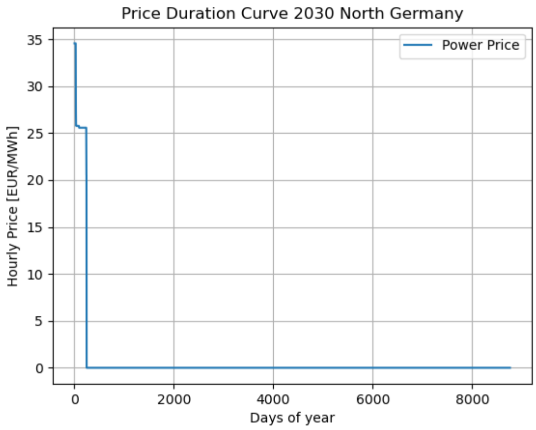
(d) Dispatch Winter 2030 South

Figure 5: Hourly Dispatch for north-south bidding zone Split in Germany

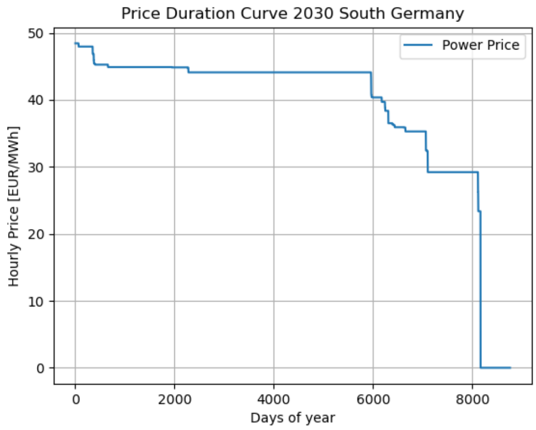
be seen in figure 6. Prices in the North region are expected to be exactly zero due to vast renewable generation with zero marginal costs. There are only a few hours where conventional power plants need to chip in. For the South region, we see an opposite image. We can see a similar price duration behaviour as for the BASE scenario (see figure 1b. Prices as mainly defined by the last operating conventional power plant. There are only little hours of demand served only be renewable generation, which would lead to a price equal to zero.

4 Conclusion

We developed a simple Linear Programming model for hourly dispatch of electricity market. The model was applied on the German electricity market. We could investigate that the the goals for installed capacity of renewable power plants as proclaimed by latest German legislation would lead to a vast shift in hourly dispatch. This would lead to more time intervals of negative residual load, over-generation is occurring frequently.



(a) Price Duration Curve North 2030



(b) Price Duration Curve South 2030

Figure 6: Price Duration Curves for Bidding zone Split

Nevertheless, still conventional power plants need to fill the remaining times of low renewable generation. For the bidding zone split into south and north Germany (for a 2030 scenario), we could gain valuable insight in generation patterns and price shifts. Key insight is, that for the simplified model, prices in north Germany may fall to zero for most times, where as south Germany might follow similar price distribution over the year, as it is currently displayed for the current German electricity market with low renewable penetration. The proposed model and the consequent analysis have several shortcomings, due to strong assumptions, a simplified dataset and the linearity of components. The insights gained only serve only as rough estimates on the German electricity market. Consequently further development of model, data quality and the assumptions in place need to be done.

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A Appendix

A.1 General

Table 2: Assumed Fixed Fuel Prices

Energy Carrier	Fuel price in EUR/MWh(thermal)
Hard Coal	17
Lignite	10
Oil	100
Biomass	40
Natural Gas	20
Waste	80

A.2 Baseline

A.3 2030 Renewabale capacity targets

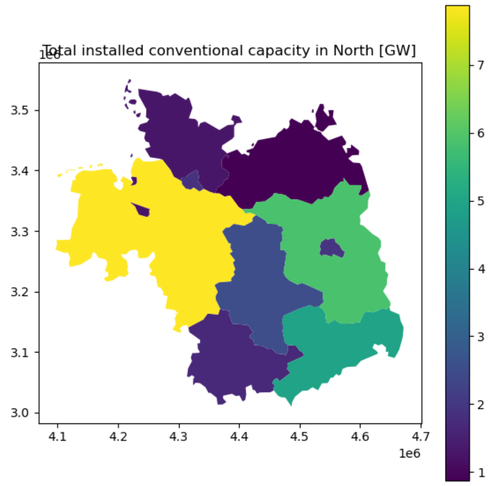
A.4 Bidding Zone Split

A.4.1 Background on German bidding zone split

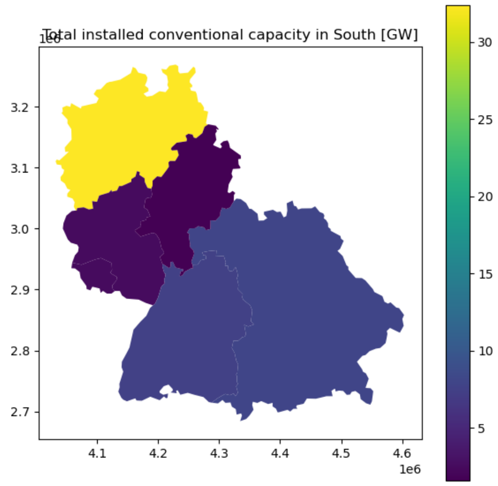
The German bidding zone takes a special position within the European electricity system. Firstly it is the largest bidding zone by amount of quantities and additionally it connects to multiple adjacent bidding zones, due to its localisation. Also, within Germany, there is some inherent problem emerging form the historical spatial division of load and generation. Historically, heavy industry was located in the Rhein-Ruhr Area, which was powered by coal fired powered plants in close proximity. Similarly, manufacturing industry is mostly based in southern and south-western Germany, hence also nuclear and gas-fired power plant were situated in close proximity.

Naturally, these local energy supplies by conventional power plants for industry in Rhein Ruhr area and southern Germany do not hold anymore with increasing decarbonisation. In fact, land availability favours the deployment of renewable energy generation in the north of Germany. Additionally, especially southern areas face increased acceptance issues regarding the deployment of wind and utility-scale solar pv power plants. Consequently, there will be more renewable energy available in the north of Germany, whereas the major load demand is still in southern and western Germany. This shift in generation and load causes tremendous distress for the transmission grid, making the economic operation of the transmission system difficult to handle. Vast expenditures for redispatch are one of the consequences of this. One solution might be to divide the German bidding zone into one part which demands load but does not supply enough renewable energy (south) and another part which supplies vast amounts of renewable energy but does not incorporate the load. This bidding zone split could lead to more efficient economic market behaviour, where prices would lead as a instrument to shift consumption and production behaviour. A complete analysis of the economic implications of German bidding zone split is however beyond the scope of this report.

A.4.2 Installed Conventional Generation Capacity South North



(a) Total Capacity North



(b) Total Capacity South

Figure 7: Installed capacity of conventional power plants per federal state in North and South region. Please note the different scaling.