Appendix: Levi et al.: *Power (re)distribution: How dominant capital regained control of the Energiewende*, Zeitschrift für Politikwissenschaft 2024

Appendix 1: Electricity Generation Categorization Alternatives

Table 5: Sociotechnical Electricity Generation categorization

Category	**Resource/Technology**	**Measures**
EEG Eligible	Onshore Wind Offshore Wind Solar PV Geothermal Biomass	Renewable Total Net Generation Renewable Installed Capacity Renewable Revenues (million€) Renewable Revenues per Energy Generation (€/MWh)
Non EEG Eligible	Hard Coal Lignite Natural Gas Nuclear Oil Waste Hydro (stored) Hydro (run-of-river) [2] Other	Conventional Total Net Generation Conventional Installed Capacity Conventional Revenues (million€) Conventional Revenues per Energy Generation (€/MWh)

Variable	Onshore Wind Offshore Wind Solar PV
Non Variable	Hard Coal Lignite Natural Gas Nuclear Oil Hydro (stored) Hydro (run-of-river) Waste Geothermal Biomass Other

Light grey alternatives to the AEG category, while the darker shade of grey represents alternatives to the CEG category. [2]Although hydropower is included as EEG eligible in the Renewable Energy Sources Act 2017, section 40 delimits restrictions to this, and the BnetzA Monitoring Report 2022 implies that a considerable amount of hydropower is unsubsidized (Bnetza, 2022:97).

Table 6: Germany Datastream Conventional and Alternative Electricity Indices

Index	Firms
Germany datastream alternative electricity (GERMANY.DS.Alt..Electricity)	ENCAVIS PNE ENERGIEKONTOR 2G Energy
Germany datastream conventional electricity (GERMANY.DS.Conv..Electricity)	EnBW Energie Baden-Wutenburg Lechwerke (E.ON subsidiary) MVV Energie

Table 7: Power-based Electricity Categorization

Category	Firms	Subsidiary
Dominant	RWE	RWE Generation SE RWE Power AG Grosskraftwerk Mannheim AG Schluchseewerk Aktiengesellschaft
	EnBW	EnBW Kernkraft GmbH Stadtwerke Düsseldorf AG Kernkraftwerk Obrigheim GmbH

		Obere Donau Kraftwerke AG
	E.ON UNIPER	Innogy SE E.ON Kernkraft GmbH Preussen Elektra GmbH Bayerische Elektrizitätswerke GmbH Gemeinschaftskraftwerk Irsching GmbH Gemeinschaftskraftwerk Kiel GmbH Gemeinschaftskraftwerk Veltheim GmbH GHD Bayernwerk Natur GmbH & Co. KG Müllheizkraftwerk Rothensee GmbH Peissenberger Kraftwerksgesellschaft mbH Peißenberger Wärmegesellschaft mbH
	Vattenfall Europe	Vattenfall Wärme Berlin AG Vattenfall Heizkraftwerk Moorburg GmbH Vattenfall Wasserkraft GmbH Vattenfall Europe Wärme AG

		Vattenfall Europe Nuclear Energy GmbH Vattenfall Hamburg Wärme GmbH Vattenfall Europe New Energy Ecopower GmbH
	LEAG	Lausitz Energie Kraftwerke AG|
Non Dominant	All other firms in conventional power generation	

Appendix 2: Data Source by Category

Table 8: Data Sources for Pecuniary and Spatio-physical data by category

Category	**Data**	**Data Source**
EEG Eligible	Total Net Generation 2000-2021	BnetzA Monitoring Reports (2006-2022)
	Total Net Nominal Generation Capacity 2000-2021	BnetzA Monitoring Reports (2006-2022)
	Total EEG Remuneration (Market Value) (2000-2021)	BMWK (EEG In Zahlen)
	Total EEG Payments (2000-2021)	BnetzA Monitoring Reports (2006-2022)
	Total EEG Market Revenue (2000-2021)	BMWK (EEG In Zahlen)
Non EEG Eligible	Total Net Generation 2000-2021	BnetzA Monitoring Reports (2006-2022)
	Total Net Nominal Generation Capacity 2000-2021	BnetzA Monitoring Reports (2006-2022)
	Fuel Use in Electricity Generation	AGEB
	Revenue from Generation	DeStatis

	Fuel Price for Electricity Generators	AGEB
Variable	Variable Energy Resources penetration	BMWK (EEG In Zahlen)
Non-Variable	Non variable generation during peak load	Statista, Fraunhoffer
Light grey represents physical data, darker shade represents pecuniary data.		

Appendix 3: Conventional tariff calculation breakdown, fuel costs calculation, and additional measures

Conventional Tariff calculation:

To calculate the conventional energy tariff, we start with data on revenue from electricity generation from the DeStatis business registry. However, its revenue category represents total annual recorded revenue, implying that revenue from the sale of forward and future contracts is also included in the data. As we are interested in the revenue from annual electricity generation only, a further 'demand side' approach was necessary to produce total generation market revenue (TGMR).

From a "demand side" perspective, total generation market revenue is calculated as follows:

$$TGMR = anhEPC * nhEC + ahEPC * hEC + ER - IC$$

Here, *anhEPC* is average non-household energy procurement cost (c€/kWh), *nhEC* is non-household energy consumption (TWh), *ahEPC* is average household energy procurement cost (c€/kWh), *hEC* is household electricity consumption (TWh), *ER* is export revenue and *IC* is import costs.[1]

Total EEG market revenue is calculated by subtracting all EEG subsidy payments from EEG total remuneration, as follows:

$$EEGMR = EEGR - EEGmkp - EEGmnp - EEGfb - EEGfint$$

Here, *EEGR* is EEG total remuneration, *EEGmkp* is EEG market premium payments (million€), *EEGmnp* is EEG management payments (million€), *EEGfb* is EEG flexibility bonus payments (million€), *EEGfint* is EEG FinT payments (million€).[2]

Thus, we reached the following equation (Equation 1) for estimating the conventional electricity tariff:

$$Conv\,Tariff = \frac{convGR}{CEG} = \frac{TGMR - EEGMR}{TNG - EEGEG} =$$

$$\frac{(ahEPC \cdot nhEC + ahEPC \cdot hEC + ER - IC) - (EEGR - EEGmkp - EEGmnp - EEGfb - EEG}{TNG - EEGEG}$$

In the absence of data on revenue from annual electricity generation only, revenue from annual generation is calculated as the sum of the product of average non-household energy procurement price component and non-household electricity consumption, the product of average household energy procurement price component and household electricity consumption, and the export surplus (the difference between export revenue and import costs). From total generation market revenue, we subtract EEG market revenue, which is the difference between total EEG remuneration and all EEG subsidy payments.[3]

Conventional gross profit proxy per energy unit calculation:

---

[1] Values adjusted to scale in all actual computations.

[2] Values adjusted to scale in all actual computations.

[3] As will be presented in the explanation of the third measure, though initially an impediment, the data on total recorded revenue from electricity generation eventually turned out to be a conceptual treasure.

The conventional gross profit proxy per energy unit (Equation 3) is defined as:

$$Conv. Profit\ per\ Energy\ Unit\ Proxy\ = \frac{convGR - fuel\ costs}{CEG} =$$

$$\frac{convGR\ -\ [(NGp\ \cdot\ NGu)\ +\ (HCp\ \cdot\ HCu)\ +\ (Lp\ \cdot\ Lu)\,]}{CEG}$$

Here, *convGR* is conventional generation revenue (million€) as calculated in Conv. Tariff measure, and *CEG* in conventional electricity generation as calculated in Conv. Tariff measure. For the fuel costs breakdown, see Appendix 3.

Fuel Costs calculation:

Fuel costs in electricity generation are calculated as follows:

$$Fuel\ Costs\ =\ (NGp\ \cdot\ NGu)\ +\ (HCp\ \cdot\ HCu)\ +\ (Lp\ \cdot\ Lu)$$

where *NGp* is natural gas price for electricity generation (€/t SKE), *NGu* is natural gas use in electricity generation (t SKE), *HCp* is hard coal price for electricity generation (€/t SKE), *HCu* is hard coal use in electricity generation (t SKE), *Lp* is lignite price for electricity generation (€/t SKE), and *Lu* is lignite use in electricity generation (t SKE).

Additional measures:

The tariff ratio is defined as:

$$Tariff\ Ratio\ = \frac{Alt\ Tariff}{Conv\ Tariff}$$

where *Alt Tariff* is alternative electricity tariff (€/MWh), and *Conv Tariff* is conventional electricity tariff (€/MWh).

The ratio of dominant firm installed capacity to peak load is expressed as:

$$DIC/PL\ ratio\ = \frac{rweIC +\ leagIC +\ enbwIC}{APHL}$$

where *DIC/PL* is dominant firm installed capacity to peak load, *rweIC* is RWE installed capacity (GW), *leagIC* is LEAG installed capacity (GW), *enbwIC* is EnBW installed capacity (GW), and *APHL* is annual peak hourly load (GW).

This measures the ratio of the combined installed capacity, controlled by the three dominant firms in electricity generation, and the annual peak hourly load.

Appendix 4: Estimation of big firm revenue for 2016-2017

The DeStatis business registry's largest firms category consists of an average of 60 firms between 2010-2021, while the number of electricity generators during this period lies between 33,000-70,000. This core of big firms (which we assume control mainly conventional generation) includes dominant firms which currently control about ⅔ of conventional production (see Table 3.). Therefore, it can be considered as a reasonable proxy for dominant firms' revenue trends in the generation segment.

The "Destatis_749196_E12_URS_RE_Abschnitt_E_4Steller_BJ06-21" data series contains data on total annual sales (Umsatz) from electricity supply (2006-2021), broken down to four business segments: electricity generation (Elektrizitätserzeugung), electricity transmission (Elektrizitätsübertragung), electricity distribution (Elektrizitätsverteilung), and electricity trading (Elektrizitätshandel). Sales are recorded in total (insgesamt), and by company size. There are four categories of company size: 0-9 employees, 10-49 employees, 50-249 employees, over 250 employees (in Germany). There are slight differences in the categories between the years, but the >250 employees category does not change.

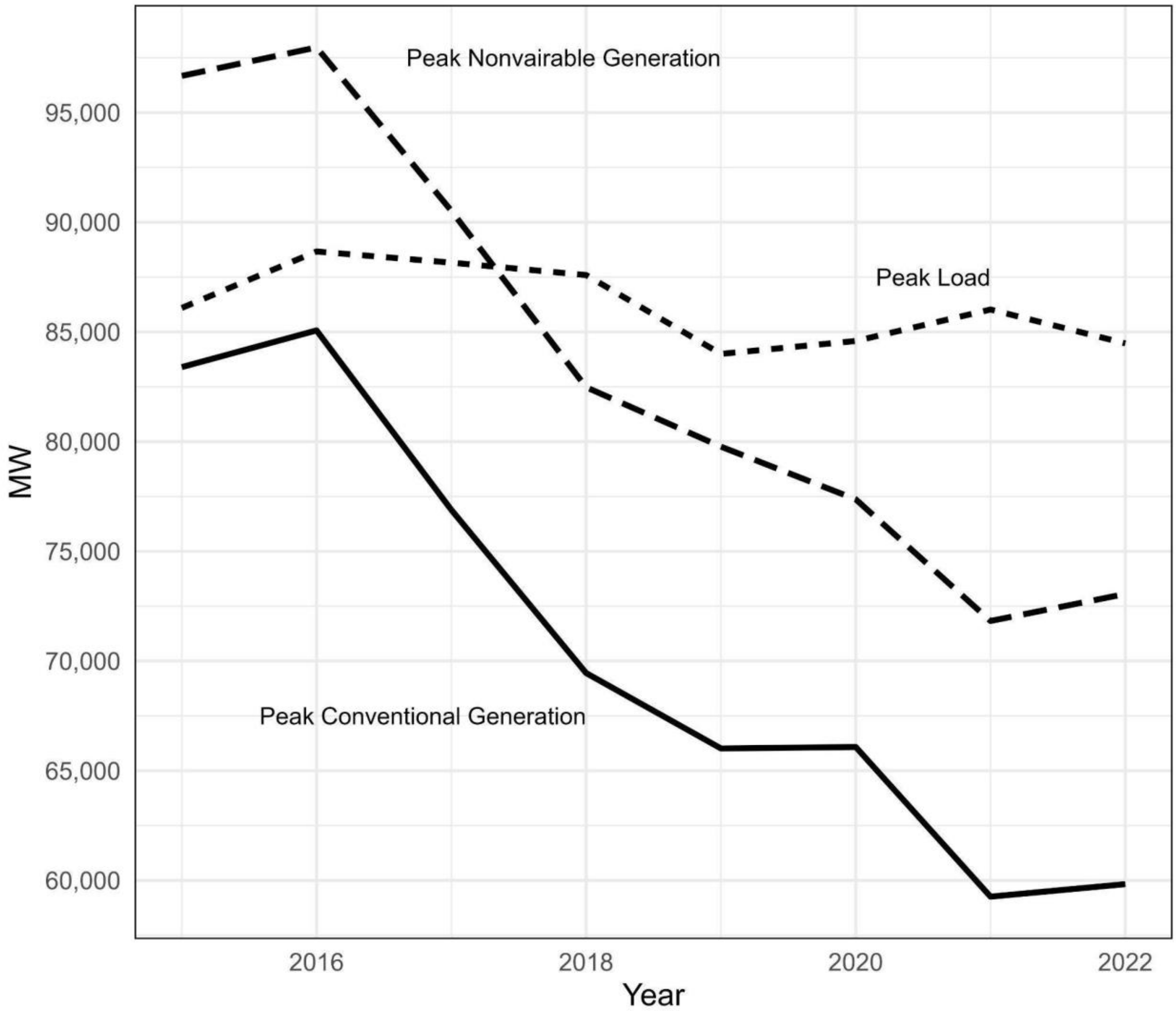
Data on generation sales for the year 2016-17 is missing for both 50-249 employees and >250 employees. We estimated these values by subtracting the sum of all remaining categories from the total sales, and then multiplying the result by the average ratio of the >250 employees category to the 50-249 category.

Appendix 5: Peak load and peak non-variable generation

Figure 18 shows the peak annual 15-minute load and peak conventional and non-variable generation.

Note that the levels of conventional and non-variable peak 15-minute generation (i.e. the 15 minutes during a year in which CEG load was the highest) remain close to those of annual peak load. This implies that while traditional generators' share in total net generation has declined, their installed capacity is still critical to ensure reliable supply.

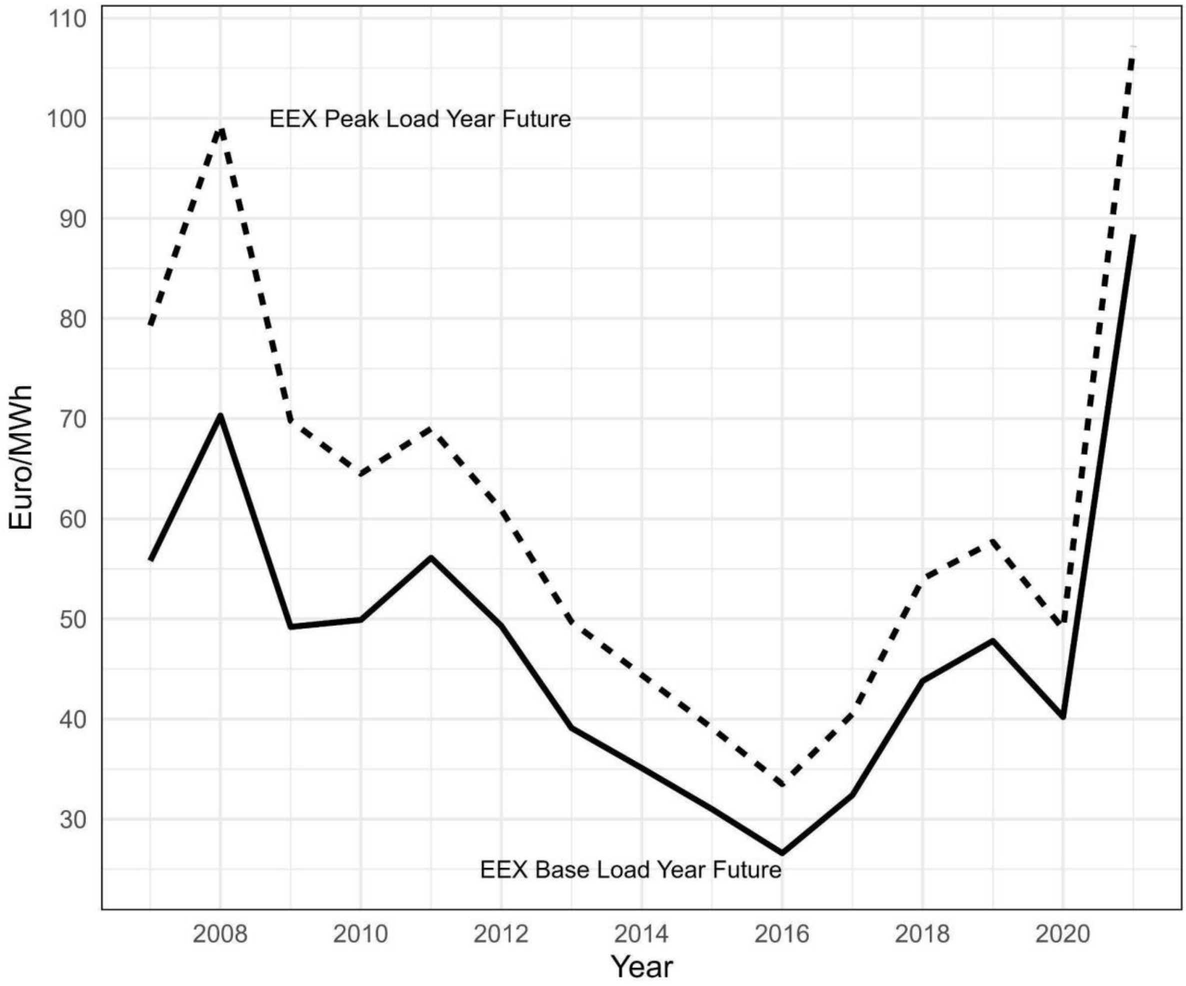
Figure 18: Peak Load and CEG



Note: Peak conventional generation refers to fossil-fuel and nuclear generation. Source: Data on 15-minute net electricity generation and load (2015-2022) was retrieved and compiled from Fraunhofer ISE: https://www.energy-charts.info/charts/power/chart.htm?l=de&c=DE&interval=year&source=total

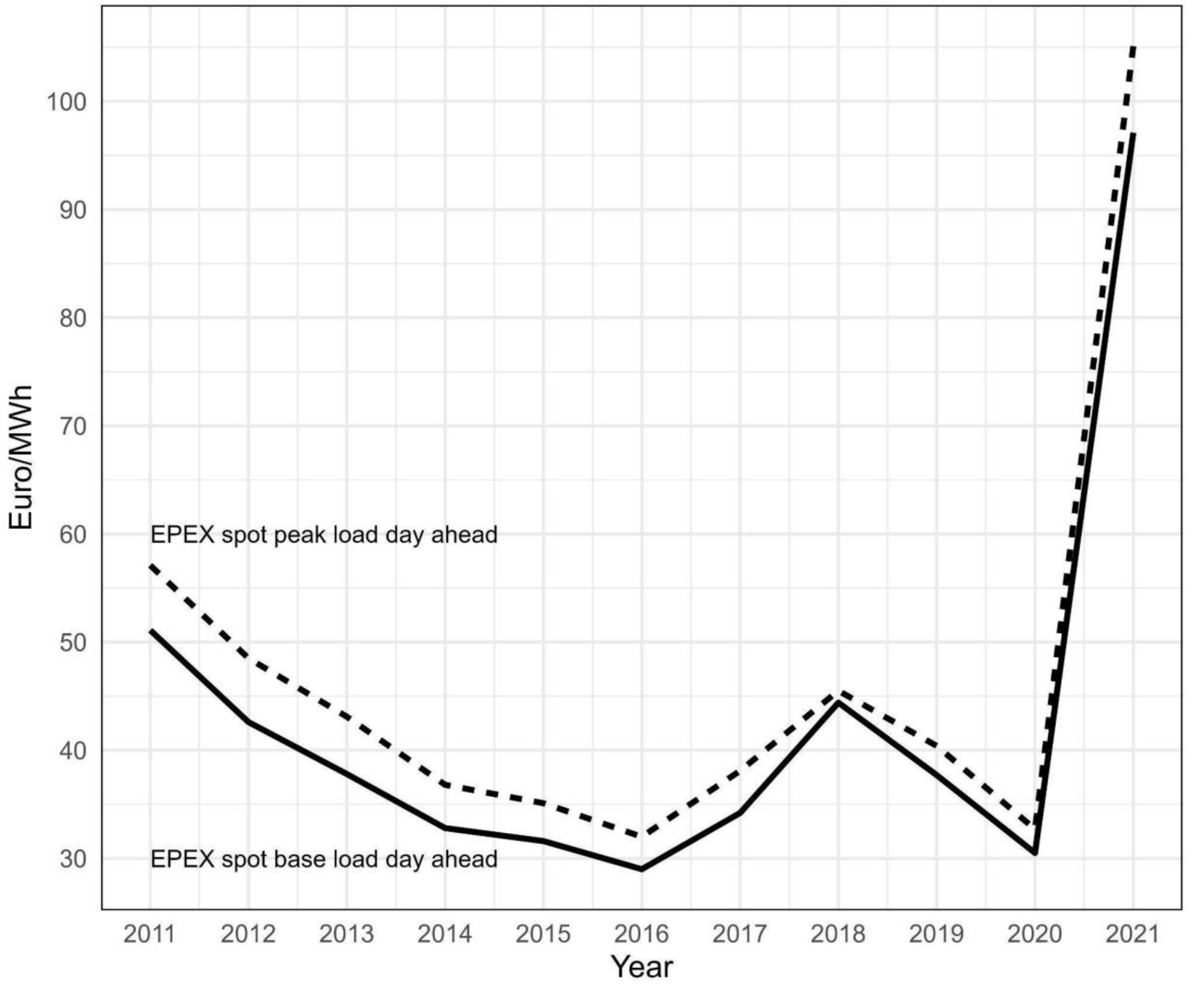
Appendix 6: EEX future and EPEX SPOT day-ahead market price development

Figure 19: EEX future market price development



Sources: data on average EEX future prices were compiled from BnetzA monitoring reports 2012-2022.

Figure 20: EPEX SPOT day-ahead market price development



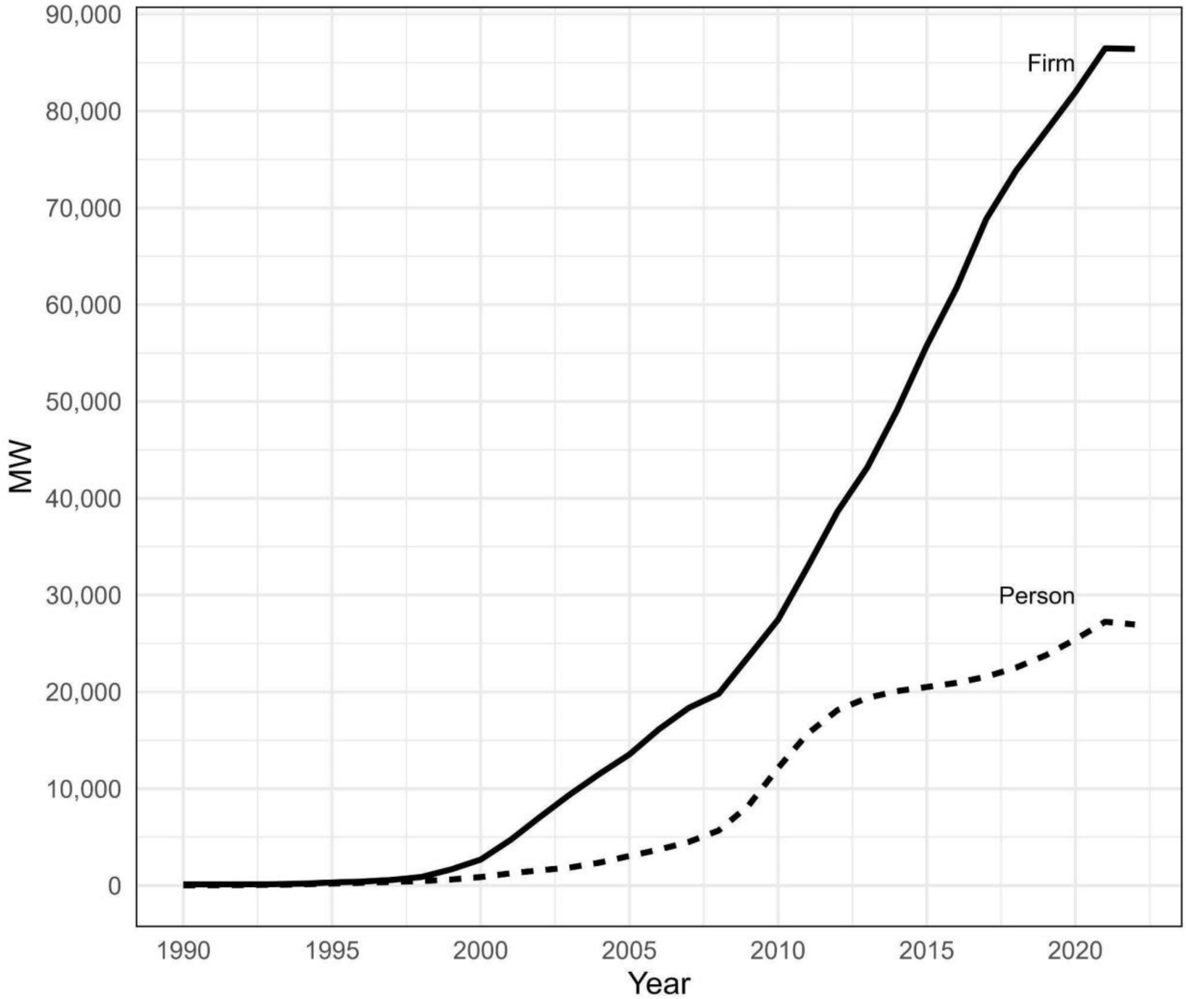
Sources: data on average EPEX spot prices were compiled from BnetzA monitoring reports 2012-2022.

Note that while average EEX Year Futures begin to rise in 2017 (as do conventional total electricity sales relative to yearly conventional revenue), average EPEX SPOT Day-Ahead prices rise only in 2021.

Appendix 7: Alternative generation development trends

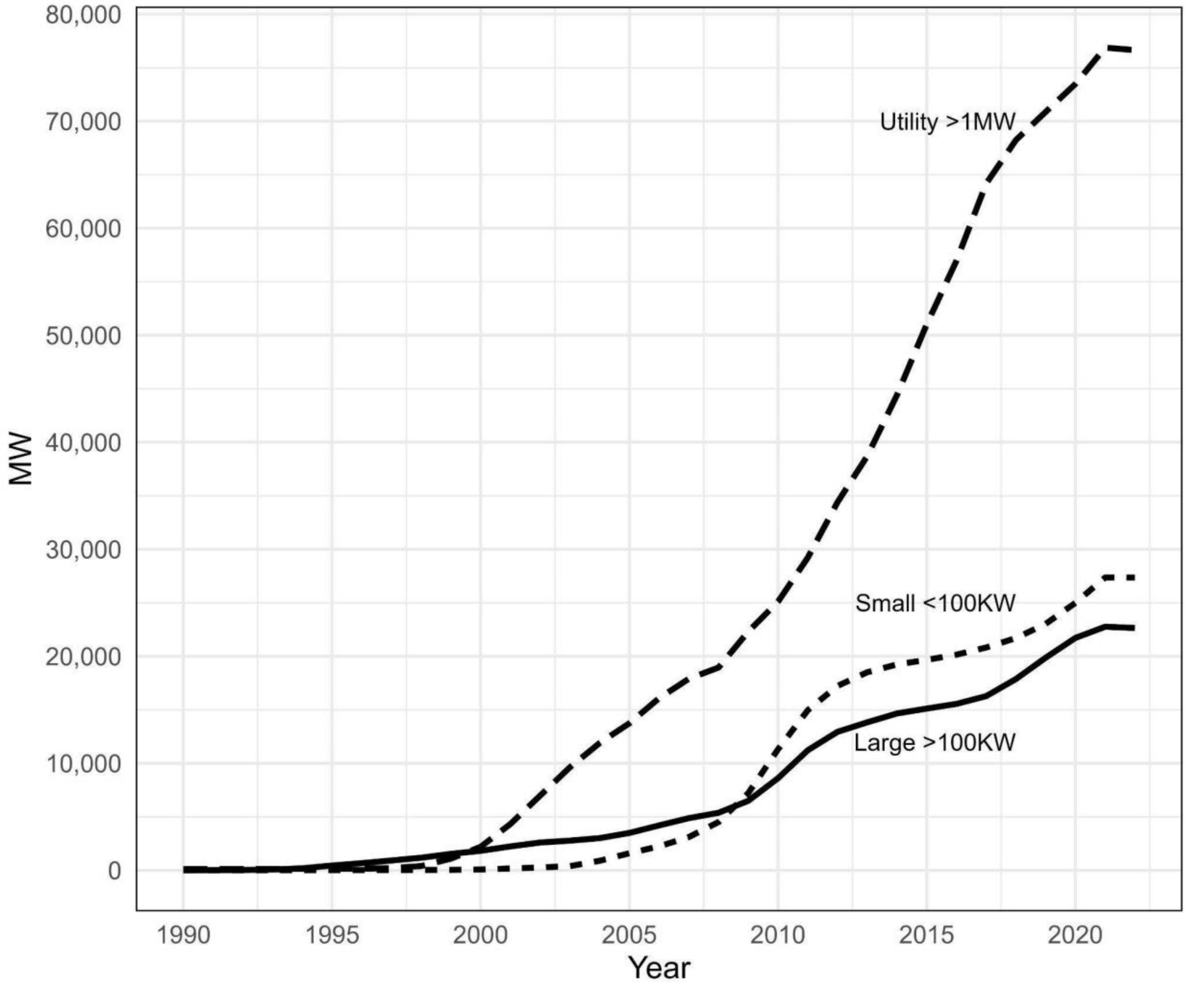
Figure 21 shows a coinciding rise in renewable ownership concentration and spatio-physical centralization.

Figure 21: Alternative Installed Capacity by operator type



Note: Data was aggregated according to operator type, plant size, energy source, commission year, and decommission year. For further details see appendix 7. Source: MaStR Stromerzeugungseinheiten register https://www.marktstammdatenregister.de/MaStR/Einheit/Einheiten/OeffentlicheEinheitenuebersicht Accessed: 30.9.2023

Figure 22: Alternative Installed Capacity by plant size

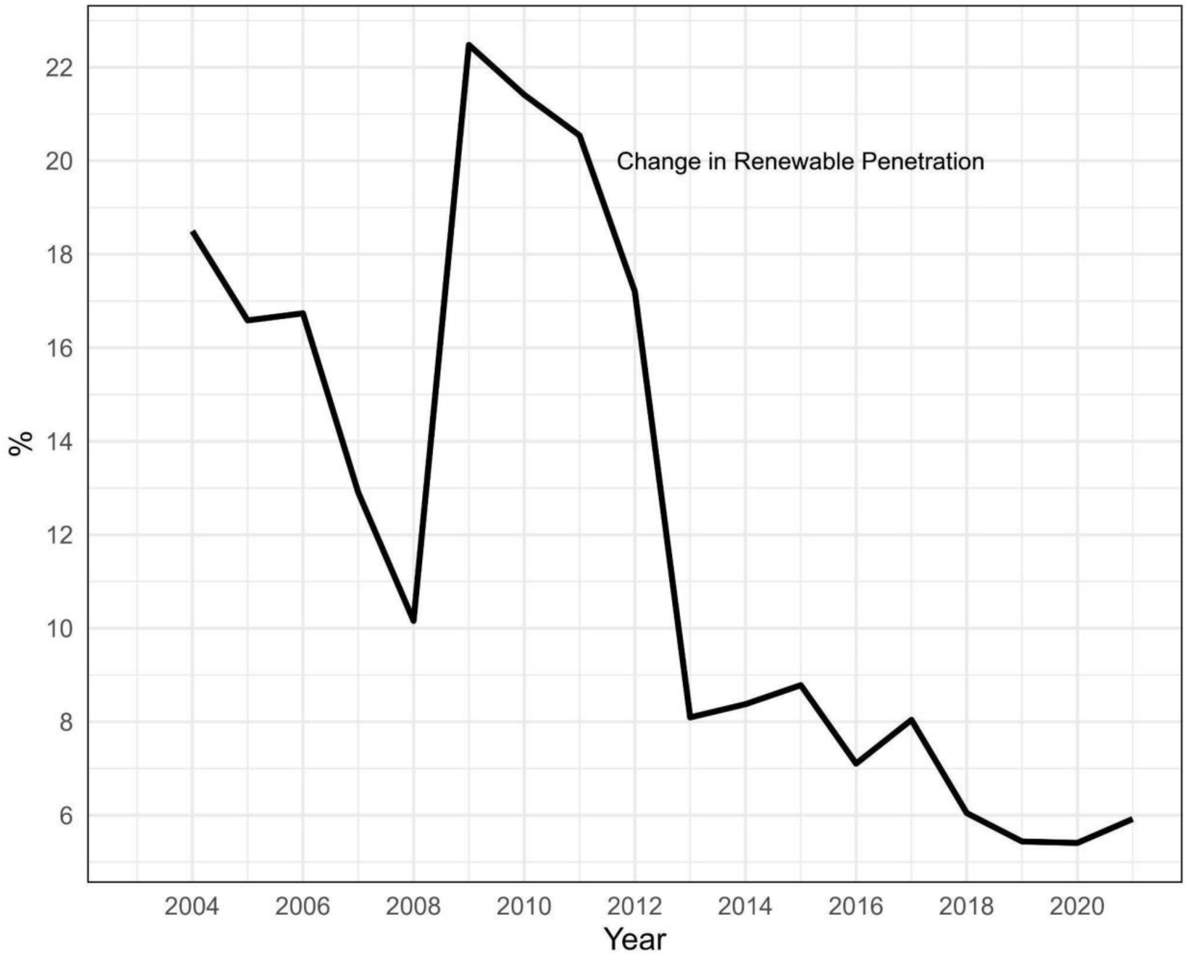


Note and Sources: see Figure 21.

While renewable prosumer installed capacity began to stagnate around 2012, renewable firm-owned installed capacity rose steadily and steeply, almost tripling in the decade between 2011-2021 (from approximately 30 GW to almost 90 GW). The same trend is displayed in the development of renewable installed capacity by plant size.

As shown in Figure 22, these results coincide with declining AEG penetration rate. In 2010, the percentage of change of AEG in installed capacity began to decline, from 22% in 2009 to 6 % in 2021, the main drop occurring between 2010-13 (from 21% to 8%).

Figure 23: Change in RES Penetration



Note: Change in share of alternative resources in total net installed generation capacityTNNGC was calculated by subtracting the share of EEG eligible total net installed generation capacityTNNGC in total net installed generation capacityTNNGC in year n from the same share in year n-1, dividing the result by the share of EEG eligible total net installed generation capacityTNNGC year n-1, and multiplying by 100. Source: Total net installed generation capacityTNNGC and Share of EEG eligible total net installed generation capacityTNNGC in total net installed generation capacityTNNGC were compiled from BnetzA Monitoring Reports 2013-2022.

These figures are the result of an analysis of the Marktstammdatenregister (MaStR). MaStR is BnetzA's open access, comprehensive, online electricity and gas market registry. It includes a mandatory register of electricity generation units (power plants). The power plant register contains over 4 million entries, with a commission year span ranging from 1900-2021 (updating). We downloaded all the entries and uploaded them to SNOWFLAKE database. Using SQL queries, we aggregated the data annually, grouped by the categories shown in Table 5.

Table 9: Aggregation Categories and Values

Category	**Values**
Commission Date	1900-2021
Operator Type	Person
	Firm
	Cooperative
	e.K
	e.V
	GbR
	OHG
	Public
	Other
Capacity Class	Small < 100 kW
	Large > 100 kW
	Utility > 1 MW
	Legacy > 500 MW
Energy Class	Alternative
	Conventional
Energy Source Class	Renewable
	Fossil
	Other
Is Dominant Operator	0

	1
Net Capacity	In kW

After aggregating the data, we exported the aggregated data as a CSV file and imported it into R, in which all further analysis was performed.

A cumulative installed capacity sum was then computed for each year by category. This was done by summing all commissioned installed capacity up to a given year, and then subtracting the sum of decommissioned capacity. All data sets and R scripts used for this study are available on the first author's (Tia Levi) Open Science Framework account under the "Power re(distribution)" project at: https://osf.io/rhe5w/.