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Wind Power and the Cost of Local Compensation Schemes: A Swedish Revenue Sharing Policy Simulation

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Abstract

Local resistance towards wind power is a central challenge for the energy transition, implying that legally imposed compensation schemes for nearby residents may become prevalent in the near future. I use GIS-coded data on detached residential buildings in Sweden to simulate a variety of revenue sharing schemes applied to every present and planned commercial scale wind power project, focusing on documenting the impact on investor costs. I compare models that entitle compensation for distances between six and ten times the tip height of the closest turbine, imposing schemes that are both constant within the eligible distance, as well as declining with the distance from the turbine. When compensations are awarded for residents as far away as ten times the turbine height, foregone revenues exceed two percent for one-fourth of the projects in the southern region even under the declining model, indicating that the scheme could have a substantive effect on the localization decisions of future investments.

Keywords: Wind power; negative externalities; local acceptance; energy transition; NIMBYism

JEL: H23; D62; D4; P18; P48

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1 Introduction

Albeit a cornerstone of the energy transition, wind power is also associated with negative local externalities in the form of visual and acoustic disturbances for local residents and worsened conditions for wildlife (Zerrahn, 2017). Concordantly, almost every published European study examining the effect of wind power on property values find a statistically and economically significant negative effect (Parsons and Heintzelman, 2022). A growing literature also demonstrates that the presence of nearby wind turbines reduces residents' willingness to participate in the energy transition in general, for example by lowering the interest in clean energy tariffs and reducing voter support for "green" politicians (Germeshausen et al., 2023).

A socially sustainable wind power expansion could therefore be facilitated by financial compensation mechanisms for nearby residents, thereby mitigating local opposition. Such mechanisms rarely arise through voluntary negotiations between developers and nearby residents, for several reasons. First, approval decisions are in most countries the responsibility of the local or county government and not the residents themselves. Thus, "negotiations" between residents and developers necessitate engagement with local planning authorities who typically lack the mandate to both design and introduce such mechanisms. Second, even under the assumption that nearby residents were responsible for approval decisions, negotiations would have to involve a large number of residents with limited means of coordination and information about the expected future impact of the project, leading to substantial transaction costs. Therefore, the prerequisites for achieving socially efficient bargaining outcomes are not met (Coase, 1960), suggesting that a legally imposed compensation scheme could serve to internalize these negative externalities. Consistent with this argument, a recent study on wind power applications in the UK finds that inefficiencies in the approval process (i.e., approving projects that should have been rejected and vice versa) have resulted in misallocation of investments due to a lack of internalization of negative externalities (Jarvis, 2022). Irrespective of the static welfare effects in terms of direct investment misallocation, local acceptance is also a prerequisite for a distributionally equitable and socially sustainable wind power expansion with broad public support.

While previous studies provide rigorous evaluations of the effectiveness of financial compensation schemes from the viewpoint of the residents, less is known about the effect on investors' revenues given that such compensation schemes would be implemented on a wider scale. The aim of the

present study is to perform a diagnostic assessment of the impact on investor revenues following two hypothetical "generic" compensation schemes imposed on the stock of current and planned wind power projects in Sweden. Common to both models is that nearby residents are entitled a share of the revenue generated by nearby turbines. None of the models incorporate topographic characteristics determining turbine visibility, although previous studies demonstrate that these are crucial determinants for quantifying the effects on property values (Jarvis, 2022). Such models would demand much more extensive data collection, severely limiting model tractability and transparency.

An international generalization of the results is not straightforward since the density of buildings around wind turbines is likely lower in Sweden than in most other European countries. It is also not certain that an introduction of a scheme would have a greater influence on actual siting in Sweden than elsewhere, since siting depends on several factors such as the attractiveness of potential sites outside populated areas, the approval process, and electricity prices. However, the main take-away of the simulation is to highlight how results vary with the type of compensation scheme employed, rather than to provide an exact international generalization of absolute levels.

In the first, "constant", model, every house within a distance of a given factor X of the tip height H of a turbine ("XH") is entitled to the spot market value of a predefined share of turbine output, and the payout remains unchanged for all distances until the threshold is reached. Investor costs are simulated for distances between 6H-10H. 6H is a natural lower bound since very few turbines are allowed at closer distances. In the case of a typical turbine with a height of 180 meters, this suggests a distance of approximately 1 km. 10H is a natural upper bound since most research on wind power and property values indicate a statistically significant negative effect up to 2 km (i.e. somewhat above 10H given a tip height of 180 m), while the effect for longer distances is limited and diminishes quickly (Parsons and Heintzelman, 2022). 10H is also the reference point for several recent laws and policy proposals in e.g. Sweden; Bavaria; and Poland (Ministry of Climate and Enterprise, 2023; Bayern Innovative, 2024; International Trade Administration, 2024). In the Swedish case, 10H marks the cutoff for a scheme proposed to compensate nearby residents. In Bavaria and Poland, previous legislation imposed 10H-minimum distances below which no turbines have been allowed, although these rules have recently been relaxed in the wake

of the recent energy crisis.

In the second, "linear", model, compensations mirror those of the constant model for distances up to 6H, and then decline linearly down to zero at distances between 6H-10H. Potentially, compensations could have varied also within distances between 0H-6H, but given that a turbine passes environmental legislation at these distances, topographic characteristics usually limit the visual impact considerably, limiting the value of differentiating the compensation further.

In both models, each household is entitled to compensation for the two turbines that generate the highest individual compensation. The choice to limit compensation to two turbines relies on the assumption that the marginal disamenities from additional turbines likely diminish rapidly, and that a more accurate mechanism would lead to a lower degree of tractability and transparency.

An alternative formulation would be to differentiate compensations only based on tip height and distance from the turbine, thereby imposing a predetermined absolute level of compensation for each household in terms of MWh. However, developers may desire to build turbines with greater capacity, and in more visible locations with better wind conditions, than what is preferred by the local community. When revenue sharing is directly proportional to output, preferences of the local community and the developer become better aligned. Further, local opposition is also sometimes based on the notion that nearby residents should get a "fair share" of the value creation from wind power. This view is especially common in the northern region, due to a historical lack of local benefits following the expansion of hydropower during the first half of the 20th century (Lindvall, 2023). It is therefore natural to allow compensation to be proportional to output.

In principle, the constant model resembles the Danish compensation scheme *VE-bonusordningen*, which gives residents within 8H of a turbine the right to the spot market value corresponding to the electricity produced by 6.5 kW of the installed capacity of a nearby wind farm, conditional on that the total compensation cost does not exceed 1.5 percent of total output (Energistyrelsen, 2024). If this cap is reached, the compensation for nearby residents is scaled down accordingly. To the best of my knowledge, no current official standardized compensation mechanism resembles the linearly declining structure of the present study.

I present simulation results separately for the north and south region of the country, since both electricity prices and population density are higher in the south. In the following, I briefly describe my results using three different metrics, focusing on the 10H linear model. First, I express the cost of each model by normalizing the cost of the 6H model to unity for each separate project (for the 6H-model, the constant and linear models are identical). The linear 10H-model then increases total costs by on average 3.7 (4.3) times in the north (south) compared to the 6H-model. Second, I compute costs as a share of total project output, by imposing a base-level of compensation for eligible households. It is not evident how to determine a sufficient level of compensation that is likely to compensate for the disamenities and thereby increase local acceptance. I here borrow from previous studies finding that free electricity for the most affected households would suffice to achieve local acceptance, and parameterize the model accordingly. Although it is beyond the scope of this study to speculate around the deeper psychological mechanisms behind this preference, it's worth noting that this type of compensation underscores the value creation from wind power in the form of electricity, as opposed to directly counterbalancing the disamenities and their subsequent effects on property values. Under the linear 10H model, the compensation then amounts to 0.2 (0.8) percent of project output for the median project in the north (south). Third, I compute the cost in kEUR/MW of installed project capacity, by also imposing assumptions on electricity prices based on historical spot market prices. Differences across regions then become more accentuated, since prices are higher in the south. Under the linear 10H-model, costs for the median project are 2 (14) kEUR in the north (south). Under the simplified assumption that the direct investment cost is about 1000 kEUR/MW, this implies a cost increase of 0.2 (1.4) percent respectively.

Last, it should also be emphasized that investors usually spend substantial time and effort to increase the probability of approval by negotiating with local policy makers, residents, and other stakeholders. Given that a compensation scheme reduces the costs associated with this negotiation, it would also lead to a cost reduction. Although a quantification of this reduction is beyond the scope of this study, it is likely that the relative cost savings would be higher in the south, due to higher population density and greater local opposition.

Another method for including compensation cost in profitability of wind power under various local compensation schemes is given by Hevia-Koch and Jacobsen (2019), where acceptance costs

are included as a component in the levelized cost of energy (LCOE) for a hypothetical nationwide expansion of wind power in Denmark. The study compares the acceptance cost of on- and offshore wind power respectively, using several different methods quantifying local acceptance, concluding that onshore does in fact not have an unequivocal cost advantage over offshore wind. However, due to the different methods used, their results are not directly comparable to the results in the present study.

In Sweden, local opposition is generally more complex than what can be explained within a standard NIMBY (Not In My Back Yard)-framework (i.e., that residents support wind power in general, but not if it is located nearby). For example, perceptions of distributional injustice, generated by the lack of local economic benefits and the geographically and socioeconomically uneven deployment of wind power, are also relevant in explaining local acceptance (Lindvall, 2023). Concordantly, Liljenfeldt and Örjan Pettersson (2017) demonstrate that the probability of approval for a wind power project is negatively associated with socioeconomic indicators, especially the level of education. Education is interpreted as a proxy for residents' knowledge regarding the possibilities to take part in and influence the planning process and to make appeals, as well as the connection to more extensive networks which can be mobilized against a wind power project. These results could be interpreted not only in terms of distributional justice, but also *procedural* justice. Unlike distributional justice, procedural justice is concerned with the process through which transition is achieved, such as how different stakeholders are enabled to participate in the approval process (McCauley et al., 2018). The most recent study on wind power resistance in Sweden is Niskanen et al. (2024), confirming that local opposition stems from several factors. For example, the study demonstrates how local resistance groups during recent years have adapted a view that could be characterized as "not in anyone's back yard", expressing a disbelief in wind power as a source of energy in general, regardless of its local environmental impact.

The international literature on the complexities of wind power opposition is also growing: Froese and Schilling (2019) study the nexus of climate change and conflict of land use from a variety of perspectives, including a rich literature review with about 20 articles on wind power and public acceptance. In another literature review of survey-studies, Anfinson (2023) finds that the public is generally more positive towards wind power relative to other energy infrastructure

projects, such as transmission lines. The study also provides a critical view on the methodology employed by most of the studies on similar topics, since surveys are often limited to one single hypothetical project, which reduces the possibility to generalize findings across studies. Bessette and Crawford (2022) review more than 100 articles in the US and Canada, and Segreto et al. (2020) present a review of around 40 European articles. A common lesson is that financial incentives matter for local acceptance, whether it is in the form of e.g. revenue sharing or lower electricity tariffs for nearby residents. Several of the included studies find that free electricity for the most affected households could serve as a guideline for the level of compensation that would be sufficient to achieve local acceptance. Financial participation is also noted as a key driver of local acceptance by a policy project conducted under the EU Horizon 2020 research and innovation program (WinWind, 2020), suggesting the removal of legal barriers for electricity sharing and other financial arrangements.

2 Institutional background and data

2.1 Wind power in Sweden

Before the turn of the century, large scale wind power plants were virtually non-existent in Sweden. A green electricity certificates system was introduced in 2003, which, together with a reduction in investment costs and inflow of international capital, led to a sharp increase in installed capacity beginning in 2007 (Swedish Energy Agency, 2021). Wind power is still expanding steadily, with the rate of increase being approximately constant during the last decade.

At the outset of deregulation in 1996, Sweden constituted one single price zone. A market splitting reform was implemented in 2011, creating four price zones. On a yearly basis, spot prices were approximately equal across zones until 2020, and have since increased relatively more in the two southern zones, together constituting about half of Sweden's area. Henceforth, I refer to these two zones as the southern region. Lundin (2022) finds that the price reform caused a moderate increase in wind power investments in the southern region, and that this effect was driven by large, commercial investors. However, a majority of the investments in terms of capacity are still undertaken in the northern region, where population density is lower.

Applications for wind power have to be approved by the local government (the so-called municipal "veto"), which means that the possibilities of approval depend on the policy preferences of

the local government. Except for local approval, the project is also subject to an evaluation conducted by non-political officials to ensure that impacts on nearby residents, birds, wildlife, and recreational areas, comply with legal environmental requirements. For a more detailed account of the application process, see Appendix B.

There are two distinct rationales behind wind power investments. First, there are commercial projects that involve multiple turbines. These projects are often investor-owned, although they may also be owned by smaller firms or local consumer-owned economic associations. These projects usually comprise five turbines or more, with the purpose of generating profit. Second, individuals and consumer-owned economic associations sometimes initiate small scale wind power projects, with the combined purpose of generating electricity for its members and an intrinsic preference for carbon-neutral electricity. As the interest of the present study lies in large, commercially viable projects, I restrict the study to projects with five or more turbines.

In 2022, the Swedish government appointed an inquiry to develop a compensation mechanism for those affected by wind power. The proposed mechanism roughly corresponds to the linear 10H-model presented here. Specifically, the proposed mechanism entitles every detached house within 1 km of a turbine a share of the estimated spot market revenue of the turbine's output. The level of the share is determined based on the presumption that households closer than 1 km from at least two representative turbines should be (approximately) fully compensated for their cost of electricity (excluding network charges), and amounts to 0.25 percent of turbine output. This figure is employed also in the models proposed in the present study. For a detailed account of how electricity expenses are mapped to the 0.25 percent sharing rule, see Appendix C. For distances between 1 km and 10H, the proposed compensation declines linearly until it reaches zero at 10H. Some key figures on the implied investor costs of this scheme are documented by the Ministry of Climate and Enterprise (2023)[pp.335-343] and were originally compiled for the inquiry by the author of the present study.

2.2 Data

Wind turbines

Data on wind turbines are from "Vindbrukskollen", a publicly available database managed by the Energy Agency. These data contain information about the coordinates, tip height, capacity,

owner, and construction year of each turbine. It also includes information on approved turbines that are currently in the planning phase, as well as data on applications for turbines where approval decisions are pending. Data on the coordinates of existing turbines are more complete than application data, and some of the projects that are still in the planning phase have therefore been dropped from the analysis. The data set is available through Lundin (2024), which also includes data on distances to residential buildings.

Buildings

Only detached houses are included in the model simulation. Potentially, also multi-family homes and commercial buildings could be regarded as eligible for some type of compensation. However, more than 95 percent of all buildings within 10H are classified as detached houses. Therefore, other buildings are excluded for the sake of tractability and transparency.

House prices

Data on house prices are on municipality level, and are publicly available through Statistics Sweden (2024).

2.3 Descriptive statistics

Table 1 summarizes the variables used in the analysis, by region (north/south). Regions are approximately equal in terms of area. The unit of observation is project, and house counts are based on all turbines in the project. The first set of variables describe the number of houses within various multiples of the tip height. The first variable counts the number of houses within three times the tip height of at least one turbine, which is around 0.5 for both regions. For the following variables, house density is larger in the south, with approximately three times as many houses for every distance band. The next variables describe house density based on kilometers from the project. Here, the difference across regions is greater than when comparing the tip height based metrics, since turbine height is lower in the south. The following set of variables describe project characteristics, highlighting that projects in the north contain both more and higher turbines than in the south, with an average installed capacity that is almost twice as large. The difference in turbine height across regions can be explained both by lower population density in the north, which has enabled higher and more turbines, and also since projects in the south

are on average two years older. The next variable is the self-reported estimated capacity factor. This variable is available for about 80 percent of the existing projects, but is lacking for almost all planned and pending projects. The mean capacity factor is 35 % and the standard deviation is 9 % in both regions. See Figure A1 for a scatter plot of this variable, by region. The last set of variables contain mean prices for permanent and holiday houses in the municipality where the project is located. As expected, prices of permanent houses are higher than holiday houses. Further, prices in the south are nearly double those in the north. Several previous international studies have highlighted that house prices nearby wind power projects are on average lower than in surrounding areas not only due to the causal impact of wind turbines, but also since wind power is usually located in less attractive areas. Wilhelmsson and Westlund (2023)[Figure 3, p. 19] demonstrate that this relationship holds also for Sweden, with approximately 15 percent lower prices in neighborhoods nearby wind power already ten years before construction.

Table 1: Summary statistics of main variables

	North		***South***		***Diff***
	Mean	Sd	Mean	Sd	
House counts based on tip height					
nr. houses < 3H	0.50	1.28	0.51	1.18	-0.01
nr. houses < 4H	1.04	3.12	2.10	3.99	-1.06**
nr. houses < 5H	2.08	5.89	6.11	9.53	-4.03***
nr. houses < 6H	4.23	10.92	12.55	17.06	-8.32***
nr. houses < 7H	6.90	16.08	21.71	28.09	-14.81***
nr. houses < 8H	10.64	23.88	33.34	44.34	-22.71***
nr. houses < 9H	14.89	30.49	47.20	59.96	-32.31***
nr. houses < 10H	19.45	38.27	63.20	79.75	-43.75***
House counts based on km					
nr. houses < 1 km	1.92	3.20	13.44	26.38	-11.52***
nr. houses < 2 km	25.53	63.17	103.79	158.23	-78.26***
nr. houses < 3 km	63.99	137.29	292.50	451.41	-228.51***
Project characteristics					
Capacity	85.79	135.67	27.91	33.61	57.88***
Nr. of turbines	29.40	31.40	10.86	7.64	18.54***
Tip height	189.31	46.10	169.37	48.88	19.94***
Construction year	2013.71	4.66	2011.38	5.82	2.33**
Capacity factor	35.42	9.20	35.06	8.96	0.37
House price in municipality					
Houseprice (permanent)	115.10	66.11	214.09	95.07	-98.99***
Houseprice (holiday)	93.39	54.22	179.97	94.92	-86.57***
Observations	148		187		335

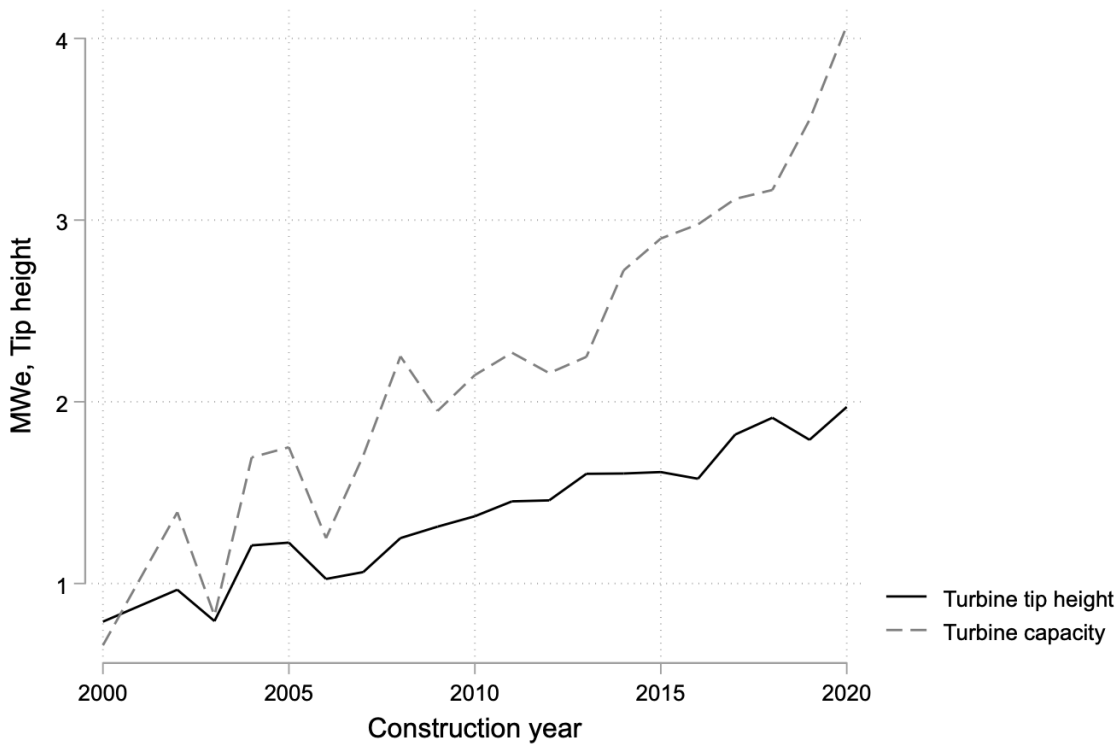
* p < .10, ** p < 0.05, *** p < 0.01
Note: Summary statistics of the main variables. Each project is a separate observation. The left (right) column contains applications in the north (south) region. Capacity in MW. Houseprices in kEUR. A *t-test* is used to test for differences in means across regions.

While Table 1 includes all projects, Table A1 contains only projects that are either planned or pending (i.e., still in the process for a final decision), demonstrating that these turbines are on

average notably higher (220 m) than the existing ones (170 m). Also for these projects, there is a difference in project capacity across regions, where the northern projects contain more turbines than those in the south, although tip heights are not statistically different.

Figure 1 demonstrates that tip heights for constructed turbines have approximately doubled between 2005 and 2020. Also depicted is turbine capacity, demonstrating an approximately fourfold increase during the same period. This is mainly since blade length increases approximately proportionally with turbine height, causing the rotor swept area (and thereby capacity) to increase at an even greater rate (since rotor swept area is $\pi \times \text{bladelength}^2$). The rotor swept area is in turn proportional to the power output of a turbine [1].

Figure 1: Trends in turbine height and capacity

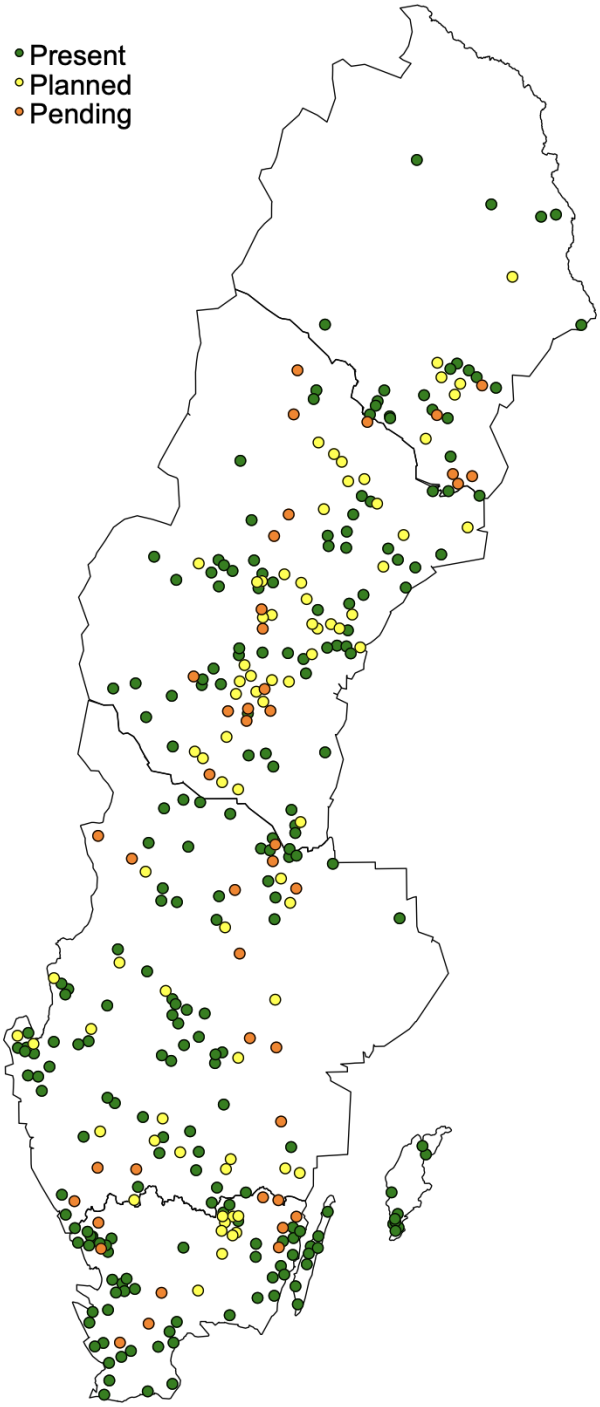


Note: Trends in turbine height (solid black) and capacity (dashed gray) of installed wind power turbines. Tip height in hundreds of meter. Capacity in MW.

Figure 2 depicts the locations of existing (green), planned (yellow) and pending (orange) projects, demonstrating that each subgroup is relatively evenly distributed across the country.

[1] Specifically, Power output of a turbine = rotor swept area $\times$ air density $\times$ wind speed^3 $\times$ power coefficient $\times \frac{1}{2}$

Figure 2: Present, planned, and pending projects



Note: Locations for existing (green), planned (yellow), and pending (orange) wind power projects. Black lines are price area borders. The two top areas (SE1 and SE2) comprise the northern region, and the two bottom areas (SE3 and SE4) comprise the southern region.

3 Formal description of the simulation model

Constant model: A house within a multiple of X times the tip height of a turbine ("XH") is entitled to a compensation corresponding to the spot market value of 0.25 percent of the output from that turbine. Distance is measured based on the centroid of the house and the turbine respectively. Compensation is awarded for at most two turbines. If more than two turbines are located within the relevant distance, compensation is awarded for the two turbines that generate the highest compensation. Simulations are conducted for discrete distances ranging between 6H-10H.

Linear model: For distances up to 6H, the compensation is computed according to the constant model described above. For distances between 6H up to a factor XH, the compensation in terms of MWh is computed according to:

$$Compensation^{MWh} = \sum_{i=1}^{2} turbine_i^{MWh} \times 0.25\ \% \times (1 - \frac{distance_i - 6H}{XH - 6H}) \tag{1}$$

Where subscript i refers to turbines 1 and 2 respectively, and $turbine_i^{MWh}$ is the output of turbine i. To compute the compensation in monetary terms, the compensation in terms of MWh is then multiplied by the corresponding hourly spot market price. Simulations are conducted for discrete distances ranging between 6H-10H. For a detailed account of how electricity expenses are mapped to the 0.25 percent sharing rule, see Appendix C.

4 Simulation results

As described in the introduction, I present results using three metrics. In the first "normalized" metric, there are no assumptions on the level of individual compensation shares or spot market prices, since costs are expressed as multiples of the 6H-model. In the second "output share" metric, I impose the 0.25 percent sharing rule discussed above and express costs as shares of project output. In the third "kEUR/MW"-metric, I impose prices corresponding to the average regional prices during 2023, adjusted by a capture rate of $\frac{3}{4}$. After the adjustment, prices correspond to 34 (50) EUR/MWh in the north (south). I also assume a project lifetime of 20 years, subject to constant yearly compensation payments using a real discount rate of five

percent. Capacity factors correspond to the observed ones where data is available, and 0.35 (i.e. the sample mean) for the remaining projects. Costs are then expressed as the cost in kEUR/MW of installed capacity. Summary statistics for each metric are presented in Table 2.

The model of most interest to policy makers is likely the 10H linear model, as it resembles most closely the model suggested by the government inquiry discussed in the introduction (Ministry of Climate and Enterprise, 2023). This model should also be of greatest interest internationally, due to the number of recent legislative debates related to the 10H threshold in e.g. Bavaria, Poland, and Ireland. Further, the fact that compensations decline with the distance to the turbine reflects that disamenities decrease with distance, and should therefore be most efficient in providing sufficient compensations to achieve local acceptance while also keeping investor costs reasonable levels. Therefore, this model is the focus of the discussion.

After presenting the results associated with each cost metric, I discuss how the compensation scheme may affect the locations and tip heights of future turbines, and if the scheme is likely to compensate for property value losses.

Table 2: Compensation levels, by region and cost metric

	North			***South***			***Diff***
	Mean	Sd	Max	Mean	Sd	Max	
Normalized (constant)							
6H	1.0	0.0	1.0	1.0	0.0	1.0	0.0
7H	1.9	1.5	13.0	2.2	1.1	9.0	-0.2
8H	3.5	4.4	38.0	3.9	3.1	25.0	-0.4
9H	5.3	7.0	58.0	6.3	6.5	52.5	-1.0
10H	7.6	10.1	83.0	9.4	11.7	107.5	-1.8
Normalized (linear)							
6H	1.0	0.0	1.0	1.0	0.0	1.0	0.0
7H	1.5	0.7	6.7	1.5	0.5	4.6	-0.1
8H	2.1	1.8	16.2	2.2	1.2	10.1	-0.2
9H	2.8	3.1	27.4	3.2	2.3	16.2	-0.3
10H	3.7	4.5	38.5	4.3	3.9	31.1	-0.6
Output share (constant)							
6H	0.1	0.2	2.2	0.5	0.6	3.1	-0.4***
7H	0.2	0.4	4.4	0.8	1.0	5.4	-0.7***
8H	0.3	0.9	7.2	1.4	1.7	12.1	-1.0***
9H	0.5	1.6	14.4	2.0	2.7	18.6	-1.5***
10H	0.7	2.5	24.7	2.9	4.1	31.0	-2.2***
Output share (linear)							
6H	0.1	0.2	2.2	0.5	0.6	3.1	-0.4***
7H	0.1	0.3	3.3	0.6	0.8	3.9	-0.5***
8H	0.2	0.5	4.5	0.9	1.0	5.7	-0.7***
9H	0.2	0.7	5.9	1.1	1.4	8.7	-0.9***
10H	0.3	1.0	8.3	1.5	1.9	12.7	-1.1***
kEUR/MW (constant)							
6H	1.1	3.0	28.4	8.9	12.0	62.2	-7.7***
7H	2.2	5.7	56.2	16.0	19.3	102.6	-13.8***
8H	4.0	11.2	92.6	26.2	33.7	243.2	-22.2***
9H	6.4	19.6	165.9	39.1	51.5	375.3	-32.7***
10H	9.2	29.9	285.6	55.2	79.1	624.6	-46.0***
kEUR/MW (linear)							
6H	1.1	3.0	28.4	8.9	12.0	62.2	-7.7***
7H	1.6	4.3	42.2	12.1	15.3	78.5	-10.5***
8H	2.3	5.9	57.4	16.5	20.3	115.9	-14.2***
9H	3.2	8.6	75.2	21.8	27.0	175.9	-18.6***
10H	4.4	12.4	95.7	28.1	36.0	257.0	-23.7***
Observations	120			183			303

* $p < .10$, ** $p < 0.05$, *** $p < 0.01$

Note: Cost of each compensation model using various cost metrics, by region. Normalized costs are expressed as multiples of the 6H constant model. Output shares are expressed in percent of project output. kEUR/MW is cost in kEUR per installed MW capacity of the project. A *t-test* is used to test for differences in means across regions.

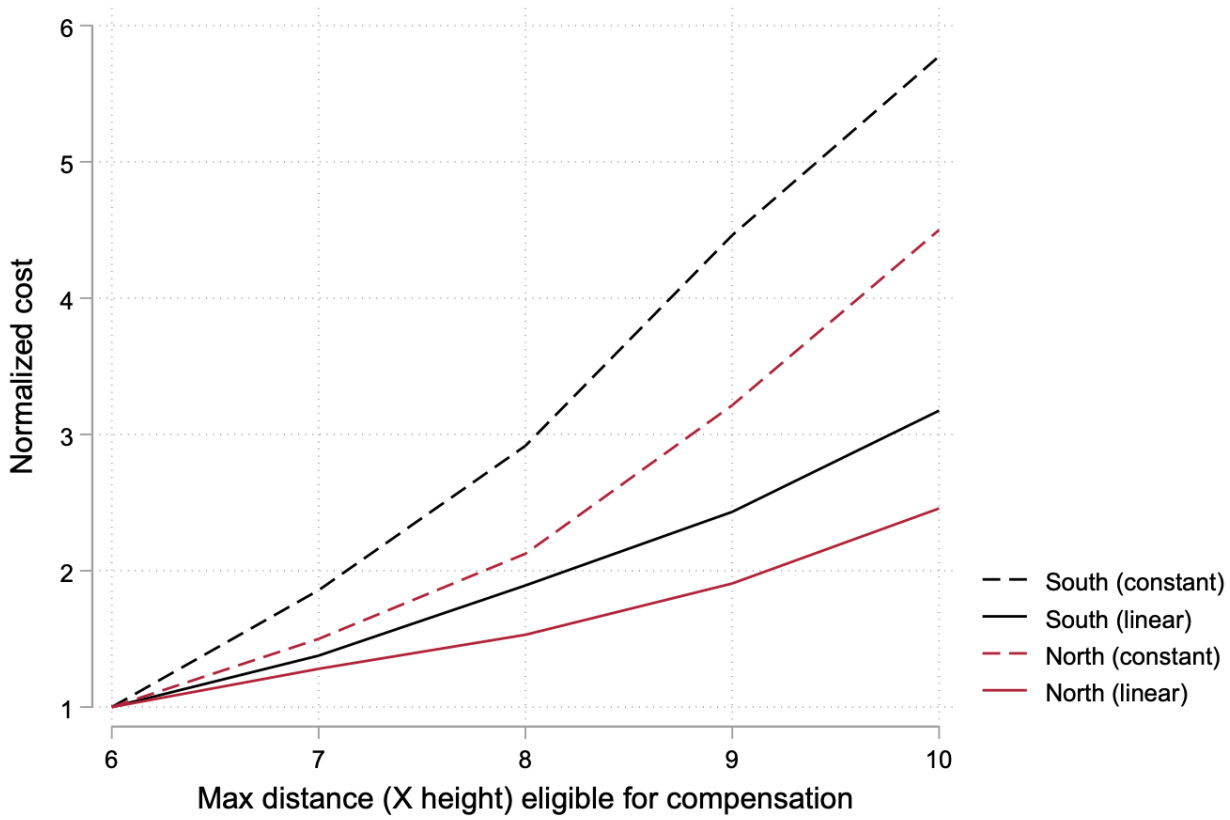
4.1 Normalized cost

Results for the constant model are presented in the top rows of Table 2, demonstrating that, on average, the constant 10H-model implies a cost corresponding to 7.6 (9.4) times the cost of the 6H model in the north (south). The corresponding figures for the linear model are 3.7 (4.3). Even though the cost increase when incorporating longer distances is greater in the south relative to the north, this difference is not statistically significant, as demonstrated by the last

column.

Since the cost distribution contains a number of outliers with very high costs, Figure 3 also depicts the same figures but for the median project. Under the constant model, the figure is then instead 4.5 (5.8) in the north (south), and the corresponding figures for the linear model are 2.5 (3.1). In both regions, costs are approximately equal under the constant 8H and linear 10H models respectively. For shorter distances, differences between the constant and linear models are less pronounced.

Figure 3: Median normalized cost, by region



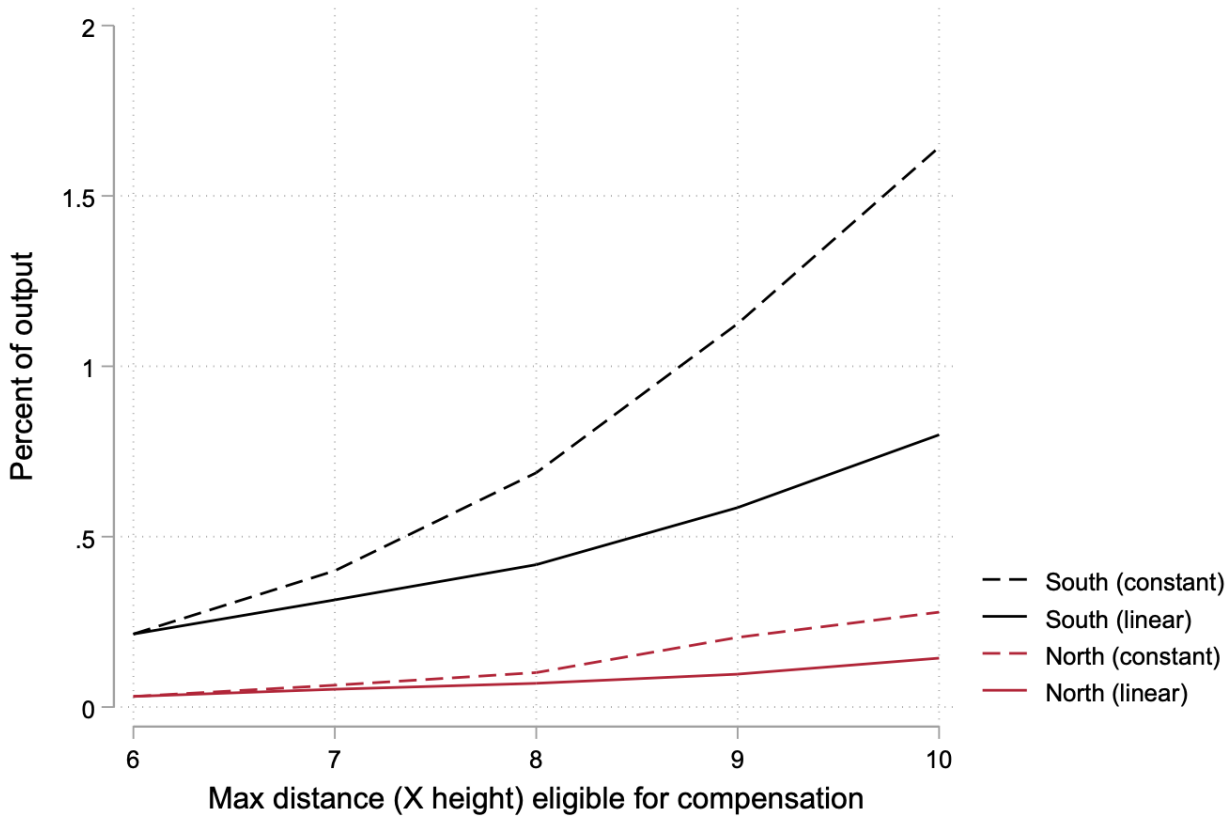
Note: Median compensation cost by model and region, expressed as a multiple of the 6H-model.

4.2 Cost in terms of output shares

The next rows in Table 2 express costs as output shares. For the constant 10H-model, average costs are 0.7 (2.9) percent in the north (south). Corresponding figures for the linear model are 0.3 (1.5) percent. Since costs are now not normalized by project using the 6H-model, differences are now also statistically different across regions.

Costs for the median project are depicted in Figure 4, demonstrating that the median cost associated with the constant 10H-model are 0.3 (1.6) percent in the north (south). The corresponding figures for the linear 10H-model are 0.2 (0.8) percent.

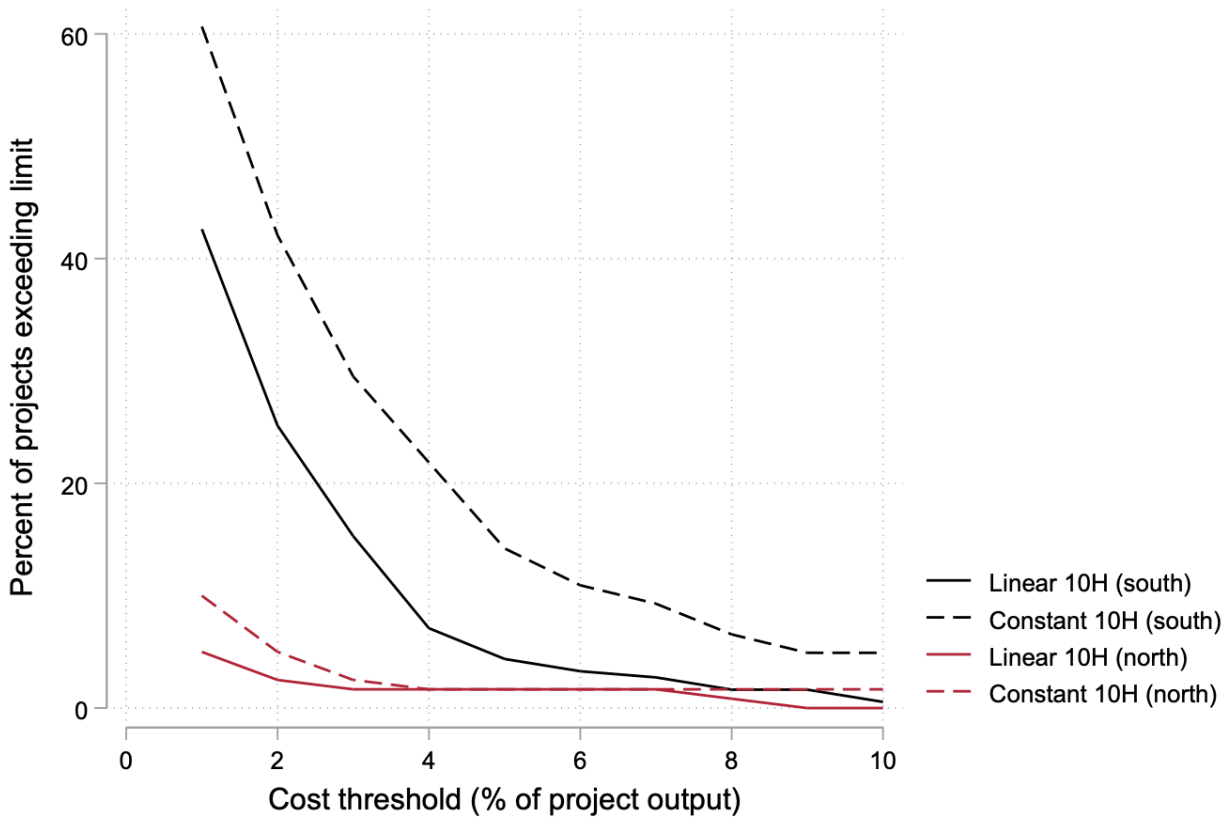
Figure 4: Median cost expressed as output shares, by region



Note: Median compensation cost by model and region, expressed as a share of project output.

Figure 5 depicts the share of projects exceeding cost limits in the range of 1 to 10 percent of output for the constant and linear 10H-models respectively, by region. In the north (south), compensations exceed two percent for about 5 (40) percent of all projects under the constant model. The corresponding figures for the linear model are 3 (25) percent. However, even in the south, these figures decline rapidly, and the compensation exceeds 4 percent only for about 10 percent of all projects under the linear model. To complement these numbers, Figure A2 depicts histograms for the total cost under the linear 10H-model, by region.

Figure 5: Percent of projects exceeding various cost thresholds, by region



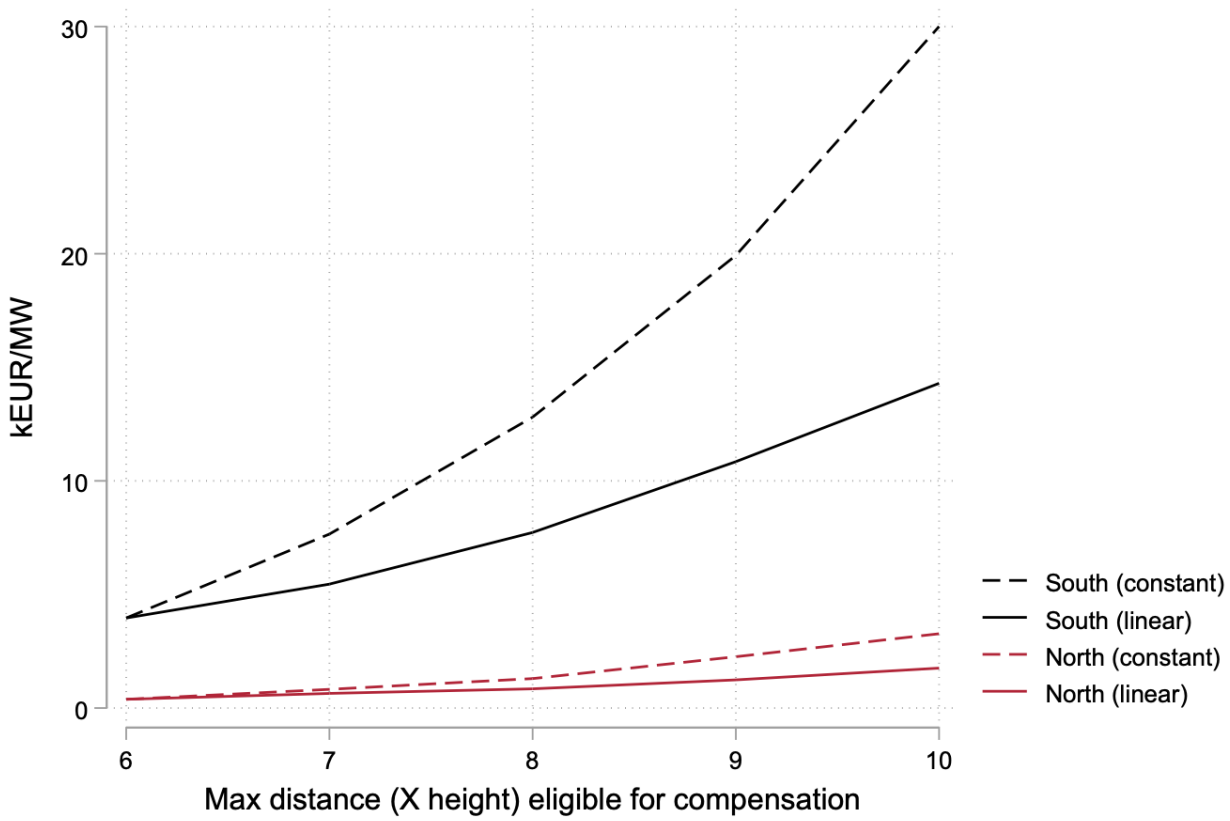
Note: Percent of projects exceeding various cost thresholds, where thresholds are in percent of project output. Southern projects in black, northern projects in red.

4.3 Cost in terms of kEUR/MW

The last rows in Table 2 express costs as kEUR/MW of installed capacity. Since electricity prices are higher in the south, differences are now more pronounced. For the constant 10H-model, average costs are 9.2 (56.4) kEUR/MW in the north (south). The corresponding figures for the linear model are 4.4 (28.8) kEUR/MW. Costs for the median project are depicted in Figure 6, demonstrating that the costs associated with the constant model are 4 (30) kEUR/MW, and 2 (14) kEUR/MW for the linear model.

Under the simplified assumption that the direct investment cost is about 1000 kEUR/MW, this implies a cost increase of 0.2 (1.4) percent respectively for the median project under the linear 10H-model.

Figure 6: Median cost in kEUR/MW, by region



Note: Median compensation cost by model and region, expressed as kEUR/MW of installed capacity.

4.4 How will compensation affect turbine locationing?

Developers often face substantial uncertainty during the planning process, with turbine costs varying as much as 25-50 %, along with variations in power prices during several decades ahead (at least for the share of output that is not contracted through power purchase agreements). Therefore, it is not likely that the comparatively modest compensation scheme proposed in this study would have substantial negative effects on absolute investment incentives, at least not for the linear models.

However, given that the negative externality from wind turbines is adequately internalized by the compensation scheme, its introduction should be followed by a more socially efficient locationing of future wind turbines. Two opposing mechanisms are in effect here. First, investor costs increase with the population density around the site, creating incentives to locate turbines further away from populated areas. Second, local acceptance is increased, which in turn increases the

probability of approval, reduces negotiation costs, and leads to lower investment costs. Naturally, the "acceptance effect" is most important in more populated areas, creating incentives to locate turbines closer to such areas given that these areas are also associated with other cost advantages, e.g. proximity to transmission. The net effect depends on the relative importance of each effect, and is likely to be heterogeneous within different areas of the country.

A similar reasoning holds when comparing investments across the northern and southern region. Since electricity prices and thereby compensations will be higher in the south, both effects will be relatively stronger compared to the north. Therefore, it is not obvious how a scheme would impact the distribution of investments across regions. It is also worth noting that even if compensation costs will be higher in the south, higher electricity prices have likely also resulted in a higher return on capital, which should render these projects more profitable *ceteris paribus*, and hence make investments less sensitive to increased costs.

4.5 How will compensation affect turbine height?

Figure A3 illustrates the increase in compensation cost (in terms of project output) following a hypothetical ten percent increase in tip height for all planned and pending turbines in the south under the linear 10H-model, demonstrating that the median increase is only about 0.3 percent. Since a ten percent increase in tip height is associated with about 14 percent increase in capacity [2], it is therefore likely that the benefits of increasing tip heights would outweigh the added compensation costs, even if a complete developer cost-benefit analysis would also have to include the added cost of constructing and maintaining larger turbines. That said, this counterfactual is based on the locations of projects that are already in the planning phase. Table A2 demonstrates that the mean compensation cost for existing projects in the south is 1.3 percent of output, compared to 2.1 percent for planned and pending projects, indicating that the most suitable locations with regard to population density have already been exploited. During the next decade, it is certainly possible that the locations left available will be even closer to more densely populated areas, so that the compensation will have a greater impact on costs, thereby strengthening incentives to reduce tip heights.

In addition, increasing turbine height also means that more non-homeowners will be indirectly af-

[2] This figure was obtained by regressing (the log of) turbine capacity on (the log of) turbine tip height for all planned and pending turbines in the sample, obtaining a statistically significant coefficient of 1.4.

fected by the turbine, especially through the impact on recreational areas, which in turn increases local opposition and the probability of rejection.

4.6 Are homeowners compensated for property value losses?

Although the main benchmark for determining compensation levels is the cost of electricity, it is also relevant to assess whether the proposed compensation would be sufficient to compensate for losses in property values. In Appendix D, I briefly address this question by computing the Net Present Value (NPV) of the compensation streams using back-of-the-envelope-computations, assuming a wind power lifetime of 20 years and a real discount rate of five percent. Results indicate that the NPV of the compensation received by the households eligible for the highest compensation (at most 6H from at least two representative turbines) corresponds to about 20 percent of the mean property value for permanent housing, which is in line with the upper bound of the effects found in the previous studies reviewed by Parsons and Heintzelman (2022). Hence, it appears likely that the proposed compensation would also compensate for property value losses, although this figure should be interpreted with care. In a risk neutral setting, the expected NPV of future payments should be internalized in the value of each individual house. However, if homeowners who consider selling their properties are risk-averse, they may instead prefer an upfront payment over a stream of payments that depend on future spot prices.

5 Conclusion

I simulate the cost of various wind power revenue sharing schemes using data from Sweden, allowing for both constant and linearly decreasing compensation levels for distances between six and ten times turbine tip height. Costs vary considerably depending on the model chosen. When a linearly declining compensation scheme is awarded for residents as far away as ten times the turbine height, foregone revenues exceed two percent for one fourth of the projects in the southern region, indicating that the scheme could have a non-trivial effect on the localization decisions of future investments.

A distinctive feature of all schemes is that compensation levels are deterministic when expressed as a fraction of the spot market revenues of the project. This could be interpreted as allocating spot price volatility risk to nearby residents. However, since residents' expenses are positively

correlated with the price of electricity, the scheme could also be characterized as a legally imposed long term contract between producers and consumers, providing price hedging for both parties, which should generally be an attractive feature of the scheme.

Future studies could discuss democratic considerations for policymakers tasked with assessing the pros and cons of the different types of models considered. For example, investors and policymakers may want to achieve local acceptance for as many residents as possible using a limited amount of resources. Then, a comparatively low compensation level with a longer distance eligibility threshold may appear attractive, while possibly at the expense of not achieving acceptance among the comparatively few households located most closely to the turbines. Future studies should also examine compensation schemes that are directly tied to individual losses in property values, since such losses could give more accurate market valuations of the negative externality associated with wind power.

6 Acknowledgements

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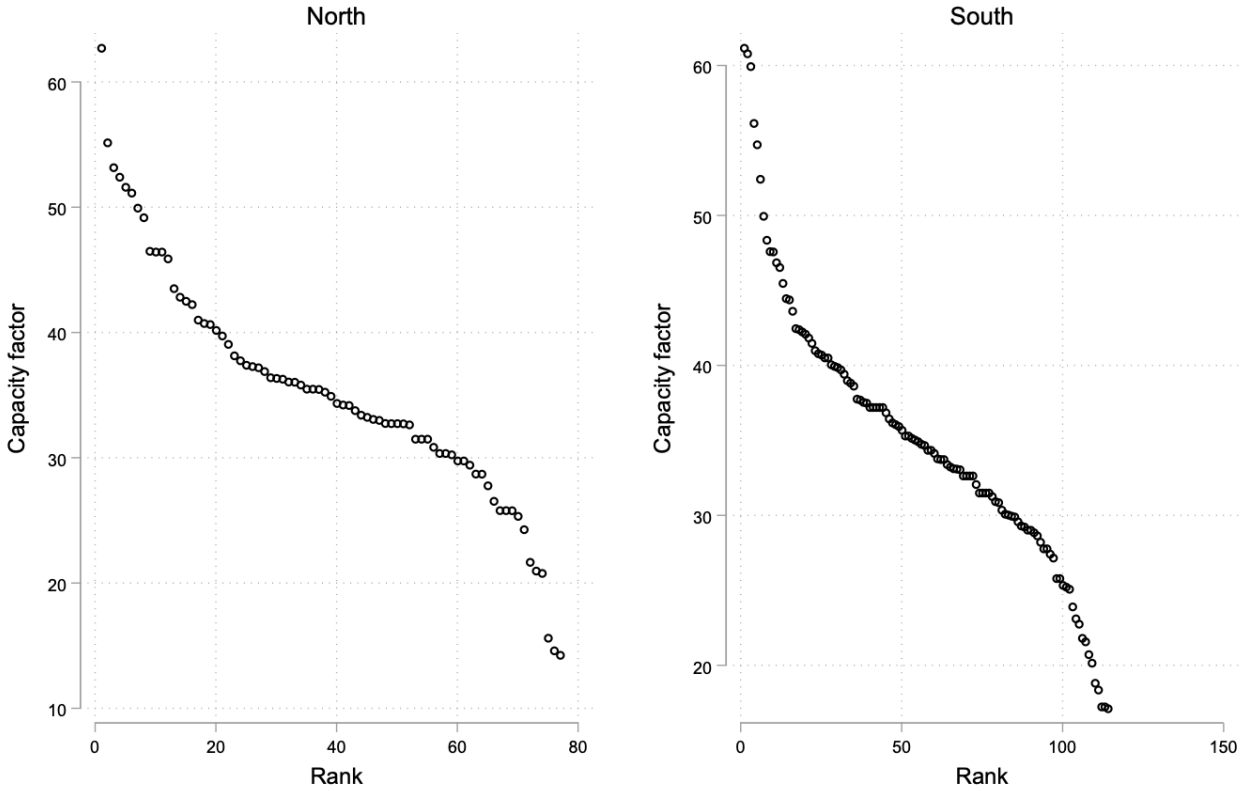
Appendix A: Additional tables and figures

Figure A1: Estimated capacity factors by region, existing projects



Note: Estimated capacity factors by region, ranked from highest to lowest. Existing projects only.

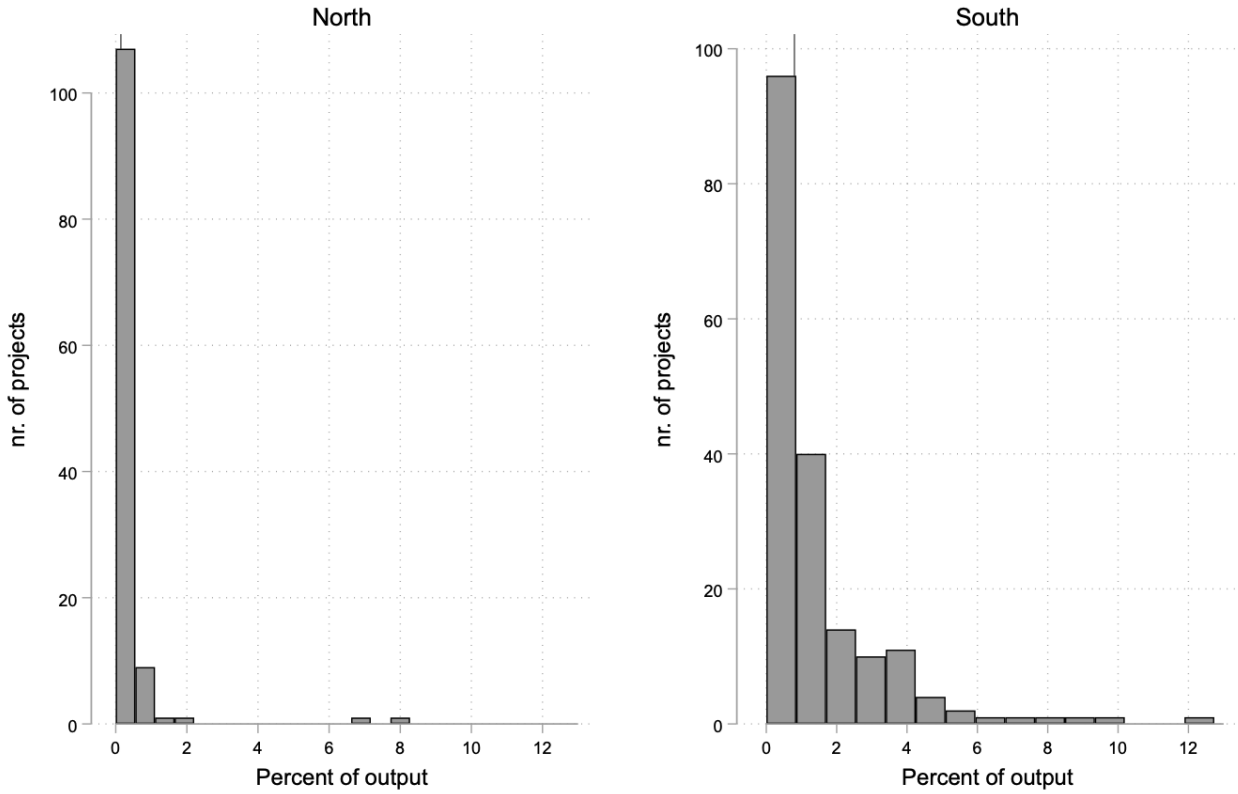
Table A1: Summary statistics, planned and pending projects

	North		***South***		***Diff***
	Mean	Sd	Mean	Sd	
House counts based on tip height					
nr. houses < 3H	0.56	1.37	0.85	1.45	-0.29
nr. houses < 4H	1.27	4.28	4.45	5.86	-3.19**
nr. houses < 5H	2.77	8.18	10.87	12.86	-8.10***
nr. houses < 6H	5.98	14.94	20.26	21.14	-14.28***
nr. houses < 7H	9.09	21.47	33.58	34.12	-24.49***
nr. houses < 8H	13.19	31.46	48.92	53.06	-35.74***
nr. houses < 9H	16.89	36.19	66.91	68.41	-50.02***
nr. houses < 10H	20.83	39.25	89.75	91.53	-68.93***
House counts based on km					
nr. houses < 1 km	1.83	3.45	7.85	9.37	-6.02***
nr. houses < 2 km	16.86	26.29	68.43	75.39	-51.57***
nr. houses < 3 km	40.61	49.85	191.60	181.80	-150.99***
Project characteristics					
Capacity	85.09	175.24	30.52	44.79	54.57*
Nr. of turbines	33.31	36.66	13.87	9.56	19.44***
Tip height	221.33	41.43	220.64	38.72	0.69
House price in municipality					
Houseprice (permanent)	103.40	54.15	191.76	89.16	-88.36***
Houseprice (holiday)	84.43	50.78	156.54	78.81	-72.10***
Observations	64		53		117

* $p < .10$, ** $p < 0.05$, *** $p < 0.01$

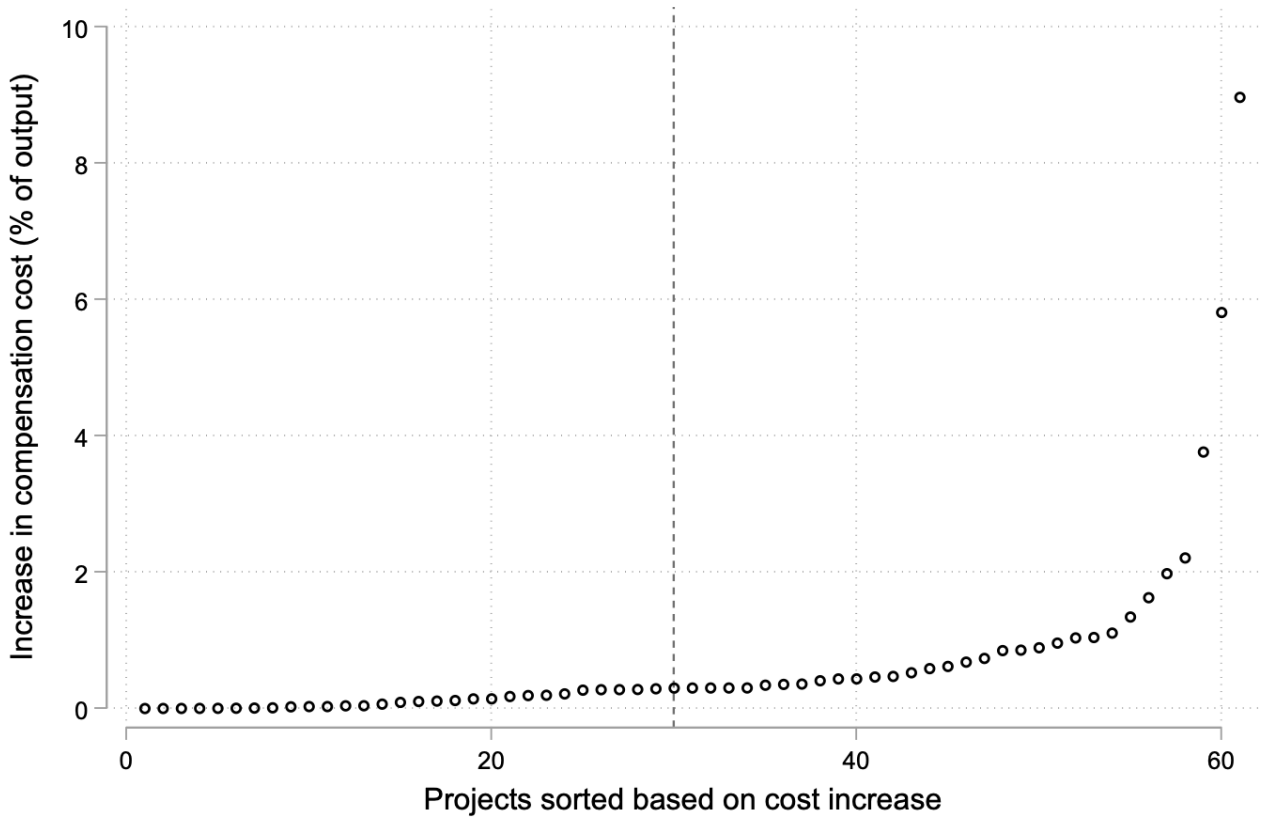
Note: Summary statistics of the main variables for planned and pending projects only. Each project is a separate observation. The left (right) column contains applications in the northern (southern) region. Capacity in MW. Houseprices in kEUR. A *t-test* is used to test for differences in means across regions.

Figure A2: Histograms of compensation cost under the linear 10H-model



Note: Histograms of the cost of the linear 10H-model, by region. Costs are expressed in percent of project output.

Figure A3: Impact on compensation cost from a ten percent increase in tip height



Note: Percent increase in compensation cost under the linear 10H-scheme from a hypothetical ten percent increase in tip height for all planned and pending applications in the south, ordered from lowest to highest impact. Cost increase is expressed as share of project output.

Table A2: Compensation levels, existing vs. planned and pending projects in the south

	Existing			*Planned and pending*			*Diff*
	Mean	Sd	Max	Mean	Sd	Max	
Normalized (constant)							
6H	1.0	0.0	1.0	1.0	0.0	1.0	0.0
7H	2.2	1.2	9.0	2.0	0.9	6.0	0.2
8H	4.2	3.5	25.0	3.2	1.7	10.0	1.0*
9H	6.9	7.4	52.5	4.9	3.4	19.0	2.0*
10H	10.6	13.6	107.5	6.8	4.7	20.0	3.9**
Normalized (linear)							
6H	1.0	0.0	1.0	1.0	0.0	1.0	0.0
7H	1.5	0.6	4.6	1.5	0.4	3.6	0.1
8H	2.3	1.4	10.1	2.0	0.7	5.2	0.3
9H	3.4	2.6	16.2	2.7	1.3	8.1	0.7*
10H	4.7	4.5	31.1	3.5	2.0	10.9	1.3*
Output share (constant)							
6H	0.3	0.5	3.1	0.7	0.8	3.1	-0.4**
7H	0.7	0.8	4.7	1.2	1.2	5.4	-0.6**
8H	1.2	1.7	12.1	1.8	1.8	8.8	-0.7*
9H	1.8	2.7	18.6	2.6	2.7	12.9	-0.8
10H	2.6	4.0	31.0	3.6	4.4	22.9	-1.1
Output share (linear)							
6H	0.3	0.5	3.1	0.7	0.8	3.1	-0.4**
7H	0.5	0.6	3.9	1.0	1.0	3.8	-0.5**
8H	0.7	0.9	5.7	1.2	1.2	5.5	-0.6**
9H	1.0	1.3	8.7	1.6	1.5	7.2	-0.6*
10H	1.3	1.8	12.7	1.9	2.0	9.6	-0.7*
kEUR/MW (constant)							
6H	6.9	10.3	62.2	13.6	14.3	58.3	-6.7**
7H	13.1	16.7	94.2	23.1	23.2	102.6	-10.0**
8H	22.9	32.8	243.2	34.4	34.7	167.2	-11.6*
9H	35.4	51.5	375.3	48.3	50.8	245.5	-12.9
10H	49.9	76.7	624.6	68.3	84.1	433.6	-18.4
kEUR/MW (linear)							
6H	6.9	10.3	62.2	13.6	14.3	58.3	-6.7**
7H	9.7	13.2	78.5	18.1	18.3	72.3	-8.4**
8H	13.7	18.1	115.9	23.4	23.5	104.6	-9.7**
9H	18.8	25.5	175.9	29.3	29.4	137.4	-10.6*
10H	24.7	34.7	257.0	36.5	38.0	181.4	-11.8
Observations	130			53			183

* $p < .10$, ** $p < 0.05$, *** $p < 0.01$

Note: Cost of each compensation model using various cost metrics, separately for existing vs. planned and pending applications in the south. Normalized costs are expressed as multiples of the 6H constant model. Output shares are expressed in percent of project output. kEUR/MW is cost in kEUR per installed MW capacity of the project. A *t-test* is used to test for differences in means across regions.

Appendix B: Application process

Below I describe the application process for a representative project in chronological order.

1. Pre-investigation and public hearing. Before an application is submitted, the investor investigates the proposed site and contacts land owners to ensure access to the land. The process is usually comparatively thorough, spanning 1-4 years (Vattenfall, 2024). The investor then organizes at least one public hearing concerning the proposed project, which is obliged by law (chapter 6, the Swedish Environmental Code). The hearing is intended for nearby residents, politicians, and other stakeholders.

2. Application submission and original decision. A formal application is then submitted to the county administration, evaluating the environmental impact of the project regarding birds, wildlife, impact on nearby residents, potential conflicts with military interests, and other related issues. The evaluation is conducted by non-political officials (*Miljöprövningsdelegationen*) and there are 21 county administrations across the country. The evaluation is independent, but the investor also needs to submit its own report on the presumed environmental impact of the project. The reports are comparatively extensive, and usually comprises several hundred pages.

If the project spans several municipalities, each municipality need to approve the turbines within its own border. The county administration then notifies the investor about its decision, with separate decisions for each turbine. Usually all turbines get the same decision, but due to e.g. differences in environmental impacts or in the exercise of the veto right across municipalities, there may be differences within each project.

3. Appeal and final decision. Original decisions may be appealed to the Land and Environmental Court (*Mark- och miljödomstolen*) by both the investor and other stakeholders. More than 40 % of all decisions are appealed. There are six courts locates across the country. Although less common, it is also possible to further appeal the decision to the national Land and Environmental Court of Appeal (*Mark- och miljööverdomstolen*).

Appendix C: Mapping household electricity expenses to the sharing rule

I largely follow Ministry of Climate and Enterprise (2023)[p.338] and employ the following assumptions:

1. The consumer cost of electricity equals the unweighted average price on the day-ahead market plus a retailer margin of 5 %, plus VAT of 25% on the price paid to the retailer.
2. Energy tax (including VAT) per kWh equals the day-ahead price excluding VAT. For 2023, the tax amounted to 49 öre/kWh (approx 0.043 EUR/kWh) which will supposedly be somewhat lower than the unweighted mean day-ahead price, but is sufficient as an approximation.
3. The capture rate of wind power is $\frac{3}{4}$. The capture rate reflects the fact that increased wind power production has a negative effect on the day-ahead price, meaning that the compensation from wind power sold on the spot market will fall below the average spot price.
4. The yearly electricity consumption of an average household in a detached house amounts to 15 000 kWh, where approximately 10 000 kWh is used for heating. This assumes that traditional electric radiators have been replaced by heat pumps (for detached houses with traditional electric radiators, yearly consumption is around 20 000 kWh).
5. The capacity of a representative turbine is 3 MW, with a capacity factor of 35 percent. Given 8760 hours per year, this implies an annual output of $3 \times 0.35 \times 8760 = 9198$ MWh.

Assumptions (1) and (2) imply that:
Consumer cost of electricity including tax = Spot price$[1 + (1.05 \times 1.25)] \approx$ Spot price $\times 2\frac{1}{3}$
Combined with assumption (3), this implies that the consumer cost of one kWh of household consumption corresponds to the revenues from $\frac{4}{3} \times 2\frac{1}{3} \approx 3$ kWh of energy from the compensation mechanism. Combined with assumption (4) this means that the yearly compensation, measured in kWh, should amount to $3 \times 15000 = 45000$ kWh= 45 MWh if the full cost of electricity should be covered by the compensation.

Given that two turbines entitle compensation and that these turbines are located within 6H of the house, assumption (5) implies that the compensation should equal $\frac{45}{9198 \times 2} \approx 0.25$ % of total turbine output.

Appendix D: Can the sharing rule compensate for the negative impact on property values?

Even if the answer largely hinges on various parametric assumptions, below I provide a "guesstimate". I apply the following assumptions:

1. In accordance with Appendix C, yearly compensation for households receiving the maximum annual compensation is 45MWh.
2. The mean spot price of electricity received by wind power is 37 EUR/MWh (which was approximately the mean price in Sweden during 2021, times a capture rate of $\frac{3}{4}$).
3. The real discount factor is 5 percent.
4. The mean price for a permanent house in municipalities where wind power is located is approximately 170 kEUR.

Combining assumptions (1)-(3) yields a NPV of $\frac{37 \times 45}{0.05} \approx 48kEUR$, which combined with assumption (4) corresponds to 20 percent of the mean house value. This is roughly in line with the upper bound of the effects found within the range of 2 km from a project in the studies reviewed by Parsons and Heintzelman (2022). Hence, it is likely that the proposed compensation will compensate for the loss in property values, although this result should be interpreted with great care due to the strong assumptions imposed.