GreenREFORM Power Market Model

Technical documentation, KF26 edition

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Abstract

This note documents the electricity and district-heat sector of the GreenREFORM model, solved on the data behind Climate Outlook 2026 (Klimafremskrivning 2026, KF26). The model is a partial model of that sector. It is not yet integrated with the GreenREFORM CGE model.

The sector is a bottom-up model of heterogeneous plants. Short-run decisions are smoothed, so supply, demand and trade are smooth functions of the equilibrium prices. The smoothing makes the sector a square system of equations. The plant list comes from the Danish Energy Agency's Ramses model.

The database aggregates the inputs in three ways. About 6,300 Danish plants become 838 plant ids. Each Danish heat network is assigned to one of four heat markets. The 8,760 hours of a year become 120 hour states. The model solves for the electricity price and the district-heat price in every state of every year from 2025 to 2050. This release solves only that 120-state version. A fully chronological version, solved one year at a time, is planned.

Plants and interconnectors have planned and unplanned outages. Capacity factors and inflows follow the Danish Energy Agency's full-load hours. The database can be built for different weather years. The inputs are corrected or extended in three places: a 2.7 GW hydrogen pipeline to Germany from 2032, heat storage that operates throughout 2050, and an hourly pattern for the grid tariffs.

The baseline uses climate year 2008, twenty-five electricity areas and planned outages placed as maintenance blocks. Four further versions are compared with it: the same year with planned outages spread flat, the same year with thirteen areas, and climate years 2009 and 1995. Appendix A lists the changes since the version of the model published for Climate Outlook 2025.

From 2038 the inputs require European hydrogen demand to be met by electrolysis. This raises electricity prices across Europe, and the model's Danish prices lie well above the published KF26 prices from 2038. We report results for 2038–2050 as provisional. We are in contact with the Danish Energy Agency about this gap.

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1 Introduction

1.1 What the model is, and what is published

This note describes the electricity and district-heat sector of the GreenREFORM model, solved on the inputs behind Climate Outlook 2026 [Klima-, Energi- og Forsyningsministeriet, 2026, Energistyrelsen, 2026]. The wider modelling framework, and the approach to linking a bottom-up energy model with a general-equilibrium model, are described in Berg and Eskildsen [2019], DREAM [2020] and Berg and Eskildsen [2021a]. The storage formulation draws on Berg and Eskildsen [2021b]. The previous version of this note, Berg and Shine [2026], documents the same model on the Climate Outlook 2025 data. We call that version KF25 below. The plant population comes from the Danish Energy Agency's Ramses model [Energistyrelsen, 2022].

The published model is a partial model of the electricity and district-heat sector. Integration with the GreenREFORM CGE model will come in a later update.

We solve the sector as a decentralized equilibrium. Each plant's short-run problem has strictly convex costs. This replaces the step-function dispatch of a linear bottom-up model with a smooth closed form in the equilibrium prices. Storage and transmission are treated in the same way. The numerical problem is to find the prices at which the hourly electricity and district-heat markets, and the annual markets, clear. Section 3.1 states the dispatch rule. Section 9 states how the square system is solved.

Versions. A *version* is one solved baseline: a climate year, a treatment of planned outages and a geography. Table 1 lists the versions this note reports; all of them are shipped with the model, and `VERSIONS.md` describes each. Climate year 1995 is solved for the twenty-five-area geography only. All versions solve the years 2025–2050 on 120 hour states per year.

Table 1: Versions reported in this note.

Version	Weather	Geography	Outages	Role
`climate_2008`	2008	25 areas (`disaggEA`)	blocks	baseline, Sec. 11
`climate_2008`	2008	13 areas (`aggEA`)	blocks	comparison, Sec. 13.2
`climate_2008_flatoutage`	2008	25 areas	flat	comparison, Sec. 13.1
`climate_2009`	2009	25 areas	blocks	comparison, Sec. 12
`climate_1995`	1995	25 areas	blocks	comparison, Sec. 12

One representation of time. This release solves only the version with 120 clustered hour states per year. A fully chronological version, with the 8,760 hours of a year in order and solved one year at a time, is planned (Section 15.1).

Results after 2037. From 2038 the KF26 inputs require European hydrogen demand to be met by electrolysis. In the model this raises electricity prices across Europe. The model's Danish prices are close to the published KF26 prices up to 2037 and well above them from 2038 (Section 11.4). We therefore report 2038–2050 as provisional. We are in contact with the Danish Energy Agency about the gap.

Figure 1 shows the model on one page. Every electricity area clears an hourly market. Denmark has three electricity areas: West Denmark (`DK1`), East Denmark (`DK2`) and Energiø Bornholm (`DK3`). Energiø Bornholm is an offshore hub from 2034, with offshore wind and lines and no consumers. The island of Bornholm is part of East Denmark. West and East Denmark each have two district-heat markets, central and decentral. Combined heat and power couples the two sides, because it sells into both. Electric boilers and heat pumps also couple them, because they buy electricity and sell heat. Each market has its own storage plants. Each foreign

area has its own hourly electricity market and its own plants. Interconnectors link neighbouring markets. Beside the hourly markets, four kinds of market clear once a year: the two hydrogen markets, the constrained domestic fuels, the carbon-capture target and the endogenous yearly level of demand.

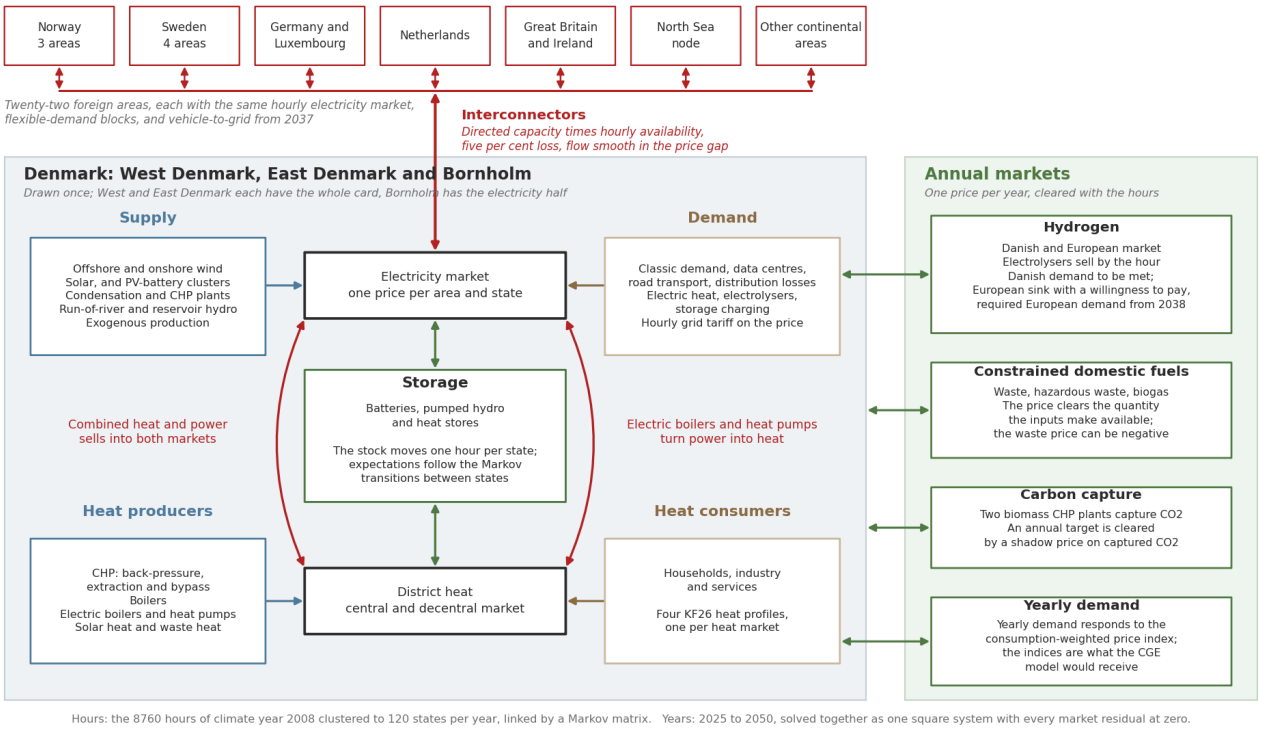


Figure 1: The model on one page. The panel shows one of the two large Danish electricity areas, with its electricity market and its central and decentral district-heat markets. Each market has its own storage plants. Energiø Bornholm (DK3) and the North Sea node have offshore wind and trade, and no demand. The other foreign areas each clear their own hourly electricity market, with their own plants, flexible-demand blocks and, from 2037, vehicle-to-grid. The column on the right is the annual markets: hydrogen, the constrained domestic fuels, carbon capture and the endogenous yearly level of demand. The line at the bottom is the time structure.

1.2 For readers of the KF25 version

The rest of the note describes the model as it is and does not compare it with the version published for Climate Outlook 2025 [Berg and Shine, 2026]. Users of that version will find every change listed in Appendix A, grouped into data, geography, model equations, solution, and outputs and use, each with a pointer to the section that describes it.

1.3 How the note is organized

The note has four parts.

- Part I (Section 2) describes the database: what is aggregated and how, the input corrections, capacity and availability, hours, and climate years.
- Part II (Sections 3–8) describes the model: the plants, demand, trade, the clearing of the hourly markets, the annual markets, and the totals passed to the CGE model.
- Part III (Sections 9–10) describes how the model is solved and how it is used.
- Part IV (Sections 11–13) reports the baseline, the other two climate years and two further versions.

Sections 14 and 15 state what the model leaves out and what is planned. Appendix A lists all changes since the KF25 version.

1.4 Notation

The note uses mathematical notation. Appendix B translates it to the GAMS names. The main indices are:

- **Time:** years t, 2025–2050. Within a year the model solves for hour states k (Section 2.6). Where the distinction does not matter, we write h and let n_h be the number of calendar hours the state stands for.
- **Goods:** demand (D) and supply (S) of electricity (E), district heat (DH) and hydrogen (H). Fuels used as inputs are indexed by b.
- **Geography:** g. For electricity, g is an electricity area, such as West Denmark. For district heat, g is one of four heat markets (Section 2.3). Where the context does not identify the good, we write g_E or g_{DH}. The area of plant i is $g(i)$.
- **Producers:** plant ids i. The producers in one market are i_E, i_{DH} and so on.
- **Fuels:** base fuels b (coal, oil, straw, wood chips, ...). A fuel type f is a mix of base fuels. The fuel type of plant i is $f(i)$.
- **Consumers:** c, or c_E for electricity where needed. If plant i is also a consumer, its consumer index is $c(i)$.
- **Plant types:** each plant id belongs to one plant type Pt. The database has 21. A plant also carries a technology label (`TechType`), which is finer: a heat pump and an electric boiler are both type `EH` with different labels. "Technology" in this note means the label.
- **Emissions:** m covers SO_2, NO_x, CO_2, CH_4 and N_2O. CH_4 and N_2O are converted to CO_2 equivalents.
- **Variation types:** v is a profile within a year. Plant i uses profile $v(i)$ and consumer c uses $v(c)$.
- **Resource zones:** r are domestic resources in constrained quantities, priced inside the model: waste, hazardous waste and biogas (Section 7.1). Plant i belongs to zone $r(i)$ where relevant.
- **Hydrogen areas:** $a \in \{\texttt{DK_H2}, \texttt{EU_H2}\}$, the two annual hydrogen markets (Section 7.3). Plant i belongs to area $a(i)$.
- **Availability:** $A_{t,h,i}$ is the share of plant i's capacity that is available in state h, and $A^X_{t,h,l}$ the same for line l (Section 2.5.3).
- **Bidding types:** type-0 plants ($i \notin \mathcal{B}_1$) bid against the spot price. Type-1 plants ($i \in \mathcal{B}_1$) are on fixed settlement contracts. The KF26 inputs put no plant in $\mathcal{B}_1$ (Section 3.1).

Part I
The database

2 The database: aggregating the inputs

The model is solved on a database that aggregates the Ramses inputs. The rest of this note uses the terms this aggregation defines: the electricity and heat areas a price is formed in, the plant ids a dispatch decision is made for, and the hour states a year is made of. The aggregation reduces five dimensions: fuel types f, geography g, producers i, consumers c and hours h. The section also describes how capacity, availability and energy are set (Section 2.5), the input corrections and additions in the baseline (Section 2.8), and the climate years (Section 2.7).

2.1 Sources and what the release holds

The plant list, capacities, efficiencies, fuel prices, taxes, demand and the foreign system come from the Danish Energy Agency's inputs for Climate Outlook 2026. Hourly profiles of demand, wind, solar and inflow come from the climate year's weather data. Where the inputs give a series for some years only, the database interpolates linearly between them; heat demand for 2038–2049 is one such series.[1] Three input choices follow the Danish Energy Agency: LPG is priced as fuel oil, hydrogen production pays no electricity tax, and the Danish grid transport cost is used in every area. The Ramses inputs contain firm-sensitive plant data. The release therefore contains the aggregated databases and the solved baselines, but not the raw inputs and not the pipeline that builds a database from them. Rebuilding a baseline from the raw inputs is not supported in this release (Section 9.3).

2.2 Fuel types

The KF26 plant list has about 250 fuel mixes f. The only symbol that depends on f is the fuel-mix parameter $\alpha_{f,b}$, the share of base fuel b in fuel type f.

Fuel types are aggregated with KMeans clustering [Pedregosa et al., 2011] into 80 clusters. With the current data, no base-fuel share differs by more than 1 percentage point from the original. The number of clusters is set by hand. Its direct effect on run time is negligible. It matters indirectly, because plants with different fuel types are never aggregated (Section 2.4).

2.3 Geography

The baseline database keeps every European price area in the KF26 inputs as its own electricity market. There are twenty-five. West Denmark (`DK1`), East Denmark (`DK2`) and Energiø Bornholm (`DK3`) are separate. So are the Nordic zones, Germany and Luxembourg, the Netherlands, Great Britain and Ireland, and the remaining continental zones. Hungary and Slovenia form one area, `HUSI`. The North Sea is its own node, the point where the offshore interconnectors meet. No area is folded into a rest-of-world market.

Energiø Bornholm (`DK3`) is an offshore hub. It is active from 2034, with one offshore wind plant (1.5 GW in 2035 and 3.0 GW in 2050) and lines to East Denmark and to Germany. It has no consumers and no district heat. It exists only in the twenty-five-area database. The island of Bornholm, including its heat network in Rønne, is part of East Denmark.

An aggregated database with thirteen areas is also built: `DK1`, `DK2`, the three Norwegian and four Swedish areas, Germany and Luxembourg, the Netherlands, and Great Britain and Ireland. Energiø Bornholm is part of `DK2`. The North Sea node and the remaining continental areas form

[1] All monetary values are in fixed 2026 prices (DKK). A supplementary workbook of fuel prices, stated in 2025 prices, is revalued to 2026 prices with the consumer price index used by the Danish Energy Agency.

one market, `ROW`. The equations are the same. The baseline uses the twenty-five-area database, because its prices are closer to the published KF26 prices. Section 13.2 compares the two.

Figures 2 and 3 draw the two geographies. Each line has one arrow per direction, with width proportional to the capacity in that direction. The North Sea node has no line in 2035. Its five lines, to Germany, Great Britain, the Netherlands, southern Norway and southern Sweden, start at 0.27 GW each in 2038 and reach 3.5 GW each in 2050. Section 11.9 shows how the lines are used in the solution.

Inside an electricity area, lines between plants that share a price are dropped. Congestion inside a bidding zone is not represented.

District heat starts from the Danish heat networks in the Ramses inputs. The database assigns each network to one of four markets: central and decentral in West Denmark (`DK1_C`, `DK1_D`) and the same split in East Denmark (`DK2_C`, `DK2_D`).[2] A plant in a central network cannot serve a decentral load. Section 15.6 discusses a finer split. Foreign areas are electricity only.

Figure 4 places the 35 named networks with their 2035 demand from the KF26 heat-demand workbook. The workbook also contains generically named local systems, all in the decentral markets. They are drawn as one "Other" disk per area: 6.8 TWh in West Denmark and 2.5 TWh in East Denmark, out of 45.6 TWh in total. Greater Copenhagen is the largest network, with 13.7 TWh.

2.4 Producers

The KF26 plant table has about 6,300 plants in about 18,000 rows, because a plant whose data change over time is stored once per spell. This aggregation matters more than the others, because almost all equations and parameters are defined over plants.

The aggregation maps many plants to one plant id. Plants are never aggregated if they differ in any of the following:

- plant type (Pt, the 21 types of Section 3);
- electricity area or heat area;
- fuel type;
- subsidy type;
- duration type (storage only, below);
- bidding type;
- technology label (used to identify incineration plants);
- CHP tax rule (Section 3.8);
- resource zone (Section 7.1).

The twenty-five-area database has 838 plant ids.

The duration ζ_i of a storage plant is its storage capacity divided by its discharge capacity: the hours it can run at full output from a full store (Section 3.12). Within each group defined above, the durations are accepted as one type if $\max(\zeta)/\min(\zeta) \le \overline{d}_{rel}$ or $\max(\zeta) - \min(\zeta) \le \overline{d}_{abs}$, with $\overline{d}_{rel} = 2$ and $\overline{d}_{abs} = 3$ hours. Otherwise the group is split by KMeans on the transformed durations

$$\tilde{\zeta}_i = \log\left(1 + \zeta_i/\mathrm{lb}\right), \qquad \mathrm{lb} = 3, \tag{1}$$

adding one cluster at a time until the tolerance is met. The transformation weighs relative rather than absolute differences.

Aggregation procedure. About 30 symbols are defined over plant ids when the database is aggregated. Capacities are summed (`ECap`, `HCap`, `HyCap`, `StorageCap`). Ratios and efficiencies are averaged with capacity weights. For combined heat and power, the weight is the sum of heat and power capacity. For storage, the weight is $Q^E_{t,i}\left[1 + \log\left(1 + \zeta_{t,i}\right)\right]$, with $Q^E_{t,i}$ the discharge

[2] The assignment is the file `heat_area_map_profile.csv`: one row per network name, and the market it clears in.

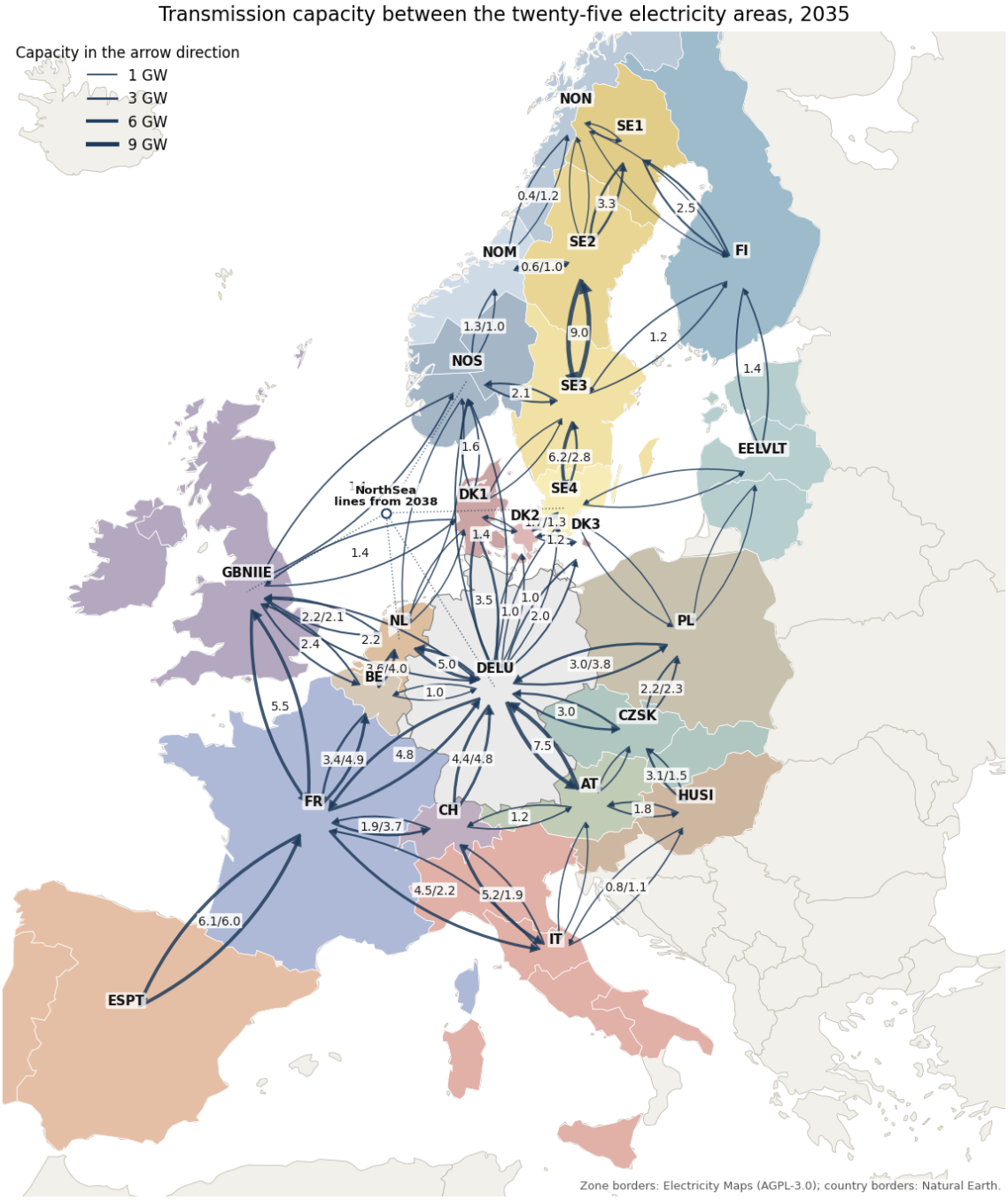


Figure 2: Transmission capacity between the twenty-five electricity areas in 2035. Each line has one arrow per direction, with width proportional to the capacity in that direction. Numbers are GW, given for both directions where they differ. Capacities are nameplate; outages are not deducted.

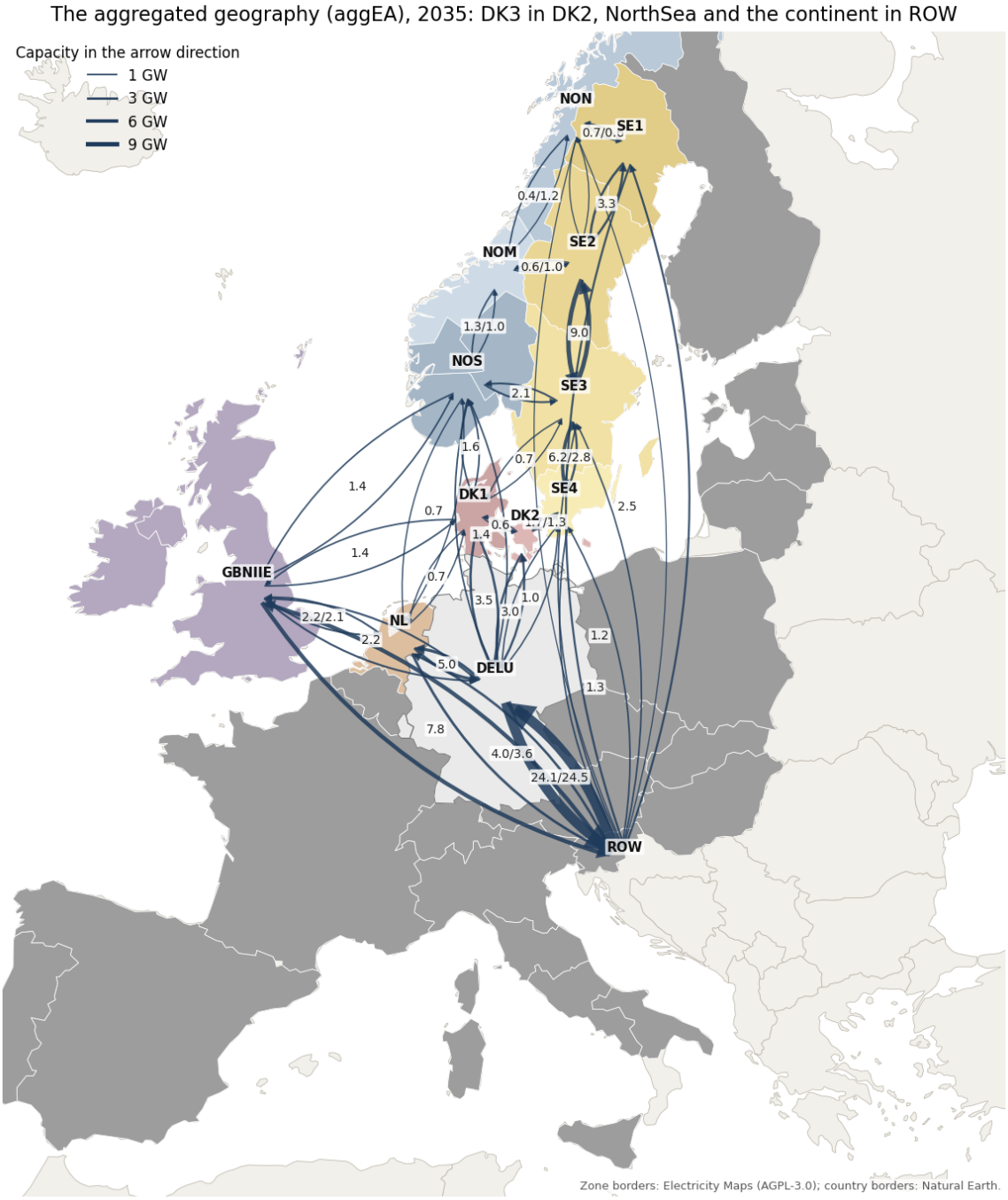


Figure 3: The aggregated geography in 2035, at the same scale. Energiø Bornholm is part of `DK2`. The grey areas are folded into `ROW`. The `ROW` node is drawn south-east of Germany, and its lines are the sums of the folded ones. Numbers are GW, labelled from 0.5 GW.

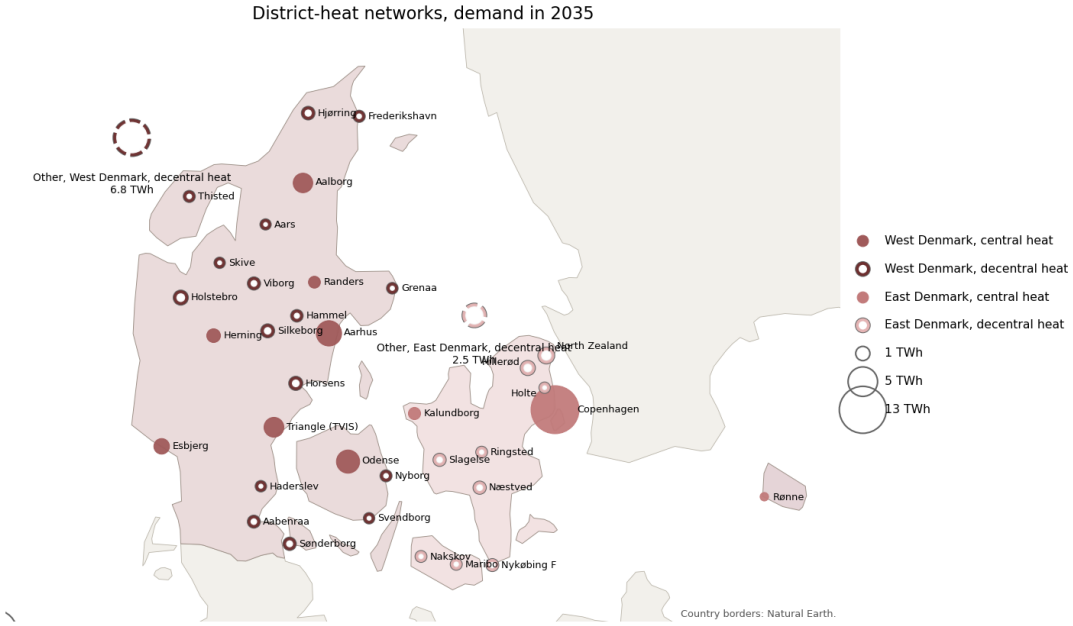


Figure 4: Danish district-heat networks in 2035 (input data). Disk area is annual heat demand. West Denmark is in dark red and East Denmark in light red, the colours of the balance figures. Filled disks are central networks and rings are decentral ones. The two dashed rings collect the generically named local systems of each decentral market.

capacity. Duration and charging speed are recomputed from the aggregated capacities instead of averaged. Outage rates are averaged with the same aggregation weights (Section 2.5.3).

For producers that are also consumers, the consumer indices are aggregated in the same way: hourly demand capacities are added, and other symbols are averaged with capacity weights.

The dispatch smoothing $\sigma_{t,i}$ of Section 3.1 is fitted at this step from the spread in the members' marginal costs. It is bounded to $[30, 300]$ DKK/MWh. Line smoothing is 30 DKK/MWh, except on the lines to `ROW` in the thirteen-area database, where it is 100 DKK/MWh. The smoothing of the electricity–heat split on CHP plants, σ^{EH}, is 10 DKK/MWh. Section 3.2 describes the fit.

2.5 Capacity, availability and energy

The capacity a plant can use in an hour state is its nameplate capacity times three factors: an annual capacity factor, an hourly profile and an availability share. Section 3 writes the decomposition out. This section describes how the annual factor and the availability share are set in the database.

2.5.1 Capacity factors and full-load hours

For wind, solar and some other technologies, the capacity factor built from the weather data does not give the annual production that the Danish Energy Agency assumes. The KF26 technology table states that production as full-load hours (FLH): the hours per year the plant would need at full output to produce its annual energy. Where the table gives full-load hours for a plant and year, the database sets the annual capacity factor to

$$CapF_{t,i} = \frac{FLH_{t,i}}{8760}. \tag{2}$$

For plants whose energy is an inflow (Section 3.12), the same rule sets the inflow factor instead. The hourly profile is unchanged. It still averages to one, so the plant produces its full-load hours

over the year when it runs whenever it can.

The rule changes 1121 of the 16868 plant-years in the 2008 database. Table 2 gives the changes by plant type. Exogenous production of heat and electricity (`EPH`, `EPE`; Section 3.7) falls most, and solar heat falls as well. Solar rises most. Onshore wind and run-of-river hydro rise a little, and offshore wind is almost unchanged. Other plant types are not affected.

Table 2: Change in the capacity-weighted mean annual capacity factor from the full-load-hour rule, 2008 database.

Plant type		Change (%)
`EPE`	exogenous electricity production	−80.8
`EPH`	exogenous heat production	−59.1
`SH`	solar heat	−22.1
`WS`	offshore wind	−1.2
`WL`	onshore wind	8.6
`RO`	run-of-river hydro	9.5
`PV`	solar	32.8

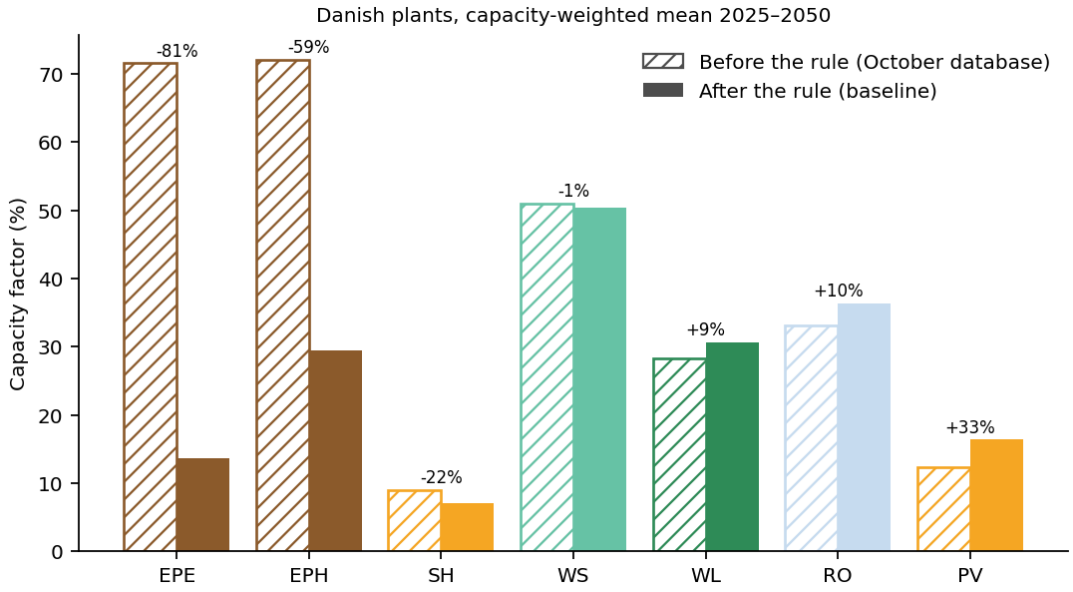


Figure 5: Annual capacity factor by Danish plant type before and after the full-load-hour rule (2), 2008 database.

2.5.2 Inflow

For some plants the KF26 inputs state the annual energy directly, as an inflow adjustment in TWh. Where this figure is positive, it replaces the annual energy that the profile and capacity factor would give. For wind, solar and run-of-river hydro, the adjustment sets the capacity factor. For hydro with storage and pumped hydro, it sets the inflow factor. If a plant has an adjustment but its profile has no energy, the profile is set flat. The adjustment applies only in the years it is listed for; it is not interpolated. It changes 8 of 697 records.

2.5.3 Outages of plants and lines

A plant or a line can be out for two reasons:

- *planned* outages (maintenance), at rate p_i: the share of the year the unit is planned out;
- *unplanned* outages (failures), at rate u_i: the share of the year the unit fails.

The rates come from the Danish Energy Agency's technology table. A rate is set by technology, and a plant-specific value replaces it where the table gives one. Rates are held constant across years. Plants of types `CD`, `BH`, `BP`, `BB`, `EX`, `EH`, `HY`, `ES` and `HYS` have outage rates. Other plant types, including heat storage and vehicle-to-grid, have none.

Interconnectors have planned and unplanned rates as well. A corridor that consists of several parallel connections gets the capacity-weighted average of their rates. The Kriegers Flak connection uses the rate of an AC connection.

In the KF26 inputs, five Danish interconnectors carry a derating factor of 0.83–0.90 on their capacity. The database represents that derating as line unavailability, not as a lower capacity. Trade capacity is therefore nameplate on every line, and availability carries the derating (Section 5).

Combining the two. The two kinds of outage are treated as independent. The share of capacity that is available in state h is

$$A_{t,h,i} = (1 - P_{t,h,i})\,(1 - u_i)\,, \tag{3}$$

where $P_{t,h,i}$ is the planned-out share in state h. Its average over the year is p_i. The database stores the unavailable share $1 - A_{t,h,i}$ (`capOut` for plants, `lineOut` for lines). A plant or line with no record is fully available. The line availability is written $A^X_{t,h,l}$.

Unplanned outages are flat. The unplanned share is the same in every hour state. The model therefore removes the expected loss of capacity in every state. It does not draw failures at random.

Planned outages are placed. Maintenance is planned, so it can be put where it costs least. In the baseline, each unit's planned rate is placed as one block of calendar hours. The block is placed on the prices of a first solve in which planned outages are flat (Section 9.2). The version `climate_2008_flatoutage` keeps the flat treatment, $P_{t,h,i} = p_i$ in every state.

Size. Weighted by capacity, 6.3 per cent of plant capacity is unavailable on average, and up to 17.7 per cent for a single plant. For lines, the figures are 11.6 per cent on average and up to 18.1 per cent for a single line. Figure 6 shows the rates by plant type.

2.6 Hours

The 8,760 hours of a year are mapped to aggregate states k. Let S_k be the set of hours mapped to state k and $n_k = |S_k|$ the number of hours in it. Before aggregation, the profile $\gamma_{h,v}$ gives the ratio of the hourly to the average value for profile type v. It has mean one.

The clustered values $\gamma_{k,v}$ can be defined in three ways:

- **Mean:** $\gamma_{k,v}$ is the average over the hours in state k.
- **Fitted distribution:** the clustered and the original values are sorted for each v separately, and $\gamma_{k,v}$ is set from the sorted original data. This keeps the spread of the original data. It represents the correlation between profile types less well.
- **Extremes:** in addition, the states that hold the minimum and maximum of a profile get the minimum and maximum of the hourly data instead of the mean of their members. The profile is then rescaled so that $\sum_k n_k \gamma_{k,v} = 8760$.

The baseline uses the fitted distribution and the extremes.

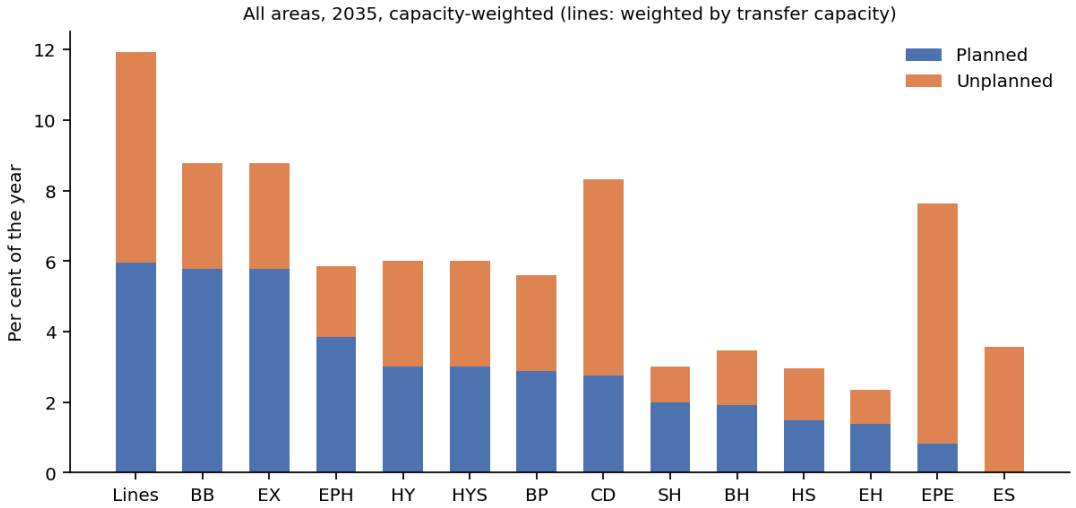


Figure 6: Planned and unplanned outage rates by plant type and for interconnectors, capacity-weighted averages, in per cent of the year.

Clustering. The year is first split into the twelve calendar months. KMeans is then applied within each month, with 10 clusters per month, which gives 120 states. The features are the standardized hourly profiles of the climate year, together with four aggregate series built from them: renewable supply, solar heat, habitual demand, and residual demand. The hourly tariff shapes (Section 4.5) are added as features with half the weight of a profile. Published prices are not a clustering feature. Every hourly profile, including the tariff profiles, is then aggregated to the states. Each climate year is clustered on its own, so the states of two climate years are different.

The chronological version. The model code can also run on the 8,760 hours in sequence. This is the version to use when the order of hours within a day matters. It is expensive, so it is solved one year at a time. This release does not include a chronological database. A chronological version is planned (Section 15.1).

Transitions between states. Once hours are clustered, "the next hour" is no longer defined. The mapping from hours to states gives transition probabilities instead. Let $n_{k,k'}$ be the number of hours with $h \in S_k$ and $h+1 \in S_{k'}$. The probability that state k is followed by state k' is

$$\Pr\left(k \to k' \,\middle|\, k\right) = n_{k,k'}/n_k, \tag{4}$$

and the probability that state k was preceded by state k' is

$$\Pr\left(k' \to k \,\middle|\, k\right) = n_{k',k}/n_k. \tag{5}$$

The count is cyclical: the last hour of the year is followed by the first. The storage problem therefore closes on itself over the year. Section 3.12.4 shows how the storage equations use these probabilities.

Figure 7 shows the matrix. Almost all probability lies in the ten-by-ten block of the current month, because states are formed within months. A thin band at the month boundaries carries the year forward. That band is what lets a storage plant move energy through the year.

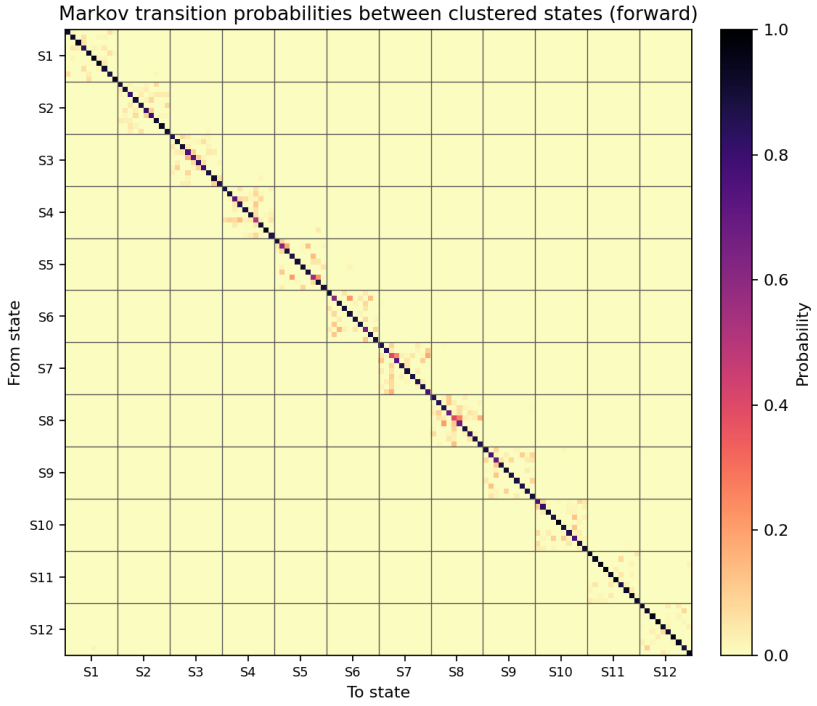


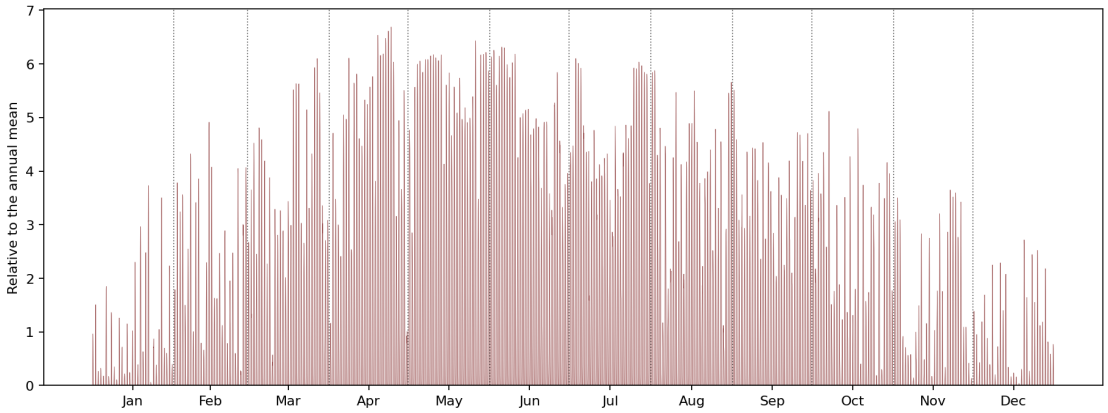
Figure 7: Transition probabilities between the 120 states of the 2008 database, $\Pr(k \to k')$. The blocks are the twelve calendar months.

What clustering does to the profiles. Figure 8 shows the solar capacity factor before and after clustering. Figures 90–92 in Appendix F do the same for electricity demand, onshore wind and hydro inflow. The variation file has Danish demand, solar and wind profiles for 2025, 2028, 2030, 2033, 2040 and 2050. The model interpolates linearly between the two nearest profiles in other years: the 2035 profile is five sevenths of the 2033 profile and two sevenths of the 2040 one. Each profile is drawn over the 8,760 hours and over the 120 states. The clustered panel keeps the months in order and sorts the states within each month from low to high.

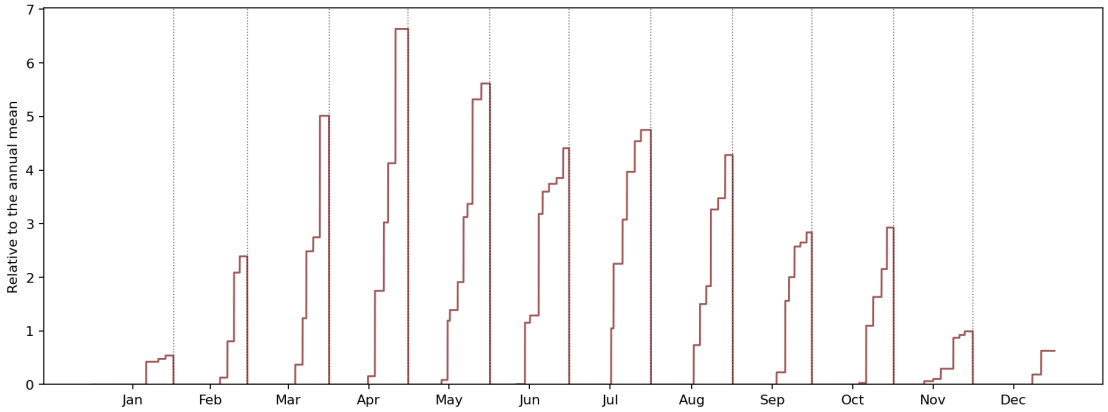
Three things follow from the figures.

- The seasonal shape survives, because states are formed within months.
- The range survives. Solar still reaches its maximum and still returns to zero, because sunny hours get their own states. The fitted distribution and the extremes protect this.
- The order within a month is lost. The model knows that sunny and dark hours both occur in June, and roughly how often one follows the other. It does not know that the sun sets every evening. A battery earns its return from that daily order (Section 3.12.4). A reservoir that moves energy from spring to autumn is not affected.

What clustering costs. Averaging within a state cannot keep an extreme hour: the most extreme state is at most as extreme as the mean of its members. The upper tail of the price distribution is therefore compressed. This can be measured without the model, by averaging published hourly prices inside the model's states. For West Denmark in 2035, this takes 232 DKK/MWh off the mean of the hundred most expensive hours (Section 11.6). Results that depend on the upper tail should be read with this in mind: scarcity rents, peak capacity values, and the profits of assets that earn their income in a few hours a year.



(a) 8,760 hours



(b) 120 clustered states

Figure 8: Solar capacity factor, ground-mounted, West Denmark 2035, before and after clustering, climate year 2008.

2.7 Climate years

A climate year is the weather year behind the hourly profiles. The baseline uses 2008. The databases for 2009 and 1995 are built in the same way.

What differs between climate years.

- The hourly profiles of electricity and heat demand, wind, solar and inflow.
- The annual capacity factors and inflows that follow from those profiles, scaled as described below.
- The hour states and the transition matrix, because each year is clustered on its own (Section 2.6).
- The placement of planned outages, because each year is placed on its own first-solve prices (Section 9.2).
- European hydrogen demand from 2039 (below).

What does not differ. Installed capacities, annual electricity and heat demand, Danish hydrogen demand, fuel and CO_2 prices, taxes, outage rates and trade capacities are the same in every climate year. Trade capacity is nameplate in every year. The hourly tariff shapes are laid on the 2018 calendar in every climate year, so weekdays and holidays fall on the same hours of the year whatever the weather year.

One input differs in 1995. In the 1995 database, the electrolyser at the North Sea node (`id869_EF`) has no minimum load in any year. In the other climate years its minimum load is 3.6 per cent of capacity in 2038, 2.8 per cent in 2039 and 2 per cent from 2040 (Section 2.8). Apart from this electrolyser the node has only offshore wind and cables, and the cables only export. In a calm 1995 hour state the minimum load used more power than the node's wind produced, so the node's market could not clear. Hydrogen output and prices at the North Sea node in 1995 are therefore not comparable one for one with the other climate years.

Scaling the adjustments. The full-load-hour and inflow rules of Sections 2.5.1–2.5.2 are stated for the reference climate year, 2008. Another climate year y keeps the 2008 proportion between the adjusted and the raw factor:

$$CapF^{y}_{t,i} = CapF^{y,\mathrm{raw}}_{t,i} \cdot \frac{CapF^{2008,\mathrm{adjusted}}_{t,i}}{CapF^{2008,\mathrm{raw}}_{t,i}}, \tag{6}$$

and likewise for the inflow factor. The ratio is taken per plant and model year, so the correction that (2) makes to a plant in the 2008 database is applied to the same plant in every climate year, in proportion. A windier year therefore keeps more wind energy than 2008, and the level is still tied to the Danish Energy Agency's full-load hours. If a 2008 raw factor is zero where year y's is not, the database build stops.

The Danish Energy Agency does not scale in proportion. It gives Danish wind and solar the same full-load hours in every climate year, so in its runs the climate years differ in when wind and solar produce, not in how much they produce over the year. We keep the proportional scaling, because it represents the differences between climate years better: a calm year is calm in its annual energy as well as in its hours.

European hydrogen demand. The KF26 inputs state the European hydrogen demand that must be met from 2038 (Section 7.3) per climate year. The Danish Energy Agency adjusts it from the ERAA and TYNDP level with PEERS runs for each climate year. In the data, demand is 450 TWh in 2038 in every climate year and differs from 2039. In 2050 it is 1,575 TWh with the 1995 weather, 1,472 TWh with 2008 and 1,403 TWh with 2009; the years between are interpolated linearly.

Figure 9 compares the main inputs of the three climate years.

2.8 Input corrections and additions in the baseline

The baseline database departs from the Ramses inputs in three places: two corrections and one addition. Each is described where it acts in the model; this section lists them together, followed by two parts of the Danish Energy Agency's inputs that matter for the results.

Hydrogen pipeline to Germany. The Ramses inputs carry a placeholder line of 0.01 MW between the Danish and the European hydrogen markets. The database replaces it with a pipeline of 2.7 GW in each direction from 2032, which is 23.652 TWh per year. The size follows Energinet's plans for a hydrogen backbone [Energinet, 2026]. Section 7.3 describes how the flow is determined.

Heat storage in 2050. The Ramses inputs decommission the Danish heat storage on 1 January 2050, so the capacity falls to nearly zero in 2050. The Danish Energy Agency has confirmed that the date is a data error. The database moves the decommissioning to 31 December 2050, so the storage operates throughout 2050.

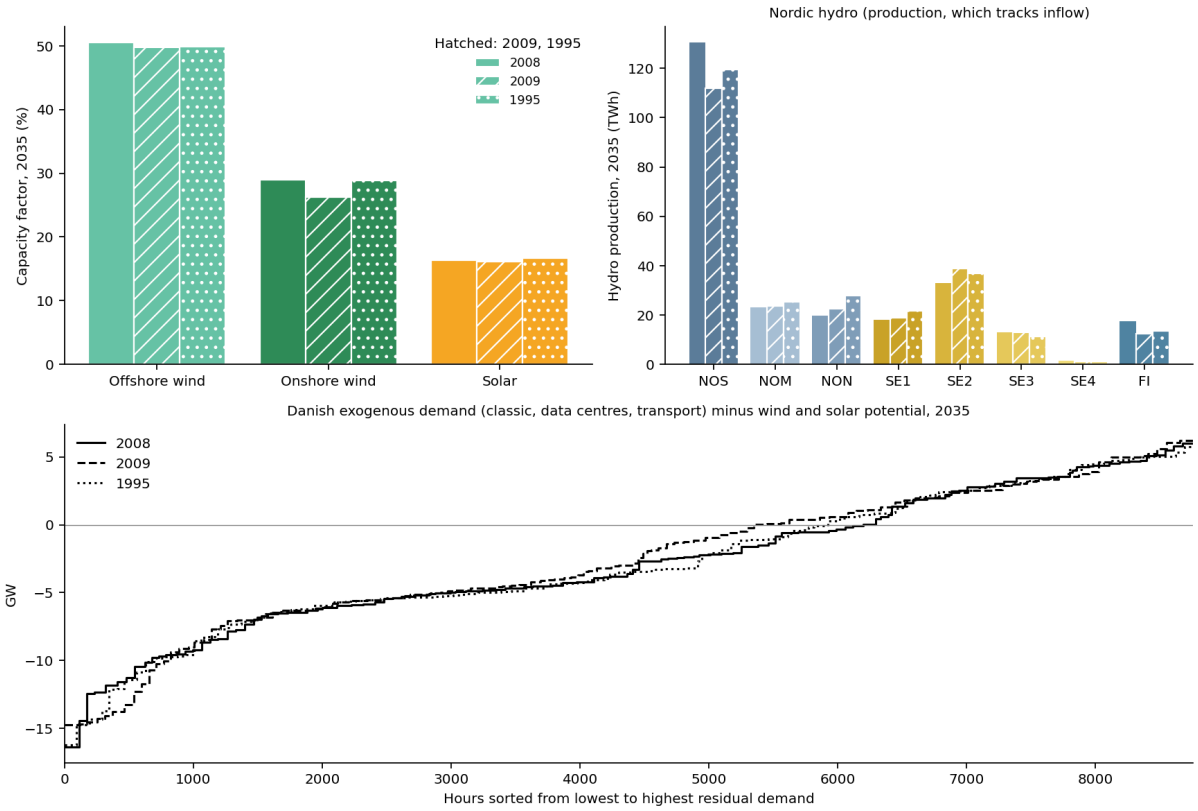


Figure 9: Inputs that differ between climate years 2008, 2009 and 1995: annual capacity factors of offshore wind, onshore wind and solar in Denmark, Nordic hydro inflow, and the duration curve of Danish residual demand in 2035, hours sorted from lowest to highest. Bars: 2008 plain, 2009 hatched with lines, 1995 hatched with dots. Curves: 2008 solid, 2009 dashed, 1995 dotted.

Hourly pattern of grid tariffs. The Ramses inputs give an annual grid tariff for each consumer type. The database multiplies it by an hourly pattern with mean one, computed from the tariffs the Danish grid companies publish (Section 4.5).

Minimum load on electrolysers. Electrolysers run at or above a minimum share of capacity, $d^{min}_{t,i}$ (Section 3.13). The values are the Ramses minimum-load factors for the two electrolyser types, `EF` and `PX`. They are 10 per cent of capacity up to 2030, fall by 0.8 percentage points a year to 6 per cent in 2035, and are 2 per cent from 2040. The path is the same in every area and in both geographies, with one exception: in climate year 1995 the electrolyser at the North Sea node has no minimum load (Section 2.7). No other plant type has a minimum load.

Electric vehicles abroad. From 2037, the Danish Energy Agency's inputs include the electric-vehicle fleets of the TYNDP 2024 in 17 foreign areas, which the model represents as vehicle-to-grid plants (Section 3.12.3). The discharge capacity grows by about 51 GW per year and reaches about 715 GW in 2050. The fleets are assumed to be always plugged in: their availability profile is flat. This is an assumption under review. It makes the foreign fleets a very large and very flexible store, which smooths foreign prices (Section 14). No Danish vehicles have the vehicle-to-grid option in the inputs.

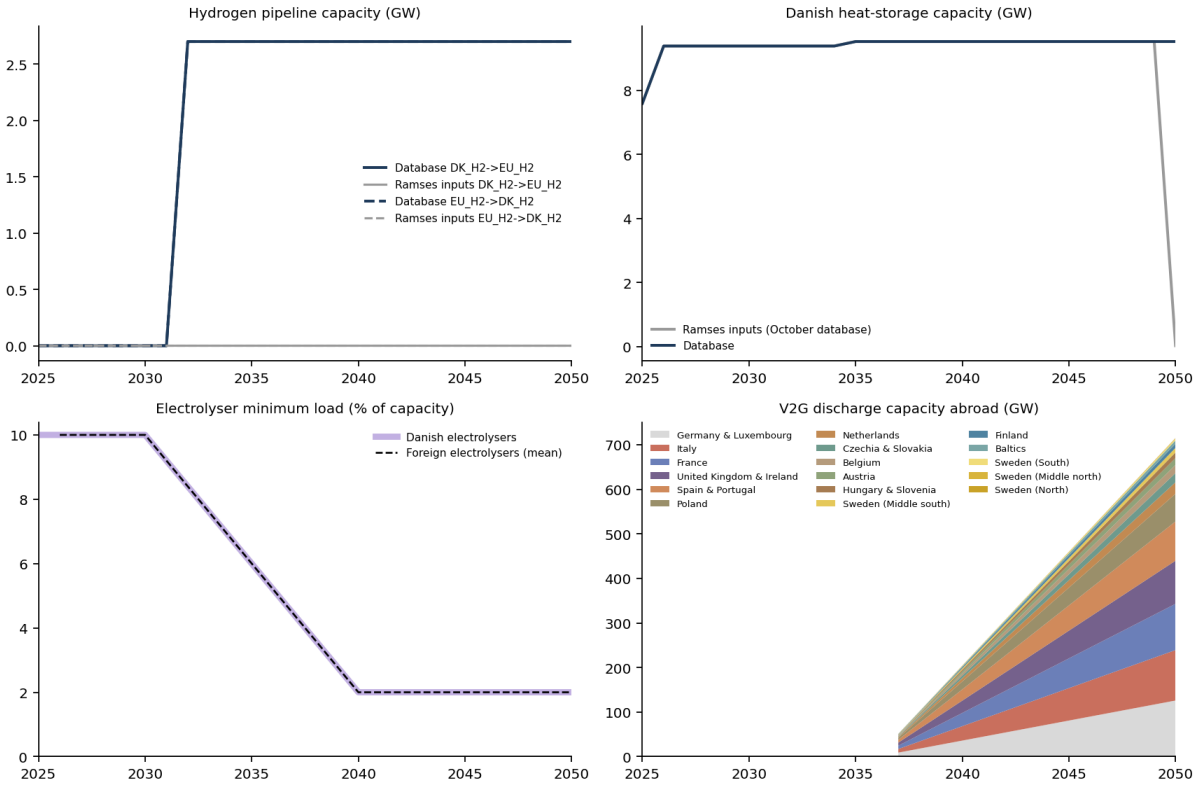


Figure 10: The two input corrections and two parts of the inputs that matter for the results (the tariff pattern is shown in Figure 25). Top left: hydrogen pipeline capacity, Ramses inputs and database, GW. Top right: Danish heat-storage capacity, Ramses inputs and database, GW. Bottom left: electrolyser minimum load, per cent of capacity. Bottom right: vehicle-to-grid discharge capacity abroad by area, GW.

Part II
The model

3 Energy-producing plants

This section sets out the data, the optimization problem and the equilibrium conditions for each plant type. Every plant id i maps to one plant type, one area, one fuel mix and one technology label, among other categories.

For most plants the short-run problem within a year is static: each hour state can be solved on its own. Storage plants are dynamic. All plants have rational expectations. Uncertainty is not modelled.

3.1 Smoothed dispatch

Nearly every dispatch decision below has the same form. The plant runs if the price covers its marginal cost, and the model writes this as $\Phi((p-c)/\sigma)$ instead of an indicator function. The interpretation is that marginal cost is not known exactly. It varies within the plant, within the state and across the hours the state stands for. $\sigma_{t,i}$ is the standard deviation of that variation, and the model computes the expected share of capacity that runs.

The smoothing does not wash out in the aggregate. At $\sigma = 30$ DKK/MWh, the dispatch share is one half when the price equals marginal cost. The plant reaches about nine tenths of capacity 38 DKK/MWh above its marginal cost, and still offers about a tenth 38 DKK/MWh

below. Summed over a fleet, this turns a merit-order staircase into a smooth supply curve (Figure 28). Figure 11 draws the rule for a plant with a marginal cost of 400 DKK/MWh at four values of σ.

Dispatch smoothing is fitted per plant id and bounded to $[30, 300]$ DKK/MWh (Section 3.2). Line smoothing $\sigma_{t,l}$ is 30 DKK/MWh, and 100 DKK/MWh on the lines to `ROW` in the thirteen-area database. The smoothing of the electricity–heat split on CHP plants, $\sigma^{EH}_{t,i}$, is 10 DKK/MWh.

The smoothing also makes the system square and differentiable: a system of indicator functions has no derivative to give a Newton-type solver. The solution procedure never changes the smoothing parameters to reach a solution (Section 9.1).

Bidding types. The code has a second bidding type. Plants on a fixed settlement price (*fast afregningspris*), the set $\mathcal{B}_1$ (`bidT1`), are not exposed to the spot price. The contract price enters marginal cost as a negative tax. Where a type-0 plant compares $p^{E}_{t,h,g(i)} - c_{t,i}$, a type-1 plant compares $-c_{t,i}$. For CHP plants only the district-heat price is kept in the price index. The KF26 inputs have no plant on a fixed settlement contract, so $\mathcal{B}_1$ is empty and every plant bids against the spot price. The mechanism is kept for later input sets. The equations below are the type-0 ones.[3]

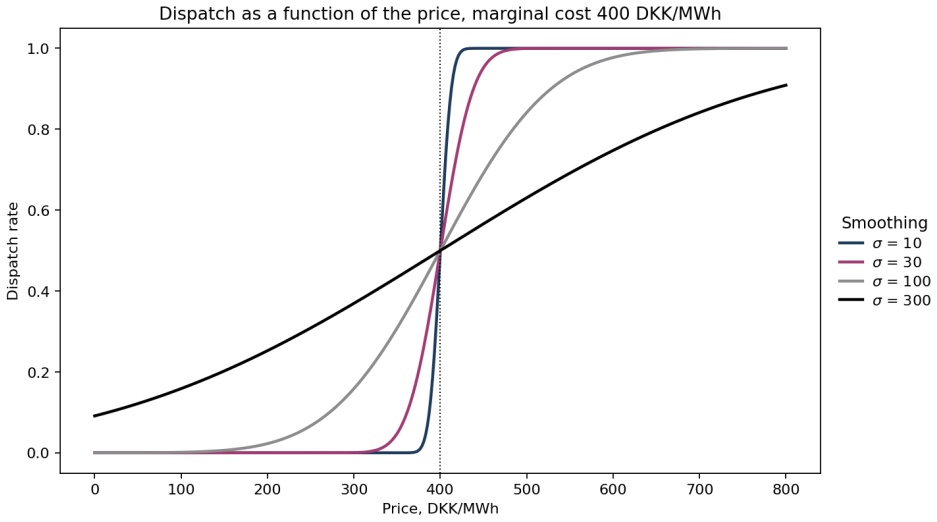


Figure 11: The dispatch rule $\Phi((p-c)/\sigma)$ for a plant with marginal cost 400 DKK/MWh, at four values of the smoothing parameter σ (DKK/MWh).

3.2 Where the smoothing parameter comes from

We estimate $\sigma_{t,i}$ so that the smoothed dispatch of an aggregate plant reproduces the supply curve of the plants combined into it (Section 2.4). The members differ in efficiency, fuel blend and plant-specific costs, so they do not share one marginal cost.

For every aggregate id and year:

1. the model's marginal-cost formulas are evaluated on the members and on the aggregate (a static evaluation, with no dispatch);
2. the capacity-weighted distribution of the members' marginal costs is formed;
3. σ minimizes the capacity-weighted squared distance between $\Phi((c_j - c)/\sigma)$ and the cumulative capacity share at the midpoint of each member's step j, with c the aggregate's marginal cost;

[3]The contracts for difference used in the new Danish offshore wind tenders are in neither the Ramses inputs nor this model.

4. the estimate is bounded to $[30, 300]$ DKK/MWh.

An aggregate with one member, or with members of identical cost, keeps the floor of 30. For flexible CHP plants (`BB`, `EX`) the cost is the back-pressure mode's, so the electricity–heat smoothing $\sigma^{EH}_{t,i}$ stays separate. Neither σ^{EH} nor line smoothing is estimated.

Take one aggregate: the seventeen gas-oil boilers of West Denmark in `id43_BH`. In 2035 the members have 171 MW of heat capacity in steps from 1,004 to 1,252 DKK/MWh, around the aggregate's marginal cost of 1,084. At $\sigma = 30$ the whole aggregate would switch on within a 100 DKK/MWh band around c. Two fifths of the capacity is cheaper than that band and a third is more expensive, so the floor fits badly. At 300, a fifth of the capacity would run 150 DKK/MWh below the cheapest member's cost. The estimate, 100 DKK/MWh, brings the root-mean-square distance to less than half that of either bound (0.085 against 0.197 and 0.191). The estimate moves with the members' costs: for this plant it rises from 82 in 2025 to 124 in 2050.

In 2035, 598 of the 628 active aggregate ids are at the floor, 23 have a fitted value between 30 and 300, and 7 are at the cap. All 30 are Danish. The foreign plant records are already one record per technology and area, so a foreign aggregate has a single member and no spread to fit. Half of the 60 Danish aggregates with several members stay at the floor, because their members' costs are within a few tens of DKK/MWh. The fitted values follow the spread of member costs, at a somewhat higher level, because the criterion spreads each member's mass over its capacity step. The seven plants at the cap are groups of condensation and back-pressure plants whose members' costs are several hundred to a few thousand DKK/MWh apart.

Three things remain to be done. Storage plants have no static marginal cost and keep the floor; an estimate for them would have to come from their dispatch [e.g. Berg and Eskildsen, 2021b]. The number of groups within a category could be chosen with the same criterion, splitting a group when its σ hits the cap. And the fit covers only the spread between members, not the variation within a plant and across hours. That is one reason to keep a floor of 30.

3.3 Condensation plants (CD)

Condensation plants produce electricity from a fuel mix $f(i)$. Their approximate marginal cost $c_{t,i}$ is the sum of fuel costs, emission taxes, other taxes and other variable operating and maintenance costs $v_{t,i}$:[4]

$$c_{t,i} = v_{t,i} + \frac{c^{fuel}_{t,f(i)} + c^{r}_{t,i}}{\eta_{t,i}} + T^{M}_{t,i} + T^{E}_{t,i} \tag{7}$$

$$c^{fuel}_{t,f(i)} = \sum_{b} \alpha_{f(i),b} \cdot p_{t,b} + \varphi_{t,i} \tag{8}$$

$$c^{r}_{t,i} = \sum_{b} \alpha_{f(i),b} \cdot p^{r}_{t,r(i),b} \tag{9}$$

$$T^{M}_{t,i} = \frac{1}{\eta_{t,i}} \sum_{m} \left(\mu^{m}_{t,i} \tau^{m}_{t,i} \right). \tag{10}$$

Here $\mu^{m}_{t,i}$ is the emission intensity of type m, $\tau^{m}_{t,i}$ the effective emission tax, $\eta_{t,i}$ the efficiency, $\alpha_{f,b}$ the fuel shares ($\sum_b \alpha_{f,b} = 1$), $p_{t,b}$ the base fuel prices, and $T^{E}_{t,i}$ other taxes and subsidies on electricity. The term $\varphi_{t,i}$ (DKK/MWh of fuel) is a plant-specific fuel-price adjustment. It carries the area-specific price factors of the KF26 inputs. The variable cost $v_{t,i}$ includes the Ramses adjustment to variable operating cost. The term $c^{r}_{t,i}$ is the shadow price of the constrained domestic resources (Section 7.1); it is zero for plants outside a resource zone.

The costs $c_{t,i}$, $v_{t,i}$, $T^{M}_{t,i}$ and $T^{E}_{t,i}$ are in DKK per MWh of electricity. The fuel indices $c^{fuel}_{t,f}$ and $c^{r}_{t,i}$ are in DKK per MWh of fuel.

[4] "Approximate", because short-run costs are assumed to be normally distributed around this mean.

Emission intensities and regulation. The CO_2e intensity is a plant-specific term $\tilde{\mu}_{t,i}^{CO_2}$, which covers CH_4 and N_2O in CO_2 equivalents, plus the CO_2 of the fuel mix.

CO_2e emissions are taxed at different rates depending on the output (electricity or heat) and on whether the plant is covered by EU-ETS1. The database has six rates:

i. the EU-ETS1 allowance price ($\tau_t^{\text{ETS-1}}$);
ii. the EU-ETS2 allowance price ($\tau_t^{\text{ETS-2}}$);
iii. the Danish tax on emissions from electricity generation covered by EU-ETS1 ($\tau_t^{CO_2,E}$);
iv. the Danish tax on emissions from electricity generation not covered by EU-ETS1 ($\tau_t^{\text{Non-ETS},E}$);
v. the Danish tax on emissions from district-heat production covered by EU-ETS1 ($\tau_t^{CO_2,DH}$);
vi. the Danish tax on emissions from district-heat production not covered by EU-ETS1 ($\tau_t^{\text{Non-ETS},DH}$).

Emissions outside EU-ETS1 pay the EU-ETS2 price plus the national rate. In this database rates iv and vi are equal in every year. For condensation plants:

$$\mu_{t,i}^{CO_2} \equiv \tilde{\mu}_{t,i}^{CO_2} + \sum_b \left(\alpha_{f(i),b} \cdot \mu_{t,b}^{CO_2}\right) \tag{11}$$

$$\tau_{t,i}^{CO_2} \equiv s_{t,i}^{\text{ETS1}} \cdot \left(\tau_t^{\text{ETS-1}} + \tau_t^{CO_2,E}\right) + \left(1 - s_{t,i}^{\text{ETS1}}\right) \cdot \left(\tau_t^{\text{ETS-2}} + \tau_t^{\text{Non-ETS},E}\right) \equiv \tau_{t,i}^{CD}, \tag{12}$$

where $s_{t,i}^{\text{ETS1}}$ is the share of the plant's emissions covered by EU-ETS1.[5] CO_2 intensities are in tonnes CO_2e per MWh of fuel, and CO_2 taxes in DKK per tonne. Figure 12 draws the rates and the base-fuel prices.

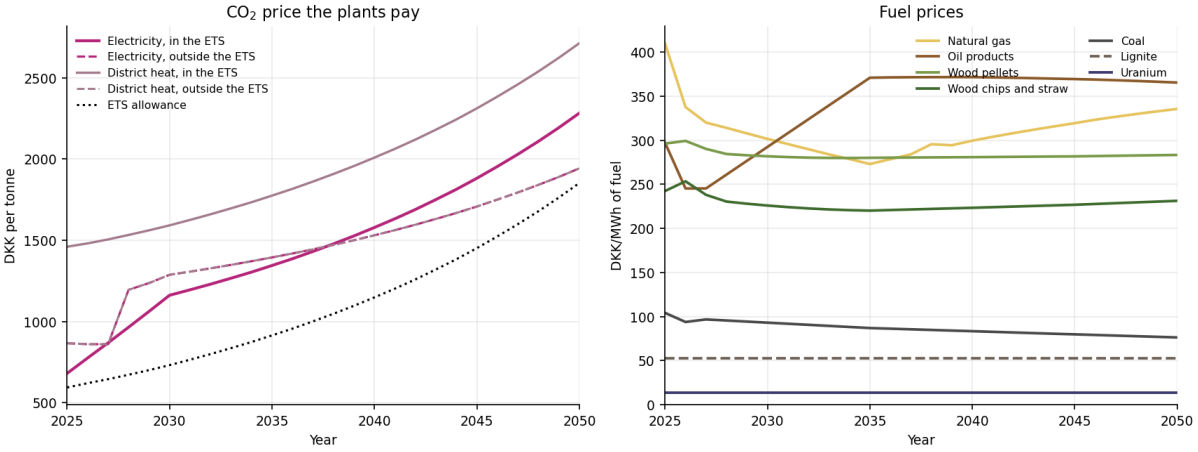


Figure 12: CO_2 rates (DKK/t) and fuel prices (DKK/MWh) in the database. The allowance is the ETS price. Electricity and district heat inside the ETS add the Danish rate for that output; production outside the ETS pays the ETS2 price plus its own Danish rate. Natural gas falls from 410 DKK/MWh in 2025 to about 270 in 2035 and rises to about 340 in 2050. Waste and biogas have no market price; their cost is the shadow price of the resource zone. The hydrogen price clears in its own market.

The NO_x intensity is a plant-specific term $\tilde{\mu}_{t,i}^{NO_x}$ with no fuel-mix part. The tax is the same for all plants. NO_x intensities are in kg per MWh of fuel and the tax in DKK per kg.

The SO_2 intensity comes from fuel use only, reduced by the plant's desulphurization share $DS_{t,i}$. The tax is the same for all plants. Intensities are in kg per MWh of fuel and the tax in

[5] It is a share so that an aggregate can hold covered and uncovered plants. In the KF26 database every entry is zero or one. It is one for every plant that burns fuel, Danish and foreign. The EU-ETS2 and Non-ETS rates are therefore charged to no plant in the baseline. A shock that puts a plant outside EU-ETS1 would use them.

DKK per kg:

$$\mu^{SO_2}_{t,i} \equiv (1 - DS_{t,i}) \sum_b \left(\alpha_{f(i),b} \cdot \mu^{SO_2}_{t,b} \right), \qquad \tau^{SO_2}_{t,i} \equiv \tau^{SO_2}_t.$$

Foreign plants. Plants outside Denmark pay only the EU-ETS price: for $i \notin DK$, $T^M_{t,i}$ is replaced by $\mu^{CO_2}_{t,i} \tau^{\text{ETS-1}}_t / \eta_{t,i}$, and $c^r_{t,i}$ is zero.

Short-run optimization. Within a year t, the producer takes its capacity $Q^E_{t,h,i}$ in each state and the prices $p^E_{t,h,g(i)}$ as given. It maximizes

$$Q^E_{t,i} \Pi_{t,i} = \sum_h n_h \, Q^E_{t,h,i} \left[p^E_{t,h,g(i)} s^E_{t,h,i} - F_{t,i} \left(s^E_{t,h,i} \right) \right] - Q^E_{t,i} \cdot FOM_{t,i},$$

where $\Pi_{t,i}$ is profit per unit of installed capacity, $s^E_{t,h,i} \equiv S^E_{t,h,i} / Q^E_{t,h,i}$ the utilization rate, $S^E_{t,h,i}$ generation, $FOM_{t,i}$ fixed operating cost per unit of capacity, and F the short-run average cost function, convex in $s^E_{t,h,i}$. If costs are normally distributed around $c_{t,i}$ with standard deviation $\sigma_{t,i}$, the optimal dispatch is

$$s^E_{t,h,i} = \Phi \left(\frac{p^E_{t,h,g(i)} - c_{t,i}}{\sigma_{t,i}} \right) \tag{13}$$

$$\pi_{t,h,i} = s^E_{t,h,i} \left(p^E_{t,h,g(i)} - c_{t,i} \right) + \sigma_{t,i} \phi \left(\frac{p^E_{t,h,g(i)} - c_{t,i}}{\sigma_{t,i}} \right) \tag{14}$$

$$Q^E_{t,i} \Pi_{t,i} = \sum_h n_h \, Q^E_{t,h,i} \pi_{t,h,i} - Q^E_{t,i} \cdot FOM_{t,i}, \tag{15}$$

where ϕ and Φ are the density and the distribution function of the standard normal distribution, and $\pi_{t,h,i}$ is the hourly profit per unit of capacity $Q^E_{t,h,i}$.

Capacity in an hour state. The capacity in state h is the yearly capacity $Q^E_{t,i}$ times three factors:

$$Q^E_{t,h,i} = Q^E_{t,i} \cdot CapF_{t,i} \cdot \gamma_{h,v(i)} \cdot A_{t,h,i}, \qquad \gamma_{h,v(i)} \equiv \sum_v \mu^{cap}_{t,i,v} \, \gamma_{h,v}. \tag{16}$$

- $CapF_{t,i} \in [0, 1]$ is the annual capacity factor (Section 2.5.1).
- $\gamma_{h,v(i)}$ is the ratio of hourly to average capacity for the plant's profile. It has mean one.[6] The shares $\mu^{cap}_{t,i,v}$ sum to one and describe a plant as a mix of base profiles. They also carry the linear interpolation between the profile years of the inputs (Section 2.6).
- $A_{t,h,i}$ is the available share after planned and unplanned outages, (3). It is one for plant types without outage rates.

Figures 13–16 draw the Danish capacity in the database. Figure 13 shows nameplate electricity capacity $Q^E_{t,i}$ by plant type. Figure 14 shows it after the capacity factor, which is the mean capacity over the year before outages. Figure 15 shows district-heat capacity in the four heat markets. Figure 16 splits the effective thermal capacity by fuel.

With this decomposition, unit profits are

$$\Pi_{t,i} = \sum_h n_h \left(CapF_{t,i} \cdot \gamma_{h,v(i)} \cdot A_{t,h,i} \cdot \pi_{t,h,i} \right) - FOM_{t,i}. \tag{17}$$

For type-1 plants, (13)–(17) apply with $p^E_{t,h,g(i)}$ set to zero.

Units: prices in DKK/MWh, generation and capacity in GWh and GW, fixed costs in million DKK per GW, and short-run profits $\Pi_{t,i}$ in million DKK per GW.

[6] For condensation plants, $CapF_{t,i} = \gamma_{h,v(i)} = 1$.

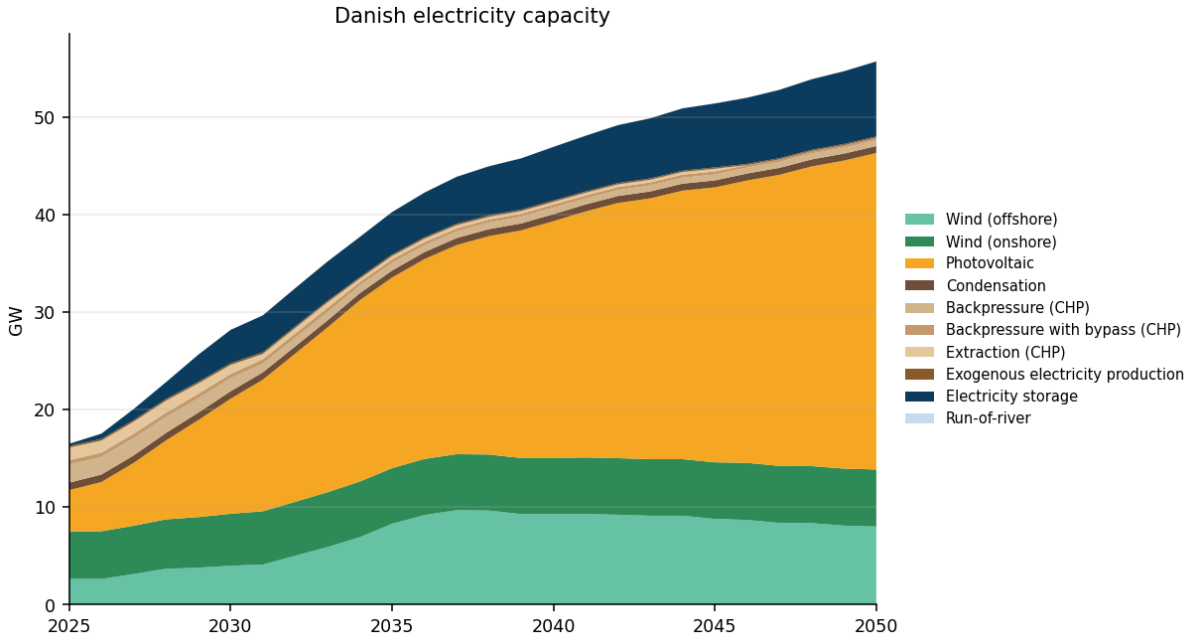


Figure 13: Danish electricity capacity by plant type, GW, including Energiø Bornholm. Solar capacity is the nameplate of the parks, which is larger than the grid connection of the solar-battery clusters of Section 3.18.

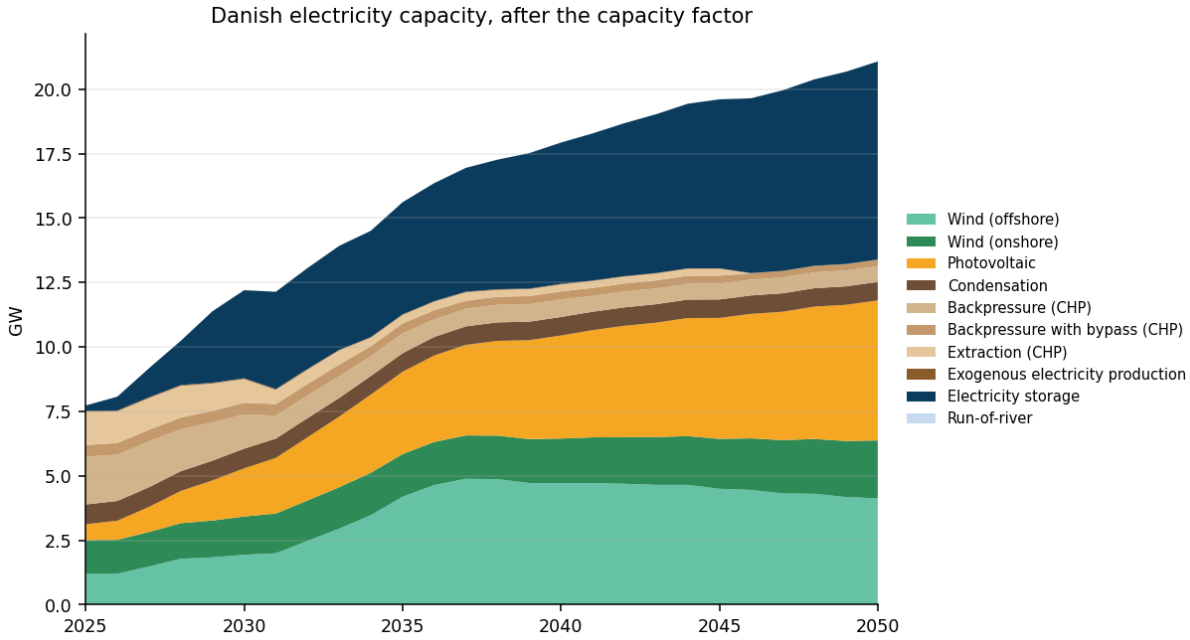


Figure 14: The capacity of Figure 13 multiplied by the annual capacity factor $CapF_{t,i}$ after the full-load-hour rule, GW. The hourly profile averages to one, so this is the mean capacity over the year before outages.

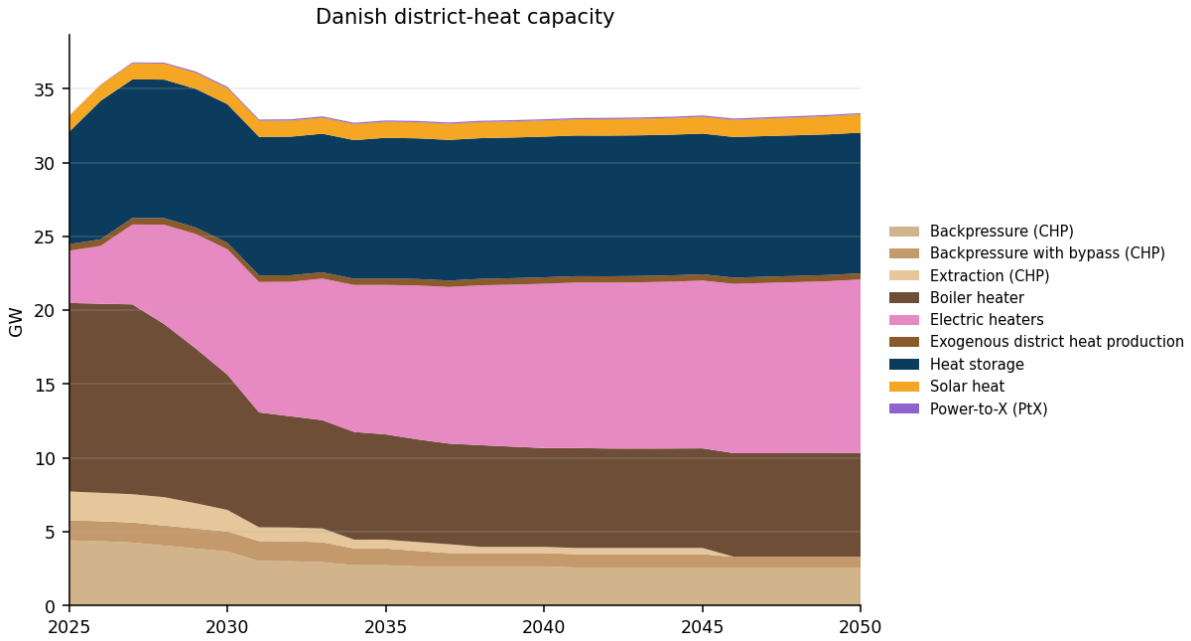


Figure 15: District-heat capacity in the four Danish heat markets, GW. Heat storage operates throughout 2050 (Section 2.8).

Interactions with other parts of the model. Supply $S^E_{t,h,i} = s^E_{t,h,i} Q^E_{t,h,i}$ enters the clearing condition of the plant's electricity area. Fuel use is production times $\alpha_{f,b}/\eta_{t,i}$, and emissions follow from fuel use and the intensities $\mu^m_{t,i}$ (Section 8).

$\Pi_{t,i}$ is what an investment decision would be based on: capacity is worth adding where unit profits are positive. Capacity is exogenous in this version, so $\Pi_{t,i}$ is reported only. Section 15.2 describes the extension.

3.4 Boiler heaters (BH)

Boiler heaters are condensation plants that sell district heat instead of electricity. There are two differences. CO_2 is taxed at the heat rates. And fuel used for heat pays a further tax specific to the base fuel, $\tau^{DH}_{t,b}$:

$$\tau^{CO_2}_{t,i} = s^{\text{ETS1}}_{t,i} \cdot \left(\tau^{\text{ETS-1}}_t + \tau^{CO_2,DH}_t\right) + \left(1 - s^{\text{ETS1}}_{t,i}\right) \cdot \left(\tau^{\text{ETS-2}}_t + \tau^{\text{Non-ETS},DH}_t\right) \equiv \tau^{BH}_{t,i} \tag{18}$$

$$T^{DH}_{t,i} = \frac{\sum_b \alpha_{f(i),b} \cdot \tau^{DH}_{t,b}}{\eta_{t,i}}. \tag{19}$$

Marginal cost is $c_{t,i} = v_{t,i} + \left(c^{fuel}_{t,f(i)} + c^r_{t,i}\right)/\eta_{t,i} + T^M_{t,i} + T^{DH}_{t,i}$, with $T^M_{t,i}$ evaluated at $\tau^{BH}_{t,i}$. Dispatch follows (13) with $p^{DH}_{t,h,g(i)}$ in place of $p^E_{t,h,g(i)}$.

3.5 Wind (WS, WL), solar (PV) and run-of-river hydro (RO)

These four types are condensation plants with no fuel and no emissions: $c_{t,i} = v_{t,i} + T^E_{t,i}$. Their capacity factors follow the full-load-hour and inflow rules of Section 2.5. They have no outage rates.

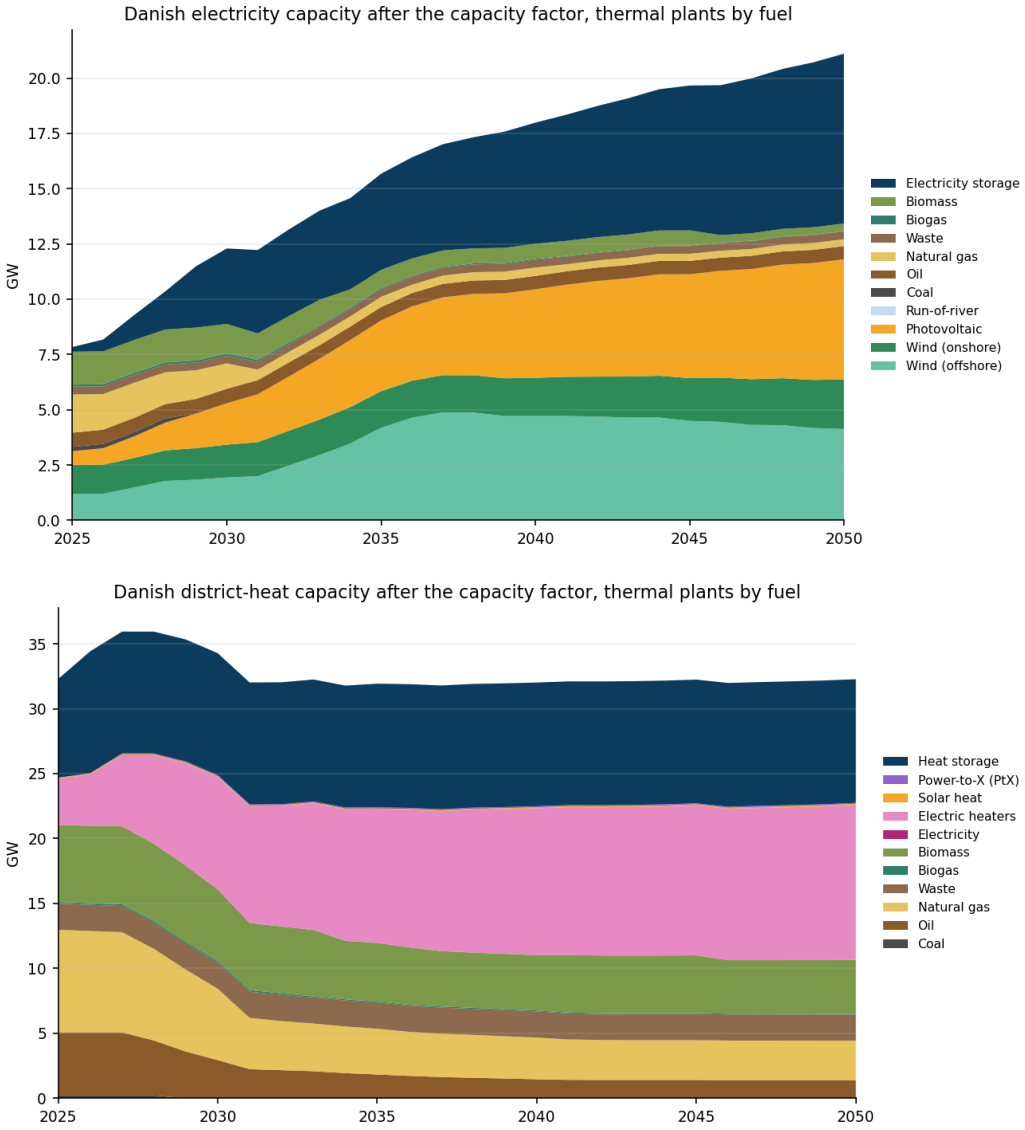


Figure 16: Effective capacity (nameplate times $CapF_{t,i}$), GW, with thermal plants grouped by fuel. Thermal means condensation, boilers, the three CHP types and exogenous production; each plant's capacity is split across fuel groups in proportion to its fuel mix. Other plants keep their plant type. In 2035 the effective thermal electricity capacity is 2.2 GW, against 4.2 GW of offshore wind and 3.2 GW of solar. Electric heaters are 10 GW of the district-heat capacity.

3.6 Solar heat (SH)

Like solar power, but selling district heat, with $c_{t,i} = v_{t,i}$.

3.7 Exogenous production (EPE, EPH)

Plants whose production is largely set outside the energy sector are modelled as condensation plants if they produce electricity (`EPE`) and as boiler heaters if they produce heat (`EPH`). In Denmark, they cover surplus electricity or heat from other industries. Some of it is fixed, and some responds to prices. The full-load-hour rule reduces their capacity factors a great deal (Table 2).

`EPE` has a second role abroad. The CHP types below are Danish only, because only the Danish areas have heat markets. Foreign thermal capacity is therefore mostly condensation plants (`CD`),

with a smaller share as `EPE` where the Ramses data treat output as fixed. Physical CHP units abroad are inside these aggregates.

This loses the tie that heat puts on a CHP plant, in both directions. A German unit in the model has no reason to run when the electricity price is below its marginal cost, where the physical plant would run to deliver heat. Nothing stops it from responding fully to a high price, where the physical plant is tied to a heat load. The hourly profile $\gamma_{h,v(i)}$ could carry a seasonal shape to impose part of the heat-driven pattern. The inputs do not use it for this. Section 14 records the direction of the bias.

3.8 CHP plants: allocating fuel and emissions between electricity and heat

Combined heat and power plants produce two outputs from one fuel input. Danish tax law taxes fuel for heat differently from fuel for electricity, so the fuel input of a CHP plant must be split between the two. The model follows the statutory rules, which the plant may choose between.

Two plant parameters appear throughout. $\kappa_{t,i}$ is the ratio of electricity to heat in back-pressure mode. $\xi_{t,i}$ is the rate at which the plant exchanges the two outputs when it leaves that mode: $\xi_{t,i}$ units of electricity for one unit of heat. A bypass plant gives up electricity for heat at that rate, and an extraction plant gives up heat for electricity. Consider a CHP plant in a given mode producing E units of electricity and H units of heat from $F = 1/\eta_{t,i}$ units of fuel, per unit of the composite output of that mode. Danish law offers two rules for splitting F into fuel for electricity, F^E, and fuel for heat, $F^H = F - F^E$:

- **The V-rule** (heat-efficiency rule): $F^H = H/\overline{\nu}$ with $\overline{\nu} = 1.25$, and $F^E = F - H/\overline{\nu}$.
- **The E-rule** (electricity-efficiency rule): $F^E = E/\overline{\varepsilon}$ with $\overline{\varepsilon} = 0.65$, and the rest is fuel for heat.

Under the V-rule, fuel for electricity is capped so that the implied electricity efficiency cannot fall below $\overline{\gamma} = 0.35$:

$$F^E \leq E/\overline{\gamma}.$$

A plant whose V-rule allocation is bound by this cap is under a *guarded V-rule*. The three values are set from the statutory rules and enter the database as scalars (`taxVRule`, `taxERule`, `taxGuardRule`). The Ramses inputs have no counterpart.

Assigning a rule to each plant. A plant is assumed to choose the rule that assigns as much fuel as possible to electricity, because fuel for heat pays both the heat CO_2 tax $\tau^{BH}_{t,i}$ and the fuel tax $\tau^{DH}_{t,b}$, while fuel for electricity pays only $\tau^{CD}_{t,i}$. For each of the (at most two) modes of a plant we compute

$$\Delta^F = \min\big(F^E_{V\text{-rule}},\, E/\overline{\gamma}\big) - F^E_{E\text{-rule}}.$$

$\Delta^F > 0$ means that the V-rule assigns more fuel to electricity. The plant gets the V-rule if $\Delta^F > 0$ in both modes and the E-rule if $\Delta^F < 0$ in both. If the sign differs between the modes, it gets the rule that wins by the larger margin. If the V-rule is chosen and the cap binds in either mode, the plant gets the guarded V-rule.

The classification is done once, on the raw plant data, and stored as a mapping $\mathcal{R}(i) \in \{V\text{-rule}, E\text{-rule}, \text{guarded } V\text{-rule}\}$ (`id2TaxRule`). Plants with different rules are never aggregated (Section 2.4). The rule is therefore fixed in a database and does not respond to shocks. Making it endogenous would add a discrete choice with a jump in marginal cost.

Fuel allocation factors. Given the rule, $a^E_{t,i}$ is fuel per unit of electricity and $a^H_{t,i}$ fuel per unit of heat, for each mode. For back-pressure mode ($E = 1$, $H = 1/\kappa_{t,i}$, $F = 1/\eta_{t,i}$):

$$\text{V-rule:} \qquad a^{E,BP}_{t,i} = \frac{1}{\eta_{t,i}} - \frac{1}{\overline{\nu}\kappa_{t,i}}, \qquad a^{H,BP}_{t,i} = \frac{1}{\overline{\nu}} \tag{20}$$

$$\text{E-rule:} \qquad a^{E,BP}_{t,i} = \frac{1}{\overline{\varepsilon}}, \qquad a^{H,BP}_{t,i} = \kappa_{t,i}\left(\frac{1}{\eta_{t,i}} - \frac{1}{\overline{\varepsilon}}\right) \tag{21}$$

$$\text{guarded:} \qquad a^{E,BP}_{t,i} = \frac{1}{\overline{\gamma}}, \qquad a^{H,BP}_{t,i} = \kappa_{t,i}\left(\frac{1}{\eta_{t,i}} - \frac{1}{\overline{\gamma}}\right). \tag{22}$$

In bypass mode ($E = 0$, $H = 1/\kappa_{t,i} + 1/\xi_{t,i}$) the E-rule and the guard assign all fuel to heat, $a^{H,BB}_{t,i} = (1/\eta_{t,i})/(1/\kappa_{t,i} + 1/\xi_{t,i})$, while the V-rule gives $a^{H,BB}_{t,i} = 1/\overline{\nu}$. In extraction mode ($E = 1 + \xi_{t,i}/\kappa_{t,i}$, $H = 0$) the V-rule assigns all fuel to electricity, $a^{E,EX}_{t,i} = (1/\eta_{t,i})/(1 + \xi_{t,i}/\kappa_{t,i})$ and $a^{H,EX}_{t,i} = 0$. The E-rule and the guard assign $a^{E,EX}_{t,i} = 1/\overline{\varepsilon}$ (or $1/\overline{\gamma}$), and the residual $a^{H,EX}_{t,i} = (1/\eta_{t,i})/(1 + \xi_{t,i}/\kappa_{t,i}) - a^{E,EX}_{t,i}$ is taxed at heat rates but levied per unit of electricity, because the mode produces no heat.

Output-oriented taxes. The tax terms in the CHP marginal costs are

$$T^{E,BP}_{t,i} = a^{E,BP}_{t,i}\,\mu^{CO_2}_{t,i}\tau^{CD}_{t,i} + \tilde{T}^E_{t,i} \tag{23}$$

$$T^{DH,BP}_{t,i} = a^{H,BP}_{t,i}\left[\mu^{CO_2}_{t,i}\tau^{BH}_{t,i} + \sum_b \alpha_{f(i),b}\tau^{DH}_{t,b}\right] \tag{24}$$

$$T^{DH,BB}_{t,i} = a^{H,BB}_{t,i}\left[\mu^{CO_2}_{t,i}\tau^{BH}_{t,i} + \sum_b \alpha_{f(i),b}\tau^{DH}_{t,b}\right] \tag{25}$$

$$T^{E,EX}_{t,i} = a^{E,EX}_{t,i}\,\mu^{CO_2}_{t,i}\tau^{CD}_{t,i} + a^{H,EX}_{t,i}\left[\mu^{CO_2}_{t,i}\tau^{BH}_{t,i} + \sum_b \alpha_{f(i),b}\tau^{DH}_{t,b}\right] + \tilde{T}^E_{t,i}, \tag{26}$$

where $\tilde{T}^E_{t,i}$ collects other taxes and subsidies per MWh of electricity (in the current data, mainly the production subsidy with a negative sign). No electricity subsidy enters $T^{DH,BB}_{t,i}$, because bypass mode produces no electricity.

CO_2 is handled entirely through these terms, so the emission tax common to both modes covers only SO_2 and NO_x:

$$T^{M,CHP}_{t,i} = \frac{1}{\eta_{t,i}} \sum_{m \neq CO_2} \mu^m_{t,i}\tau^m_{t,i}. \tag{27}$$

3.9 Back-pressure plants (BP)

A back-pressure plant is a condensation plant that uses its surplus heat for district heating. The parameter $\kappa_{t,i}$ is its fixed ratio of electricity to heat.

Let $c_{t,i}$ be the marginal cost of one more unit of electricity together with $1/\kappa_{t,i}$ units of heat:

$$c_{t,i} = v_{t,i} + \frac{c^{fuel}_{t,f(i)} + c^r_{t,i}}{\eta_{t,i}} + T^{M,CHP}_{t,i} + T^{E,BP}_{t,i} + \frac{T^{DH,BP}_{t,i}}{\kappa_{t,i}}. \tag{28}$$

- $c_{t,i}$ and $v_{t,i}$ are in DKK per unit of the composite good: 1 unit of electricity and $1/\kappa_{t,i}$ units of heat.
- One unit of the composite good needs $1/\eta_{t,i}$ units of fuel, so all per-fuel terms are scaled by $1/\eta_{t,i}$, including $T^{M,CHP}_{t,i}$.
- $T^{E,BP}_{t,i}$ is per unit of electricity and $T^{DH,BP}_{t,i}$ per unit of heat, so they are weighted by 1 and $1/\kappa_{t,i}$.

Short-run optimization. The producer takes capacity and the prices $p^E_{t,h,g(i)}, p^{DH}_{t,h,g(i)}$ as given and maximizes

$$Q^E_{t,i}\Pi_{t,i} = \sum_h n_h\, Q^E_{t,h,i}\left[s^E_{t,h,i}p_{t,h,i} - F^c_{t,i}\left(s^E_{t,h,i}\right)\right] - Q^E_{t,i}\cdot FOM_{t,i},$$
$$p_{t,h,i} \equiv p^E_{t,h,g(i)} + \frac{1}{\kappa_{t,i}}p^{DH}_{t,h,g(i)}.$$

With normally distributed costs, the solution is the condensation plant's with prices and costs redefined:

$$\Delta^q_{t,h,i} \equiv p_{t,h,i} - c_{t,i} \tag{29}$$
$$s^E_{t,h,i} = \Phi\left(\frac{\Delta^q_{t,h,i}}{\sigma_{t,i}}\right) \tag{30}$$
$$\pi_{t,h,i} = s^E_{t,h,i}\Delta^q_{t,h,i} + \sigma_{t,i}\phi\left(\frac{\Delta^q_{t,h,i}}{\sigma_{t,i}}\right) \tag{31}$$
$$\Pi_{t,i} = \sum_h n_h\left(CapF_{t,i}\cdot\gamma_{h,v(i)}\cdot A_{t,h,i}\cdot\pi_{t,h,i}\right) - FOM_{t,i}. \tag{32}$$

For type-1 plants, $p_{t,h,i} = p^{DH}_{t,h,g(i)}/\kappa_{t,i}$.

Interactions with other parts of the model. Supply is $S^E_{t,h,i} = n_h\, s^E_{t,h,i}Q^E_{t,h,i}$ and $S^{DH}_{t,h,i} = S^E_{t,h,i}/\kappa_{t,i}$. Fuel use is $S^E_{t,h,i}\alpha_{f(i),b}/\eta_{t,i}$, because $\eta_{t,i}$ is the efficiency of electricity generation.

3.10 Back-pressure with bypass (BB)

A bypass plant can run in back-pressure mode or convert electricity to heat at the constant rate $\xi_{t,i} > 0$, the loss of electricity per unit of extra heat.[7] The choice between the two modes is smoothed.

Let $c^{BP}_{t,i}$ be the marginal cost in back-pressure mode, (28). In bypass mode each unit of electricity becomes $1/\xi_{t,i}$ units of heat, so the outputs are 0 electricity and $1/\xi_{t,i} + 1/\kappa_{t,i}$ heat. The cost in bypass mode is

$$c^{BB}_{t,i} = v_{t,i} + \frac{c^{fuel}_{t,f(i)} + c^r_{t,i}}{\eta_{t,i}} + T^{M,CHP}_{t,i} + \left(\frac{1}{\kappa_{t,i}} + \frac{1}{\xi_{t,i}}\right)T^{DH,BB}_{t,i}. \tag{33}$$

The difference in margin between back-pressure and bypass mode is

$$\Delta_{t,h,i} = p^E_{t,h,g(i)} - \frac{p^{DH}_{t,h,g(i)}}{\xi_{t,i}} + c^{BB}_{t,i} - c^{BP}_{t,i}.$$

It tends to be positive when electricity is expensive relative to heat, or when heat is taxed more than electricity. The share in back-pressure mode is

$$u^{BP}_{t,h,i} = \Phi\left(\frac{\Delta_{t,h,i}}{\sigma^{EH}_{t,i}}\right). \tag{34}$$

For type-1 plants, the p^E term drops out of $\Delta_{t,h,i}$.

[7] In the current database $\xi_{t,i} = 1$ for every BB plant.

Short-run optimization. Revenues and costs are a mix of the two modes:

$$\Delta^{q}_{t,h,i} = u^{BP}_{t,h,i}\left[p^{E}_{t,h,g(i)} + \frac{p^{DH}_{t,h,g(i)}}{\kappa_{t,i}} - c^{BP}_{t,i}\right] + \left(1 - u^{BP}_{t,h,i}\right)\left[\left(\frac{1}{\kappa_{t,i}} + \frac{1}{\xi_{t,i}}\right) p^{DH}_{t,h,g(i)} - c^{BB}_{t,i}\right] \tag{35}$$

$$s^{E}_{t,h,i} = \left[g^{min}_{t,i} + \left(1 - g^{min}_{t,i}\right)\Phi\left(\frac{\Delta^{q}_{t,h,i}}{\sigma_{t,i}}\right)\right] \cdot CapF_{t,i} \cdot \gamma_{h,v(i)} \cdot A_{t,h,i}. \tag{36}$$

For the CHP types, the capacity factor, the profile and the availability multiply the dispatch rate directly. The code allows a minimum generation share $g^{min}_{t,i}$. It is zero for every plant in the baseline.

Interactions with other parts of the model. Supply is

$$S^{E}_{t,h,i} = n_h\, Q^{E}_{t,i}\, s^{E}_{t,h,i}\, u^{BP}_{t,h,i} \tag{37}$$

$$S^{DH}_{t,h,i} = n_h\, Q^{E}_{t,i}\, s^{E}_{t,h,i}\left[\frac{1}{\kappa_{t,i}} + \frac{1 - u^{BP}_{t,h,i}}{\xi_{t,i}}\right]. \tag{38}$$

Fuel use is proportional to $n_h Q^{E}_{t,i} s^{E}_{t,h,i}/\eta_{t,i}$, the composite output. This is why the fuel accounting treats BB and EX plants separately from BP plants (Section 8).

3.11 Extraction plants (EX)

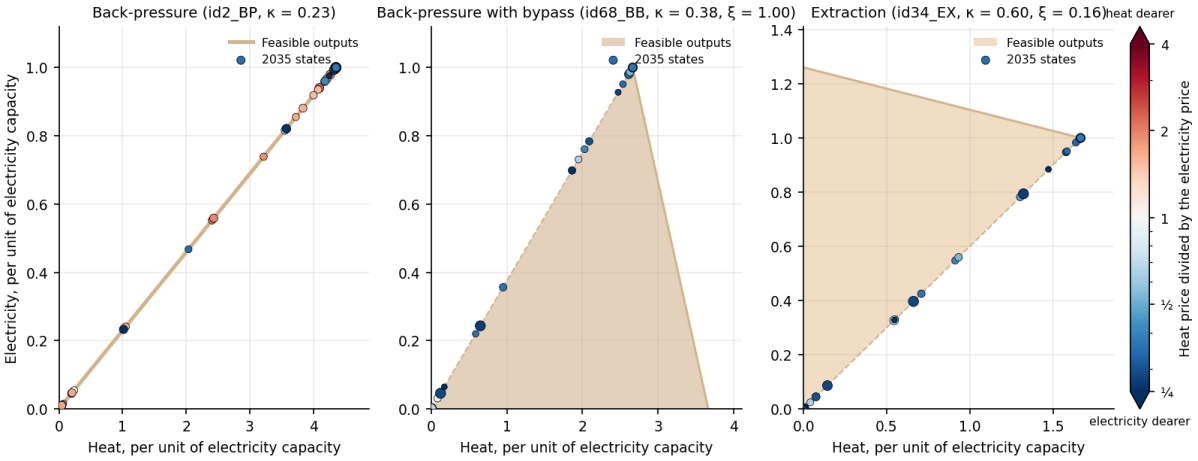


Figure 17: Feasible heat and electricity per unit of electricity capacity, for one Danish plant of each CHP type in 2035. The shaded triangles are the outputs the bypass and extraction plants can reach; the back-pressure plant moves along its line. Points are the solved 2035 states in which the plant runs, with marker area proportional to the hours in the state. Colour is the heat price divided by the electricity price: blue when electricity is the more expensive good, red when heat is.

An extraction plant can run in back-pressure mode or in extraction (condensing) mode. $\xi_{t,i}$ is again the loss of electricity per unit of extra heat. In extraction mode the outputs are $1+\xi_{t,i}/\kappa_{t,i}$ electricity and 0 heat.[8] The cost in extraction mode is

$$c^{EX}_{t,i} = v_{t,i} + \frac{c^{fuel}_{t,f(i)} + c^{r}_{t,i}}{\eta_{t,i}} + T^{M,CHP}_{t,i} + \left(1 + \frac{\xi_{t,i}}{\kappa_{t,i}}\right) T^{E,EX}_{t,i}. \tag{39}$$

[8] From $\xi_{t,i} \equiv -\Delta E/\Delta H$: setting $\Delta H = -1/\kappa_{t,i}$, the extra electricity is $\Delta E = \xi_{t,i}/\kappa_{t,i}$.

The difference in margin between back-pressure and extraction mode is

$$\Delta_{t,h,i} = \frac{p^{DH}_{t,h,g(i)}}{\kappa_{t,i}} - \frac{\xi_{t,i} p^{E}_{t,h,g(i)}}{\kappa_{t,i}} + c^{EX}_{t,i} - c^{BP}_{t,i},$$

and $u^{BP}_{t,h,i} = \Phi(\Delta_{t,h,i}/\sigma^{EH}_{t,i})$. The composite margin is

$$\Delta^{q}_{t,h,i} = u^{BP}_{t,h,i} \left[p^{E}_{t,h,g(i)} + \frac{p^{DH}_{t,h,g(i)}}{\kappa_{t,i}} - c^{BP}_{t,i} \right] + \left(1 - u^{BP}_{t,h,i}\right) \left[\left(1 + \frac{\xi_{t,i}}{\kappa_{t,i}} \right) p^{E}_{t,h,g(i)} - c^{EX}_{t,i} \right], \tag{40}$$

with dispatch as in (36) and supply

$$S^{E}_{t,h,i} = n_h \, Q^{E}_{t,i} \, s^{E}_{t,h,i} \left(1 + \left[1 - u^{BP}_{t,h,i} \right] \frac{\xi_{t,i}}{\kappa_{t,i}} \right) \tag{41}$$

$$S^{DH}_{t,h,i} = n_h \, Q^{E}_{t,i} \, s^{E}_{t,h,i} \, \frac{u^{BP}_{t,h,i}}{\kappa_{t,i}}. \tag{42}$$

Figure 17 draws the feasible sets of the three CHP types in the heat–electricity plane, for one Danish plant of each type in 2035, with the plant's solved states. Output is per unit of electricity capacity $Q^{E}_{t,i}$. The dispatch rate moves a state along a ray from the origin, and the mode share moves it across the set.

- A back-pressure plant has only the line $E = \kappa H$.
- A bypass plant has the triangle between that line and full heat: at full load it can move from $(1/\kappa, 1)$ to $(1/\kappa + 1/\xi, 0)$.
- An extraction plant has the triangle between the back-pressure line and full electricity: at full load it can move from $(1/\kappa, 1)$ to $(0, 1 + \xi/\kappa)$.

Each state is coloured by the ratio of the heat price to the electricity price, which shows which good was the more expensive. Appendix C draws the dispatch rate of the same three plants over the whole price plane.

Figure 18 shows the CHP plants of the two West Danish heat markets over the year 2035. The top panel is the electricity price and the two heat prices. The middle and bottom panels are electricity and heat output, stacked by plant type. Over the year the back-pressure plants produce 0.84 TWh of electricity and 4.22 TWh of heat, the bypass plants 0.28 and 0.88 TWh, and the extraction plants 0.03 and 0.12 TWh. The plants run mainly from November to February, when the heat prices are highest. From May to mid-August, when the heat prices fall to about 100–150 DKK/MWh, they are almost idle. In spring and autumn they run in the states with a high electricity price, so their electricity output follows the peaks of the top panel.



Figure 18: Prices (DKK/MWh) and output (GW) of the CHP plants in the two West Danish heat markets, 2035. Top: the electricity price in West Denmark and the central and decentral heat prices. Middle: electricity output. Bottom: heat output, stacked by plant type; the dotted line is the total electricity output of the same plants. States are in calendar order, each as wide as the hours it stands for.

3.12 Storage plant types

The model has five storage plant types: hydro with reservoir (HY), pumped hydro (HYS), electricity storage (ES), district-heat storage (HS) and electric vehicles with vehicle-to-grid (EV, Section 3.12.3). They share one structure and one set of macros in the code. Two features matter:

1. Every type exists in a `chronological` and a `clusterAvg` state. The first is for the 8,760 hours in order, where "the next hour" is defined. The second is for clustered hour states, where a transition matrix carries the dynamics (Section 3.12.4). This release solves the `clusterAvg` state.
2. Charging and discharging are netted, so a plant does not charge and discharge at the same time.

Figure 19 draws the solved decision of a pumped-storage plant over the year. Appendix D does the same for one plant of each other type.

3.12.1 Hydro with reservoir (HY)

Hydro plants with a reservoir get an exogenous inflow, like wind and solar get wind and sun. They can delay production by storing the energy. Marginal cost is that of wind and solar, $c_{t,i} = v_{t,i} + T^E_{t,i}$, but the decision to produce or wait is dynamic.

Let $Q^E_{t,i}$ be the generating capacity and $\zeta_{t,i}$ the duration: storage capacity divided by generating capacity, the hours the plant can produce at full output from a full reservoir. The generating capacity is constant within a year; the inflow varies. $CapF^I_{t,i}$ is the average inflow relative to capacity and $\gamma^I_{h,v(i)}$ the ratio of hourly to average inflow.[9]

Let $R_{t,h,i}$ be the stock at the end of hour h, in MWh, between zero and $\zeta_{t,i}Q^E_{t,i}$. Per unit of capacity, $r_{t,h,i} \equiv R_{t,h,i}/Q^E_{t,i}$ is measured in hours of full output and lies between zero and $\zeta_{t,i}$. The plant solves

$$\begin{aligned} \max\ \Pi_{t,i} &= \sum_h n_h \left[p^E_{t,h,g(i)} s^E_{t,h,i} - F^c_{t,h,i}\left(s^E_{t,h,i}, r_{t,h,i}\right)\right] - FOM_{t,i} \\ \text{s.t. } r_{t,h,i} &= r_{t,h-1,i} + \gamma^I_{h,v(i)} \cdot CapF^I_{t,i} - s^E_{t,h,i}. \end{aligned}$$

With convex costs F^c of a specific form [Berg and Eskildsen, 2021b], the optimal path satisfies

$$s^E_{t,h,i} = A_{t,h,i}\,\Phi\left(\frac{p^E_{t,h,g(i)} - c_{t,i} - \lambda_{t,h,i}}{\sigma_{t,i}}\right) \tag{43}$$

$$\lambda_{t,h,i} = \lambda_{t,h+1,i} + \Lambda(r_{t,h,i}) \tag{44}$$

$$r_{t,h,i} = r_{t,h-1,i} + \gamma^I_{h,v(i)} \cdot CapF^I_{t,i} - s^E_{t,h,i}, \tag{45}$$

where $A_{t,h,i}$ is the availability (3) and the marginal storage cost is

$$\Lambda(r) \equiv x^{out}_{t,i}\left(\frac{\zeta_{t,i}}{2} - r\right) + \left(\frac{x^{out}_{t,i}}{2} - \frac{x^{in}_{t,i}}{\zeta_{t,i}}\right)\left(\sqrt{r^2 + \left(x^{\Delta}_{t,i}\right)^2} - \sqrt{\left(r - \zeta_{t,i}\right)^2 + \left(x^{\Delta}_{t,i}\right)^2}\right). \tag{46}$$

The first condition says that the plant produces if the price exceeds marginal cost plus the continuation value $\lambda_{t,h,i}$ of keeping the energy. The second says that the continuation value is next hour's value plus a storage cost that depends on how full the reservoir is. Λ is a smooth version of a kinked linear cost with two regimes: a high marginal cost outside $(0, \zeta_{t,i})$ and a low one inside. The parameters are $x^{out}_{t,i}$ (cost outside the bounds), $x^{in}_{t,i}$ (cost inside) and $x^{\Delta}_{t,i}$ (smoothing between the two).[10] The code allows the bounds 0 and $\zeta_{t,i}$ to be replaced by a narrower state-of-charge window. Only the vehicle-to-grid plants use one (Section 3.12.3). The KF26 inputs also give regional limits on hydro generation and reservoir levels. The database carries them, and they are switched off in the baseline.

Profits per unit of capacity are[11]

$$\Pi_{t,i} = \sum_h n_h \left(s^E_{t,h,i}\left(p^E_{t,h,g(i)} - c_{t,i}\right) + A_{t,h,i}\,\sigma_{t,i}\phi\left(\frac{p^E_{t,h,g(i)} - c_{t,i} - \lambda_{t,h,i}}{\sigma_{t,i}}\right)\right) - FOM_{t,i}. \tag{47}$$

[9] $CapF^I_{t,i} \equiv I_{t,i}/(8760 \cdot Q^E_{t,i})$, where $I_{t,i}$ is the yearly inflow. The inflow rule of Section 2.5.2 sets $I_{t,i}$ where the inputs give an inflow adjustment.

[10] In the baseline $x^{in}_{t,i} = 0.1$ and $x^{\Delta}_{t,i} = 10^{-3}$ for all plants, and $x^{out}_{t,i} = \max(100, 3000/\zeta_{t,i})$; Section 3.12.4 explains the scaling.

[11] Approximately: the nonlinear costs of moving $r_{t,h,i}$ are left out. At the baseline parameters they are very close to zero.

3.12.2 Pumped hydro (HYS), electricity storage (ES) and district-heat storage (HS)

Pumped hydro differs from HY in that it can also fill the reservoir by pumping, using electricity. $\eta_{t,i} \in (0,1)$ is the round-trip efficiency, and the charging speed $\chi_{t,i}$ is charging capacity relative to discharging capacity.[12] Electricity storage (ES) is the same without inflow. District-heat storage (HS) is ES in the heat market, with $c_{t,i} = v_{t,i}$.

The plant forms a discharge intent $s^E_{t,h,i}$ and a charge intent $d^E_{t,h,c(i)}$:

$$s^E_{t,h,i} = A_{t,h,i}\,\Phi\left(\frac{p^E_{t,h,g(i)} - c_{t,i} - \lambda_{t,h,i}}{\sigma_{t,i}}\right) \tag{48}$$

$$d^E_{t,h,c(i)} = A_{t,h,i}\,\Phi\left(\frac{\lambda_{t,h,i}\eta_{t,i} - p^E_{t,h,g(i)} - c_{t,c(i)}}{\sigma_{t,i}}\right), \tag{49}$$

where $c_{t,c(i)}$ is the marginal cost of charging on top of the price: the variable cost of charging plus the hourly grid tariff (Section 4.5). Heat storage has no outage rate, so $A_{t,h,i} = 1$ for HS.

Netting of charge and discharge. A plant close to indifferent between charging and discharging would, with smooth rules, do both at once. That would create false round-trip losses and false volumes in the clearing conditions. The two intents are therefore netted:

$$\widetilde{s}_{t,h,i} \equiv \max\left(s^E_{t,h,i} - \chi_{t,i}d^E_{t,h,c(i)},\,0\right) = \tfrac{1}{2}\left(\left|s^E_{t,h,i} - \chi_{t,i}d^E_{t,h,c(i)}\right| + s^E_{t,h,i} - \chi_{t,i}d^E_{t,h,c(i)}\right) \tag{50}$$

$$\widetilde{d}_{t,h,i} \equiv \max\left(\chi_{t,i}d^E_{t,h,c(i)} - s^E_{t,h,i},\,0\right). \tag{51}$$

The absolute value is smoothed in the code, $|x| \approx \sqrt{x^2 + 10^{-8}}$. Only the net position affects the stock, the market and profits:

$$r_{t,h,i} = r_{t,h-1,i} + \gamma^I_{h,v(i)}CapF^I_{t,i} - \widetilde{s}_{t,h,i} + \eta_{t,i}\widetilde{d}_{t,h,i} \tag{52}$$

$$S^E_{t,h,i} = n_h\,Q^E_{t,i}\,\widetilde{s}_{t,h,i}, \qquad D^E_{t,h,c(i)} = n_h\,Q^E_{t,i}\,\widetilde{d}_{t,h,i}. \tag{53}$$

Profits per unit of capacity are

$$\begin{aligned}\Pi_{t,i} = &\sum_h n_h\left[\widetilde{s}_{t,h,i}\left(p^E_{t,h,g(i)} - c_{t,i}\right) + A_{t,h,i}\sigma_{t,i}\phi\left(\frac{p^E_{t,h,g(i)} - c_{t,i} - \lambda_{t,h,i}}{\sigma_{t,i}}\right)\right]\\ &- \sum_h n_h\left[\widetilde{d}_{t,h,i}\left(p^E_{t,h,g(i)} + c_{t,c(i)}\right) - A_{t,h,i}\sigma_{t,i}\phi\left(\frac{\eta_{t,i}\lambda_{t,h,i} - p^E_{t,h,g(i)} - c_{t,c(i)}}{\sigma_{t,i}}\right)\right] - FOM_{t,i}.\end{aligned} \tag{54}$$

ES and HS have no inflow term. For HS, electricity prices and quantities are replaced by their heat counterparts.

Figure 19 draws the solved decision of one pumped-storage plant, `id664_HYS` in Austria, in 2035. States are in calendar order, each as wide as the hours it stands for.

- The top panel is the area price against the two thresholds. The plant discharges when the price is above $\lambda + c$ plus the injection tariff, and charges when it is below $\eta\lambda - c_{c(i)}$, where $c_{c(i)}$ includes the charging tariff. The band between them is about 475 DKK/MWh wide: the round-trip loss plus the two marginal costs.
- The middle panel is net discharge (up) and net charge (down) as shares of capacity, with inflow. The netting (50) keeps the two from appearing in the same state.

[12] A plant that can use twice as much electricity per hour as it can generate has $\chi_{t,i} = 2$.

- The bottom panel is the stock in hours of full output, against the storage window of 287 hours. The stock goes from empty to full, a swing of 287 hours, between winter and late summer, so the plant arbitrages both within the month and across seasons.

Appendix D draws the same panels for electricity storage in each Danish area, heat storage in central West Denmark, and the Norwegian reservoir.

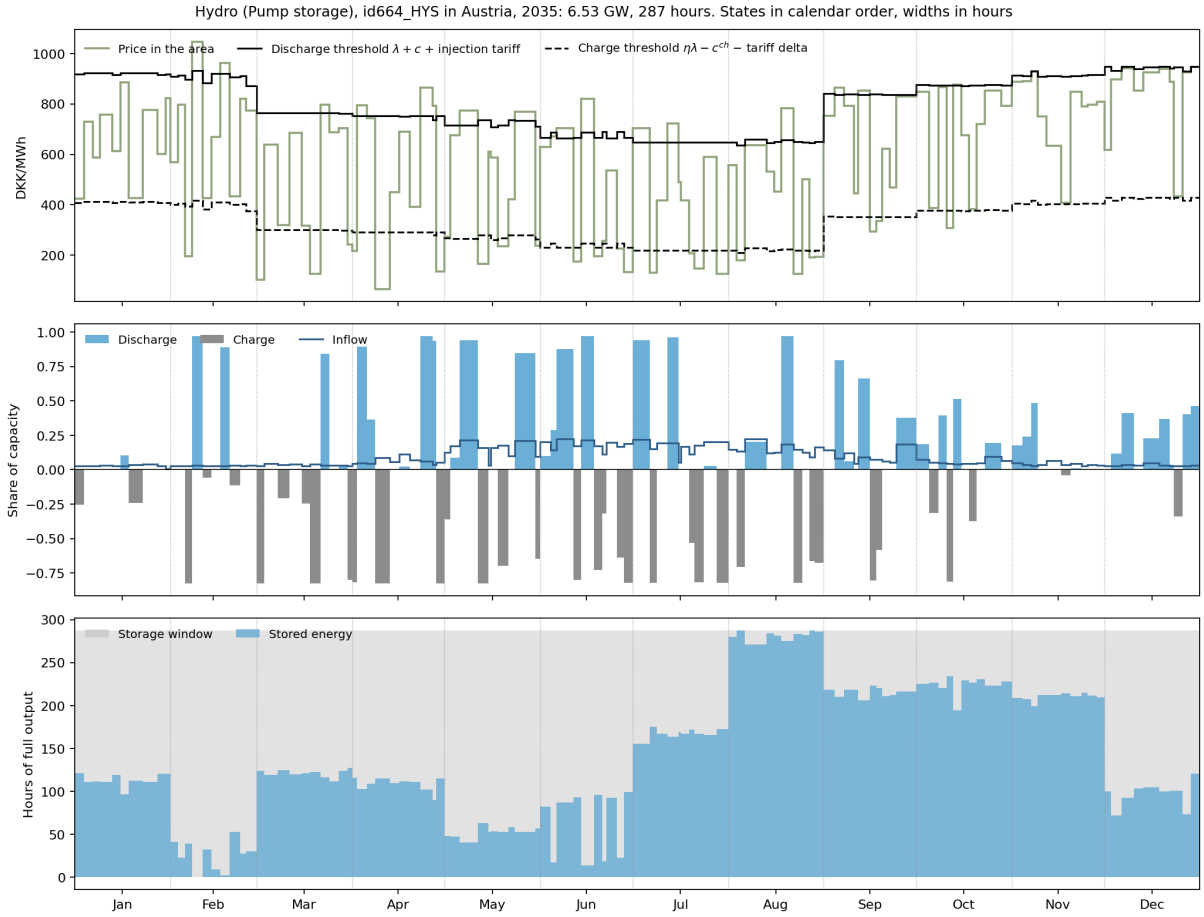


Figure 19: Pumped storage in Austria, 2035: `id664_HYS`, 6.5 GW, about 290 hours of storage, round-trip efficiency 0.70. Top: the area price, the discharge threshold $\lambda + c$ plus the injection tariff, and the charge threshold $\eta\lambda - c_{c(i)}$, where $c_{c(i)}$ includes the charging tariff, DKK/MWh. Middle: net discharge (up) and net charge (down), share of capacity, with inflow. Bottom: the stock in hours of full output against the storage window.

3.12.3 Vehicle-to-grid (EV)

From 2037, the Danish Energy Agency's inputs include the electric-vehicle fleets of the TYNDP 2024 in seventeen foreign areas, which the model represents as vehicle-to-grid plants. The discharge capacity grows by about 51 GW a year and reaches about 715 GW in 2050. No Danish vehicles have the option in the inputs. Danish charging is demand of the transport segment (Section 4.4).

An EV plant is a battery of the ES type, with three differences:

- **Availability.** Only parked and connected vehicles can trade. An hourly availability $\alpha^{av}_{h,v(i)} \in [0,1]$ multiplies both intents: $s^{E}_{t,h,i} = \alpha^{av}_{h,v(i)}\Phi(\cdot)$ and $d^{E}_{t,h,c(i)} = \alpha^{av}_{h,v(i)}\Phi(\cdot)$. EV plants have no outage rate.
- **Driving.** Driving draws on the battery whatever the price. The stock equation has an extra outflow $\delta^{drv}_{t,h,i}$: annual driving consumption spread over the states by a driving profile,

per unit of discharge capacity.

- **Losses on the way out.** Discharge to the grid has its own efficiency η^{dis}, read from the input file. The battery gives up $1/\eta^{dis}$ units per unit delivered, and the discharge intent compares the price with $\lambda_{t,h,i}/\eta^{dis}$.

In the clustered representation the stock equation is

$$r_{t,h,i} = \sum_{h'} \mathrm{Pr}^{-}(h' \to h)\, r_{t,h',i} - \frac{\widetilde{s}_{t,h,i}}{\eta^{dis}} - \delta^{drv}_{t,h,i} + \eta_{t,i}\widetilde{d}_{t,h,i}, \tag{55}$$

with the stock held between a minimum and a maximum state of charge (0.4 and 0.6 of the battery). Charging enters the clearing as demand of the consumer type `EVStorage`, and discharge as supply.

An assumption under review. The representation is simple. Each area's fleet is one battery. The availability profile is flat ("always plugged in"), the driving profile is flat, and the battery and charger sizes per vehicle are placeholders. With about 715 GW of discharge capacity abroad in 2050, this makes the foreign fleets a very large and very flexible store. It smooths foreign prices, and the effect reaches Denmark through trade. We state it as an assumption under review. An improved representation, with hourly driving and availability patterns and TYNDP battery and charger sizes, is being prepared (Section 15).

Figure 20 shows the solved fleet in 2050, summed over the foreign areas with the option.

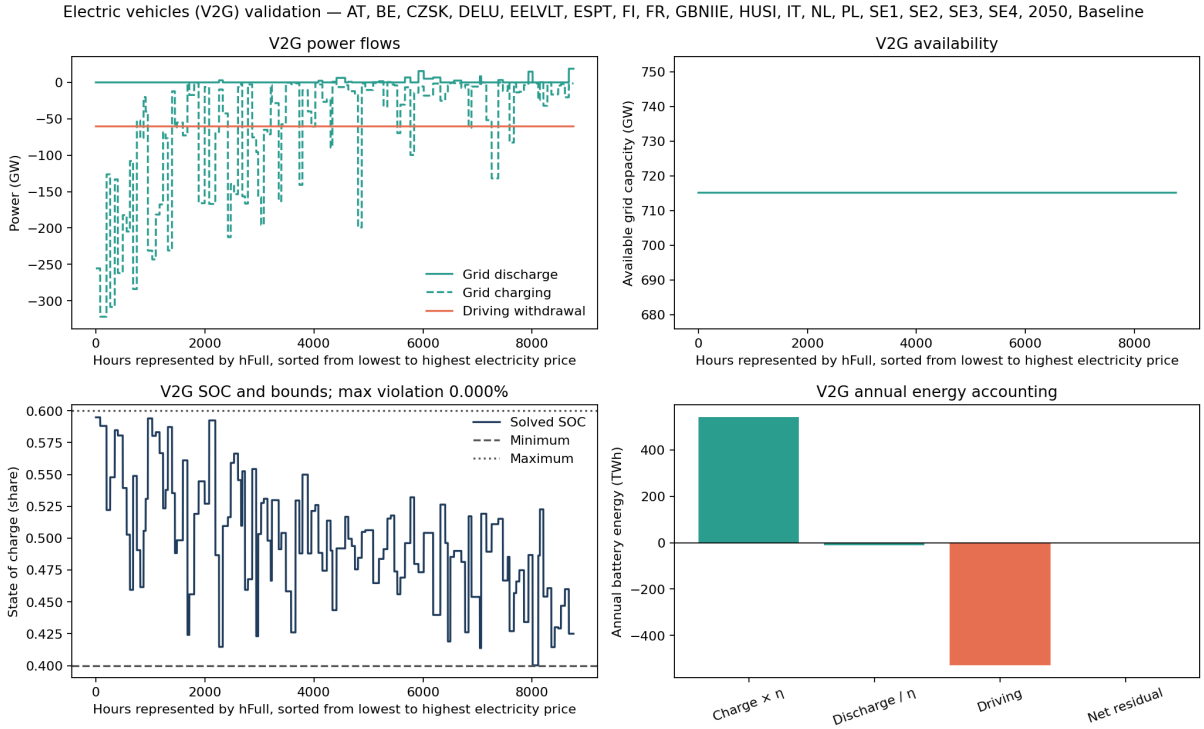


Figure 20: Vehicle-to-grid in 2050, all areas with the option: charging, discharge to the grid and driving (GW), and the stock (GWh), by state in calendar order. Availability is flat.

3.12.4 Non-chronological representation

When hours are clustered, "$h+1$" and "$h-1$" are not defined. They are replaced by expectations under the transition matrices of Section 2.6. $\Pr^+(h \to h')$ is the probability that state h is followed by h', and $\Pr^-(h' \to h)$ the probability that state h was preceded by h'. The continuation value and the stock equation become

$$\lambda_{t,h,i} = \sum_{h'} \Pr^+(h \to h')\, \lambda_{t,h',i} + \Lambda(r_{t,h,i}) \tag{56}$$

$$r_{t,h,i} = \sum_{h'} \Pr^-(h' \to h)\, r_{t,h',i} + \gamma^I_{h,v(i)} CapF^I_{t,i} - \widetilde{s}_{t,h,i} + \eta_{t,i}\widetilde{d}_{t,h,i}, \tag{57}$$

with the other equations unchanged.

No hour weight in the stock equation. The flow terms in (57) carry no hour weight n_h. The transition probabilities are estimated from consecutive hours, so one step from h' to h is one physical hour, and the stock changes by one hour of net flow. The hour weight counts how often a state occurs in the year. It enters annual production, consumption and profits, where each state counts n_h times. The same holds for every storage type: electricity and heat storage, hydro reservoirs, pumped storage and vehicle-to-grid.

The representation tracks the *state average* of the stock, not its full distribution. A dynamic program over the joint distribution of state variables is not tractable at the scale of the model.

Keeping the stock inside its bounds. In the chronological model the stock equation is a chain, and $r_{t,h,i}$ is pinned down hour by hour. With an expectation in place of $h-1$, the stock is determined only up to its level: adding a constant to $r_{t,h,i}$ in every state satisfies the same equations. What ties the level down is the penalty $x^{out}_{t,i}$ outside $(0, \zeta_{t,i})$ in (46). If the penalty is weak relative to the price differences the plant arbitrages, the stock can drift outside its physical range in a solution the solver accepts.

This is why $x^{out}_{t,i} = \max(100,\, 3000/\zeta_{t,i})$. The stock is in hours of full output, so a given drift is a much larger share of a three-hour battery than of a reservoir with 600 hours. Scaling by $1/\zeta_{t,i}$ makes the cost of a given *fractional* drift roughly equal across plants. The floor keeps a meaningful penalty on long reservoirs.

The penalty limits the drift; it does not remove it. A battery with a few hours of storage cycles within the day, and the state average of its stock is what the clustered representation captures least well. Results that depend on short-duration storage should be read with this in mind (Section 15.9).

What the plant knows. The problem is deterministic. Prices, inflows and the transition matrix are known when the plant chooses its path, so no operator is surprised, and energy is never left in a reservoir because a scarce week was not foreseen. On its own, this makes storage in the model better informed than in reality.

The clustered representation removes part of that foresight. A chronological model with perfect foresight knows which week is dry and which fortnight is still. This model knows only the distribution of states and the probabilities of moving between them, and (46) prices the stock against that distribution. This is close to the information a hydro operator uses: water values from a stochastic dynamic program are the standard tool in the Nordic system. The model lies between perfect foresight and no foresight.

3.13 Electric heaters (EH)

Electric boilers and heat pumps share one formulation; their parameters and taxes differ. They use electricity to produce district heat with a time-varying coefficient of performance (COP).[13] The hourly COP is $\eta_{t,h,i} \equiv \eta_{t,i} \cdot CapF_{t,i} \cdot \gamma_{h,v(i)}$.

Marginal cost per unit of electricity is

$$c_{t,h,i} = v_{t,i} + p^{E}_{t,h,g(i)} + T^{E,EH}_{t,i}, \tag{58}$$

where $v_{t,i}$ is the cost of heat production per unit of electricity and $T^{E,EH}_{t,i}$ the taxes and tariffs per unit of electricity. The producer takes its electricity capacity $Q^{E}_{t,c(i)}$ and prices as given. With normally distributed costs:

$$\Delta_{t,h,i} \equiv \eta_{t,h,i} \cdot p^{DH}_{t,h,g(i)} - c_{t,h,i} \tag{59}$$

$$d^{E}_{t,h,c(i)} = A_{t,h,i}\left[d^{min}_{t,i} + \left(1 - d^{min}_{t,i}\right)\Phi\left(\frac{\Delta_{t,h,i}}{\sigma_{t,i}}\right)\right] \tag{60}$$

$$\pi_{t,h,i} = A_{t,h,i}\left[d^{min}_{t,i}\Delta_{t,h,i} + \left(1 - d^{min}_{t,i}\right)\left(\Phi\left(\frac{\Delta_{t,h,i}}{\sigma_{t,i}}\right)\Delta_{t,h,i} + \sigma_{t,i}\phi\left(\frac{\Delta_{t,h,i}}{\sigma_{t,i}}\right)\right)\right] \tag{61}$$

$$\Pi_{t,i} = \sum_{h} n_h\, \pi_{t,h,i} - FOM_{t,i}. \tag{62}$$

Minimum load. The share $d^{min}_{t,i}$ is a must-run share of capacity: the plant uses at least this share whatever the prices, and the rest is dispatched on the margin. The same formulation applies to electrolysers (Sections 3.14–3.15). In the baseline, only electrolysers have a positive minimum load, from the Ramses minimum-load factors (Section 2.8). Electric heaters have $d^{min}_{t,i} = 0$.

The capacity factor and the profile enter through the COP, not through the capacity. The availability $A_{t,h,i}$ scales the whole rule.

Interactions with other parts of the model. Electricity use is $D^{E}_{t,h,c(i)} = n_h\, d^{E}_{t,h,c(i)} Q^{E}_{t,c(i)}$ and heat production $S^{DH}_{t,h,i} = \eta_{t,h,i} \cdot D^{E}_{t,h,c(i)}$.

Figure 21 shows the rule in West Denmark in 2035. A heat pump gets several units of heat per unit of electricity, so it runs whenever the COP times the heat price covers the electricity price plus costs. An electric boiler has a COP of one, so it needs electricity below the heat price. In 2035 heat pumps produce 12.5 TWh of heat, the large geothermal heat pump 0.90 TWh, and electric boilers 1.8 TWh.

3.14 Electrolysers (EF)

Each electrolyser belongs to one of two hydrogen markets, $a(i) \in \{\texttt{DK_H2}, \texttt{EU_H2}\}$: Danish electrolysers to the first and foreign ones to the second. The hydrogen price $p^{H}_{t,a}$ is the same in every hour of a year. It clears an annual hydrogen balance (Section 7.3). Above its minimum load, the electrolyser produces in the hours in which electricity is cheap relative to $p^{H}_{t,a(i)}$. If hydrogen demand is high, the price rises until the electrolysers run enough hours to meet it.

The formulation is that of an electric heater whose output is priced at the hydrogen price. Cost per unit of electricity is $c_{t,h,i} = v_{t,i} + p^{E}_{t,h,g(i)} + T^{E,EF}_{t,h,i}$, where the last term is the grid tariff (Section 4.5). Dispatch follows (60) with

$$\Delta_{t,h,i} \equiv \eta_{t,h,i} \cdot p^{H}_{t,a(i)} - c_{t,h,i}, \tag{63}$$

[13] The COP of a heat pump falls with the "lift", the temperature difference between the heat sink and the source, so it varies over the year.



Figure 21: Electric heaters in West Denmark, 2035. Top: the electricity price and the two district-heat prices, DKK/MWh. Bottom: heat output from electric heaters by technology, GW, summed over the central and decentral markets. States are in calendar order, each as wide as the hours it stands for.

and $A_{t,h,i} = 1$, because electrolysers have no outage rate. The minimum load $d^{min}_{t,i}$ makes the electrolyser use at least that share of capacity in every state. Electricity use is $D^E_{t,h,c(i)} = n_h\, d^E_{t,h,c(i)} Q^E_{t,c(i)}$ and hydrogen production $S^H_{t,h,i} = \eta_{t,h,i} D^E_{t,h,c(i)}$.

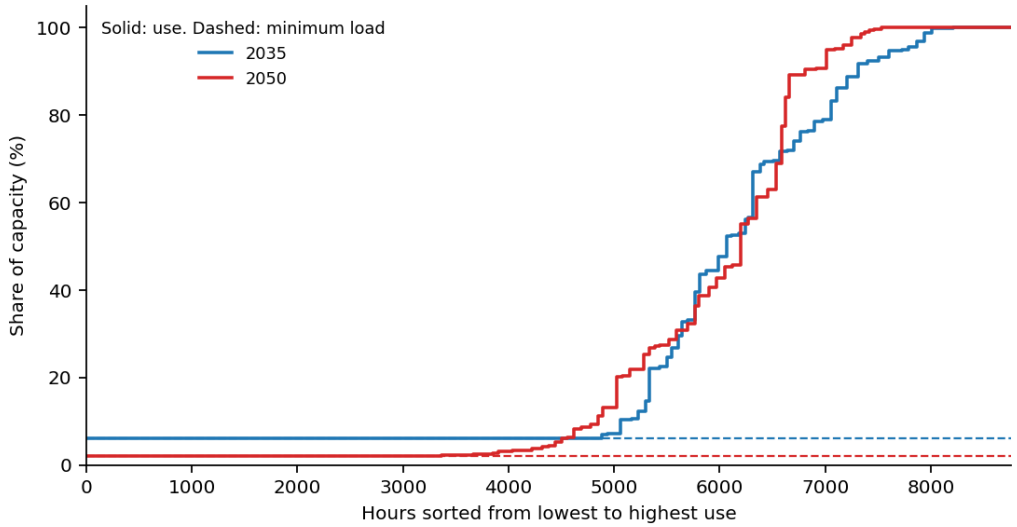


Figure 22: Utilization of Danish electrolysers in 2035 and 2050, states sorted from lowest to highest use, share of capacity, with the minimum load as a dashed line.

3.15 Electrolysers with heat (PX)

PX plants are EF plants that also produce $1/\kappa_{t,i}$ units of district heat per unit of hydrogen.[14] The margin per unit of electricity is

$$\Delta_{t,h,i} \equiv \eta_{t,h,i} \left(p^{H}_{t,a(i)} + \frac{p^{DH}_{t,h,g(i)}}{\kappa_{t,i}} \right) - c_{t,h,i}, \tag{64}$$

with the other conditions, including the minimum load, as for EF. Hydrogen production is $S^{H}_{t,h,i} = \eta_{t,h,i} D^{E}_{t,h,c(i)}$ and heat production $S^{DH}_{t,h,i} = S^{H}_{t,h,i}/\kappa_{t,i}$.

3.16 Other plant types

- The KF26 plant list has no hydrogen producer other than the electrolysers `EF` and `PX`. From 2038, when European hydrogen demand has to be met, electrolysis is the only supply in the inputs (Section 7.3).
- Condensing plants that burn hydrogen buy it at the price of their hydrogen market. Their use is a demand item in the hydrogen balance.
- Flexible demand (FD) is blocks of interruptible consumption. Ramses represents them as plants producing "negawatts": a block is shed when the price rises above its marginal cost, and the load is not taken up later. The model keeps them so, each with a capacity and a marginal cost. Blocks with a marginal cost of 100,000 DKK/MWh or more are dropped. The database has 82 blocks, 75 of them active in 2035 and 44 in 2050, all abroad. Their marginal costs in 2035 run from under 100 to about 31,000 DKK/MWh, with a median of about 3,000. In the baseline the blocks shed 9 TWh in 2035 and 156 TWh in 2050. Danish demand responds through the demand system of Section 4, which moves consumption within the month instead of shedding it.
- Carbon capture in the inputs is attached to two Danish CHP units. It is part of those plants (Section 3.17).

3.17 Carbon capture on CHP plants

Two biomass bypass plants in central East Denmark, `id37_BB` and `id71_BB`, carry carbon capture in the KF26 inputs from 2026 to 2045. Capture is part of the plant and has no dispatch decision of its own: when the plant burns fuel, a fixed share $\rho_{t,i}$ of the CO_2 in the fuel is captured. In the baseline $\rho_{t,i} = 0.9$.

Let $e^{f}_{f(i)}$ be the fossil and $e^{b}_{f(i)}$ the biogenic CO_2 content of the fuel, in tonnes per MWh of fuel. Captured CO_2 per MWh of fuel, and the taxed and net emissions, are

$$k_{t,i} = \rho_{t,i} \left(e^{f}_{f(i)} + e^{b}_{f(i)} \right), \tag{65}$$

$$e^{tax}_{t,i} = (1 - \rho_{t,i})\, e^{f}_{f(i)}, \qquad e^{net}_{t,i} = (1 - \rho_{t,i})\, e^{f}_{f(i)} - \rho_{t,i}\, e^{b}_{f(i)}. \tag{66}$$

CO_2 taxes and allowances apply to e^{tax} only. Net emissions are negative for a plant on biomass.

Each tonne captured uses $\epsilon^{E}_{t,i} = 0.229$ MWh of electricity and $\epsilon^{DH}_{t,i} = 0.254$ MWh of heat, bought in the plant's own markets, plus a variable cost $v^{CCS}_{t,i}$. Each tonne earns the price $p^{CCS}_{t,z}$ of the capture zone z (Section 7.2). Per MWh of output, the plant's margin falls by

$$c^{CCS}_{t,h,i} = v^{CCS}_{t,i} + \frac{k_{t,i}}{\eta_{t,i}} \left(\epsilon^{E}_{t,i}\, p^{E}_{t,h,g(i)} + \epsilon^{DH}_{t,i}\, p^{DH}_{t,h,g(i)} - p^{CCS}_{t,z(i)} \right). \tag{67}$$

[14] Unlike for CHP plants, $\kappa_{t,i}$ here is hydrogen per unit of heat.

This is subtracted from the composite margin $\Delta^q_{t,h,i}$ of the bypass plant. It changes the dispatch rate and leaves the choice between back-pressure and bypass unchanged. A high price on captured CO_2 makes the plant run more.

3.18 PV-battery clusters

The KF26 inputs contain solar parks that share a grid connection with a battery. The connection is smaller than the solar and battery capacity behind it, so the park cannot always export what it produces. The model has four such clusters: fixed and tracking solar, each in West and East Denmark. Each has one solar plant and one battery. The connections total 0.02 GW in 2025, 4.6 GW in 2035 and 9.8 GW in 2050.

Behind the connection there is a cluster price $p^{cl}_{t,h,j}$. The solar plant sells at it, and the battery charges and discharges at it (Section 3.12). The connection is a short line with an export and an import capacity, $\overline{X}^{cl}_{t,j}$ and $\overline{M}^{cl}_{t,j}$. Net export to the area is

$$X^{cl}_{t,h,j} = n_h \left[\overline{X}^{cl}_{t,j} \, \Phi\left(\frac{p^{E}_{t,h,g(j)} - T^{inj}_{t,h,j} - p^{cl}_{t,h,j}}{\sigma^{cl}} \right) - \overline{M}^{cl}_{t,j} \, \Phi\left(\frac{p^{cl}_{t,h,j} - p^{E}_{t,h,g(j)} - T^{cons}_{t,h,j}}{\sigma^{cl}} \right) \right], \tag{68}$$

with σ^{cl} equal to the smoothing of the cluster's solar plant. T^{inj} is the injection tariff (zero in the baseline) and T^{cons} the consumption tariff (Section 4.5). The cluster price clears the balance behind the connection:

$$S^{PV}_{t,h,j} + S^{ES}_{t,h,j} = D^{ES}_{t,h,j} + X^{cl}_{t,h,j} - J^{cl}_{t,h,j}, \tag{69}$$

where S^{PV} and S^{ES} are the park's and the battery's supply, D^{ES} the battery's charging, and $J^{cl}_{t,h,j}$ a residual that is zero in a cleared solution (Section 6). $X^{cl}_{t,h,j}$ enters the clearing of the area as supply. When the sun is strong and the connection is full, p^{cl} falls below the area price and the battery charges from the park. This is why the cluster is modelled: part of the battery's value comes from the connection limit.

Figure 23 shows the fixed-tilt cluster in West Denmark in 2035. In the baseline, export stays below 1.6 GW of the 2.19 GW connection, and the cluster price is 4–92 DKK/MWh above the area price in most states. With a smoothed connection, export below half the capacity requires a cluster price above the area price.

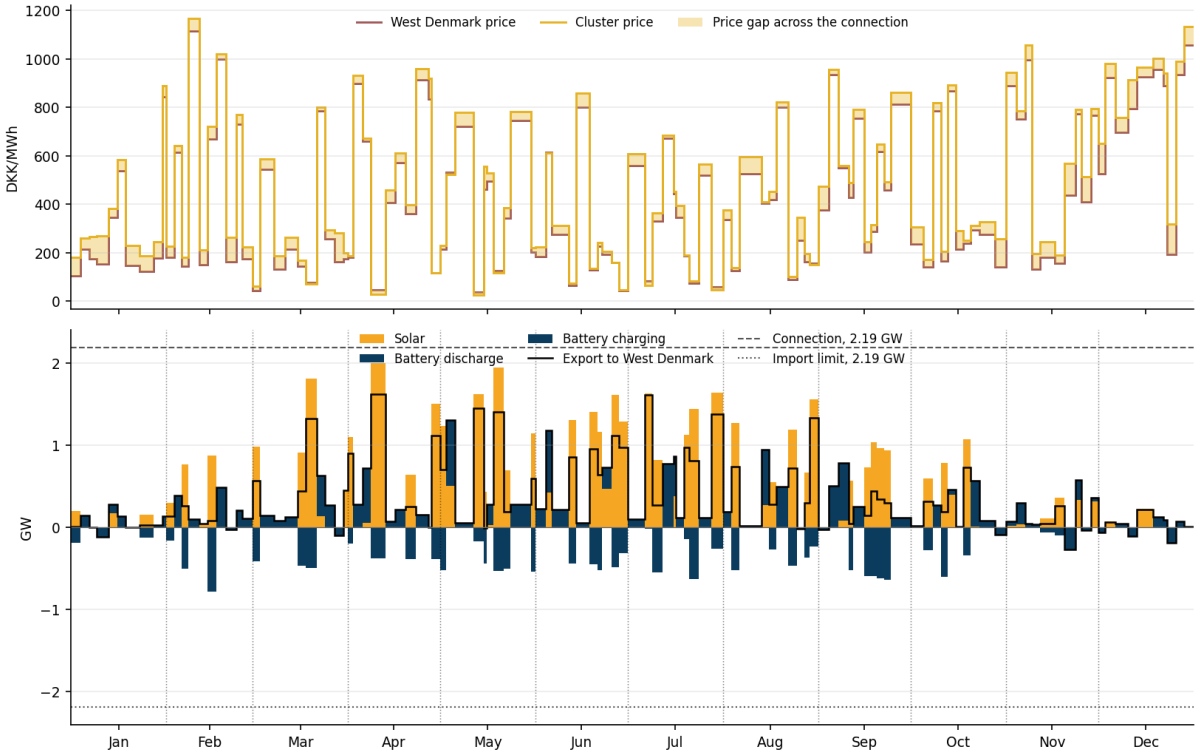


Figure 23: The fixed solar park and its battery in West Denmark, 2035. Top: the area price, the cluster price and the gap, DKK/MWh. Bottom: solar output and battery discharge (up), battery charging (down) and net export through the connection (black line), GW. States are in calendar order, each as wide as the hours it stands for.

4 Demand for electricity and district heat

Many plants also consume electricity or heat: storage charging, electric heaters and heat pumps, electrolysers. Their hourly demand comes from the plant problems of Section 3 and enters the clearing conditions as "plant demand".

This section describes the other consumers, in aggregate. In the integrated model, the CGE model sets the yearly level of electricity and heat demand from yearly average prices. Demand flexibility in this model should therefore mainly move demand between hours, not change its yearly level. The model separates two margins:

- an *hourly allocation* of a given yearly level (Section 4.1);
- an *endogenous yearly level* that responds to the consumer price index (Section 4.2).

The hourly allocation is split once more. Consumers can move consumption between hours of the same month much more easily than between summer and winter. The model therefore has one elasticity for moving demand within a month and one for moving it between months. In the baseline the first is 0.1 and the second is zero, so load moves inside a month and monthly totals follow the habits in the data.

4.1 A discrete-choice-like demand system

Let $D^E_{t,c}$ be yearly consumption and $\mu_{h,c}$ exogenous habits, normalized so that $\sum_h n_h \mu_{h,c} = 8760$. Let $\underline{p}^E < 0$ be a global price floor. The hourly share of demand is

$$\frac{D^E_{t,h,c}}{D^E_{t,c}} = \frac{n_h \mu_{h,c} \left(\dfrac{p^{E,del}_{t,h,c} - \underline{p}^E}{\overline{p}^E_{t,c} - \underline{p}^E} \right)^{-\sigma_{t,c}}}{\sum_{h'} n_{h'} \mu_{h',c} \left(\dfrac{p^{E,del}_{t,h',c} - \underline{p}^E}{\overline{p}^E_{t,c} - \underline{p}^E} \right)^{-\sigma_{t,c}}}, \tag{70}$$

where $p^{E,del}_{t,h,c}$ is the delivered price, the area price plus the consumer's hourly grid tariff (Section 4.5), and $\overline{p}^E_{t,c}$ is a normalizing price index. Three remarks:

- With constant prices, the shares equal the habit shares $n_h \mu_{h,c}/8760$.
- If a single state is small relative to the year, $\sigma_{t,c}$ is approximately the elasticity of substitution between hours.
- Prices may be negative but never below the floor. The floor is a lower bound on the price variables, $p^E_{t,h,g} \geq \underline{p}^E + 10^{-4}$, so the expression is always defined.

Within and between months. Equation (70) has one elasticity for the whole year. The model nests it. Let $s(h)$ be the calendar month of state h and write $x_{t,h,c} = (\overline{p}^E_{t,c} - \underline{p}^E)/(p^{E,del}_{t,h,c} - \underline{p}^E)$. With $M_{s,c} = \sum_{h \in s} n_h \mu_{h,c}$ the habit weight of month s,

$$\frac{D^E_{t,h,c}}{D^E_{t,c}} = \frac{n_h \mu_{h,c}\, x^{\sigma^W_{t,c}}_{t,h,c}}{W_{t,s(h),c}} \cdot \frac{M_{s(h),c} \left(W_{t,s(h),c}/M_{s(h),c} \right)^{\sigma^B_{t,c}/\sigma^W_{t,c}}}{\sum_{s'} M_{s',c} \left(W_{t,s',c}/M_{s',c} \right)^{\sigma^B_{t,c}/\sigma^W_{t,c}}}, \qquad W_{t,s,c} = \sum_{h \in s} n_h \mu_{h,c}\, x^{\sigma^W_{t,c}}_{t,h,c}. \tag{71}$$

The first factor shares the month's demand across its hours with elasticity $\sigma^W_{t,c}$. The second shares the year across months with elasticity $\sigma^B_{t,c}$, against a price index for each month, $P_{t,s,c} = (\overline{p}^E_{t,c} - \underline{p}^E)(M_{s,c}/W_{t,s,c})^{1/\sigma^W_{t,c}}$. With $\sigma^B_{t,c} = \sigma^W_{t,c}$ it collapses to (70). With $\sigma^B_{t,c} = 0$, the baseline value, monthly totals are fixed at their habit shares. District heat has the same nesting and the same baseline values.

$\overline{p}^E_{t,c}$ is fixed within a solve (`pEt_C_cIdx_exo`). It appears in numerator and denominator, so it cancels from the shares and serves only as a numerical normalization. The district-heat expressions replace E by DH and $\underline{p}^E$ by $\underline{p}^{DH}$.

Parameters. The baseline sets the within-month elasticity to 0.1 and the between-month elasticity to zero for every consumer segment, in electricity and district heat, and both price floors to -500 DKK/MWh. $\sigma^W_{t,c}$ is indexed by consumer, so each segment can have its own value.

Recent evidence on Danish household demand could sharpen these values. Andersen and Dietrich [2026] estimate hourly price responses from Danish smart-meter data, using wind production as an instrument for the price. Most households do not respond at all; roughly a third respond substantially. Their estimates are semi-elasticities (per cent per krone), not elasticities of substitution, and they come from largely within-day price variation. They therefore speak to the within-month elasticity σ^W.

The parameters should be revisited when new flexible consumers are added, for example smart charging of electric vehicles. The independence of irrelevant alternatives assumed here is a simplification, and the model has no cost of moving demand.

4.2 Endogenous yearly demand

The yearly demand level responds to the consumer's delivered price index, so the model has a demand response at the yearly margin when it runs on its own:

$$D^{E}_{t,c} = u^{E}_{t,c} \left(\frac{\overline{p}^{E,del}_{t,c}}{p^{E,C,del}_{t,c}} \right)^{\sigma^{E,t}_{t,c}} \tag{72}$$

$$D^{DH}_{t,c} = u^{DH}_{t,c} \left(\frac{\overline{p}^{DH}_{t,c}}{p^{DH,C}_{t,c}} \right)^{\sigma^{DH,t}_{t,c}} . \tag{73}$$

Here $p^{E,C,del}_{t,c}$ is the segment's delivered price index: its consumption-weighted wholesale price plus its annual grid tariff (Section 4.6). $\overline{p}^{E,del}_{t,c}$ is the same index fixed at its baseline value (`pEt_C_cIdx_deliv_exo`), $\sigma^{E,t}_{t,c}$ is the elasticity of yearly demand and $u^{E}_{t,c}$ a level parameter. A rise in the delivered index above the reference reduces yearly demand.

The level parameters $u^{E}_{t,c}$ and $u^{DH}_{t,c}$ are the yearly demand levels of the inputs. The reference index equals the delivered index in the baseline, so yearly demand in the baseline is the projected path. In a shock, yearly demand moves away from it as far as the delivered index moves. In the baseline, the yearly elasticities are 0.1 for the consumer segments with an hourly profile.

4.3 Distribution losses

Consumer demand is measured where it is consumed; the market clears at the level of the electricity area. The difference is distribution losses. Let $\delta_{t,g} \in (0, 1]$ be the distribution efficiency (one minus the loss rate). Demand enters the clearing condition as $D^{E}_{t,h,g}/\delta_{t,g}$, and the loss volume

$$L^{E}_{t} = \sum_{g \in DK} \left(\frac{1}{\delta_{t,g}} - 1 \right) D^{E}_{t,g} \tag{74}$$

is a separate item in the energy balance. Losses apply to the consumer segments only; plants are connected at transmission level. In the baseline $\delta_{t,g}$ is about 0.88–0.90 in West Denmark and 0.93–1.00 in East Denmark.

4.4 Consumer types

Every consumer index c has a type. The types that follow the demand system above are:

- **classic**: households, services and industry, one segment per area. Individual heat pumps in Danish buildings are part of it; the foreign demand input has a separate heat-pump class;
- **hsdc**: large data centres, in West and East Denmark;
- **transport**: charging of road vehicles, in West and East Denmark;
- **district_heat**: heat demand, one segment per heat market.

Each type has its own annual level, hourly habit profile and grid tariff. Table 3 gives the Danish electricity levels in the inputs. Data centres and transport grow from a little more than a tenth of classic demand in 2025 to about two thirds of it in 2050.

The other consumer types are plants: storage charging (`ES`, `HYS`, `HS`), electric heaters (`EH`), electrolysers (`EF`, `PX`) and vehicle-to-grid charging abroad (`EVStorage`). Figure 24 stacks the solved Danish demand.

Table 3: Annual Danish electricity demand by consumer type in the inputs, West and East Denmark together, before distribution losses.

TWh	2025	2035	2050
classic	31.7	34.9	41.2
hsdc (data centres)	1.4	8.2	13.2
transport	2.6	11.0	14.8

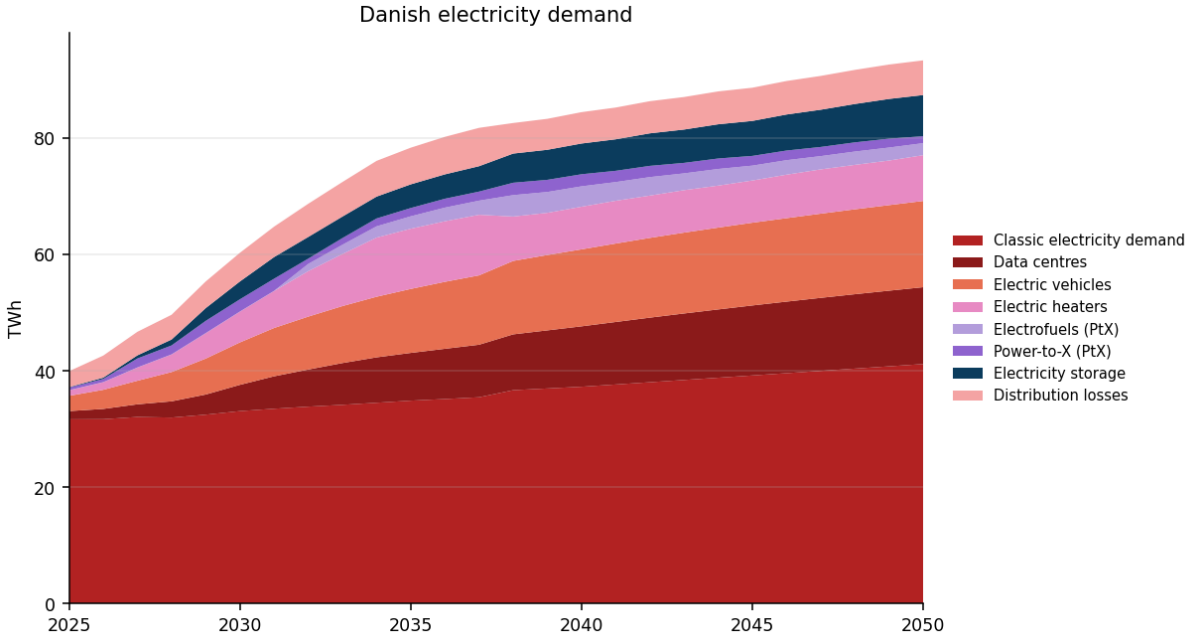


Figure 24: Solved electricity demand in West and East Denmark, TWh. Classic demand, data centres and transport are the rows of Table 3. Electric heaters, electrolysers and storage charging are plant demand. The top band is distribution losses.

4.5 Grid tariffs

Consumers and electricity-using plants pay a grid tariff on top of the area price. The annual level is the Ramses transport cost. It differs between large consumers and households, and the Danish Energy Agency applies the Danish level in every area. The model multiplies the annual level by an hourly shape with mean one:

$$T^{E}_{t,h,c} = \overline{T}_{t,c}\, \omega_{h,\theta(c),w(c)}, \tag{75}$$

where $\overline{T}_{t,c}$ is the annual level, $\theta(c)$ the tariff area (West Denmark, East Denmark, abroad) and $w(c)$ the voltage class. The hourly shapes are ours. They are computed from the tariffs the Danish grid companies publish on Energi Data Service, fixed at their 2026 form, on one calendar for all climate years. There are two classes:

- class **C** (low voltage) for classic demand and transport. Over the 8,760 hours the factor runs from about 0.56 to 2.68; on the 120 states, from about 0.66 to 1.87;
- class **A_Høj** (high voltage) for data centres, storage charging, electric heat, electrolysers and all other plants. The factor stays between about 0.92 and 1.12.

Figure 25 shows the 2035 pattern. Low voltage has a morning step and a high evening block, and loses its sharpest peaks in the clustering. High voltage moves by a few per cent.

Foreign areas have a flat shape. The tariff enters every hourly decision that buys from the grid: the delivered price in (71), the charging cost of storage, and the cost of electric heat

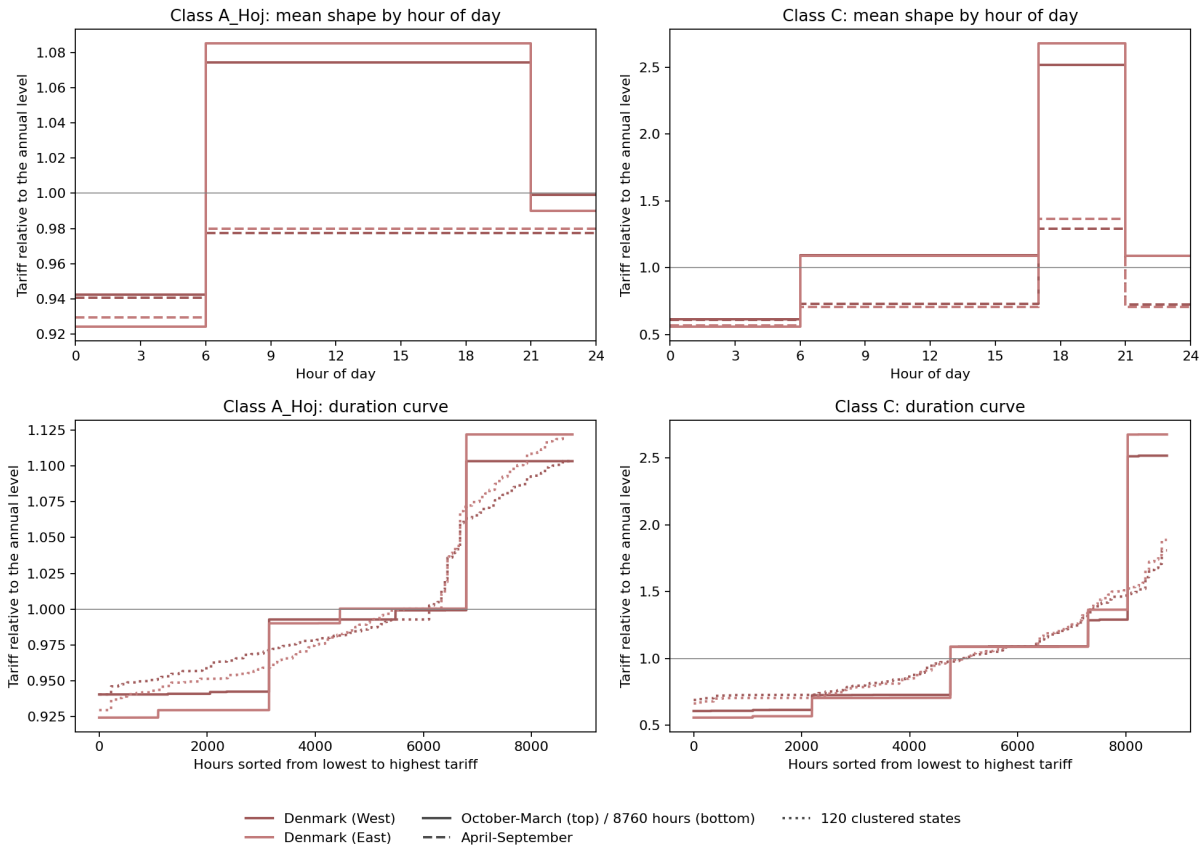


Figure 25: Grid-tariff shapes in 2035, relative to the annual level. Top: mean by hour of day, October to March (solid) and April to September (dashed). Bottom: hours sorted from the lowest tariff to the highest, the 8,760-hour pattern against the 120 clustered states of the 2008 database.

and electrolysis. The code has an injection tariff by tariff area; it is zero in the baseline. The database also carries the electricity tax on electric heat, entered as a negative subsidy on the subsidy types `ElPatronD` and `ElHeatD`, of about 8 and 4 DKK/MWh. With the high-voltage tariff level of about 170 to 200 DKK/MWh, electric heat pays about 175 to 210 DKK/MWh on top of the area price.

4.6 Price indices

The model computes quantity-weighted price indices. They enter yearly demand (72), they are what would be passed to the CGE model, and they are the main reporting variables. All are in DKK/MWh. Table 4 lists them.

The consumer index of segment c is defined by

$$p^{E,C}_{t,c} \sum_{h} D^{E}_{t,h,c} = \sum_{h} p^{E}_{t,h,g(c)} D^{E}_{t,h,c}, \tag{76}$$

and the delivered index adds the annual tariff, $p^{E,C,del}_{t,c} = p^{E,C}_{t,c} + \overline{T}_{t,c}$. The export and import prices are

$$p^{E,X}_{t,DK} X^{E}_{t,DK} = \sum_{h,l,g \in DK, g' \notin DK} p^{E}_{t,h,g} X_{t,h,l,g \to g'} \tag{77}$$

$$p^{E,M}_{t,DK} M^{E}_{t,DK} = \sum_{h,l,g \in DK, g' \notin DK} p^{E}_{t,h,g'} M_{t,h,l,g' \to g}, \tag{78}$$

Table 4: Electricity and heat price indices (DKK/MWh). "Consumer" weights are the hourly demand of the consumer segments of this section; "plant" demand is storage charging, electric heat, electrolysers and vehicle-to-grid charging. The Danish aggregates cover `DK1` and `DK2`, and `DK3` where noted.

GAMS name	Definition
`pEt_C_cIdx`[t,c]	segment c: wholesale price weighted by the segment's hourly demand
`pEt_C_cIdx_deliv`[t,c]	segment c: `pEt_C_cIdx` plus the segment's annual grid tariff; enters (72)
`pEt_C`[t,g]	area g: wholesale price weighted by consumer demand
`pEt_C_deliv`[t,g]	area g: consumer-weighted delivered price (wholesale plus tariff)
`pEt_C_all`[t,g]	area g: wholesale price weighted by consumer and plant demand
`pEt_S`[t,g]	area g: wholesale price weighted by production
`pEt_hWeight`[t,g]	area g: time-weighted average price, $\sum_h n_h p^E_{t,h,g}/8760$
`pEt_hWeight_deliv`[t,g]	area g: `pEt_hWeight` plus the consumer-weighted annual tariff
`pEt_C_DK`, `pEt_C_DK_deliv`, `pEt_C_all_DK`, `pEt_S_DK`	the Danish aggregates of the area indices above
`pEt_hWeight_DK`, `pEt_hWeight_deliv_DK`	Danish time-weighted average over all Danish areas, including `DK3`; with tariff
`pEt_S_DK_prod_sector`[t,s]	Danish production-weighted price by sector, $s \in$ {Waste, NonWaste}; waste is the incineration plants
`pEt_Export_DK`, `pEt_Import_DK`	Danish average export and import prices
`pHt_C_cIdx`, `pHt_C`, `pHt_S`, `pHt_C_DK`, `pHt_S_DK`, `pHt_S_DK_prod_sector`	the district-heat counterparts

with the import price at the price of the *sending* area. The difference between them is the congestion rent plus transmission losses.

The time-weighted average `pEt_hWeight` is the index that is comparable with published annual prices, which are simple averages over the hours of the year. It is the index used for the comparison with KF26 in Section 11.4. The Danish time-weighted index `pEt_hWeight_DK` includes `DK3`, which has no consumers, so the comparison uses the mean of `DK1` and `DK2` instead.

The segment indices feed back into demand, so they are always endogenous. The others are reporting variables, endogenous in the `priceIndex_regional` state, which the baseline uses.

5 Trade in electricity

Electricity areas are connected by transmission lines l. A line has an efficiency $\eta_{t,l} \in (0,1)$, 0.95 on every line in the database, and a capacity in each direction. The model stores a directed capacity $Q_{t,l,g\to g'}$ for each ordered pair of areas a line connects, so asymmetric lines are handled in the data.

Available capacity. The capacity available in state h is the nameplate capacity times the line's availability $A^X_{t,h,l}$ (Section 2.5.3). The code also allows an annual capacity factor $CapF^X_{t,l}$ and an hourly profile $\gamma^X_{h,v(l)}$; both are one in the baseline. The derating of five Danish interconnectors in the KF26 inputs is carried by $A^X_{t,h,l}$ (Section 2.5.3).

Short-run optimization. Within a year, a system operator uses line l to earn arbitrage income given prices and capacity. With normally distributed short-run costs, the signal to use

the line in each direction is

$$x_{t,h,l,g\to g'} = \Phi\left(\frac{\eta_{t,l}p^E_{t,h,g'} - p^E_{t,h,g}}{\sigma_{t,l}}\right). \tag{79}$$

The line carries power in one direction at a time, so the two signals are combined into a signed utilization,

$$s_{t,h,l,g\to g'} = x_{t,h,l,g\to g'} - x_{t,h,l,g'\to g} \in (-1, 1). \tag{80}$$

It is zero when the two prices are equal and positive exactly when $p^E_{t,h,g'} > p^E_{t,h,g}$. The directed capacities turn it into a signed flow. With capacity in both directions,

$$F_{t,h,l,g\to g'} = \frac{2\,Q_{g\to g'}Q_{g'\to g}\,s}{Q_{g\to g'} + Q_{g'\to g} + \left(Q_{g'\to g} - Q_{g\to g'}\right)s}, \tag{81}$$

with t, h, l dropped on the right. F is zero at $s = 0$, tends to $Q_{g\to g'}$ as $s \to 1$ and to $-Q_{g'\to g}$ as $s \to -1$. The slope at $s = 0$ is the harmonic mean of the two capacities, so the flow is smooth through zero. With equal capacities, $F = Q\,s$. On a line with capacity in one direction only (five cables from the North Sea node from 2038), the open direction carries $F = Q_{g\to g'}\max(s, 0)$. The gross flow is the positive part of the signed flow, scaled by availability:

$$X_{t,h,l,g\to g'} = \max\left(F_{t,h,l,g\to g'}, 0\right) \cdot CapF^X_{t,l} \cdot \gamma^X_{h,v(l)} \cdot A^X_{t,h,l} \cdot n_h. \tag{82}$$

Both $\max(\cdot, 0)$ are replaced in the code by $\frac{1}{2}\left(\sqrt{z^2 + \epsilon^2} + z\right)$, with $\epsilon = 10^{-6}$ in (82) and $\epsilon = 0.05$ on the one-way lines. The wider smoothing is for the North Sea node, whose only connections are such cables. Without it, in a state where the cables are closed, the node's electrolysers are at full load and it still has wind to place, its clearing condition is flat in its own price and the square system has no pivot. The cost is a flow of 2.5 per cent of the open capacity at equal prices, falling below half a per cent once $s < -0.2$.

At equal prices, a two-way line carries no net flow, whatever the two capacities. The alternative of applying each signal to its own capacity, $X_{g\to g'} \propto x_{g\to g'}Q_{g\to g'}$, lacks this property: at equal prices it moves $x\left(Q_{g\to g'} - \eta Q_{g'\to g}\right)$ toward the area with the smaller return capacity. On the line from middle-south to southern Sweden, 6.2 GW one way and 2.8 GW the other in 2035, that is close to 0.9 GW with no price difference. Figure 26 draws (81) for that line and a one-way North Sea cable.

The gross flows are netted line by line, which also does the loss accounting:

$$NX_{t,h,l,g\to g'} = X_{t,h,l,g\to g'} - \eta_{t,l}X_{t,h,l,g'\to g} \tag{83}$$

$$X^{net}_{t,h,l,g\to g'} = \max\left(NX_{t,h,l,g\to g'}, 0\right), \qquad M^{net}_{t,h,l,g\to g'} = \max\left(-NX_{t,h,l,g\to g'}, 0\right). \tag{84}$$

Exports and imports of an area are the sums over lines and partner areas,

$$X^E_{t,h,g} = \sum_{l,g'} X^{net}_{t,h,l,g\to g'}, \qquad M^E_{t,h,g} = \sum_{l,g'} M^{net}_{t,h,l,g'\to g}, \tag{85}$$

and enter the clearing condition (Section 6). Netting is done before summing, so an area with several lines, like Denmark, can export and import in the same state.

The profit of the line operator, $\Pi_{t,l}$, is the congestion rent: in each state, the price at the receiving end minus the price at the sending end, times the net flow. The flow runs from the cheap area to the expensive one, so the rent is non-negative. It is largest when the line is at its limit and the prices are far apart. The model keeps one rent per line and direction and does not split it between the owners. Section 11.8 draws the rent on the Danish lines in 2035.

Figure 27 draws the solved net flow on the five derated Danish lines in 2035 against the available capacity in each direction, $A^X_{t,h,l}Q_{t,l}$. In 2035, West Denmark exports 12.8 TWh to Germany and imports 0.7 TWh, imports 8.7 TWh from Norway and 3.3 TWh from Sweden, and East Denmark imports 6.0 TWh from Sweden.

Lines between two areas that are aggregated into one are removed (Section 2.3).

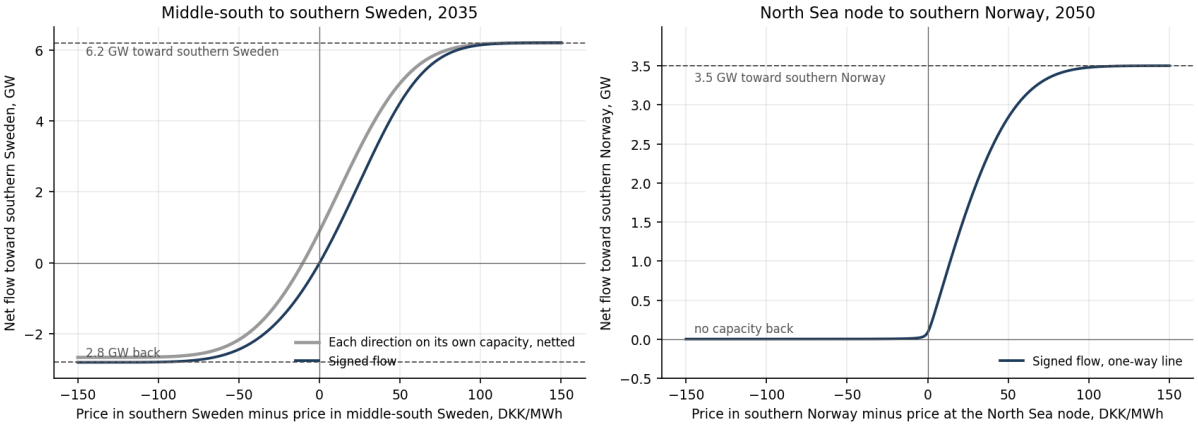


Figure 26: Net flow on a line (GW) against the price difference (DKK/MWh), at a price of 400 DKK/MWh in the exporting area. Left: middle-south to southern Sweden, 2035, 6.2 GW toward southern Sweden and 2.8 GW back. Right: a one-way cable from the North Sea node, 2050, 3.5 GW. Dashed lines are the directed capacities. The grey line applies each direction's signal to its own capacity and nets the two; it shows a flow at equal prices. Availability is not applied.

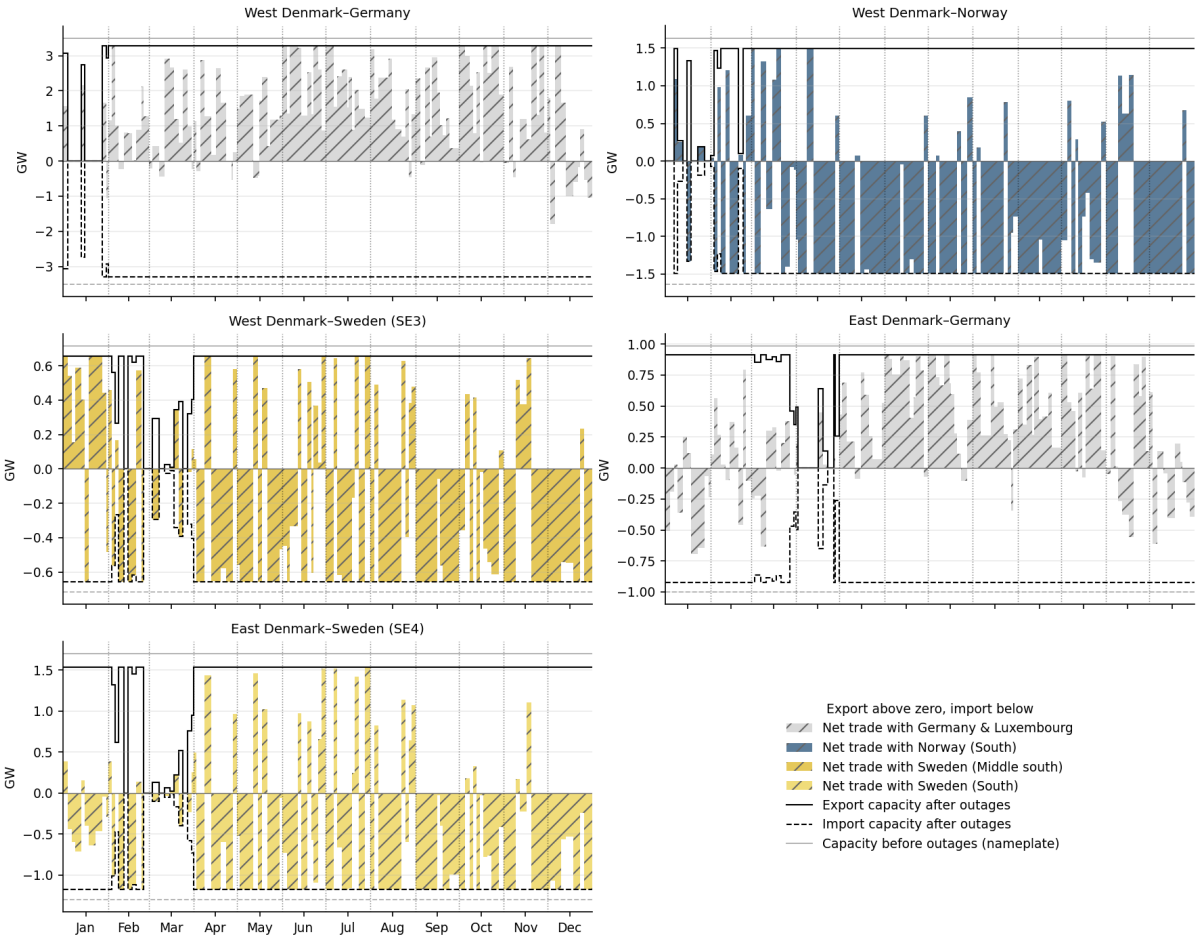


Figure 27: Net flow on the five derated Danish lines, 2035, GW. Export from Denmark is positive. The black lines are the capacity the model allows in each direction after outages (nameplate times one minus the outage share, which combines the placed planned outage and the flat unplanned rate), solid for export and dashed for import. The grey lines are the nameplate capacity before outages. States are in calendar order, each as wide as the hours it stands for.

A possible extension: losses that depend on the flow. The efficiency $\eta_{t,l}$ is constant, so a line loses the same share at a tenth of capacity as at the limit. Physically, resistive losses rise with the square of the current. Making η fall with utilization would put a cost on the last MWh across a congested line, in the scarce hours where it matters most. It is not implemented.

6 Market clearing

The clearing conditions for electricity and district heat are

$$D^{E,\text{plants}}_{t,h,g} + D^{E,\text{CCS}}_{t,h,g} + \frac{D^{E,\text{cons}}_{t,h,g}}{\delta_{t,g}} + X^{E}_{t,h,g} = S^{E}_{t,h,g} + M^{E}_{t,h,g} + \sum_{j \in g} X^{cl}_{t,h,j} + J^{E}_{t,h,g} \tag{86}$$

$$D^{DH,\text{plants}}_{t,h,g} + D^{DH,\text{CCS}}_{t,h,g} + D^{DH,\text{cons}}_{t,h,g} = S^{DH}_{t,h,g} + J^{DH}_{t,h,g}, \tag{87}$$

where $D^{\cdot,\text{plants}}$ is plant demand (storage charging, electric heaters, electrolysers, vehicle charging abroad), $D^{\cdot,\text{CCS}}$ the electricity and heat used for carbon capture (Section 3.17), and $D^{\cdot,\text{cons}}$ the demand of the consumer segments (Section 4). $X^{cl}_{t,h,j}$ is the net export of a PV-battery cluster (Section 3.18); the plants inside a cluster are counted there and not in $S^{E}_{t,h,g}$. The distribution efficiency $\delta_{t,g}$ applies only to consumer demand.

$J^{E}_{t,h,g}$ and $J^{DH}_{t,h,g}$ are residuals. A solution is accepted only if every residual is at most 10^{-6} in absolute value (Section 9). In an accepted solution, (86)–(87) are ordinary clearing conditions. The annual markets of Section 7 have residuals of their own, with the same rule.

Clearing conditions are imposed only for *active* areas, the pairs (t, g) with at least one plant.

One product, and one node per area. Two simplifications are easy to miss. First, energy is the only product. There is no market for reserves, balancing or other ancillary services, so no plant holds capacity back to be called. A resource whose value lies in changing output quickly earns nothing for it here (see also Section 15.10). Second, each price area is a single node. Within an area, transmission is free, so a plant in northern and one in southern Jutland are perfect substitutes. Real congestion inside a zone is resolved by redispatch at a cost, which is a reason for system operators to withhold border capacity. Both simplifications are shared with Ramses.

6.1 What clearing looks like

Figures 28 and 29 draw the same state of the solved baseline twice: a June state in West Denmark in 2035 (hAgg3_S6), with a solved price of 275 DKK/MWh. Each figure has three panels on that price axis:

- left: domestic demand, stacked by type, with demand present at every price on the inside;
- middle: domestic supply and the clearing;
- right: net exports by partner, positive for export, with the sum as a black line.

In Figure 28 the middle panel is the merit order: each plant is a block at the price where it runs at half of its available capacity, ordered from cheap to expensive. The black curve is the smoothed supply the market clears against, $\sum_i Q^{E}_{t,i} s^{E}_{t,h,i}(p)$; the gap between staircase and curve is the dispatch smoothing. The dashed red curve is domestic demand, and the solid red curve adds net exports. They cross at the solved outcome. Figure 29 stacks each technology's smoothed supply instead.

Reading the blocks. Wind and solar blocks sit at their marginal cost, close to zero. A storage block sits at $\lambda + c$: the plant bids the value of keeping the energy for a later state, so the price in one state also reflects the prices of the states that follow it. A CHP block sits at its electricity cost net of the value of the heat it produces at the same time. When domestic supply is short,

the price is set by the net-export curve, that is, by the neighbouring areas. Appendix E draws the most expensive and the cheapest state of 2035 and 2050, and Germany in the year before and after European hydrogen demand begins.

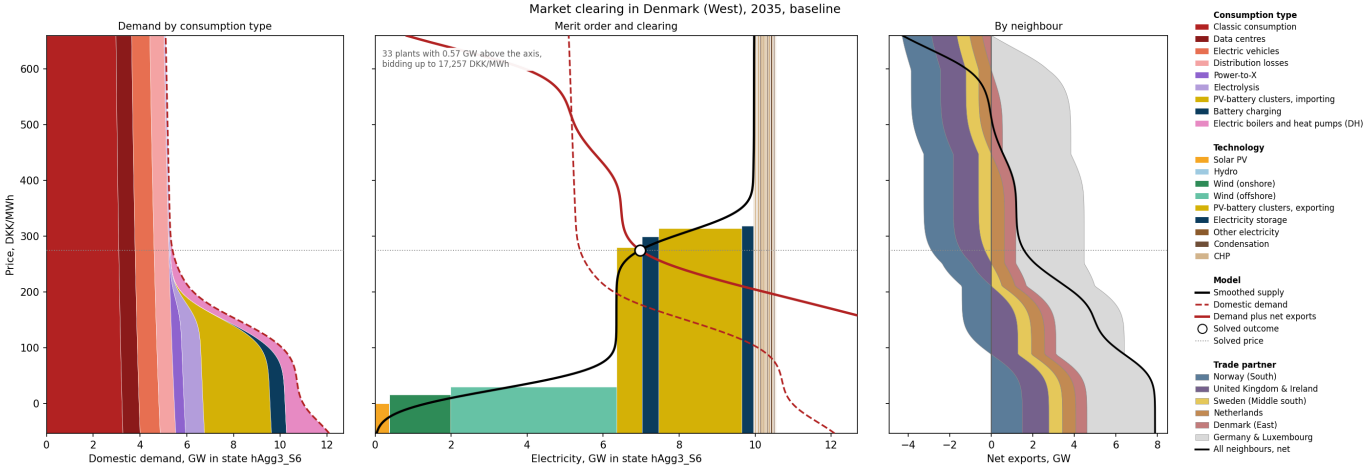


Figure 28: Market clearing in a June state in West Denmark, 2035. Discrete merit order, with the smoothed supply drawn over it. Prices in DKK/MWh, quantities in GW.

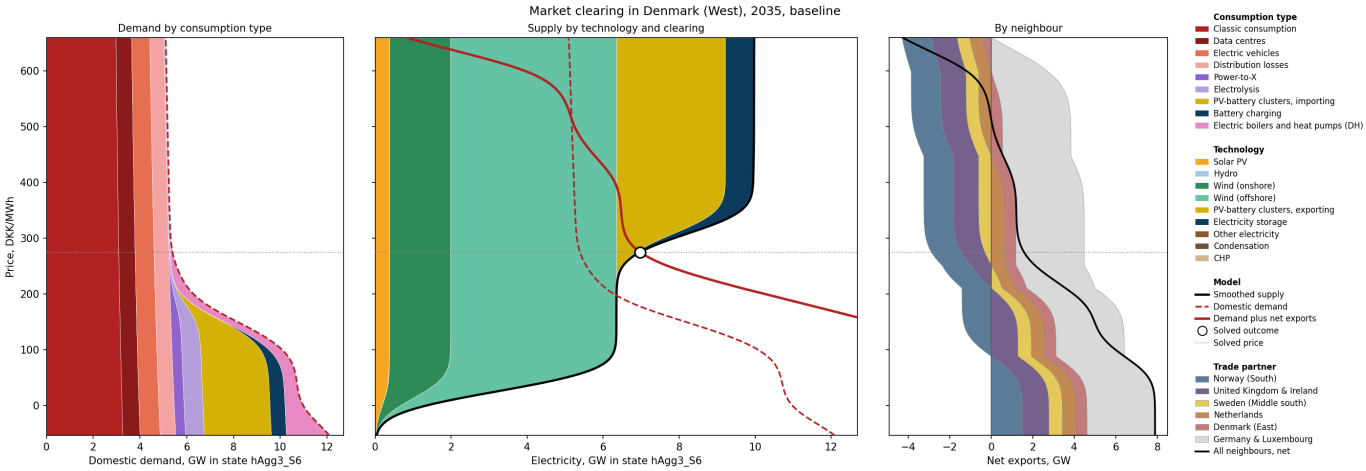


Figure 29: The same state, with supply stacked by technology along the smoothed dispatch.

7 Annual markets

Besides the hourly markets, three kinds of market clear once a year, each with one price per year and a residual of its own: the constrained domestic fuels, the carbon-capture target, and the two hydrogen markets. The plants decide hour by hour (Section 3). The annual market sums their decisions over the year and sets the price at which the annual balance holds.

7.1 Constrained domestic resources

Waste, hazardous waste and biogas are not available at an exogenous world price. Their quantities are largely set outside the energy system, by waste generation and by agriculture. Treating them as available in any quantity at a fixed price would let any policy that raises their value expand their use without limit.

The model therefore has a market for each resource. Let r index resource zones, $r \in \{\texttt{DK_Affald}, \texttt{DK_Farligt_Affald}, \texttt{DK_Biogas}\}$, and $b(r)$ the base fuel of the zone (waste for the first two, biogas for the third). Each plant belongs to at most one zone. $\overline{R}_{t,r}$ is the available quantity from the Ramses resource-zone data, and $F_{t,r,b}$ the fuel use of plants in zone r. The clearing condition is

$$F_{t,r,b(r)} = \overline{R}_{t,r} - J^r_{t,r,b(r)}, \tag{88}$$

with residual J^r. The shadow price $p^r_{t,r,b}$ is added to the fuel cost of every plant in the zone,

$$c^r_{t,i} = \sum_b \alpha_{f(i),b}\, p^r_{t,r(i),b}, \tag{89}$$

cf. (7). A plant that burns the resource only in part pays the shadow price only on that part.

$p^r_{t,r,b}$ is the scarcity rent on the resource. In the baseline it is the price at which the model uses exactly the available quantity. Plants in different zones are never aggregated (Section 2.4). All three markets clear in every year, 2050 included. The code handles any number of zones and resources.

Figure 30 draws the three markets. Biogas availability falls from 1.3 TWh in 2025 to about 0.24 TWh. In the baseline the shadow price on waste is 86 DKK/MWh in 2025, −35 in 2035 and −35 in 2050. A negative price means that the available waste must be burned and the plants are paid to take it. The shadow price on biogas is 213–398 DKK/MWh. Hazardous waste is fully used at a negative shadow price, −161 DKK/MWh in 2025 and −298 in 2050.

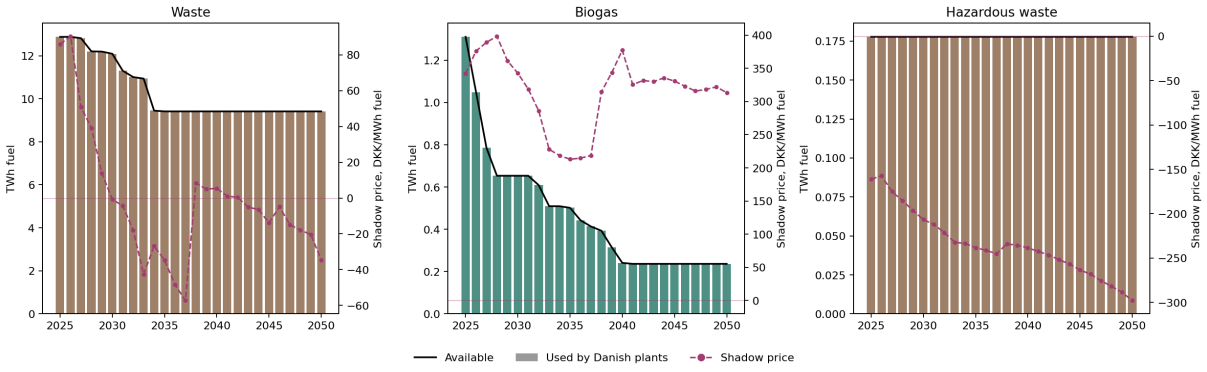


Figure 30: Resource zones. Bars are fuel used by Danish plants (TWh), the black line is availability (TWh), and the dashed line is the shadow price (DKK/MWh).

7.2 The carbon-capture target

The two capture plants (Section 3.17) are paid $p^{CCS}_{t,z}$ per tonne captured, and that price is set in an annual market. The inputs set an annual quantity of captured CO_2 for the zone `CCS_Orsted`: 0.32 million tonnes in 2026 and 0.43 million tonnes each year from 2027 to 2045. The price clears

$$\sum_h \sum_{i \in z} n_h \frac{S_{t,h,i}}{\eta_{t,i}}\, k_{t,i} = \overline{K}_{t,z} - J^{CCS}_{t,z}, \tag{90}$$

where $S_{t,h,i}/\eta_{t,i}$ is fuel use, $k_{t,i}$ the CO_2 captured per MWh of fuel, $\overline{K}_{t,z}$ the target and $J^{CCS}_{t,z}$ the residual. The price is the one at which the plants run enough to meet the target: the value of capture that the Ramses run assumes the plants receive. Electricity and heat used for capture are demand in the hourly markets. In the baseline the price is 491–530 DKK per tonne in 2027–2037 and 441–458 DKK per tonne in 2038–2045 (Figure 31).

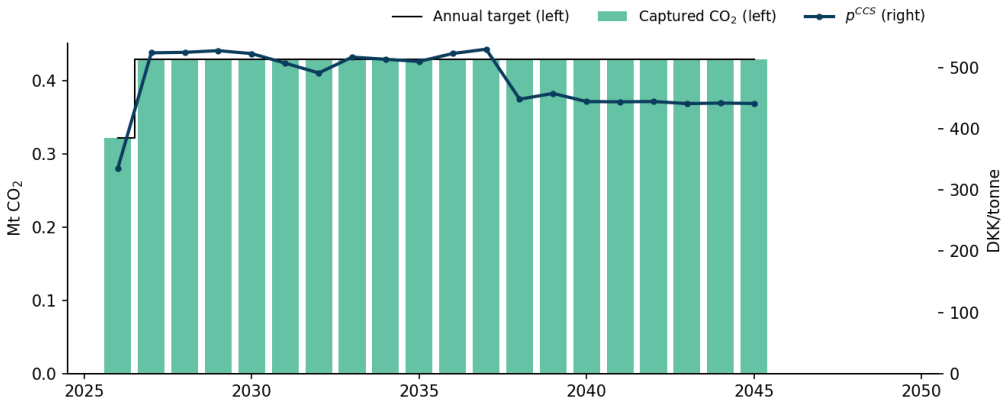


Figure 31: Carbon capture in the baseline. Bars are captured CO_2 (million tonnes), equal to the annual target in every year. The line is the price that clears the target (DKK per tonne).

7.3 Hydrogen markets

Hydrogen clears as in Ramses, in two areas, $a \in \{\texttt{DK_H2}, \texttt{EU_H2}\}$. Danish electrolysers sell in the first and foreign electrolysers in the second. Each area has one price per year, $p^H_{t,a}$, which every electrolyser in the area receives and every hydrogen-fired plant pays. A pipeline links the two areas from 2032.

The two areas differ in what the hydrogen is for. In `DK_H2` a Danish demand must be met every year. In `EU_H2` there is a sink with a willingness to pay up to 2037, and from 2038 also a European demand that must be met. That European demand moves electricity prices more than anything else in the baseline.

7.3.1 The annual balance

Let $Q^H_{t,a} = \sum_h \sum_{i \in a} S^H_{t,h,i}$ be annual electrolyser output in area a, $\overline{H}_{t,a}$ the exogenous demand, and $D^{H,\text{plants}}_{t,a}$ the hydrogen burned by plants in the area. The balance is

$$Q^H_{t,a} + \sum_{a'} F_{t,a' \to a} = \overline{H}_{t,a} + D^{H,\text{plants}}_{t,a} + \sum_{a'} F_{t,a \to a'} + \mathbf{1}[a = \texttt{EU_H2}]\, Z_t - J^H_{t,a}, \tag{91}$$

where F is pipeline flow, $Z_t \geq 0$ hydrogen sold to the European sink, and J^H the residual.

The pipeline. The database has a pipeline between the two areas of 2.7 GW in each direction from 2032, 23.652 TWh per year (Section 2.8). Each direction carries

$$F_{t,a \to a'} = \overline{F}_{t,a \to a'}\, \Phi\left(\frac{p^H_{t,a'} - p^H_{t,a}}{\sigma^H}\right), \qquad \sigma^H = 50 \text{ DKK/MWh}. \tag{92}$$

At equal prices each direction carries half its capacity and the net flow is zero. A price difference of one σ^H moves the net flow to about two thirds of capacity toward the expensive area. Only the net flow, $F_{t,a \to a'} - F_{t,a' \to a}$, is meaningful; the gross flows are large by construction. In the baseline each direction carries between 10.6 and 13.1 TWh a year from 2032. With the pipe open, the two hydrogen prices stay within a few σ^H of each other unless the pipe is full.

Figure 32 draws the two markets, the electrolyser capacity behind them, and how much of it the baseline uses. Figures 33 and 34 show the two prices and the net pipe flow.

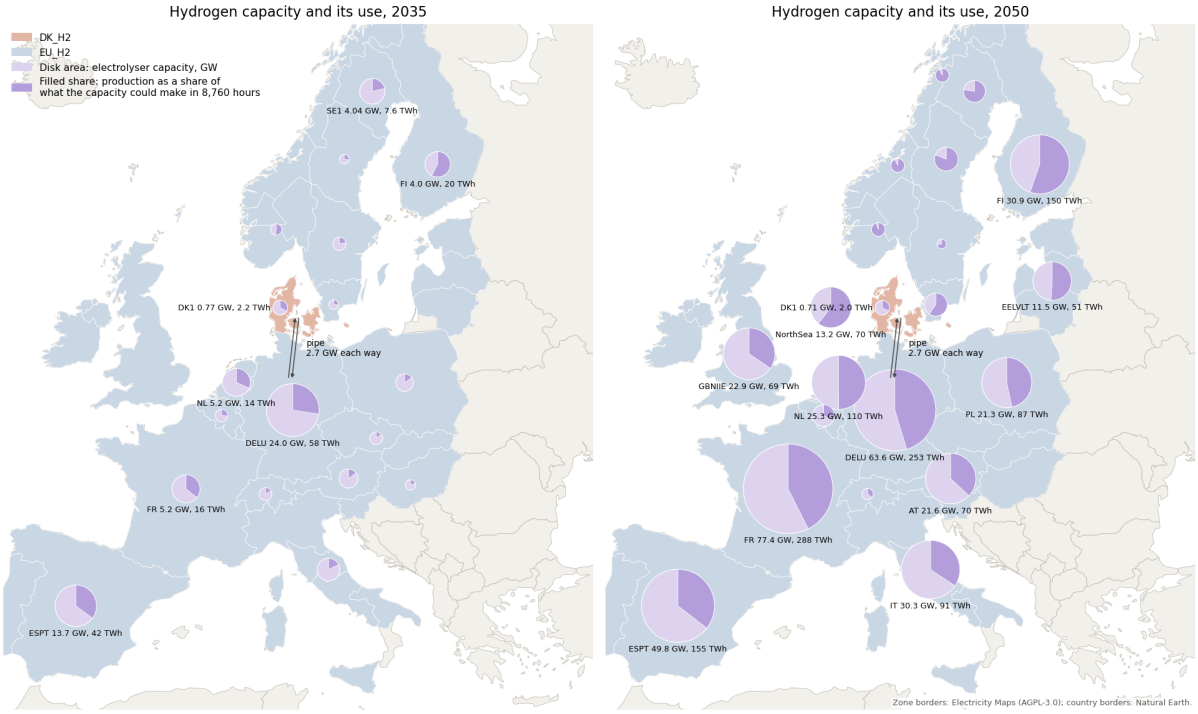


Figure 32: The two hydrogen markets and the pipeline between them (2.7 GW in each direction from 2032). The Danish areas form `DK_H2` and every foreign area belongs to `EU_H2`. Disk area is electrolyser capacity by electricity area in 2035 and 2050; the filled wedge is the baseline's production as a share of what the capacity could make in 8,760 hours.

7.3.2 The European sink

The sink stands for European buyers who take any quantity at a price w_t. The willingness to pay is from ERAA: 628 DKK/MWh in 2025–2028, between 598 and 648 up to 2037, then falling by about 40 DKK/MWh a year to 80 in 2050. The sink is a complementarity condition,

$$Z_t \geq 0, \qquad p^H_{t,\texttt{EU_H2}} \geq w_t, \qquad Z_t \left(p^H_{t,\texttt{EU_H2}} - w_t\right) = 0 : \tag{93}$$

either hydrogen is sold to the sink and the price equals the willingness to pay, or the price is above it and nothing is sold. A square system cannot hold an inequality, so the condition is smoothed,

$$\frac{Z_t \left(p^H_{t,\texttt{EU_H2}} - w_t\right)}{100} = 10^{-6} + J^{sink}_t, \tag{94}$$

with the bounds $Z_t \geq 0$ and $p^H_{t,\texttt{EU_H2}} \geq w_t$ on the variables. With $J^{sink} = 0$, a sale of 100 TWh puts the price 10^{-6} DKK/MWh above w_t, and a price 600 DKK/MWh above w_t leaves a sale of $1.7 \cdot 10^{-7}$ TWh.

Inert years. In a year in which the European area has no output, no demand and no hydrogen-fired plant, there is nothing to sell. Then $Z_t = 0$, and (94) can only hold with $J^{sink}_t = -10^{-6}$. In such years the price is fixed at w_t and J^{sink}_t takes that value. It is the one non-zero residual in an accepted solution, and the residual report labels it.

7.3.3 Two regimes in EU_H2

The Danish Energy Agency builds the European hydrogen market from two sources. Up to 2037 it uses ERAA, which gives a price: the sink. In 2050 it uses TYNDP, which gives a quantity that must be produced. In the inputs, European demand $\overline{H}_{t,\texttt{EU_H2}}$ is zero up to 2037, starts at 450 TWh in 2038[15] and rises linearly to 1,472 TWh in 2050, while the willingness to pay falls. The Danish Energy Agency solves 2025–2037 and 2050 and interpolates its results in between. The model solves every year on the interpolated inputs, so it reports years the Agency does not solve.

The two regimes clear differently:

- **2026–2037: the price is set by the sink.** European demand is zero, so European output that is not piped to Denmark is sold to the sink, and the price is w_t. Output is what the electrolysers find profitable at that price.
- **2038–2050: the quantity is set by demand.** The willingness to pay is well below the cost of producing the required quantity. Nothing goes to the sink, and the price rises until the electrolysers produce $\overline{H}_t$.

The break in 2038. European output must roughly double from 2037 to 2038. The electrolysers do it by running in many more hours, and their electricity use roughly doubles. That demand lands on the electricity markets of every area with electrolysers, and on Denmark through trade. In the baseline, the time-weighted price in West Denmark goes from 407 DKK/MWh in 2037 to 653 in 2038, in France from 263 to 586, and in Sweden SE3 from 234 to 670 (Figure 35). The Danish Energy Agency notes that solving the intermediate years would need the phase-in calibrated, so the electricity price does not jump. This has not been done in the baseline.

7.3.4 DK_H2

The Danish market has no sink and no change of regime. Danish demand, 0.28 TWh in 2025, 3.8 TWh from 2032 and 3.5 TWh in 2050, is met by Danish electrolysers (one EF id and two PX ids, about 0.77 GW of hydrogen capacity from 2032 and 0.71 GW in 2050) and, from 2032, by the pipeline. The price clears that balance. Without a pipeline, the Danish price is whatever makes the Danish electrolysers run enough hours to meet Danish demand, and it follows the cost of electricity in the cheapest hours of the Danish year. With the pipeline open, the Danish price is tied to the European price. In the baseline the net flow runs from the European to the Danish market in every year from 2032 (the negative values in Table 5). European hydrogen is cheaper than Danish hydrogen without the pipe, so the Danish price falls to the European level from 2032 and Danish electrolysers produce less than they would on their own.

Table 5 and Figures 33–35 put the two markets side by side.

7.3.5 How the hydrogen markets are solved

The Danish price is free. The European price is free with the lower bound w_t, and the sink quantity with the lower bound zero. Both residuals J^H and J^{sink} are fixed at zero, except the sink residual in inert years. A shock solves with the same settings, so a shock that raises European electricity demand is felt in the hydrogen price, and the other way round.

[15] The KF26 workbook lists the demand by climate year, and each database uses the row of its own climate year. The figures in the text are the 2008 row. In the 2009 and 1995 databases, demand reaches 1,403 and 1,575 TWh in 2050.

Table 5: The two hydrogen markets in the baseline. Rows marked (input) are data.

	2025	2030	2035	2037	2038	2045	2050
p^H, DK_H2 (DKK/MWh)	1622	1455	623	602	1457	1416	1359
p^H, EU_H2 (DKK/MWh)	628	612	618	599	1456	1413	1355
Sink willingness to pay (DKK/MWh, input)	628	612	618	599	559	279	80
EU demand $\overline{H}$ (TWh, input)	0	0	0	0	450	1,046	1,472
EU output (TWh)	0	26	172	215	450	1047	1473
EU sale to sink (TWh)	0	26	170	214	0	0	0
Net pipe flow DK→EU (TWh)[a]	–	0.0	−1.6	−1.3	−0.2	−1.2	−1.5
EU electrolyser electricity (TWh)	0	41	268	337	693	1540	2104
DK demand (TWh, input)	0.28	1.29	3.80	3.80	3.80	3.80	3.53

[a] Negative values are a net flow from the European to the Danish market.

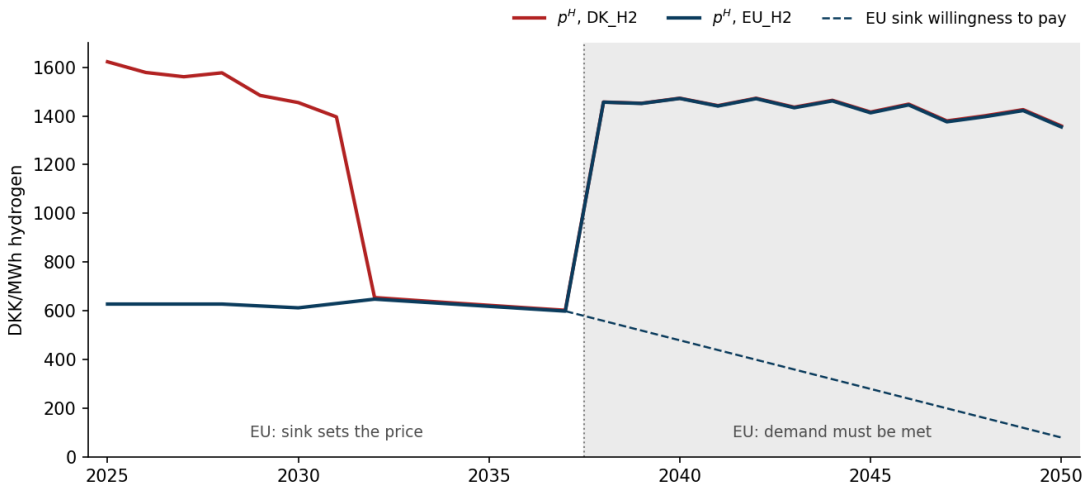


Figure 33: Hydrogen prices in the baseline (DKK/MWh). Up to 2037 the European price is the sink's willingness to pay. From 2038 (shaded) European demand must be met, and the price separates from the willingness to pay.

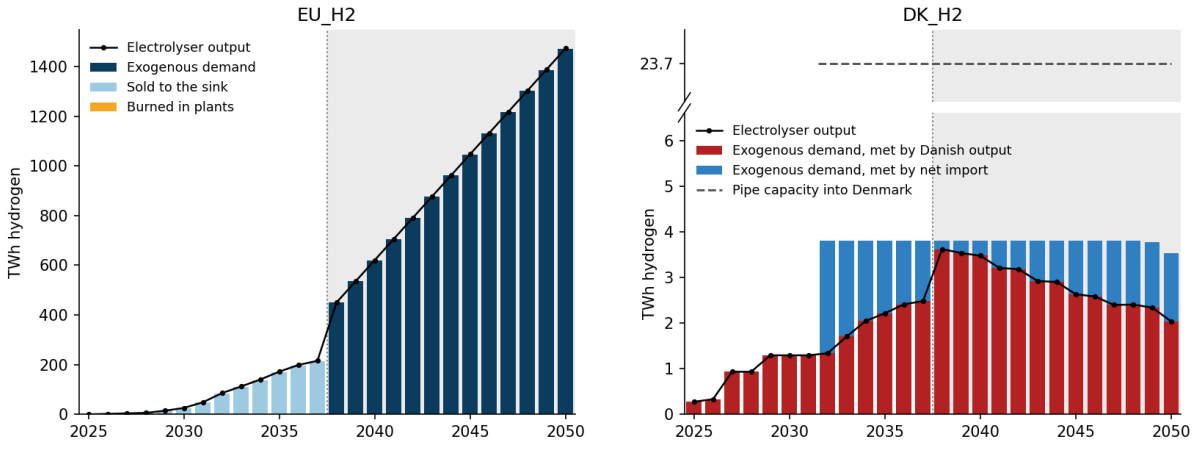


Figure 34: Hydrogen balances (TWh). Left: `EU_H2`, output to the sink up to 2037 and to the exogenous demand from 2038. Right: `DK_H2`. The bars are the Danish demand, split into the part met by Danish output (red) and the part met by net import through the pipe (blue); the black line is electrolyser output. The upper band, on a broken axis, is the pipe capacity into Denmark (23.7 TWh, 2.7 GW): the net import never uses more than about a tenth of it.

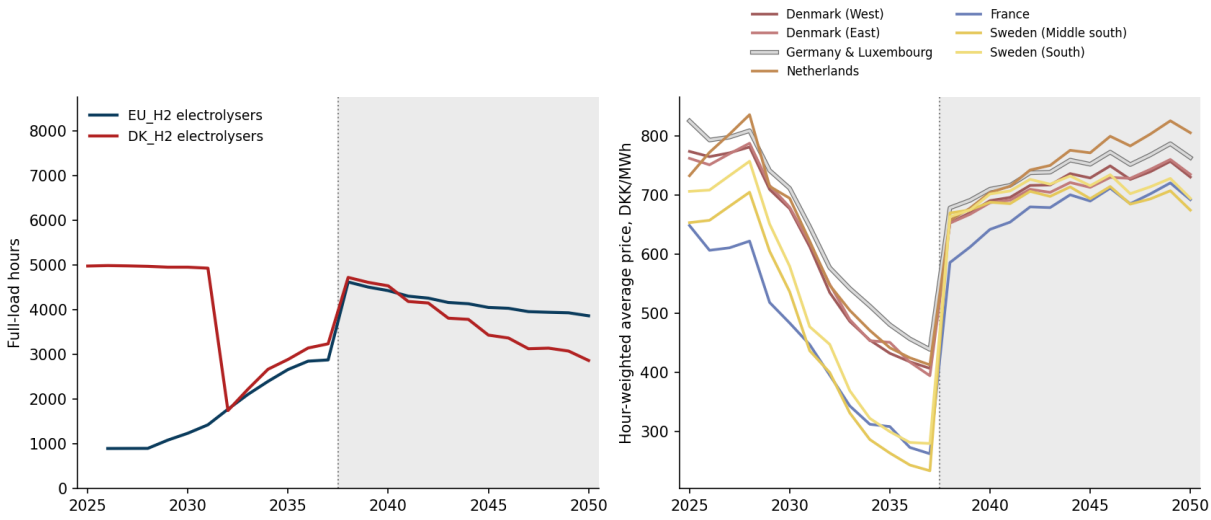


Figure 35: Left: full-load hours of electrolysers. Right: time-weighted average electricity prices (DKK/MWh). The step in 2038 is the European hydrogen demand.

8 Aggregates and the interface with the CGE model

A separate module collects the totals that the reporting layer, and later the CGE model, need. Every equation is an accounting identity. The fuel accounting for CHP plants is not trivial, which is why the module is described here.

Production and demand. Hourly production of electricity, heat and hydrogen is summed over plants within each area, and yearly totals over states. Demand is summed in the same way, split into plant demand and consumer demand. Danish totals sum `DK1` and `DK2`. Production is also split by sector, $s \in \{\text{Waste}, \text{NonWaste}\}$, where the waste sector is the incineration plants.

Fuel use. Use of base fuel b in area g is

$$F_{t,g,b} = \sum_{h} \Bigg[\sum_{i \in \{CD,EPE,BP\}} \alpha_{f(i),b} \frac{S^{E}_{t,h,i}}{\eta_{t,i}} + \sum_{i \in \{EX,BB\}} \alpha_{f(i),b} \frac{n_h Q^{E}_{t,i} s^{E}_{t,h,i}}{\eta_{t,i}} + \sum_{i \in \{BH,EPH\}} \alpha_{f(i),b} \frac{S^{DH}_{t,h,i}}{\eta_{t,i}} \Bigg]. \tag{95}$$

For CD, EPE and BP plants, $\eta_{t,i}$ is the efficiency of electricity generation, so fuel use follows electricity output. For BH and EPH plants it is the efficiency of heat generation. For EX and BB plants neither output alone is proportional to fuel use, because the mix varies with $u^{BP}_{t,h,i}$; fuel use is proportional to the composite output $Q^{E}_{t,i} s^{E}_{t,h,i}$. The same sum over the plants of a resource zone gives $F_{t,r,b}$ in (88).

Fuel use by tax purpose. For the interface with the tax model, fuel use is split into the part attributed to electricity and the part attributed to heat, with the allocation factors of Section 3.8. For a BP plant under the E-rule, fuel for electricity is $S^{E}_{t,h,i}/\bar{\varepsilon}$; under the V-rule it is $S^{E}_{t,h,i}/\eta_{t,i} - (S^{E}_{t,h,i}/\kappa_{t,i})/\bar{\nu}$. For BB and EX plants the split is formed mode by mode and weighted by $u^{BP}_{t,h,i}$. The heat part is the residual, $F^{H}_{t,s,b} = F_{t,s,b} - F^{E}_{t,s,b}$, so the two add up to total fuel use. These quantities are computed by production sector s.

What would be passed to the CGE model. The model documented here runs on its own, against exogenous demand levels, fuel prices, tax rates, capacities and ETS prices from Climate Outlook 2026. When coupled, it would deliver yearly quantities (production, demand, net exports, fuel use by base fuel and by tax purpose, distribution losses) and yearly price indices (consumer and producer, by area and for Denmark, plus export and import prices). It would receive fuel prices, tax rates and ETS prices, and the CGE model's yearly demand would replace the yearly demand function of Section 4.2 in the two Danish areas. Other areas keep their own yearly demand functions. Generating capacity stays outside the interface. Section 15.3 describes the coupling.

Part III
Solution and use

9 Solution

9.1 The square system

The model is a large square system of nonlinear equations, solved with GAMS as a constrained nonlinear system (CNS) with CONOPT [GAMS Development Corporation, 2024, Drud, 1994]. There is no optimization at the level of the whole model: every optimization is done analytically for the individual plant, consumer or line, and only the first-order conditions enter. Dispatch is a composition of normal distribution functions, flat far from the switching point, and storage couples every state of the year through the continuation value. Both need a starting point that is already close.

A baseline is the whole horizon, 2025–2050, solved as one system. In the system every price is free and every active residual is fixed at zero: electricity, heat, cluster prices, resource zones, hydrogen, the hydrogen sink and carbon capture. The yearly demand elasticities are 0.1.

When a solution is accepted. A solve is *accepted* only if every active market residual is at most 10^{-6} in every year. The model then prints one line saying that every market cleared. Otherwise it names the markets and years that are still open. The only exception is the sink residual in inert years (Section 7.3).

What the code does when a solve fails. The code has three fallbacks. None of them changes the model: every accepted solution is a solution of the model as specified, with the smoothing and storage parameters at their stated values.

1. **Interrupted-iterate retry.** If CONOPT is interrupted, for example by a time limit, the solve is run once more from the iterate where it stopped, not from the starting point.
2. **Checkpoint restore.** A failed solve never replaces the last accepted solution. The database keeps the previous point, and the next attempt starts from it.
3. **Per-year fallback.** If a block of years fails as one system, the failed years are solved again in smaller blocks, down to one year at a time, so that a hard year is isolated. A year whose starting point does not fit the equations is first brought to a consistent point by a feasibility solve of the same equations.

If a shock still fails, the user can walk it in smaller steps or solve fewer years (Section 10.4).

9.2 Two solves: placing planned outages

Each baseline with placed outages is solved twice.

First solve: flat planned outages. Every plant and line loses its planned rate p_i in every hour state: $P_{t,h,i} = p_i$ in (3). This solve is the version `climate_2008_flatoutage`.

Placing the blocks. The prices of the first solve are used to place maintenance. Each unit, and each line, is planned out in one block of $p_i \cdot 8760$ consecutive calendar hours, starting at midnight. The block is placed where the unit loses least, judged on the first-solve prices:

- **thermal and CHP plants and heat pumps:** where their operating surplus (utilization times margin) is lowest. For CHP plants and electric boilers, utilization is output over capacity. The node price breaks ties;
- **storage and hydro** (`ES`, `HY`, `HYS`): where the price is closest to its yearly median, because storage earns from price differences, not price levels;
- **lines:** where the price difference between the two ends is smallest.

Three rules apply when the blocks are placed:

- Units of one plant, and lines of one corridor, are not out at the same time when their blocks fit in the year.
- In each area, the share of capacity planned out at any time is capped at the larger of twice the area's average planned share and the share of its largest unit. Power capacity counts in its electricity area, and heat-only units and heat pumps in their heat area.
- Units with the largest planned energy are placed first.

Lines that touch an area without consumers (`DK3`) keep the flat treatment. The calendar blocks are then aggregated to plant ids with the aggregation weights of Section 2.4, and to hour states with the map from calendar hours to states. The result is the planned-out share $P_{t,h,i}$ in each state.

Second solve: placed planned outages. The database with the placed shares is solved again. This is the baseline. Unplanned outages are flat in both solves. Each climate year, and each geography, has its own first solve and its own placement.

Figure 36 shows the result for Danish plants in 2035: the capacity planned out by day against the monthly price of the first solve. Figure 37 shows the same for the Danish interconnectors. Bypass and extraction CHP plants are planned out in summer, when heat prices are low. Condensing plants are planned out mostly in March and June; March has the lowest first-solve price of the year in West Denmark.

9.3 How the published baselines were built

A baseline cannot be solved from a cold start. The published baselines were built in three steps:

1. Each year was solved on its own by continuation: starting from fixed prices, all markets were brought in together in small steps. A year was started from the solution of its neighbour year, and plants that are new in a year were given levels from an earlier solution.
2. The years were then solved together as one system, which gives the first-solve baseline with flat planned outages.
3. Planned outages were placed on those prices, and the database with placed outages was solved from the first-solve baseline.

The thirteen-area database was solved first and used as a start for the twenty-five-area database. A year counted as solved only when a solve of that year had been accepted. A residual of zero is not enough on its own, because a starting point copied from another solution carries that solution's residuals.

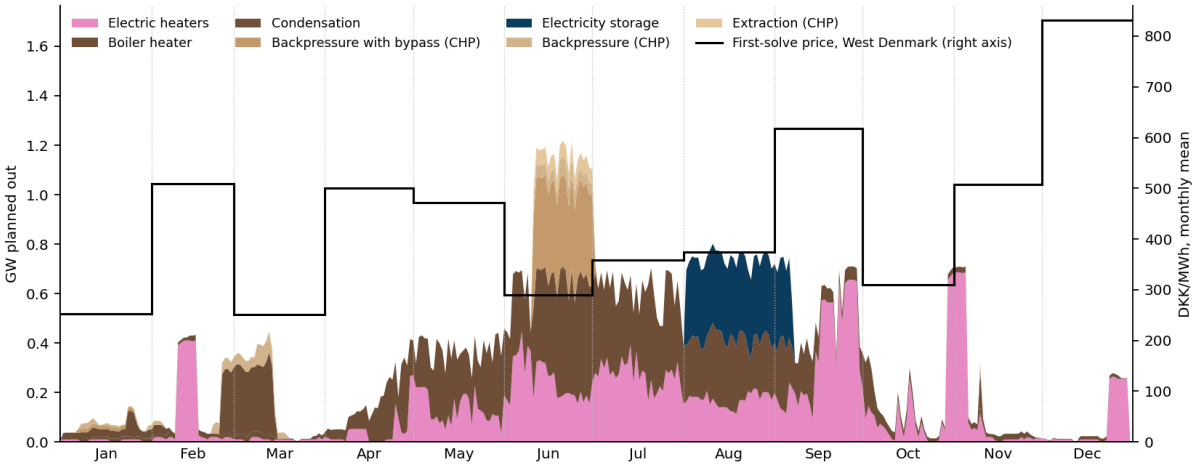


Figure 36: Placed planned outages, Danish plants, 2035, climate year 2008. Areas: capacity planned out by day and plant type (GW, left axis). Steps: monthly time-weighted West Denmark price of the first solve (DKK/MWh, right axis).

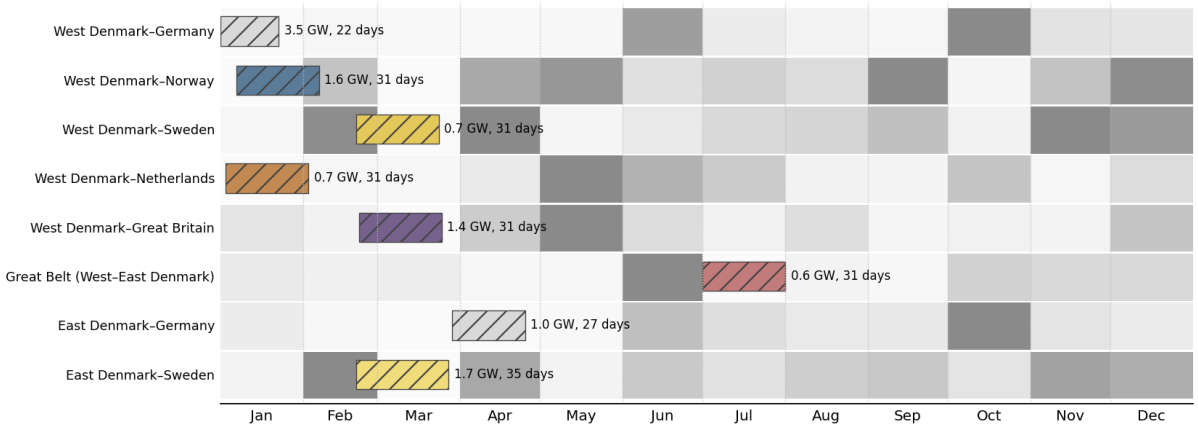


Figure 37: Placed planned outages, Danish interconnectors, 2035, climate year 2008. Each bar is the one block in which the line is planned out, with the capacity it takes out and its length; the colour is the partner area, as in the balance figures. The background shades each line's months by the mean first-solve price difference between its two ends, light for the smallest difference of that line and dark for the largest. The rules of the placement (one corridor at a time, the cap on each area's planned share) keep some blocks out of the lightest month.

Climate year 1995. With the 1995 weather, several years from 2037 did not clear by the steps above. They were cleared one at a time, in order. 2038, the first year with European hydrogen demand, was started from the prices of the thirteen-area 1995 solution, and each later year from the cleared year before it. Storage units that are new in a year were first held out and then brought in with wider smoothing, which was walked back to the stated values. Within a year the electricity markets were cleared in groups of areas, then the hydrogen markets, then all markets together. The years were then solved together as one system, as for the other versions. The accepted solution is at the stated parameters: no smoothing or bound is left changed.

What a user can reproduce. The release contains the solved baselines and the databases they were solved on. A shock starts from a solved baseline (Section 10.4). The notebook `1_Baseline.ipynb` can re-solve a shipped database from its own solution, into `work\`, which needs GAMS and many hours. Rebuilding a baseline from the raw inputs, or placing outages again, is

not supported in this release: the data build and the outage placement are not part of it.

10 Using the model

This section is the user guide. The release file `README.md` has the same material in more detail, including installation and troubleshooting.

10.1 Module states

The GAMS model is assembled from modules (`*.module.gms` files), each of which can be in one of several *states*. A state selects which variables are endogenous, which are exogenous, and which equations are imposed. The Python layer (`pyGRE.models`) assembles a GAMS model from a combination of module states. Two dimensions matter here:

- **Time representation:** `exoInputs`, `HY`, `HYS`, `ES`, `HS` and `EV` have a `chronological` and a `clusterAvg` state (Section 3.12.4). This release uses `clusterAvg`.
- **Closure:** `equilibrium` and `demand_DCIIA` have states that switch between exogenous and endogenous prices, and between exogenous and endogenous yearly demand.

Appendix B lists the states.

10.2 Versions and folders

A version is one solved baseline (Table 1). Each version has its own folder under `data\KF26_clusterAvg\`. The file `versions.json` in that folder lists each version with its folder, geographies, outage treatment, and the size and SHA-256 hash of each file. A version folder holds, per geography:

- `db_<geography>_aggHours`: the hour database;
- `checkpoints\<geography>\all_years\baseline.pkl`: the solved baseline, 2025–2050;
- `checkpoints\<geography>\all_years\residual_report.csv`: the residual of every year and market.

A version is selected by name, never by copying files. The versions `climate_2008` and `climate_2008_flatoutage` have the same hours and plant ids, so the model cannot detect a mix-up.

What the database contains is the result of the aggregation of Section 2. After that step, a plant id no longer names a Ramses unit, and the weights inside it are not stored. A user can see an id's plant type, area, fuel and capacity, but cannot split it into the units it was built from. A shock cannot change which units share an id, which hours share a state, or which network belongs to which heat area.

Where things are.

Folder or file	Content
`README.md`, `VERSIONS.md`, `docs\SHOCK.md`	user guide, versions, how to write a shock
`makeModels\1_Baseline.ipynb`	re-solves a baseline (needs GAMS; writes to `work\`)
`makeModels\2_Analysis.ipynb`	loads a baseline, runs a shock, draws figures, runs the model checks
`pyGRE\settings.py`	`RunSettings`: the one place for run settings
`pyGRE\gmsModels\`	GAMS source: one module per plant type, plus markets, trade, demand
`pyGRE\models\`	assembles a GAMS model from module states
`pyGRE\makeModels\`	the stacked solve, the shock catalogue, added plants
`data\KF26_clusterAvg\`	one folder per version, plus `versions.json` (read only)
`data\published_outlook\`	the published Climate Outlook 2026 results workbooks, used by the comparison figures
`work\<run>\`	solver scratch, resume files, shocked databases
`results\<topic>\<run>\`	figures and tables

Where to change what.

To change	Open
version, geography, years, shock, run name	the settings cell of the notebook
a tax, fuel price, capacity, transmission capacity or demand level	a shock in `pyGRE\makeModels\kf26_shocks.py`
an equation, or a plant type's behaviour	the `.module.gms` file under `pyGRE\gmsModels\`
which modules or module states are solved	`pyGRE\models\presets.py`
plant population, hour clustering, heat areas	not possible in this release

10.3 Running the model

The model runs from two notebooks in `makeModels\`, in Python 3.12 with `gamsapi` matching the GAMS version. Reading and plotting a baseline needs no GAMS. Solving a shock or a baseline needs GAMS with a CONOPT licence. Loading a baseline needs about 7 GB of memory.

One settings cell. Each notebook has exactly one settings cell. It creates a `RunSettings` object from `pyGRE\settings.py`, and the other cells read from it. The main fields are:

```
S = RunSettings(
    climate_year=2008,      # a climate year listed in versions.json
    outage='planned',       # 'planned' or 'flat'
    geography='disaggEA',   # 'disaggEA' or 'aggEA'
    solution='shipped',     # 'shipped', or 'baseline/<run>' (1_Baseline)
    shock=None,             # None, or a name from the shock catalogue
    years=None,             # None for 2025-2050, or a tuple such as (2035,)
    run_name=None,          # None builds a name from the settings
)
```

`RunSettings` finds the version folder through `versions.json` and refuses a version or geography that is not shipped. No environment variables are needed.

Outputs. A run writes solver scratch and resume files to `work\<run>\`, and the solved shock (`solution\shock.pkl` with `shock.json`), figures and tables to `results\<topic>\<run>\`. Nothing is written into `data\`.

First run. Run `2_Analysis.ipynb` with the default settings. Every solve and shock switch is off by default, so this does not start GAMS. The notebook loads the default version and prints the line from the version's residual report saying that every market cleared.

10.4 Running a shock

A shock starts from a solved baseline and re-solves the same model with some inputs changed. The data are not rebuilt and the baseline is not replaced. A shock must use the database of its own version, because the starting levels are only valid on the same hour states.

Writing a shock. Inputs such as tax rates, fuel prices, transmission capacity (`trCap`), demand levels and smoothing parameters are fixed variables. Two rules follow:

1. **Use `.fx`, not `.l`.** Only `.fx` changes the value that is solved. An assignment to `.l` is reset when the model is solved.
2. **Write from the original value,** such as `trCap_init`, not from the current value. Then repeating a step does not apply the shock twice.

For example, the DK1–NOS line at a factor f of its capacity:

```
trCap.fx[t,line,EA,EAEA]$(activeLineEA[t,line,EA,EAEA] and
     ((sameas(EA,'DK1') and sameas(EAEA,'NOS')) or
      (sameas(EA,'NOS') and sameas(EAEA,'DK1'))))
   = trCap_init.l[t,line,EA,EAEA] * f;
```

The walk. A large change may not solve in one step. The walk applies it as a share of the full change, from 0 (the baseline) to 1, and each step starts from the last accepted solution. If a step fails, it is halved, down to a minimum step. The shocked database is saved only if the full change was accepted and every market cleared. If a shock does not solve, walk it in smaller steps, solve fewer years to find the first year that fails, and read the residual report, which names the market and the year. A shock that empties a market or a corridor may have no solution.

The shock catalogue. Shocks are run by name from the catalogue in `pyGRE\makeModels\kf26_shocks.py`. Each entry is a function that returns the GAMS text at a given share of the change and writes the shocked inputs back onto the database. The release has three examples:

Name	What it changes
`dk1_nos_interconnector`	the DK1–NOS line, both directions, at a factor of its capacity (default 0: closed)
`offshore_wind_cut`	offshore wind capacity in one area cut by a share from a start year (default DK1, 25%, 2035)
`dk_hydrogen_demand`	Danish hydrogen demand times a factor from a start year (default 1.25 from 2030)

A new shock is a function added to the catalogue. Start with one year (`years=(2035,)`) and the thirteen-area geography to check that it solves, then run 2025–2050.

10.5 Adding a plant

A plant that is not in the database can be added after the baseline levels are installed and before the first solve (`pyGRE\makeModels\kf26_added_plants.py`). It can have any plant type of Section 3; it gets the sets and starting levels that type uses. Efficiency, capacity factor or storage duration are passed with the plant. Condensing and wind plants need a smoothing parameter.

`start_year` is the first year at full capacity and `end_year` the last; leave `end_year` unset to keep the plant through 2050. With a phase-in year, capacity is zero in that year and rises linearly to full capacity in `start_year`. With a phase-out year, capacity falls linearly from full capacity in `end_year` to zero.

CHP plants need the back-pressure ratio $\kappa_{t,i}$ (`cm`); bypass and extraction plants also need $\xi_{t,i}$ (`cv`). For an extraction plant, the capacity given is electricity in full extraction; the stored electricity capacity is that divided by $1 + \xi_{t,i}/\kappa_{t,i}$, and heat capacity is that divided by $\kappa_{t,i}$. The heat area defaults to the central market of the electricity area.

Existing capacity can be removed in the same step. A fixed cut removes a stated nameplate from one technology in one area. An offset removes, year by year, effective capacity equal to what the new plants add. If the first technology cannot cover the offset, the cut either stops or continues through a list of technologies.

The procedure has three steps. A control solve holds the new plants at zero capacity and must reproduce the baseline prices within 0.01 DKK/MWh. The shock then raises their capacity, walked in if needed. The solved capacities are written onto the database before it is saved with the shock (`results\<topic>\<run>\solution\`).

10.6 Model checks

`2_Analysis.ipynb` has two switches for checks, both off by default. With `report_residuals=True` it prints the residual of every year and market. With `diagnostics=True` in `FigureOptions` it draws the market-clearing diagnostics: the residual report of the stacked solve, the vehicle-to-grid, prosumer-cluster, hydrogen, carbon-capture, resource-zone and hydro components, and the energy and fuel balances of every area in the detail year. When a user changes the model or adds a shock, two solves check the machinery:

- a null shock (no change), which must reproduce the baseline electricity prices within 0.01 DKK/MWh (`docs\SHOCK.md`);
- the control solve for added plants, which the notebook runs before it raises the new capacity (Section 10.5).

Part IV
Results

11 The baseline: climate year 2008, twenty-five areas, placed outages

This section reports the baseline, version `climate_2008` with twenty-five areas. It opens with the comparison with Climate Outlook 2026 (Section 11.1). Sections 11.2–11.5 follow Danish production, emissions, prices and trade through the horizon. Sections 11.6–11.9 open one year, 2035. Section 11.10 reports the monetary account. Danish totals are `DK1`, `DK2` and `DK3`.

11.1 Comparison with Climate Outlook 2026

Generation and fuel use are compared for 2035 and 2050. Filled bars are the model and hatched bars the published projection. Both count the offshore wind at Energiø Bornholm. Some bars cannot match by construction: a plant id does not carry the Ramses unit list, and the published sheets do not use the model's plant types one for one.

Electricity. Figure 38 shows generation without storage discharge. Offshore wind is 36 TWh in 2035 against a published 34 TWh. Solar is 28 TWh against 28 in 2035 and 47 against 47 in 2050. CHP is 3.1 TWh against 3.9 in 2035. The full-load-hour rule (Section 2.5.1) moves the wind and solar bars toward the Agency's annual production.

Heat. Figure 39 shows district-heat generation without storage discharge. In 2035 the model produces 11.8 TWh of CHP heat against 13.5, 3.8 TWh from boilers against 5.7, and 28.1 TWh from electric heaters against 23.7. Heat storage operates throughout 2050 (Section 2.8), so the 2050 heat panel is comparable with the earlier years.

Fuel. Figure 40 shows Danish fuel use by fuel. Hydrogen is left out: the published figure counts hydrogen produced and the model figure hydrogen burned.

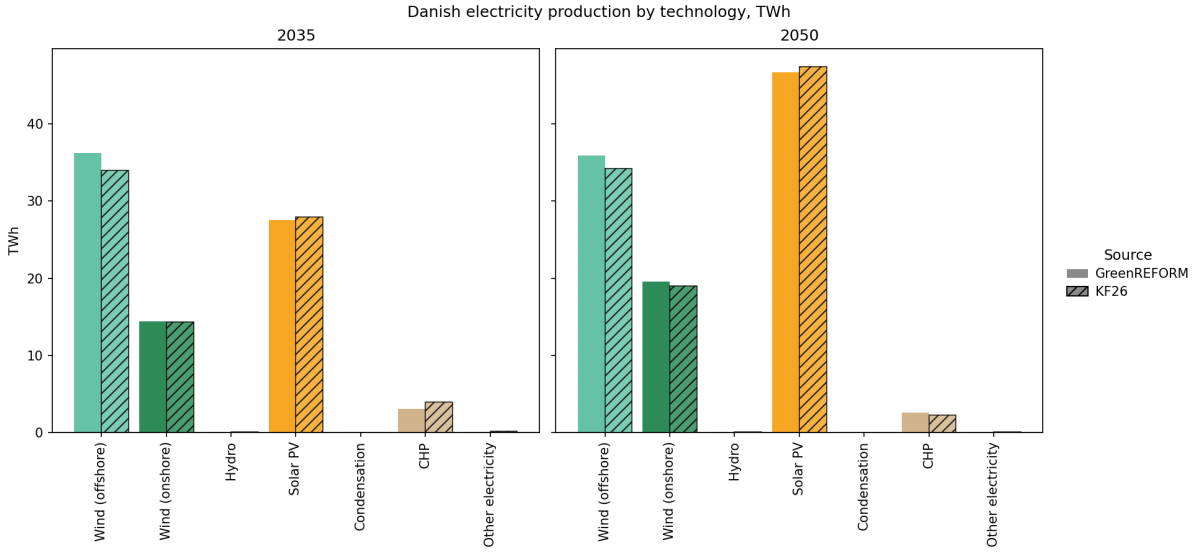


Figure 38: Danish electricity production in 2035 and 2050, TWh. Filled bars are the model, hatched bars Climate Outlook 2026. Storage discharge and the consumption of electric heat and electrolysers are left out. Solar includes the parks in the PV-battery clusters.

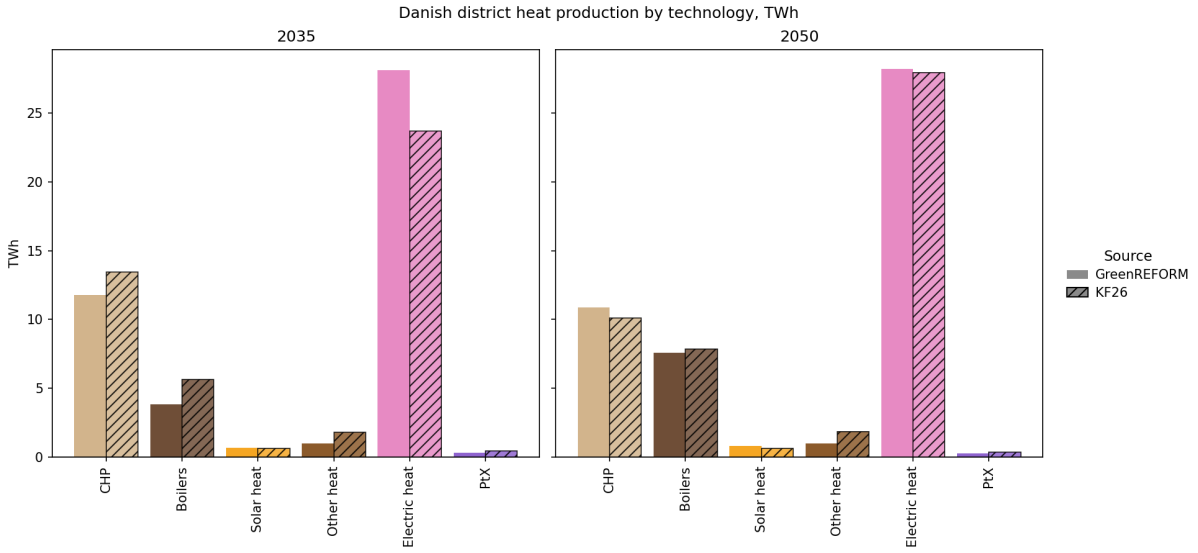


Figure 39: Danish district-heat production in 2035 and 2050, without storage discharge, TWh.

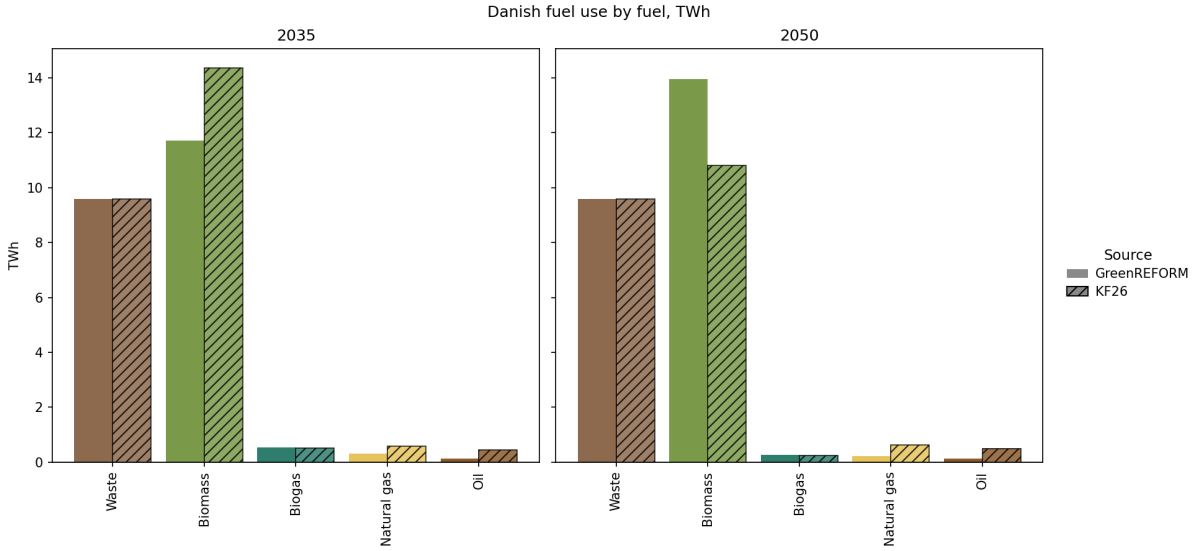


Figure 40: Danish fuel use in 2035 and 2050, TWh. Hydrogen is excluded.

11.2 Danish production, 2025–2050

Figures 41 and 42 show Danish production in every year, by plant type and with thermal output split by fuel. Storage discharge counts as production. Electricity production rises from 39 TWh in 2025 to 76 TWh in 2035 and 92 TWh in 2050. District-heat production is 41 TWh in 2025 and 46 TWh in 2035. Electric heaters take over the heat supply: 3 TWh in 2025 and 28 TWh in 2035.

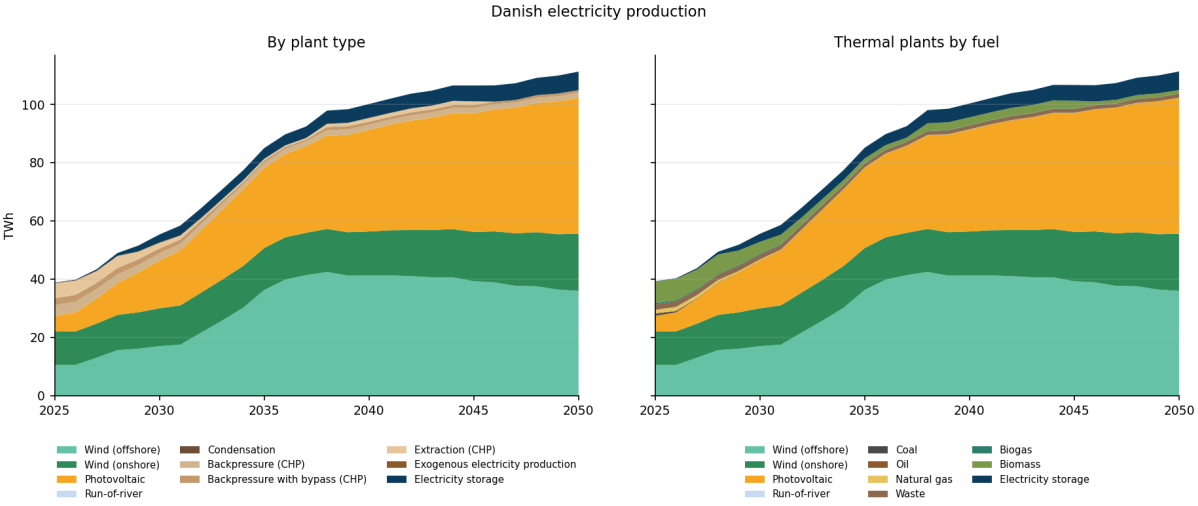


Figure 41: Danish electricity production in the baseline, 2025–2050, TWh. Left: by plant type. Right: thermal production split by fuel group.

What wind and solar leave. Figure 43 shows residual demand: price-responsive demand (classic, transport and data centres, with distribution losses) minus wind, solar and run-of-river production, state by state, sorted from the lowest to the highest hour. Hours below zero are covered by electric heaters, electrolysers, storage charging and exports; hours above zero by thermal plants, storage discharge and imports. In West Denmark in 2035 the curve crosses zero after 5746 hours, and the surplus over the year is 18.9 TWh against a deficit of 7.8 TWh.

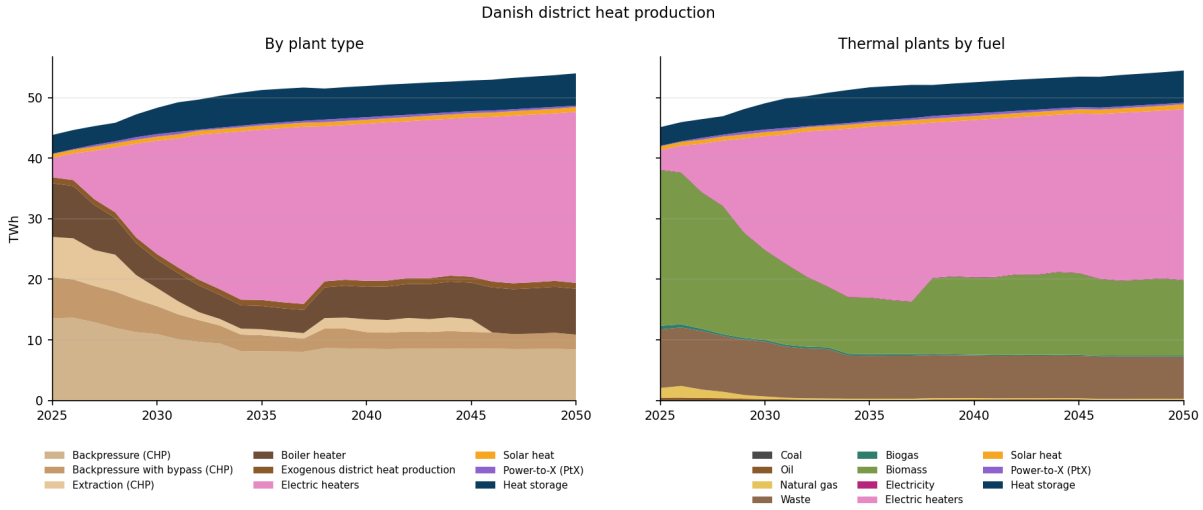


Figure 42: Danish district-heat production in the baseline, 2025–2050, TWh. Left: by plant type. Right: thermal production split by fuel group.

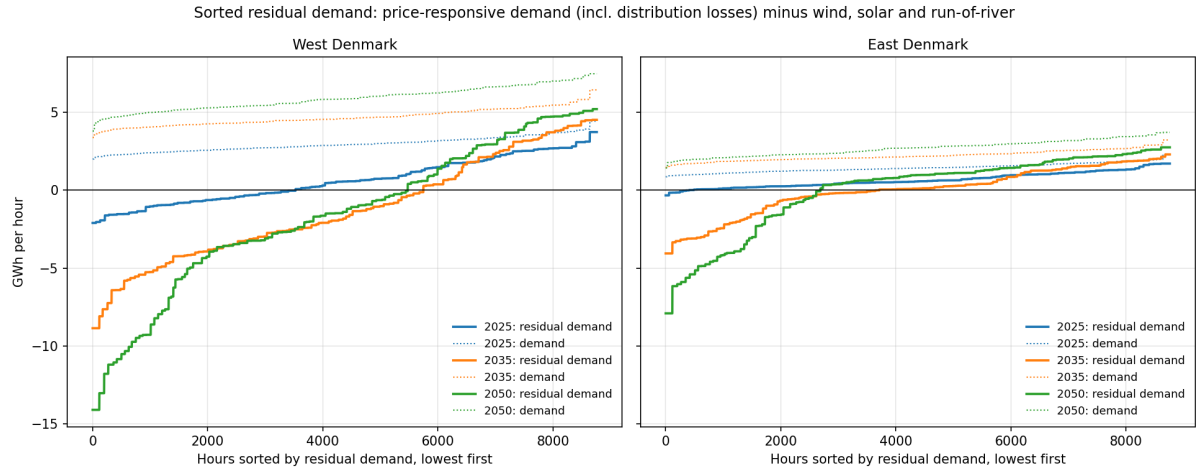


Figure 43: Residual demand in West and East Denmark, 2025, 2035 and 2050, GWh/h, sorted from the lowest hour to the highest. Dotted lines are demand alone, sorted the same way.

11.3 CO_2 emissions, 2025–2050

Figure 44 shows the greenhouse gases that follow from the fuel use. Bars above the axis are the fossil CO_2 in the fuel burned and the plant-specific CH_4 and N_2O term. Bars below are the CO_2 captured by the two capture plants (Section 3.17). The line is the net. The left panel splits fossil CO_2 by fuel; the right panel by the output the fuel is attributed to under the tax rules (Section 3.8). Fossil CO_2 falls from 2.5 million tonnes in 2025 to 0.9 in 2035; what remains is mostly the fossil share of waste. Capture follows the target: 0.32 million tonnes in 2026 and 0.43 a year in 2027–2045.

11.4 Electricity prices, 2025–2050

Figure 45 and Table 6 compare the model's time-weighted average price (`pEt_hWeight`) with the published annual prices of Climate Outlook 2026 (sheet *Årlige elpriser*). The published years are 2026–2037 and 2050. Both the model and the published series are in fixed 2026 prices (Section 2.1). The Danish Energy Agency's line between 2037 and 2050 is an interpolation, not a model result.

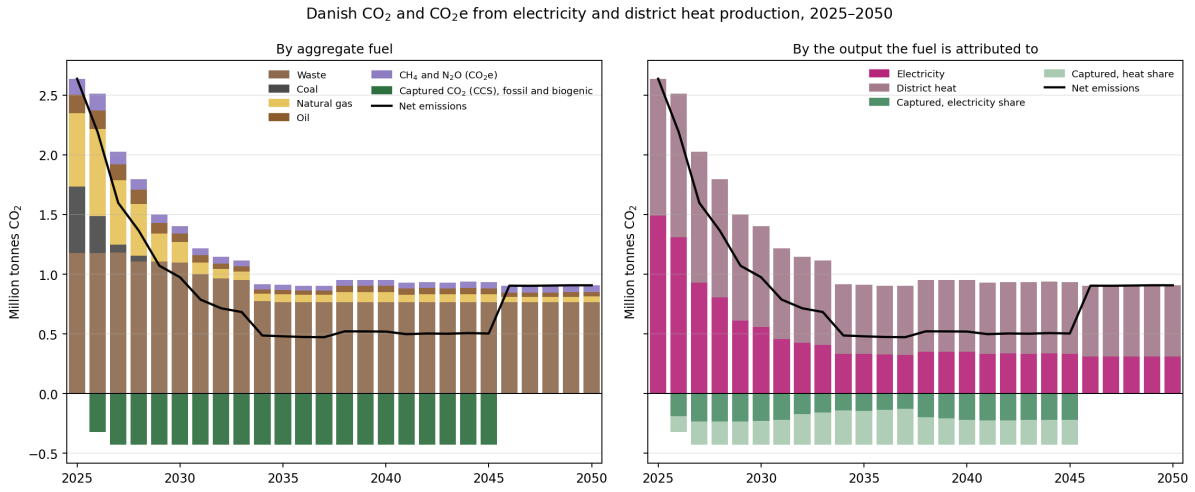


Figure 44: Danish CO_2 and CO_2e from electricity and district heat in the baseline, 2025–2050, million tonnes. Above the axis: fossil CO_2 by fuel (left) and by attributed output (right), and the CH_4 and N_2O term. Below the axis: CO_2 captured. The line is the net.

Table 6: Time-weighted average electricity price, model and published Climate Outlook 2026, DKK/MWh. 2045 is not published.

	2030	2035	2037	2038	2045	2050
West Denmark, model	678	433	407	653	729	731
West Denmark, published	642	445	427	–	–	457
East Denmark, model	680	451	395	653	714	735
East Denmark, published	640	467	431	–	–	458

Up to 2037. The published prices fall from about 700 DKK/MWh in 2026–2028 to about 430 in 2037. In the baseline, the West Danish price is 433 DKK/MWh in 2035 against a published 445.

From 2038. The model steps up in 2038 in every area, because European hydrogen demand begins and must be met (Section 7.3). The published 2050 price, 457 DKK/MWh in West Denmark and 458 in East Denmark, is close to the published 2037. From 2038 the model lies 224–303 DKK/MWh above the published path in West Denmark, where the path between 2037 and 2050 is the Agency's interpolation. We report 2038–2050 as provisional and are in contact with the Danish Energy Agency about the gap.

The shape differs as well as the level. The published 2050 median price in West Denmark is 172 DKK/MWh, against 712 in the model: matching the mean would not match the shape of the year (Figure 48).

Price indices. Figure 46 draws the time-weighted price beside the other weights: consumption, production, imports and exports (Section 4.6). The production-weighted price is lower, because wind and solar produce in the cheap hours. Figure 47 takes the weights one technology at a time: the average price each technology sells or buys at.

The shape of the year. Figure 48 shows price-duration curves for 2025, 2035 and 2050: the hours of the year sorted from cheapest to most expensive, each state price repeated for the hours in the state. In 2035 the West Danish mean is 433 DKK/MWh and the cheapest state 37. The

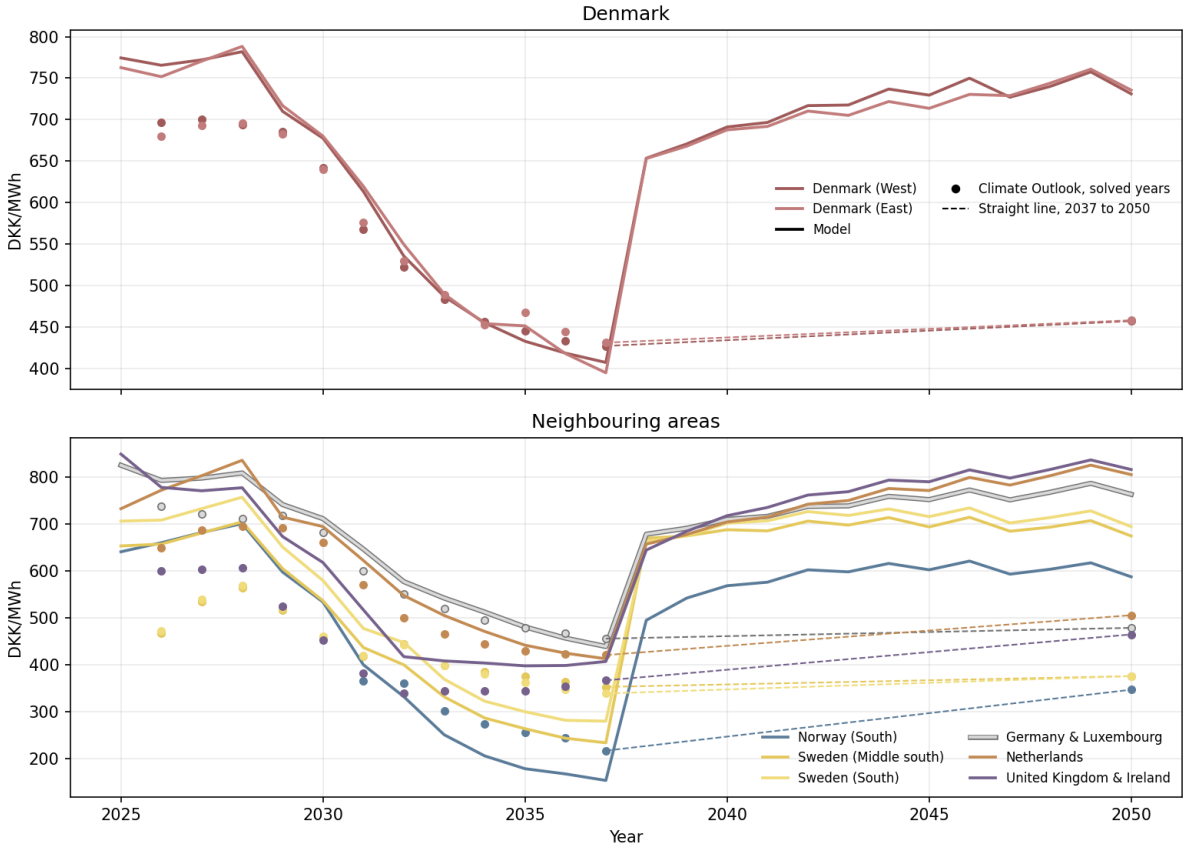


Figure 45: Time-weighted average electricity price, 2025–2050, DKK/MWh. Lines are the model. Dots are the published years of Climate Outlook 2026; the dashed segment is the Agency's interpolation between 2037 and 2050.

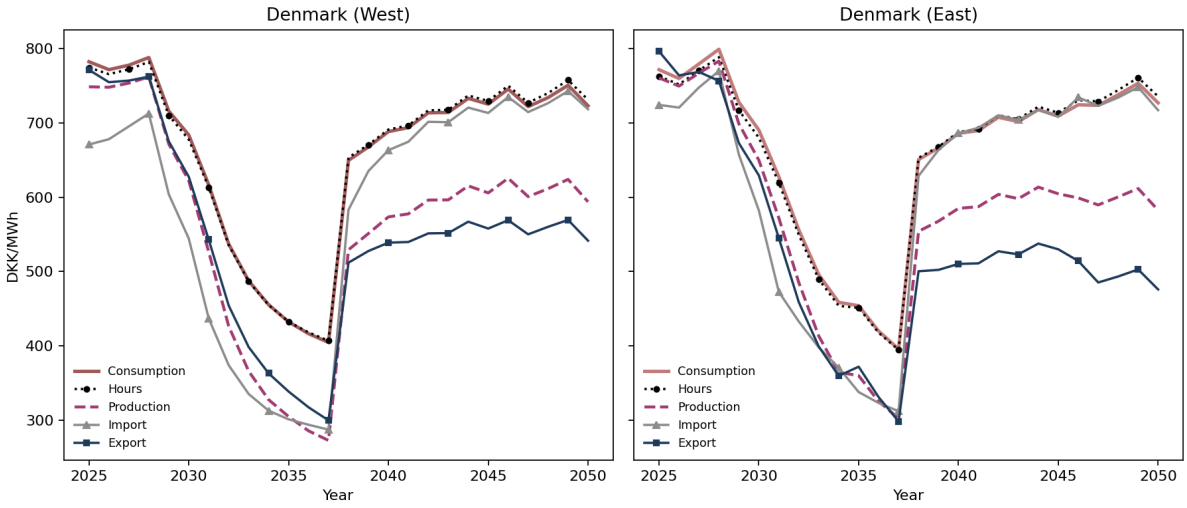


Figure 46: Electricity price indices, West and East Denmark, 2025–2050, DKK/MWh: consumption-, time- and production-weighted, and area import and export prices.

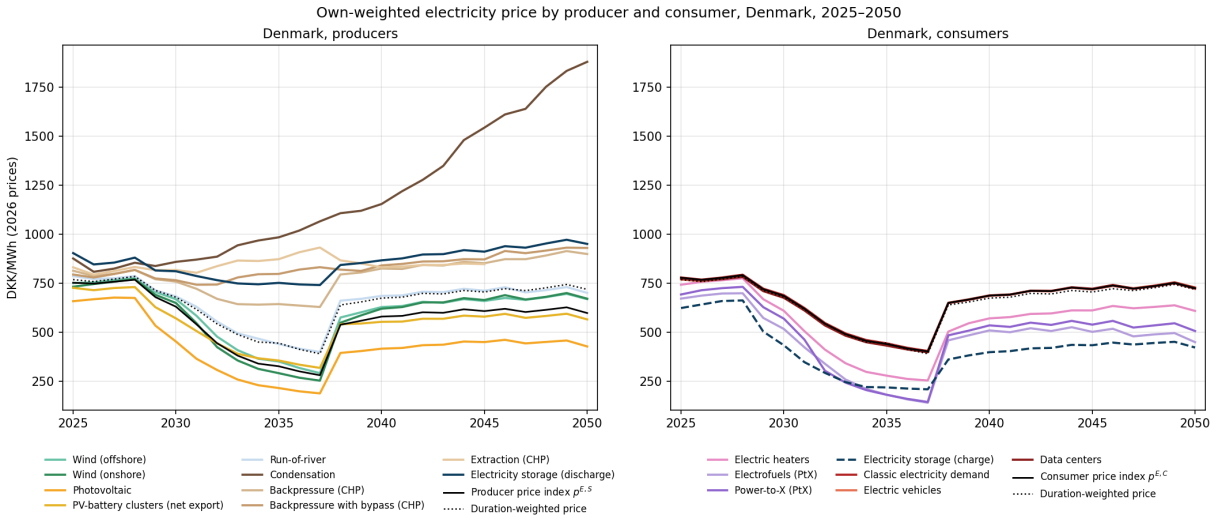


Figure 47: The average price each technology sells at (left) or buys at (right), Denmark, 2025–2050, DKK/MWh. The solid black line is the Danish producer (left) or consumer (right) price index; the dotted line is the time-weighted price.

lift of the middle of the 2050 curve is the hydrogen demand, which from 2038 gives every hour with spare electrolyser capacity a buyer at the hydrogen value.

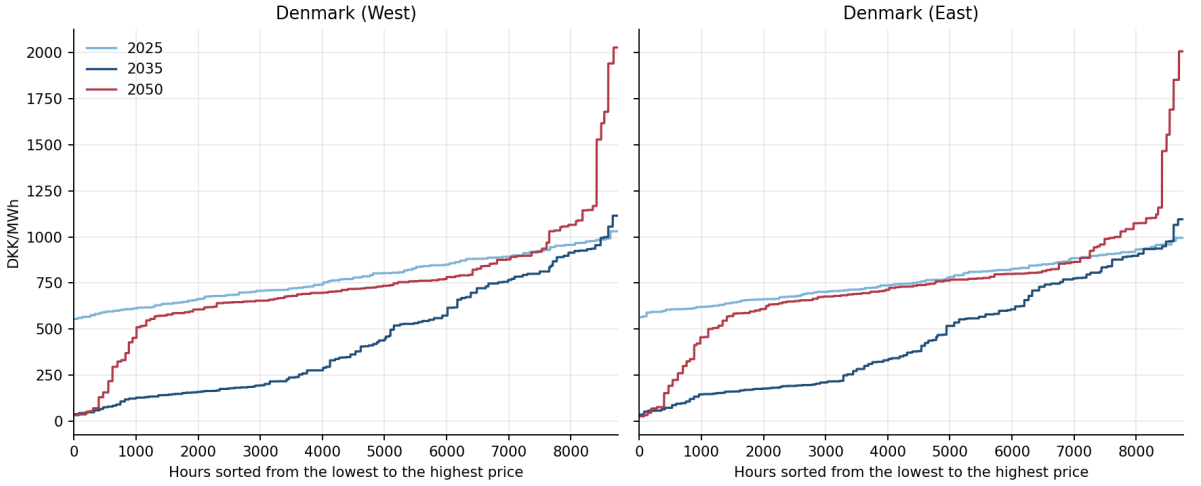


Figure 48: Price-duration curves in the model, 2025, 2035 and 2050, DKK/MWh. West Denmark left, East Denmark right.

11.5 Trade, 2025–2050

Figure 49 shows Danish electricity trade by partner: exports above the axis, imports below, net exports as the black line. The three Danish areas are taken together. Flows are netted state by state on each line, with the loss taken off the incoming direction. In the baseline Denmark is a net importer of 1.2 TWh in 2025 and a net exporter of 15.1 TWh in 2038. Interconnectors trade at nameplate times availability (Section 5).

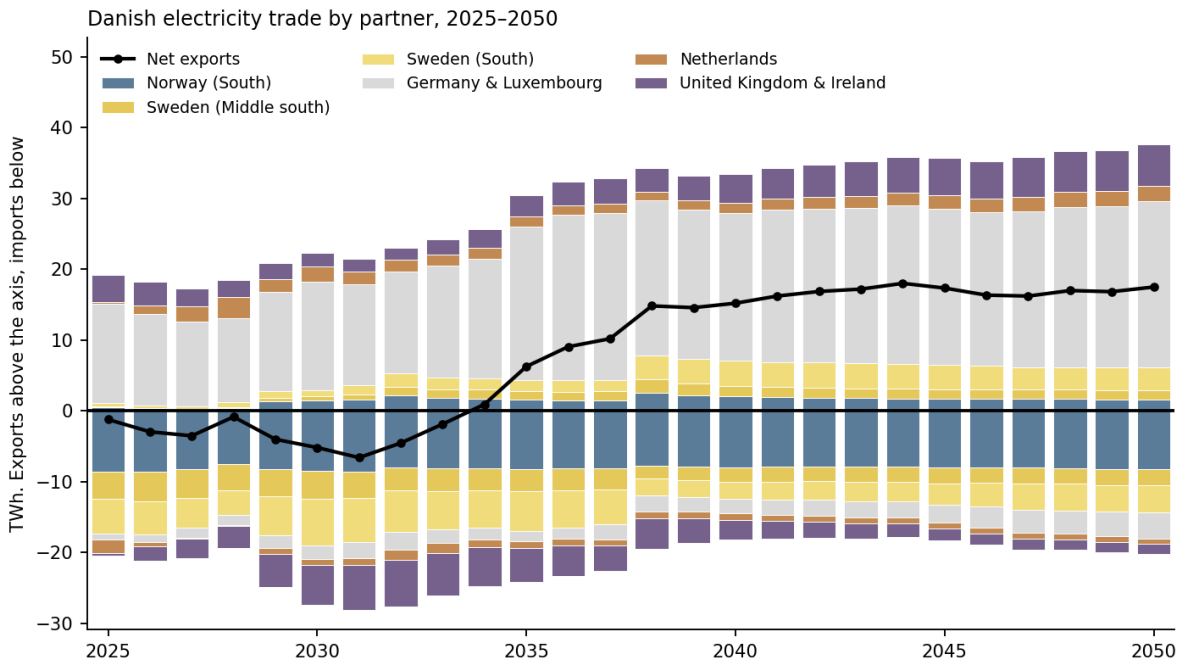


Figure 49: Danish electricity exports, imports and net exports by partner, 2025–2050, TWh.

11.6 Hourly prices in 2035

Figure 50 compares three price-duration curves for 2035 in West Denmark: the published hourly price, the published price averaged within the model's hour states, and the model. The middle curve isolates what clustering does to the published prices before the model does anything: it takes 232 DKK/MWh off the mean of the hundred most expensive hours. The published mean in 2035 is 445 DKK/MWh and the model mean 433.

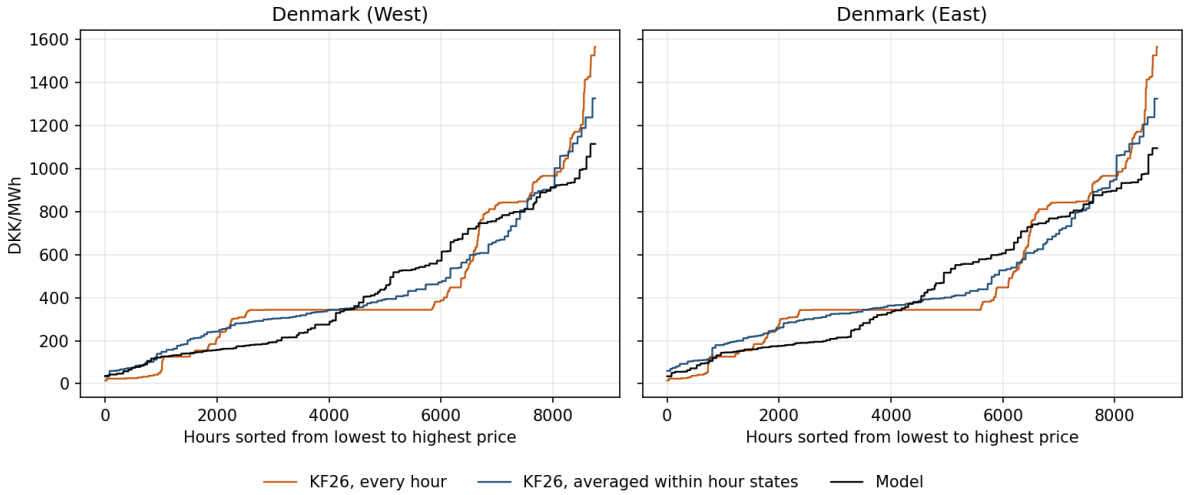


Figure 50: Price-duration curves, 2035, DKK/MWh: published hourly prices, published prices averaged within the model's hour states, and the model.

11.7 Balances in 2035

Figures 51–55 show the 2035 balances state by state, with the states sorted by the electricity price and each state as wide as the hours it stands for. Supply is above the axis and demand below. The electricity balances show which plants produce at which price, where the electricity goes, and how trade closes the balance. The heat balances show the four markets, with electric heaters, CHP, boilers and storage. Appendix J draws the same balances in calendar order.

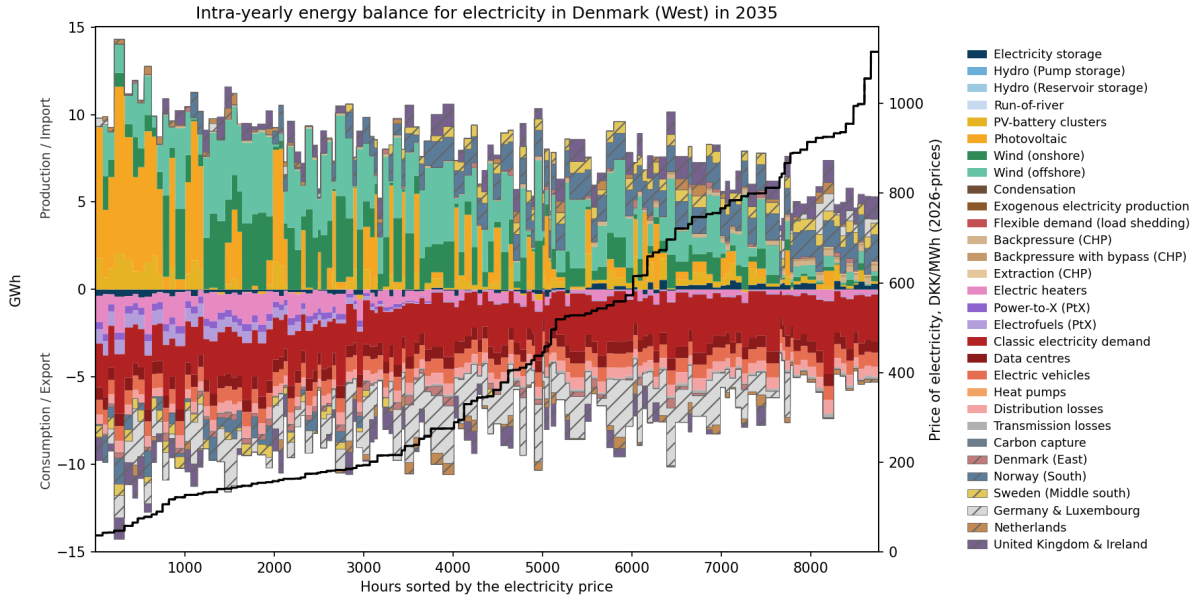


Figure 51: Electricity balance, West Denmark, 2035, GW. Net flow is hatched in each partner's area colour.

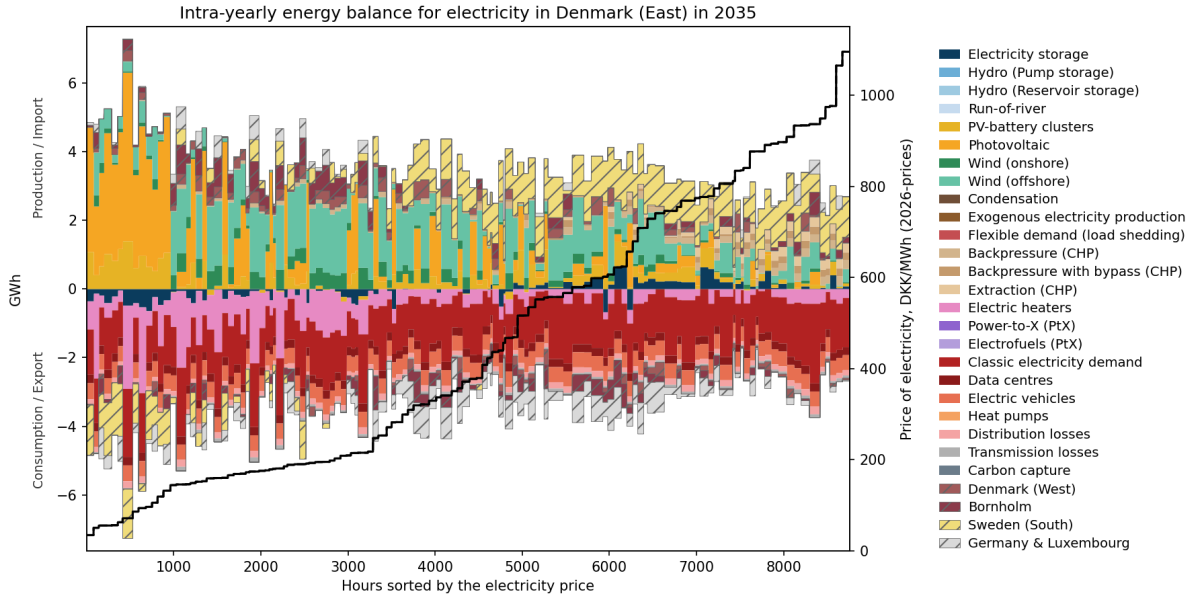


Figure 52: Electricity balance, East Denmark, 2035, GW. Net flow is hatched in each partner's area colour.

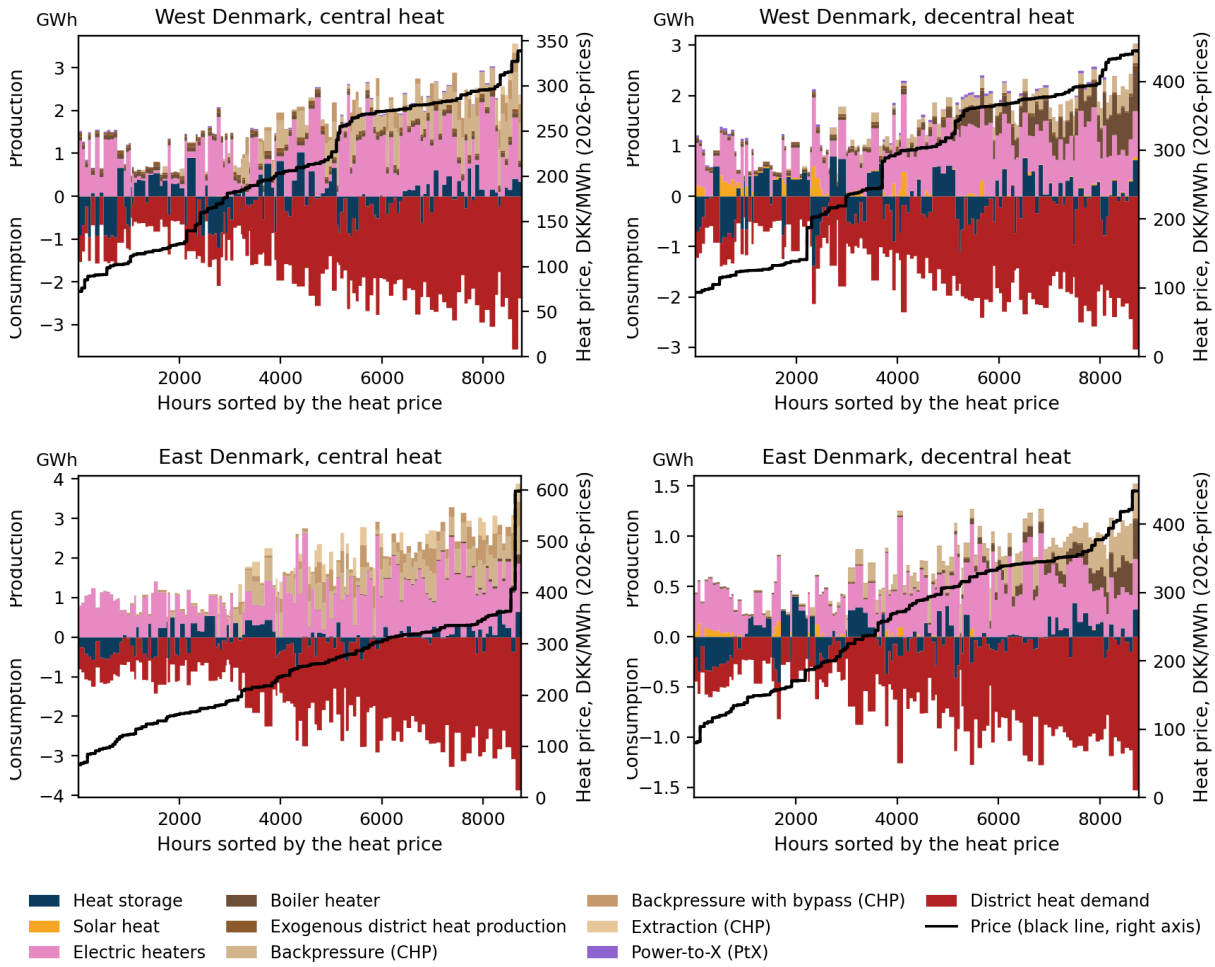


Figure 53: District-heat balances in the four heat markets, 2035, GW. Top: West Denmark central and decentral. Bottom: East Denmark central and decentral. Hours are sorted by the heat price (black line, right axis); the legend below applies to all four panels.

11.8 Trade in 2035

Figures 56 and 57 show trade on each Danish connection in 2035, state by state. Figure 58 draws the congestion rent on the Danish lines. Appendix K shows each connection on its own.

11.9 Europe on the map, 2035

Figures 59–65 draw the European system in 2035: production and flows, the production mix, consumption by use, prices, CO_2 intensity, and production relative to consumption. Appendix L draws 2025 and 2050.

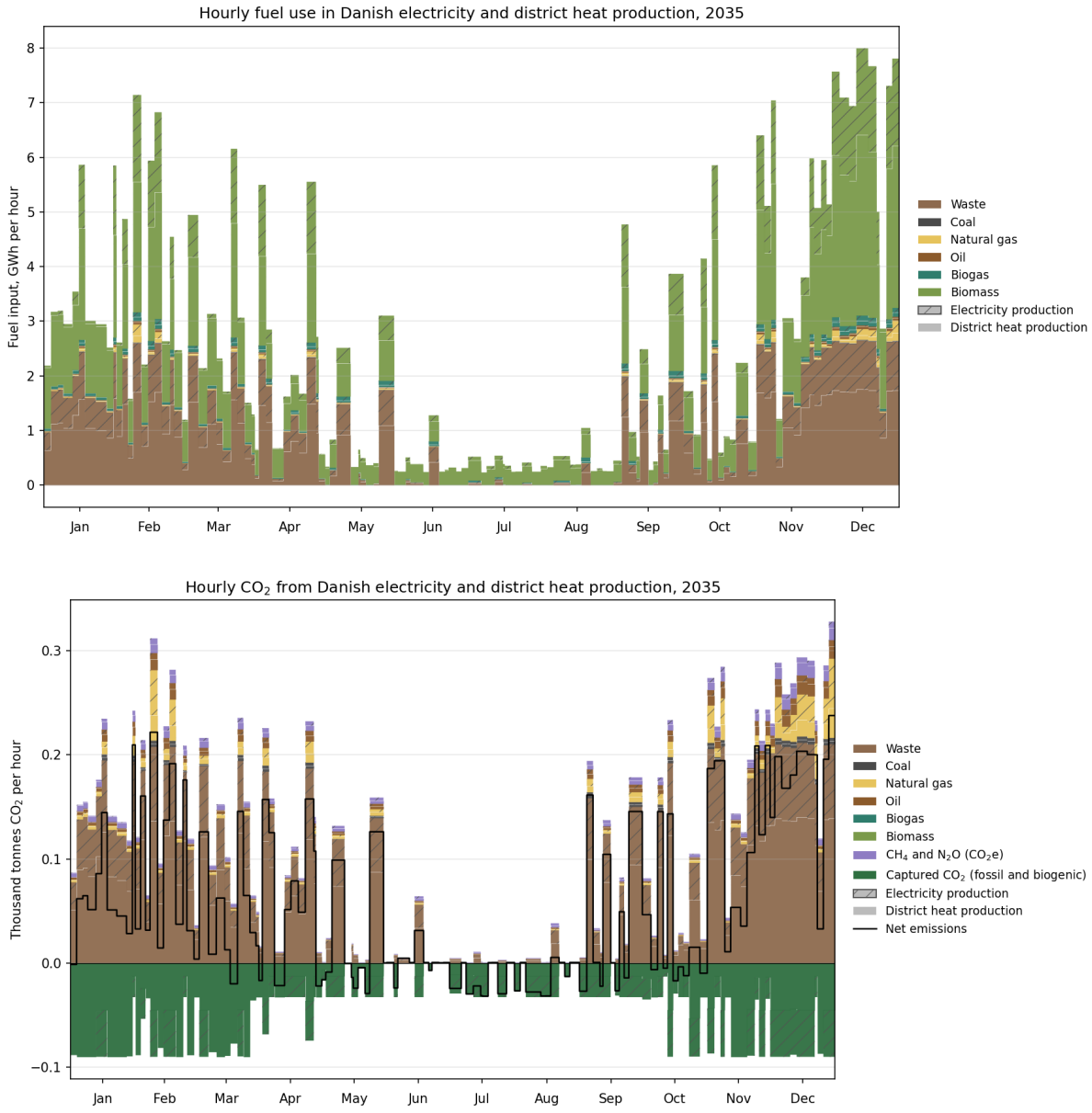


Figure 54: Danish fuel use (top, GW of fuel) and CO_2 emissions (bottom, tonnes per hour) by state, 2035.

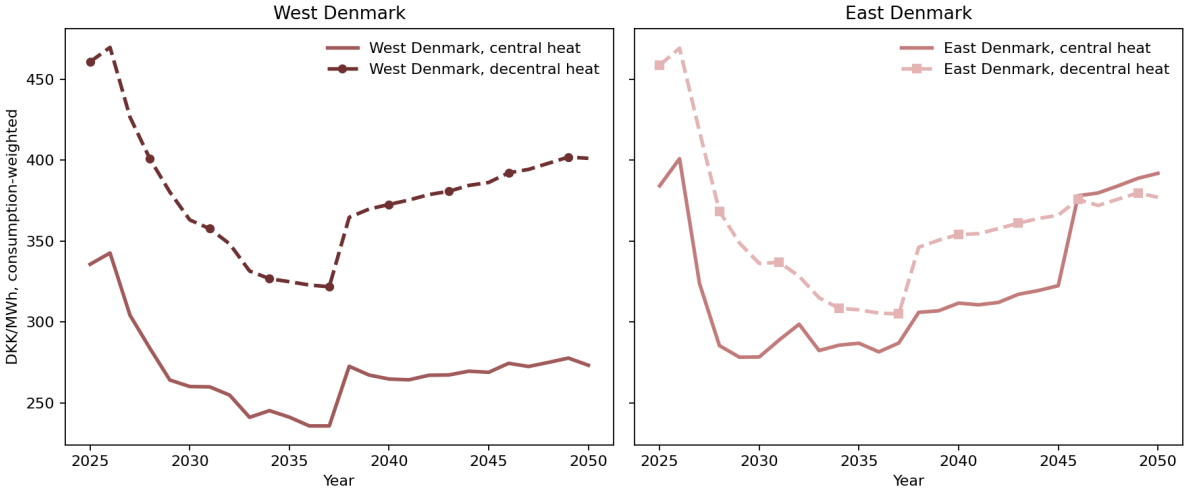


Figure 55: District-heat price indices in the four heat markets, 2025–2050, DKK/MWh.

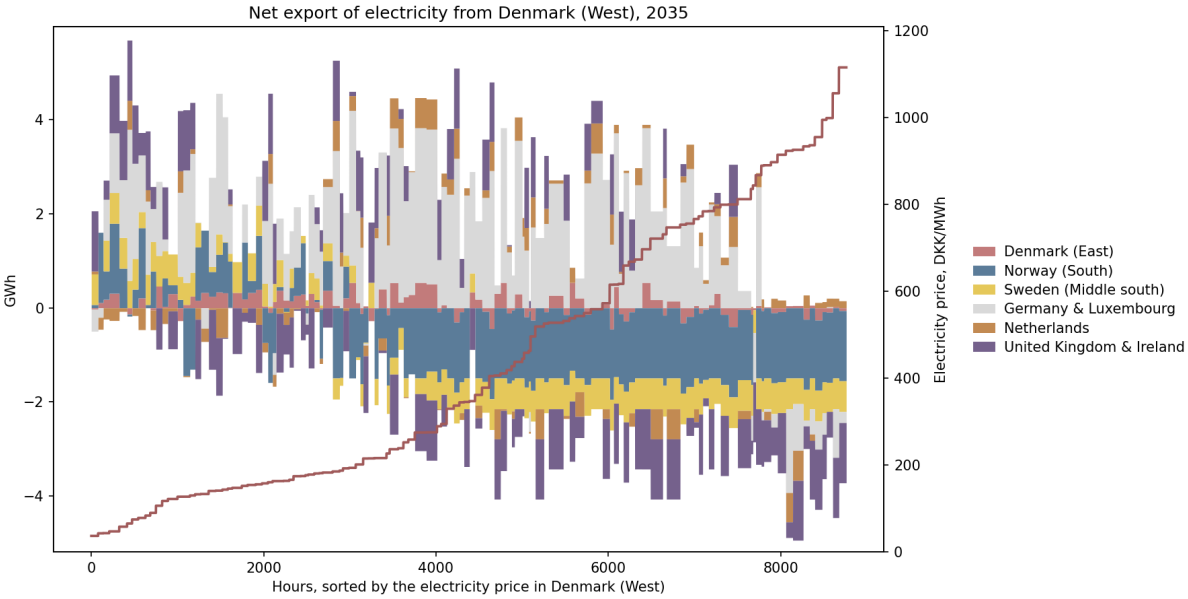


Figure 56: Net exports from West Denmark by connection, 2035, GW.

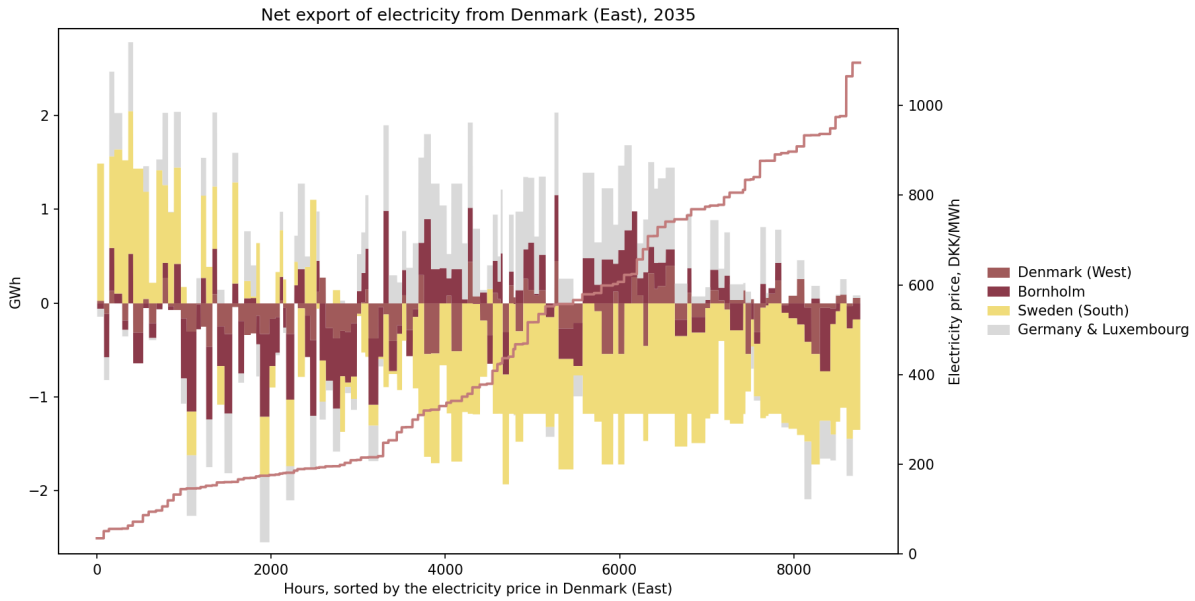


Figure 57: Net exports from East Denmark by connection, 2035, GW.

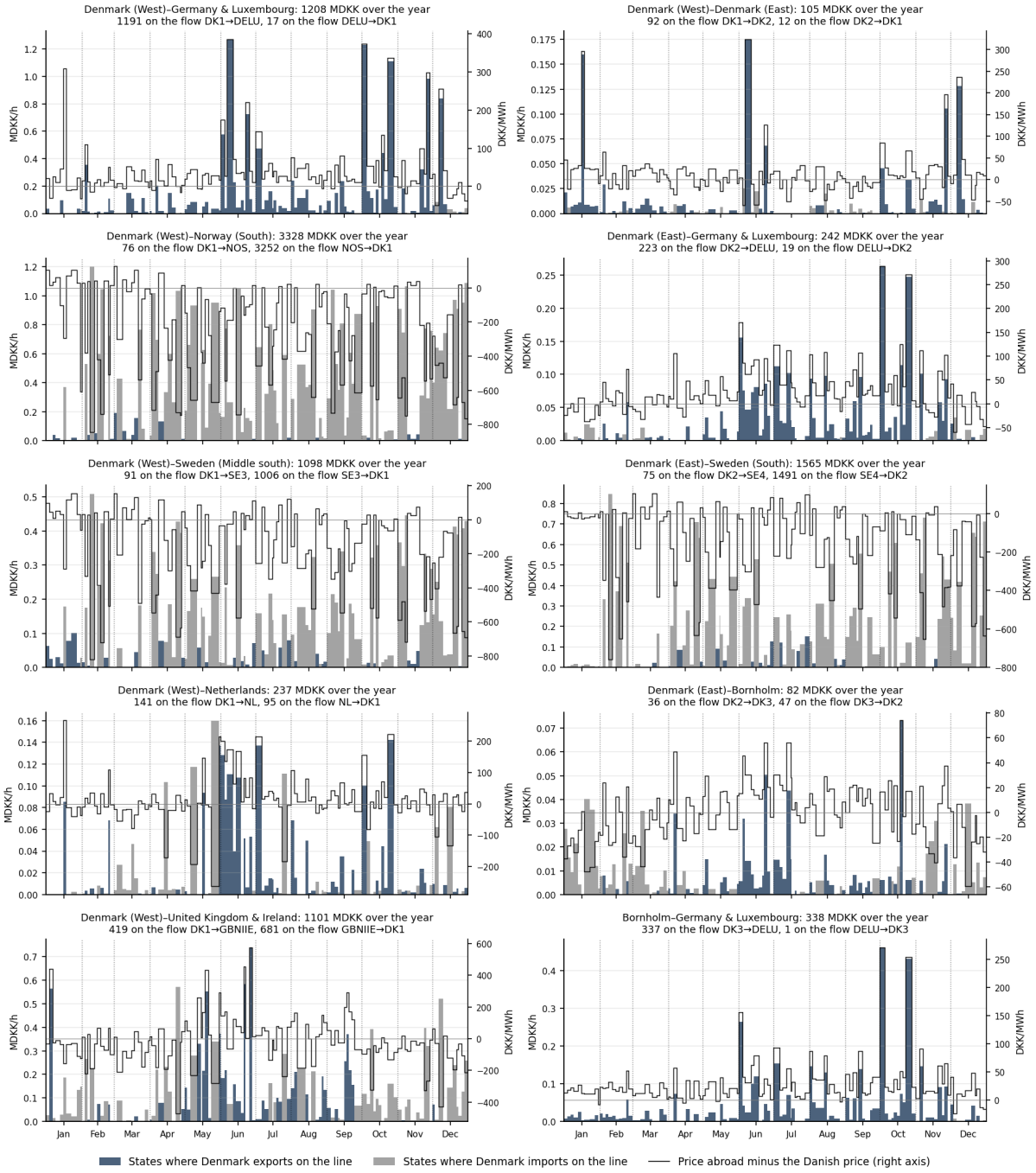


Figure 58: Congestion rent on the Danish lines, 2035, million DKK.

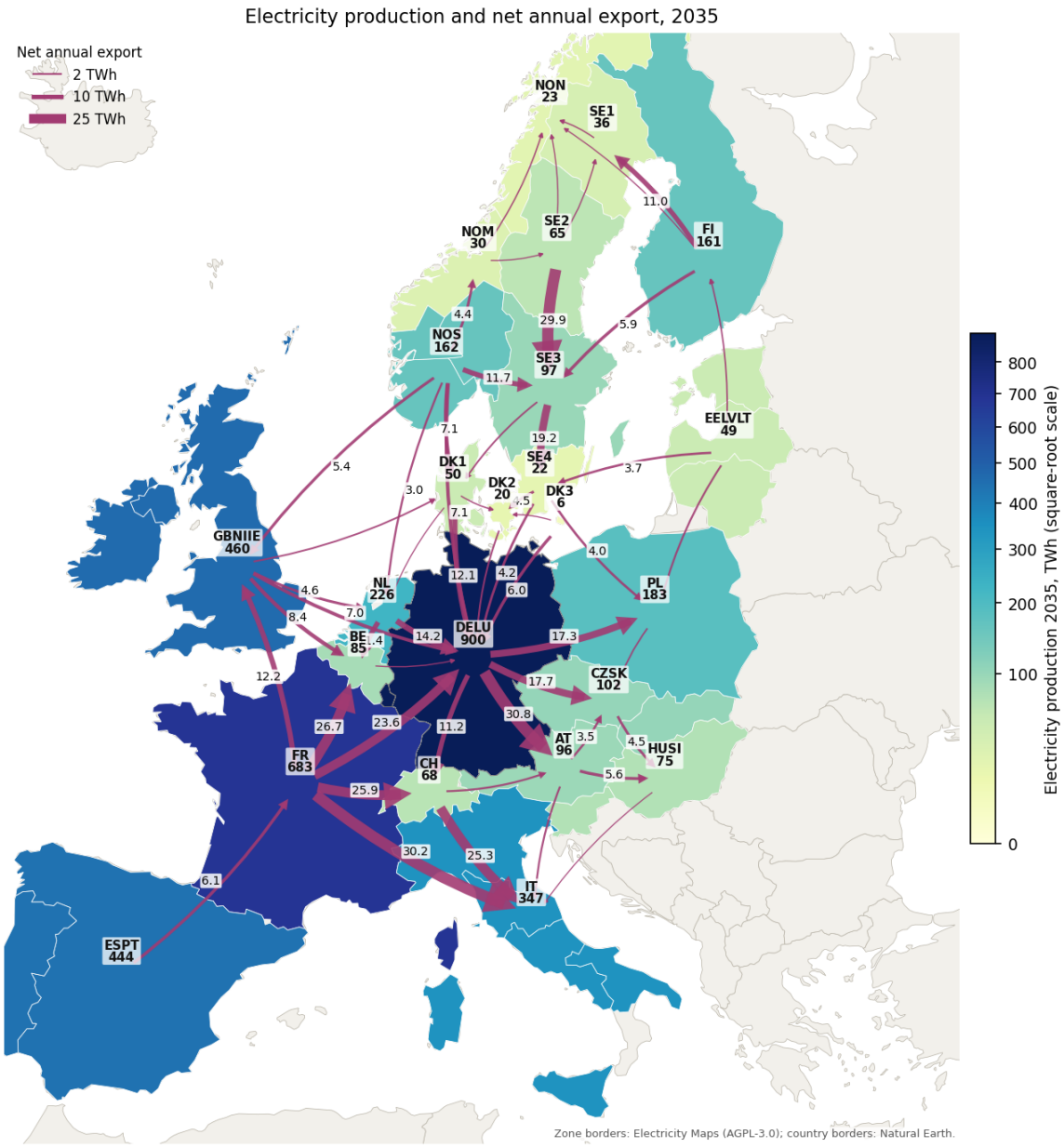


Figure 59: Annual net flows on the lines (TWh) and production by area, 2035. Production includes storage discharge and leaves out the plants inside PV-battery clusters.

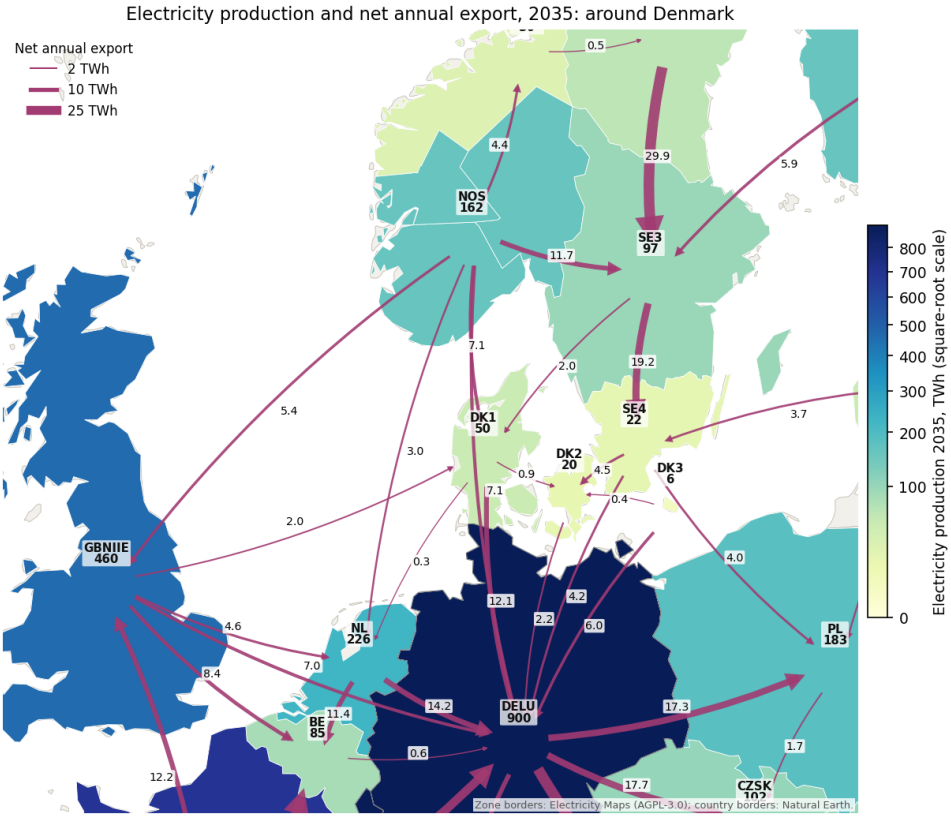


Figure 60: Annual net flows around Denmark, 2035, TWh. Production includes storage discharge.

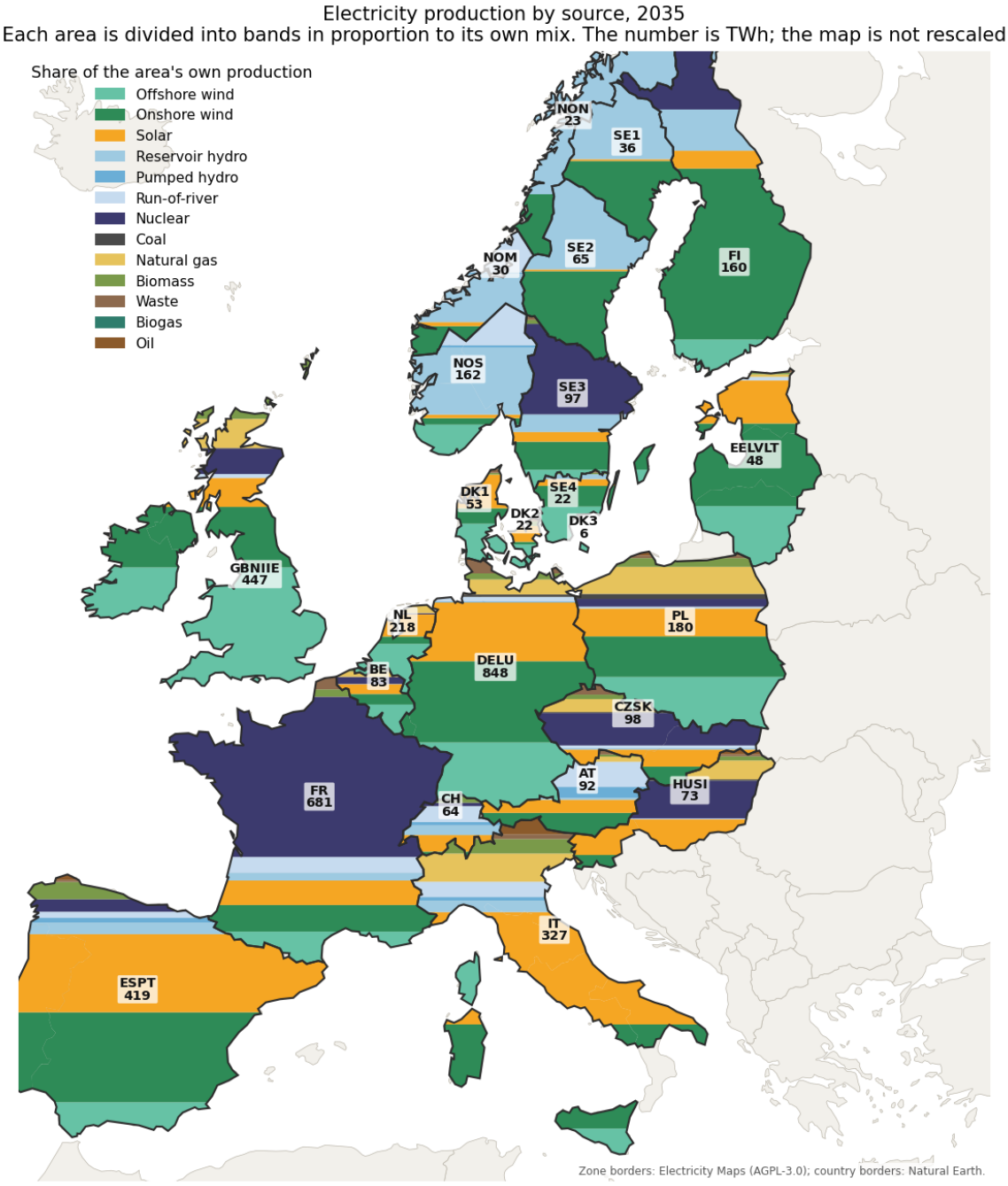


Figure 61: Production mix by area, 2035.

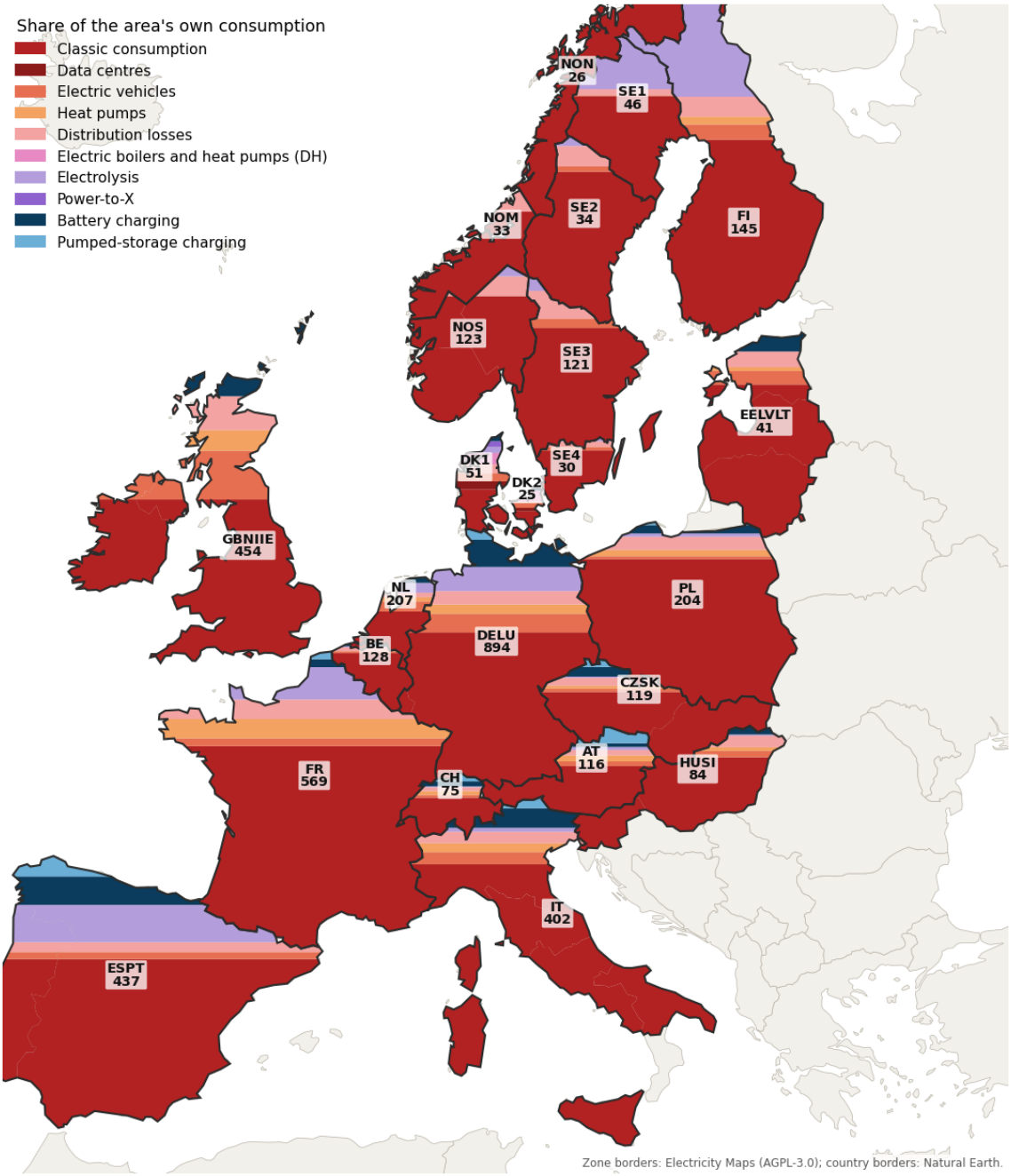


Figure 62: Consumption by use and area, 2035.

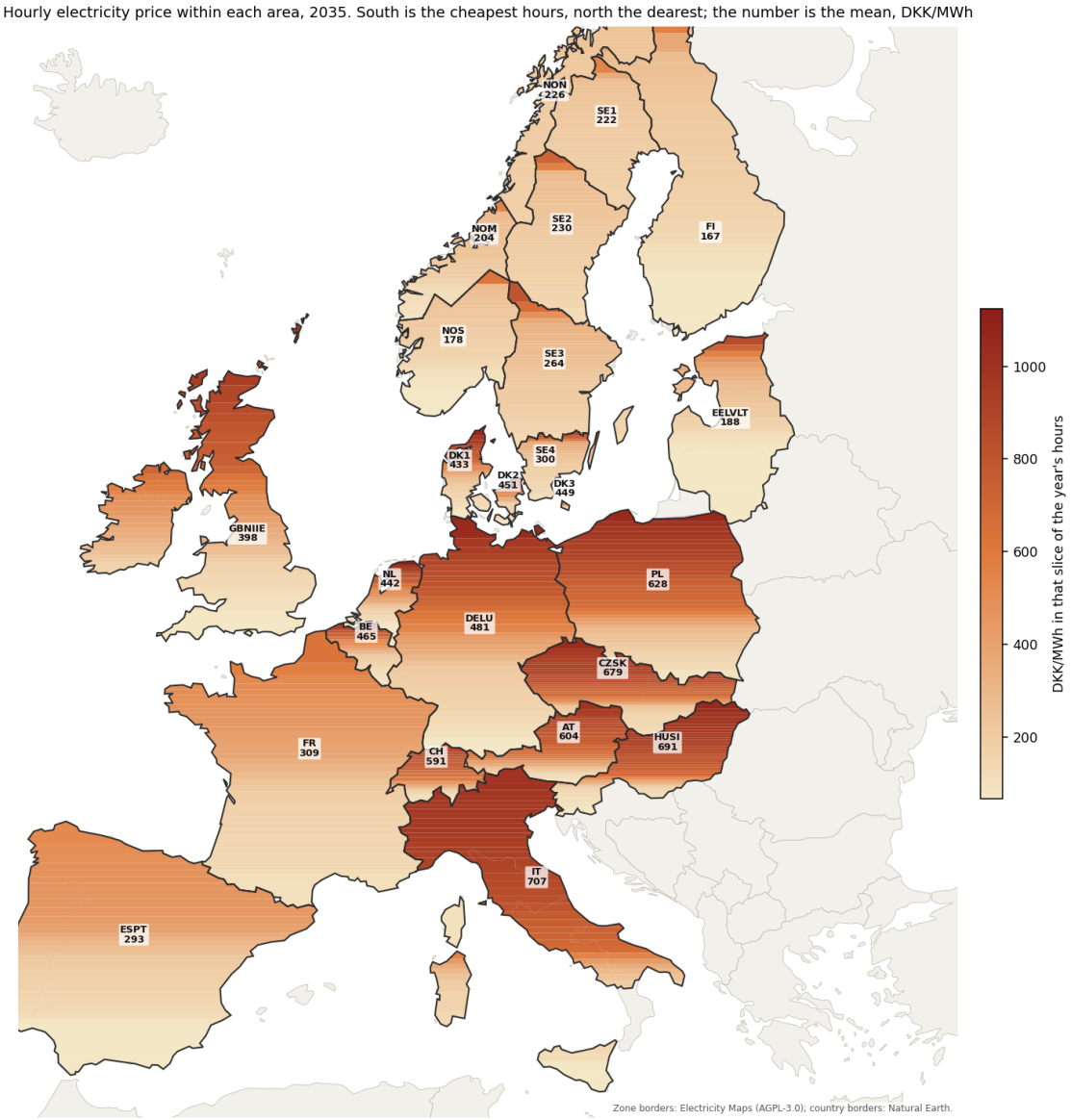


Figure 63: Price-duration curves by area, 2035, DKK/MWh.

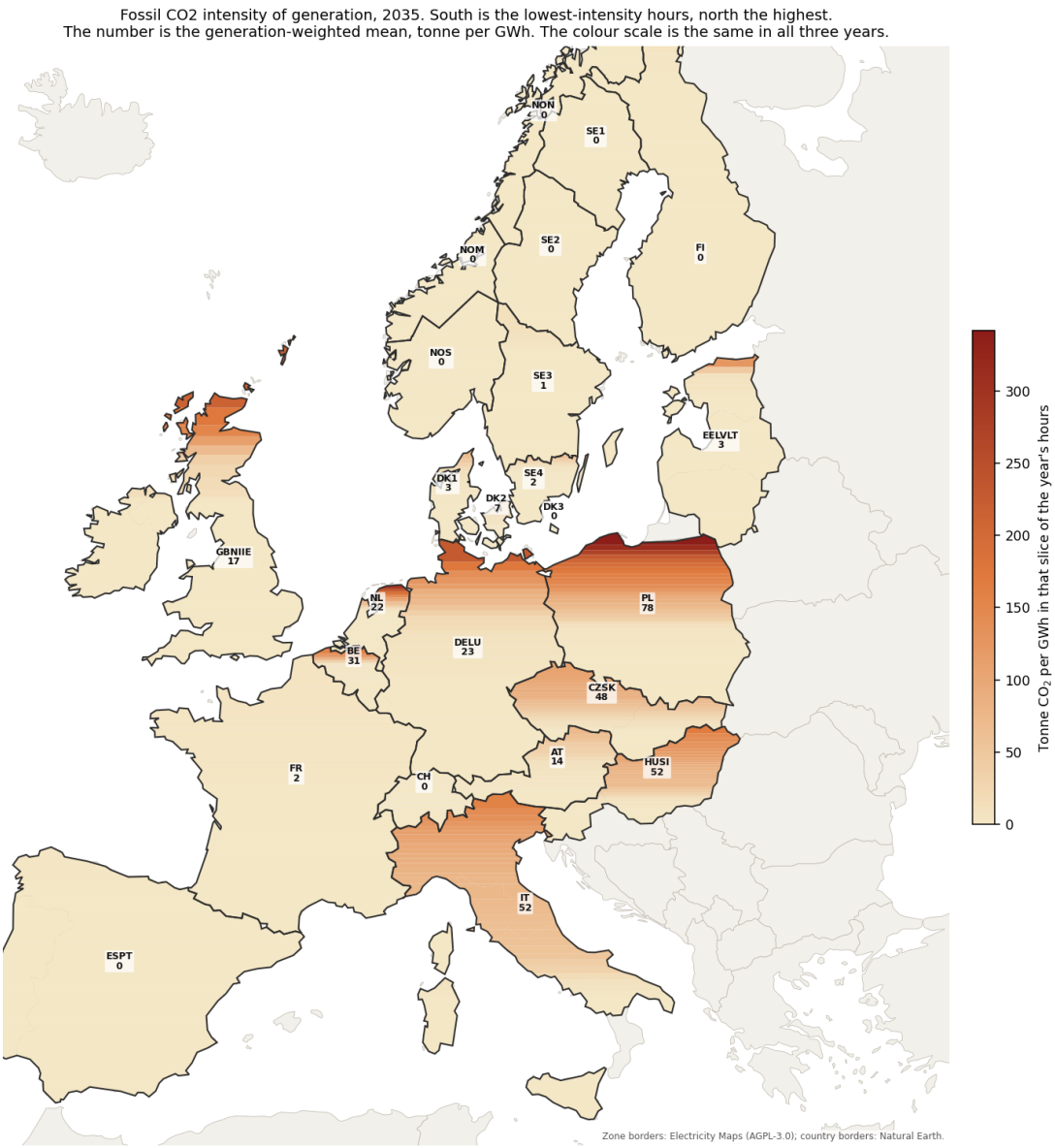


Figure 64: Fossil CO_2 intensity of generation by area, 2035, kg/MWh.

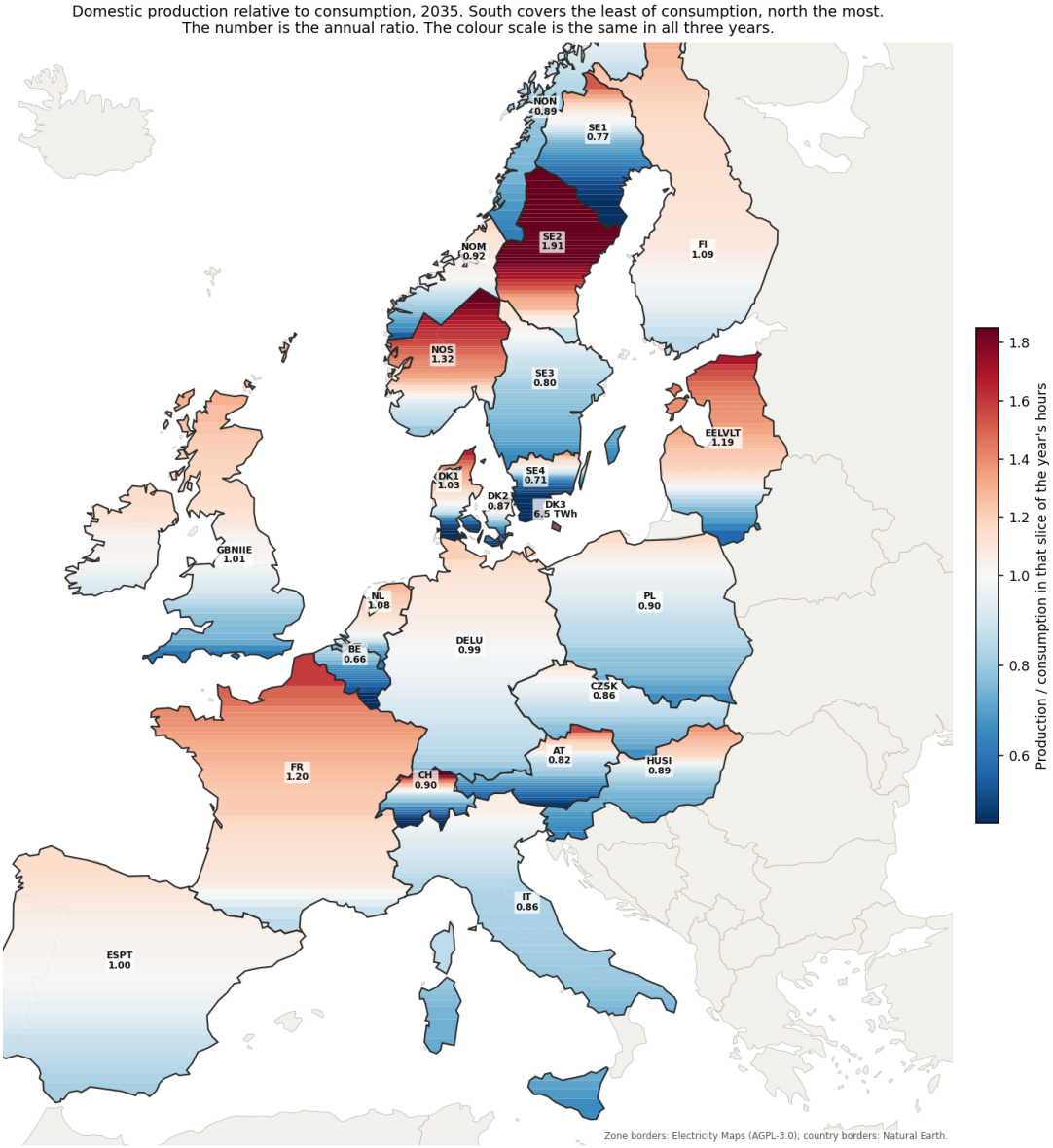


Figure 65: Domestic generation relative to consumption by area, 2035.

11.10 Monetary flows

Figures 66–71 report the Danish monetary account of the baseline: public revenue from taxes and tariffs, what consumers pay, trade income and congestion rent, and producers' revenue, costs and unit profits. Appendix M gives the 2035 account as a table.

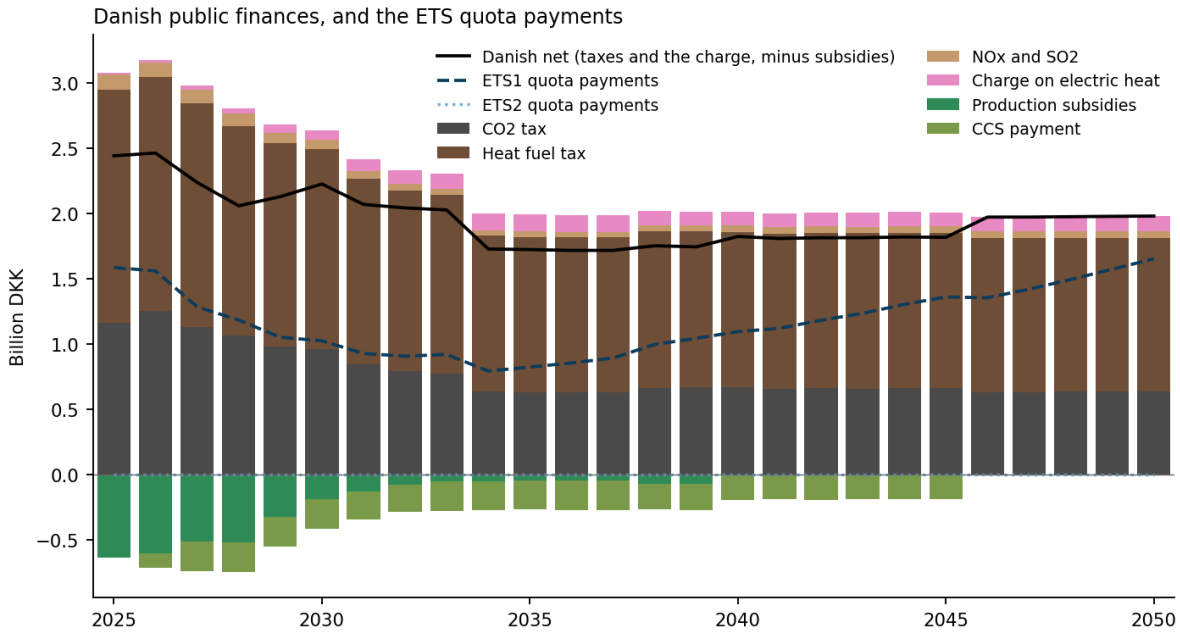


Figure 66: Public revenue from the Danish electricity and heat sector, 2025–2050, billion DKK.

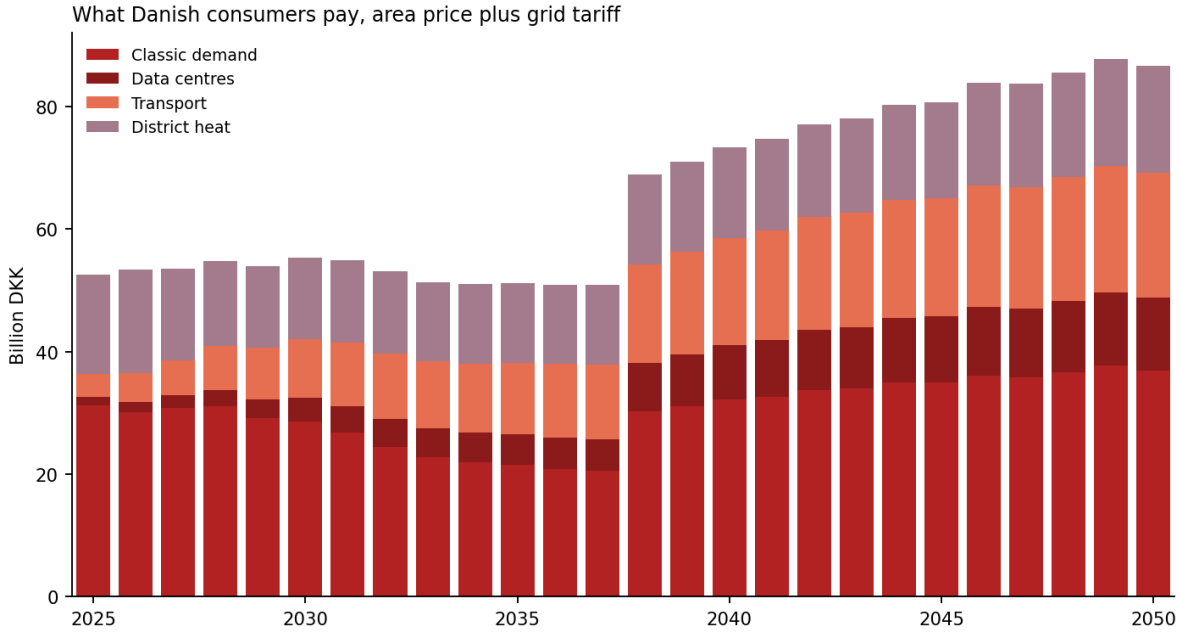


Figure 67: What Danish consumers pay, 2025–2050, billion DKK.

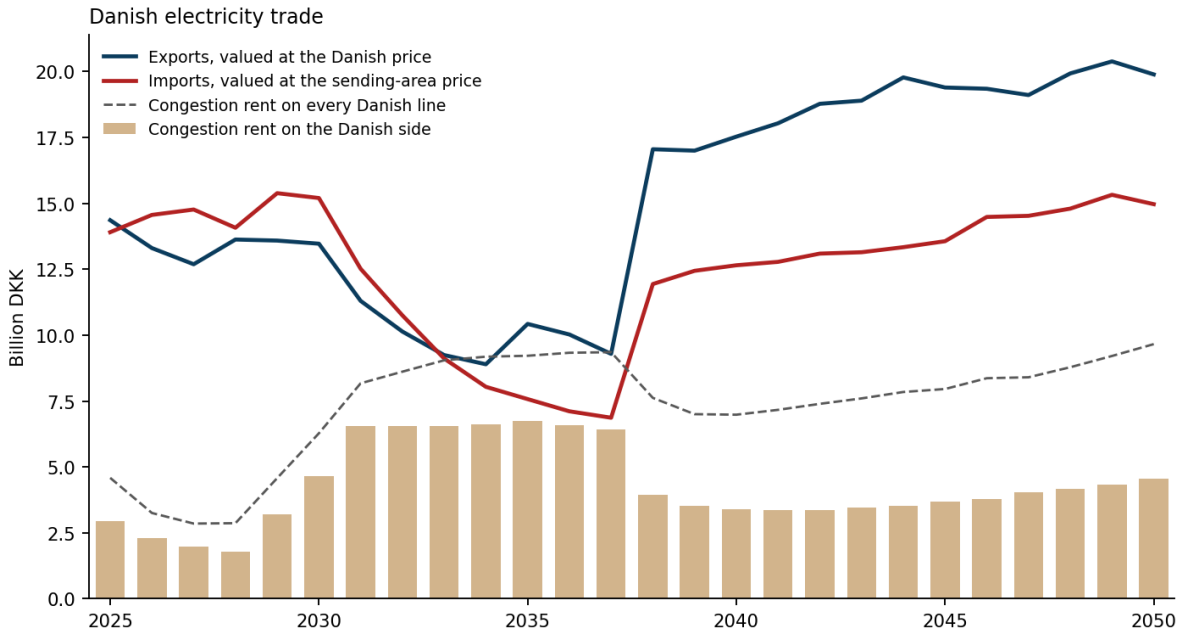


Figure 68: Danish trade income and congestion rent, 2025–2050, billion DKK.

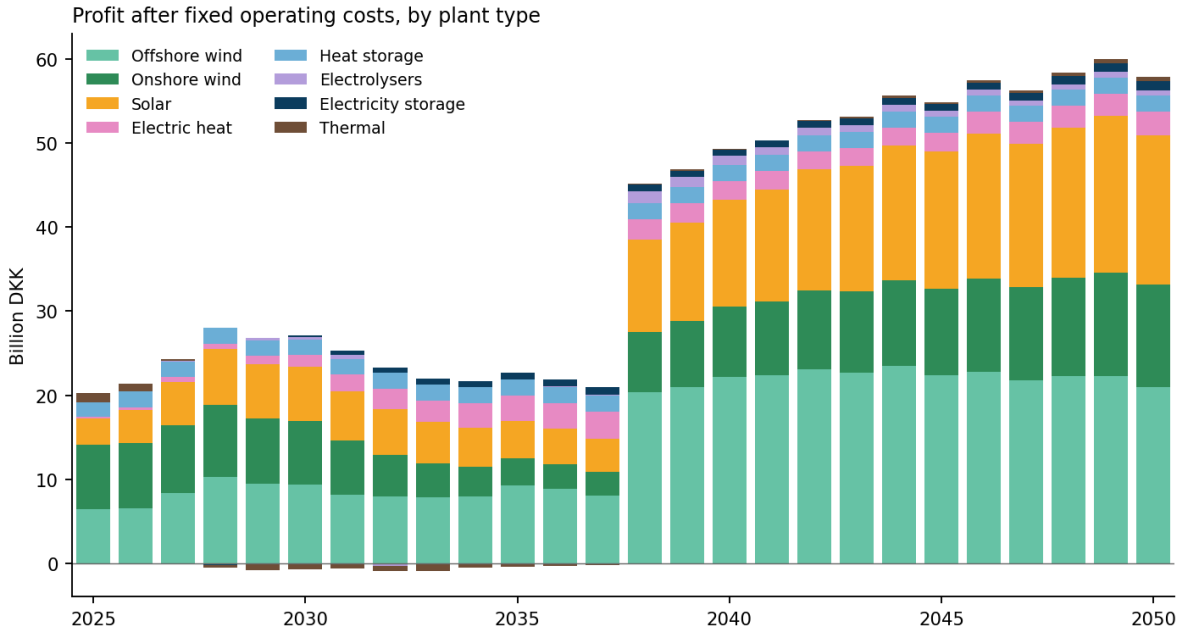


Figure 69: Revenue and costs of Danish plants by plant type, 2025–2050, billion DKK.

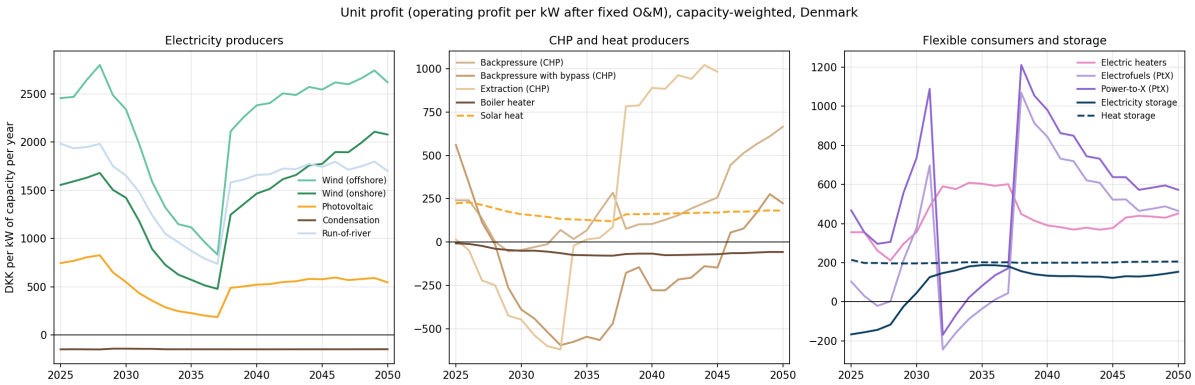


Figure 70: Unit profits $\Pi_{t,i}$ of Danish plants by plant type, 2025–2050, million DKK per GW.

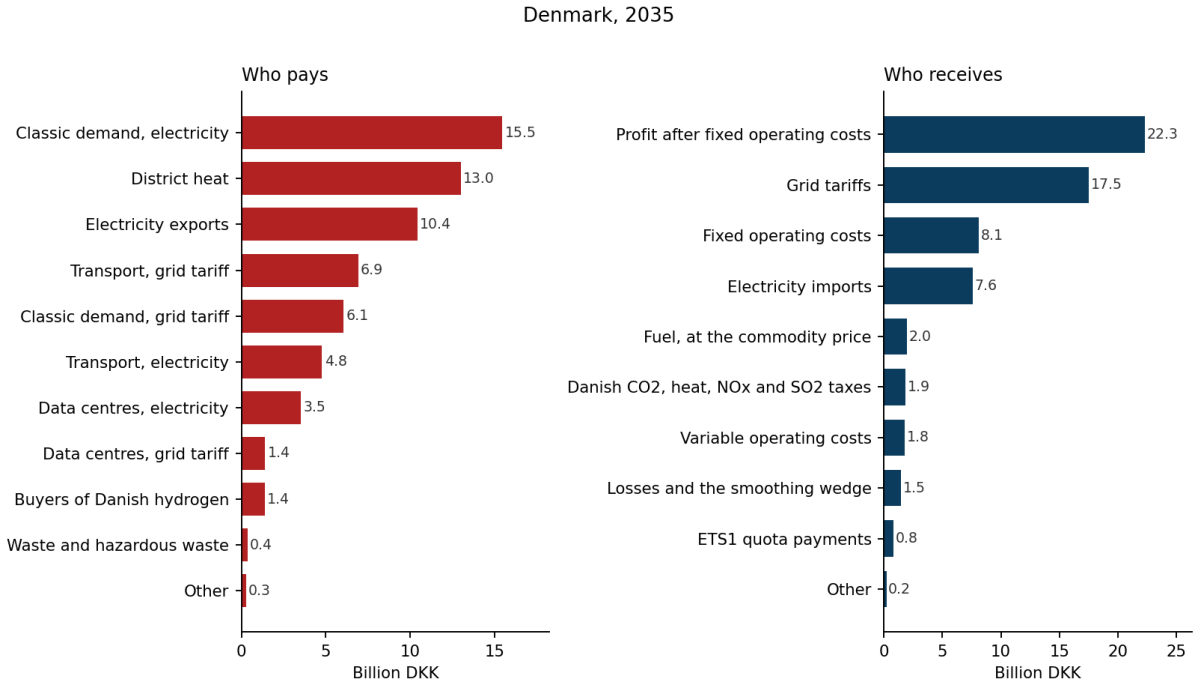


Figure 71: Monetary flows in the Danish electricity and heat sector, 2035, billion DKK.

12 Climate years

This section compares the baseline with versions `climate_2009` and `climate_1995`: the same model, data and outage rates on the weather of 2009 and of 1995. Section 2.7 lists the inputs that differ. In 1995 the electrolyser at the North Sea node also has no minimum load.

What differs in the inputs. Figure 9 compares the inputs: wind and solar capacity factors, Nordic inflow and Danish residual demand. Each year has its own hour states and its own placement of planned outages, so hourly comparisons are made on calendar hours, not on states.

What differs in the results. Figure 72 shows the price path of the three years against the published prices. The West Danish price with the 2009 weather minus the price with the 2008 weather is 93 DKK/MWh in 2035 and 163 DKK/MWh in 2050. With the 1995 weather the difference is 7 DKK/MWh in 2035 and 111 DKK/MWh in 2050; in East Denmark it is 4 and 107 DKK/MWh. Figure 73 compares the price-duration curves, and Figure 74 the Danish

production and trade. Danish net exports with the 1995 weather differ from the baseline by −0.9 TWh in 2035 and −0.1 TWh in 2050.

Between these two years the 1995 path crosses the baseline: the West Danish price with the 1995 weather is lower from 2038 to 2044 and higher from 2045. The 1995 weather makes electricity cheap in France, Spain and Portugal, and Finland, where much of the European electrolysis is located. Once European hydrogen demand starts in 2038, that lowers the hydrogen price (1,111 against 1,456 DKK/MWh in 2038), and the Danish price follows. The 1995 hydrogen demand is the same in 2038 but grows faster from 2039, to 1,575 TWh in 2050 against 1,472 TWh with the 2008 weather (Section 2.7), which lifts the later years.

What it means for reading the baseline. The differences between three weather years are a lower bound on the weather uncertainty around every result: three years do not span the range. Results that depend on the tail of the price distribution move most. Hydrogen output and prices at the North Sea node also reflect the missing minimum load in 1995.

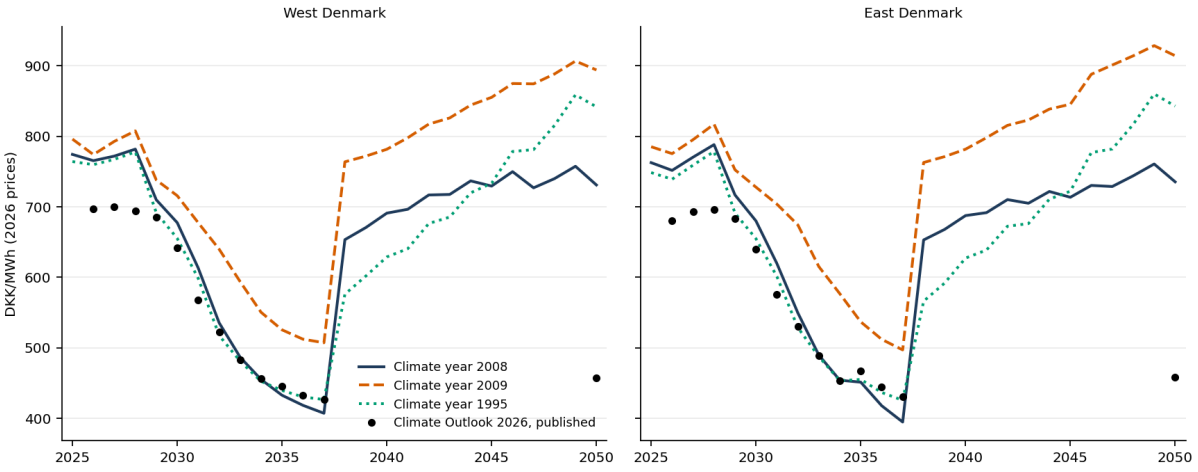


Figure 72: Time-weighted average electricity price, 2025–2050, DKK/MWh. Left: West Denmark. Right: East Denmark. Climate years 2008 (dark blue, solid), 2009 (orange, dashed) and 1995 (green, dotted). Black dots are the published Climate Outlook 2026 prices.

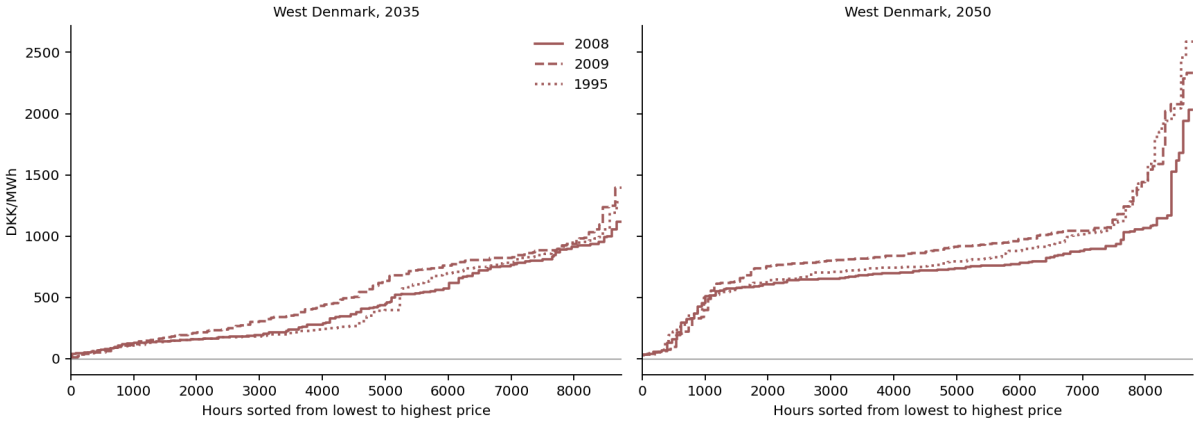


Figure 73: Price-duration curves, West Denmark, 2035 and 2050, climate years 2008 (solid), 2009 (dashed) and 1995 (dotted), DKK/MWh.

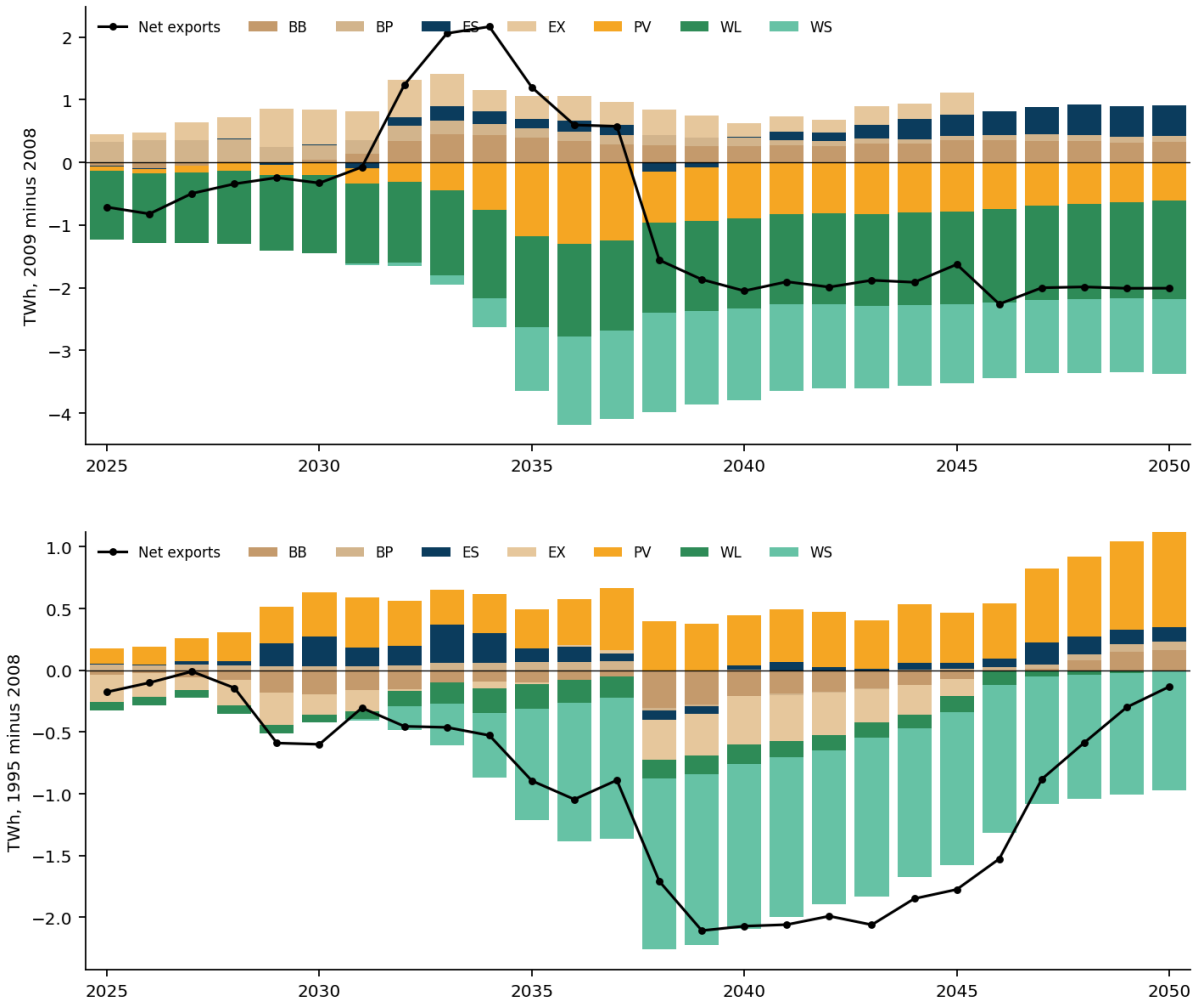


Figure 74: Danish production by plant type and net exports, 2025–2050, TWh. Upper panel: climate year 2009 minus 2008. Lower panel: climate year 1995 minus 2008.

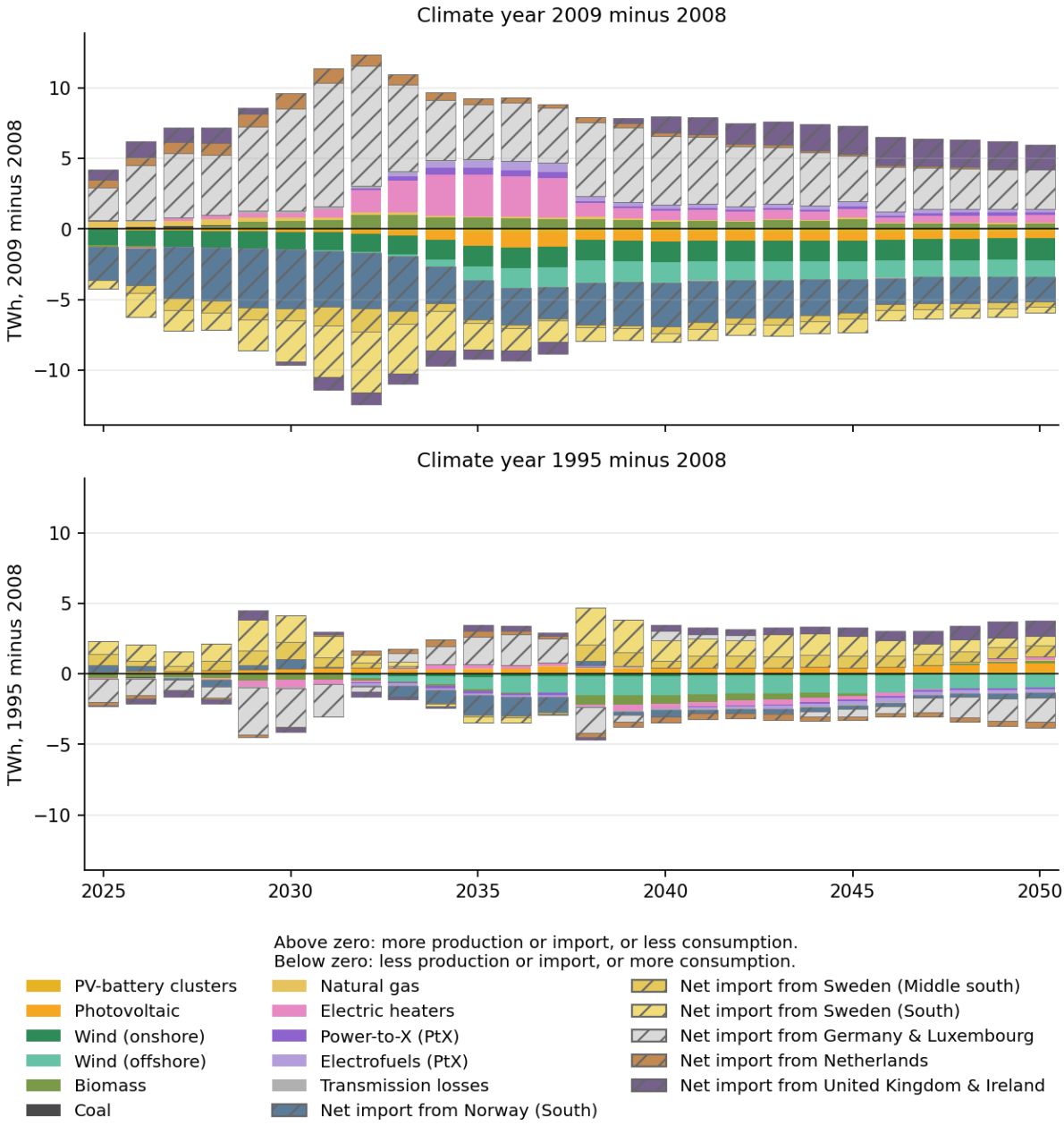


Figure 75: Danish electricity balance by fuel, 2025–2050, TWh: the change in each item, with fuels aggregated as in the fuel balances (Appendix H). Upper panel: climate year 2009 minus 2008. Lower panel: climate year 1995 minus 2008. Above zero is more production or import, or less consumption; below zero the reverse, so each bar sums to zero. Net import is hatched in each partner's area colour.

13 Two further versions of the baseline

Each comparison in this section changes one thing relative to the baseline.

13.1 Planned outages placed versus spread flat

Version `climate_2008_flatoutage` is the first solve of Section 9.2: the same data, with each planned rate spread over every state. Comparing it with the baseline isolates the effect of placing maintenance. Placing maintenance in the cheap hours makes more capacity available in the expensive hours. In the baseline the annual West Danish price differs by at most 6 DKK/MWh between the two versions. Figure 76 shows the difference in prices and capacity by month.

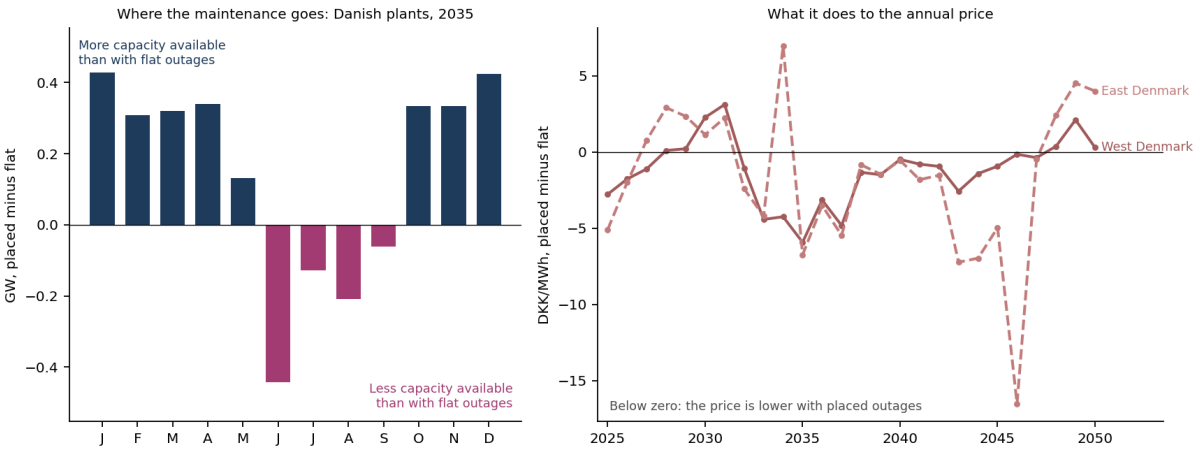


Figure 76: What placing maintenance does, climate year 2008: the baseline (placed planned outages) minus the first solve (the same planned rates spread flat). Left: Danish plant capacity available, by month, 2035, GW. Placing moves about 0.3–0.4 GW of maintenance out of October–April and into the summer, above all June. Right: time-weighted annual price, West and East Denmark, DKK/MWh. Below zero the price is lower with placed outages. The difference is a few DKK/MWh in most years and at most 2.3 percent of the price (East Denmark, 2046).

13.2 The aggregated geography

Version `climate_2008` with thirteen areas folds Energiø Bornholm into `DK2`, and the North Sea node and the remaining continental areas into `ROW` (Section 2.3). It solves much faster and is the place to test a shock. Figure 77 compares the Danish prices of the two geographies. In the baseline the West Danish price with thirteen areas differs from the twenty-five-area price by −5 DKK/MWh in 2035 and −27 DKK/MWh in 2050.

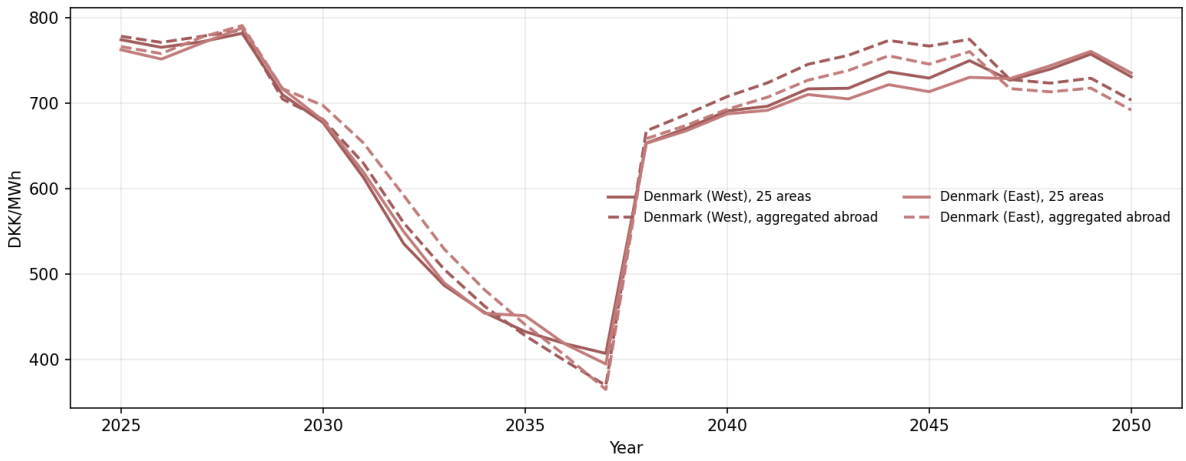


Figure 77: Time-weighted average electricity price in West and East Denmark, twenty-five areas (solid) and thirteen areas (dashed), 2025–2050, DKK/MWh.

Limits and plans

14 What the model leaves out

The omissions below are properties of the equations or the inputs, and they hold in every solve. Each moves a result in a direction that can be named. Section 15 describes extensions that would remove them.

Capacity follows the projection. A shock that raises prices does not bring new plants in, unless the shock adds them (Section 10.5). The price effect that entry would compete away stays in the price.

No start-up costs or ramp rates. A thermal plant has no start-up cost, no minimum up or down time and no ramp rate, and CHP plants have no minimum generation. Only electric heaters and electrolysers can have a minimum load (Sections 3.13 and 3.14). The model prices energy and understates the value of moving quickly (Section 15.10).

Energy is the only product, and each area is one node. There are no reserve or balancing markets, and congestion inside an area is free (Section 6).

No heat market abroad. Foreign thermal plants follow the electricity price where a physical CHP unit would be tied to a heat load (Section 3.7).

Outages are expected values. Unplanned outages remove the expected capacity in every state. The model does not draw failures, so a state in which several large units fail together is not represented, and the tail of the price distribution is softer than it would be.

Hours are clustered. Clustering replaces an extreme hour by the mean of its state, so the top of the price distribution is softer than in the hourly data (Section 2.6). Three climate years are reported; they do not span the range of weather.

Storage has no neighbour in clock time. The continuation value and the penalty outside the feasible range stand in for the chronological stock equation (Section 3.12.4). Short-duration storage is where this is weakest.

Foreign vehicle-to-grid is large and always available. The foreign fleets reach about 715 GW of discharge capacity in 2050 and are assumed always plugged in (Section 3.12.3). This makes foreign storage very large and very flexible, which flattens foreign prices and, through trade, Danish prices. The assumption is under review.

European hydrogen demand from 2038. The inputs require European hydrogen demand to be met from 2038, and the model meets it with electrolysis. This lifts electricity prices across Europe above the published KF26 prices (Section 11.4).

15 Projects

15.1 A chronological version

This release solves only the version with 120 clustered hour states. A fully chronological version, with the 8,760 hours of each year in order and solved one year at a time, is planned for a future update. It removes the approximation in the storage equations and keeps the extreme hours. It can also inform the clustering: the endogenous price variation of the chronological solution could be used to choose which hours share a state.

15.2 Endogenous investment in generating capacity

Generating capacity follows the projection and does not respond to prices, so every result is a short-run result. For a large shock this biases the answer in a known direction: the price effect that entry would compete away stays in the price. Figure 70 shows the unit profits an entry margin would act on.

A working extension exists. Vestergaard and Carlsen [2026] add an investment margin for solar, onshore wind and electricity storage, with capacity chosen against the model's own price path. Applied to a halving of transmission capacity, a substantial part of the price effect is absorbed by entry, with storage supplying the largest share. It is built on a separate vintage of the model and is not part of this release. The intention is to publish it on the KF26 data in a future update.

15.3 Coupling to the CGE model

The model runs on its own, against demand, fuel prices, taxes and capacities from the outlook. Coupling it to the GreenREFORM CGE model, so that those paths respond to the power prices, is the next step (Section 8).

15.4 Vehicle-to-grid

The foreign vehicle-to-grid fleets will get hourly driving and availability patterns and TYNDP battery and charger sizes, with an analysis of what the representation does to prices, published alongside a later version of the model.

15.5 Stochastic unplanned outages

Unplanned outages are an expected loss in every state. A third solve could draw failures and measure their effect on prices and on the value of flexible capacity, which is close to a balancing question.

15.6 Disaggregated district-heating areas

The database splits the district heat of each Danish electricity area into a central and a decentral market (Section 2.3). In 2035 the model still produces less CHP heat and more electric heat than the projection (Section 11.1). Whether a finer grouping, for example by the technology that supplies the network, would close more of the gap is open.

15.7 Grid costs and tariffs

Tariffs are exogenous. Endogenous distribution costs and losses, which would let tariffs respond to how hard the grid is used, and a fuller treatment of the electricity tax are relevant extensions.

15.8 Transmission capacity

Every line trades at nameplate times availability. Real system operators withhold part of the capacity, especially when prices are high; the EU requires at least 70 per cent of cross-zonal capacity to be offered. A derating that binds only when the system is tight is a data setting (an hourly profile $\gamma^{X}_{h,v(l)}$). What is missing is a defensible rule for how much to withhold, and when.

A larger question is whether to move from net transfer capacities to a flow-based representation, as European and Nordic capacity allocation is doing. With net transfer capacities, each line is constrained on its own, so the model can treat as feasible a combination of flows the network cannot carry at once. A flow-based representation needs transfer distribution factors and margins for each critical network element, which are not in the Ramses inputs and are not published to 2050. Until then the model gives an upper bound on how much trade can relieve a tight hour.

15.9 A design-days approach with uncertainty

One extension replaces the clustered year with four seasons, week types within each season, days within each week type, and intraday blocks (for example night, morning, midday and evening). Seasons, days and blocks are in chronological order. Weeks are archetypes, covering the extremes and some average states, with known transition probabilities. This keeps the daily order that batteries trade on.

15.10 Start-up costs, minimum load and ramping

A thermal plant faces the same cost per MWh whether it runs for a week or covers one expensive state. The smoothed dispatch softens the step, and an aggregate stands for many units, but neither covers timing, which is what a start-up cost is about. Three extensions are possible, in increasing order of ambition:

1. give inflexible plants a wide smoothing band, as a reduced form for adjustment costs;
2. solve a chronological version with ramp constraints and use its capacity factors to bound those of the clustered model;
3. represent commitment directly, which needs integer variables or a continuous relaxation in the chronological version.

Until then, results that depend on fast response, such as the value of an interconnector to a hydro system, understate what that flexibility is worth.

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A Changes since the KF25 version

This appendix is for users of the version of the model published for Climate Outlook 2025 [Berg and Shine, 2026] (the KF25 version). It lists every change since that publication, in data, geography, model equations, solution, and outputs and use. Each line states the change and points to the section that describes the model as it is. Ideas that were tried and not kept are not listed.

Data.

- **Inputs.** The Danish Energy Agency's inputs for Climate Outlook 2026 replace those for 2025; a missing KF26 series falls back on the KF25 one (Section 2.1).
- **Horizon.** 2025–2050 (KF25: 2020–2050); series given for some years only are interpolated, among them heat demand for 2038–2049 (Section 2.1).
- **Price base.** All monetary values are in fixed 2026 prices; the supplementary fuel prices are revalued from 2025 prices (Section 2.1).
- **Full-load hours.** Annual capacity factors are set from the Agency's full-load hours (Section 2.5.1).
- **Inflow.** Annual energy is set from the Agency's inflow adjustments where they are positive (Section 2.5.2).
- **Climate years.** Databases can be built for other weather years, with the 2008 adjustments carried over in proportion; 2009 and 1995 are reported beside 2008 (Section 2.7).
- **Outage rates.** Plants and interconnectors have planned and unplanned outage rates from the Agency's technology table; KF25 had none (Section 2.5.3).
- **Line derating.** The KF26 derating of five Danish interconnectors is carried as line unavailability, and trade capacity is nameplate (Section 2.5.3).
- **Hydrogen pipeline.** 2.7 GW each way between the Danish and European hydrogen markets from 2032, replacing a placeholder of 0.01 MW (Section 2.8).
- **Heat storage in 2050.** Danish heat storage operates throughout 2050; the input decommissioned it on 1 January (Section 2.8).
- **Electrolyser minimum load.** The Ramses minimum-load factors for EF and PX plants, 10 per cent up to 2030 and 2 per cent from 2040; none for the North Sea node electrolyser in climate year 1995 (Section 2.8).
- **Vehicle-to-grid abroad.** The TYNDP 2024 electric-vehicle fleets of seventeen foreign areas from 2037 (Sections 2.8 and 3.12.3).
- **European hydrogen demand.** The KF26 inputs give a European demand that must be met from 2038, by climate year from 2039 (Sections 7.3 and 2.7).
- **Fuel-price and operating-cost adjustments.** The Ramses area-specific factors on fuel prices and variable operating costs enter the plant costs (Section 3.3).
- **Emission prices outside the ETS.** Emissions outside EU-ETS1 pay the EU-ETS2 price plus the Danish rate (Section 3.3).
- **Charge on electric heat.** In KF25, electric heaters paid one charge of about 240 DKK/MWh, a negative subsidy on the schemes `ElHeatD` and `ElPatronD`; the KF25 database has no separate grid tariff on electricity-using plants, so that charge stood for both tariff and tax. In KF26 the two are separate: the high-voltage grid tariff of about 170 to 200 DKK/MWh and a tax of about 4 or 8 DKK/MWh on the same schemes, together about 175 to 210 DKK/MWh (Section 4.5).
- **Grid tariffs.** Annual tariff levels by consumer type, with hourly shapes by area, voltage level and direction on the 2018 calendar; the injection tariff is zero (Section 4.5).
- **Hour clustering.** The hourly tariff shapes are clustering features with half weight (Section 2.6).
- **Flexible demand abroad.** Interruptible demand blocks abroad are included, except those with a marginal cost of 100,000 DKK/MWh or more (Section 3.16).

- **No fixed-settlement plants.** The KF26 inputs put no plant on a fixed settlement price; in KF25, eight plant ids (five back-pressure and three condensing) bid against their contract price (Section 3.1).
- **Other input choices.** LPG is priced as fuel oil, hydrogen production pays no electricity tax, and the Danish grid transport cost is used in every area (Section 2.1).
- **Hydro limits.** Regional limits on hydro generation and reservoir levels are in the database and switched off (Section 3.12.1).

Geography.

- **Twenty-five areas.** The detailed geography has twenty-five electricity areas (KF25: twenty-three), including Hungary and Slovenia as one area and the North Sea node (Section 2.3).
- **Energiø Bornholm.** `DK3` is an offshore hub from 2034, with offshore wind, lines to East Denmark and Germany, and no consumers (Section 2.3).
- **Four heat markets.** West and East Denmark each have a central and a decentral heat market (KF25: one per electricity area) (Section 2.3).

Model equations.

- **Availability.** An availability share $A = (1 - P)(1 - u)$ multiplies the dispatch of every plant type with outages and the capacity of every line (Section 2.5.3).
- **Storage stock.** In the clustered model the flow terms of the stock equation carry no hour weight, for every storage type; KF25 multiplied them by n_h, which overstated how fast a store fills and empties (Section 3.12.4).
- **Storage cost inside the bounds.** $x^{in} = 0.1$ DKK/MWh (KF25: 1) (Section 3.12.1).
- **State-of-charge window.** Storage bounds can be narrowed to a window; vehicle-to-grid uses 0.4–0.6 (Sections 3.12.1 and 3.12.3).
- **Netting.** The absolute values in the netting of storage charge and discharge and of line flows are smoothed (Sections 3.12 and 5).
- **Vehicle-to-grid plants.** A new storage type with availability, driving draw and discharge losses (Section 3.12.3).
- **Minimum load and generation.** Electric heaters and electrolysers have a must-run share d^{min} (Section 3.13); CHP plants have a minimum generation share g^{min}, zero in the baseline (Section 3.8 ff.).
- **Fuel-price adjustment.** A plant-specific term φ in the fuel cost (Section 3.3).
- **Hydrogen markets.** Two annual hydrogen markets with endogenous prices, a smoothed pipeline flow and a European sink; KF25 used one exogenous hydrogen price (Section 7.3).
- **Resource zones.** A general resource-zone market for any number of zones; biogas clears in 2050 (Section 7.1).
- **Carbon capture.** Capture on two biomass CHP units, with an annual target cleared by a price (Sections 3.17 and 7.2).
- **PV-battery clusters.** Solar parks and batteries behind a shared grid connection, each cluster with its own price (Section 3.18).
- **Flexible-demand plants.** Interruptible demand blocks are plants that "produce" by not consuming (Section 3.16).
- **Consumer types.** Danish demand is classic demand, large data centres and road transport (KF25: an elastic third and an inelastic two thirds) (Section 4.4).
- **Nested flexibility.** Separate elasticities for moves within a month and between months (Section 4.1).
- **Delivered price.** Consumers, storage charging and electric heat respond to the price including the grid tariff (Sections 4.2 and 4.5).
- **Price indices.** Indices of the delivered price, wholesale plus tariff, are added (Section 4.6).

- **Signed line flow.** One signed utilization per line replaces two independent directional flows, so equal prices give zero net flow (equation (81)).
- **Plant smoothing.** σ is fitted per plant id within $[30, 300]$ DKK/MWh (KF25: 50 for every plant) (Section 3.2).
- **Line smoothing.** 30 DKK/MWh, and 100 on the lines to `ROW` in the thirteen-area geography (KF25: 50 and 200) (Section 2.4).

Solution.

- **All years in one system.** The baseline is one square system for 2025–2050, accepted when every residual is at most 10^{-6}; KF25 used five closure stages (Section 9.1).
- **Fallbacks.** A failed solve is retried from the interrupted iterate, restored from the last accepted point, or split into smaller blocks of years, without relaxing the model (Section 9.1).
- **Two solves.** Each baseline is solved with flat planned outages, and again with planned outages placed as blocks on the first-solve prices (Section 9.2).
- **Accepted years.** A year counts as solved only when a solve of that year has been accepted (Section 9.3).

Outputs and use.

- **Versions.** The release ships five solved versions, described in `VERSIONS.md` (Sections 1.1 and 10.2).
- **Clustered data only.** The release has the 120-state databases only; KF25 also shipped chronological ones (Section 2.6).
- **Settings and folders.** One settings cell per notebook; scratch in `work\` and output in `results\` (Section 10.3).
- **Shocks.** A catalogue of named shocks, solved in steps (Section 10.4).
- **Adding plants.** Plants that are not in the database can be added with an offset (Section 10.5).
- **Model checks.** The analysis notebook has switches for a residual report and market-clearing diagnostics (Section 10.6).
- **Published outlook.** The release includes the KF26 published-results workbooks used for the comparisons (Sections 10.2 and 11.1).

B Dictionary: from LaTeX to GAMS

The tables below map the notation of this note to the GAMS names. Domains use the GAMS index names: `t` years, `h` hours or clustered states, `id` producers, `cIdx` consumers, `EA`/`HA` electricity/heat areas, `HyArea` hydrogen areas, `Ft` fuel-mix types, `BFt` base fuel types, `hvt` variation types, `line` transmission lines, `rZone` resource zones, `St` subsidy types and `Pt` plant types. `St` has 20 members. A subsidy scheme for one named plant has a neutral label in the released database.

B.1 Sets and mappings

Math	GAMS	Description
t	`t`	Years, 2025–2050
h, k	`h`, `hh`	Hours (8760) or clustered short-run states
i	`id`	Producer ids
c	`cIdx`	Consumer ids
g_E	`EA`, `EAEA`	Electricity areas (price zones)
g_{DH}	`HA`	District heat areas
b	`BFt`	Base fuel types
f	`Ft`	Fuel-mix types (linear combinations of base fuels)
a	`HyArea`	Hydrogen areas, `DK_H2` and `EU_H2`
v	`hvt`	Hourly variation types
l	`line`	Transmission lines
r	`rZone`	Resource zones
s	`prod_sector`	Production sector (Waste / NonWaste)
—	`Pt`	Plant types (CD, BP, BB, EX, BH, ...)
—	`St`	Subsidy types, 20 of them
—	`Dt`	Duration types for storage plants
—	`hyLine`	Hydrogen pipelines
—	`cluster`	PV-battery clusters, each with its own price
z	`ccsZone`	CO_2 capture zones, one in the baseline
θ, w	`tariffArea`, `tariffClass`	Grid tariff areas (`DK1`, `DK2`, `Foreign`) and tariff (voltage) classes
—	`TechType`, `id2TechType`	Technology labels, and the label of producer i
$g(i)$	`id2EA`, `id2HA`	Area of producer i
$f(i)$	`id2Ft`	Fuel type of producer i
$c(i)$	`id2cIdxE`, `id2cIdxH`	Consumer index of producer i
$r(i)$	`id2rZone`	Resource zone of producer i
$\mathcal{R}(i)$	`id2TaxRule`	CHP fuel allocation rule of producer i
$b(r)$	`rZone2BFt`	Base fuel associated with resource zone r
$\mathcal{B}_1$	`bidT1`	Producers on fixed settlement contracts; empty in the KF26 database
—	`DKId`, `DK_EA`	Danish producers / Danish electricity areas
—	`activeId`, `activeEA`	Active (t, i) / (t, g_E) combinations
—	`activeCE`, `activeCH`	Active consumers of electricity / heat
—	`activeLine`, `activeLineEA`	Active lines / directed line-area pairs
—	`EA_dem`	Areas with exogenous yearly consumer demand
—	`cIdx_DCIIA`	Consumers described by the demand system

Math	GAMS	Description
—	VREId, storageId, chargeId	Variable renewable / storage / charging producers
—	CHPId, CHPIdFlex, CHHyId	CHP producers / flexible CHP (BB, EX) / combined hydrogen and heat producers
—	UPId	Producers for which unit profits are computed

B.2 Exogenous parameters

Math	GAMS	Domain	Description / unit
$Q^E_{t,i}$	ECap	t,id	Electricity generating capacity, GW
$Q^{DH}_{t,i}$	HCap	t,id	Heat generating capacity, GW
$Q^H_{t,i}$	HyCap	t,id	Hydrogen generating capacity, GW
$Q^E_{t,c}$	EDCap	t,cIdx	Demand capacity for electricity, GW
$CapF_{t,i}$	capFCap	t,id	Capacity factor, scaled to full-load hours
$CapF^I_{t,i}$	capFInf	t,id	Capacity factor of inflow to reservoirs
$CapF^X_{t,l}$	capFExp, capFImp	t,line	Capacity factor on line, export/import direction
$1 - A_{t,h,i}$	capOut	t,h,id	Unavailable share of plant capacity, $1-(1-p)(1-u)$
$1 - A^X_{t,h,l}$	lineOut	t,h,line	Unavailable share of transmission capacity
$d^{min}_{t,i}$	dMin	t,id	Must-run electricity consumption of EH, EF and PX, share of demand capacity
$g^{min}_{t,i}$	gMin	t,id	Must-run generation of thermal plants, share of available capacity; zero in the baseline
$\varphi_{t,i}$	fuelPriceAdjustment	t,id	Area-specific adjustment to the fuel-mix price, DKK/MWh input
$\gamma_{h,v}$	hvar	h,hvt	Hourly-to-average ratio, mean one
$\mu^{cap}_{t,i,v}$	uHvtCap	t,id,hvt	Weights on base variation profiles, capacity
$\mu^{inf}_{t,i,v}$	uHvtInf	t,id,hvt	Weights on base variation profiles, inflow
$\mu_{h,c}$	uHvtDemE, uHvtDemH	t,cIdx,hvt	Weights on base variation profiles, demand
—	uHvtExp, uHvtImp	t,line,hvt	Weights on base variation profiles, lines
n_h	hWeight	h	Number of full hours represented by state h

Math	GAMS	Domain	Description / unit
$\eta_{t,i}$	Eff	t,id	Conversion efficiency (definition varies by plant type)
$\kappa_{t,i}$	Cm	t,id	Electricity-to-heat ratio (hydrogen-to-heat for PX)
$\xi_{t,i}$	Cv	t,id	Electricity loss from a marginal increase in heat
$v_{t,i}$	VOM	t,id	Variable O&M costs, DKK/MWh
$c_{t,c(i)}$	VOM_charge	t,id	Variable O&M costs of charging, DKK/MWh
$FOM_{t,i}$	FOM	t,id	Fixed O&M costs, million DKK/GW/year
$\zeta_{t,i}$	duration	t,id	Storage capacity over dispatch capacity, hours
$\chi_{t,i}$	chargeSpeed	t,id	Charge-to-discharge capacity ratio
$x_{t,i}^{out}$	parMCOut	t,id	Cost of exceeding storage bounds, DKK/MWh
$x_{t,i}^{in}$	parMCIn	t,id	Cost of adjusting storage within bounds, DKK/MWh
$x_{t,i}^{\Delta}$	parMCSmooth	t,id	Smoothing between the two storage cost regimes
$\sigma_{t,i}$	sigmaID	t,id	Dispatch smoothing parameter, DKK/MWh
$\sigma_{t,i}^{EH}$	sigmaID_EH	t,id	Mode-choice smoothing parameter for BB/EX
$\sigma_{t,l}$	sigmaLine	t,line	Line utilization smoothing parameter
σ^{H}	sigmaHyLine	t,hyLine	Hydrogen-pipeline smoothing, DKK/MWh
$\sigma_{t,c}$	sigmaCE, sigmaCH	t,cIdx	Hourly demand elasticity
$\sigma_{t,c}^{E,t}$	sigmaCEt, sigmaCHt	t,cIdx	Yearly demand elasticity
$\alpha_{f,b}$	fm	Ft,BFt	Fuelmix coefficients
$p_{t,b}$	fp_t	t,BFt	Base fuel prices, DKK/MWh
$\tau_{t,b}^{DH}$	heatTax	t,BFt	Fuel tax on inputs to heat production, DKK/MWh
$\mu_{t,b}^{CO_2}$	CO2prop	t,BFt	CO_2 intensity of base fuel, ton/MWh
$\mu_{t,b}^{SO_2}$	SO2prop	t,BFt	SO_2 intensity of base fuel, kg/MWh
$\tilde{\mu}_{t,i}^{CO_2}$	uCO2e_id	t,id	Plant CO_2e intensity beyond fuelmix, ton/MWh
$\mu_{t,i}^{NO_x}$	uNOx	t,id	NO_x intensity, kg/MWh input
$DS_{t,i}$	Desulp	t,id	Degree of desulfurization
$s_{t,i}^{\text{ETS1}}$	CO2Cap	t,id	Share of emissions covered by EU-ETS1
$\tau_{t}^{\text{ETS-1}}$	taxCO2_ETS	t	EU-ETS price, DKK/ton
$\tau_{t}^{\text{ETS-2}}$	taxCO2_ETS2	t	EU-ETS2 price, DKK/ton

Math	GAMS	Domain	Description / unit
$\tau_t^{CO_2,E}$	taxCO2_E	t	Additional CO_2 tax, ETS electricity, DKK/ton
$\tau_t^{\text{Non-ETS},E}$	taxCO2_xETS_E	t	CO_2 tax, non-ETS electricity, DKK/ton
$\tau_t^{CO_2,DH}$	taxCO2_H	t	Additional CO_2 tax, ETS heat, DKK/ton
$\tau_t^{\text{Non-ETS},DH}$	taxCO2_xETS_H	t	CO_2 tax, non-ETS heat, DKK/ton
$\tau_t^{SO_2}$	taxSO2	t	SO_2 tax, DKK/kg
$\tau_t^{NO_x}$	taxNOx	t	NO_x tax, DKK/kg
$\tilde{T}_{t,i}^{E}$	subsidy	t,St	Subsidy per MWh energy output (enters with $-$)
$\overline{\nu}$	taxVRule	scalar	Heat-efficiency rule, 1.25
$\overline{\varepsilon}$	taxERule	scalar	Electricity-efficiency rule, 0.65
$\overline{\gamma}$	taxGuardRule	scalar	Guard on the V-rule, 0.35
$Q_{t,l,g\to g'}$	trCap	t,line,EA,EAEA	Directed transmission capacity, TW
$\eta_{t,l}$	trEff	t,line	Transmission line efficiency
$\delta_{t,g}$	distrEff	t,EA	Distribution efficiency
$\overline{H}_{t,a}$	hyDemand	t,HyArea	Exogenous hydrogen demand, TWh
w_t	hySinkPrice	t,HyArea	Willingness to pay of the EU hydrogen sink, DKK/MWh
$\overline{F}_{t,a\to a'}$	hyLineCap	t,hyLine, HyArea,HyAreaTo	Hydrogen pipeline capacity, TWh
$\overline{K}_{t,z}$	ccsDemand	t,ccsZone	Annual capture target, million tonnes
$\rho_{t,i}$	ccsCaptureRate	t,id	Capture rate
$\epsilon_{t,i}^{E}, \epsilon_{t,i}^{DH}$	ccsElecPerTonne, ccsHeatPerTonne	t,id	Energy use of capture, MWh/tonne
$\delta_{t,h,i}^{drv}$	v2gDrive, uHvtV2GDrive	t,id, t,id,hvt	Annual driving draw on V2G batteries, TWh, and its hourly profile weights
$\alpha_{h,v(i)}^{av}$	uHvtV2GAvailability	t,id,hvt	Weights on the V2G availability profile
η^{dis}	v2gEffDischarge	t,id	Grid-discharge efficiency of V2G fleets
$\overline{X}_{t,j}^{cl}, \overline{M}_{t,j}^{cl}$	clusterExportCap, clusterImportCap	t,cluster	Cluster grid connection, GW
$\overline{T}_{t,c}$	elTransportCost_cIdx, elTransportCost	t,cIdx, t,id	Annual grid tariff level, DKK/MWh
$\omega_{h,\theta,w}$	tariffVariation	t,h,tariffArea, tariffClass, tariffDirection	Hourly tariff shape, mean one
$\sigma_{t,c}^{W}, \sigma_{t,c}^{B}$	sigmaCEWithin, sigmaCEBetween	t,cIdx	Demand elasticity within and between months
$\underline{p}^{E}, \underline{p}^{DH}$	pE_min, pH_min	scalar	Price floors, DKK/MWh

Math	GAMS	Domain	Description / unit
$D_{t,c}^{E,\text{data}}$	DEt, DHt	t,cIdx	Exogenous yearly consumer demand, TWh
$\overline{p}_{t,c}^{E}$	pEt_C_cIdx_exo	t,cIdx	Reference consumer price index, electricity
$\overline{p}_{t,c}^{DH}$	pHt_C_cIdx_exo	t,cIdx	Reference consumer price index, heat
$\overline{R}_{t,r}$	rDemand	t,rZone	Available quantity of the resource, TWh
$\Pr^{+}, \Pr^{-}$	markovPr_plus, markovPr_minus	h,hh	Forward/backward transition probabilities

B.3 Endogenous variables

Math	GAMS	Domain	Description / unit
$c_{t,i}$	MC	t,id	Marginal cost, DKK/MWh (or per composite output)
$c_{t,i}^{BP}$	MC_BP	t,id	Marginal cost in back-pressure mode
$c_{t,i}^{BB}$	MC_BB	t,id	Marginal cost in bypass mode
$c_{t,i}^{EX}$	MC_EX	t,id	Marginal cost in extraction mode
$c_{t,c(i)}$	MC_charge	t,id	Marginal cost of charging
$c_{t,f}^{fuel}$	fuelCost	t,Ft	Fuel price index, DKK/MWh input
$c_{t,i}^{r}$	fuelCost_rZone	t,id	Resource shadow price per MWh input
—	fuelTaxH	t,Ft	Heat fuel tax index, DKK/MWh input
$\mu_{t,f}^{CO_2}$	uFuelCO2	t,Ft	CO_2 intensity of fuel type, ton/MWh
$\mu_{t,f}^{SO_2}$	uFuelSO2	t,Ft	SO_2 intensity of fuel type, kg/MWh
$s_{t,h,i}^{E}$	dUtil	t,h,id	Dispatch rate per installed GW
$d_{t,h,c(i)}^{E}$	dUtilC	t,h,id	Charge rate per installed GW
$u_{t,h,i}^{BP}$	uCHP_BP	t,h,id	Share of flexible CHP plant in back-pressure mode
$\Delta_{t,h,i}^{q}$	pEH	t,h,id	Short-run profit margin per composite output
$\lambda_{t,h,i}$	contVal	t,h,id	Continuation value of stored energy, DKK/MWh
$r_{t,h,i}$	stored	t,h,id	Stored energy relative to installed GW
$\Pi_{t,i}$	UP	t,id	Unit profits, million DKK/GW
$S_{t,h,i}^{E}$	SEh	t,h,id	Electricity supply, GWh
$S_{t,h,i}^{DH}$	SHh	t,h,id	District heat supply, GWh
$S_{t,h,i}^{H}$	SHyh	t,h,id	Hydrogen supply, GWh

Math	GAMS	Domain	Description / unit
$D^E_{t,h,c}$	DEh	t,h,cIdx	Hourly electricity demand, GWh
$D^{DH}_{t,h,c}$	DHh	t,h,cIdx	Hourly district heat demand, GWh
—	DEscale, DHscale	t,cIdx	Denominator of the demand share function
$D^E_{t,c}$	DEt_endo	t,cIdx	Endogenous yearly electricity demand, TWh
$D^{DH}_{t,c}$	DHt_endo	t,cIdx	Endogenous yearly heat demand, TWh
$u^E_{t,c}, u^{DH}_{t,c}$	uEt, uHt	t,cIdx	Level parameters in yearly demand
$J^E_{t,c}, J^{DH}_{t,c}$	J_DEt, J_DHt	t,cIdx	Residuals in the yearly demand calibration
$p^E_{t,h,g}$	pE	t,h,EA	Hourly electricity price, DKK/MWh
$p^{DH}_{t,h,g}$	pH	t,h,HA	Hourly district heat price, DKK/MWh
$J^E_{t,h,g}, J^{DH}_{t,h,g}$	jE, jH	t,h,EA/HA	Residuals in market clearing
$p^r_{t,r,b}$	p_rZone	t,rZone,BFt	Resource shadow price, DKK/MWh
$J^r_{t,r,b}$	j_rZone	t,rZone,BFt	Residual in resource market clearing
$p^H_{t,a}$	pHy	t,HyArea	Hydrogen price, DKK/MWh
$J^H_{t,a}$	jHy	t,HyArea	Residual in hydrogen market clearing, TWh
Z_t	qHySink	t,HyArea	Hydrogen sold to the EU sink, TWh
J^{sink}_t	jHySink	t,HyArea	Residual in the smoothed sink condition
$F_{t,a\to a'}$	qHyFlow	t,hyLine, HyArea,HyAreaTo	Hydrogen pipeline flow, TWh
$p^{CCS}_{t,z}$	pCCS	t,ccsZone	Price on captured CO_2, DKK/tonne
$J^{CCS}_{t,z}$	jCCS	t,ccsZone	Residual in the capture target
$p^{cl}_{t,h,j}$	pCluster	t,h,cluster	Price behind a cluster connection, DKK/MWh
$X^{cl}_{t,h,j}$	qClusterNet	t,h,cluster	Net export of a cluster, TWh
$J^{cl}_{t,h,j}$	jCluster	t,h,cluster	Residual in a cluster balance
$X_{t,h,l,g\to g'}$	lineExport	t,h,line, EA,EAEA	Gross exports through a line, TWh
$X^E_{t,h,g}$	qExportsE	t,h,EA	Net exports of an area, TWh
$M^E_{t,h,g}$	qImportsE	t,h,EA	Net imports of an area, TWh
—	qExportsE_t, qImportsE_t	t,EA	Yearly exports/imports, TWh
$S^E_{t,h,g}$	qProdE	t,h,EA	Electricity production by area, TWh
$S^{DH}_{t,h,g}$	qProdH	t,h,HA	District heat production by area, TWh

Math	GAMS	Domain	Description / unit
$S^{H}_{t,h,g}$	qProdHy	t,h,EA	Hydrogen production by area, TWh
$D^{E,\text{cons}}_{t,h,g}$	qDemandE_DCIIA	t,h,EA	Consumer electricity demand, TWh
$D^{E,\text{plants}}_{t,h,g}$	qDemandE_plants	t,h,EA	Plant electricity demand, TWh
L^{E}_{t}	qDemandE_loss_t_DK	t	Distribution losses in Denmark, TWh
$F_{t,g,b}$	qFuel_t	t,EA,BFt	Fuel use by area and base fuel, TWh
$F_{t,r,b}$	qFuel_t_DK_rZone	t,rZone,BFt	Fuel use by resource zone, TWh
$F^{E}_{t,s,b}$	qFuelUseE_t_DK_prod_sector	t,prod_sector,BFt	Fuel attributed to electricity, TWh
$F^{H}_{t,s,b}$	qFuelUseH_t_DK_prod_sector	t,prod_sector,BFt	Fuel attributed to heat, TWh
$p^{E,C}_{t,c}$	pEt_C_cIdx	t,cIdx	Consumer price index by segment, DKK/MWh
—	pEt_C_cIdx_deliv	t,cIdx	Delivered consumer price index by segment, including tariff, DKK/MWh
$p^{E,C}_{t,g}$	pEt_C	t,EA	Consumer price index by area, DKK/MWh
$p^{E,S}_{t,g}$	pEt_S	t,EA	Producer price index by area, DKK/MWh
—	pEt_hWeight	t,EA	Time-weighted price by area, DKK/MWh
$p^{E,C}_{t,DK}$	pEt_C_DK	t	Danish consumer price index, DKK/MWh
$p^{E,S}_{t,DK,s}$	pEt_S_DK_prod_sector	t,prod_sector	Producer price index by sector, DKK/MWh
$p^{E,X}_{t,DK}$	pEt_Export_DK	t	Average export price, DKK/MWh
$p^{E,M}_{t,DK}$	pEt_Import_DK	t	Average import price, DKK/MWh

B.4 Macros and functions in `functions.gms`

GAMS macro	Corresponds to
F_normPdf(x)	$\phi(x)$, standard normal density
errorf(x)	$\Phi(x)$, standard normal CDF (GAMS built-in)
F_PlantAvail	$A_{t,h,i} = 1 - \texttt{capOut}$, plant availability
F_LineAvail	$A^{X}_{t,h,l} = 1 - \texttt{lineOut}$, line availability
F_dUtilDMin	$d^{min} + (1 - d^{min})\Phi(\cdot)$, dispatch with a minimum load (EH, EF, PX)
F_FuelCost	$c^{fuel}_{t,f(i)} + \varphi_{t,i}$, the plant's fuel price
F_HvarCap	$\gamma_{h,v(i)}$ for capacity, $\sum_v \mu^{cap}_{t,i,v}\gamma_{h,v}$

GAMS macro	Corresponds to
F_HvarInf	$\gamma^{I}_{h,v(i)}$ for reservoir inflow
F_HvarDemE(h), F_HvarDemH(h)	$\mu_{h,c}$, the demand variation profile
F_uCO2, F_uSO2	$\mu^{CO_2}_{t,i}$, $\mu^{SO_2}_{t,i}$
F_taxCO2_E, F_taxCO2_H	$\mu^{CO_2}_{t,i}\tau^{CD}_{t,i}$ and $\mu^{CO_2}_{t,i}\tau^{BH}_{t,i}$
F_EmTax_E, F_EmTax_H	$T^{M}_{t,i}$ for electricity / heat producers
F_EmTax_CHP	$T^{M,CHP}_{t,i}$, excluding CO_2
F_EmTax_For	$T^{M}_{t,i}$ for foreign plants (EU-ETS only)
F_ETax, F_HTax	$\tilde{T}^{E}_{t,i}$ and $T^{DH}_{t,i}$
F_FuelE_BP, F_FuelH_BP	$a^{E,BP}_{t,i}$, $a^{H,BP}_{t,i}$
F_FuelH_BB	$a^{H,BB}_{t,i}$
F_FuelE_EX, F_FuelH_EX	$a^{E,EX}_{t,i}$, $a^{H,EX}_{t,i}$
F_ETax_BP, F_HTax_BP	$T^{E,BP}_{t,i}$, $T^{DH,BP}_{t,i}$
F_HTax_BB, F_ETax_EX	$T^{DH,BB}_{t,i}$, $T^{E,EX}_{t,i}$
F_RatioE, F_RatioH	$(p-c)/\sigma$ for electricity / heat producers
F_RatioBT1	$-c/\sigma$, the type-1 (fixed contract) counterpart
F_RatioEH	$\Delta^{q}_{t,h,i}/\sigma_{t,i}$
F_pEH(dE,dH,MC)	$d_E p^E + d_H p^{DH} - c$, the composite margin
F_dUtilCHP	$(g^{min} + (1-g^{min})\Phi(\Delta^q/\sigma))\, CapF\, \gamma\, A$
F_Delta_BP_BB, F_Delta_BP_EX	$\Delta_{t,h,i}$, mode-choice margin
F_CW(x)	$\sigma\phi(x) CapF\, \gamma$, the cost wedge in unit profits
F_CW_EH(x)	$\sigma\phi(x)$, cost wedge for EH/EF/PX
F_RatioE_CHR, F_RatioCE_CHR	Dispatch and charge ratios including $\lambda_{t,h,i}$
F_contVal_CHR	$\Lambda(r)$, cf. (46)
F_NetDischarge, F_NetCharge	$\widetilde{s}_{t,h,i}$, $\widetilde{d}_{t,h,i}$, cf. (50)
F_COP, F_COPh	$\eta_{t,h,i}$, the hourly coefficient of performance
F_RatioExport, F_RatioRev	The arguments of $x_{t,h,l,g\to g'}$ and $x_{t,h,l,g'\to g}$
F_sLine	$s_{t,h,l,g\to g'}$, the signed utilization
F_lineSigned	$F_{t,h,l,g\to g'}$, cf. (81); F_lineBoth and F_lineOne select the two-way and one-way form
F_linePos(x), F_sPos(x)	The smooth positive part $\frac{1}{2}(\sqrt{x^2+\epsilon^2}+x)$, with $\epsilon = 10^{-6}$ on a flow in GW and 0.05 on the signed utilization of a one-way line
F_lineExport	$X_{t,h,l,g\to g'}$, including $A^{X}_{t,h,l}$
F_NXLine_h	$NX_{t,h,l,g\to g'}$
F_ExportLine_h, F_ImportLine_h	X^{net}, M^{net} after netting
F_SECTOR_COND	Selects plants in the Waste / NonWaste sector
F_FM	$\alpha_{f(i),b}$ for the plant's own fuel type

B.5 Module states

Module	State	Meaning
exoInputs	chronological	Hours ordered in time; no Markov matrices. Not used in this release
	clusterAvg	Clustered states; Markov matrices declared
HY, HYS, ES, HS, EV	chronological	$\lambda_{t,h}$ and $r_{t,h}$ use $h \pm 1$
	clusterAvg	$\lambda_{t,h}$ and $r_{t,h}$ use the Markov matrices
equilibrium	exo_prices	Every price fixed (electricity, heat, cluster, resource zones, hydrogen, sink, CCS); every J-term endogenous
	endo_prices	Electricity, heat and cluster prices endogenous; the annual prices fixed and their J-terms endogenous
	endo_prices_rZone	Every price endogenous; every J-term fixed. The state of the solved baseline
demand_DCIIA	base	$u^E_{t,c}$ and $J^E_{t,c}$ both exogenous
	clusterAvg	Starting values for the monthly demand nesting on clustered states
	DCIIA_endo_J	$J^E_{t,c}$ endogenous (residual measurement)
	DCIIA_endo_u	$u^E_{t,c}$ endogenous (level calibration)
aggregates	base	Hourly aggregates only
	aggregates_yearly	Adds yearly production, demand and fuel aggregates
transmission	base	Hourly line flows only
	transmission_yearly	Adds yearly exports and imports
priceIndex	base	Segment-level consumer price indices only
	priceIndex_regional	Adds all regional, sectoral and trade price indices

C The CHP plants' response to the two prices

Figure 17 shows where the three CHP plants ended up in 2035. Figure 78 shows the rule that put them there: the dispatch rate $\Phi(\Delta^q/\sigma)$ of the same three plants at every pair of a district-heat price and an electricity price, with the 2035 price pairs of each plant's two markets drawn on top. For the back-pressure plant the composite margin $p^E + p^{DH}/\kappa - c^{BP}$ is a single line in the plane, and the plant runs when the price pair is above it. The slope of that line is $-1/\kappa$: with $\kappa = 0.23$, a heat price of 100 DKK/MWh is worth as much to the plant as an electricity price of 435 DKK/MWh. For the two flexible plants the contours of the back-pressure share u^{BP} are thin blue lines. Below and to the right of the 50 per cent line the bypass plant bypasses the turbine, and only the heat price matters. For the extraction plant the condensing side lies to the upper left, where electricity is expensive relative to heat, and only the electricity price matters there.

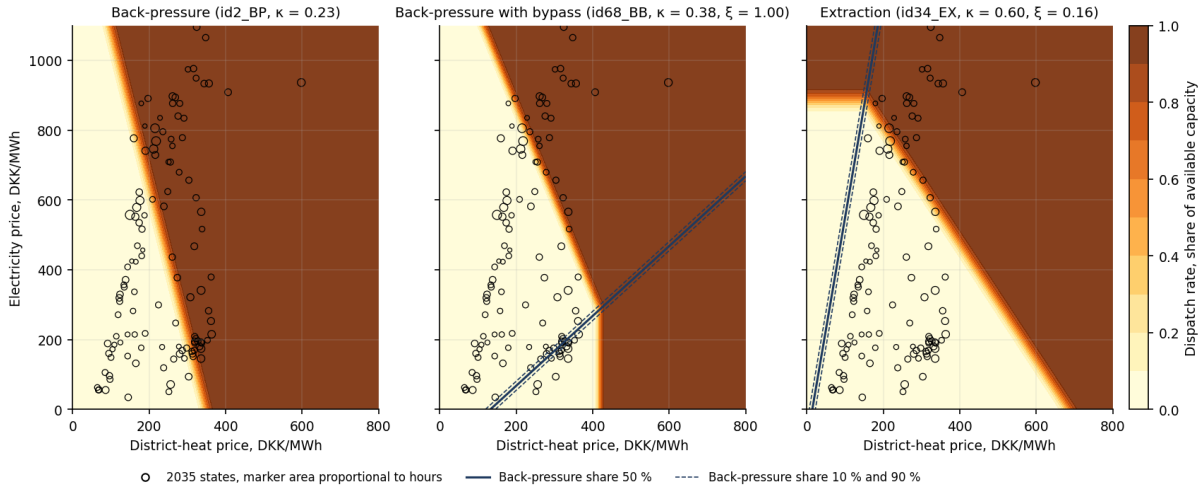


Figure 78: Dispatch rate of the three CHP plants of Figure 17 at every pair of district-heat price and electricity price (DKK/MWh), 2035 parameters. Dark is full load, light is off. Thin blue lines are the back-pressure share of the two flexible plants, 50 per cent solid and 10 and 90 per cent dashed. Circles are the 2035 states, with area proportional to the hours in the state.

D Storage over the year

A storage plant discharges when the area price is above its continuation value and charges when the price is below it. Figure 19 draws that decision for a pumped-storage plant. The figures in this appendix draw it for one plant of each other type, in the same layout. The states are in calendar order and each is as wide as the hours it stands for. The top panel is the area price, the discharge threshold $\lambda + c$ plus the injection tariff and, where the plant can charge, the charge threshold $\eta\lambda - c_{c(i)}$, where $c_{c(i)}$ includes the charging tariff. The middle panel is discharge (up) and charge (down) as a share of available capacity, with inflow where the plant has one. The bottom panel is the stock, in hours of full output, against the storage window. The heat store is drawn in 2035 and in 2050; with the correction of Section 2.8 it operates through 2050.

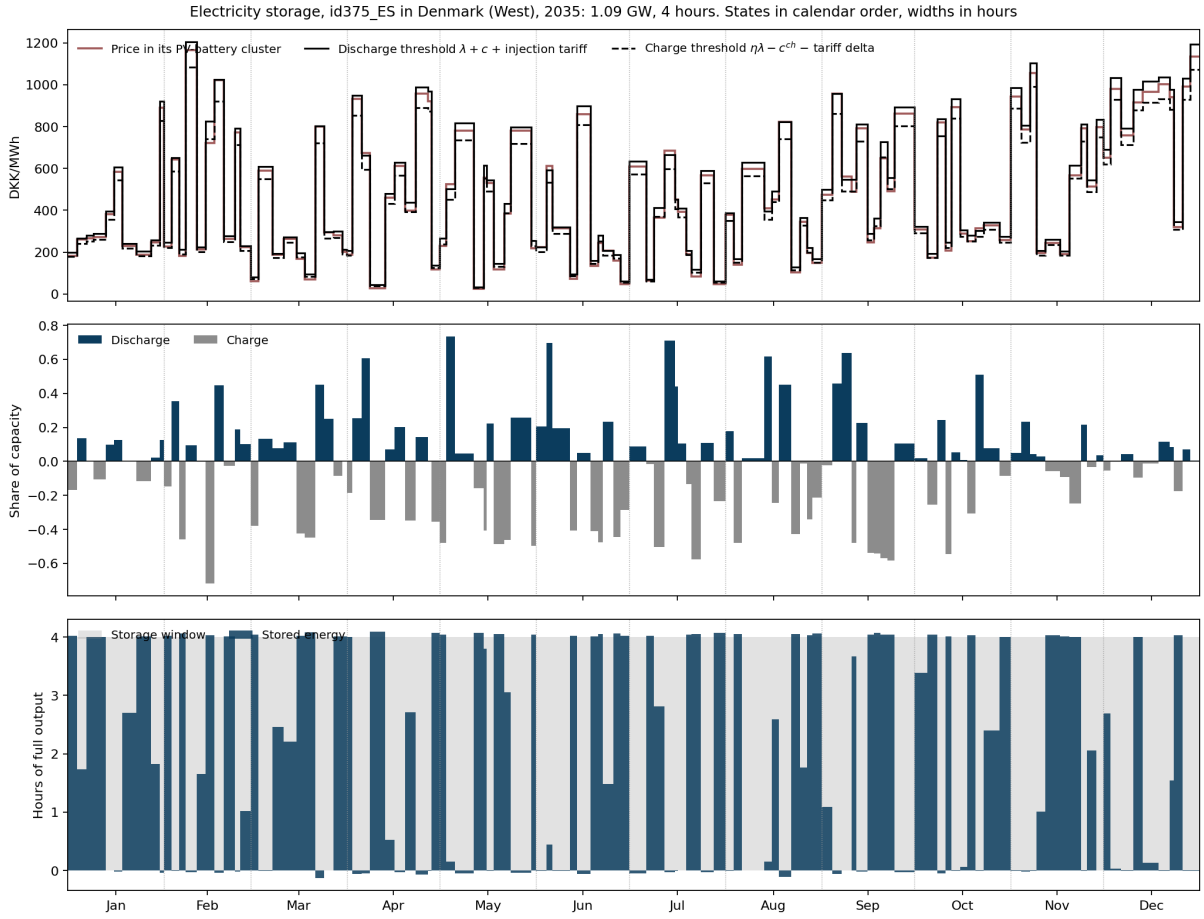


Figure 79: Electricity storage in West Denmark, 2035: a battery inside a PV-battery cluster, drawn against the cluster price.

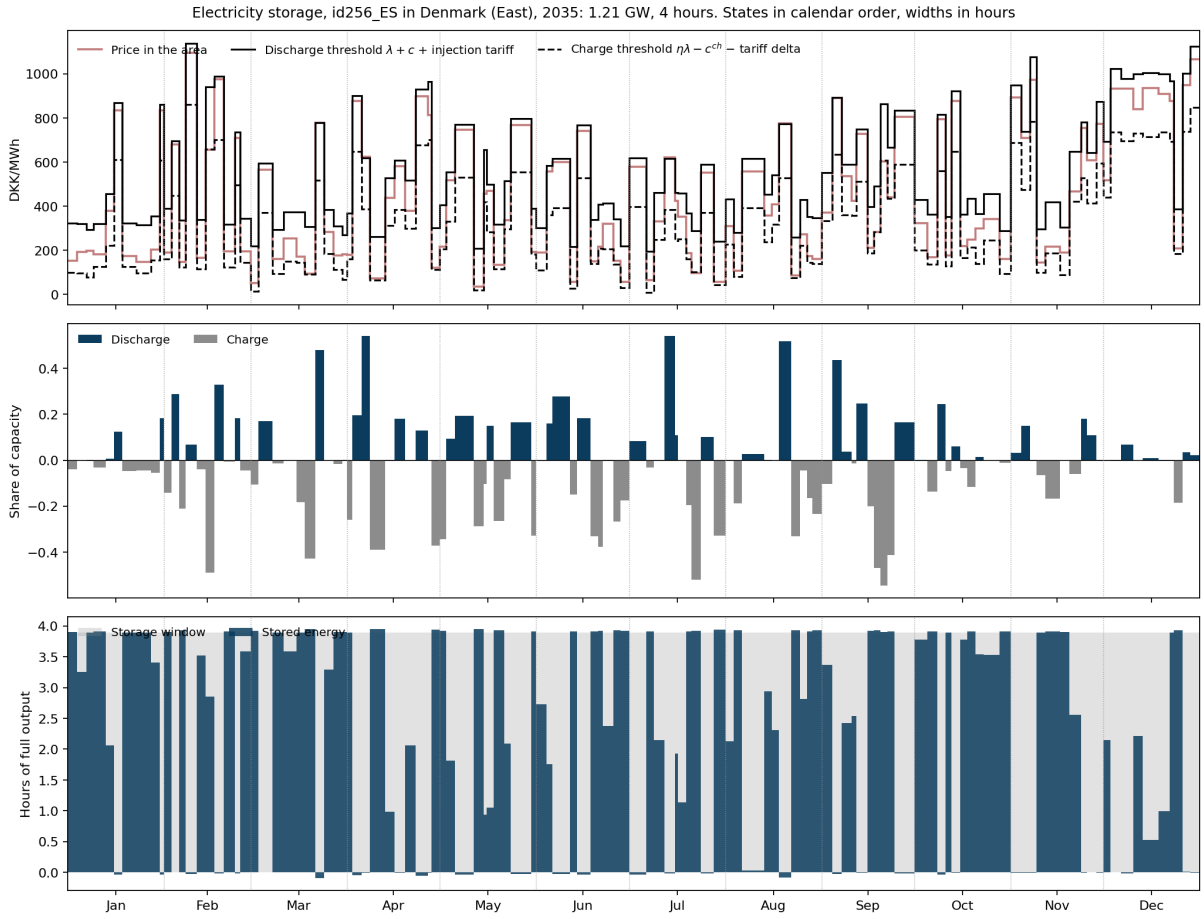


Figure 80: Electricity storage in East Denmark, 2035.

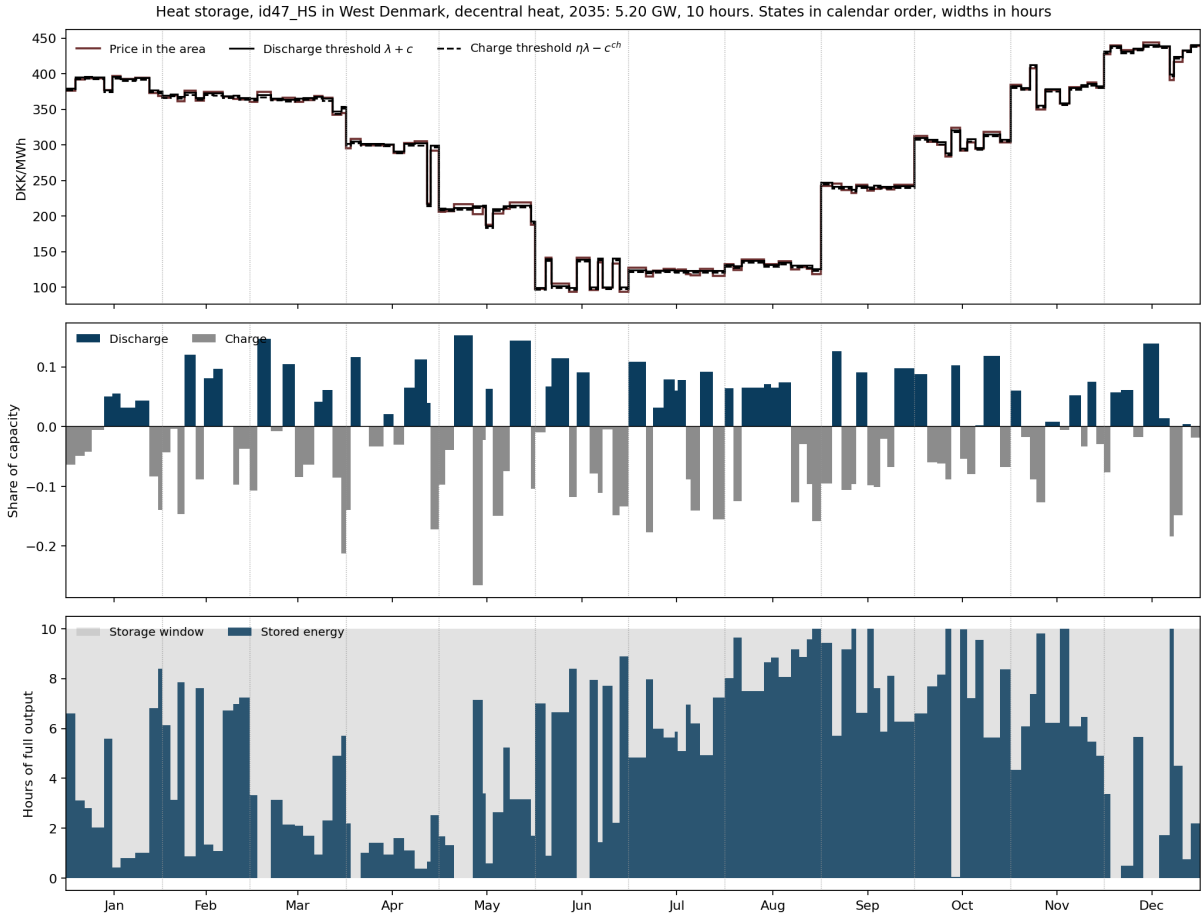


Figure 81: Heat storage in central West Denmark, 2035.

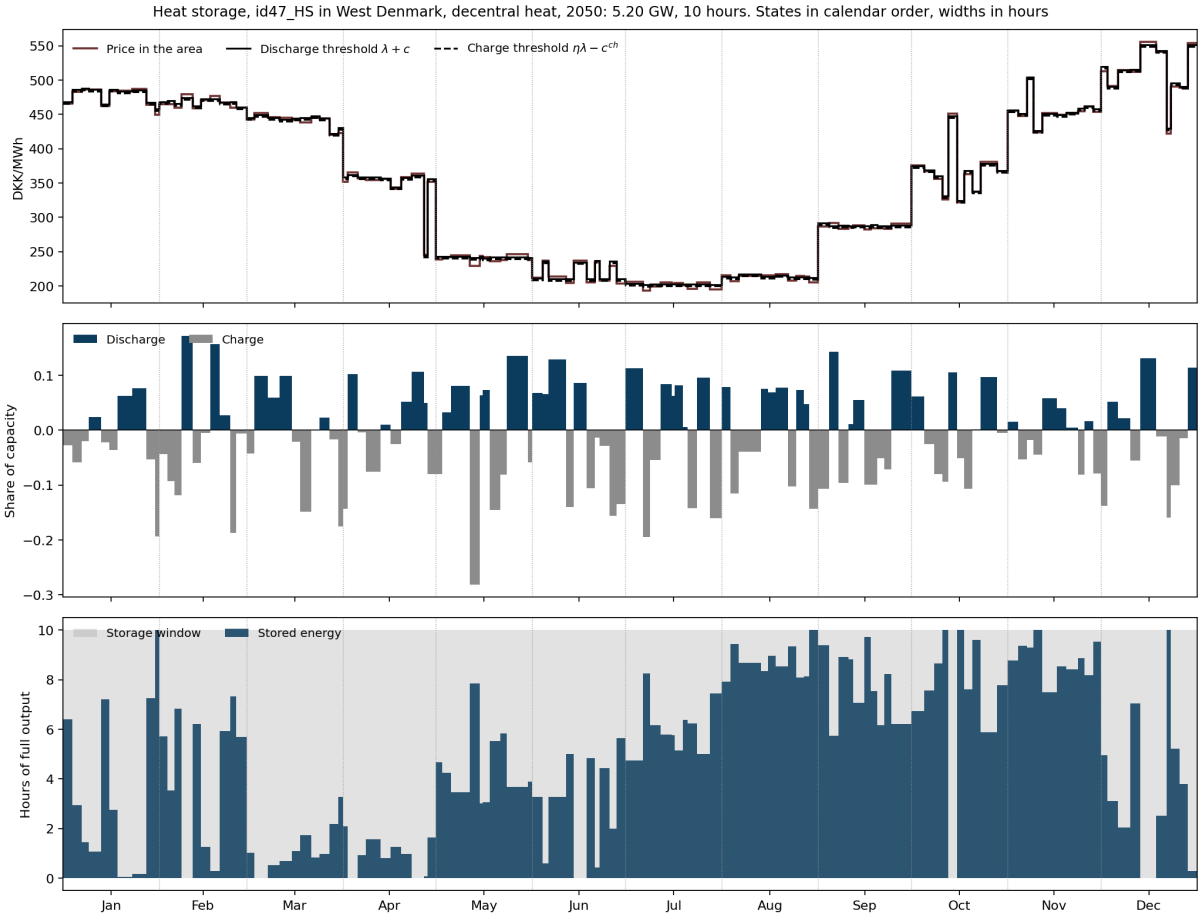


Figure 82: The same heat store in 2050.

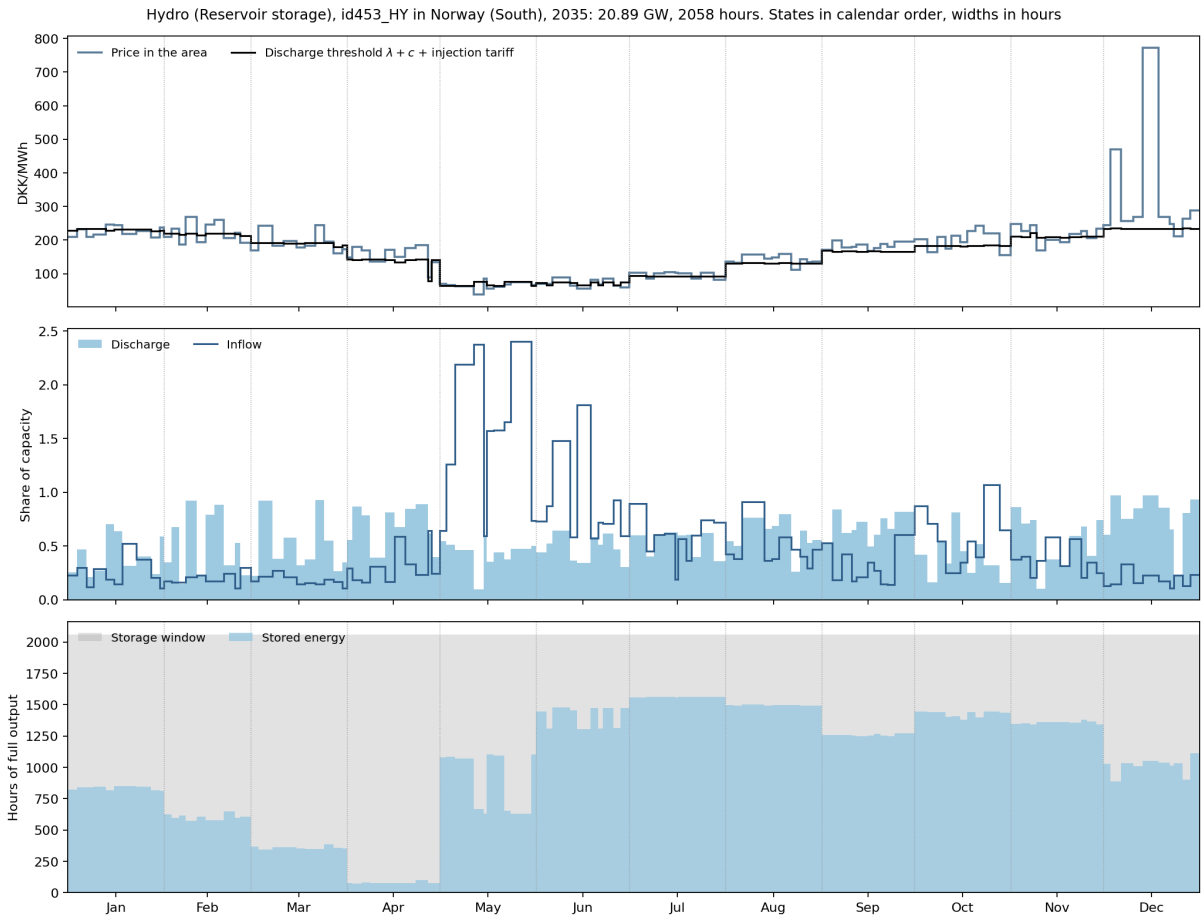


Figure 83: Reservoir hydro in southern Norway, 2035. Inflow arrives in spring and the stock is drawn down over the winter.

E Clearing at the extremes

Section 6.1 draws one state in West Denmark. The same picture at the most expensive and the cheapest state shows who is on the margin at either end. It also shows a German state either side of the 2038 hydrogen step.

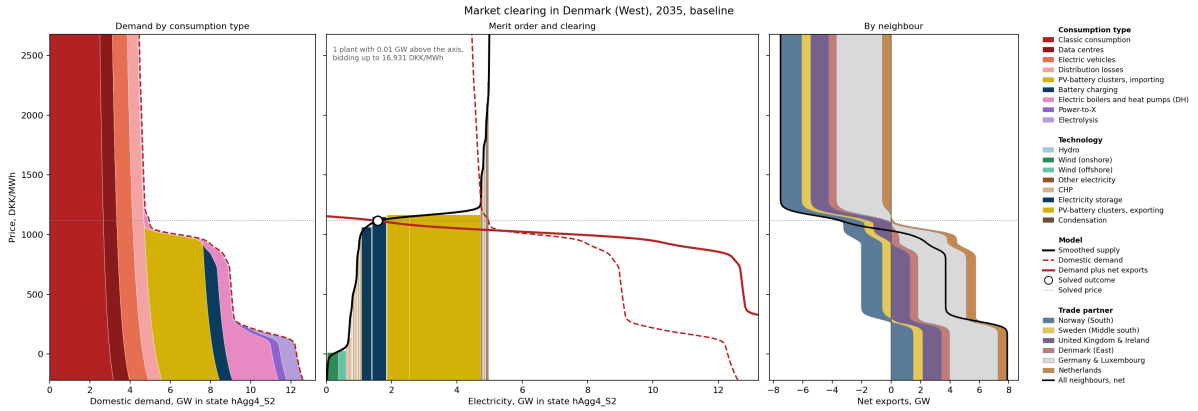


Figure 84: Market clearing in West Denmark, 2035, the most expensive state.

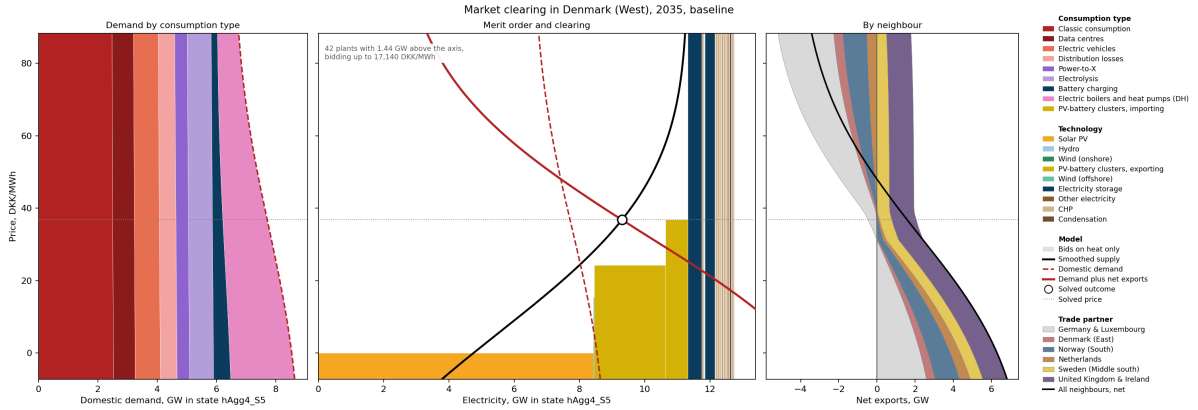


Figure 85: Market clearing in West Denmark, 2035, the cheapest state.

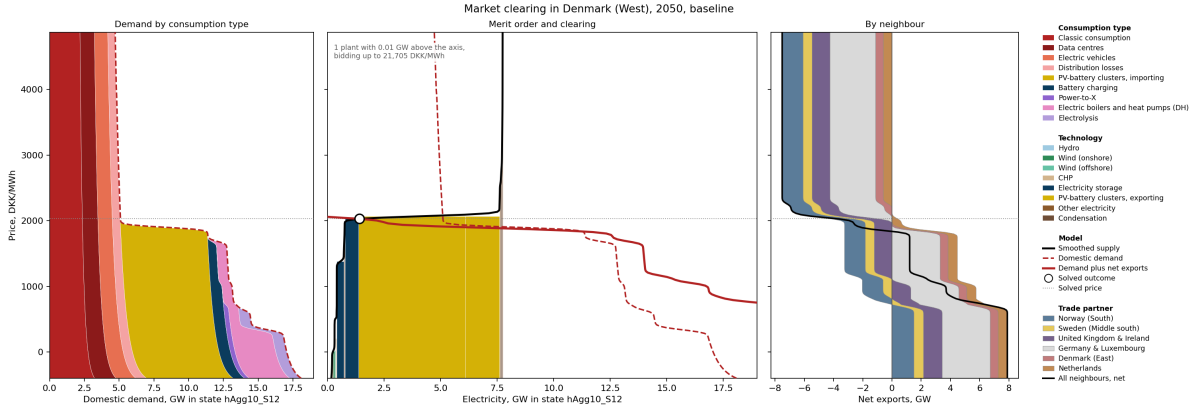


Figure 86: Market clearing in West Denmark, 2050, the most expensive state.

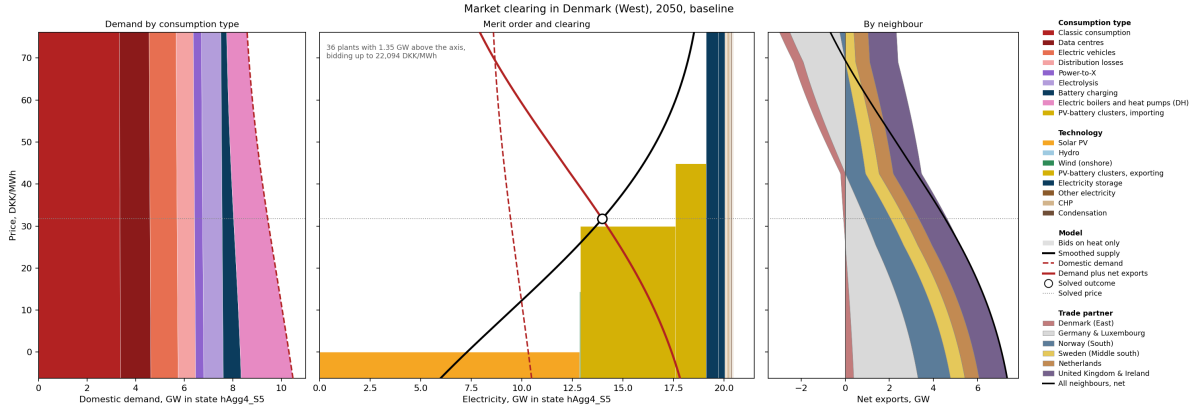


Figure 87: Market clearing in West Denmark, 2050, the cheapest state.

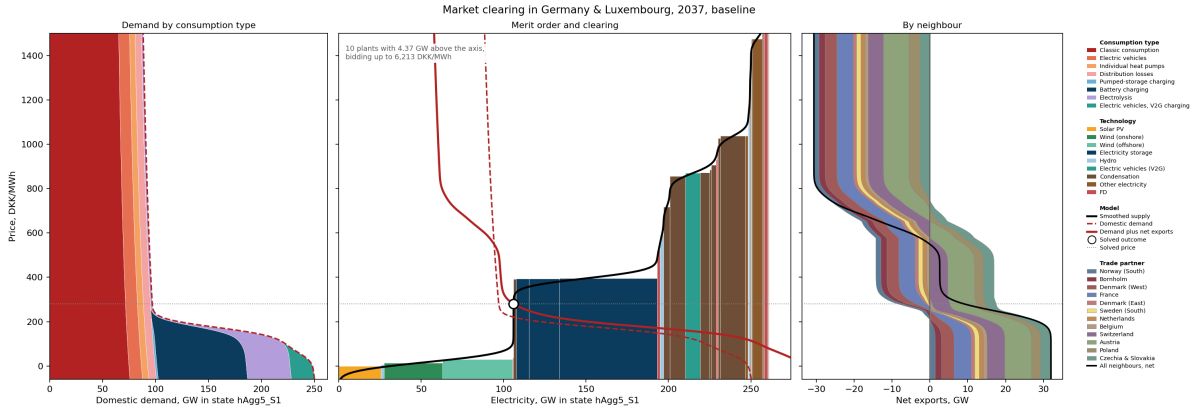


Figure 88: Market clearing in Germany and Luxembourg, 2037.

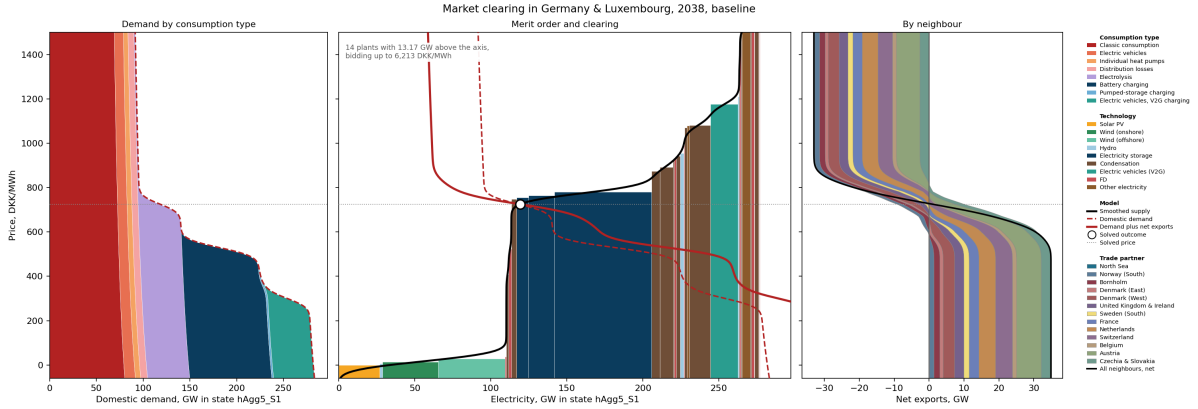
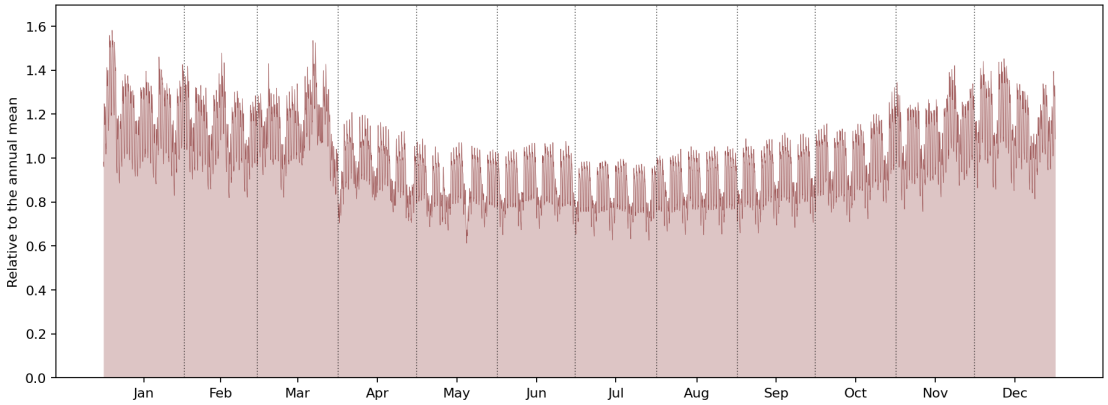


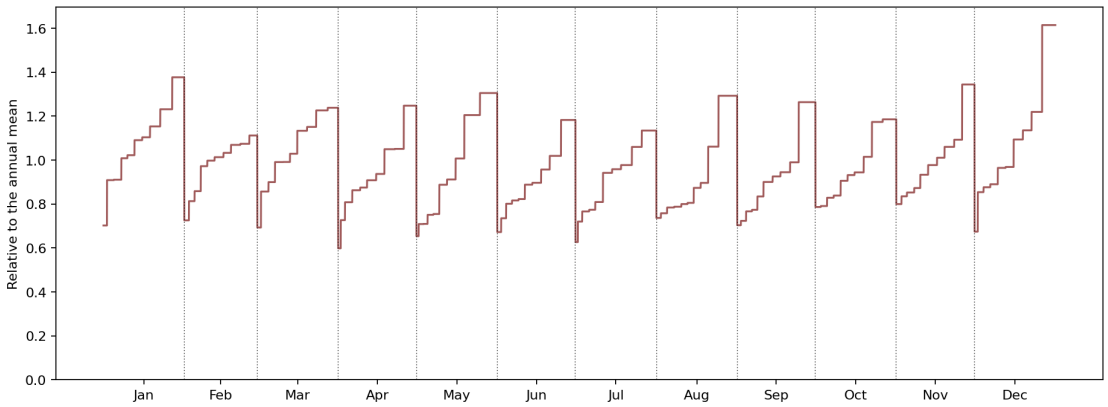
Figure 89: The same state in 2038, after European hydrogen demand begins.

F Variation profiles before and after clustering

Section 2.6 draws the solar capacity factor of West Denmark over the 8,760 hours of the raw data and over the 120 states. This appendix draws the same pair for three other profiles that matter for prices: West Danish electricity demand and onshore wind, and hydro inflow in southern Norway. The seasonal shape and the range survive the clustering; the order of the hours within a month is lost. The clustered panels keep the months in calendar order and sort the states within each month from low to high.

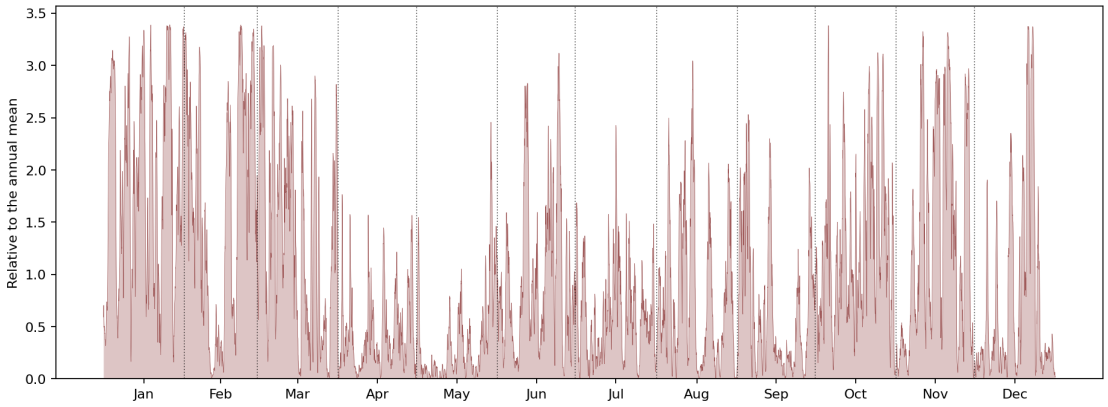


(a) 8,760 hours

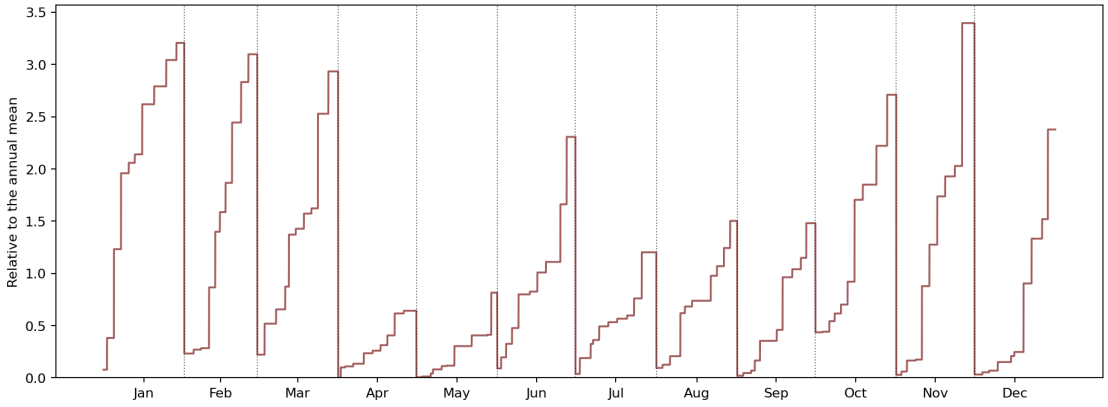


(b) 120 clustered states

Figure 90: Electricity demand, West Denmark 2035, before and after clustering, climate year 2008.

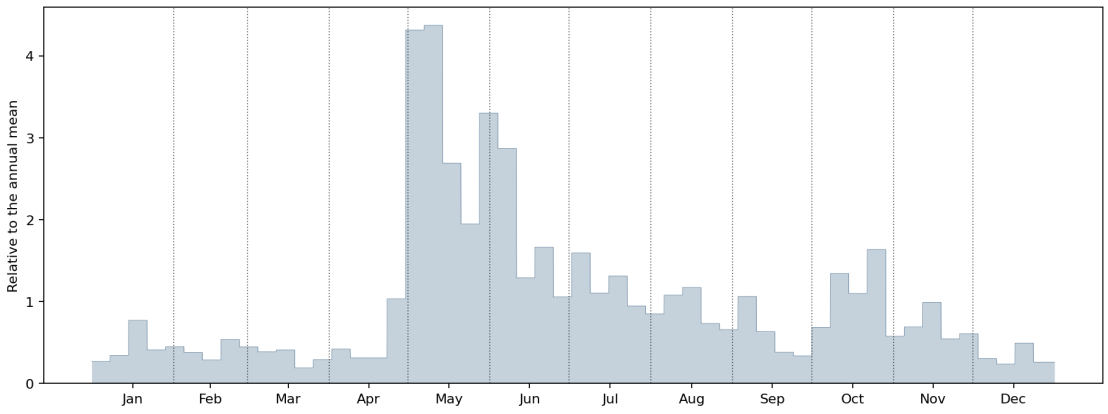


(a) 8,760 hours

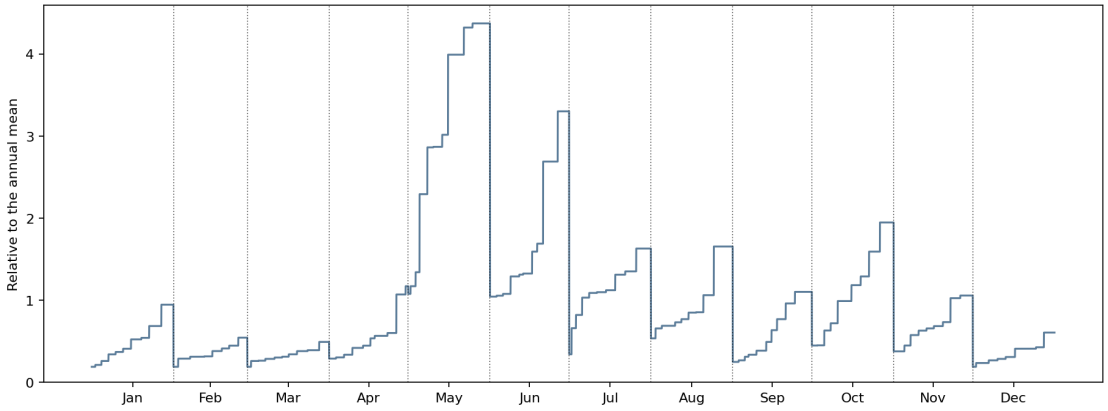


(b) 120 clustered states

Figure 91: Onshore wind capacity factor, West Denmark 2035, before and after clustering, climate year 2008.



(a) 8,760 hours



(b) 120 clustered states

Figure 92: Hydro inflow, southern Norway, before and after clustering, climate year 2008.

G Prices, renewables and trade within 2035

The published hourly workbook and the model can be compared state by state, once the published hours are averaged inside the model's states. Prices are drawn in calendar order; renewable generation and interconnector flows both as duration curves and in calendar order.

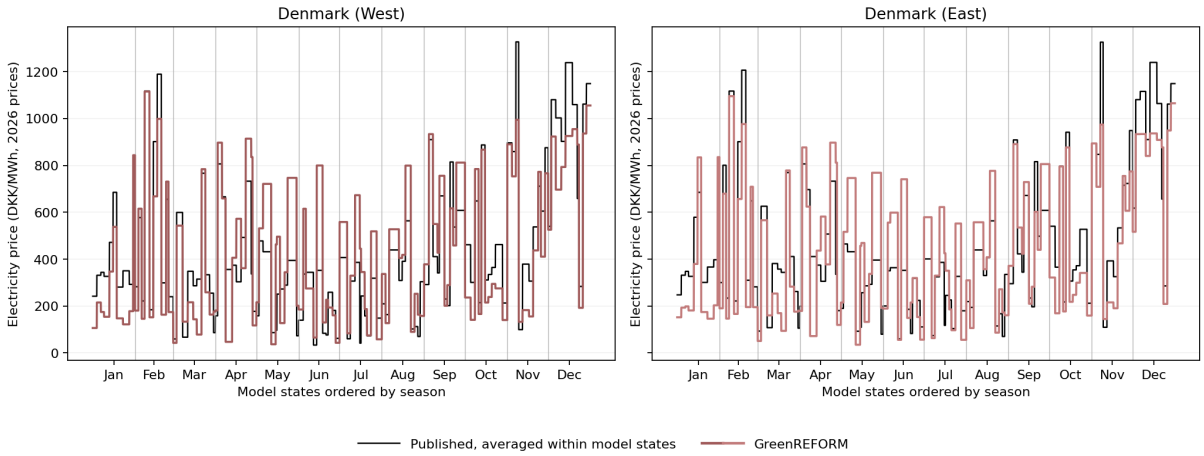


Figure 93: Electricity prices in 2035, model and published, states in calendar order, DKK/MWh. In this appendix the published hourly series is light grey, its average within the model's states black, and the model is drawn in its balance colour: the area colour for prices and flows, the technology colour for wind and solar.

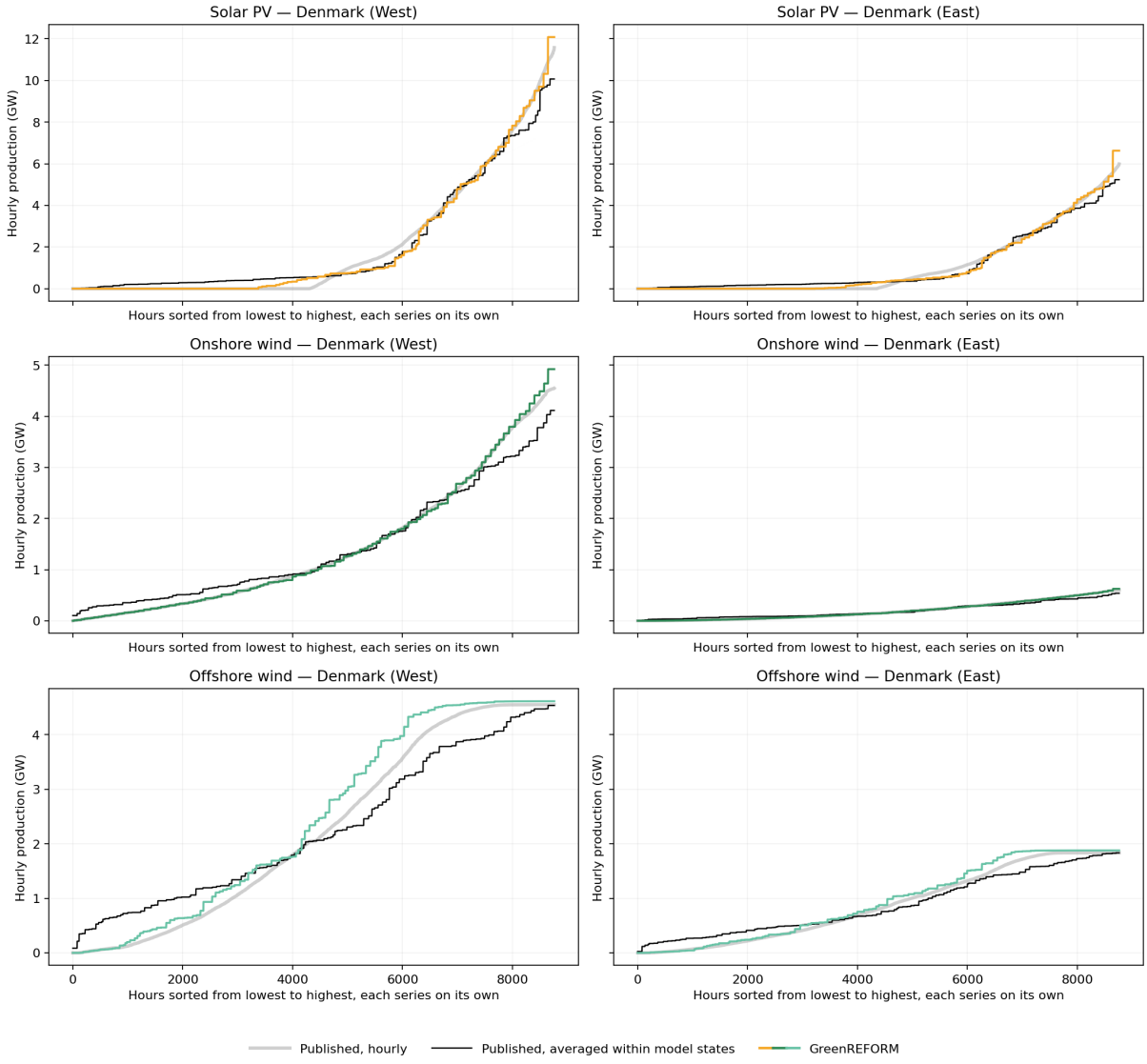


Figure 94: Wind and solar generation in 2035, model and published, each series sorted on its own from lowest to highest, GW.

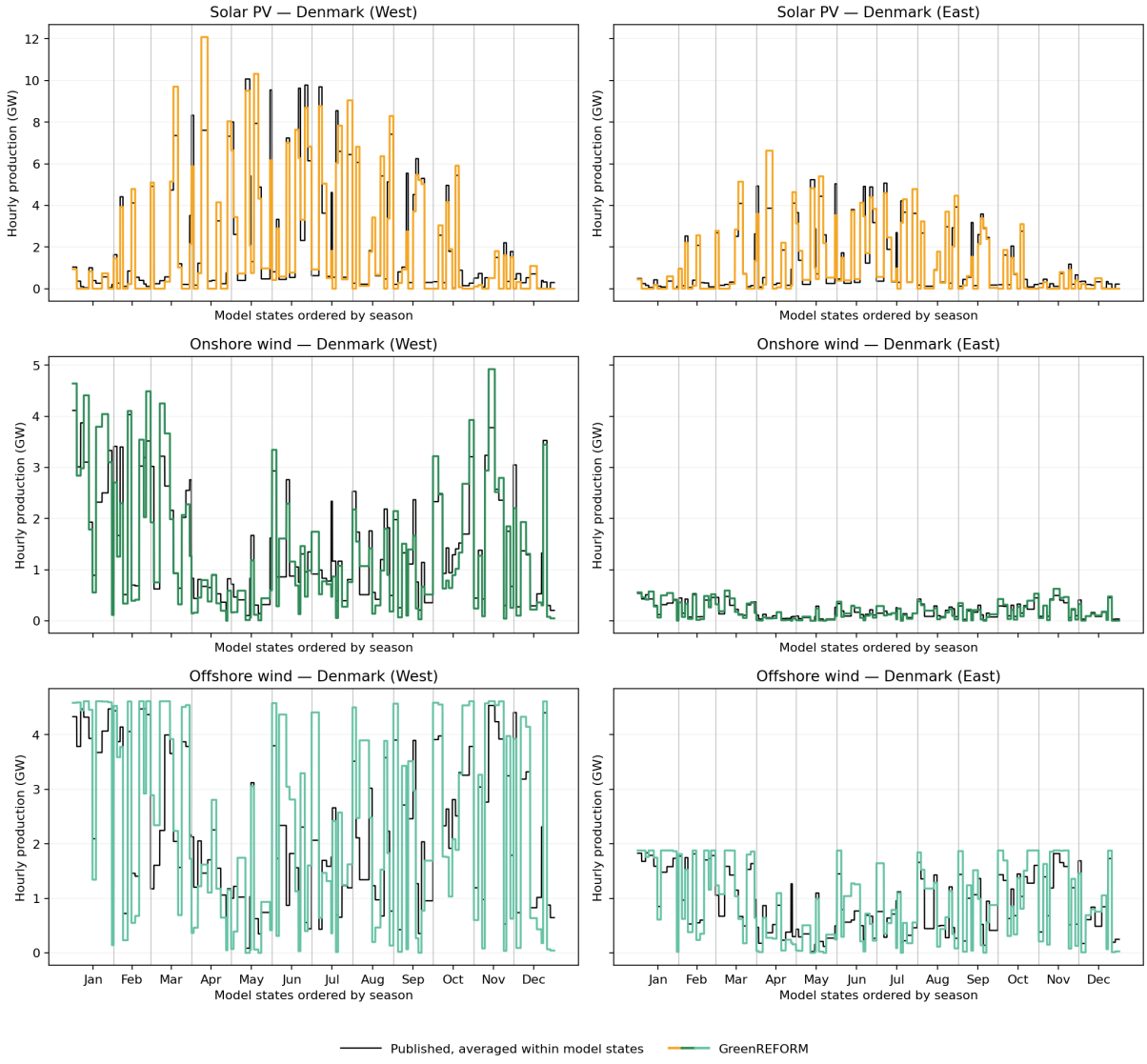


Figure 95: Wind and solar generation in 2035, states in calendar order, GW.

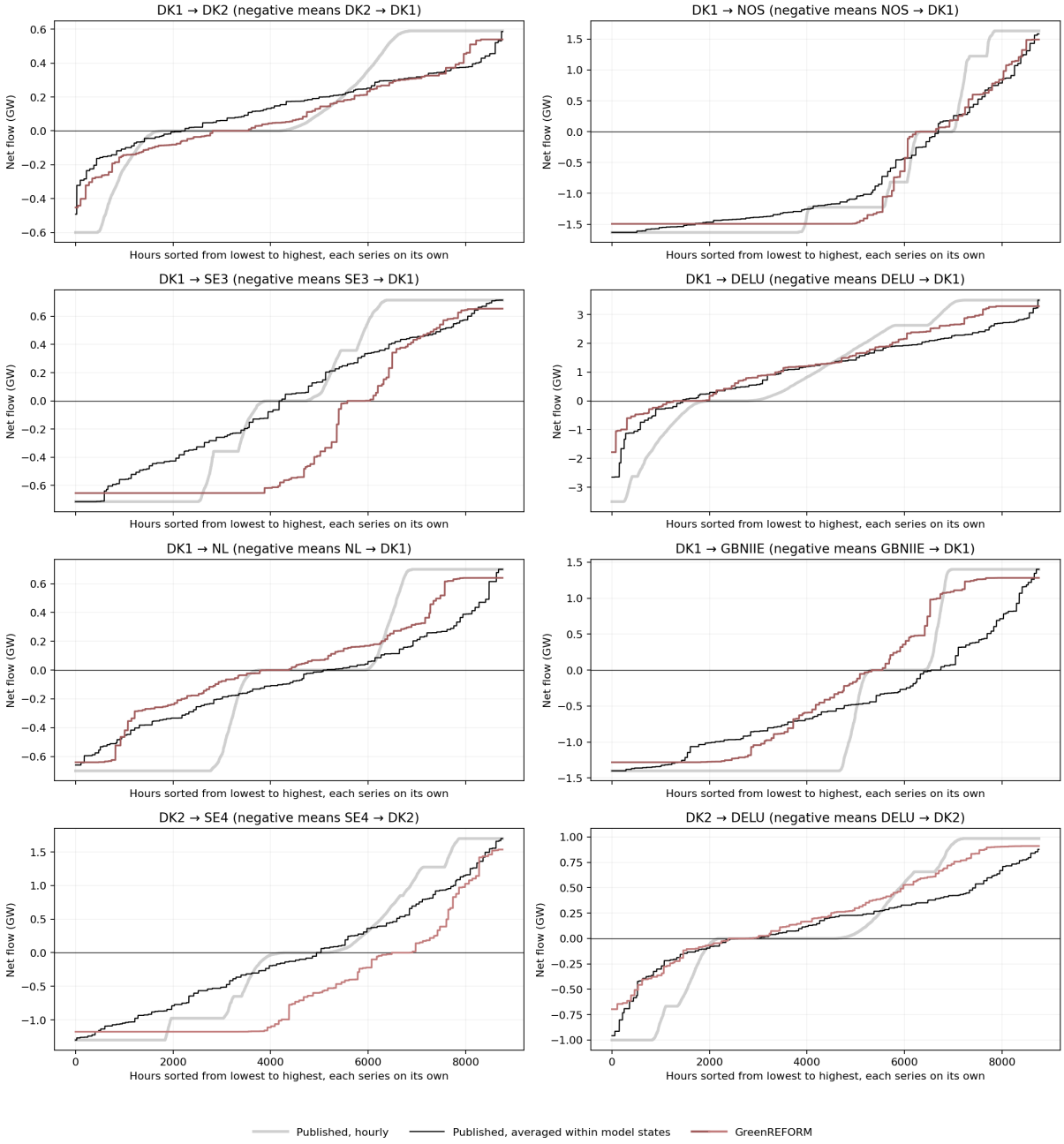


Figure 96: Net flow on the Danish interconnectors in 2035, model and published, each line sorted on its own from lowest to highest, GW.

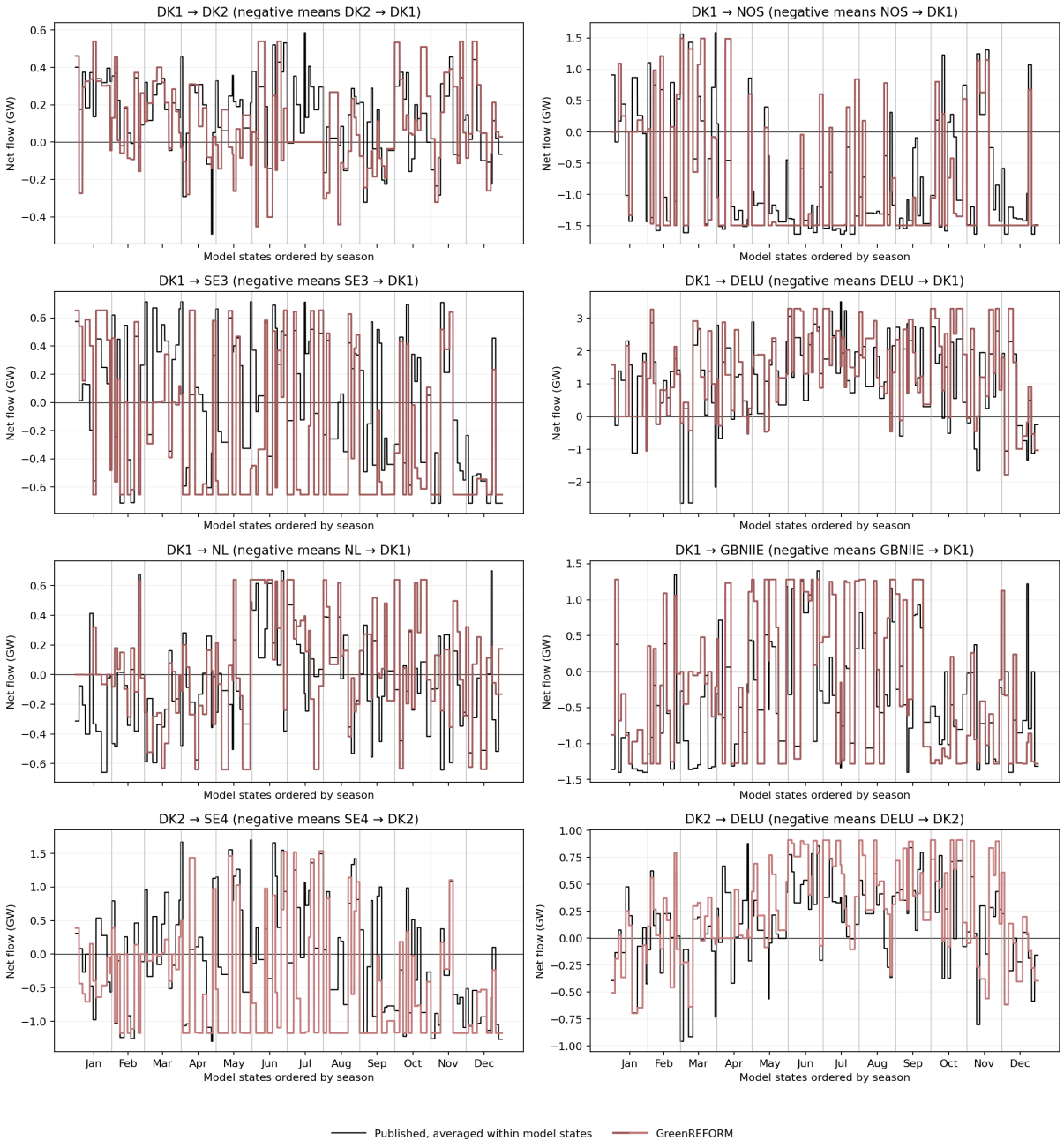


Figure 97: Net flow on the Danish interconnectors in 2035, states in calendar order, GW.

H Fuel balances

The balances of Section 11.7 stack supply by technology. The figures below stack the same states by fuel, for 2035, in West and East Denmark and in the four heat markets. The 2025 and 2050 versions are in the figure set that accompanies the release.

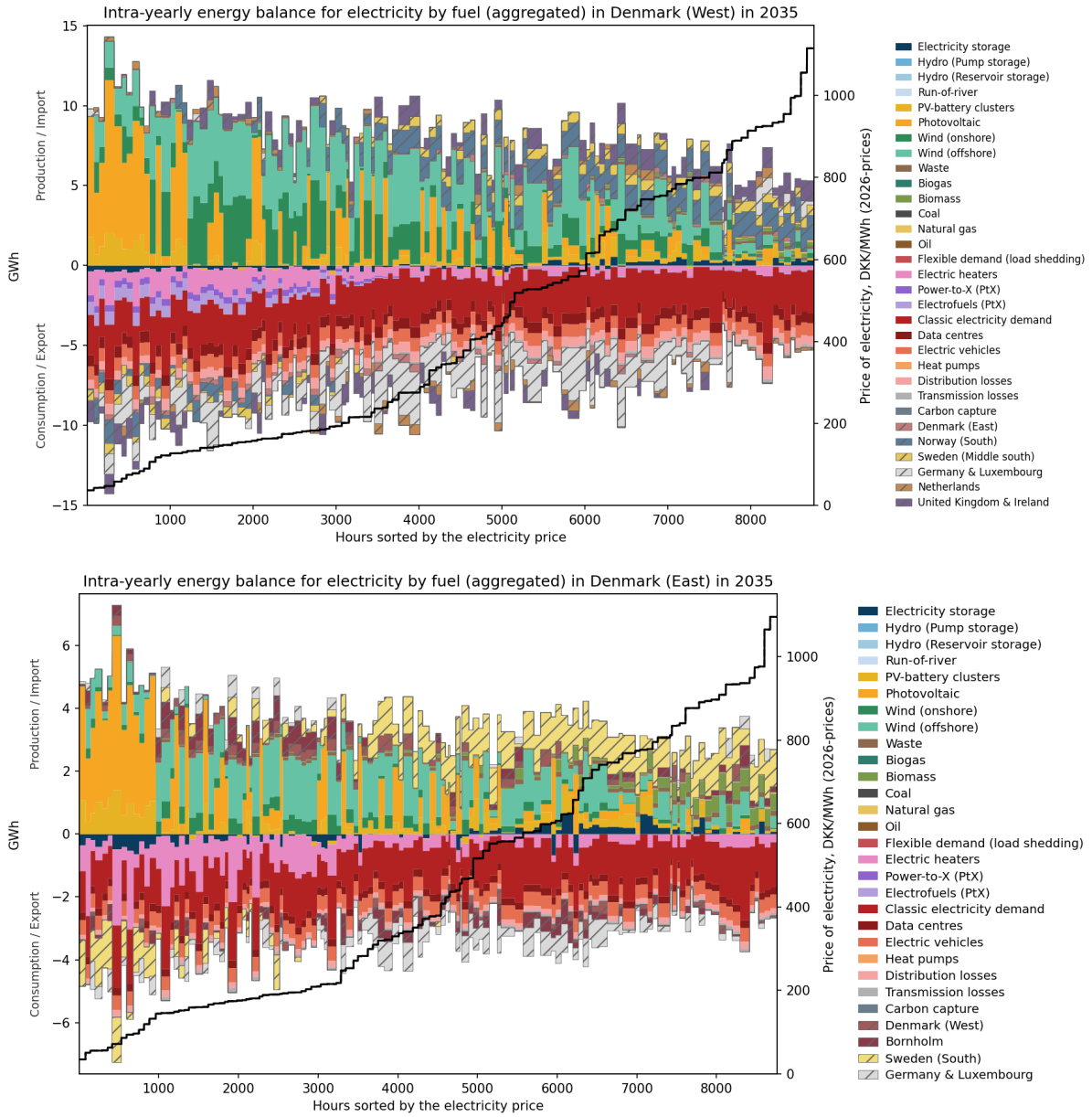


Figure 98: Electricity in West Denmark (top) and East Denmark (bottom), 2035, thermal generation by fuel, GW.

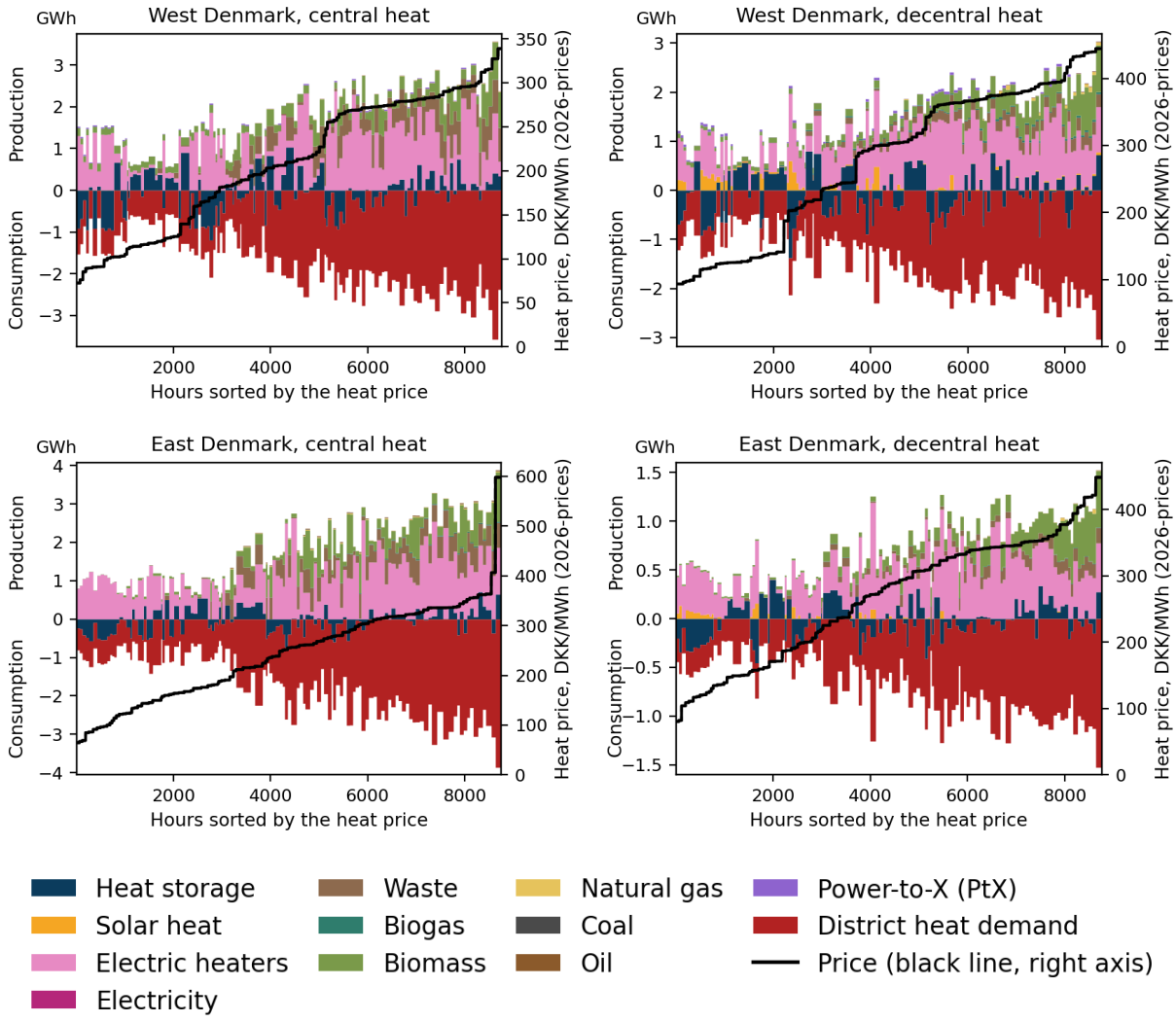


Figure 99: District heat by fuel in the four heat markets, 2035, GW. Hours are sorted by the heat price (black line, right axis); the legend below applies to all four panels.

I Where the electricity goes

The traced balance follows generation through to the use it serves, with states sorted by price. West and East Denmark are drawn for 2035; the 2050 technology balances follow.

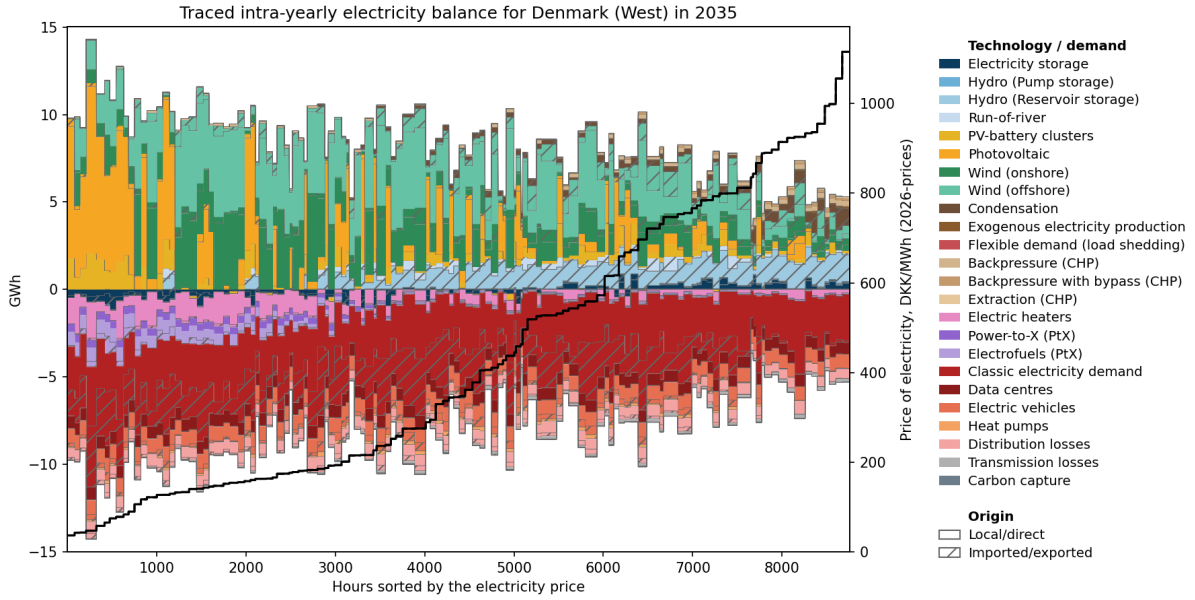


Figure 100: Traced electricity balance, West Denmark, 2035, GW.

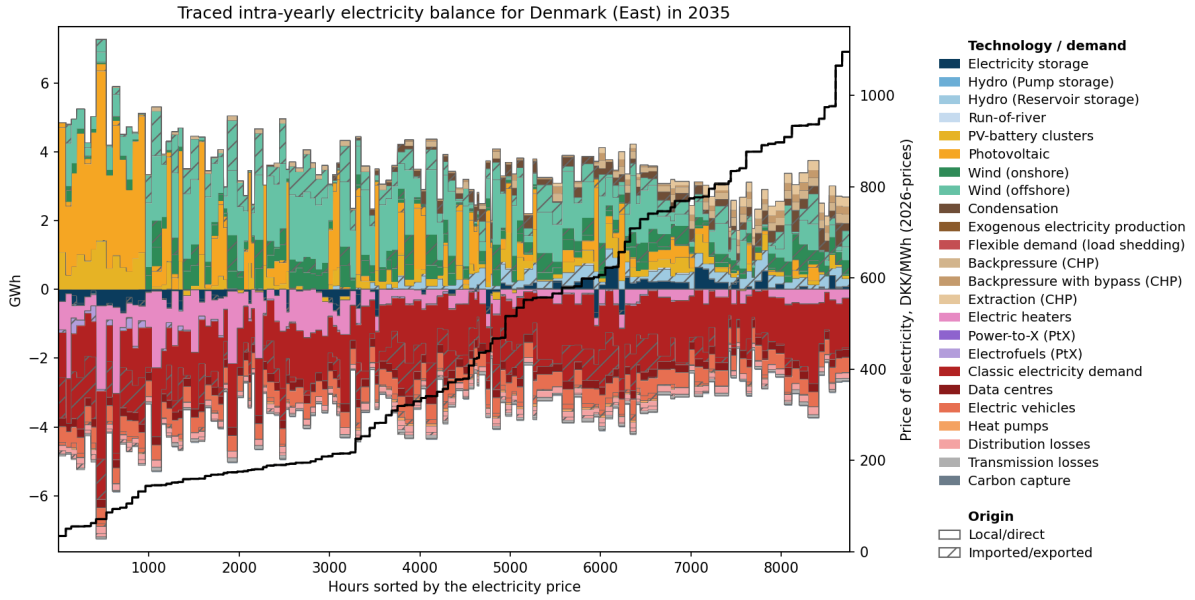


Figure 101: Traced electricity balance, East Denmark, 2035, GW.

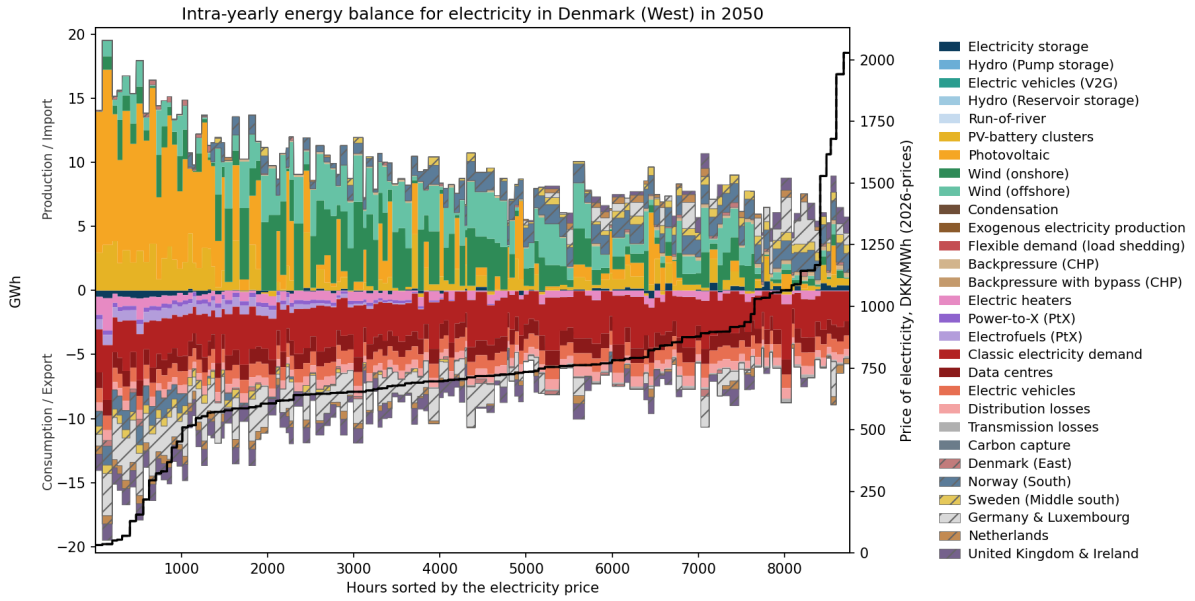


Figure 102: Electricity balance in West Denmark, 2050, GW. Net flow is hatched in each partner's area colour.

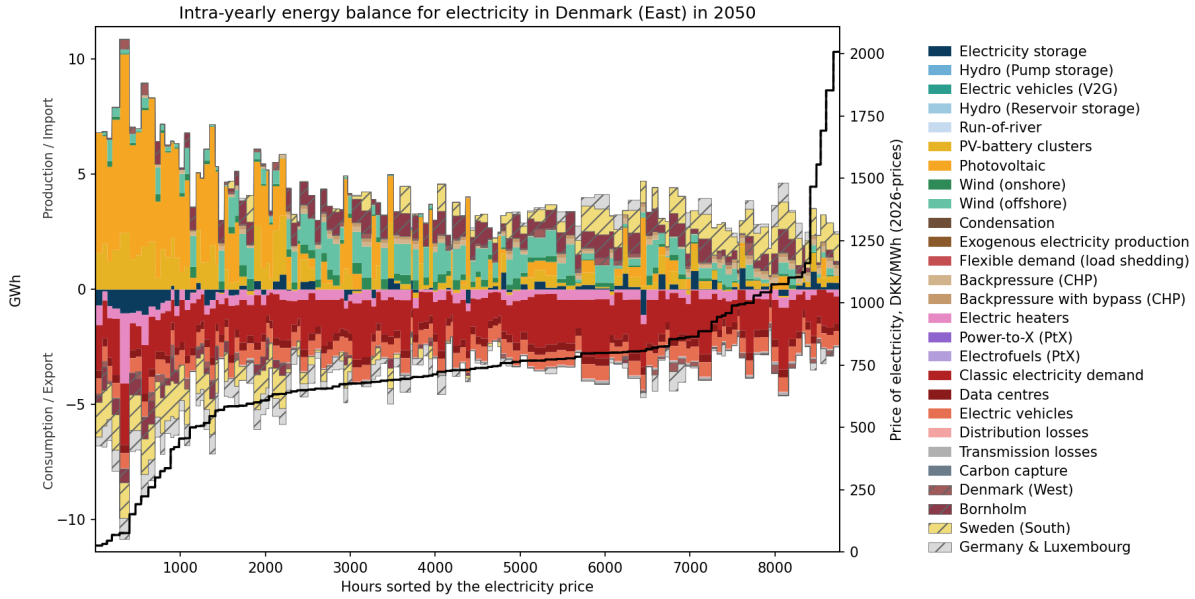


Figure 103: Electricity balance in East Denmark, 2050, GW. Net flow is hatched in each partner's area colour.

J Balances in calendar order

The balances of Section 11.7 sort the states by price, which shows what runs at which price. The same balances in calendar order show when. Each state is drawn at the position of its month, and its width is the number of hours it stands for. The price is the black line on the right axis. In electricity the seasonal signal is solar; in district heat it is demand.

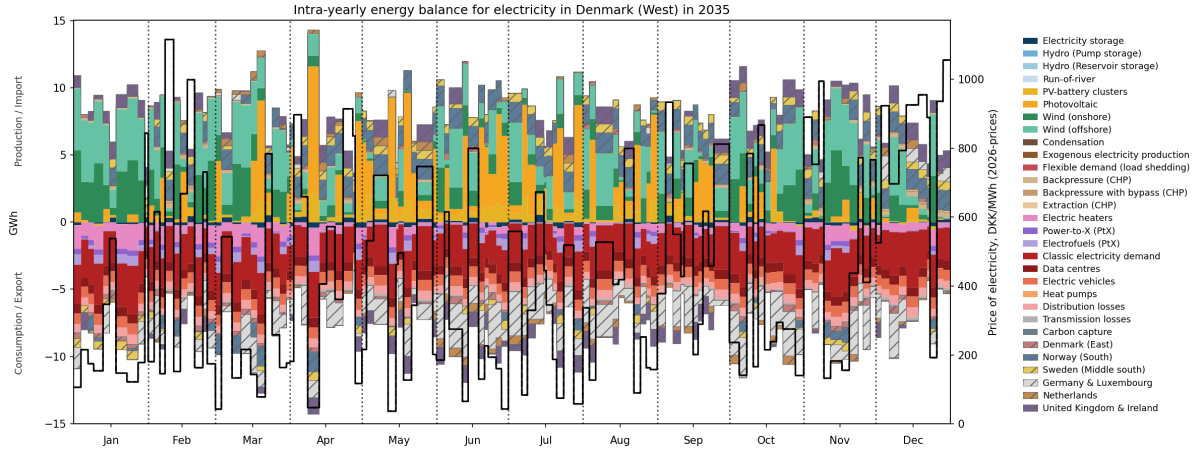


Figure 104: Electricity balance in West Denmark, 2035, states in calendar order, GW.

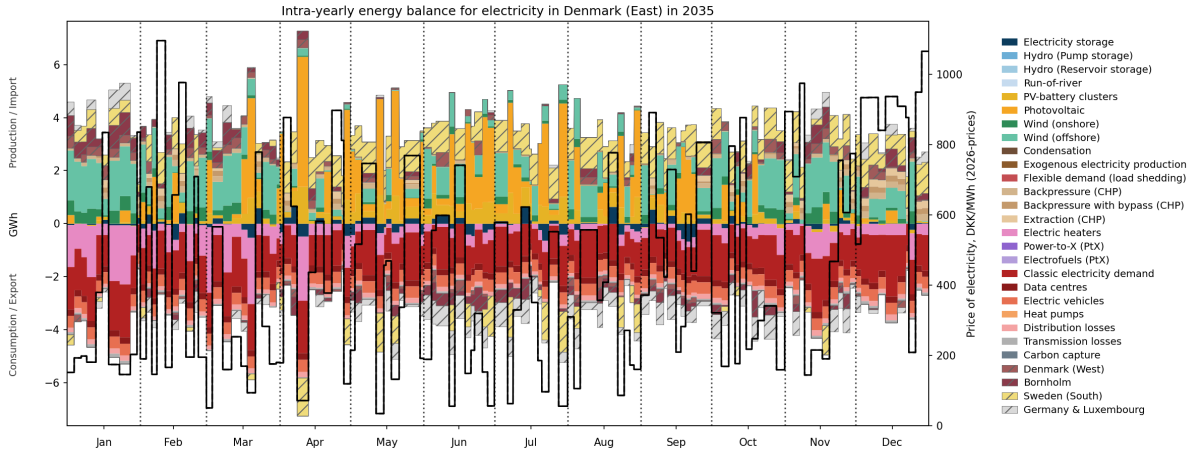


Figure 105: Electricity balance in East Denmark, 2035, states in calendar order, GW.

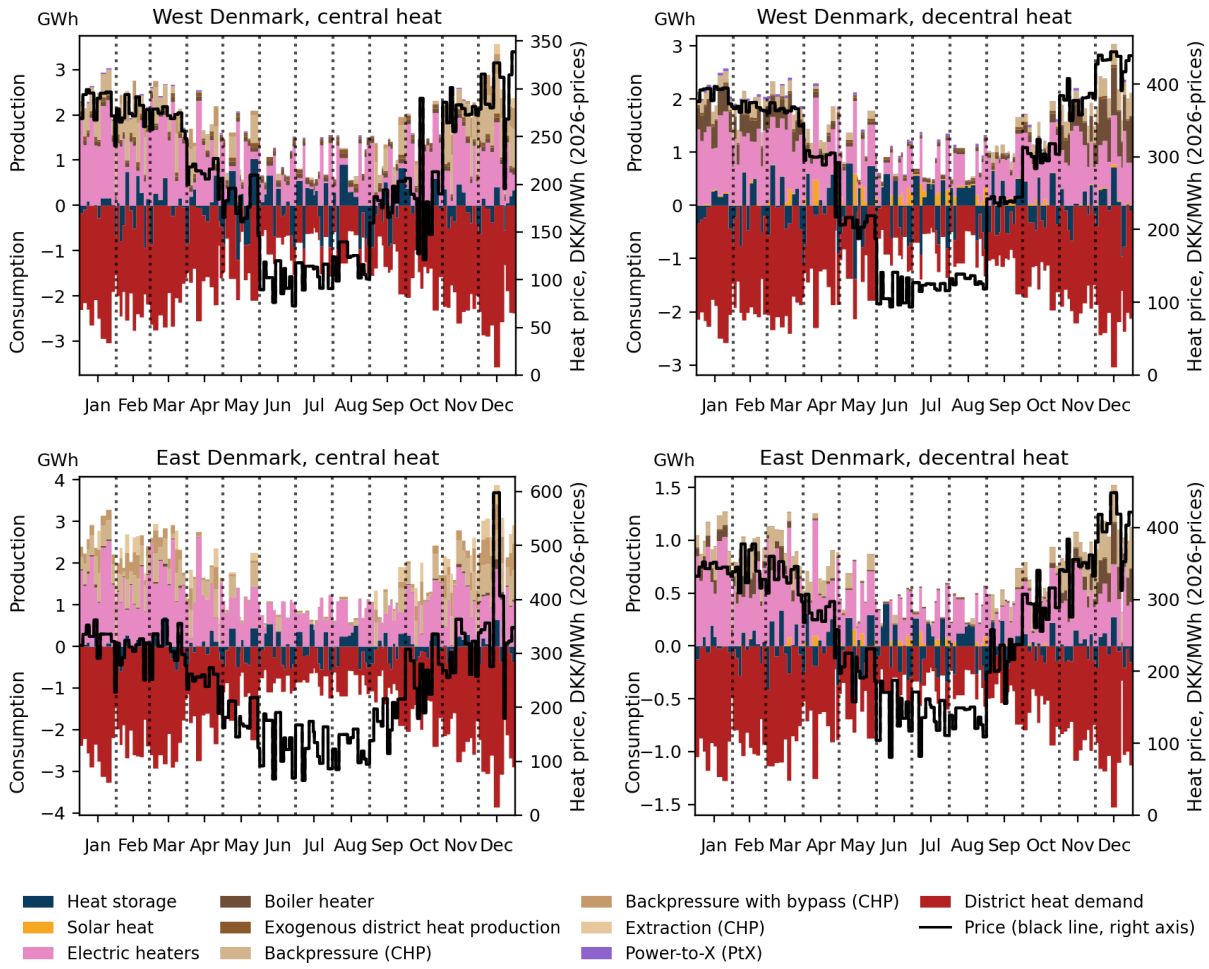


Figure 106: District heat in the four heat markets, 2035, states in calendar order, GW. The legend below applies to all four panels.

K Each Danish connection on its own

Figures 56 and 57 net the partners of an area against one another. The figures here take one connection at a time, in 2035, and split the net flow by the plant types that produced it: when the Danish area exports, across its own supply mix in that state; when it imports, across the partner's supply mix (below the axis, hatched). States are sorted by the Danish price.

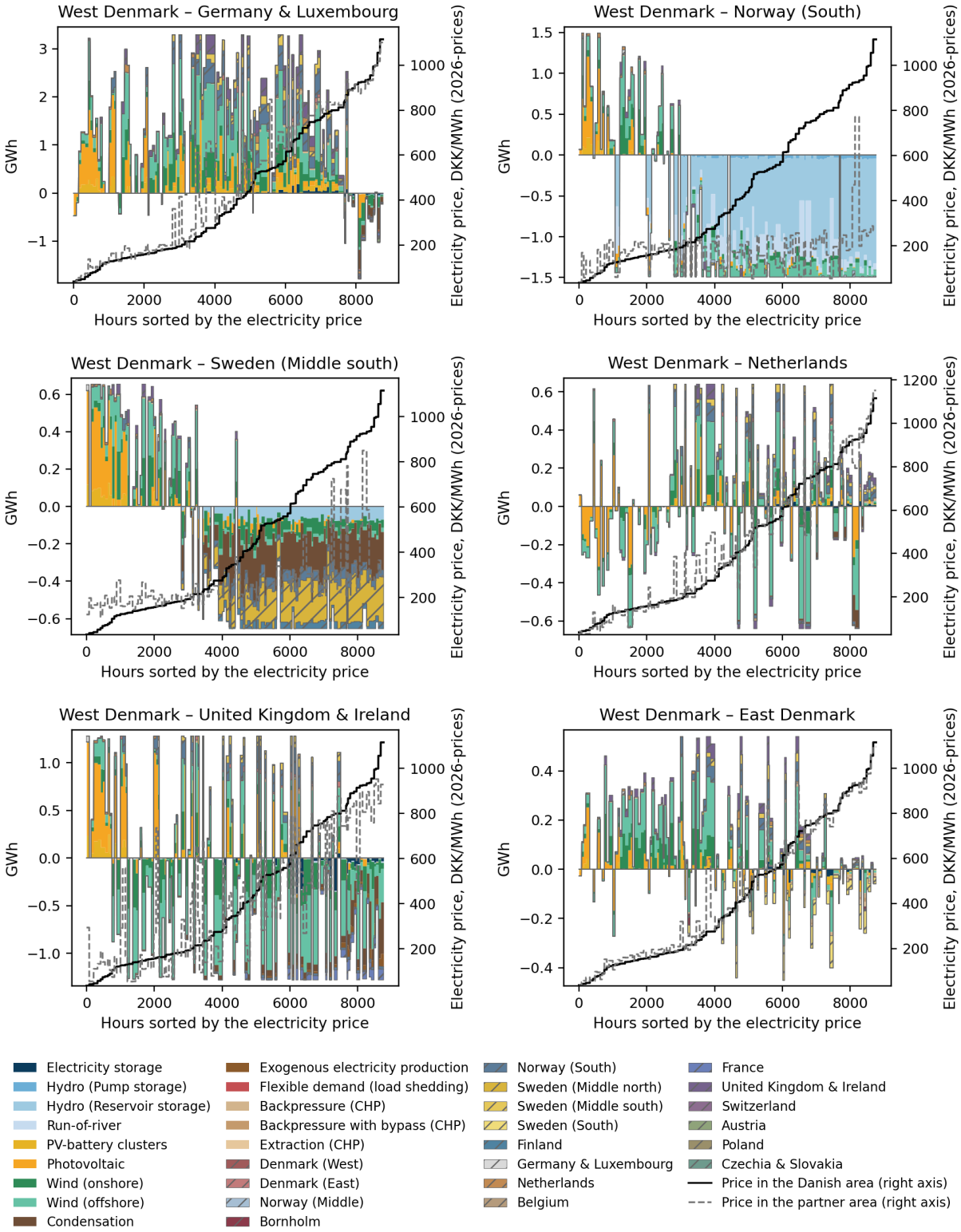


Figure 107: The connections of West Denmark, 2035, net flow by plant type, GW: Germany, southern Norway, middle Sweden, the Netherlands, Great Britain and Ireland, East Denmark. Black line: West Danish price; grey dashed line: the partner's price (right axis). The legend below applies to all six panels.

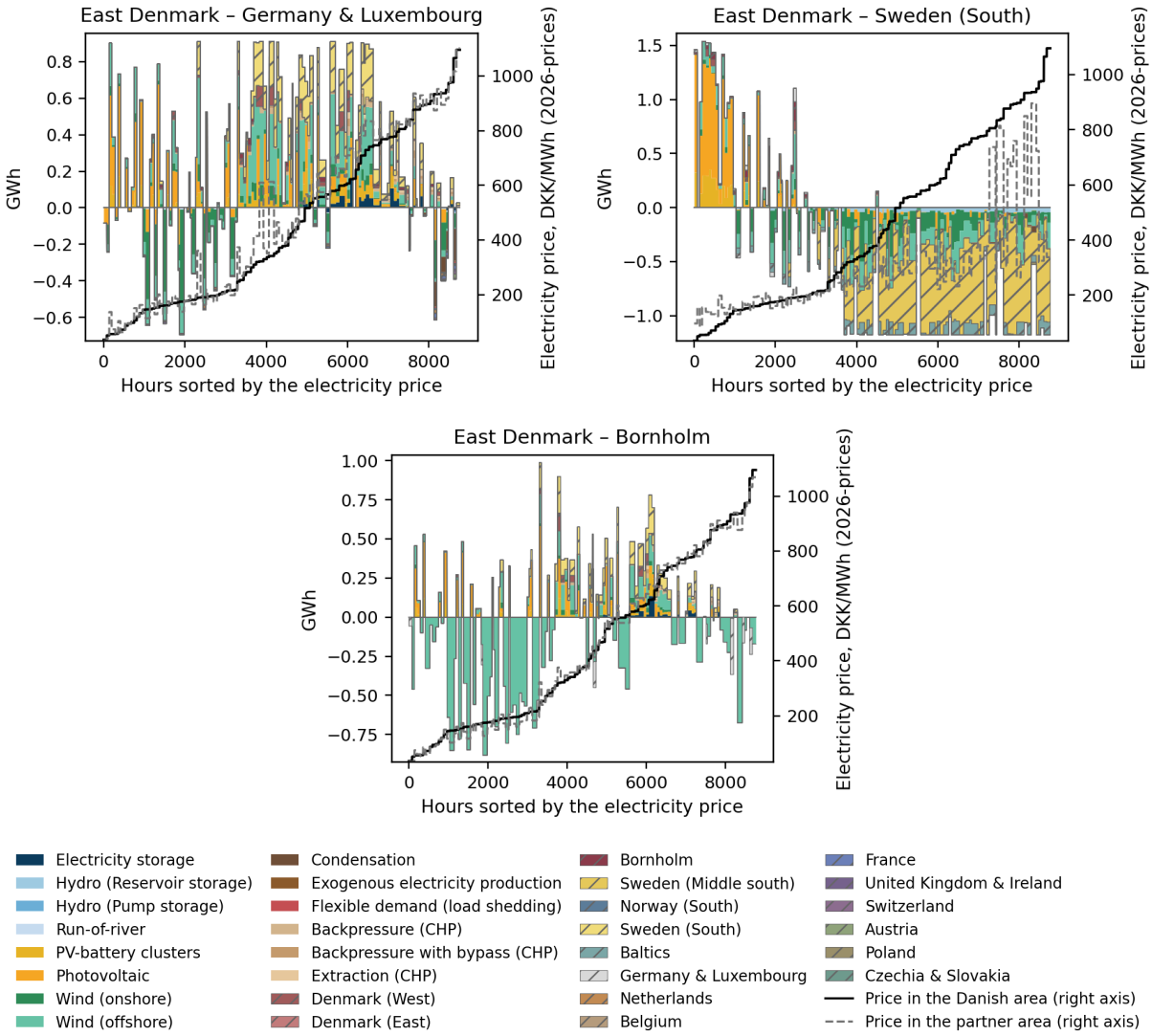


Figure 108: The connections of East Denmark, 2035, net flow by plant type, GW: Germany, southern Sweden, Energiø Bornholm. Black line: East Danish price; grey dashed line: the partner's price (right axis). The legend below applies to all three panels.

L Production, consumption and prices on the map, 2025 and 2050

The maps of Section 11.9, drawn for 2025 and 2050.

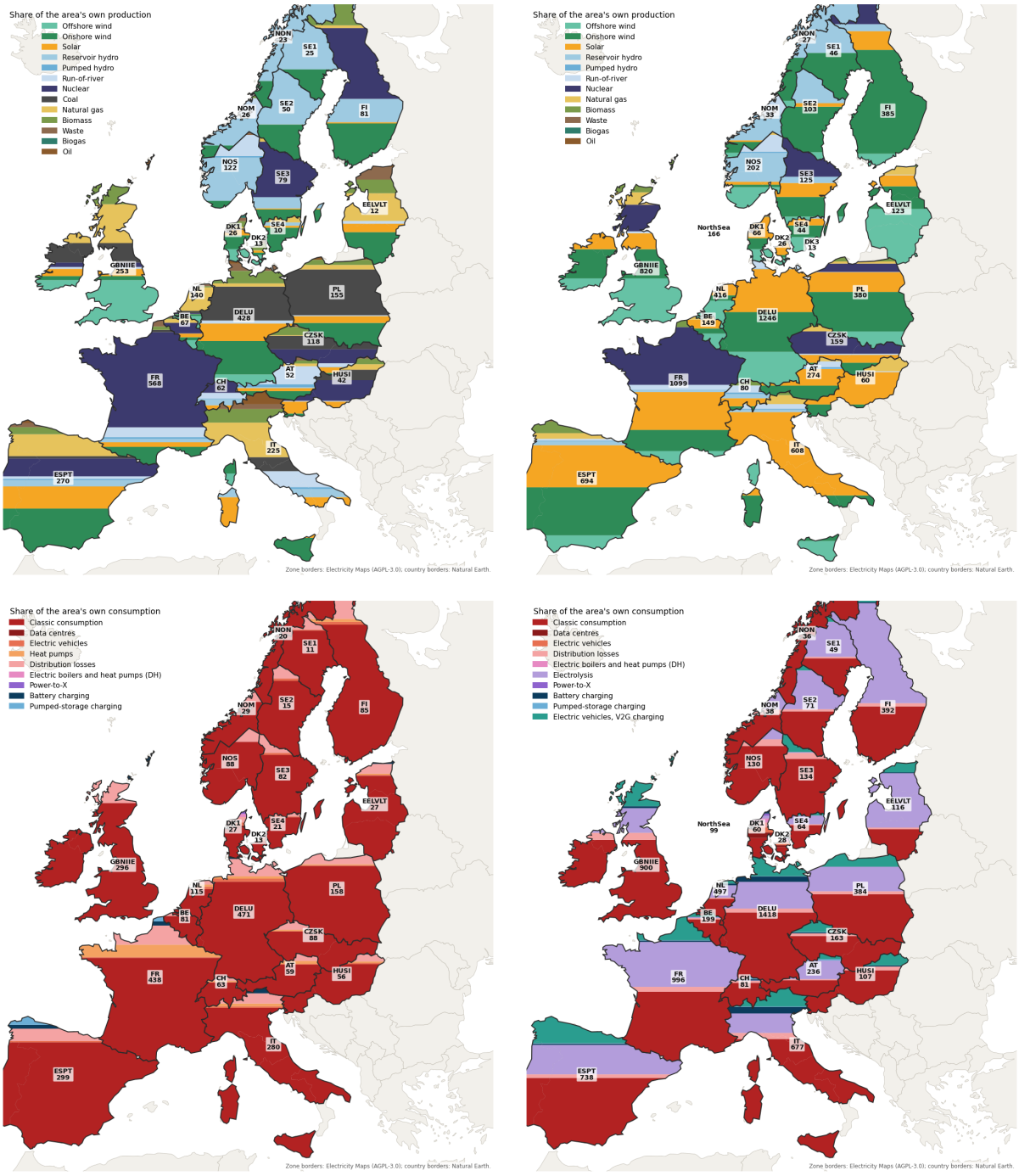


Figure 109: Production mix (top) and consumption by use (bottom), 2025 (left) and 2050 (right).

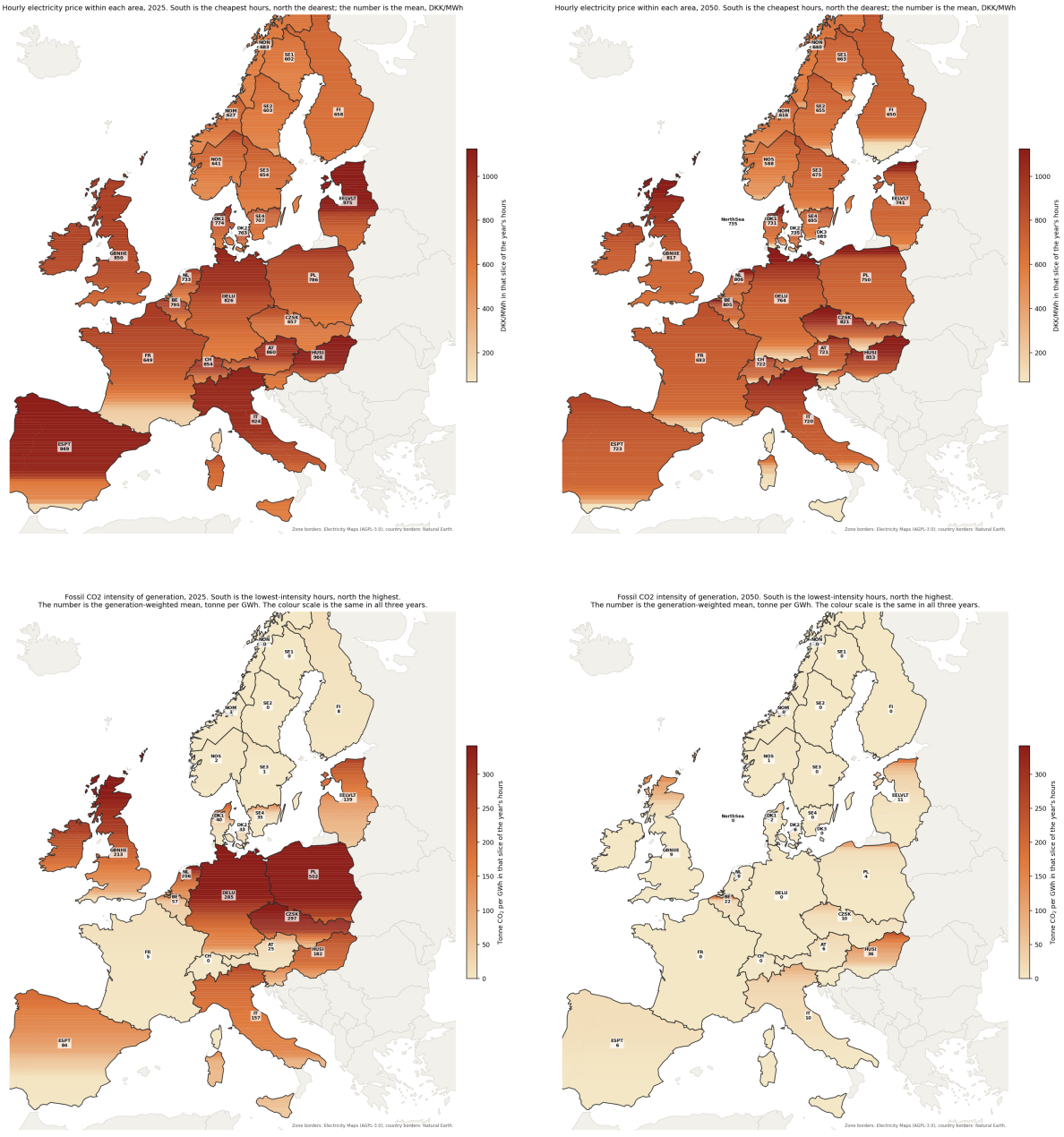


Figure 110: Price-duration curves (top, DKK/MWh) and fossil CO_2 intensity (bottom, kg/MWh), 2025 (left) and 2050 (right).

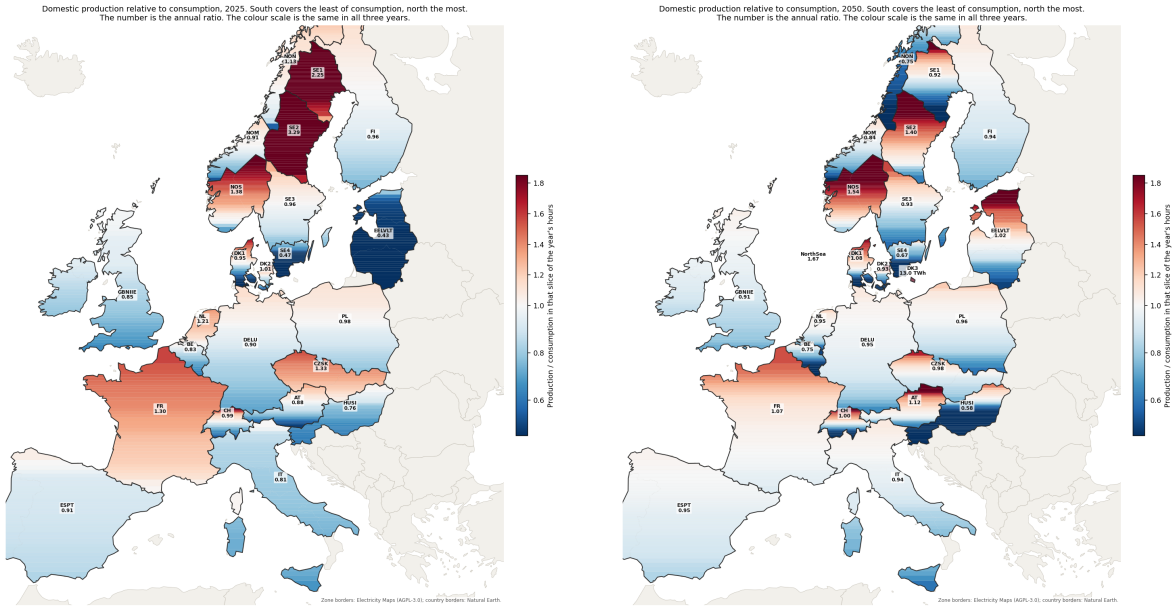


Figure 111: Generation relative to consumption, 2025 (left) and 2050 (right).

M The 2035 money account

Table 12 reports the account behind Figure 71, billion DKK. The paying side is what leaves a buyer; the receiving side is where it lands. Profit is after fixed operating costs and before investment. The last line closes the account: distribution losses, the transmission loss and the smoothing wedge in unit profit.

Table 12: Who pays and who receives in Denmark, 2035, billion DKK.

Who pays	
Classic demand, electricity	15.5
Classic demand, grid tariff	6.1
Data centres, electricity	3.5
Data centres, grid tariff	1.4
Transport, electricity	4.8
Transport, grid tariff	6.9
District heat	13.0
Buyers of Danish hydrogen	1.4
Electricity exports	10.4
Waste and hazardous waste	0.4
Production subsidies and the CCS payment	0.3
Total	63.6
Who receives	
Profit after fixed operating costs	22.3
Fixed operating costs	8.1
Variable operating costs	1.8
Fuel, at the commodity price	2.0
Biogas resource rent	0.1
Danish CO_2, heat, NO_x and SO_2 taxes	1.9
Charge on electric heat	0.1
ETS1 quota payments	0.8
Grid tariffs	17.5
Electricity imports	7.6
Losses and the smoothing wedge	1.5
Total	63.6