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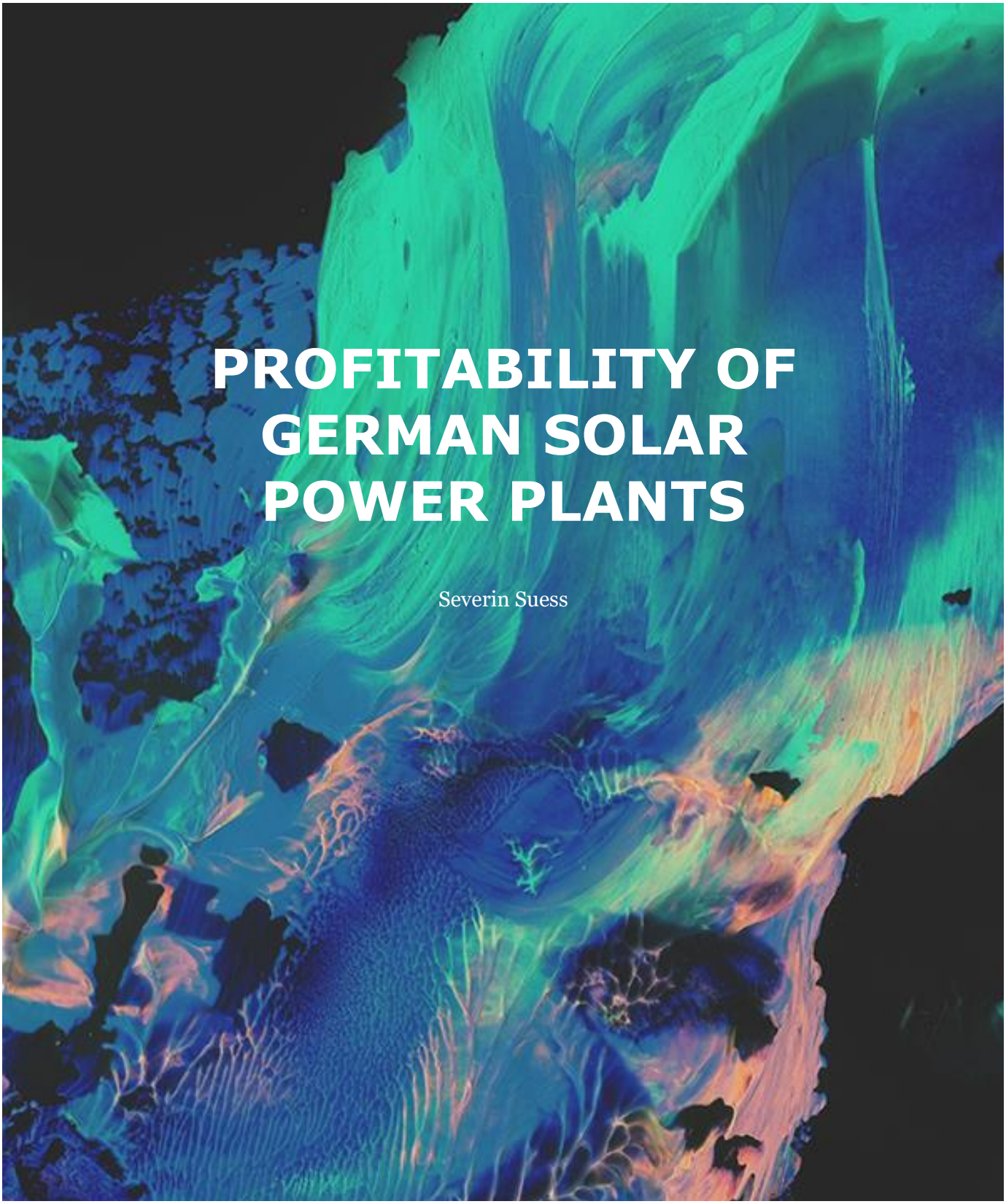

PROFITABILITY OF GERMAN SOLAR POWER PLANTS

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Abstract:

The recent revision of the German law on renewable energy (EEG) set ambitious expansion paths for the future domestic renewable energy generation and included technology specific target capacities. For non-roof mounted photovoltaic plants, these amount to a yearly expansion of 11GW. Using exemplary data provided by Vattenfall, this thesis calculates the profitability of agricultural land in the German region of Saxonia-Anhalt using scraped information on land leasing costs. Together with information on costs of technical components and assumed wholesale electricity price paths, it tries to answer the question if these expansion targets are feasible without further political aid such as subsidies.

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1. Introduction

While climate change and constraints on conventional energy sources have been motivating the shift to renewable electricity generation for quite a while now, recent political developments introduced additional motivating factors. Rapidly increasing gas prices drastically increased German electricity prices and sparked fears of black- and brown outs due to dependencies from Russian fuel supplies.

The German government responded with plans to increase renewable rollout, set the exit from coal generated electricity to 2035 and implemented policies to reduce the consumers' electricity price through a revision of the currently existing policy structure. Among other factors this entailed a yearly expansion of the renewably generated electricity through photovoltaic plants of 22GW.

To assess the feasibility of this policy target, I will use an exemplary model provided by Vattenfall on the profitability of a solar power plant in Germany from 2022. This provides information on up to date costs of technical components together with their expected runtime. Additionally, I got access to a previous selection of large scale areas in Saxonia-Anhalt (SA) that are of interest for future operation of renewable power plants. While this selection is helpful in identifying regions that are potentially interesting in regards to their structure, distance to cities or to the nearest structure, it is to coarse to assess plot level costs.

To do this, I scraped administrative information on geographical characteristics of small scale units within the selection. These Flurstuecke are the smallest unit of measurement for public administration and hold among other aspects, information on their usage (agricultural, residential, infrastructure etc.), agricultural land quality and size. From this dataset I can calculate the expected land leasing costs which constitute the bulk of a plant's operational costs. Through this, I can calculate the net present value of 5000 hypothetical photovoltaic plants in the selected area. In the end, I extrapolate a minimum necessary net present value needed to fulfil the political expansion targets within my random exemplary region and answer this thesis research question:

Is the goal of 22GW feasible in the current political structure? Does it require more political support policies such as subsidies?

The operational characteristics for this question to be answered are given in the analysis chapter 6. If the capacity threshold is unachievable with profitable plots, then further subsidies is required. In case of the capacity threshold to be feasible with profitable plots lone, I concur that no further political aid is necessary.

This analysis is based on a set of assumptions such as future electricity prices or land leasing prices. To provide some measure of robustness, I present a set of 10 different scenarios and draw my final conclusion from the optimal and most critical case. There I find that the target is achievable within my random selection alone and can be fulfilled using only comparatively highly profitable plots. This indicates that as long as the electricity price do not go below the lowest path considered in this analysis, the policy goal should be feasible.

2. Policy Description and Case Selection

As my thesis wants to assess the profitability of PV plants in Saxonia Anhalt relative to the German political goal, I will first present recent policies related to renewable energy rollout before deriving the hypothesis from this. The following subchapters will give a brief description of the historical background of renewable energy support policies, starting with the German renewable energy law or Erneuerbare Energien Gesetz (EEG).

2.1. Renewable Energy Law – Increased share of RES

To increase domestic renewable energies generation capacities, in April 2000 the German government passed a law specifying a subsidy programme for renewable energy sources. While the details of the policy have been subjected to a series of revisions and changes, the underlying logic of fixed minimum payments for renewably generated electricity remained largely unchanged (Büsgen & Dürrschmidt, 2009, p. 2536). The overarching idea is to increase renewable sources' competitiveness against conventional energy sources (Bode & Groscurth, 2006, p. 736). This support policy works through two channels. The first ensures prioritized grid access for renewably generated electricity. Therefore, grid or transmission system operators can't buy conventionally sourced electricity before the supply of renewably sourced one is exhausted. The second factor is a fixed wholesale price for the individual plant operator (Croonenbroeck & Hennecke, 2020, p. 2). Depending on plant characteristics such as capacity, technology and energy source, wholesale prices are fixed for a time period but decreasing over time. These so called feed in tariffs (FIT) as site specific renumerations vary considerably between technology. In 2011 the average ensured tariff for geothermal generation was at 0.3€/kWh and 0.0679 €/kWh for sewage gas (Mennel, 2012, p. 19). From a producer's or plant operator's point of view this eliminates both volume and price risk. Since the prioritized access ensures priority over coal, gas or nuclear electricity, plant operators face virtually no risk of overproduction. Since wholesale prices are ensured ex ante, risks from volatility in electricity prices are eliminated (Mitchell et al., 2006, p. 301).

As this insurance against low prices results in an artificially increased electricity price, the subsidy introduces additional costs to the society. Under the EEG, these costs typically are to be paid by the consumer through a surcharge on electricity consumption. Between 2000 to

2012 and 2012 to 2017 this so called EEG reallocation charge increased from 0.05 ct/kWh[1] in 2000 to 3.6 ct/kWh in 2012 to 6.88 ct/kWh in 2017 before it decreased to 3.72 ct/kWh in 2022. In July 2022, as a response to high energy prices, the surcharge had been decreased to 0 ct/kWh (*Bundesnetzagentur - Homepage - EEG-Umlage*, 2023; Mennel, 2012, p. 20). Since 2023 this surcharge has been abolished completely (Die Bundesregierung informiert, 2023). Previously, only energy intensive companies had been exempt from the surcharge to ensure competitiveness of the German industry (Bode & Groscurth, 2006, p. 736). Some authors argue for the initial steep increase in the surcharge costs to be due to capacities associated with cheaper technologies having been implemented first. Consequently, in later years, additional implementation required higher subsidies to still ensure profitability due to increased innovation requirements (Mennel, 2012, p. 20).

Since the specific policy goal was to increase domestically generated electricity from renewable sources, the policy's success can easily be assessed trough a comparison of German RES generation against the EU wide share. Between 2001 and 2006 the RES capacities contributed to the grid increased from 3% to approximately 10% and to 35% in 2015 (Bode & Groscurth, 2006, p. 736; Böhringer et al., 2017, p. 189). In the same time, the RES share in the EU as a whole increased by 88% until 2012, the share in Germany quintupled (Mennel, 2012, p. 18).

An assessment of costs is hard to do, as there exists some debate about what factors to count against benefits and costs. While the impact of the surcharge on prices is obvious and easy to measure through the premium on the electricity price in absence of the policy, the increased rollout also negatively impacts the electricity price. Through the system of the merit order, the electricity market ensures the lowest possible price. Supply capacities are sorted by marginal costs and those of the last distinct unit needed to satisfy electricity demand sets the electricity price for all technologies. Since renewable energy sources have marginal costs close to zero, sufficiently large increases in renewable production capacities can crowd out conventional, high marginal cost technologies and consequently reduce the overall electricity price (Bode & Groscurth, 2006, p. 739).

[1] 1 ct = 1/100€.

2.2. EEG 2023 – Revision

To ensure Germany's adherence to the 1.5° goal as agreed upon in the Kyoto protocol, the German government set the goal of 80% renewable energy supply by 2030. This involves increased tendering for onshore wind and solar plants to reach the goal of 80% renewably generated electricity by 2030. This new target superseded the previous goal of 65% RES electricity in 2035, as domestic electricity generation is planned to happen almost exclusively through renewable sources (Drucksache 162/22, 2022, p. 1). Compared against the current situation, where in 2021 only 42% of gross domestic production had been generated renewably, this indicates close to 100% increase within the next decade, under the unrealistic assumption of constant gross electricity consumption (ibid.). To achieve this transformation, implementation targets are increased for 2030, measured against an assumed gross electricity demand of 750TWh. 80% renewable generation therefore equals 600TWh renewable generation capacity (Drucksache 162/22, 2022, p. 2).

In addition to this capacity goal, the revision also indicates technology specific yearly implementation quantities necessary to achieve the combined goal of 600TWh across all renewable technologies. Of special interest for this thesis are the implementation goals for photovoltaic generation. With an expansion of 22GW per year the total capacity generated from solar power is planned to amount to 250GW (ibid.). These 22GW are to be distributed equally among roof mounted and conventional plants. Additionally, for conventional plants, the new EEG revision includes new areas into the tendering process such as permanently restored wetlands or dual usage areas for both agriculture and electricity production through solar panels. Additionally, municipalities gain further options to help in financing the setup and operation of both wind and solar plants (ibid.). While changes to the tendering process and avenues for municipality based financing are relevant in assessing the profitability of a power plant and the costs associated, they are extremely hard to quantify from the current ex ante perspective. Therefore, for my analysis, the most relevant information is that of the implementation target of 22GW.

Among the most decisive changes implemented in the 2022 revision of the EEG is that of a complete overhaul of the financing of the supporting structure. The past system of a feed in tariff financed through a surcharge on the consumers' electricity price is exchanged for income from national emission trading on fuel. Since this only impacts the consumer price,

through the absence of a surcharge, it is however irrelevant when analysing for the profitability of production plants, as this depends on the wholesale price, determined through the merit order curve as sketched previously. The only channel of impact between consumer prices and PV plant profitability is through supply and demand. If the abolishment of the surcharge decreased the consumers' electricity price, and this in turn increased their electricity demand, then the change in financing should increase prices. However, comparing the 3.72 ct/kWh in 2022 against the total electricity price of 37.07 ct/kWh consumers faced before the EEG surcharge had been lowered, this price effect is negligeable (Bdew, 2023). Especially when compared against findings of consumers' price elasticity when in regards to electricity consumption, I decide to disregard the effect of changes in financing for subsidies (Brännlund & Vesterberg, 2021). As I only focus on conventional PV plants, the threshold to measure the successful implementation of PV plants against is 11GW. Assuming a distribution linked to historical shares, then between 6% and 7% of this should be implemented in Saxonia (SA) Anhalt. The development of this share over time is plotted in Figure 1. Measured against the threshold of 11GW, this indicates a capacity of between 660 and 770MW. These two thresholds are used to answer the research question in the analysis chapter 6.4. Starting from this revision of the policy, I will now present the literature discussion on the feasibility of the capacity expansion.

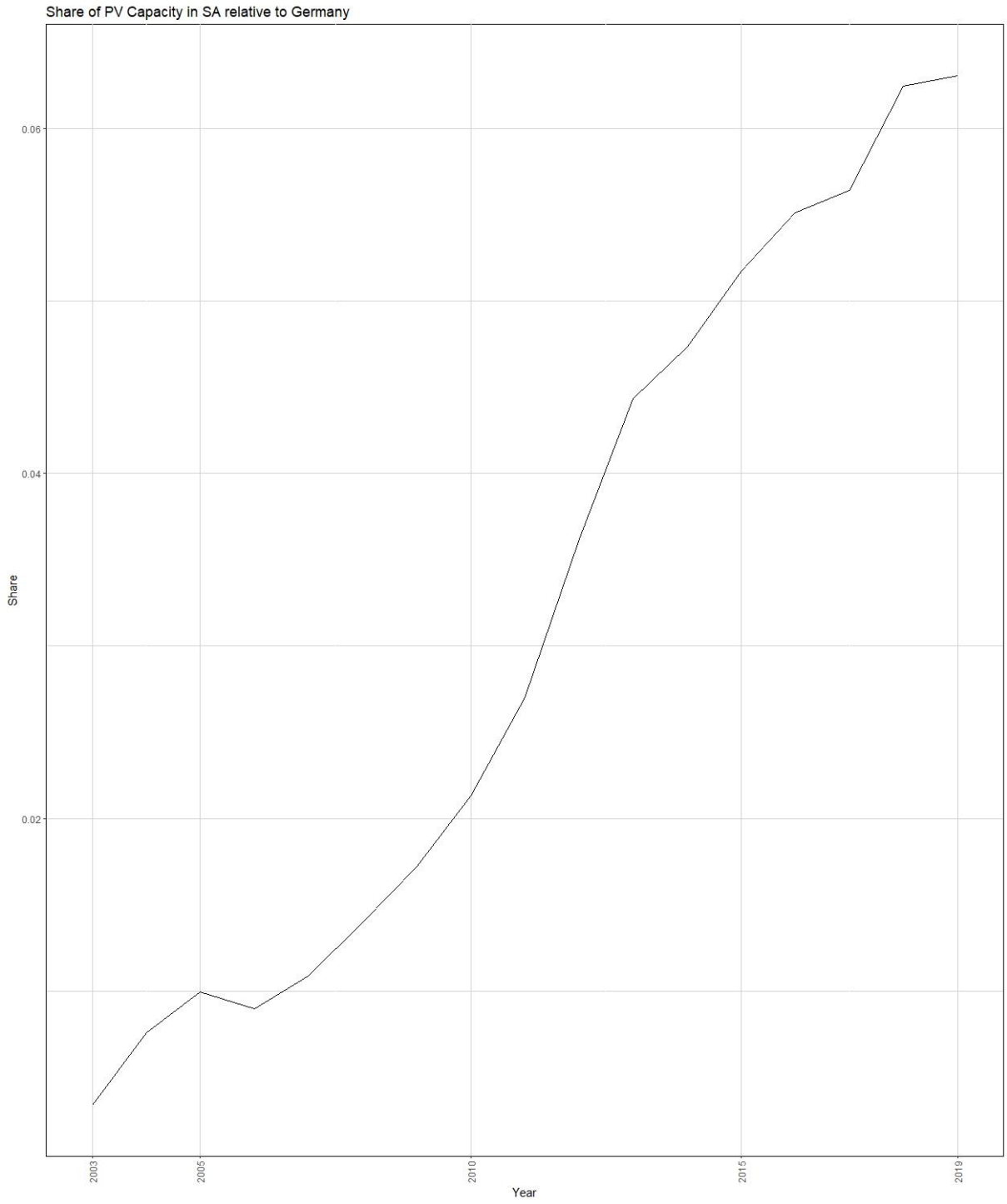

Figure 1: Photovoltaic Capacity in Saxonia-Anhalt Relative to Germany as a Whole.

3. Literature Discussion

This chapter will give insights into relevant research. To optimally represent the research structure I found, the subchapters correspond to the three overarching categories of 1) policy discussions such as the feasibility of energy transition in Germany or Europe, 2) analysis' varying on a regional level such as the inclusion of geographic factors and 3) papers on technicalities of profitability analysis of photovoltaic plants and renewable energy plants, such as operation and maintenance or fault diagnosis. The first subchapter will be the one on policy analysis followed by the one on regional variation. The final category of technical issues will lead over into the model discussion.

3.1. Discussion of Past Policies

As briefly discussed in the previous chapter on the history of the EEG, the past years of subsidiary policies are avidly discussed in terms of cost effectiveness and goal achieving. As chapter 2.1 has predominantly focussed on the explanation of the structure of the feed in tariffs as such, it did not focus on the most recent years but instead has been more weighted towards the earlier periods. To assess the success of the EEG subsidiary policies and other energy transition policies up to this point, I will now give information on research on the later periods.

In their study on the optimal technology choice for the capacity expansion of renewably sourced electricity, Kreifels et al. (2014) analyse the optimal expansion of photovoltaic and aeolic (wind) power plants depending on the flexibility of pre-existing conventional power plants and storage capacity. For the years 2011 and 2012 and the respective load and weather characteristics the current system is estimated as a starting point scenario. This scenario is compared against one where the must run capacity of conventional plants is reduced and against one where storage capacities are expanded. From this comparison the authors conclude, among other findings, that a balanced ratio of wind and PV plants among all penetration levels of renewable energy sources is optimal (Kreifels et al., 2014).

A more recent analysis by Egerer et al. (2022) uses increases in the gas prices to short and long term effects of policies to crowd out and avoid gas fuelled plants. For the period of 2022 to 2027 they assume additional renewable capacities of between 95.2 GW and 138.7 GW, depending on the level of regional subsidies. However, when assessing the impact on

German electricity prices, they find alternative factors such as availability of nuclear power in France to be the more decisive factor. Nevertheless, an estimated negative price effect of increased domestic generational capacities exists (Egerer et al., 2022).

To estimate the comparative success of the past EEG subsidiary policies, Buchholz et al. (2019) estimate the costs of incentivizing technological progress in RES technologies and measure it against reduction in prices for solar panels. Costs for the subsidy are calculated staggered by cohorts to capture the variation over time relative to 2014 and assume a plant of average size of 25.5kWp (kilo Watt peak capacity) (Buchholz et al., 2019, p. 769). In the absence of discounting the calculate excess costs of 117.8 bio € (Buchholz et al., 2019, p. 770). These costs are then measured against the cumulative solar capacity in Germany against the rest of the world to conclude that through the EEG, Germany took a pioneering role in the market for PV modules (Buchholz et al., 2019).

To compare the effect of nationally differing subsidy policies, Milanés-Montero et al. (2018) analyse the effect of different feed in tariff subsidies on the profitability of PV companies. Their study covers the period of 2008 – 2012 in Germany, Italy, France and Spain. The authors focus on the feed in design specifically, as this is the most common tool for subsidizing renewable energy with greater efficiency then policies such as tradeable green certificates (Milanés-Montero et al., 2018, p. 2). Through improved investment conditions for renewable technologies, feed in tariffs promote investment and technological progress in otherwise comparatively costly technologies such as solar power (Milanés-Montero et al., 2018, p. 3). After controlling for country specific time invariant characteristics through a fixed effects model, they find a positive impact of FIT policies on the profitability of solar plants making it an especially useful tool in the period covered, when PV technology had been comparatively more expensive than today (Milanés-Montero et al., 2018, p. 14). Proceeding from this country level analysis, the next subchapter will delve more deeply into studies on regional differences and determinants for renewable energy profitability.

3.2. Regional Analysis

Closely linked to the question of the EEG and its mechanism of feed in tariffs is the question of optimal technology expansion path. Depending on the objective in question, the optimal expansion path may differ considerably between different technologies. Including

information on local generation efficiency through geographic factors such as weather, Groissböck (2020) defines three distinct objectives which determine which technology should be expanded at which point in time to achieve the objective maximizing outcome. The first minimizes capex requirement and corresponds to a scenario of a total absence of public subsidiary policies. In their model, this objective is optimized under a strong focus on aeolic generation throughout the RES expansion planning. If the goal was instead to maximize the capacity contributed by residential generation, then this relates to an expansion plan that maximizes curtailment as the deliberate reduction in output below the technically feasible amount or maximizes zero net load hours. This corresponds to a focus on photovoltaic plants over wind power plants. The outcome is similar to the case with an objective function maximizing excess electricity to be used in other sectors such as transport or building (Groissböck, 2020).

A different approach on local weather related characteristics is undertaken by Croonenbroeck and Hennecke (2020). The authors use a spatial profitability analysis for a random selection of points in Germany regarding their sensitivity on wind speeds and technical plant characteristics and how they interact with the subsidiary incentive system for wind power plants. The feed in tariff (FIT) ensured to a plant is the result of a underbidding process of plant operators on how little compensation they demand for a plant on a location. To ensure both attractive and less attractive locations to remain competitive, a correction factor is included that increases with decreasing location quality and is calculated based on expected capacity or yield relative to the reference yield which measures the theoretically possible production depending on the technology used (Croonenbroeck & Hennecke, 2020, 3f.). From their analysis, the authors find that the EEG achieves its goal of treating locations of different quality separately and therefore results in increased profitability with increased expected wind probability while still allowing for low quality zones to remain attractive (Croonenbroeck & Hennecke, 2020, p. 12).

An alternative approach by López Prol (2018) compares the success of FIT based support policies for photovoltaic plants in Germany and Spain between 2004 – 2014 through comparing the profitability of different PV installations. The author measures expected profitability through the internal rate of return. The general result mirrors what was presented previously and indicates a positive and persistent effect of the German FIT design

on PV plant profitability with a larger effect for larger systems. This is contrasted by a more bubble like scenario in Spain, where specifics of the subsidy design together with overall uncertainty resulted in a less lasting effect on PV implementation (López Prol, 2018, p. 1177).

Since this subchapter indicates the EEG and the German subsidiary policy framework to work as is intended, the next chapter will delve more deeply into questions of budgeting for solar power plants.

3.3. Budgeting for Solar Power Plants

Proceeding from the last subchapter on regional and national comparisons, this subchapter will instead focus on more technical aspects of PV plant budgeting such as operation and maintenance aspects of seasonal variation in generational efficiency. This will lead over into the model description.

A logical starting point from the last paragraphs on regional variation through weather and location quality is the paper by Shravanth Vasisht et al. (2016). For a roof mounted solar system in India, the authors observe variation in performance and yield throughout the season to estimate both a Capacity Utilisation Factor and the plant's Performance Ratio. In general, they find efficiency to highly depend on module temperature, with peak efficiency around 45° in summer and 55° in winter. In summer, higher temperatures decrease efficiency whereas they have no effect in winter (Shravanth Vasisht et al., 2016, p. 45).

To highlight the role of the Performance Ratio as an indicator for generational quality, Khalid et al. (2016) compare international monitoring standards and guidelines for their methods of calculating the PR of grid connected PV plants. The key takeaway for my thesis is the relative regional persistence of PR and the associated standard specific yield values as compared to final yield. For Germany, values between 950 kWh/kWp and 1050 kWh/kWp are reasonable assumptions (Khalid et al., 2016, p. 1140). Apart from that more specific value, the authors find the PR to still be hard to estimate, due to variation in monitoring guidelines and inaccurate insolation measures (Khalid et al., 2016, p. 1156).

More technical in nature are studies by Enbar et al. (2016) on the role of operation and maintenance activities and their accounting and one by Osmani et al. (2020) on general maintenance strategies. Pillai and Rajasekar (2018) instead focus more on costs and benefits of fault diagnosis systems. Issues of proactive maintenance are also of concern in the study

by Rukijkanpanich and Mingmongkol (2020) on increasing the overall performance of PV plants through maintenance policies. Across all papers, the authors show a positive effect on performance on profitability through both proactive and reactive maintenance.

4. Model

The following chapter will explain the model for assessing profitability of a PV plant. While in its core a very straight forward and simple computation of a net present value, it is nevertheless useful as it provides me with information on actual costs such as modules and additional setup costs in 2022. For my analysis in chapter 6, most information can be taken as given, with land usage costs as the main endogenous variable of interest. This chapter will provide a descriptive overview. A more detailed discussion of some assumptions related to prices (such as electricity prices and leasing costs) and the discount rates are given in 6.1 and 6.2 respectively in the analysis chapter to provide some frame of reference. For the model and later my analysis I assume the plant to operate 30 years, with one initial setup period without electricity generation. Both benefits and costs are discounted with a constant discount rate. It can be combined into one net present value calculation containing both benefits and costs discounted to the initial period t0. The following expression describes this total calculation:

$$NPV_i = B_{it} - C_{it}$$

Where:

- B_{it} is the sum of the yearly benefits discounted to period t0 (2022)
- C_{it}, equivalently is the sum of the yearly costs discounted to period t0.

The exemplary plant which my analysis is based upon is located in Germany and has been commissioned in 2022, starting production in 2023. The following subchapters start with a description of the present value of a given plant's benefits before switching to the cost component.

4.1. Benefits

The plant produces benefits through the generation of electricity that can then be sold at a certain price. Electricity sales is the only source of benefits I consider. The discounted value of a plant's benefits in the initial period t0 can be expressed through:

$$B_{it} = \sum_{t=0}^{31} \frac{PCount_i * PCapa * NetYield * Corr_t * p_t}{(1+i)^t}$$

Where:

- $PCount_i$ is the number of panels installed at a site. This is a function of the number of panels per sqm multiplied the site's size, 0.2448 $\frac{panels}{sqm} * area_i = PCount_i$.
- $PCapa$ is a constant measuring the assumed generational capacity of an individual panel at peak generation. For modern panels, a reasonable estimation is 430 Watt at peak generation, based on the information given in the exemplary model. The product of the panel count and peak capacity is the total installed capacity at a park, measured in Megawatt at peak generation (MWp), $PCount_i * PCapa = ICapa_i$.
- $NetYield$ is a constant indicating the yield per MW installed capacity. While theoretically varying geographically, 1015 Megawatthours per MW (MWh/MW) is a reasonable estimation for Northern Germany as spatial variation is sufficiently small to assume the value as constant for all observed plant sites (Khalid et al., 2016, p. 1140). The product of the installed capacity and the assumed net yield is the total gross production of a plant, measured in MWh, $ICapa_i * Netyield = GProd_i$.
- $Corr_t$ is a time varying correction term indicating the panels deterioration over time. As generative capabilities decrease over the panels' lifetime, overall production capabilities have to decrease as well. Since this correction term is technology specific, it can be assumed to be uniform across all regions. The product of a site's gross production and the correction term is net or real annual generation $GProd_i * Corr_t = NetProd_{it}$.
- p_t is the price from electricity sales measured in €/MWh.

After this description of site benefits, I will now describe the cost part of the net present value calculation.

4.2. Cost factors

From the model on the exemplary PV plant, I get a list of certain cost factors. Most of them are scaled to plant size. As plant size is a direct function of the space available, these costs can be scaled proportionally to the specifications of any observation in my dataset. Following the distinction made in the assessment of the exemplary plant, the costs can roughly be organized into two main groups.

The mathematical expression for the present value cost function in period t0 is:

$$C_i(ICapa_i) = ICapa_i * (1 + conting) * \sum_{l=1}^{k} CAPEX_{l\ i} + \sum_{t=0}^{31} \frac{(\sum_{l=1}^{z} OPEX_l)_t * ICapa_i + leasing_{it}}{(1+i)^t}$$

Where:

- $ICapa_i$ denotes the gross installed capacity at plant i
- $conting$ is a constant representing a share of the CAPEX reserved for contingencies
- $CAPEX_l$ is an individual factor of capital expenditure occurring in the initial period t0
- $OPEX_l$ is a factor of operational expenditure, the size of which is time specific
- $leasing_{it}$ are time and plant specific leasing costs.

After this short presentation of the cost function, the following two subchapters will discuss both capital and operational expenditure costs in more detail.

4.2.1. Capital Expenditure Costs

The first, capital expenditure only occurs in the initial pre-operation period t0. It includes costs for modules, inverters, mounting hardware cabling and additional factors. A list of all CAPEX factors with their respective costs per module is given in Table 1. As these costs are scaled directly to the number of modules and therefore the capacity installed, which, as mentioned previously, can be computed from the area available, I can calculate these cost factors for each observation. While the costs for technical components such as modules and inverters can reasonably be assumed as constant across different building sites, other factors such as landscaping and permit fee will vary on a plant to plant and area to area basis. However, as site specific information is very hard to come by and the impact relative to the overall costs is generally negligeable, I decided to use the given values as an overall estimate. When adjusting the costs to the installed capacity, I use the area specific product of 0.2448 as the number of panels per sqm multiplied by $area_i$ to calculate the number of panels in a plant. As the number of panels is directly proportional to plant capacity, it is multiplied with individual panel capacity ($430 * 10^{-6}$ Megawatt at peak capacity)[2]. While these cost estimators provide a first educated estimator of costs, they can still be discussed under

[2] For an exemplary plant of 5 ha (50 000 sqm), I assume 50 000 * 0.2448 = 12 240 panels. With a capacity of $\frac{12\,240*430}{1\,000\,000} = 5.26\ MWp$ (Megawatt peak), this hypothetical plant therefore results in costs of $5.263\ MWp *\ 420\,291.5\ \frac{€}{MW} = 2\,211\,994.165$ €.

several aspects. Technical components may vary in price over time, resulting in different costs for the same plant depending on the commissioning time. As my dataset on land prices and characteristics is from 2022 it matches the prices given. Since I evaluate all projects against a theoretical starting date of 2022, I can disregard issues of price development when it comes to components. More interesting is the discussion of grid connection costs. While the example assumes grid connection as relative to the capacity, and consequently the same costs for all areas, it is more reasonable to assume varying grid connection costs due to geographic factors and distance to the nearest grid access point.

4.2.2. Operational Expenditures

The second block of costs are those of operational expenditures occurring not in the setup period t0 but instead during operation. These may vary across periods. Here I include costs for panel maintenance (both preventive and reactive). Examples for preventive maintenance may include passive or active cooling of panels, protection from lightning strikes (Osmani et al., 2020, 19 ff.; see also Rukijkanpanich & Mingmongkol, 2020). Reactive maintenance entails exchange or fixing of already broken or worn out components. Projects beyond a capacity of 1MW usually have around 70% of all maintenance budget attributed to preventive maintenance (Enbar et al., 2016, p. 9). In my analysis, I assume both preventive and reactive maintenance costs to be scaled up to installed capacity and to stay constant over the runtime. The second large cost factor occurring yearly during operation is the one of land leasing costs. In my analysis I assume these leasing costs to be a function of agricultural quality and size. It is important to denote that reactive maintenance does not include replacement of modules or other technical components such as inverters. These time varying values are included as a separate cost factor. More on the calculation of these leasing costs is given in the analysis chapter 6.2.

Since operational costs occur every year, factors such as maintenance costs are weighted for inflation and the total yearly operational costs are discounted to year 2022 (t0). Additionally, Vattenfall's exemplary model assumes a share of 7% of total gross production capacities to already be operational within the first period. This induces operational costs in the initial pre-operation year. However, as the exact share is project dependent and very hard to assess without plant to plant information, I assume operation (and generation) to only start in year t1 (2023) for all power plants. Therefore, operational costs are zero in the initial period.

Table 1: Capital expenditure, initial costs in period t0.

Factor	Assumed Costs in 2022, in €, per module
Module Costs	150 000
Inverters	16 815
Mounting Hardware	53 215
Mechanical Installation	21 412
Transformers	27 086
LV Assemblers	17 790
MV Assemblers	3 310
Cabling	8 964
Monitoring	8 964
Construction Management	12 803
Landscaping	6 262
Permit Fees	247
Devex	5 526
Grid Connection	29 384
Other Factors (EPC Margins, additional electrical works etc.)	52 591
Sum	408 599
Contingencies	0.028616 * 408 599
Total Capex	420 291.5

5. Data

The following chapter briefly describes they structure of administrative census data in Germany. It starts with a description of the separate layers and also presents some relevant information on average are size. After this, I will talk about the specific process of how the data has been collected and talk about shortcomings and biases resulting from this.

5.1. Description of Land Survey Data

In Germany, survey agencies separate geographical data into x progressively finer layers of spatial aggregation. Starting from the top-level layer, Saxonia Anhalt (20452 km^2) is split into 14 districts (11 rural and 3 urban districts) with sizes between 2424 km^2 (Stendal) and 135 km^2 (Halle). Each district is then split into a varying number of municipalities. For the largest district, the 25 municipalities range between 294 km^2 and 92km^2. These municipalities are the smallest administrative units. Any territorial units below that are purely due to spatial identification but hold no political importance. Within these spatial units of separation, the Gemarkung (Gmrk) is the largest one. The average size of a Gmrk in my dataset is roughly 12km^2. A Gmrk is further separated into different Flure (FL). These FL vary considerably, both in size and in the number of units they entail. The smallest unit of separation is that of actual plots. These Flurstuecke (FS) are what is used as unit of observation in my dataset. Within one FL, they are identified through a combination of a denominator and numerator value. For most FS, the denominator value is missing, resulting in a FS that is uniquely identified through the numerator value. Both the numbers can have up to five figures. As numerator values are assigned in increasing order, any FS that are split at a later date are identified through a combination of denominator and numerator coding. As a result, any FS is identifiable through one unique combined number. Similar to issues mentioned previously, FS identified through a denominator are hard rather costly to identify automatically. As I can't use a list of existing FS, downloading those plots required to test for hyperlink existence of every numerator FS. So, where previously I had to test for FS with numerator 1, 2, etc. in any FL, I would now have to test for 1_1, 1_2, 1_3 etc. Therefore, my dataset contains a second major limitation, which is that it only includes numerator FS. Two sources of bias against the true population are possible. Firstly, it is plausible to assume that numerator FS resulting from splits in existing plots on average are smaller then unsplit plots. While my model for profitability assumes a plant's output and costs to respectively increase

and decrease in a linear fashion with area size, leasing costs could be non-linearily impacted by plot area. A second source of bias could be that the agricultural quality differs systematically between split an unsplit land. This could be the case if for example high yield acres typically remain unsplit, whereas low yield plots or residential areas are split more frequently after selling and or inheritance. Similar to the solution presented previously, one way to assess the size of this bias is to take a random sample of sufficiently small sample to still be feasible.

5.2. Data Collection

From Vattenfall's department for onshore wind, I got access to a dataset entailing information on a past survey on suitable spaces for renewable energy plants in Saxonia-Anhalt. To reduce the amount of information that had to be scraped down to a feasible quantity, I selected only those Gmrks that were part of this preselected dataset. While a list on all Gmrks in Saxonia-Anhalt can be collected, scraping all Gmrks for their FS is far beyond the feasible. For every additional Gmrk, the number of potential hyperlinks referring to FS increases by the number of FLs in a Gmrk multiplied by 10.000. With an averaged sleeptime of 2 seconds between different scraping actions, for a Gmrk with 20 FLs, the addition of one Gmrk adds an additional 7 days to the scraping process if I assume an average download time of one second.[3] Ideally, the analysis covered all Gmrks and consequently all FLs in Saxonia-Anhalt. Since there exists no publicly available dataset on FS, time constraints make this first-best solution impossible. The second-best approach would be to take a random sample of all FS in Saxonia-Anhalt that is large enough in population size to allow for sufficient coverage and small enough to keep computation time down to a manageable level. However, as the number of FS in FL is not uniform and there exists no list of all existing FS, the process of testing for which hyperlinks and FS exist almost takes as much time as the actual download. Consequently, it is impossible to obtain an ex-ante overview of the true population of FS to draw an accurate random subsample before starting the scraping process. Both the scraping and the testing for hyperlinks take too long to obtain an accurate overview of the entire sample.

[3] $1*20*10.000*3/(60^2*24) \approx 7$

To circumvent this issue, I decided to make use of the pre-selection in the low-medium-vulnerability dataset to identify Gmrk which are more suitable for renewable power plant operation then the average Gmrk. The resulting FS dataset is consequently inherently biased towards more suitable observations. In the final analysis, the result of a share of suitable areas is therefore also biased upwards. While this can be a problem if the results indicate a share beyond the exogenous political goal, a share below the publicly set threshold even in the presence of the aforementioned bias further confirmed the necessity for subsidies. One potential robustness test is to generate a second, much smaller dataset based on a random sample of Gmrks and then test the average size of the bias against my full Flurstueck dataset.

Through an exogenously given selection of larger scale areas (Gemarkung, abbr. Gmrk) that may include potentially suitable FSs, I get a list of Gmrks whose FS are of interest for further studying. As mentioned previously, this selection results from information on suitable areas for wind power plants. As Germany imposes exceptionally strict distance constrained between residential areas and onshore plants, areas included there can also be assumed as suitable for PV plants. Unfortunately, the resulting, this coarser unit of geographical separation is still two layers above the unit of interest. Administration splits each Gmrk into several so called Flure (FL). Each FL is then divided into FS of varying size. While information on the Flure is publicly available on the land surveying office's webpage, this does not include FSs. Instead of a complete dataset, information on individual FSs can be accessed in the form of a PDF file if its specific number is known. Through generation of a hypothetical list of all FS that could theoretically exist for every Flur in every Gmrk, I get a list of roughly 10.000 FS index numbers across all Flure across all Gmrks. This list indicates roughly 3.3 mio potential observations that could exist. As the hyperlinks to the FS PDFs follow a clear reproducible structure, I can generate links to first test for the existence and then download all FSs. The resulting dataset of ca. 400.000 FSs provides information on the area's size, its usage and consequently its leasing costs. The leasing cost are directly linked to a value resulting from the steuerliche Ertragsmesszahl (tax Measure of Income, srEMZ) relative to the total area size. This information has to be extracted from the Flurstueck PDFs through text extraction tools.

The resulting information on leasing costs can now be used in the previously mentioned profitability model to answer the question on how many areas in Saxonia-Anhalt allowed the

profitable operation of a PV plant. For ease of analysis, I decided to focus my selection on a random subsample of 5000 plots the total 407 848 observations. This is necessary since costs and benefits of plants vary over time. To accurately assess a net present value, I therefore need to construct a panel dataset of 30 years.

6. Analysis

The following chapter will now use the dataset on leasing prices and plot characteristics in the previously sketched model. To discuss for different developments, I present an assortment of scenarios, varying forecasted wholesale electricity prices, land leasing prices and discount rates. After a brief discussion about which prices and leasing costs to consider, I will present the profitability results.

6.1. Electricity Price

In essence the electricity price is among the most influential factors for future profitability of solar power plants. Unfortunately, recent political developments and their impact on the gas prices resulted in a high degree of variation in the prediction of (wholesale) electricity prices (Bâra et al., 2023; see also Ferriani & Gazzani, 2023; Hernández Rodríguez et al., 2023). To deal with this, I give several cases of predicted price development.

The first is the expected price as given in the Vattenfall exemplary model. However, since this does not give any information on the process behind, I use it mainly as a starting point for my analysis. It is important to note, that all price forecasts have to be on the wholesale price, not on consumer prices as this is what the producers receive from the TSOs.

A second estimation comes from a study for the union of Bavarian Economy on future energy prices in Germany. Their forecast is based on a set of assumptions on the expansion of renewable energy supply until 2040. For 2030, the report forecasts a share of around 74% of all electricity generated in Germany and is based on an assumption of a complete discontinuation of electricity production from coal around 2030 (vbw, 2022). While the spread between their forecasted high, medium and low price path is very large in 2022 – 2025, it decreased noticeably afterwards. Unfortunately, the forecast only covers the time frame until 2040, while my model assumes a 30 year uptime for a solar park and therefore extends up to 2052. Since the price fluctuation in the last years is very low, I decided to use the 2040 value for the remaining years. Figure xxx presents the four different price paths used in my analysis. The most noticeable difference is that the three price paths from prognos feature a much more pronounced increase in prices between 2022 and 2025. Afterwards, electricity prices decrease slightly for the three Prognos forecasting paths while

the Vattenfall prediction increases continuously. As will be discussed in chapter 6.3, these four pricing paths have a significant impact on the NPV.

6.2. Leasing Costs

Using information on agricultural quality from the srEMZ as explained in chapter 5.2, I use a model by Mundt (2018) on the relationship between land leasing prices, area and agricultural quality. Based on a dataset of actual market leasing prices for all leased agricultural land within a region, the author estimates the effect of agricultural quality on leasing prices in Saxonia in 2013 through the model:

$$P_i = (-31{,}0337 * FL_i) + \left(4.1745 * {FL_i}^{1.0389}\right) * AZ_i$$

Where:

- P_i: Is the leasing price of an agricultural area,
- FL_i: Is the geometric area,
- AZ_i: Is the Ackerzahl (AZ) as the result of $AZ_i = srEMZ_i * \frac{100}{FL_i}$, which ranges from 0 to 100, where 0 indicates land of extremely low value for agriculture and 100 indicates highly productive land. Through the srEMZ, this value includes information on slope, shade and climatical considerations. Typically, acres with an AZ of < 20 are deemed as unusable for conventional profit oriented agriculture (*AgriLexikon - Ackerzahl*, 2023).

Ideally, one would replicate this leasing cost estimation for current prices. However, this requires access to a dataset of land leasing costs, AZ values and plot size to estimate, which is unfortunately not publicly available. However, in the last decade, land leasing costs increased almost linearly by 45% on average (agrarheute, 2022). Therefore, the mean of leasing values resulting from the implementation of the aforementioned model using my data multiplied with 1.45 should give a value close to the average value in Saxonia-Anhalt. Information on the average leasing costs of agricultural land separate for the German regions is available on the website of the BVVG, for 2021 the value of the average agricultural lease is reported as 584 €/ha (BVVG Bodenverwertungs- und -verwaltungs GmbH, 2022). As reported in Figure 2, this is slightly higher than the calculated average lease. This is plausible considering that my preselection isn't a random sample of all areas in Sachsen-

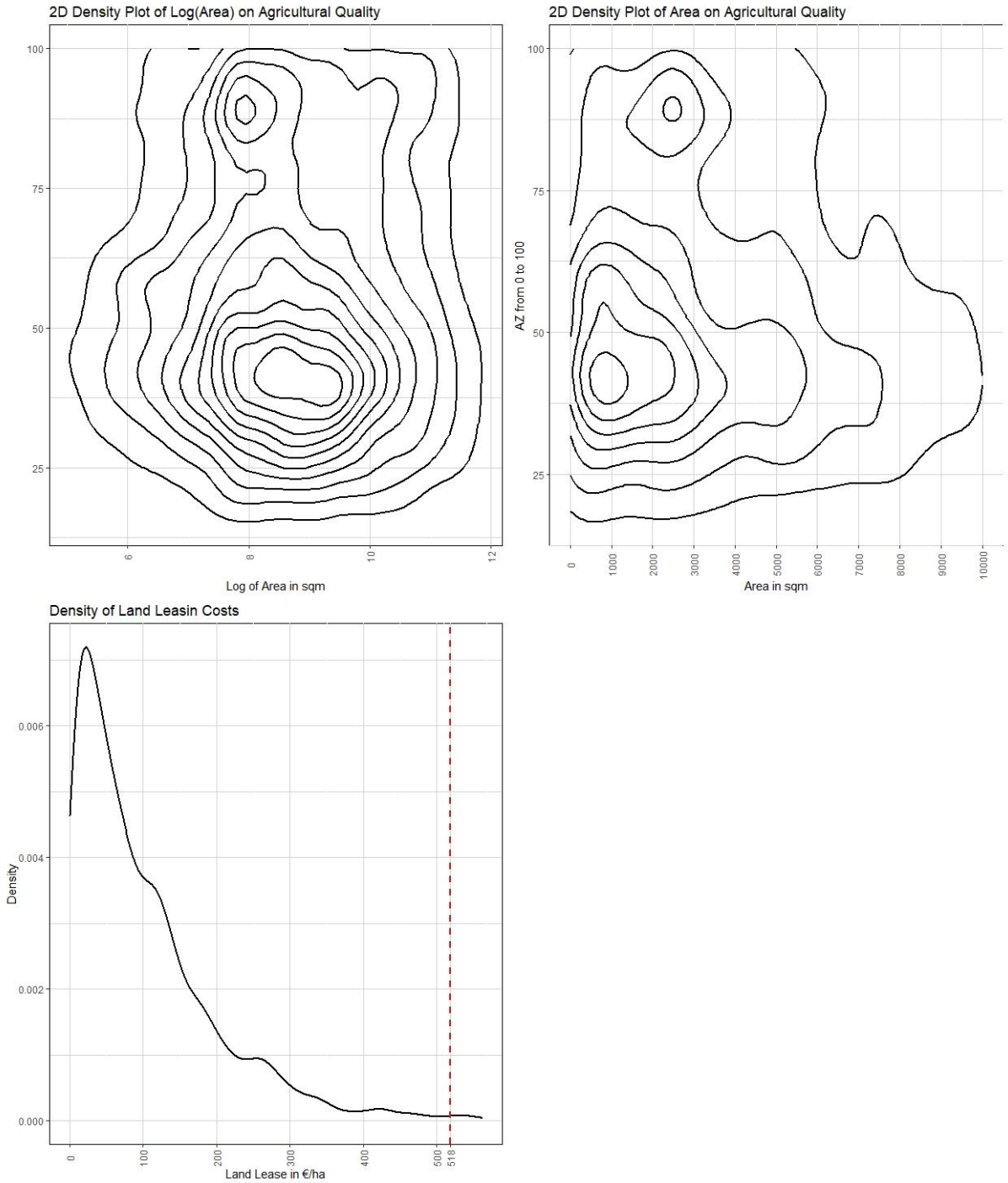

Figure 2: Density and 2D Density of Leasing Costs and Agricultural Quality.

Anhalt areas but instead a focus on areas with more than average suitability for RES generation.

To give different scenarios, I will include both a low cost case, in which leasing prices remain at the calculated 2022 level over the duration of the plant life. The only price increase results from inflation adjusted leasing prices. While this scenario is probably unrealistic, it helps to give a bottom line case with the lowest possible costs. Additionally, since leasing price had

been increasing almost linearly during the last decade, I decided to use this trend to estimate increasing leasing prices over time. To not overly complicate the presentation of my results, I will however only give the dynamic leasing costs scenario for the two cases of high and low electricity prices. Figure 2 shows the distribution of leases as well as a 2D density plot of agricultural quality to size. To improve accessibility, I excluded extreme outliers of 3 very large plots and limited the graphical representation to plots smaller than 10.000 sqm. Additionally, I include a second plot of logged area on quality. In both cases, there is no clear relationship between quality and size, with the contourlines indicating the majority of plots to lie between 1000 and 3000 sqm and a majority of qualities below an AZ of 50, which makes sense give the preselection of the underlying data. The density plot of leasing costs indicates a highly right skewed distribution of leasing costs. Again, this shows a selection of the overall dataset that is limited to plots smaller equal 10.000 sqm.

6.3. Scenario Overview

In essence, this analysis chapter will present the results of 10 scenarios as presented in Table 2. The baseline of comparison is the replication of the exemplary solar park as given by Vattenfall. This model includes the price path as presented in the first column of Table 4: Electricity wholesale price forecasts in €/MWh. in the Appendix. Model 1, 5, 6 and 10 are given in the top-right graph in Figure 3. It is interesting to note that across all model specifications, the NPV is always > 0, which indicates that all areas allow for a profitable operation of solar plants. Additionally, the overarching relationship between NPV and size is always almost perfectly linear, regardless of the model specification chosen. The main difference lies in the slopes of the relationships. As can be seen in plot (A), changing the price path has a stark effect, which is most pronounced for large plots. This relationship is easily explained since plant benefits are a linear function of plant capacity which is a linear function of the area.

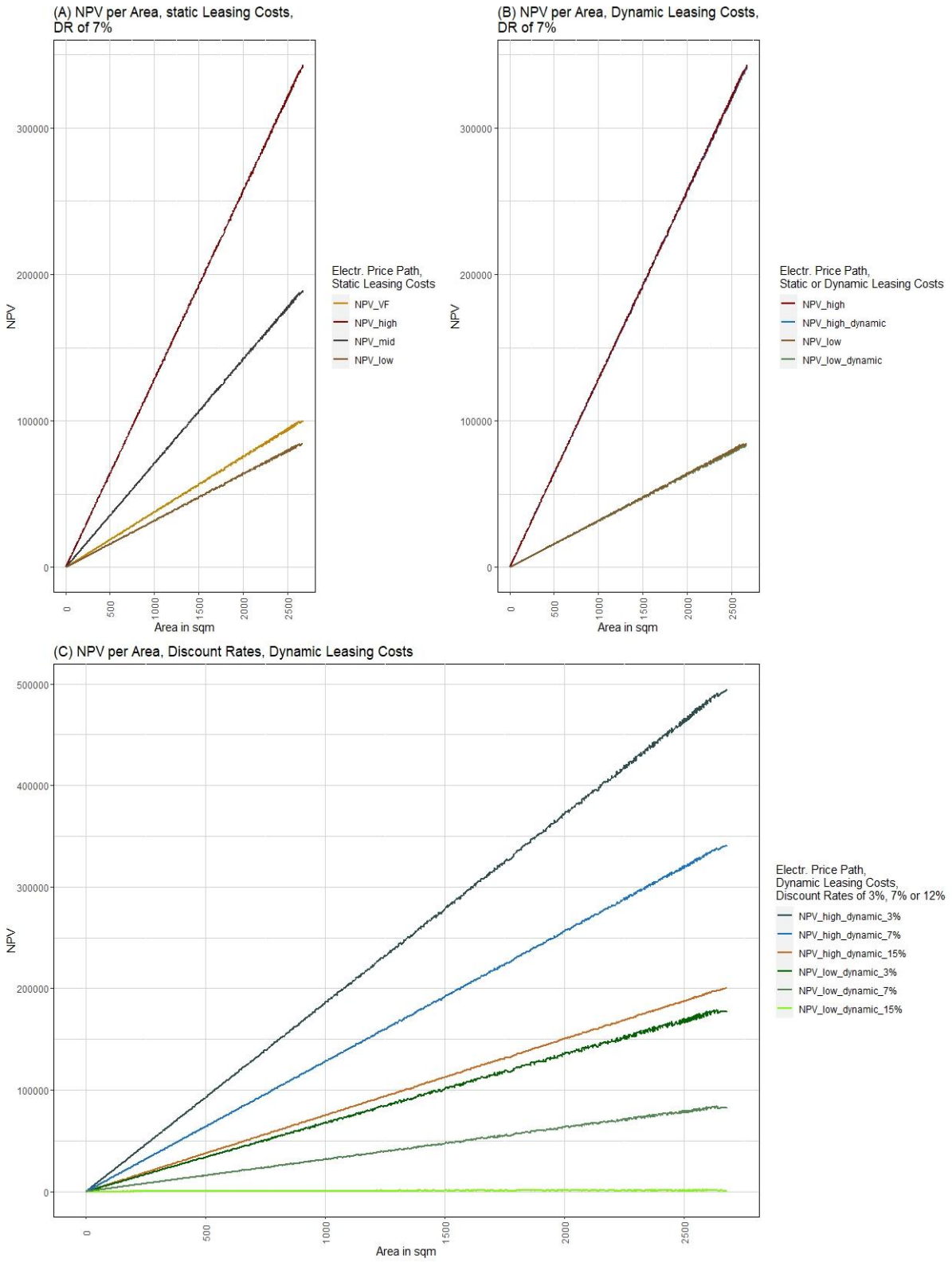

Figure 3: NPV Values Relative to Determinants.

Table 2: Schematic overview of presented scenarios.

Price Path	VF	Low Price				Mid	High Price			
Leasing Model	Static	Dynamic			Static	Static	Dynamic			Static
Discount Rate	7% (1)	3% (2)	7% (3)	15% (4)	7% (5)	7% (6)	3% (7)	7% (8)	15% (9)	3% (10)

As can be seen in plot (B), differences between dynamic and non-dynamic leasing costs are marginal. Therefore, the actual specification of leasing cost increases over time are not really crucial in determining the investment decisions. As the graph on the low cost curve is below the Vattenfall exemplary model for all acre sizes, I decide to use the Prognos high price path and the Prognos low price path as an upper and lower bound for further analysis.

To show the effect of changing the discount rate, I use two values proposed by Johannsen et al. (2023) in a recent study on future paths to a higher share of renewable energy usage in the European industry. The authors propose a 3% discount rate to mirror socioeconomic discounting. Additionally, they use a 15% discount rate to account for the "investment hurdles faced […] in industries" (Johannsen et al., 2023, p. 5). Interestingly, the case of a high discount rate of 15% together with an assumed low price path pushes the NPV values close to 0.

After discussing the effects of these scenario specifications, I will now discuss the effect on the generated capacity and measure it against what is theoretically necessary to fulfil the 22GW target set by the recent. German EEG revision

6.4. Results and Associated Capacities

The previous chapter presented the results of my analysis separated for 10 models. In all considered case, all plots allowed for the profitable operation of PV plants. The generated capacity is therefore 100% of what could theoretically be generated on the available space. Figure 4 gives the cumulative distribution of capacities across the NPV values for the case of a low price path, increasing leasing rates and high discount rate. This case is selected as a least likely case. If the capacity is enough in the unlikely case then it can implicitly be assumed as enough in all other cases of higher profitability such as higher price paths or

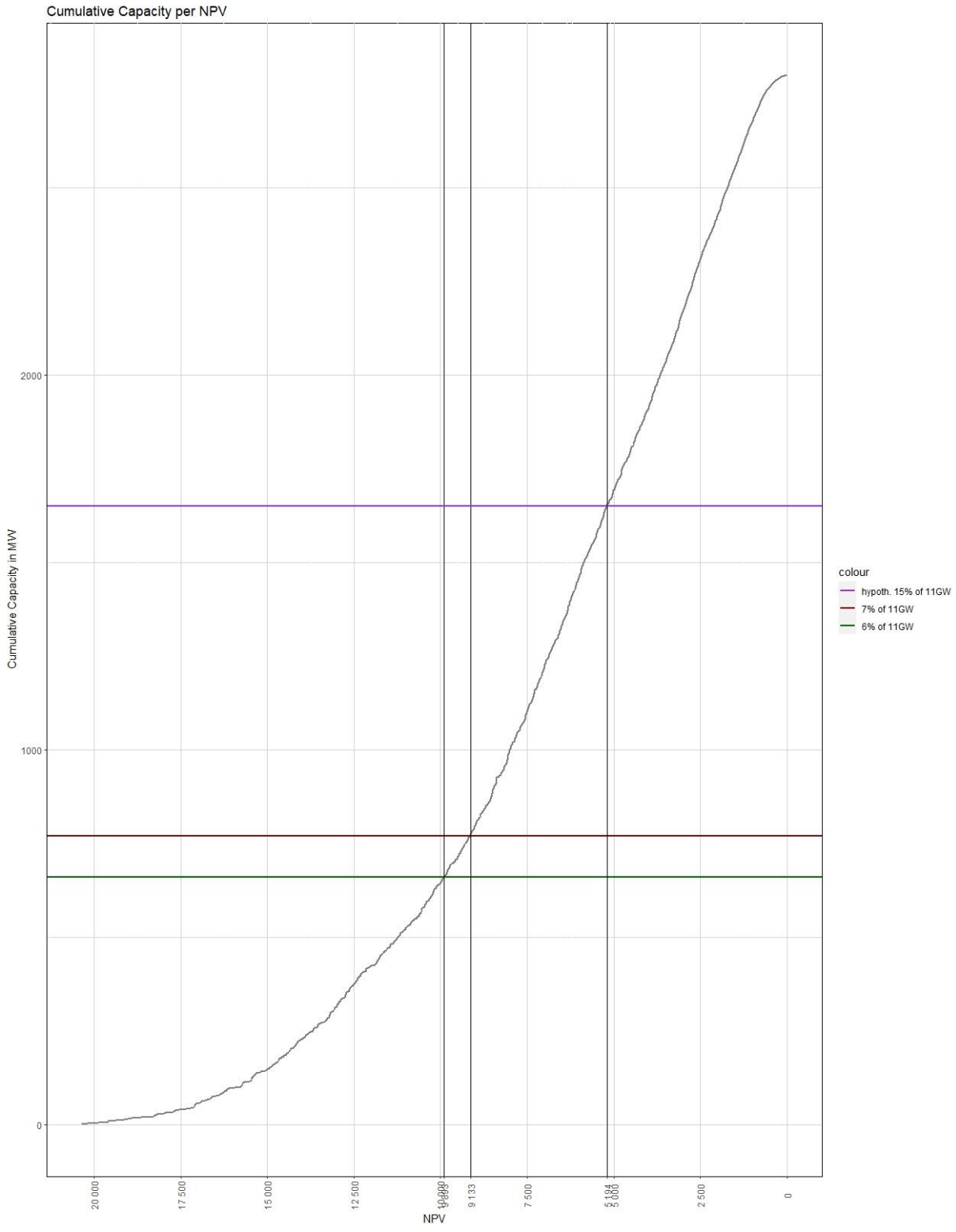

Figure 4: Cumulative Capacity per NPV (descending).

lower interest rates. In Figure 4 the horizontal lines mark both the case of 6% share of the 11GW German renewable capacity plans and the more ambitious 7% case. The associated vertical lines indicate the marginal NPV value that is necessary to ensure the cumulative capacity of either 660MW or 770GW. For 6% of the yearly 11GW non-roof mounted PV

plants to be set up in SA, a NPV of at least 9893 is required. For the more ambitious goal of 7%, the NPV decreases to 9133. In case of a very ambitious 15% (1100MW) to be implemented in SA, the necessary NPV decreases to 5194 and therefore includes more low profitable projects. For the 6% case, this equals 7.4% of all covered observations or an associated 23.5% of all land covered (~6.5sqkm). The numbers increase to 9%, 27.5% and 7.6 sqkm for the 7% goal and 24.6%, 59% and 16 sqkm for the hypothetical 15% goal. Table xxx presents these number. It is important to note that these threshold values assume all of the necessary capacity to be implemented in my random subsample. Unfortunately the total area of potentially suitable area in SA is hard to assess without a very time consuming geographic information based analysis.

Table 3: Thresholds for Shares.

	Min Necessary NPV	Share of Obs.	Share of Land	Area
6% (660MW)	9893	7.4%	23.5%	6.5 sqkm
7% (770MW)	9133	9%	27.5%	7.5 sqkm
15% (1650MW)	5194	24.6%	59%	16 sqkm
Full sample (2797MW)	/	100%	100%	27 sqkm

7. Criticism

Following the analysis and presentation of the results, this section will give the main points of criticism. Starting with issues of my estimation method for land leasing prices, I will then present some issues related to electricity price forecasts and discount rates.

7.1. Land Leasing Prices

Among the main points of criticism is my estimation of land leasing prices. While the comparison against average leasing prices in 2021 shows that the value is realistic, it is still only an estimation based on a model on data from 2013 and from a different region. Ideally one would either use the actual leasing prices for the specific pieces of land used, or at least estimate the relationship between agricultural quality, size and leasing price for a dataset of current level prices and on actual agricultural land in the regions selected in my dataset. Both approaches are however outside of what is feasibly for this thesis.

A second point of critics is the assumption of constant increase in leasing prices. At the moment, as Figure 2 shows, extremely low quality land is basically worthless with leasing prices close to 0. This is reasonable, if we consider that acres with an AZ smaller than 20 are deemed unusable for profitable agriculture. In the current market, where demand for agricultural land is almost exclusively motivated through agriculture, demand for these low quality plots should be practically non existent. With increased RES rollout, demand for agricultural land should increase across the curve. It is reasonable to assume this increase non-uniformely across the supply of land, as cheaper, low lease plots are more interesting for electricity generation than their expensive high quality counterparts. Ideally one would model a leasing price increase over time dependent on grouped land quality.

Luckily, these effects demand side effects for (especially low quality) land can reasonably be expected to happen at the end of the analysed period. Due to discounting any changes in the leasing prices impact the discounted net present value comparatively little. As has been discussed in the analysis section, the difference between static leases and dynamic leases is marginal.

While not directly linked to land leasing prices, one additional cost factor related to plot characteristics is that of grid expansion costs. Although of great interest, it was unfortunately

to time consuming to obtain an accurate assessment of related costs for each plot in the dataset. As such I had to omit these type of costs.

7.2. Electricity Prices

A second point of criticism are the assumptions about future electricity prices. Ideally one would compare different estimations for future wholesale electricity prices. However, price estimates panning the whole period of 31 years are surprisingly hard to come by. Especially fluctuation in the early years can have a large effect on the results.

Additionally, as indicated in the chapter on the history of the EEG, an increase in RES can over time crowd out conventional power plants and as a result reduce the electricity price through the merit order effect. In theory, this creates a very interesting effect of inverted simultaneous determination, where a high price forecast results in more renewable plants being build reducing the electricity price and vice versa.

7.3. Discount Rates

The discussion about discount rates is far from trivial and they can crucially affect the NPV outcomes, much more so than leasing prices. However, the corridor presented in Figure 3 is already very broad. Even in its extreme scenario of a 15% discount rate, all plots allow for the profitable operation of PV plants. Therefore, while a discussion on which value to use for the discount rate matters in a private setting where firms have to weigh up different forms of investment, for a social point of view the main take away is likely to remain unchanged as long as the discount rate doesn't significantly exceed the 15% upper bound considered here.

8. Conclusion

This analysis has shown that the respective share of the 11GW conventionally mounted PV plants for SA is feasible in my random selection of plots. This therefore my initially posted research question for the necessity of further political aid in that it is not necessary to implement further subsidies since a sufficiently large share of land allows for the profitable operation of solar powered plants under the assumption of a price path that is at least similar to the one considered here as the low price path.

Additionally I find that the exact development path of leasing prices matter comparatively little, especially in the current environment of very high electricity prices. The immediate gains of a power plant are very likely to outweigh incrases in losses due to increasing land prices.

While the findings of this thesis as such indicate that this is feasible even when restricting expansion to the more profitable plants, it is only a rough overview of potential factors determining the profitability. Ideally one would include a more in depth discussion of the evolution of component costs, electricity prices and leasing costs. Further research could focus on the dynamic relationship between land leasing costs and increased RES roll out as at some point the current resource of cheap low yield agricultural land might become comparatively scarce, increasing land prices beyond the current path which is exclusively determined through agricultural demand.

Additionally, modelling profitability in dependence of the electricity prices induces a second source of interesting simultaneity as a higher share of RES might crowd out conventional plants and therefore decrease the electricity price.

9. Appendix

Table 4: Electricity wholesale price forecasts in €/MWh.

Model	Vattenfall	VBM High	VBM Mid	VBM Low
2022	50,4	300	170	170
2023	56,2	512	189	104
2024	57,1	300	165	82
2025	61,5	160	150	80
2026	61,4	140	115	77
2027	62,7	105	90	70
2028	61,7	100	85	67
2029	60,9	95	82	65
2030	62,7	98	84	66
2031	63,5	89	80	64
2032	65,9	87	78	62
2033	67,8	86	75	60
2034	71,8	85	72	57
2035	74,6	84	70	55
2036	78	87	75	57
2037	80,3	88	78	60
2038	85	88	79	62
2039	88,5	80	72	57
2040	89,4	79	69	57
2041	91,7	79	69	57
2042	94,1	79	69	57
2043	96,5	79	69	57
2044	99,5	79	69	57
2045	102	79	69	57
2046	104	79	69	57
2047	106,5	79	69	57
2048	108,4	79	69	57
2049	111	79	69	57
2050	113	79	69	57
2051	117	79	69	57
2052	121,1	79	69	57

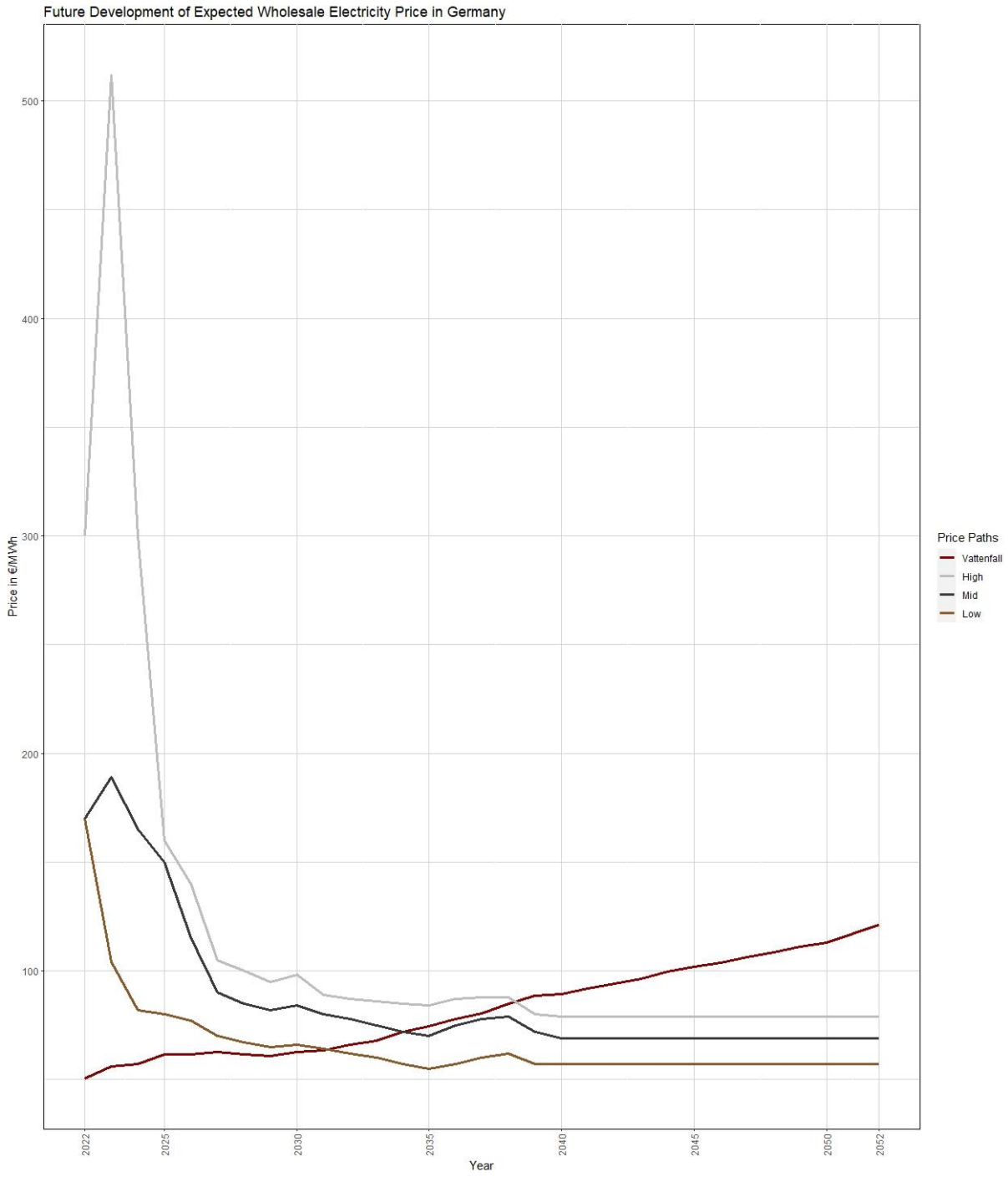

Figure 5: Wholesale Electricity Price Paths.

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