Modelling weather risks for the evaluation of renewable investments

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joint work with Margarita Flores and Francisco Gaspar Machado

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Agenda

Weather risks in electricity markets

Modelling long term power markets

Financing renewable investments

Remarks and conclusions

Weather risks in electricity markets

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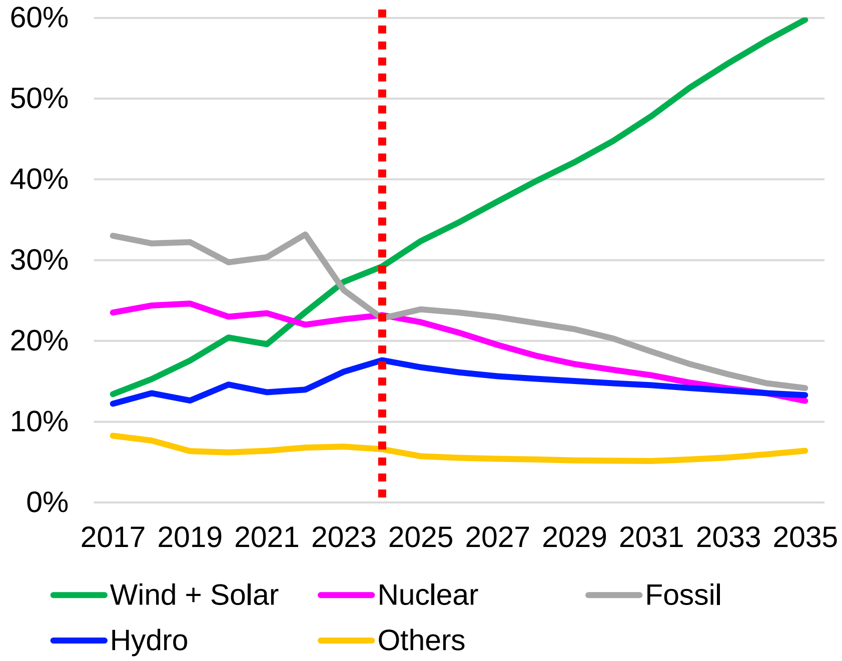
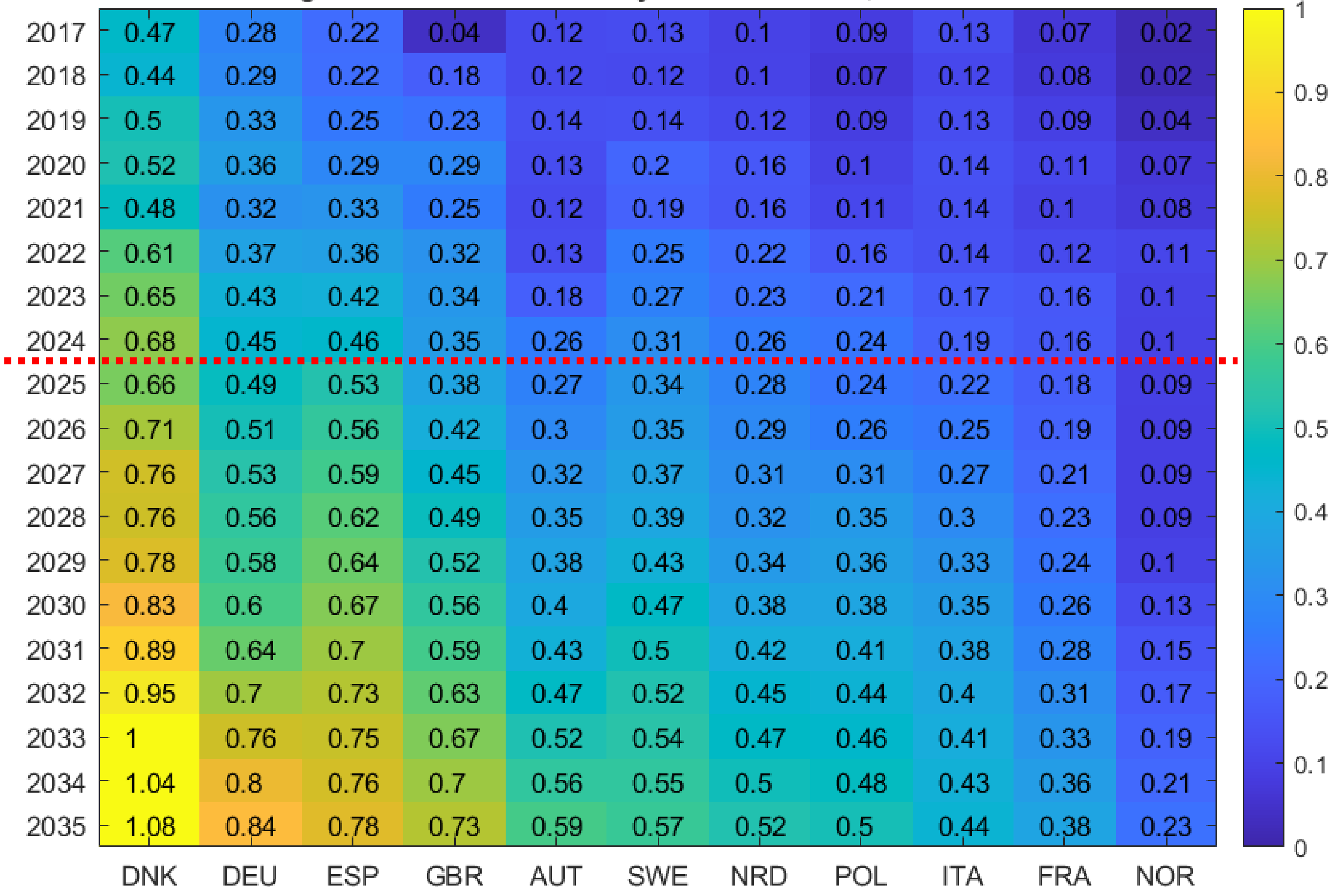
Intermittent renewable generation in Europe

Percentage of power demand covered by different tech, EU



Percentage of demand covered by solar and wind, selected countries



	DNK	DEU	ESP	GBR	AUT	SWE	NRD	POL	ITA	FRA	NOR
2017	0.47	0.28	0.22	0.04	0.12	0.13	0.1	0.09	0.13	0.07	0.02
2018	0.44	0.29	0.22	0.18	0.12	0.12	0.1	0.07	0.12	0.08	0.02
2019	0.5	0.33	0.25	0.23	0.14	0.14	0.12	0.09	0.13	0.09	0.04
2020	0.52	0.36	0.29	0.29	0.13	0.2	0.16	0.1	0.14	0.11	0.07
2021	0.48	0.32	0.33	0.25	0.12	0.19	0.16	0.11	0.14	0.1	0.08
2022	0.61	0.37	0.36	0.32	0.13	0.25	0.22	0.16	0.14	0.12	0.11
2023	0.65	0.43	0.42	0.34	0.18	0.27	0.23	0.21	0.17	0.16	0.1
2024	0.68	0.45	0.46	0.35	0.26	0.31	0.26	0.24	0.19	0.16	0.1
2025	0.66	0.49	0.53	0.38	0.27	0.34	0.28	0.24	0.22	0.18	0.09
2026	0.71	0.51	0.56	0.42	0.3	0.35	0.29	0.26	0.25	0.19	0.09
2027	0.76	0.53	0.59	0.45	0.32	0.37	0.31	0.31	0.27	0.21	0.09
2028	0.76	0.56	0.62	0.49	0.35	0.39	0.32	0.35	0.3	0.23	0.09
2029	0.78	0.58	0.64	0.52	0.38	0.43	0.34	0.36	0.33	0.24	0.1
2030	0.83	0.6	0.67	0.56	0.4	0.47	0.38	0.38	0.35	0.26	0.13
2031	0.89	0.64	0.7	0.59	0.43	0.5	0.42	0.41	0.38	0.28	0.15
2032	0.95	0.7	0.73	0.63	0.47	0.52	0.45	0.44	0.4	0.31	0.17
2033	1	0.76	0.75	0.67	0.52	0.54	0.47	0.46	0.41	0.33	0.19
2034	1.04	0.8	0.76	0.7	0.56	0.55	0.5	0.48	0.43	0.36	0.21
2035	1.08	0.84	0.78	0.73	0.59	0.57	0.52	0.5	0.44	0.38	0.23

Wind + solar in Europe:

- ~ 370 TWh (2017)
- ~ 700 TWh (2023)
- > 2000 TWh (2035)

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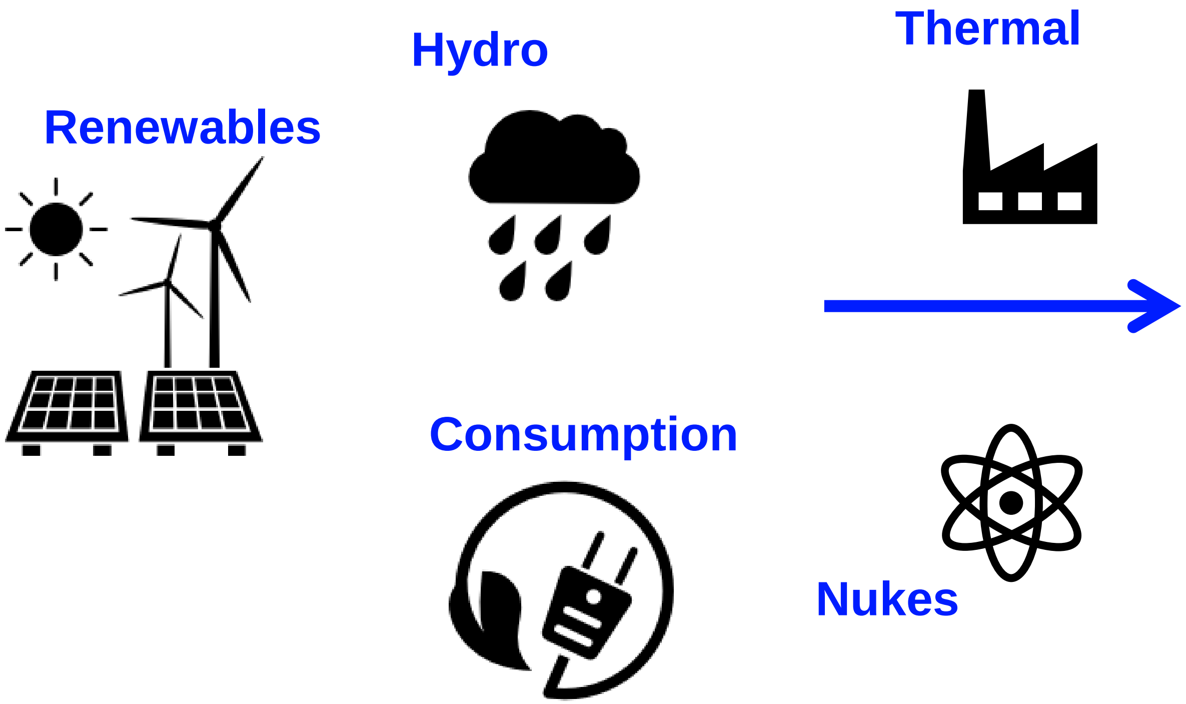
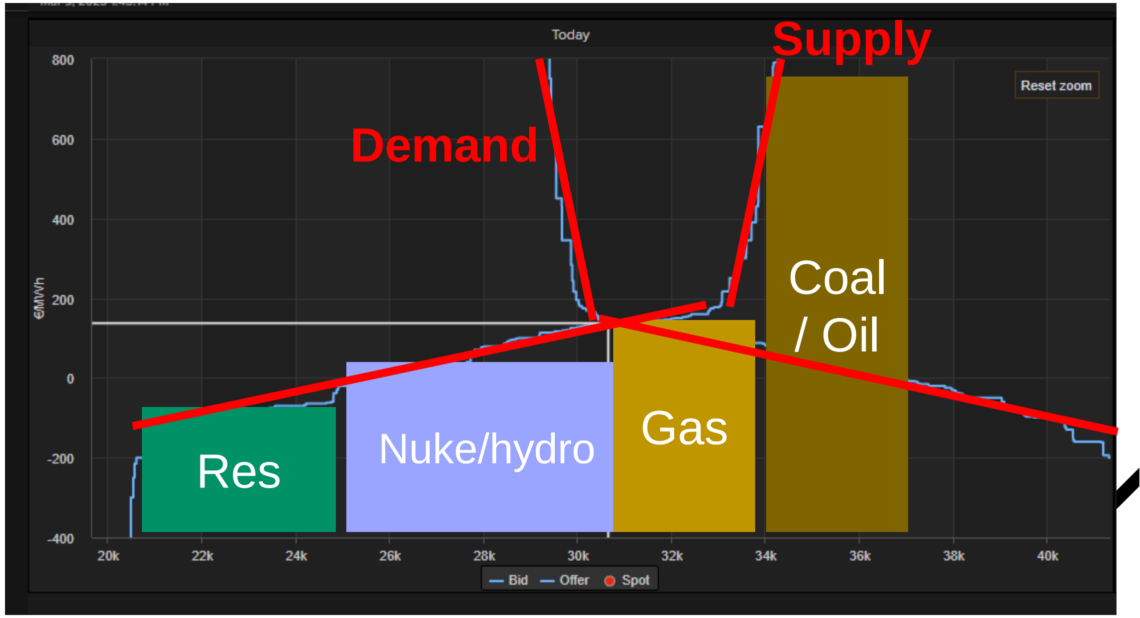
How is intermittent generation integrated in electricity markets

Formation of the electricity price:

- **Liberalized power market** where different actors are free to bid and offer their energy at their optimal (marginal) price
- Spot price derives from **the intersection between supply and demand**
- **Single coupled market across all Europe →** the spot price calculation algorithm (Euphemia) accounts for the possibility of flows and optimizes such flows





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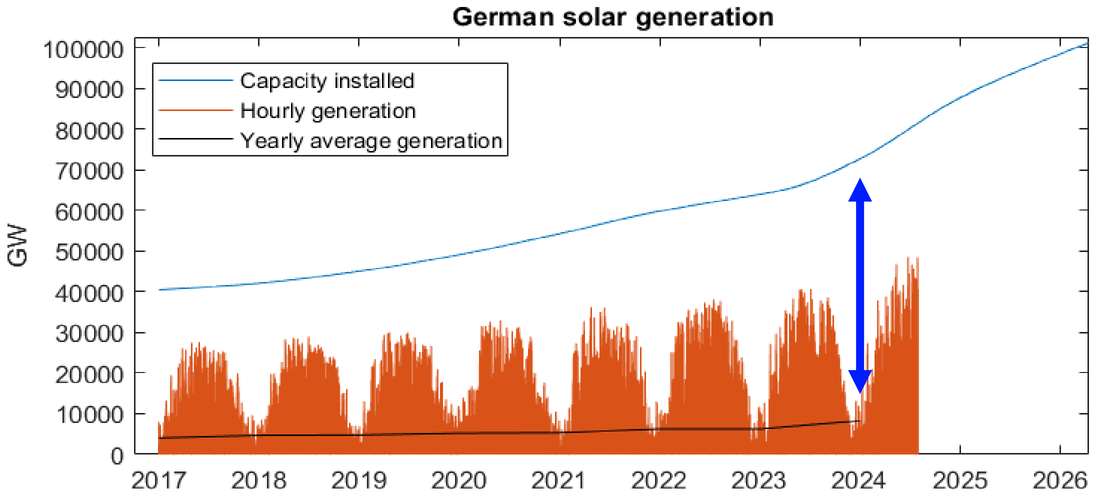
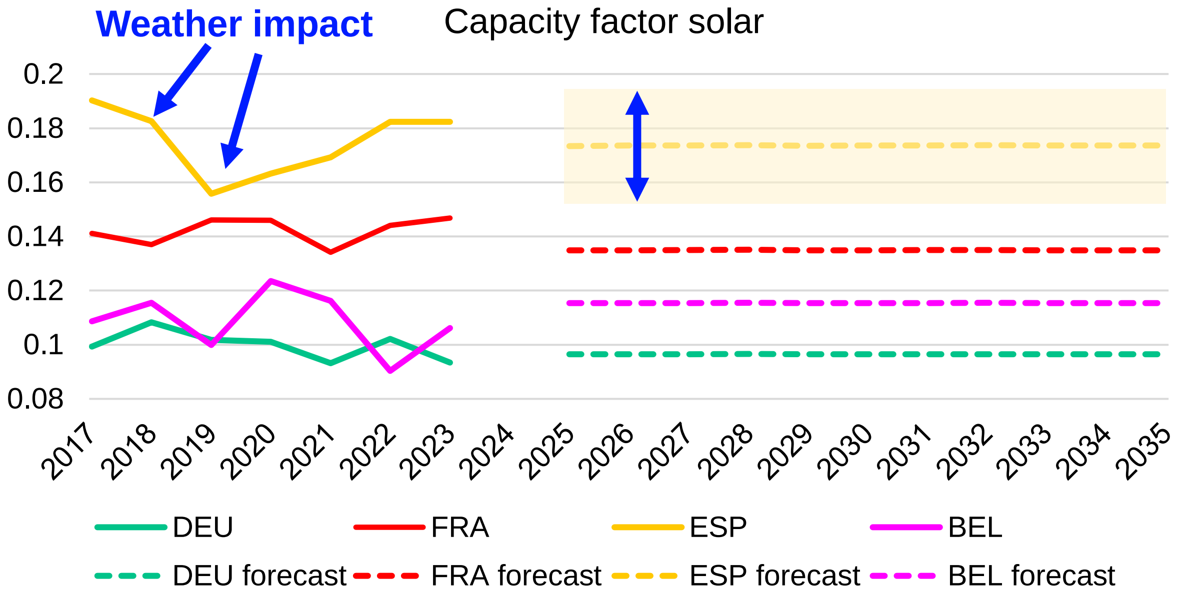
Challenges of **intermittent renewables** vs traditional electricity forms (nuclear, thermal, hydro):

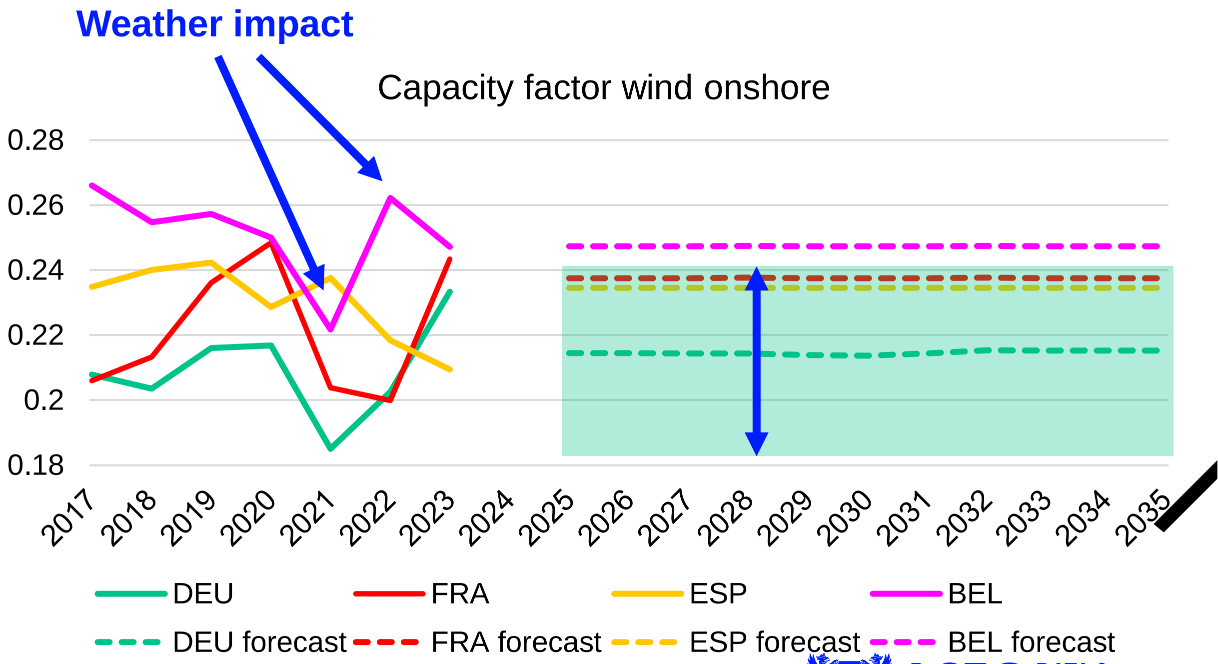
1) Low capacity factors
2) Cannibalization across countries
3) Correlation in weather risk
4) Curtailment / Negative prices
5) Forecast errors

1) Capacity factor (load factor)



- Load factor for renewables is low (~10% for solar, ~22/25% for wind onshore, ~33/37% for wind offshore)
- Large differences due to weather. Also, large seasonal differences
- Impacted by curtailment (voluntary or forced reduction)
- Impacted by climate change! (wind decreasing in North Sea)
- Impacted by technology (+) and by location of new farms (-)





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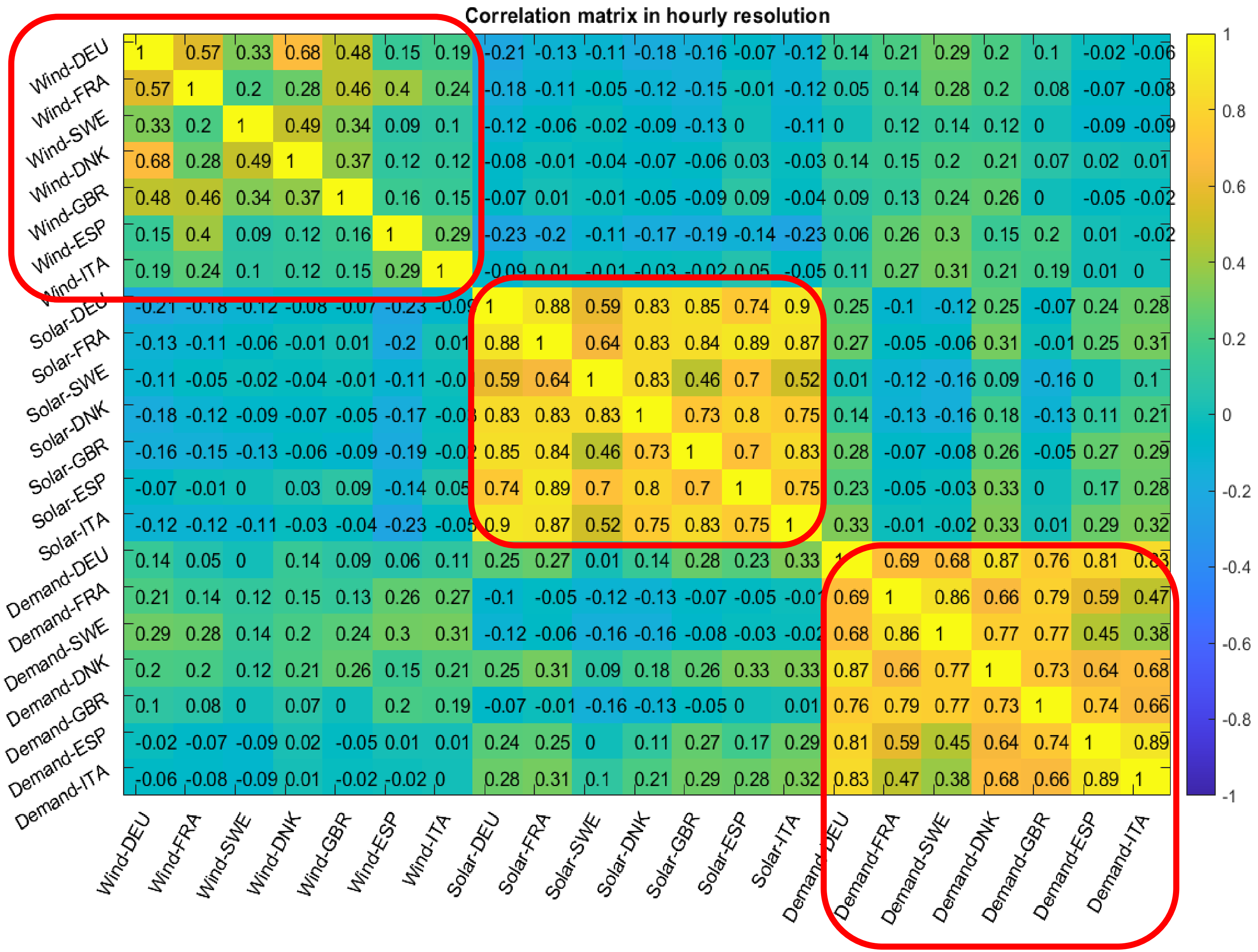
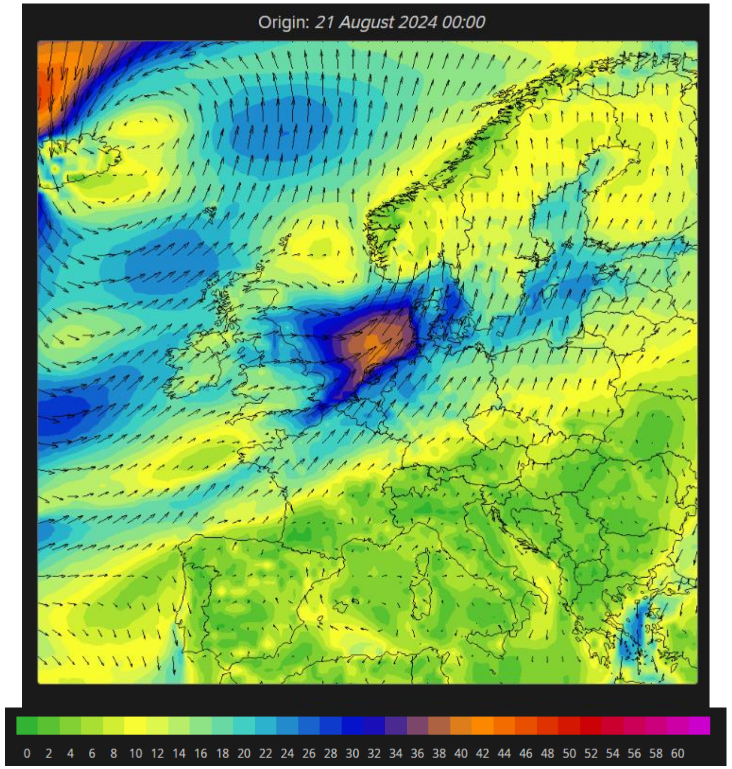
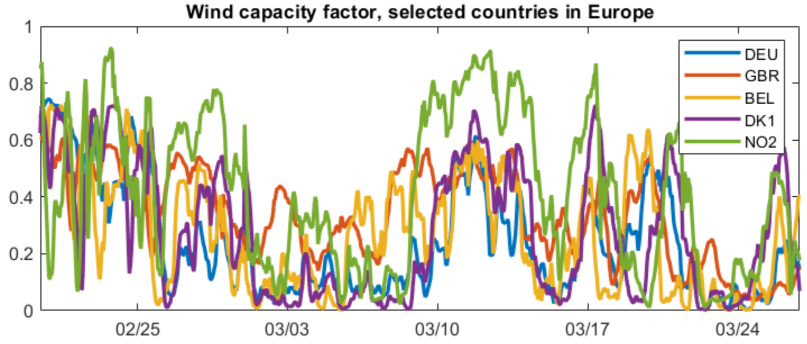
2) Cannibalization across countries



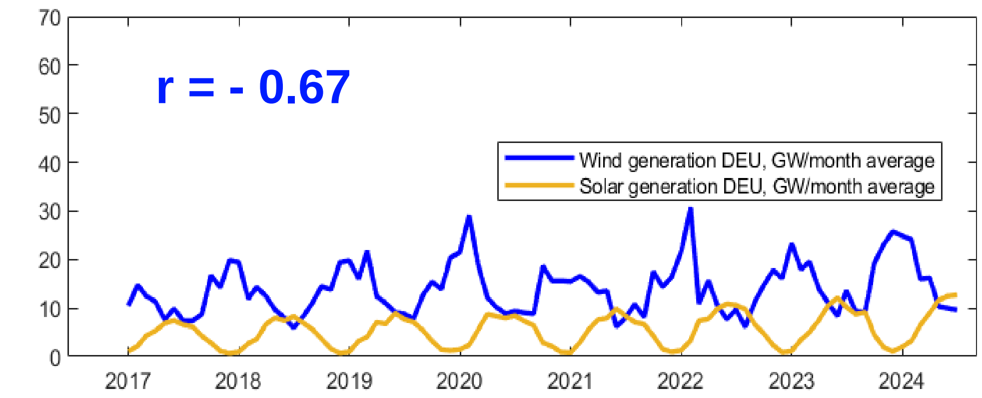
Correlation matrix in hourly resolution

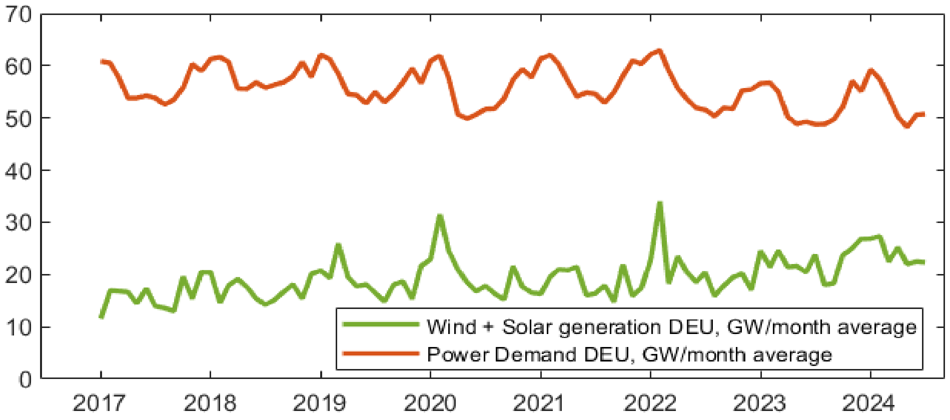
	Wind-DEU	Wind-FRA	Wind-SWE	Wind-DNK	Wind-GBR	Wind-ESP	Wind-ITA	Solar-DEU	Solar-FRA	Solar-SWE	Solar-DNK	Solar-GBR	Solar-ESP	Solar-ITA	Demand-DEU	Demand-FRA	Demand-SWE	Demand-DNK	Demand-GBR	Demand-ESP	Demand-ITA
Wind-DEU	1	0.57	0.33	0.68	0.48	0.15	0.19	-0.21	-0.13	-0.11	-0.18	-0.16	-0.07	-0.12	0.14	0.21	0.29	0.2	0.1	-0.02	-0.06
Wind-FRA	0.57	1	0.2	0.28	0.46	0.4	0.24	-0.18	-0.11	-0.05	-0.12	-0.15	-0.01	-0.12	0.05	0.14	0.28	0.2	0.08	-0.07	-0.08
Wind-SWE	0.33	0.2	1	0.49	0.34	0.09	0.1	-0.12	-0.06	-0.02	-0.09	-0.13	0	-0.11	0	0.12	0.14	0.12	0	-0.09	-0.09
Wind-DNK	0.68	0.28	0.49	1	0.37	0.12	0.12	-0.08	-0.01	-0.04	-0.07	-0.06	0.03	-0.03	0.14	0.15	0.2	0.21	0.07	0.02	0.01
Wind-GBR	0.48	0.46	0.34	0.37	1	0.16	0.15	-0.07	0.01	-0.01	-0.05	-0.09	0.09	-0.04	0.09	0.13	0.24	0.26	0	-0.05	-0.02
Wind-ESP	0.15	0.4	0.09	0.12	0.16	1	0.29	-0.23	-0.2	-0.11	-0.17	-0.19	-0.14	-0.23	0.06	0.26	0.3	0.15	0.2	0.01	-0.02
Wind-ITA	0.19	0.24	0.1	0.12	0.15	0.29	1	-0.09	0.01	-0.01	-0.03	-0.02	0.05	-0.05	0.11	0.27	0.31	0.21	0.19	0.01	0
Solar-DEU	-0.21	-0.18	-0.12	-0.08	-0.07	-0.23	-0.09	1	0.88	0.59	0.83	0.85	0.74	0.9	0.25	-0.1	-0.12	0.25	-0.07	0.24	0.28
Solar-FRA	-0.13	-0.11	-0.06	-0.01	0.01	-0.2	0.01	0.88	1	0.64	0.83	0.84	0.89	0.87	0.27	-0.05	-0.06	0.31	-0.01	0.25	0.31
Solar-SWE	-0.11	-0.05	-0.02	-0.04	-0.01	-0.11	-0.01	0.59	0.64	1	0.83	0.46	0.7	0.52	0.01	-0.12	-0.16	0.09	-0.16	0	0.1
Solar-DNK	-0.18	-0.12	-0.09	-0.07	-0.05	-0.17	-0.03	0.83	0.83	0.83	1	0.73	0.8	0.75	0.14	-0.13	-0.16	0.18	-0.13	0.11	0.21
Solar-GBR	-0.16	-0.15	-0.13	-0.06	-0.09	-0.19	-0.02	0.85	0.84	0.46	0.73	1	0.7	0.83	0.28	-0.07	-0.08	0.26	-0.05	0.27	0.29
Solar-ESP	-0.07	-0.01	0	0.03	0.09	-0.14	0.05	0.74	0.89	0.7	0.8	0.7	1	0.75	0.23	-0.05	-0.03	0.33	0	0.17	0.28
Solar-ITA	-0.12	-0.12	-0.11	-0.03	-0.04	-0.23	-0.05	0.9	0.87	0.52	0.75	0.83	0.75	1	0.33	-0.01	-0.02	0.33	0.01	0.29	0.32
Demand-DEU	0.14	0.05	0	0.14	0.09	0.06	0.11	0.25	0.27	0.01	0.14	0.28	0.23	0.33	1	0.69	0.68	0.87	0.76	0.81	0.83
Demand-FRA	0.21	0.14	0.12	0.15	0.13	0.26	0.27	-0.1	-0.05	-0.12	-0.13	-0.07	-0.05	-0.01	0.69	1	0.86	0.66	0.79	0.59	0.47
Demand-SWE	0.29	0.28	0.14	0.2	0.24	0.3	0.31	-0.12	-0.06	-0.16	-0.16	-0.08	-0.03	-0.02	0.68	0.86	1	0.77	0.77	0.45	0.38
Demand-DNK	0.2	0.2	0.12	0.21	0.26	0.15	0.21	0.25	0.31	0.09	0.18	0.26	0.33	0.33	0.87	0.66	0.77	1	0.73	0.64	0.68
Demand-GBR	0.1	0.08	0	0.07	0	0.2	0.19	-0.07	-0.01	-0.16	-0.13	-0.05	0	0.01	0.76	0.79	0.77	0.73	1	0.74	0.66
Demand-ESP	-0.02	-0.07	-0.09	0.02	-0.05	0.01	0.01	0.24	0.25	0	0.11	0.27	0.17	0.29	0.81	0.59	0.45	0.64	0.74	1	0.89
Demand-ITA	-0.06	-0.08	-0.09	0.01	-0.02	-0.02	0	0.28	0.31	0.1	0.21	0.29	0.28	0.32	0.83	0.47	0.38	0.68	0.66	0.89	1

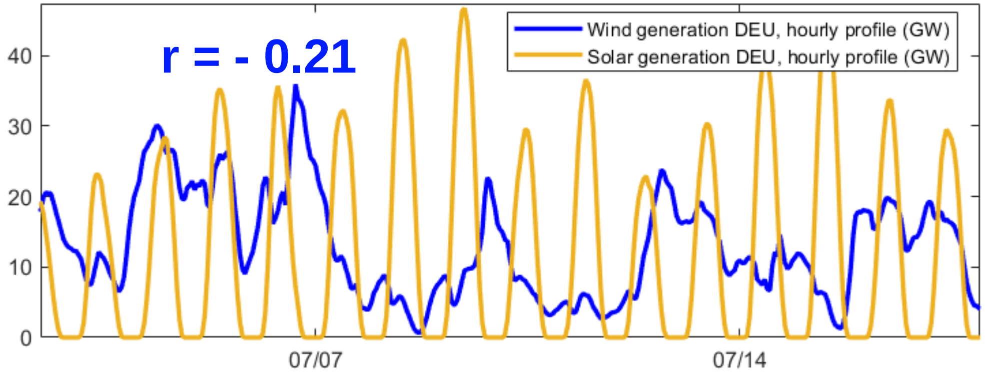




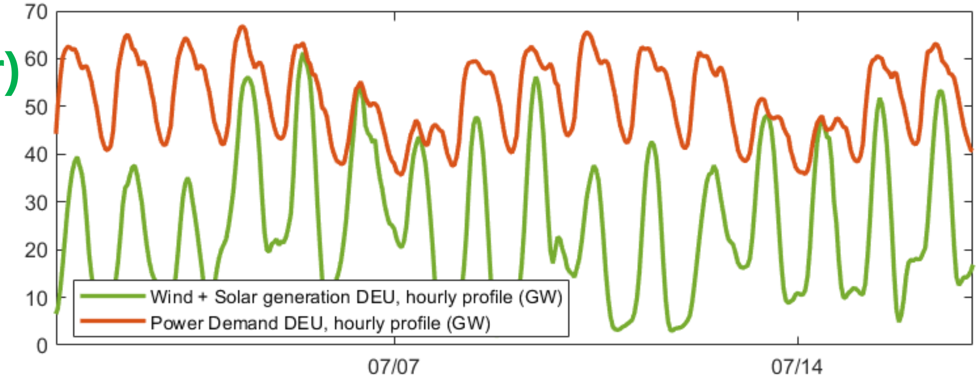
3) Correlation in weather risks



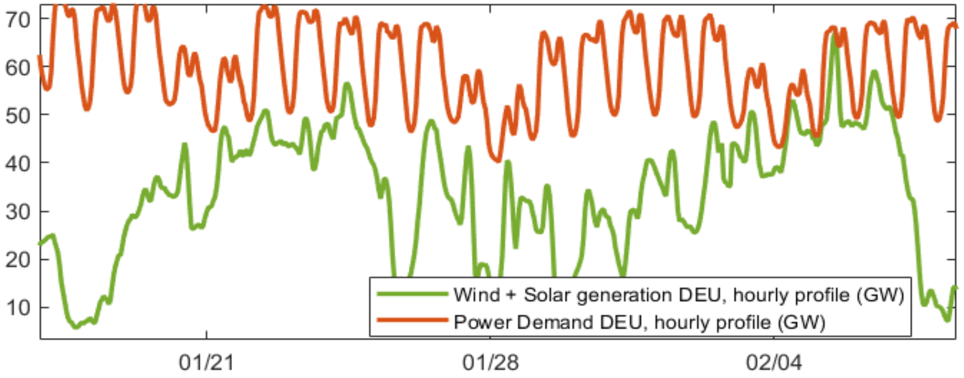




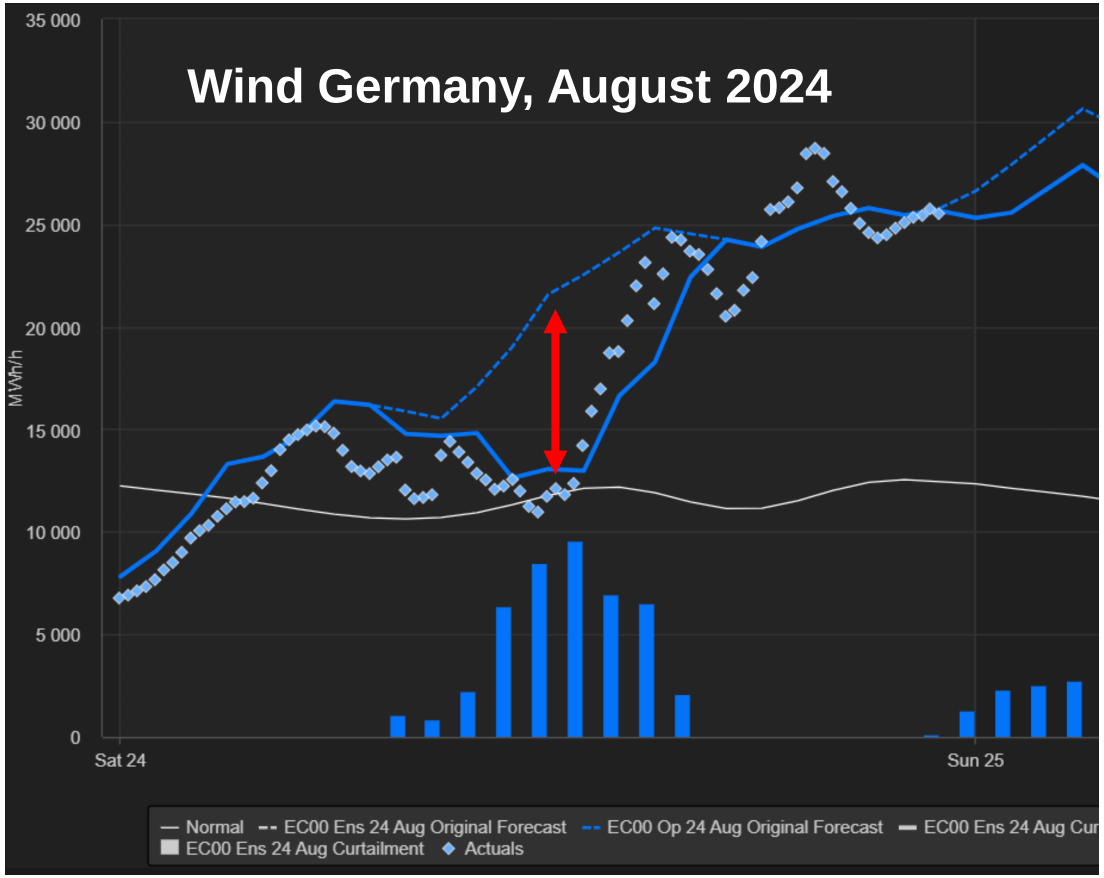
(summer)

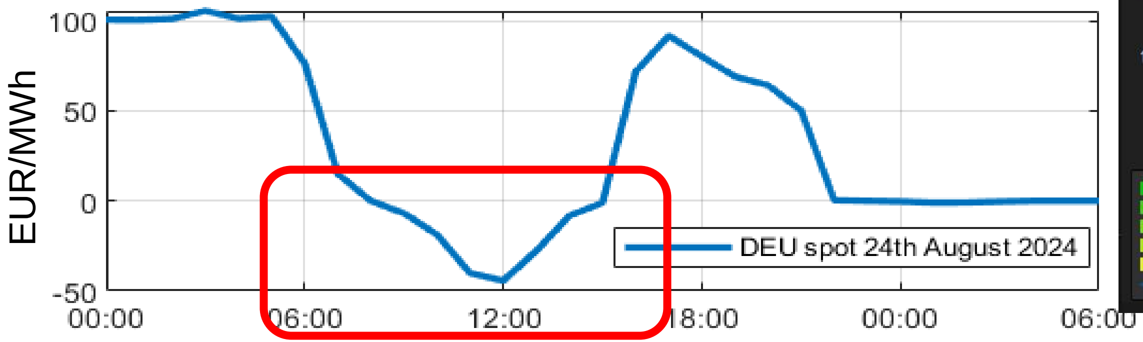


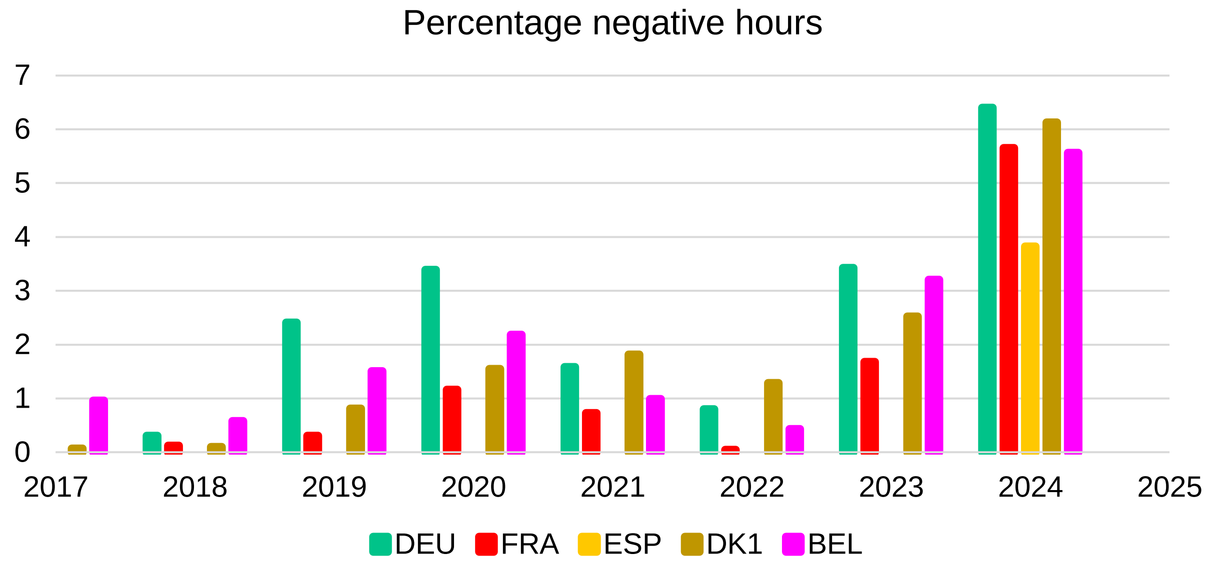
(winter)

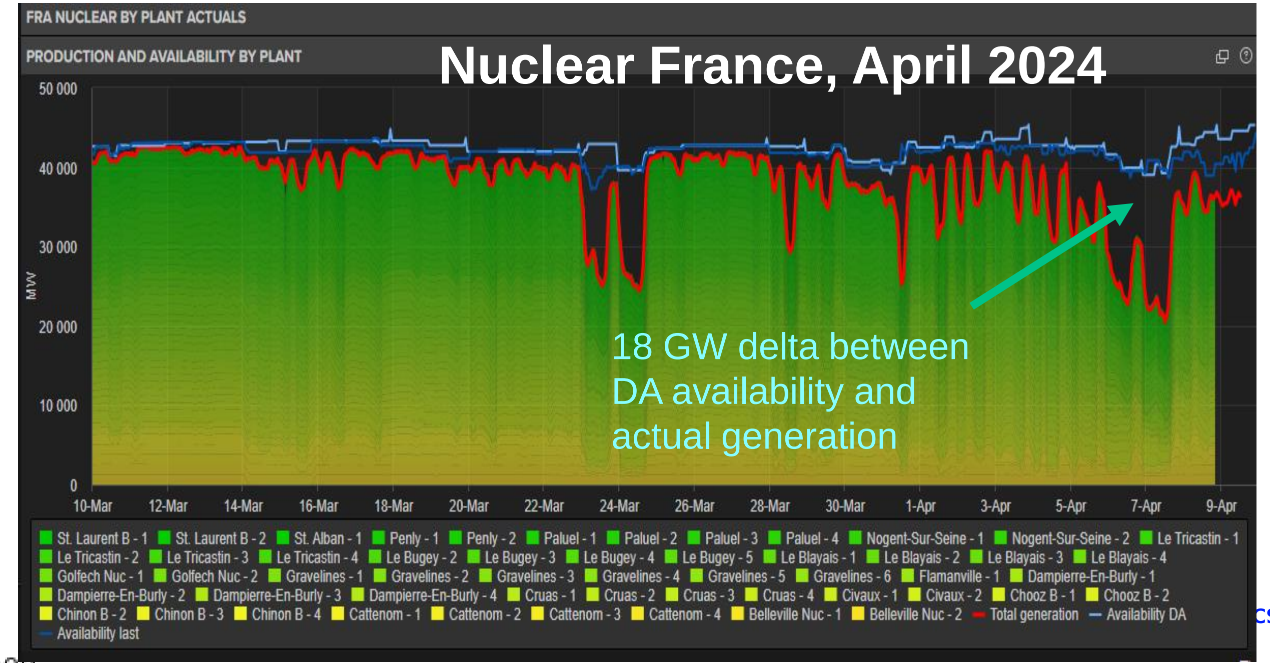


4) Curtailment / Negative prices



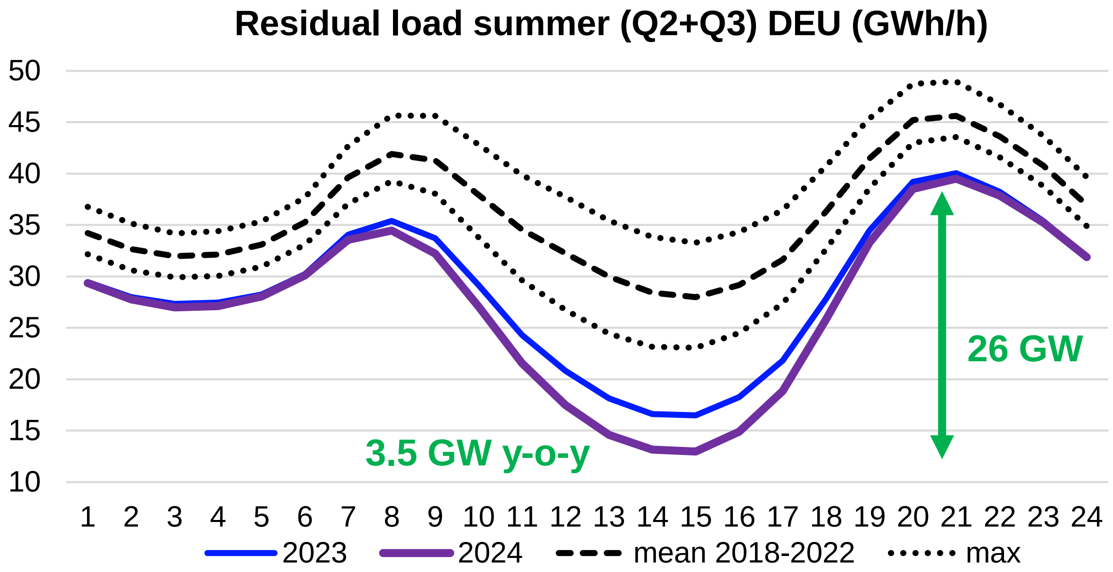


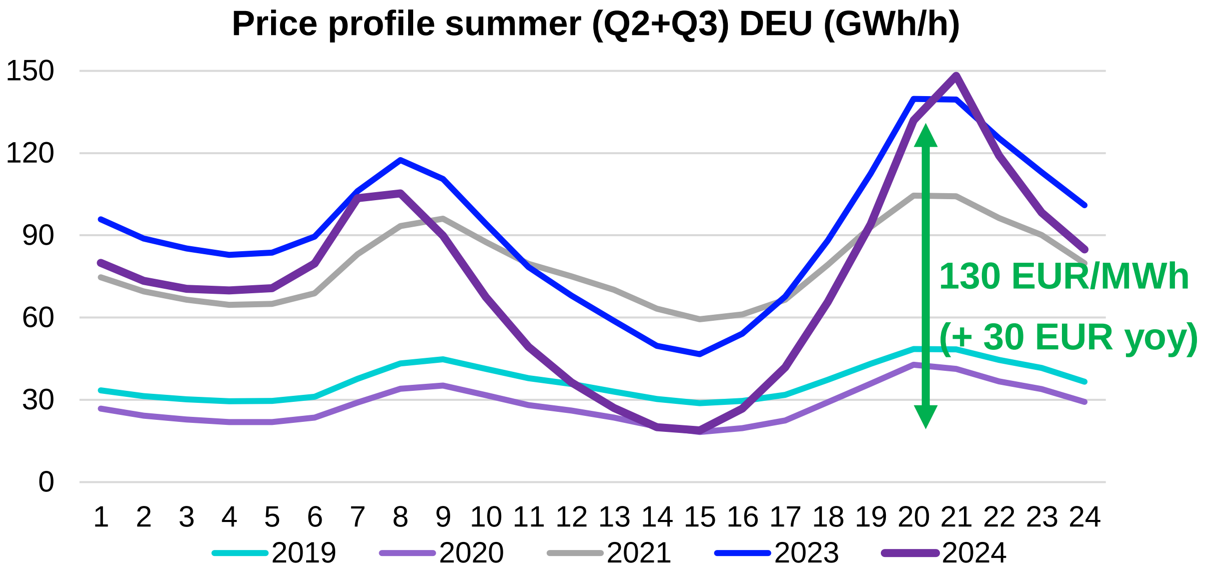




4) Curtailment / Negative prices

- The solar hours are becoming cheaper and cheaper every year.
- The residual demand in summer in these hours is going rapidly → 0 in most countries





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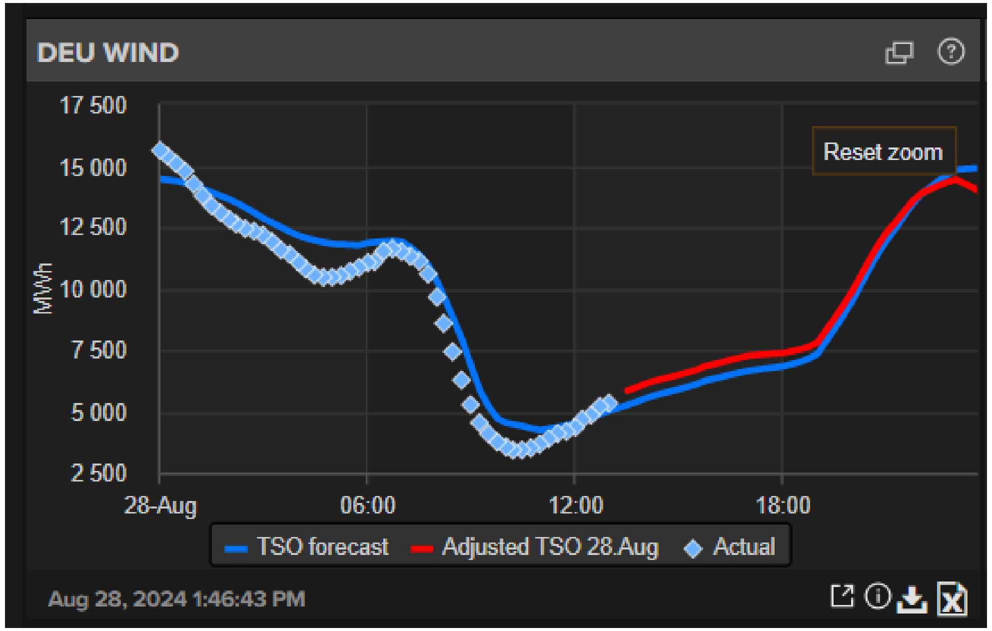
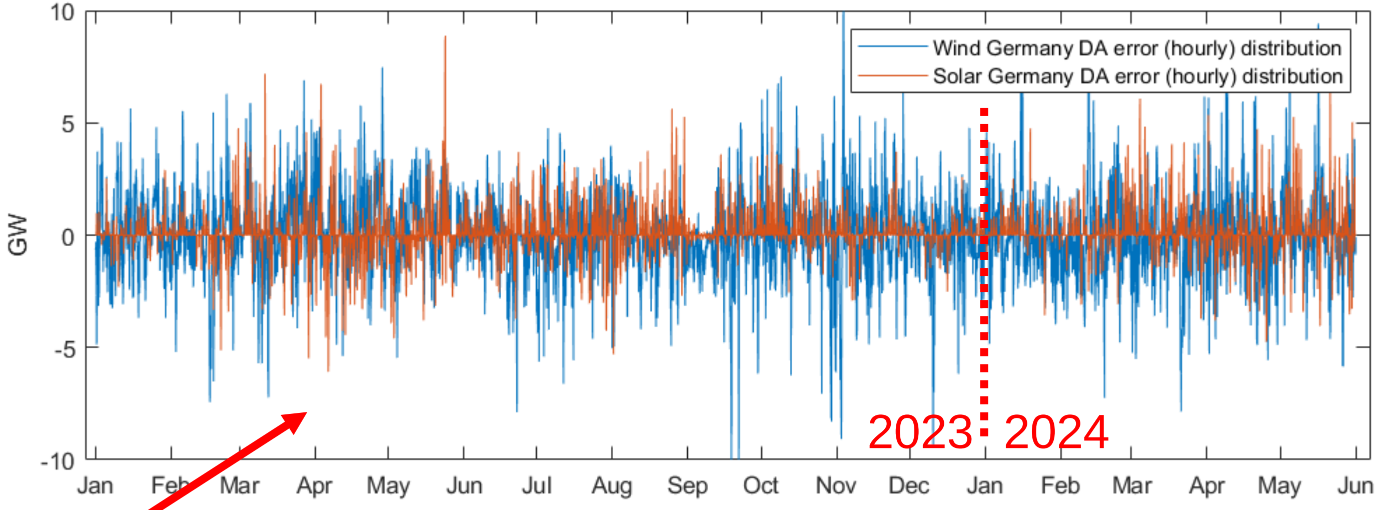
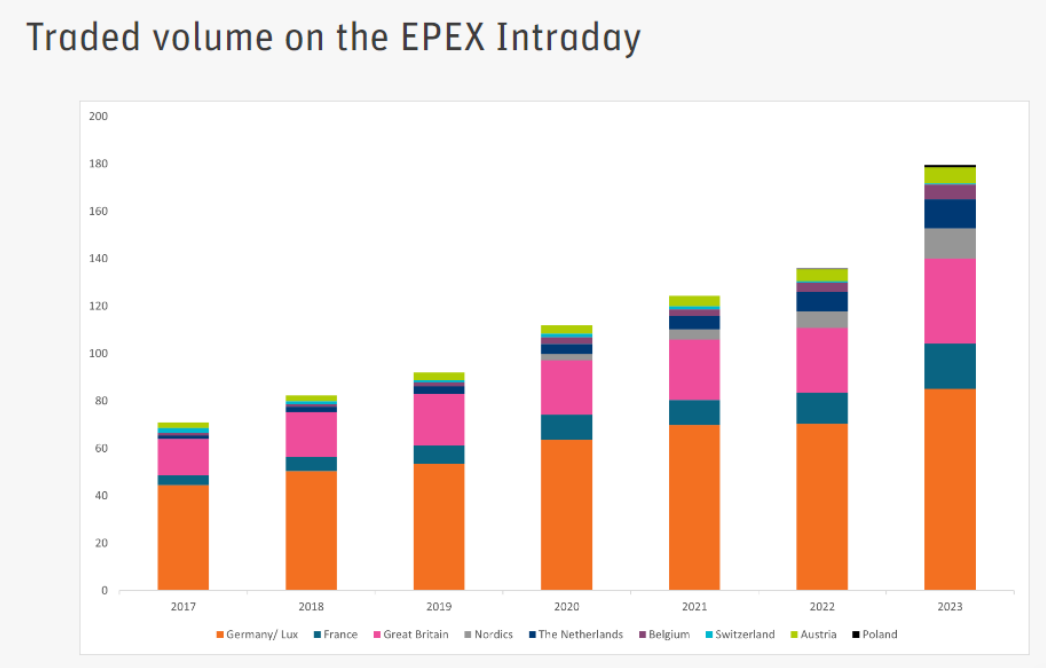
5) Forecast errors





12 TWh in 2023 (wind)
4 TWh in 2023 (solar)



This allows to calculate the imbalance cost (worst case scenario):

- Because of cannibalization/correlation, the hours with high balancing costs are not fully compensated by the hours with higher revenues!

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Modelling long term power markets

Stack model for 2035 Europe

Inputs

- Demand
- Renewable power generation
- Short duration storage capacity
- Thermal and nuclear availabilities
- Fuel and carbon prices
- Cross-border transfer capacities

- Hourly dispatching: front month to 2035
- **30 real weather scenarios 1991-2020** -> 30 price forecasts
- Coverage: 87% of EU27 demand / 90% of Europe

Outputs

- Prices (spot, capture, PPAs)
- Emissions
- Generation mix
- Fuel burn
- Border flows
- Need for flexibility

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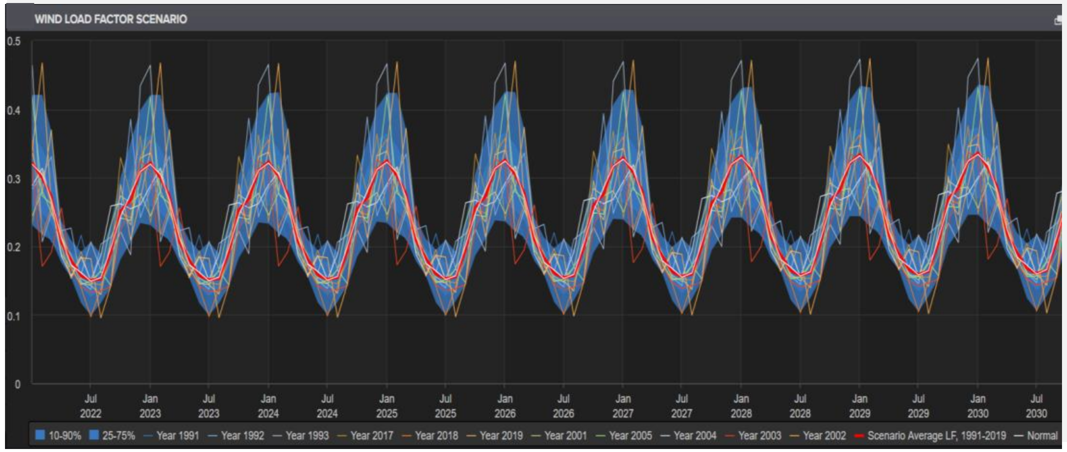
Weather scenarios for the energy transition

Country-specific hourly load factors from our fundamental models based on 30 historical weather years (1991 – 2020)



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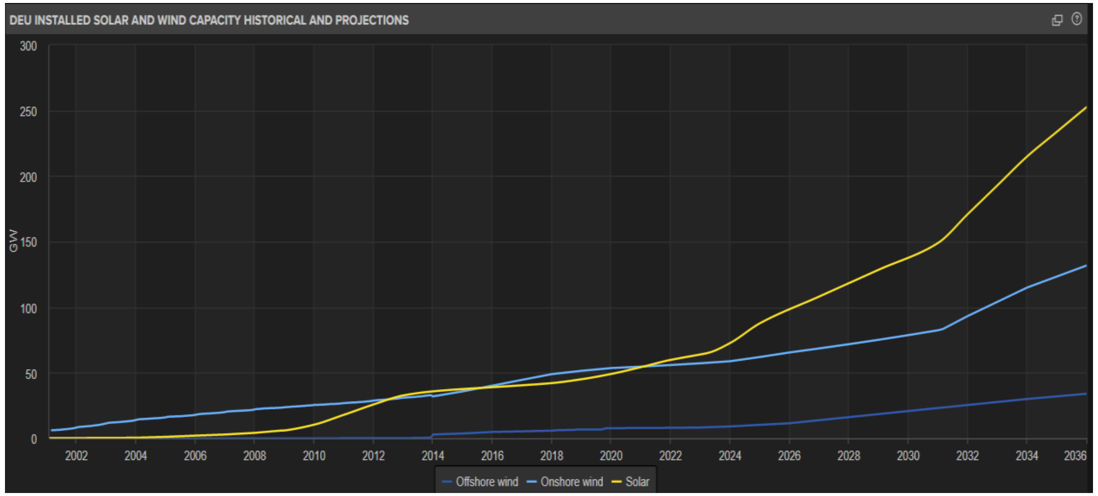
Capacity buildout assumptions, GW



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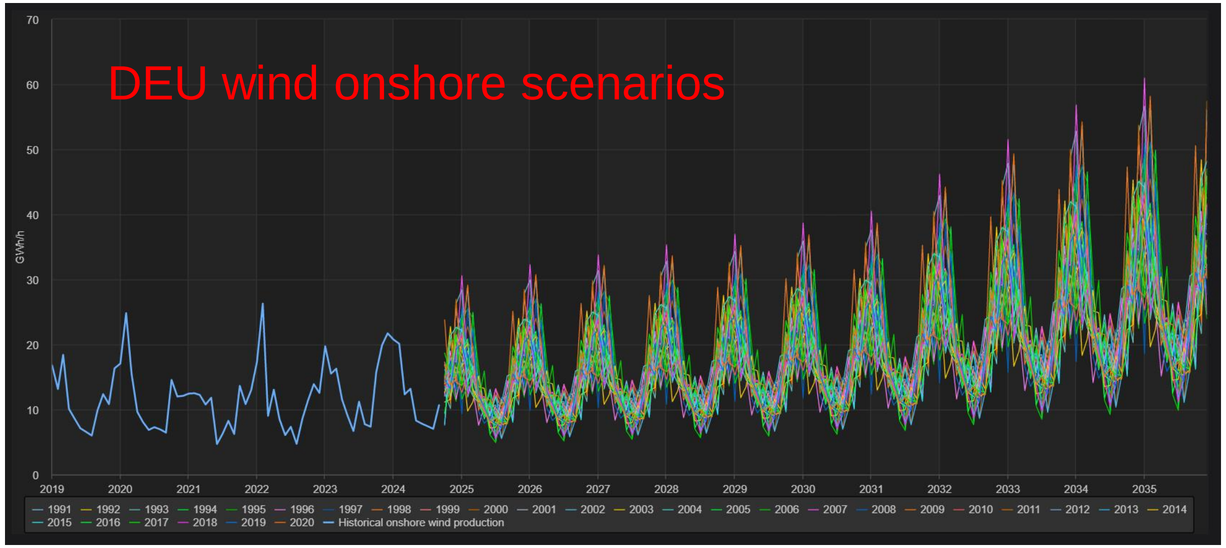
Weather scenarios in hourly resolution from now until 2035



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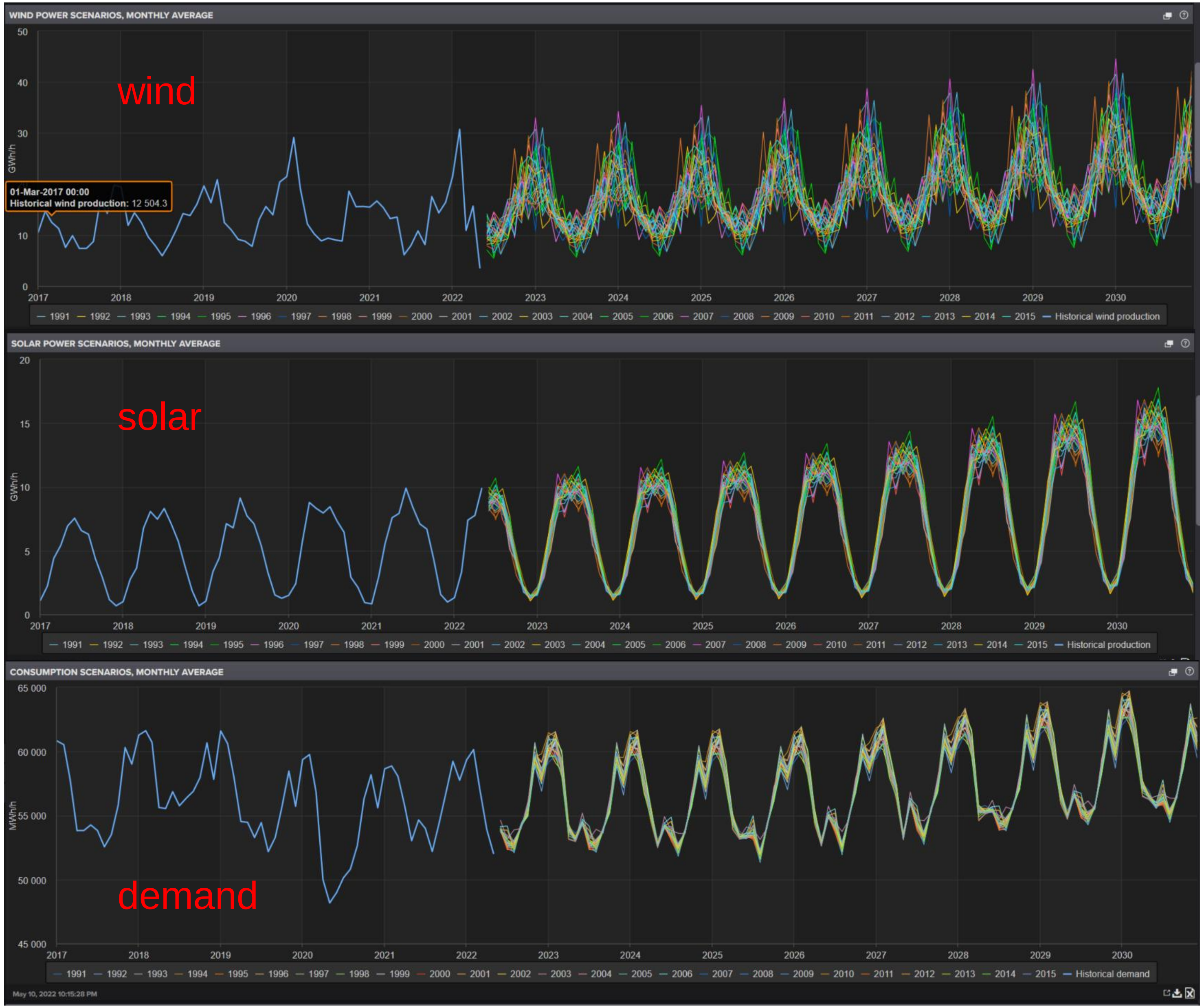
Weather scenarios for the energy transition



- Similar methodology (but different data) for wind, solar and demand scenarios
- Building good weather scenarios requires:
  - ✓ good physical/regression/ML models (wind, solar, demand)
  - ✓ complete actuals/reanalysis data
  - ✓ reliable and updates capacity estimates

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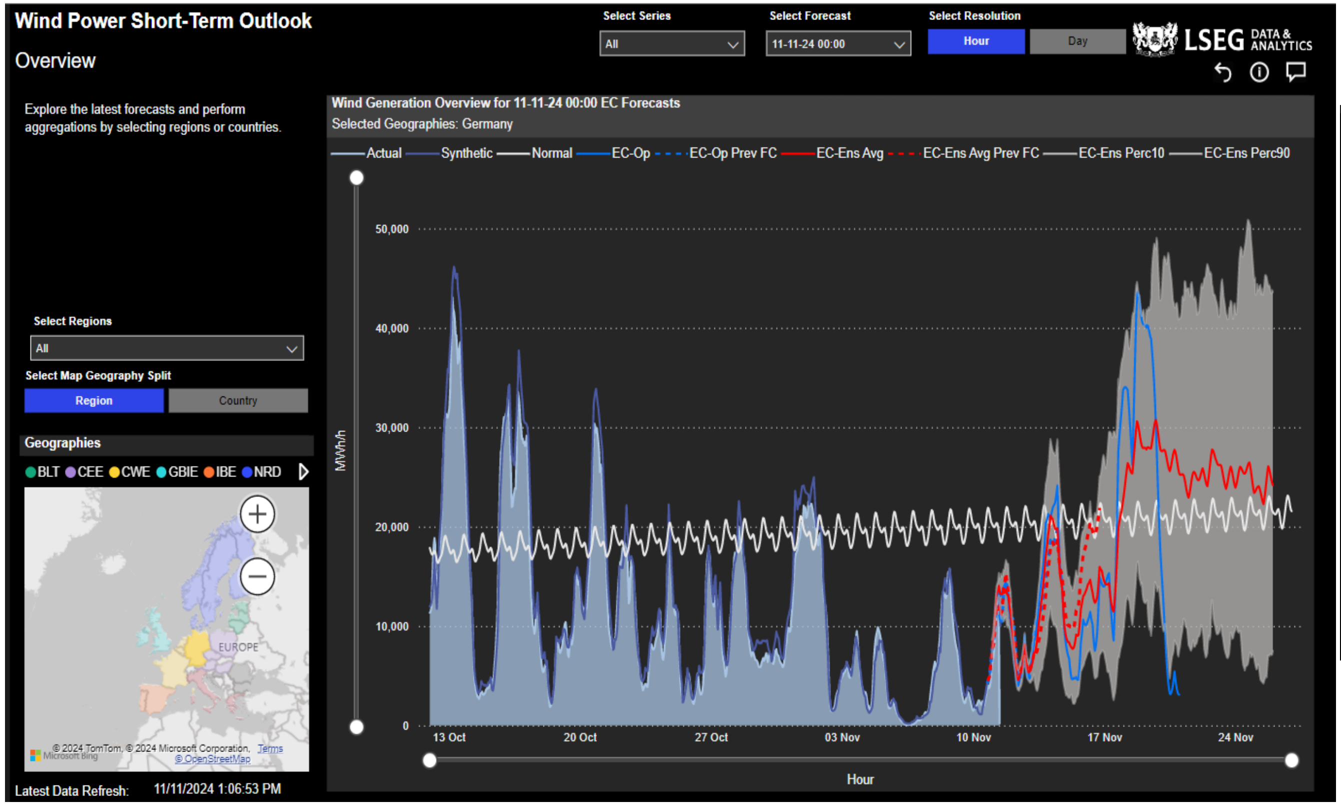
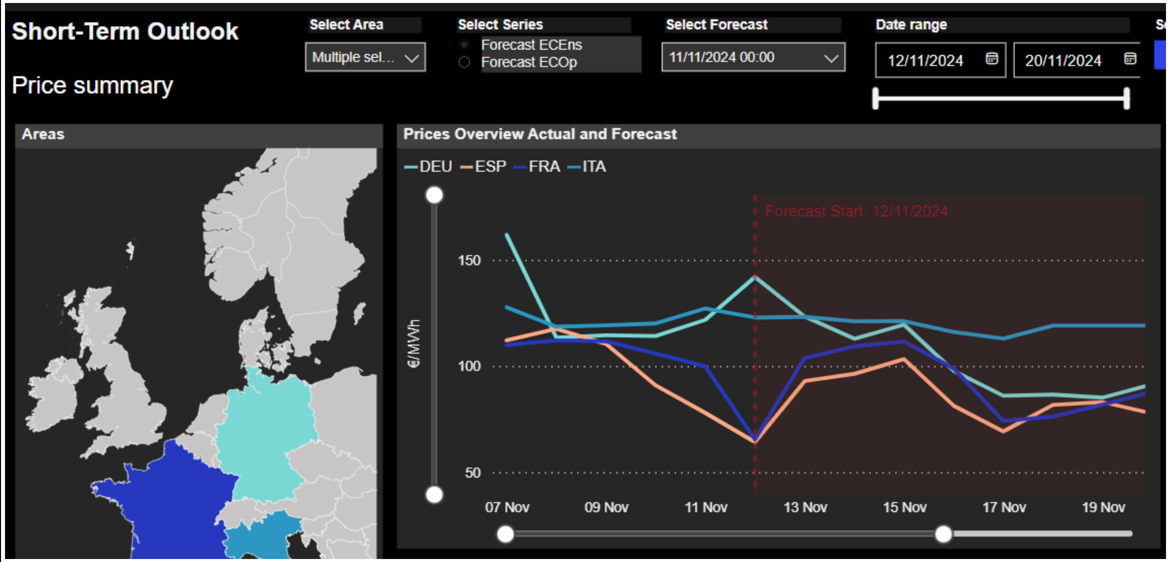
Short term results

$$Min \sum_{i \in genset} \sum_{z \in zones} c_{z,i} * g_{z,i}(h)$$

$$\sum_{i} g_{z,i} + \sum_{z'} f_{z',z} = d_z \quad , \forall z \in zone$$

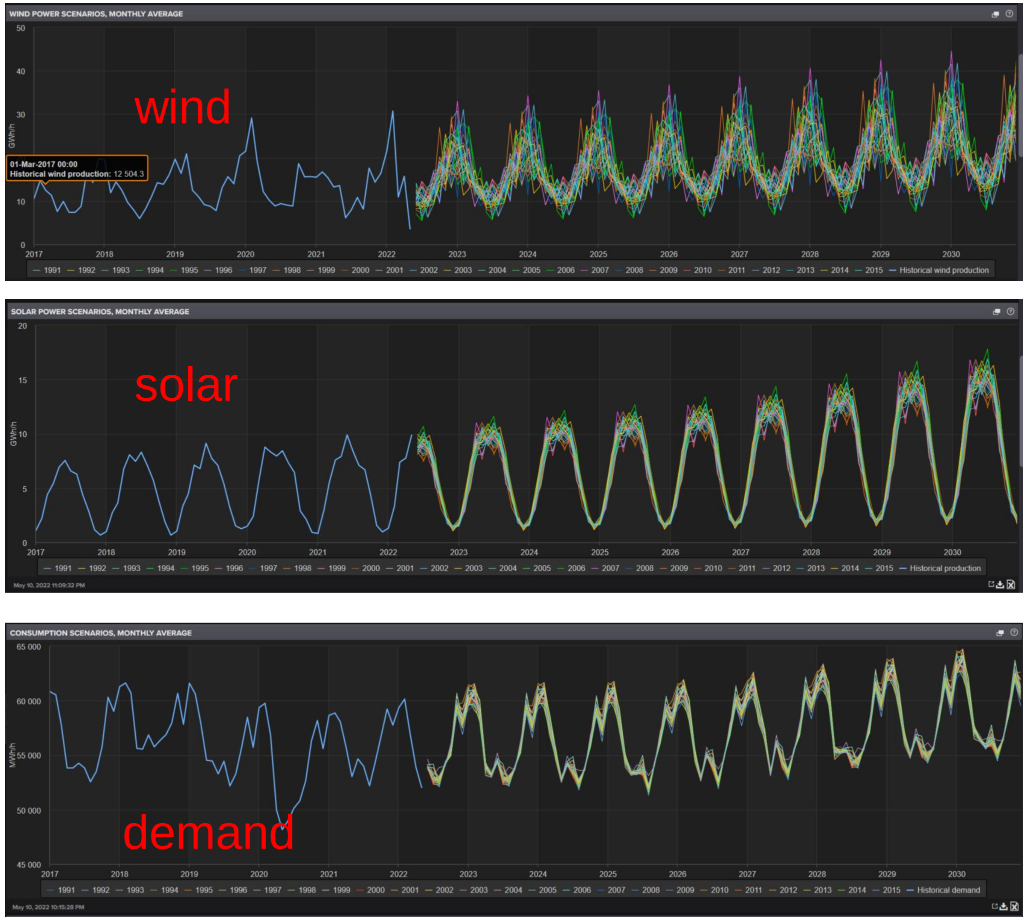
$$0 \leq f_{z,z'} \leq \overline{f_{z,z'}}, \qquad \forall z, z' \in zones$$

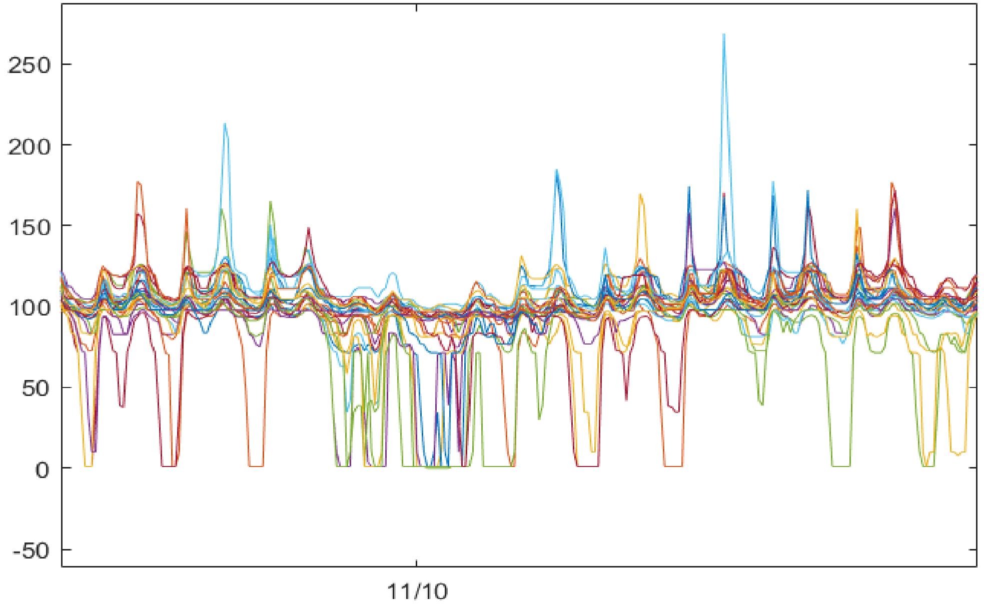




Main results

- Each weather scenario yields a price path (in hourly resolution) for each of the countries modeled, fully coupled, that represent realistic price paths under different weather conditions





30 paths

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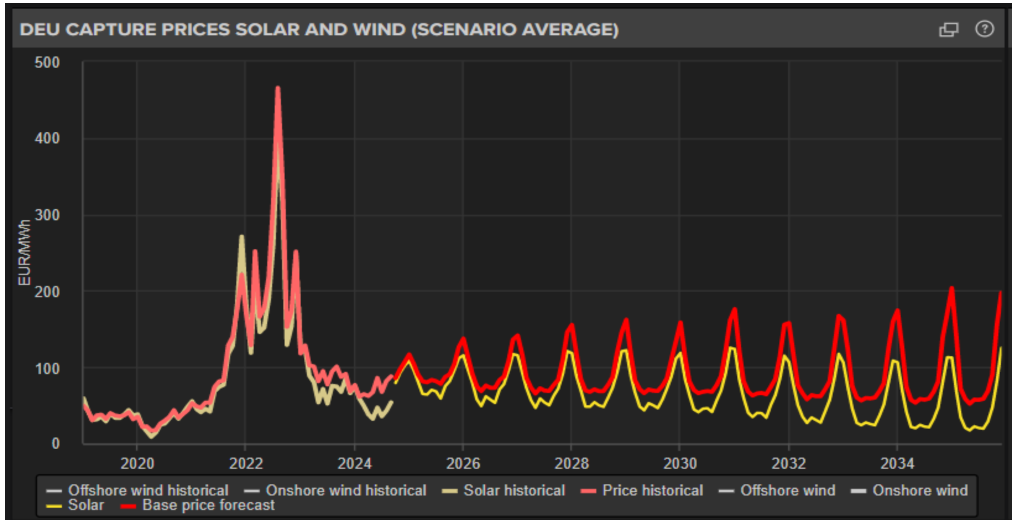
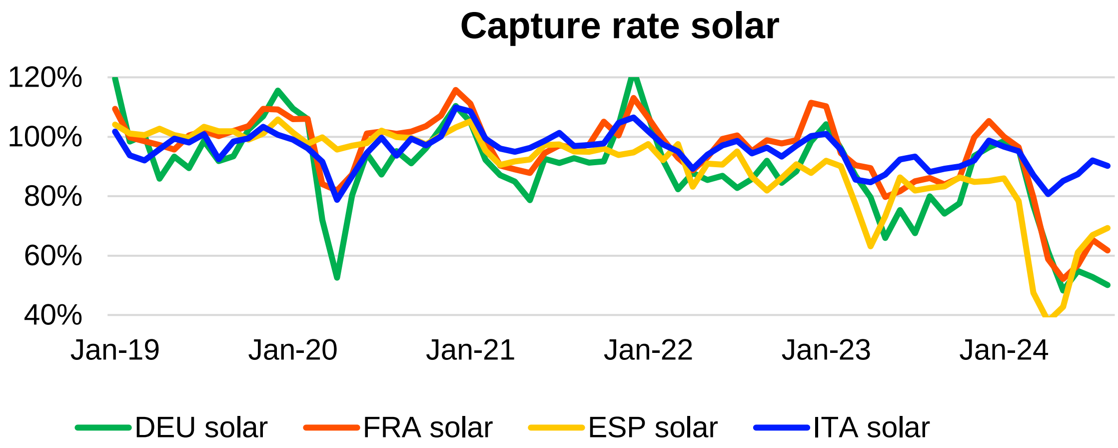
Capture prices and capture rates (value of renewable generation)

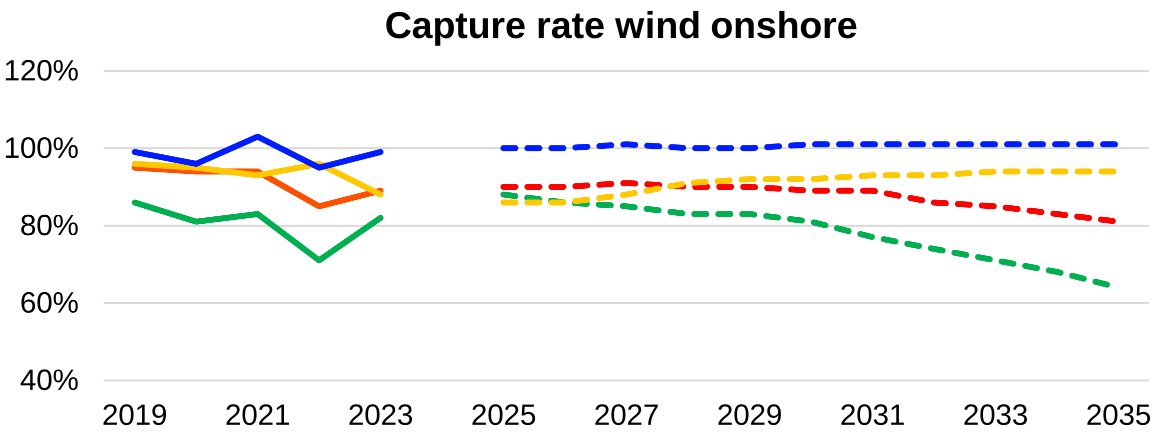
- What happens to the hours with lot of renewables? The avg price of these hours drop below the average → Capture rate

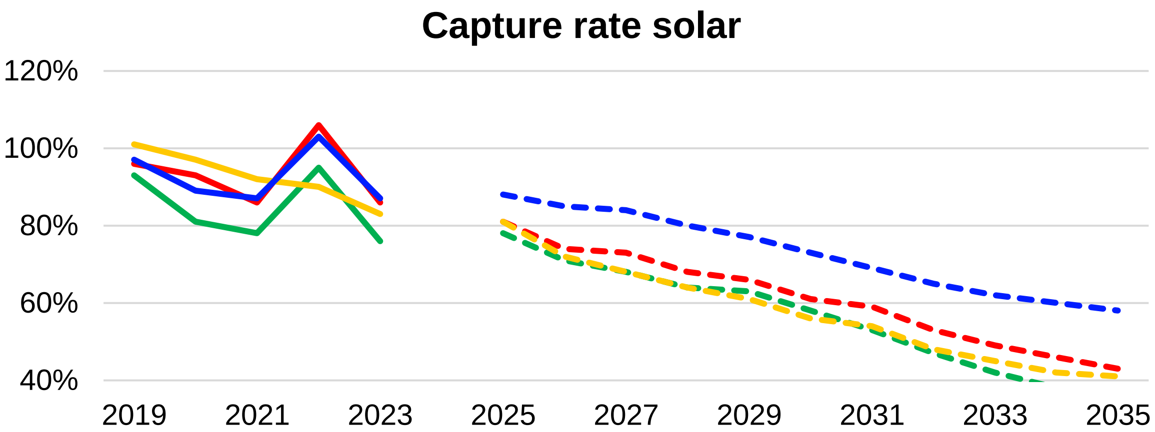
$$CP(w) = \sum_h \frac{wind_h * price_h}{\sum_t wind_t}$$

$$CP(s) = \sum_h \frac{solar_h * price_h}{\sum_t solar_t}$$

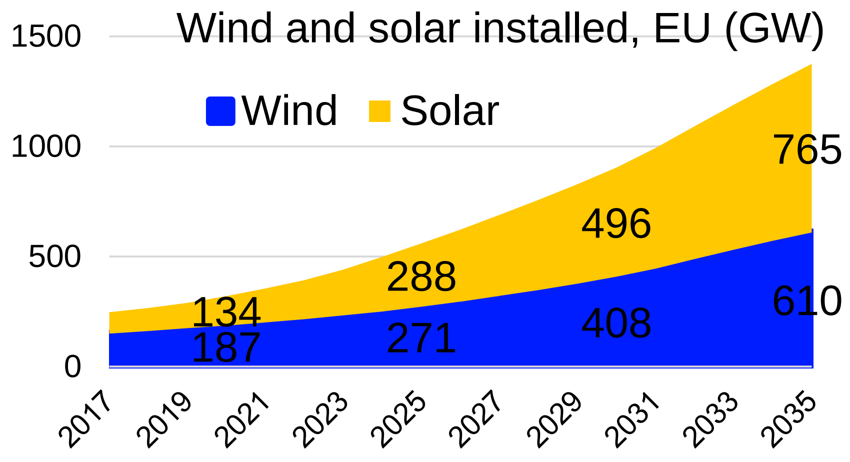


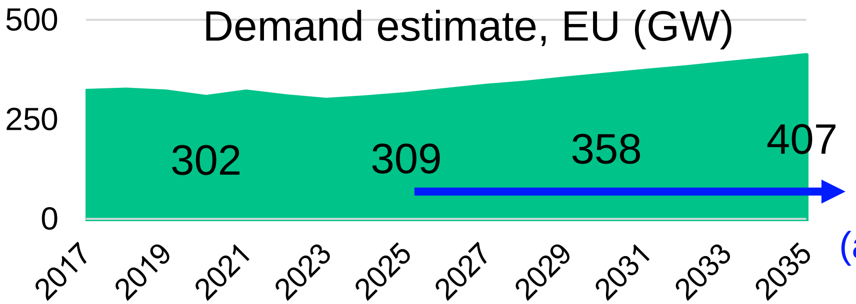


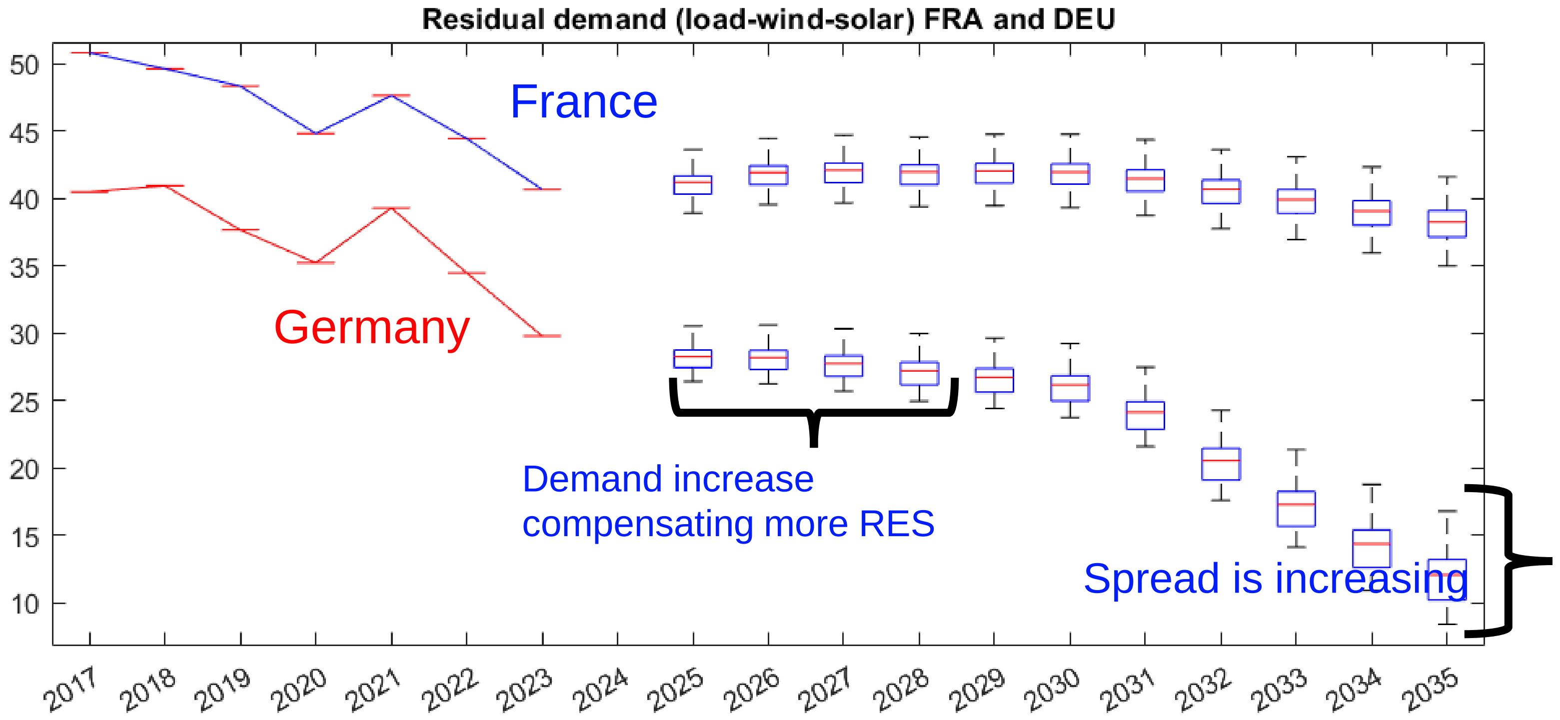




Residual load development (risk of renewable generation)







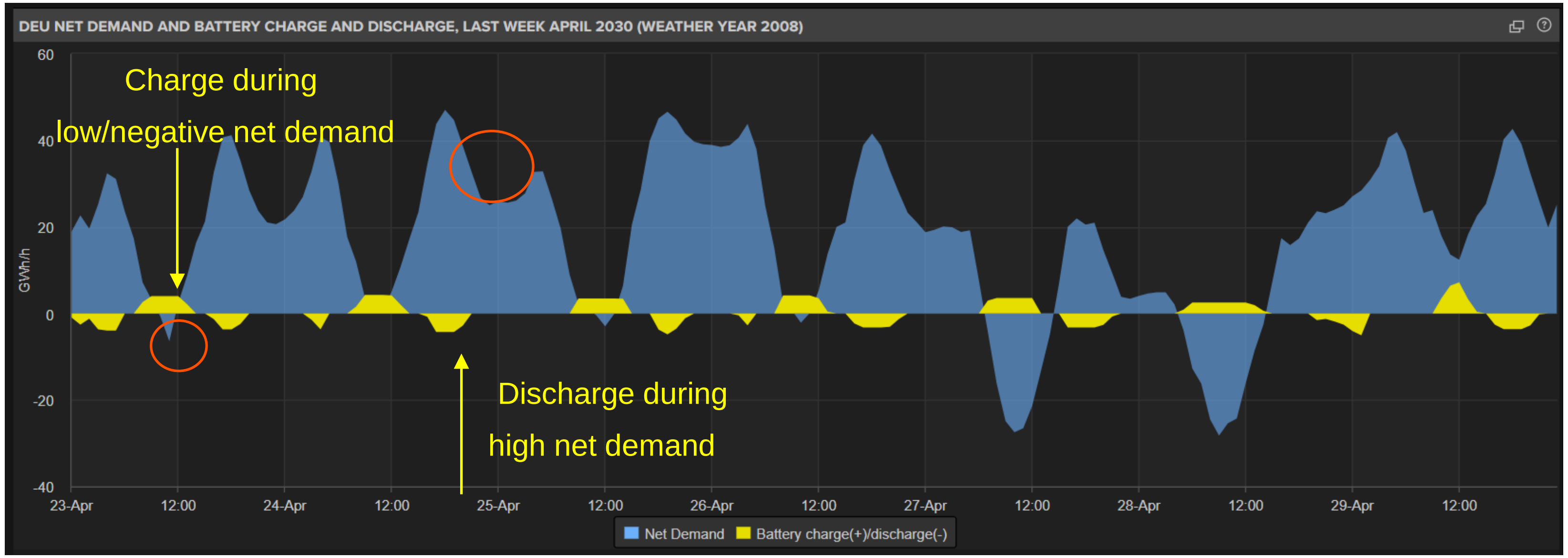
(almost 1000 TWh in the next decade, from ~2600 TWh to ~3500 TWh!)

Weather variability is increasing fast, and it is correlated in Europe:

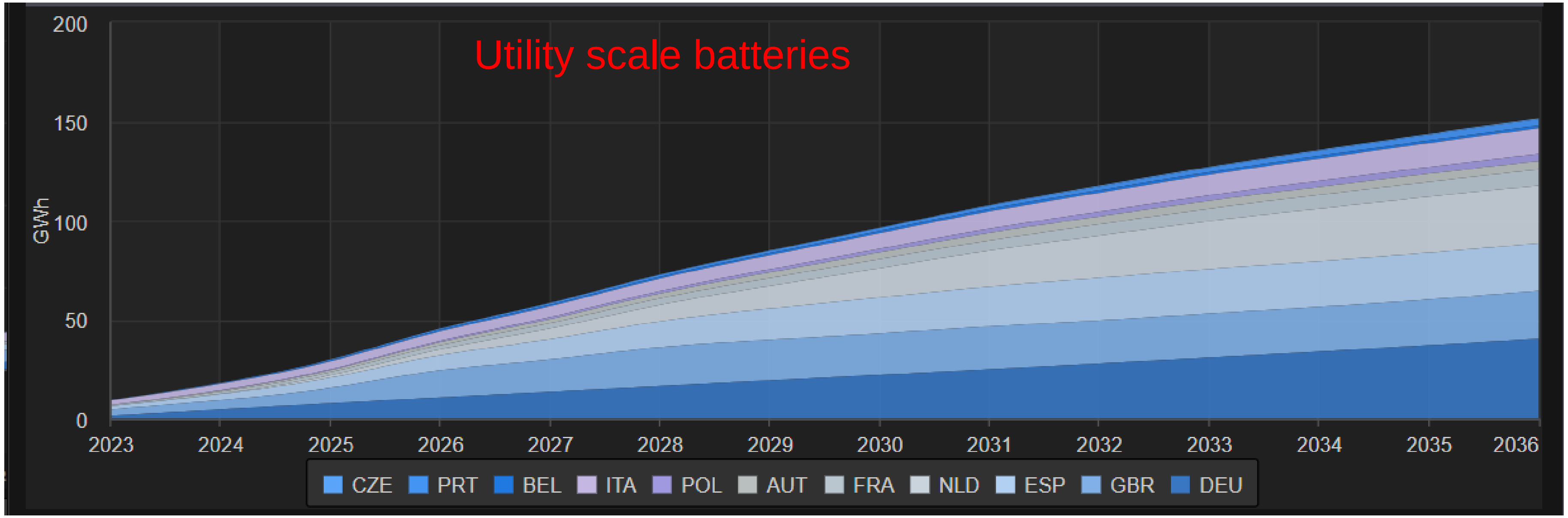
- In Germany in 2025 4 GW between the most favourable and least favourable RES scenario (→ 35 TWh), in 2035 8 GW
- In Europe in 2025 20 GW and in 2035 > 33 GW (300TWh!) between favourable and not favourable weather scenarios

This study is through simulating 30 weather years (1991-2020), therefore already accounting for “real” scenarios

Batteries and other flexibility



- Battery storage is increasing, but more flexibility is needed
- Despite high ambitions to install more batteries, they are not enough to flatten out the net demand curve. Fossil-fuels will still be the price-setters.
- Flexibility goes beyond batteries (demand-side-response, interconnectors, hydrogen production/consumption, etc)



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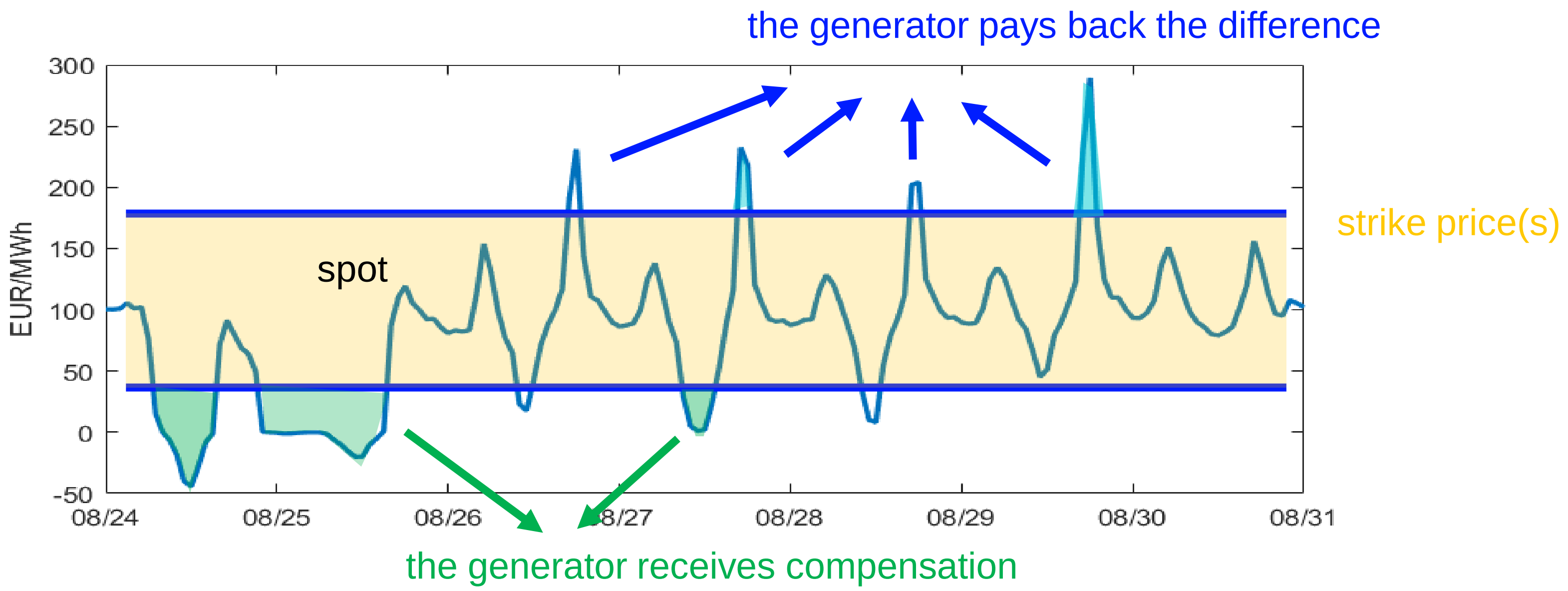
Financing renewable investments

How to finance renewable investments: Contract for differences

(Two-way) Contract for Difference (CfD), as proposed by European Commission in the Electricity Market Reform:

The generator sells the electricity in the market but then settles the difference between the market price and the strike price agreed in advance with the public entity. Any excess revenues shall be distributed to final customers, with some flexibility for member states.



Sources:

www.eurelectric.org

https://www.consilium.europa.eu/

Potential issues:

- Plants no longer face **incentives** to increase production in high-price hours and curtail in low-price hours “The issue of dispatch distortion becomes particularly problematic during periods of negative prices, when energy production is incentivised even when there is excess supply in the system. Consequently, regulations have suspended renewable support during negative price events”
- Setting the strike price entails some trade-offs in allocating costs and risks between parties → possible **distortion** of price signals
- Risk that CfD cannibalize other (market driven) tools for fostering low-carbon investments such as PPA

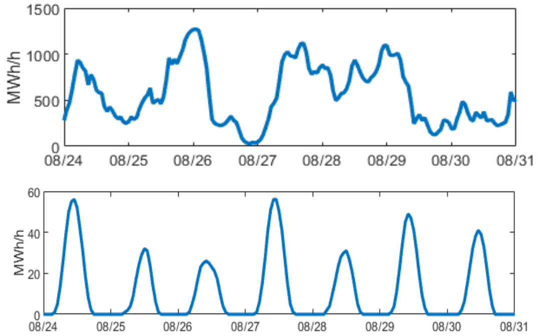
How to finance renewable investments: PPA (Power purchase agreements)

Power purchase agreements (PPAs) are long-term contracts between a supplier and buyer of electricity. The energy provider is generally an electricity generator, and the buyer is often a utility or a corporate / energy intensive industry.

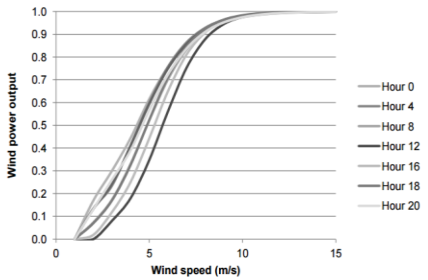
A PPA includes all the terms of the agreement, such as the amount of electricity to be supplied, the negotiated price, who bears what risks, the required accounting, and the penalties if the contract is not honored. As it is a **bilateral agreement**, a PPA can be adapted to the wishes of the parties involved, so the supply contract can take many forms.

Pay as produced

Actual generation



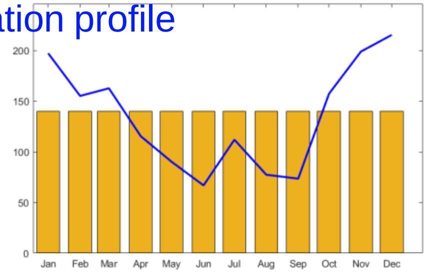
Proxy generation



Pay as contracted

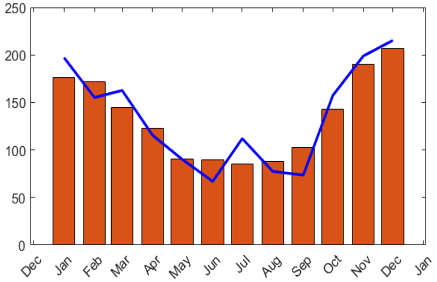
Yearly baseload

generation profile



Contracted volume

Monthly baseload



Contracted volume

Sources:

www.eurelectric.org

https://www.consilium.europa.eu/

Benefits:

- **Price**: by guaranteeing a price – or a price range – the generator knows what they will receive for the electricity they generate thereby making the business case for the project become more sustainable thanks to higher and clearer visibility over their returns.
- **Volume**: the customer secures stability as they can guarantee the amount of electricity they source from the generator and how much it will cost them.

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Main types of PPA contracts

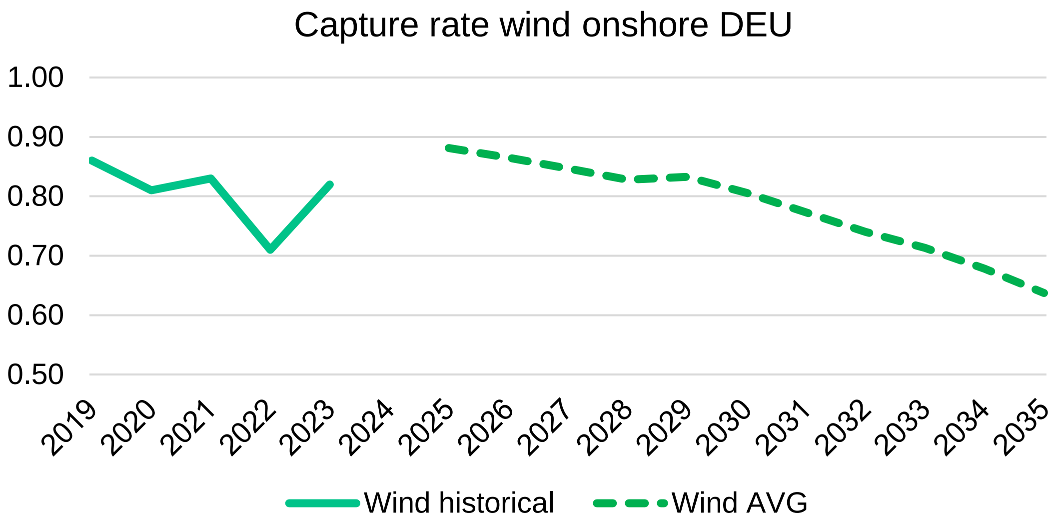
Pay as produced: A Pay-as-Produced PPA is an agreement where the payment to the energy producer is based on the actual energy generated and delivered:

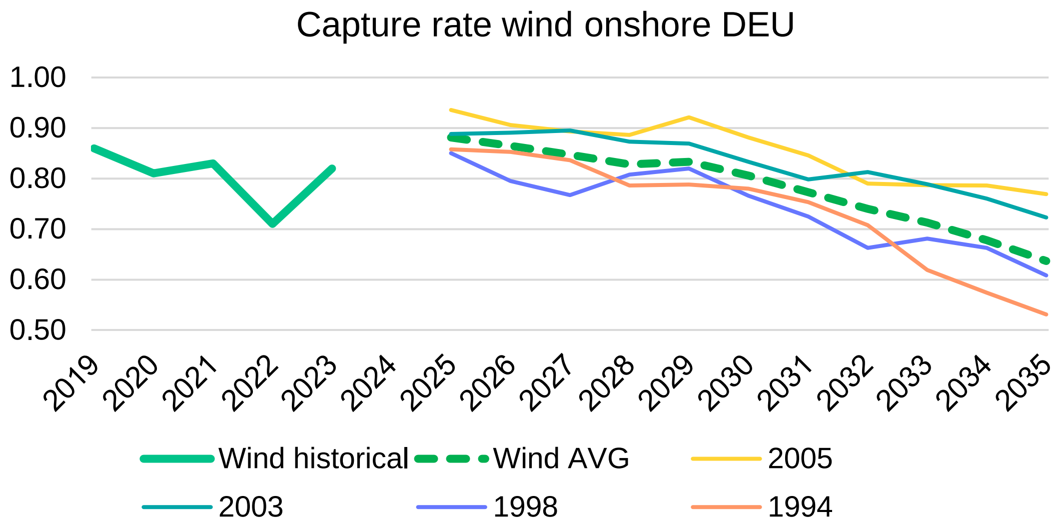
- **Pros : Hedging Against Price Uncertainty:** Pay-as-Produced PPAs provide a level of revenue certainty by hedging against the volatility and uncertainty of spot market prices.
- **Pros:** Pay-as-Produced PPAs increase the **bankability** of projects by providing this required revenue stability.
- **Pros: Alignment with Renewable Energy Production:** This PPA model is well-suited to the variable nature of renewable energy sources like solar and wind, where production is dependent on environmental factors.
- **Cons**: not very suited for consumers that need stable generation profiles
- **Cons**: producers often have to accept a lower price for the certainty of revenue.

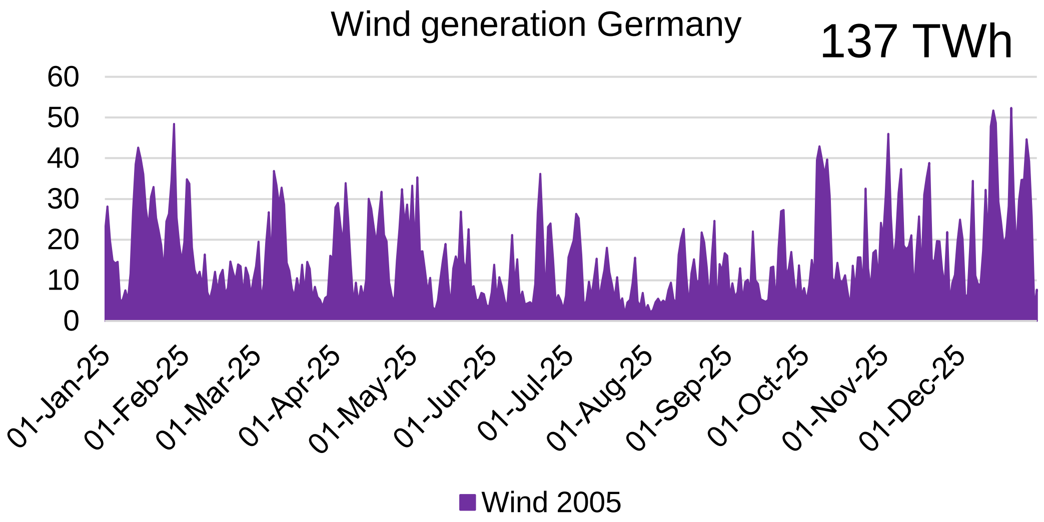
Baseload PPAs : structured to provide a consistent, fixed amount of energy delivery, reflecting the steady output typically associated with conventional power plants.

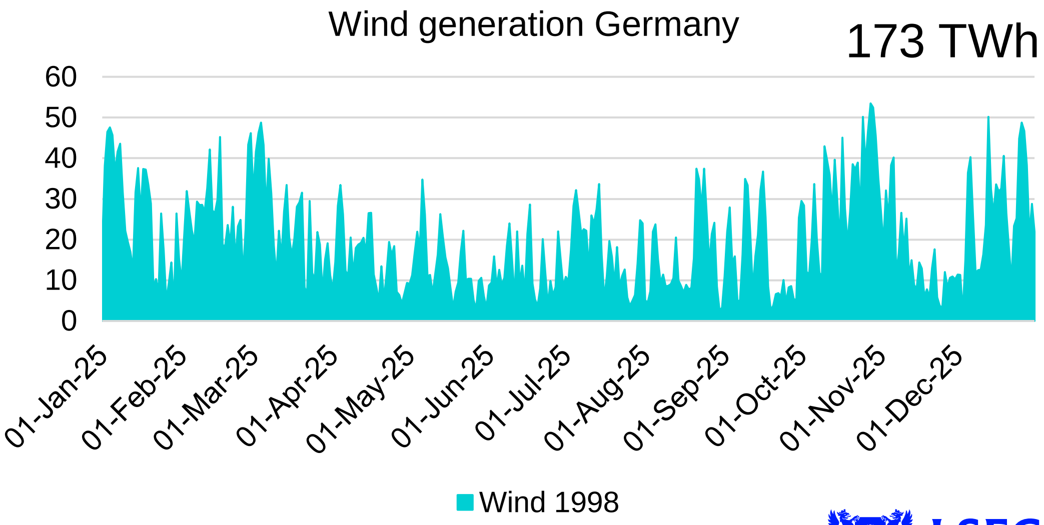
- **Pros:** This PPA model is designed for energy sources that can guarantee a constant supply of electricity.
- **Cons: Risk of Underproduction:** There's a risk that the renewable energy source will underproduce, leading to the obligation to buy electricity at potentially inflated spot market prices to meet the PPA commitments.
- **Cons: Prediction Challenges:** Accurately predicting the expected production of a renewable energy source can be complex and subject to errors.

How weather affect capture rates / capture prices?

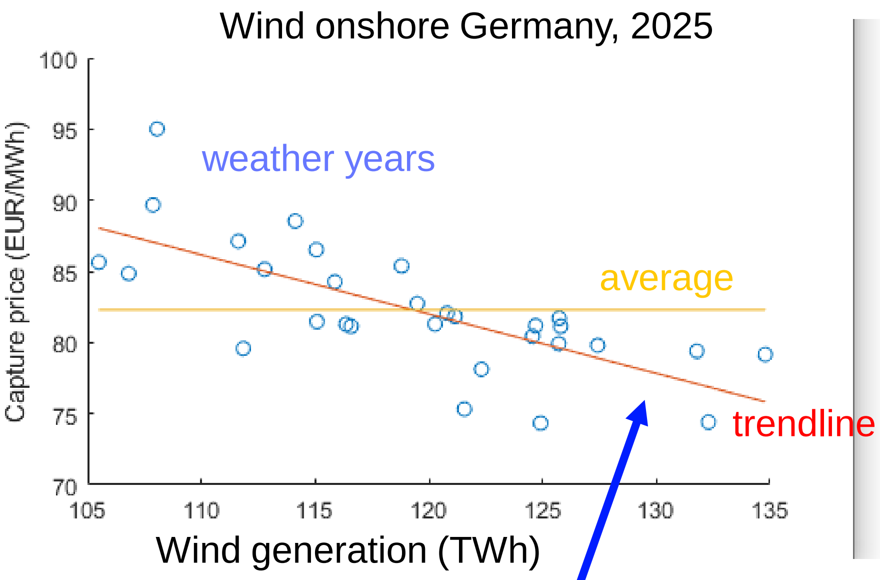


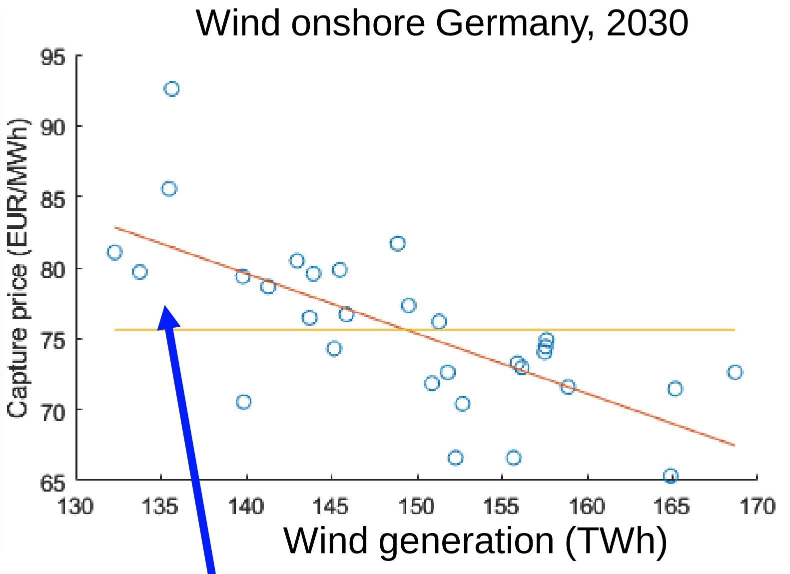


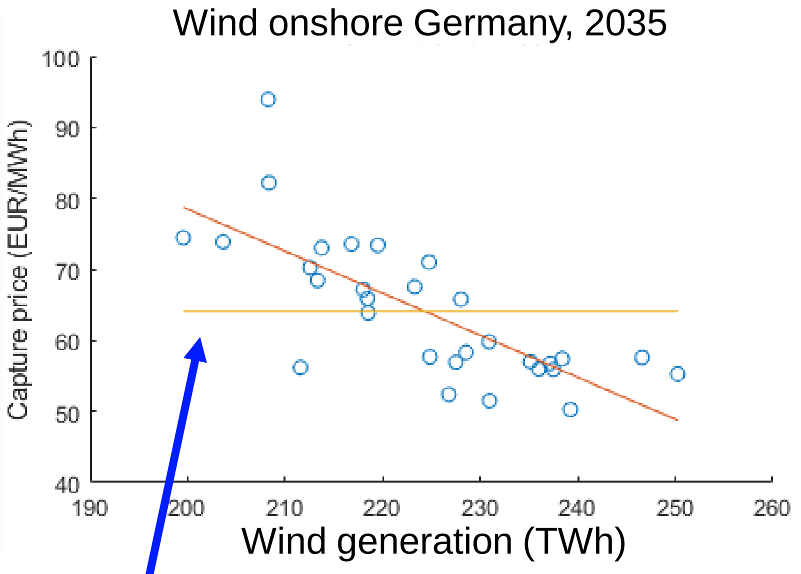




Windy weather leads to lower wind capture prices







All things equal, lower capture prices in windy weather years due to higher cannibalization

Higher capture prices in weather years with low wind due to lower cannibalization

Average (expected) capture prices are often seen as the fair PPA prices, prior to discounts

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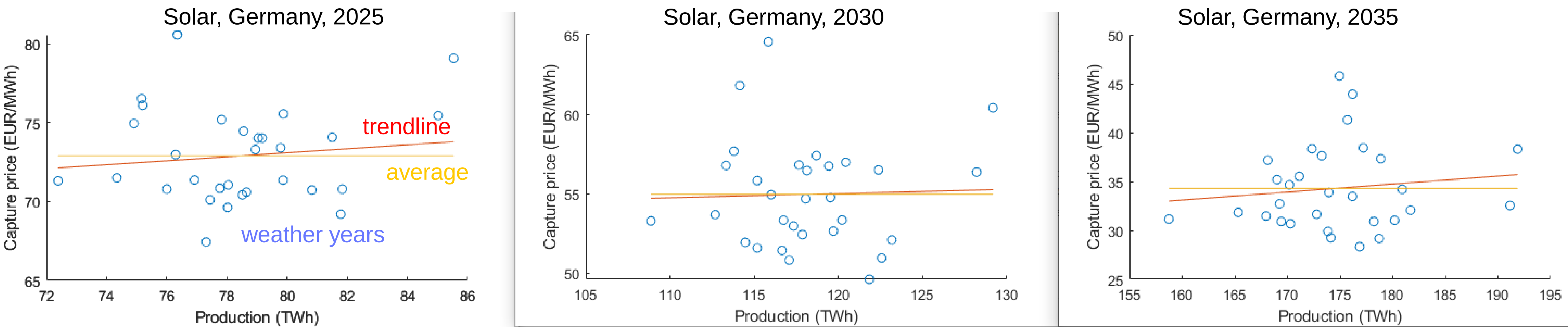
Solar capture prices are not so affected by weather scenarios



- No correlation between capture price and solar generation (variability in solar generation is much smaller)
- Wind is the main driver → Years with high wind yield low wind capture prices (as seen), and also as a consequence low spot prices and low solar capture prices
- Trendline actually slopes (slightly) upward due to (low) negative correlation between solar and wind power production

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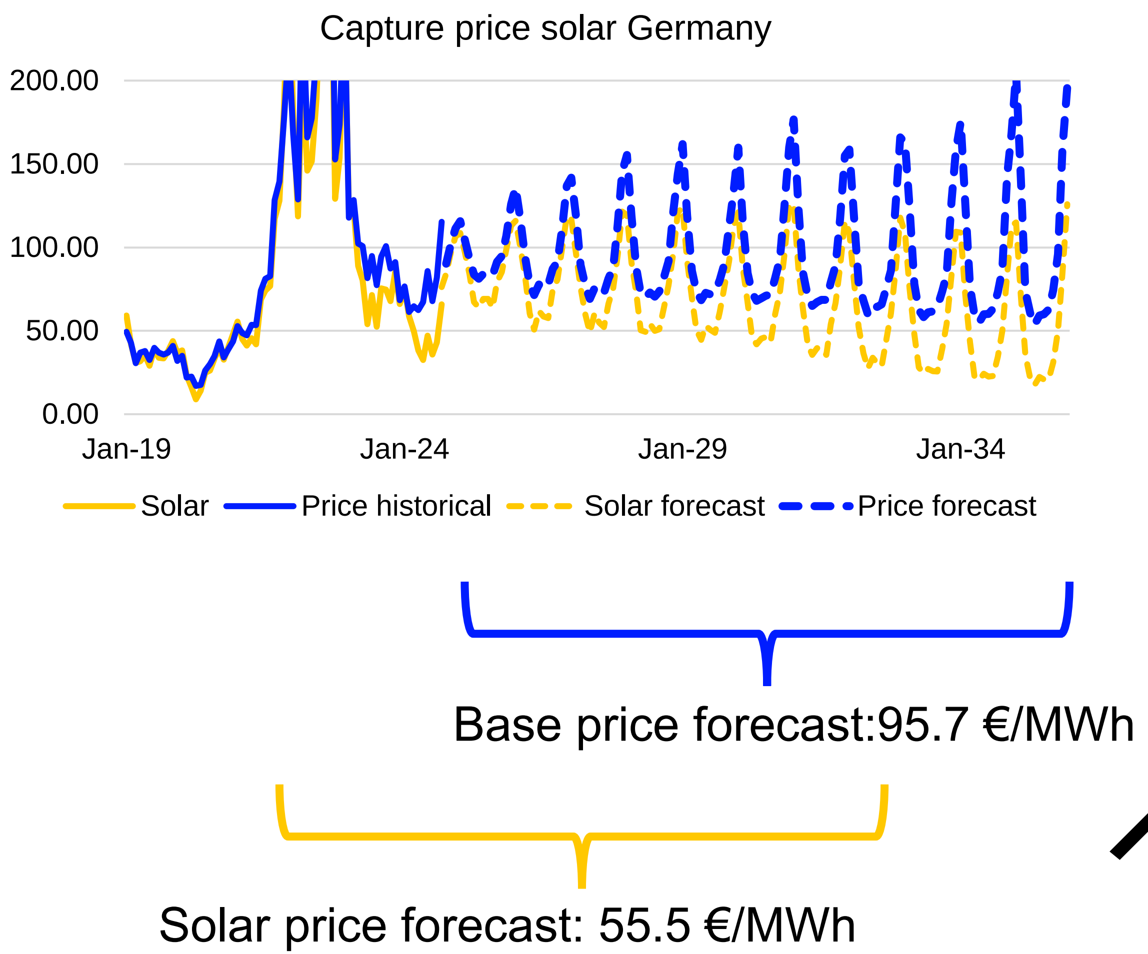
How to optimally price PPA?

Ideally the "fair value" PPA price should be the price at which is indifferent to selling your wind power "merchant" on the market:

- Base price (expectation over the next 10 years)
- Capture price
- Imbalance cost
- Other revenues (GOs,..)



How to optimally price PPA? (solar)

Ideally the “fair value” PPA price should be the price at which is indifferent to selling your wind power “merchant” on the market :

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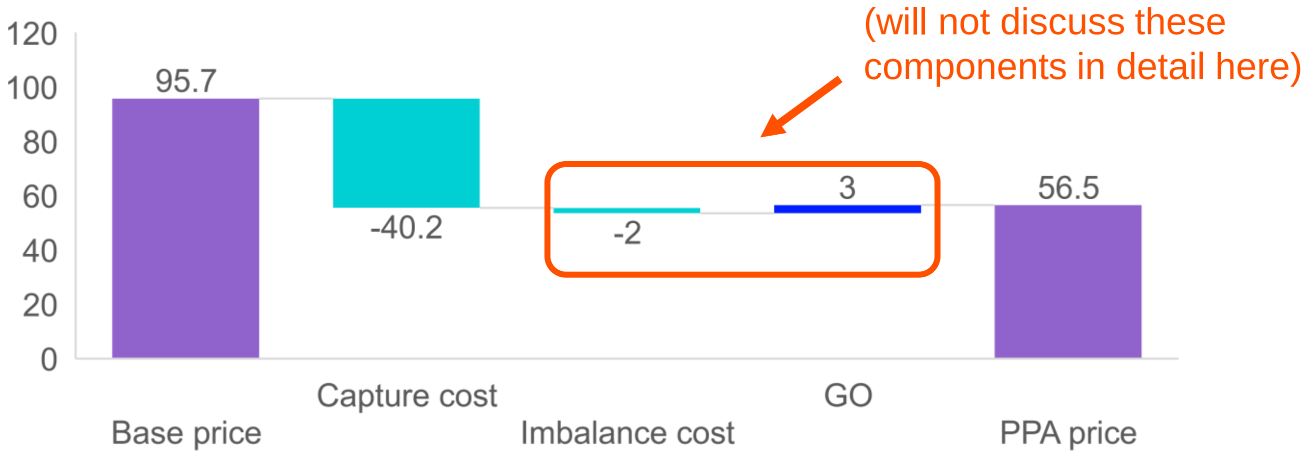
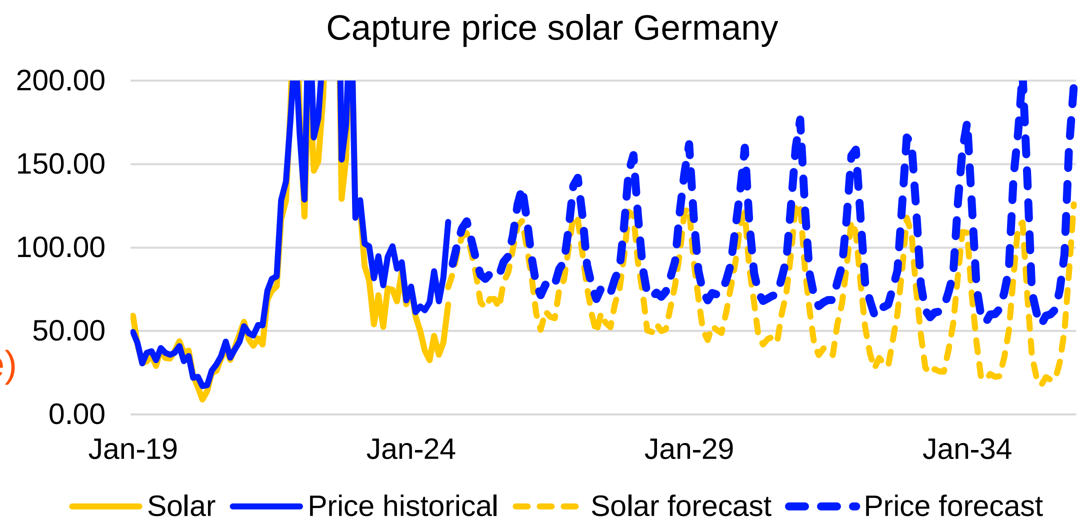
- Capture price
- Imbalance cost
- Other revenues (GOs,..)



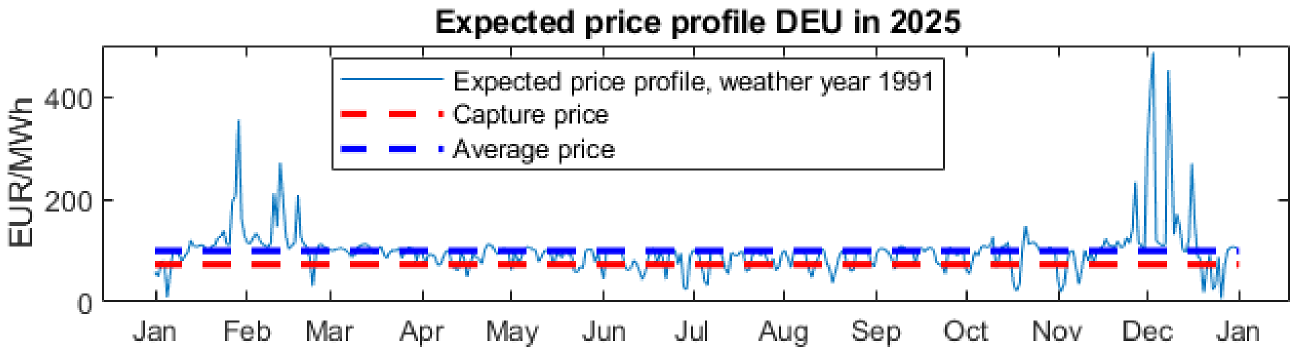


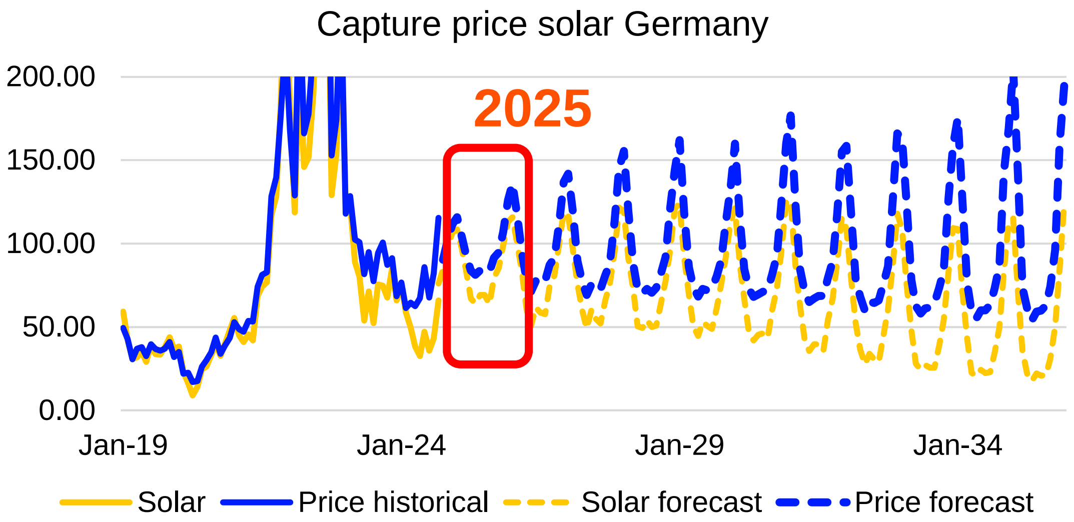
Base price forecast:95.7 €/MWh

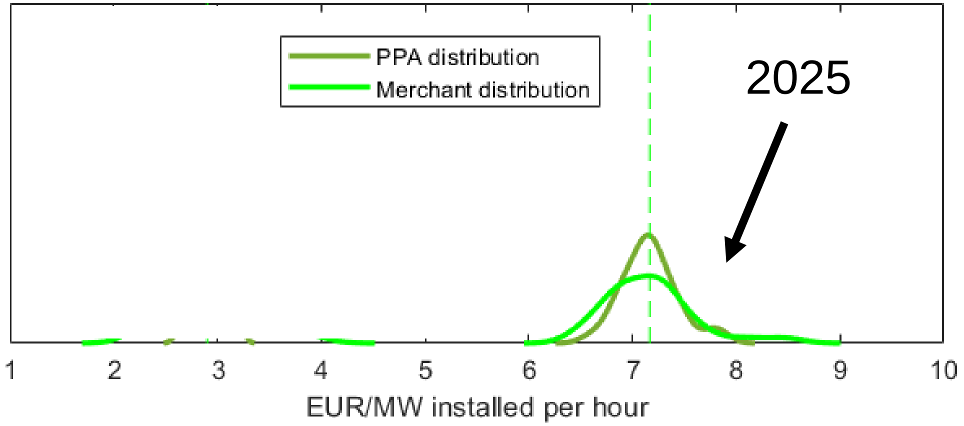
Solar price forecast: 55.5 €/MWh

Test → We use this “fair price” and apply to different weather scenarios and check what happens to the risk vs selling the wind/solar merchant

How to optimally price PPA? (solar)

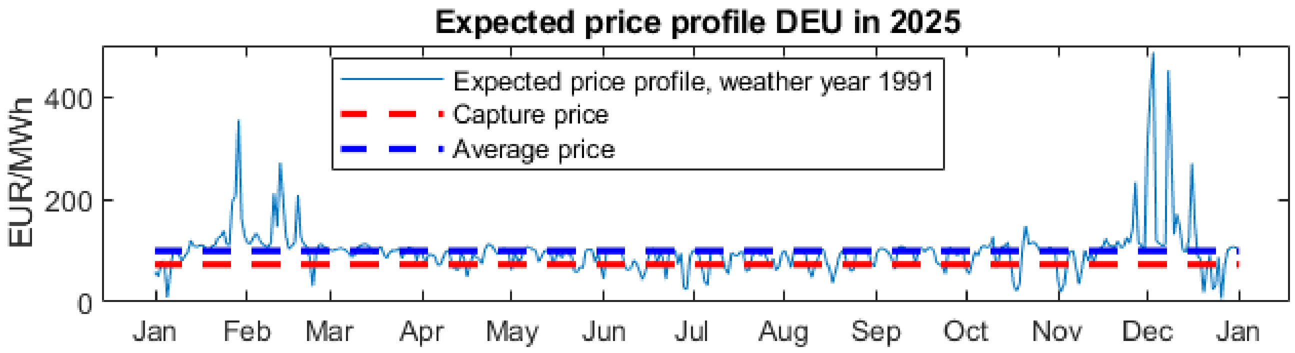


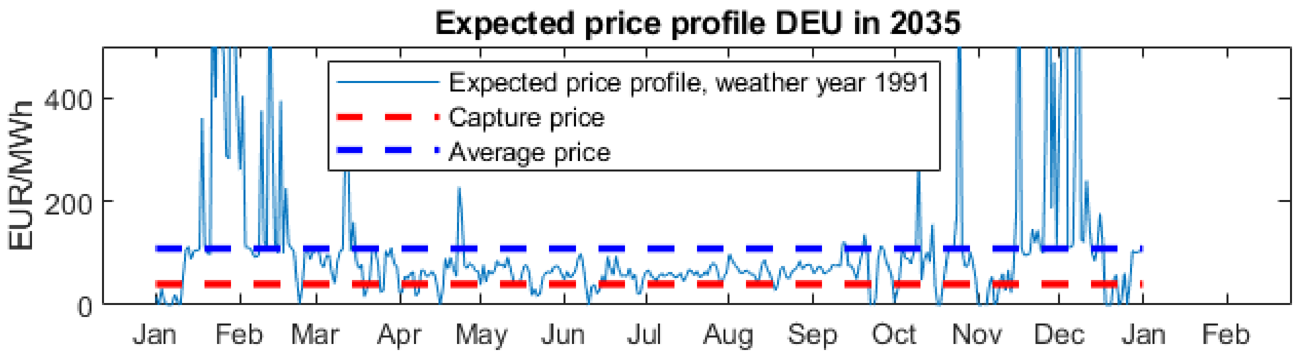


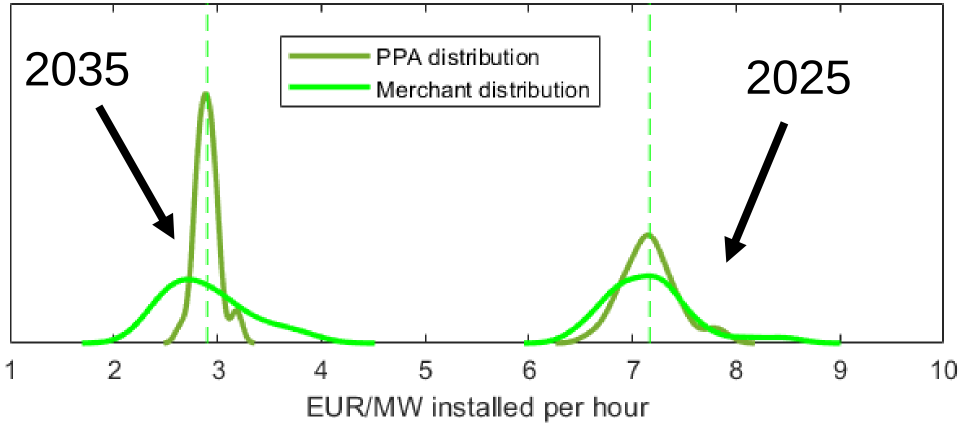


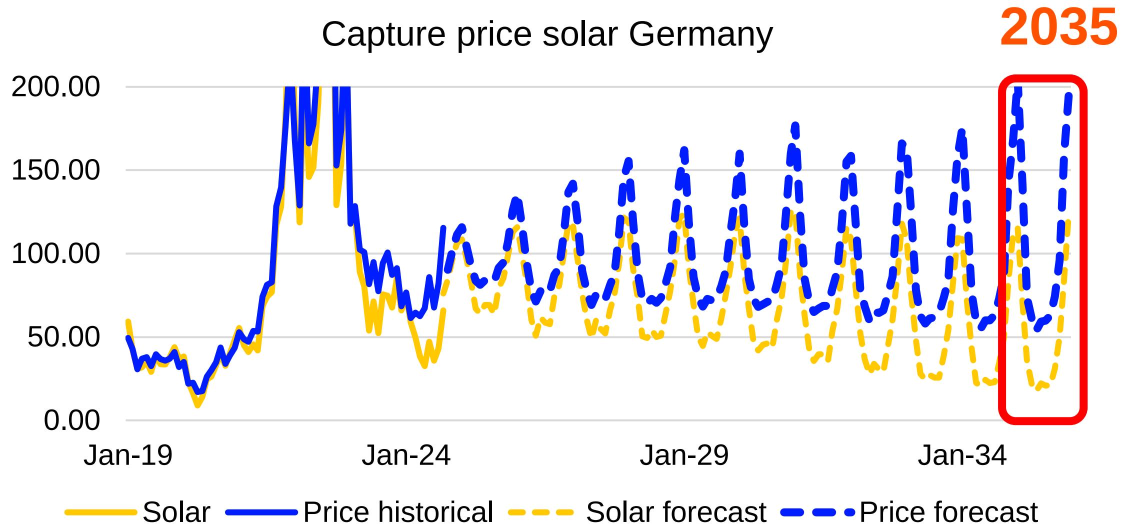
- Going fully merchant
  - In 2025 you have a distribution of possible outcomes ranging from roughly 6 to 9 €/MW installed, with average marginally above 7 €/MW installed.
  - This corresponds to ~9.6% effective capacity factor
- Sign a PPA @ fair price →
  - In 2025 you get a narrower distribution of possible outcomes, from ~6.5 €/MW to ~8 €/MW
  - Expected revenues are the same since we priced this PPA arbitrage-free
  - PPA has helped to derisk your outcomes

How to optimally price PPA? (solar)









- Going fully merchant
  - In 2035 because of the wide spread of capacity factor the range of possible outcomes is even larger
  - The average revenues/MW installed are much lower due to much lower capture rate. ! The value of sunny hours drop, and you have to accept massive curtailment, bringing effective capacity factor down to 8.2%
- Sign a PPA @ fair price →
  - In 2035 because of cannibalization the value of your solar power decreases, however again PPA helps derisking
  - Expected revenues are still the same

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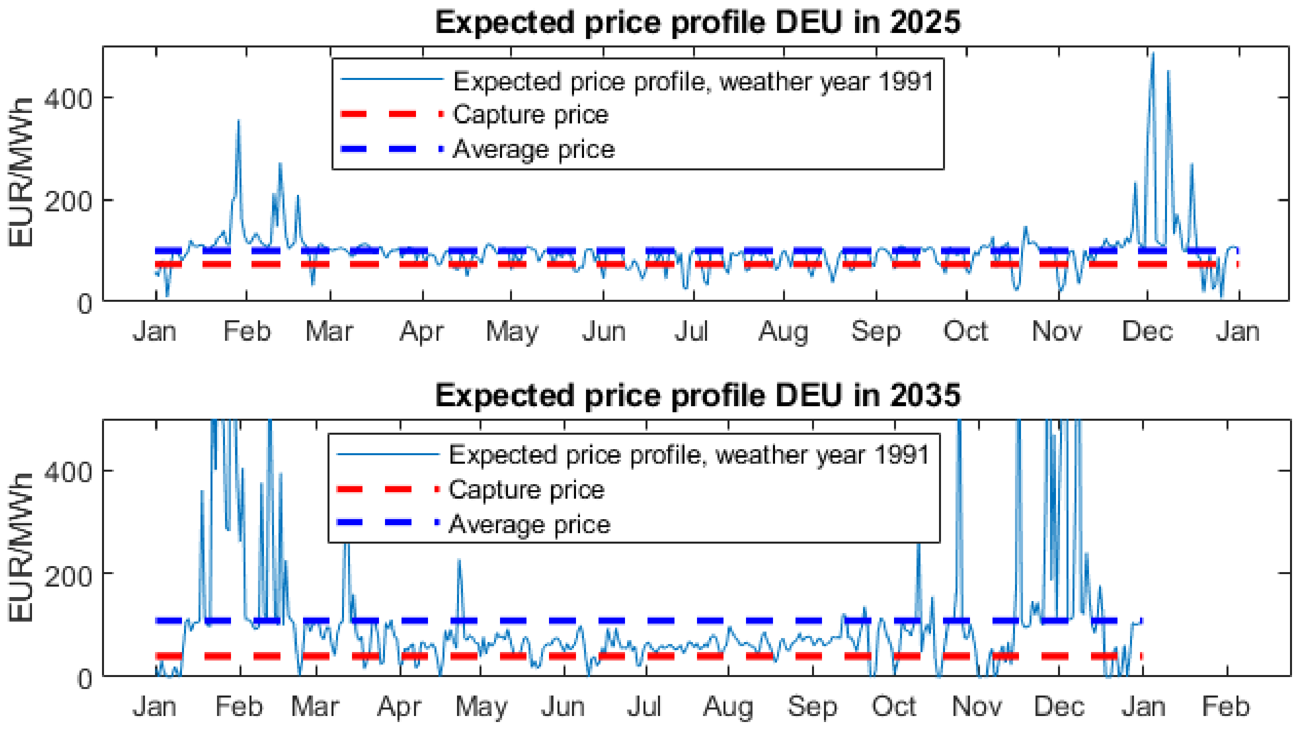
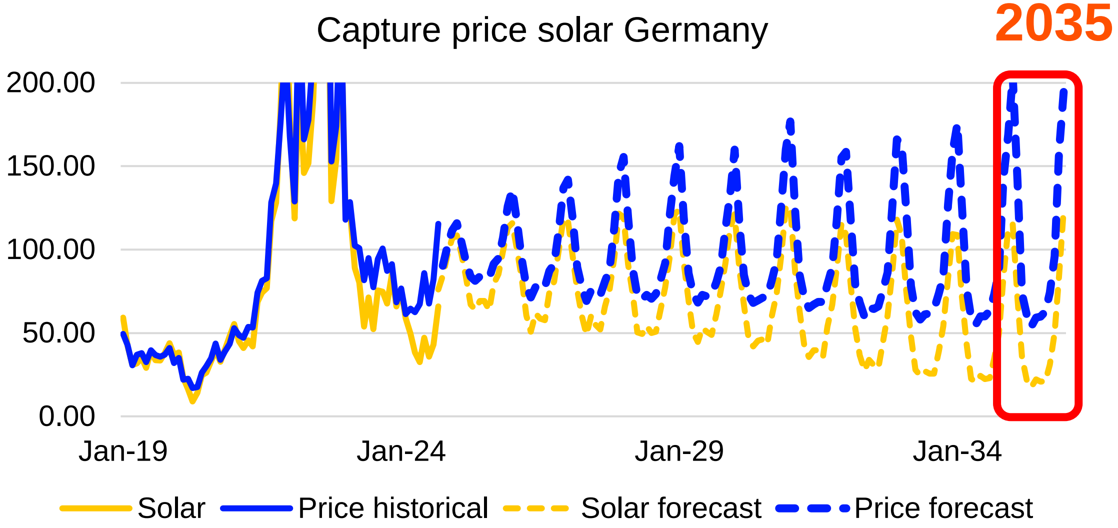
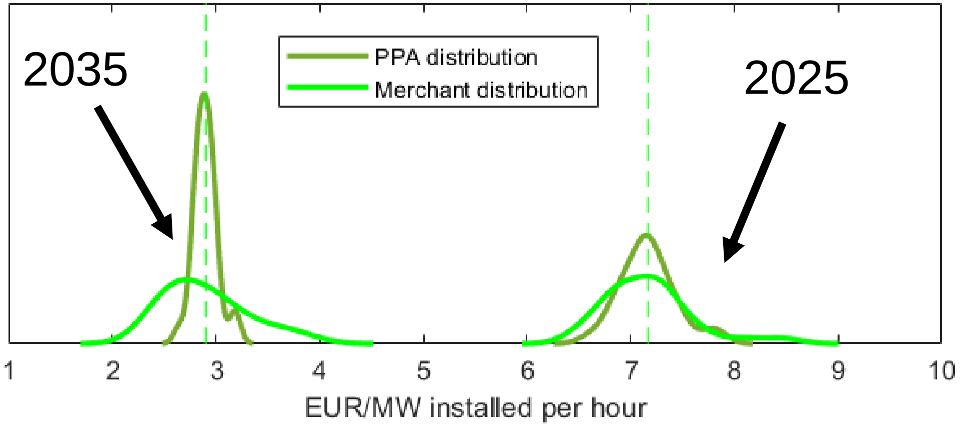
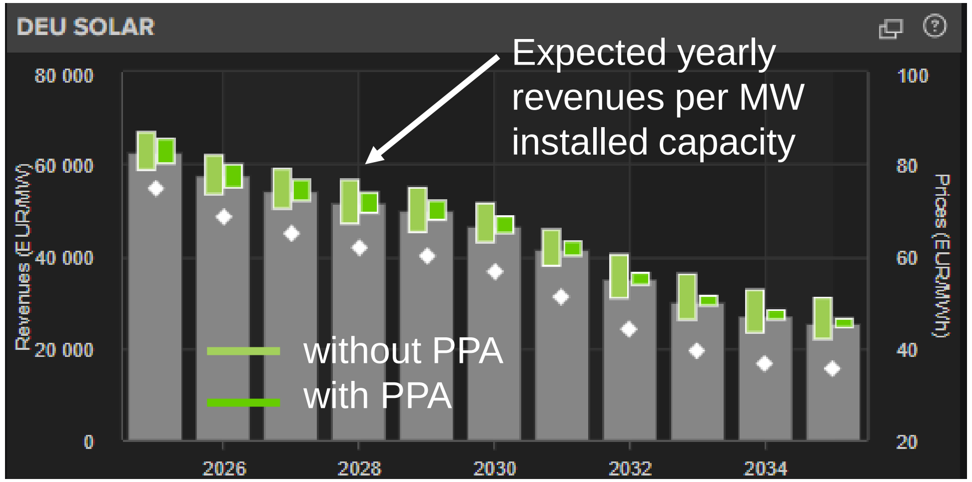
How to optimally price PPA? (solar)

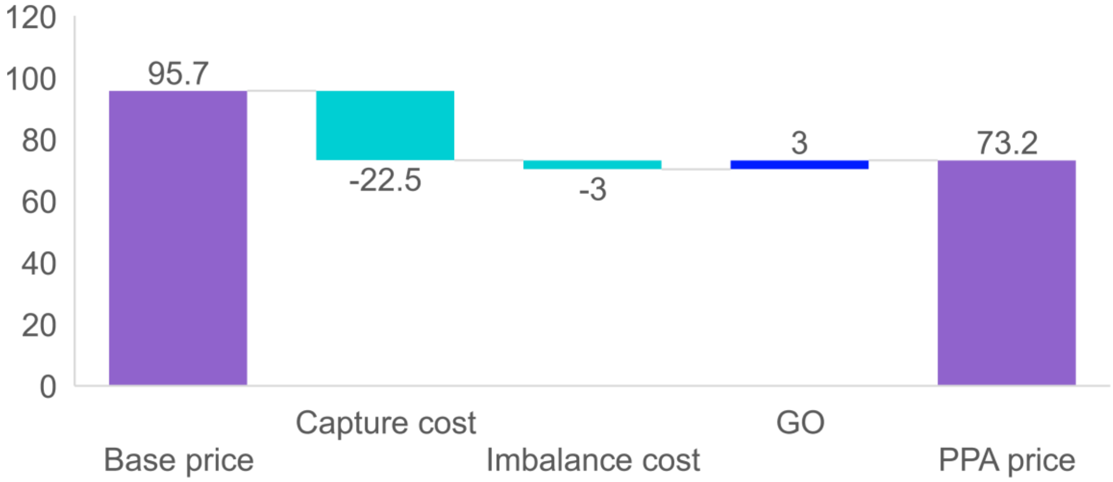


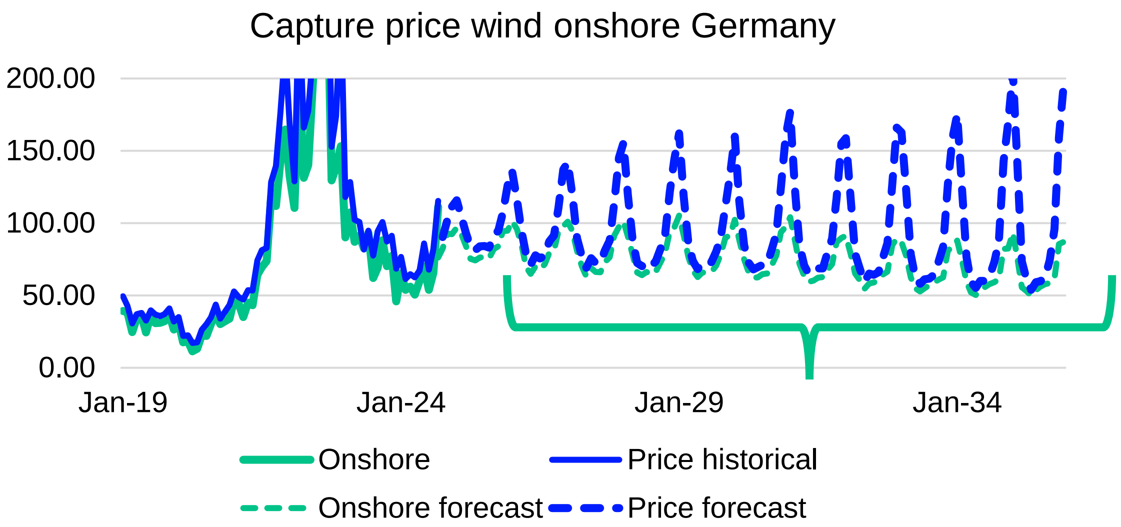


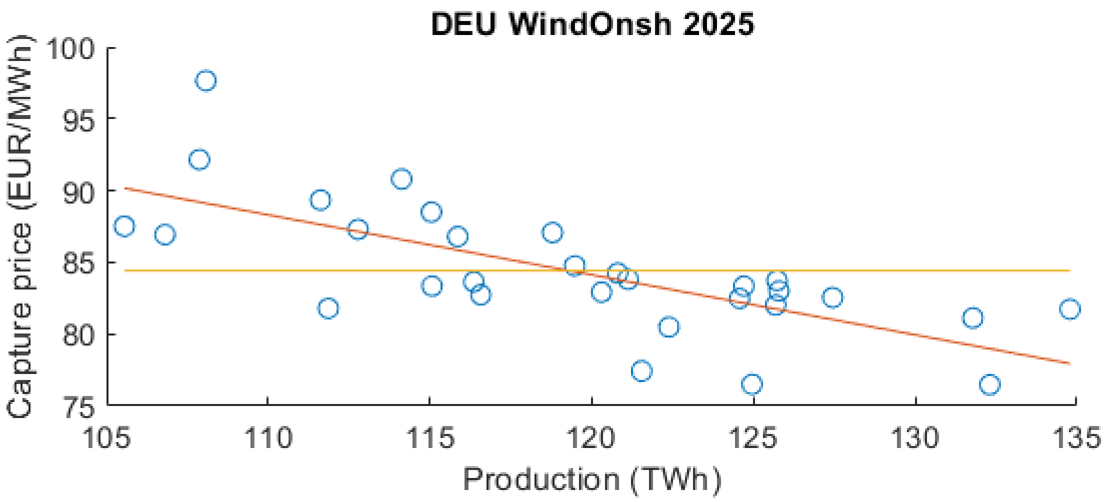


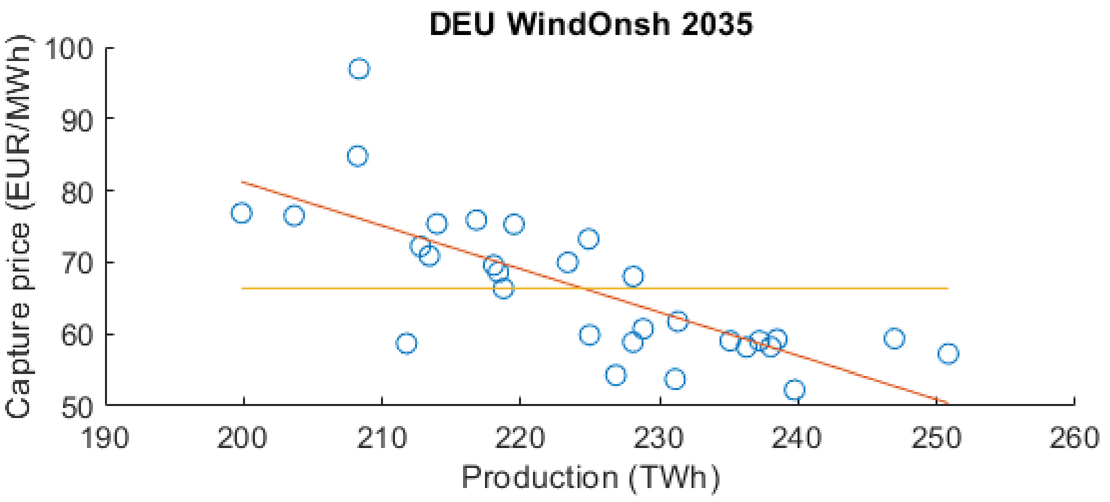


How to optimally price PPA? (wind)



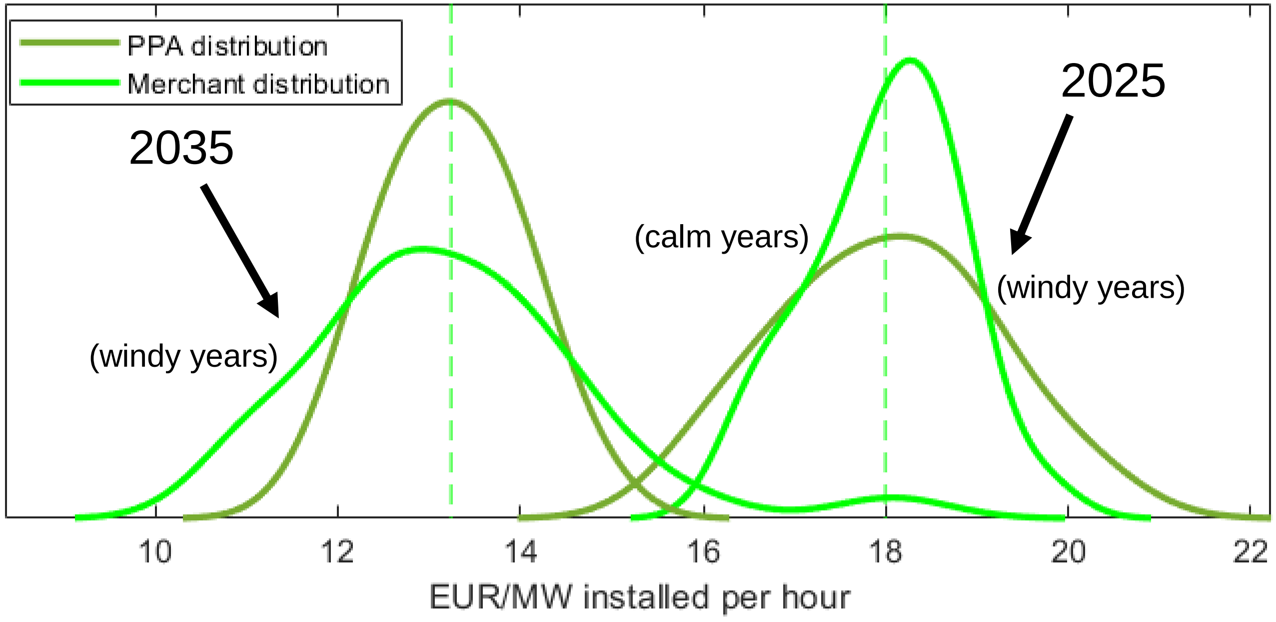


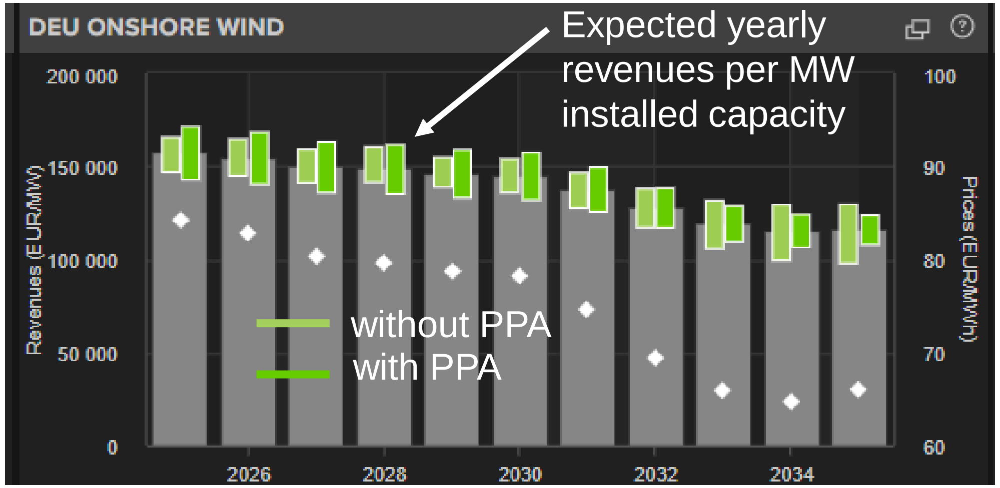


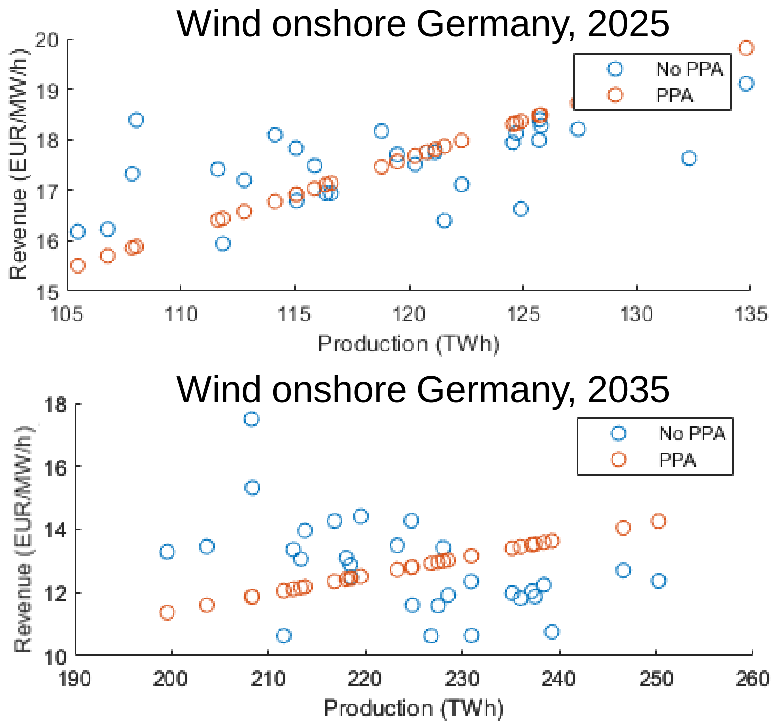


- Wind capture prices are higher than solar
- Heavy correlation between capture price and wind generation

How to optimally price PPA? (wind)







Signing a wind PPA @fair price vs going full merchant

- In 2025 you get a PPA distribution of possible outcomes larger than going merchant. How is that possible?
- You accept a lower (average) price for your wind in the calm years, and a higher (average) price for the windiest years. Since the weather variability and the variability in capture rate is so large (and they are negatively correlated!), the amount of money that you lose in the calm years is large
- In 2035, on the other side, the cannibalization is so strong that signing a PPA will be beneficial since without a PPA it will be windiest years to give the lowest revenues! (paradox)

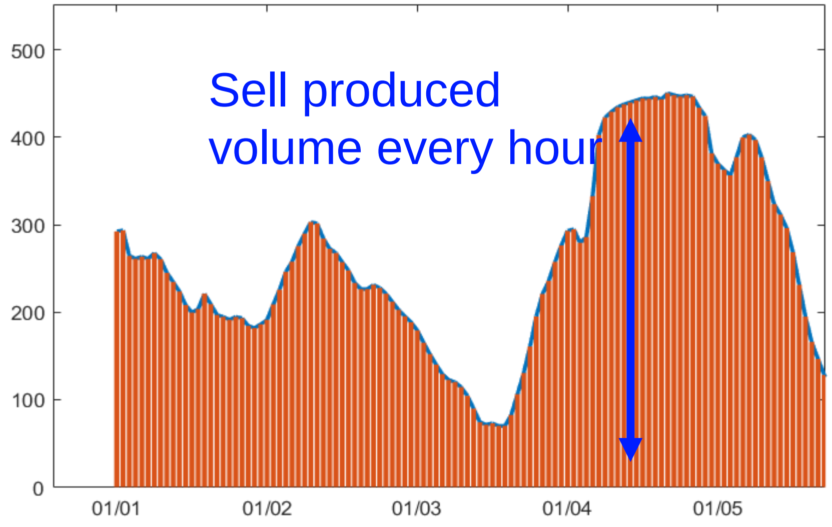
Pay as produced vs baseload PPA

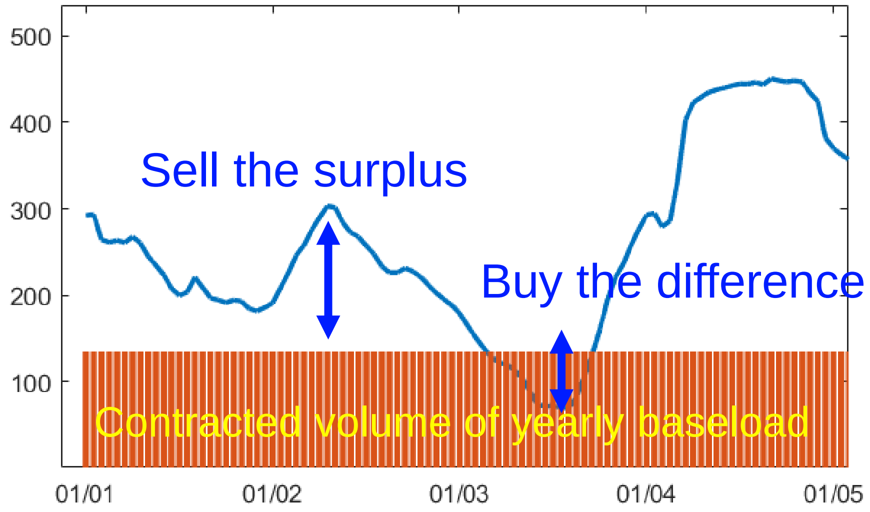
- Higher risk for producers in baseload PPA
- Buy back the difference when actual generation is lower
- Sell the surplus when actual generation is larger

- Typically baseload contracts need a 25% higher price than PayAsProduced to reach the same expected revenues (!), and risk increases considerably (see later)

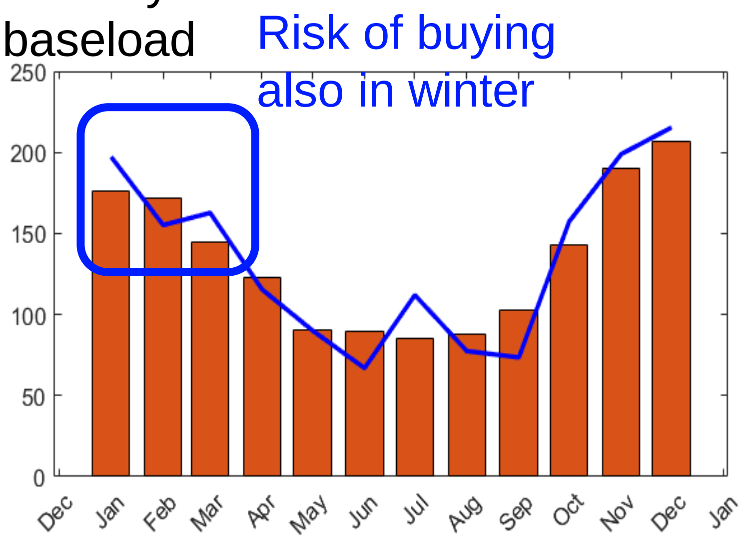
- For **wind** farms: Monthly baseload riskier than annual baseload (counterintuitive) → low generation in winter months is very expensive!

- For **solar** farms: Annual baseload is riskier than monthly baseload (not so much difference in weather years, and winter months are usually more expensive)

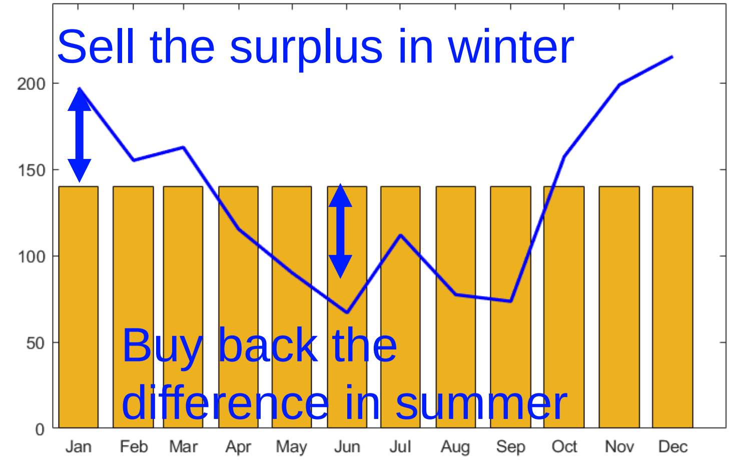




Monthly baseload



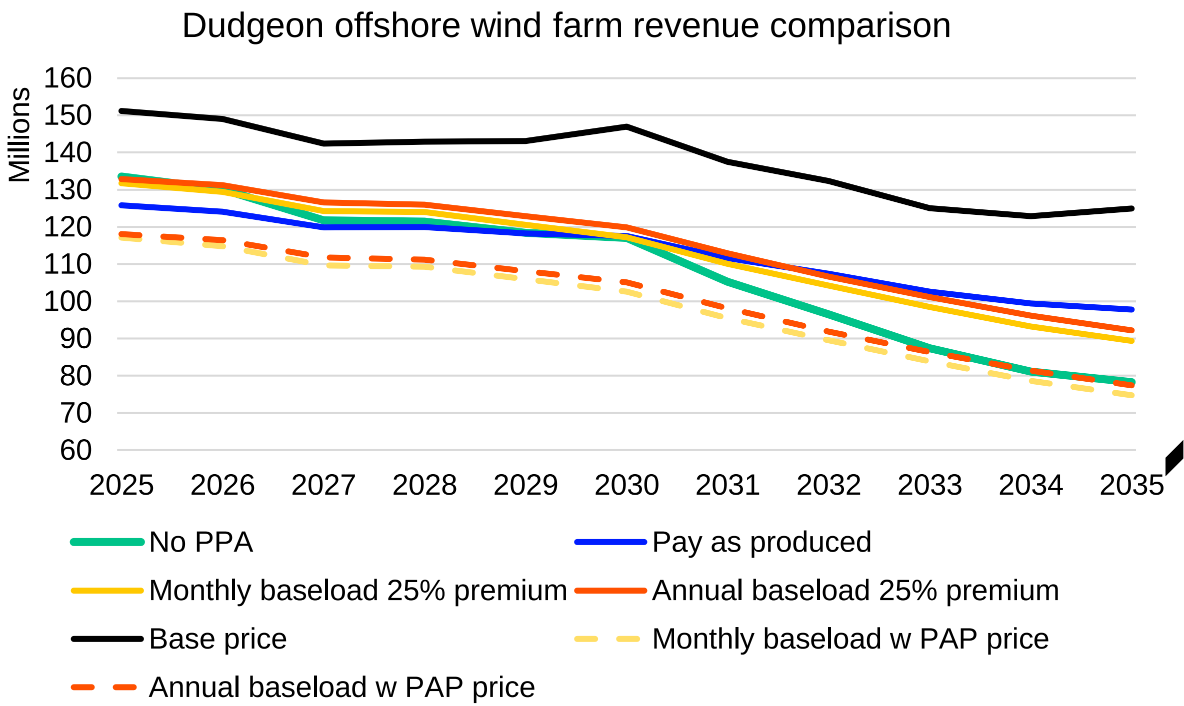
Yearly / Annual baseload



Example: Dudgeon offshore windfarm in the UK

- Installed capacity of 402 MW ; consists of 67 Siemens 6 MW turbines.
- We calculate the hourly production for 30 distinct weather years, which are the actual weather in that location from 1991 to 2020 (ERA5 data)
- In order to calculate future revenues, our model retrieves the hourly prices from our long term price model for each of the 30 weather years.
- The renewable asset may reduce market exposure by the means of a PPA (Power Purchase Agreement). Different types of PPAs are compared. Revenues are pre-tax and do not include sales of GOs nor imbalance costs.

1.No PPA: Selling all production on the DA market.
2.Pay-as-Produced PPA: Pay as produced PPA for 50% of the production sold at "fair value" (as previous slide). Rest sold on the DA market.
3.Annual Baseload PPA: Baseload PPA with 50% of the yearly P50 production sold at a 25% premium over our "fair value" PPA. The rest is sold/bought on the DA market.
4.Monthly Baseload PPA: Baseload PPA with 50% of the monthly P50 production sold at a 25% premium over our fundamental pay-as-produced PPA price. The rest is sold/bought on the DA market.
5.Base price: Calculated revenue for the windfarm assuming the scenario average monthly base price (for comparison). Basically assuming no curtailment and no capture risk (100% capture rate)



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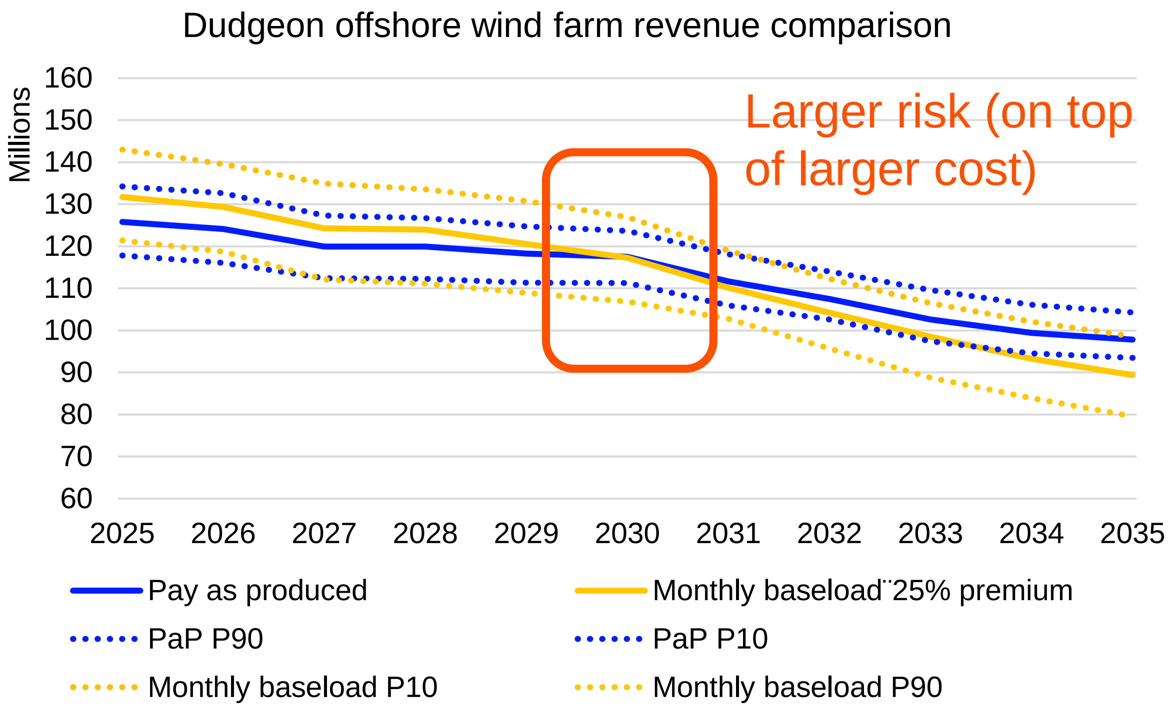

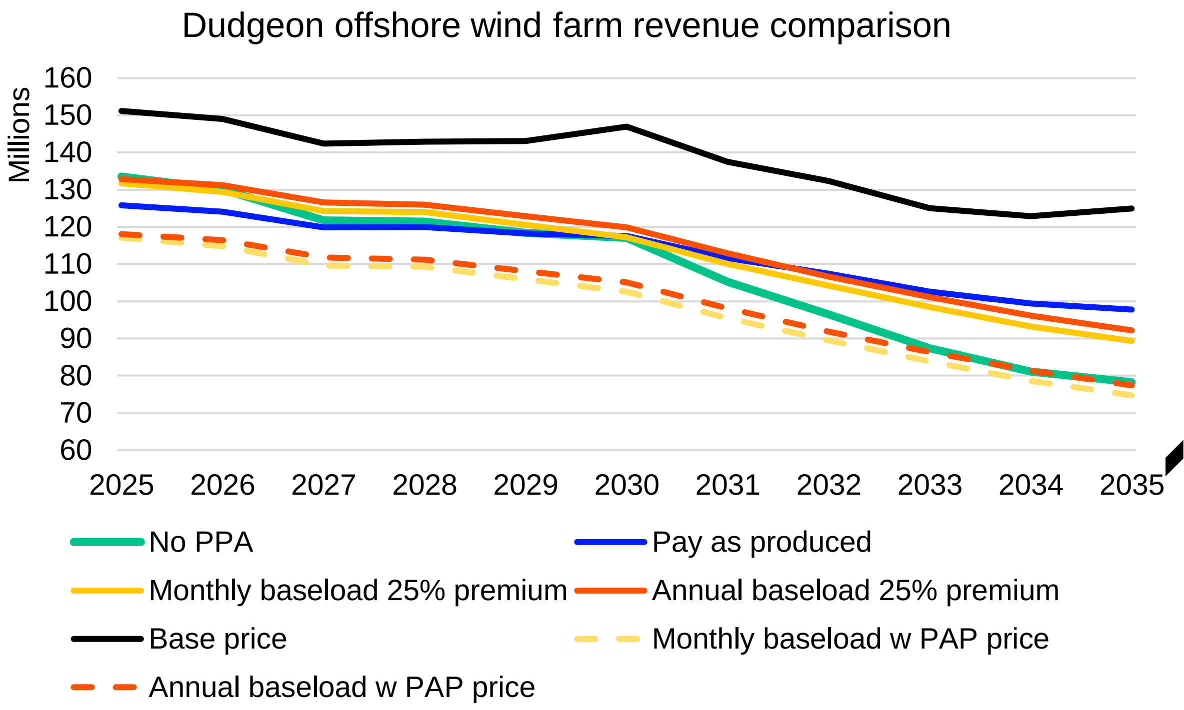

Example: Mula solar farm in Spain

- Installed capacity of 494 MW (largest in Europe at time of opening, 2019).
- We calculate the hourly production for 30 distinct weather years, which are the actual weather in that location from 1991 to 2020 (ERA5 data)
- In order to calculate future revenues, our model retrieves the hourly prices from our long term price model for each of the 30 weather years.
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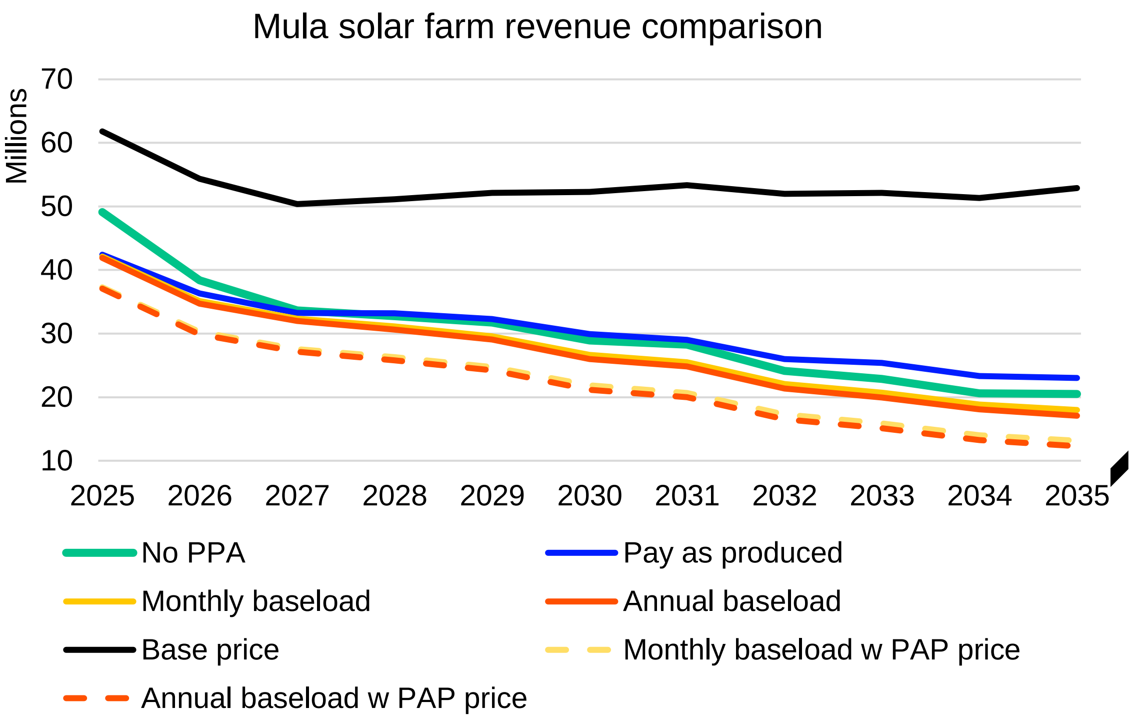

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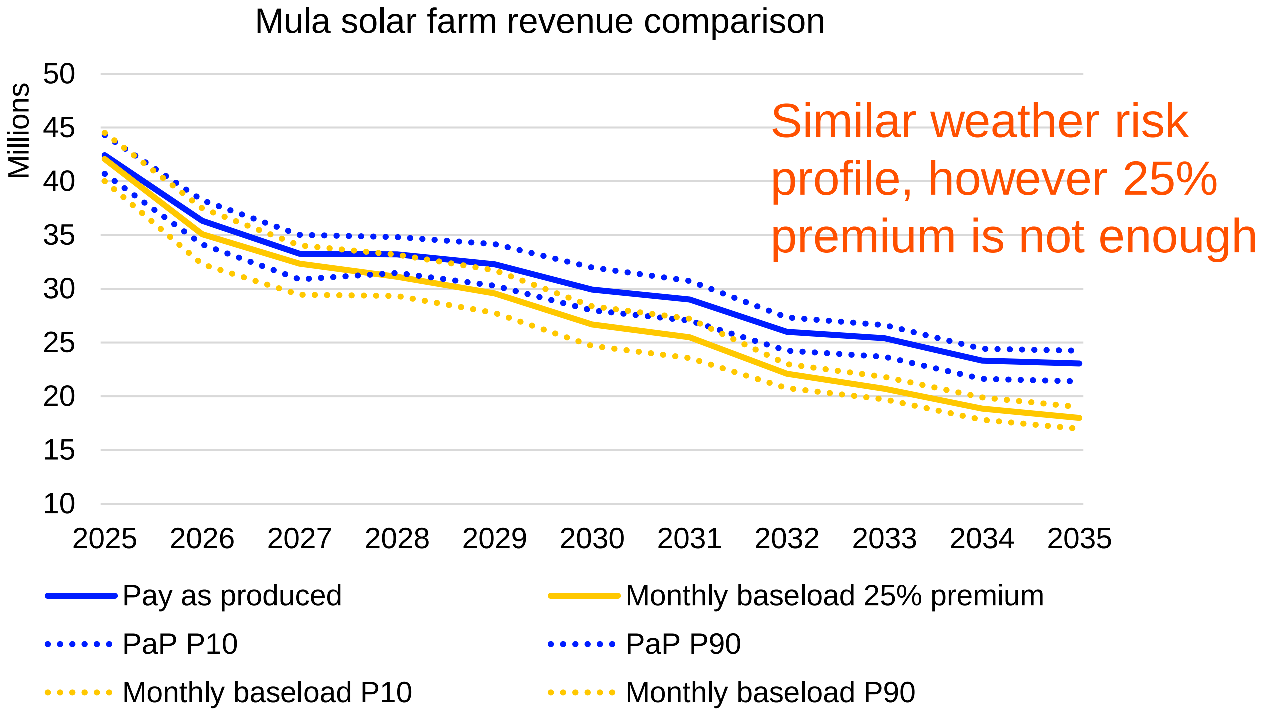
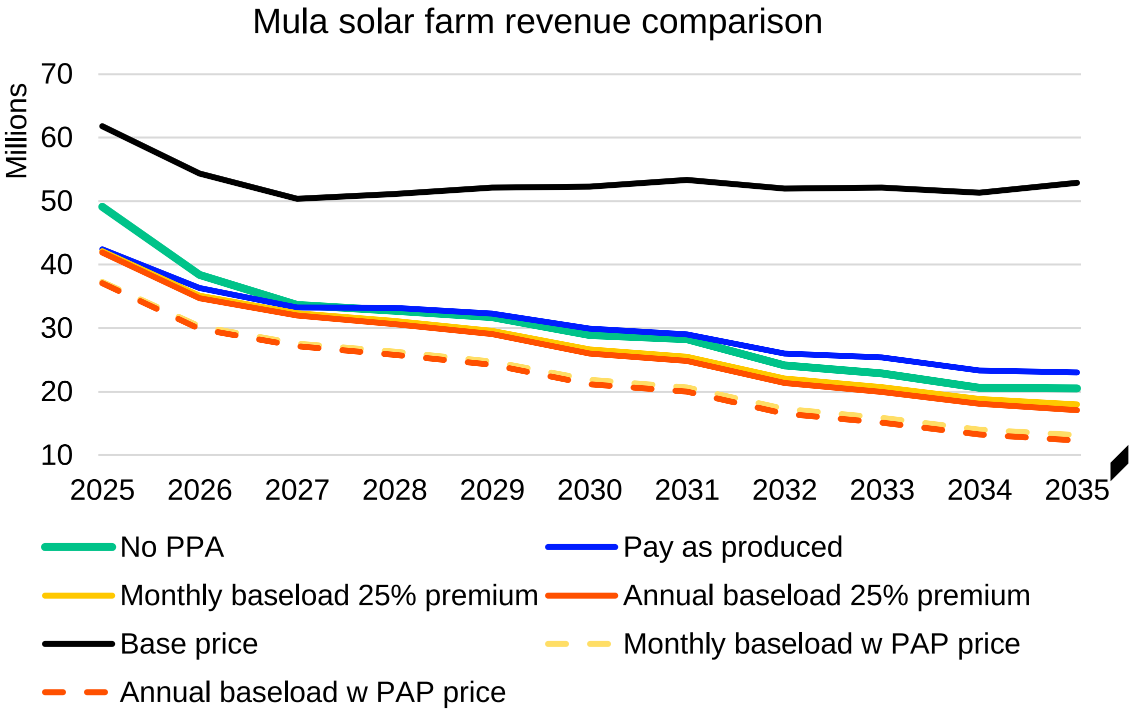
- We calculate the hourly production for 30 distinct weather years, which are the actual weather in that location from 1991 to 2020 (ERA5 data)
- In order to calculate future revenues, our model retrieves the hourly prices from our long term price model for each of the 30 weather years.
- The renewable asset may reduce market exposure by the means of a PPA (Power Purchase Agreement). Different types of PPAs are compared. Revenues are pre-tax and do not include sales of GOs nor imbalance costs.





Remarks and conclusions

Main findings

- Hourly resolution price models are crucial to understand the implications of a power system with growing renewable penetration
- The system is evolving quickly, and the penetration of renewables does not align (for the moment) with the deployment of flexibility solutions (batteries, demand side response,…)
- The challenges that we see today with vRES are going to increase in the near future (negative prices, cannibalization,…)

- For all these reasons financing renewable projects is becoming more expensive and more challenging
- PPA and 2-sides CfD are good answers, however no “one fits all” solution, and deep quant modeling are required to understand the risk profiles of these financial tools

- A PPA does not always reduce risk: Baseload PPAs increase weather-dependent revenue risk (vs no PPA) and even pay-as-produced PPAs are shown to increase risk wrt weather in some technologies and markets
- Pay as produced PPA get penalized in low wind scenarios that have above average capture rates
- Baseload PPAs require a price premium (>25%) over base prices to reach same expected revenues, yet significantly increase risk
- Monthly baseload PPAs provide no advantage in revenues nor risk vs annual baseload PPAs (for wind)
- Imbalance costs as GO prices are hard to forecast but non-negligible in renewables revenues

Thank you

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