Dauphine | PSL
CHAIRE EUROPEAN ELECTRICITY MARKETS

The hidden financial costs of intermittent power generation

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Introduction

- The rise of renewable energy is driven by growing concern about global warming and energy security.
- Renewables are expected to provide 40% of global electricity generation by 2027 (International Energy Agency, 2022).
- The intermittent nature of renewable power creates physical and financial risk management challenges.
- More volatile prices raise the cost of hedging.
- Electricity futures cannot be priced by arbitrage because electricity is not storable.
- We employ the **Market equilibrium approach**

$$F_{t,T} = E(S_T) \pm RP_{t,T},$$

This paper

Our objective: Quantify impact of intermittent power on spot/futures prices, and risk premia.

1. Empirical evidence of the link between intermittent power and futures prices/risk premia.
2. Develop a theoretical model with two type of producers (conventional & renewables) with two trading periods (spot and futures).
3. Estimate model parameters using data on the German-Austrian market (2013-2018).
4. Quantify the impact of intermittent power on risk exposures and premia.
    - 1% increase in intermittent energy lowers spot prices by 1.89%, but raises risk premia by 0.39%.
    - Effects more pronounced in Winter & for wind power.

⇒ Shadow value of storage capacities (or improving interconnection).

Reduced form analysis

Electricity prices and intermittent power generation

- We assess the impact of intermittent power generation (wind, solar) on electricity prices:

$$Y_T = a_0 + a_1 Q_T^{wind} + a_2 Q_T^{solar} + X_T + \eta_T$$

- We use sunshine duration (resp. wind speed) as instruments for solar (resp. wind) power generation First Stage

	Spot Price	One month-ahead Risk Premium
SOLAR POWER Q^{solar}	0.848	-0.994
	(0.581)	(-0.665)
WIND POWER Q^{wind}	-0.919**	0.880**
	(-2.139)	(1.998)
(...)		
Constant	0.964	-6.510
	(0.0241)	(-0.159)
Year FE	yes	yes
Observations	66	66
R-squared	0.775	0.467

⇒ Wind and solar do not have the same impact

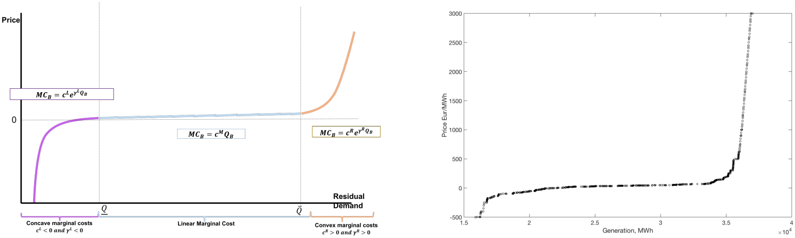
Model

We depart from BL (2002) by changing the production mix.

N_G green producers, N_B conventional producers and N_R retailers.

Date 1 **Futures Market**	**Date 2** **Spot Market**	**Delivery**
-All maximize the expected utility of their final profits: max $EU(\pi_i) = E(\pi_i) - \frac{A}{2} Var(\pi_i)$ -Retailers and producers decide their futures trading volume (q_i^F).	-Conventional producers: *Serve residual demand *Optimize their production: max $SQ_{Bi}^W + FQ_{Bi}^F - TC_{Bi}$ Produce electricity from difference sources according to their respective MC -Green production is random $\tilde{Q}_G$. *Low marginal constant cost (δ) *Receive feed in tariffs (θ) → first to serve demand -Retailers must serve a random demand $\tilde{Q}_D$	-Total demand $\tilde{Q}_D$ realized -Total renewable $\tilde{Q}_G$ realized
-Fut. market clears: F s.t. $q_i^F = 0$ -Obtain risk premium and futures price.	-Spot market clears: S s.t. $Q_D = Q_S$ -Obtain the spot price	

Shape of conventional producers’ costs



Left-Shape of conventional producers’ costs. Right-Snapshot of (spot market) limit order book data, January 02, 2018, at 12am.)

- Below some threshold $\underline{Q}$: concave curve, negative reservation prices
- Above some threshold $\overline{Q}$: convex curve → turning on less efficient/more expensive power plants (gas, oil, coal)

⇒ Concavity / convexity is captured by our cost parameters (c^L, c^R), c^M and (γ^L, γ^R)

Theoretical Predictions

Solving the model backward

Date 2→Spot prices show the **merit order effect**, depend on $\tilde{Q}_D$ and $\tilde{Q}_G$

$$\tilde{S}^* = \begin{cases} c^L \exp(\frac{\gamma^L}{N_B}\tilde{Q}_N) & \text{if } \tilde{Q}_N < \underline{Q} & \text{Region } \mathscr{R}_1 \text{ (concave)} \\ \frac{c^M}{N_B}\tilde{Q}_N & \text{if } \underline{Q} \leq \tilde{Q}_N \leq \overline{Q} & \text{Region } \mathscr{R}_2 \\ c^R \exp(\frac{\gamma^R}{N_B}\tilde{Q}_N) & \text{if } \tilde{Q}_N > \overline{Q} & \text{Region } \mathscr{R}_3 \text{ (convex)} \end{cases} \tag{1}$$

Date 1→ Futures price F^* such that $\sum_i q_i^F = 0$:

$$F^* - E(S) = \underbrace{\underbrace{\overline{A}}_{>0}\, cov(TC_B(\tilde{Q}_B), \tilde{S})}_{\text{Conv. Prod. Cost Risks}} \underbrace{\underbrace{+\overline{A}\,(\delta - \theta)}_{>0 \text{ if } \delta > \theta}\, cov(\tilde{Q}_G, \tilde{S})}_{\text{Green Prod. Cost Risks}} \underbrace{\underbrace{-\overline{A}P_R}_{<0}\, cov(\tilde{Q}_D, \tilde{S})}_{\text{Retailers Revenue Risks}} \tag{2}$$

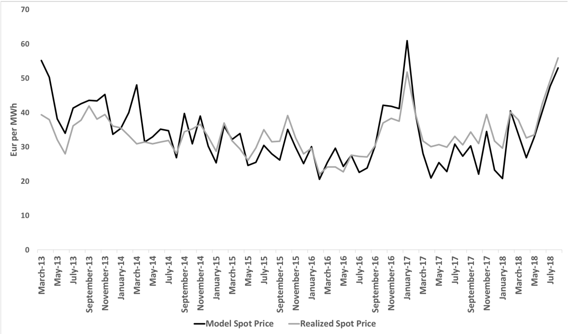
where $\overline{A} = \frac{A}{N_B + N_G + N_R}$ is a weighted risk-aversion coefficient.

- Risk premium is a function of producers' cost risks and retailers' revenue risks that contribute to **aggregate risk** (other risks cancel out) Detailed formula

Comparative statics depends on model's parameters → our next step = estimating the model parameters

Structural estimation

Prices on the spot market



Model spot prices (using estimated cost functions) vs Realized Spot Prices

Consistency check: realized prices vs predicted prices.

Counterfactual analysis

Counterfactuals

We analyze the impact of a 1 % increase in intermittent power generation in the production mix.

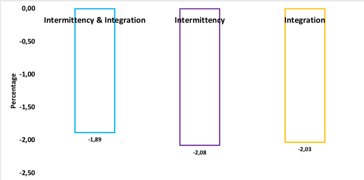
- We use the cost parameters from the structural estimation

Parameter	$\underline{Q}$	$\overline{Q}$	$\underline{S}$	$\overline{S}$	c^L	γ^L/N_B	c^M/N_B	c^R	γ^R/N_B	α_1	α_2	P_R/S	δ/S	θ/S	$\overline{A}$
All	18.98	23.02	-0.98	43.17	-278.79	-0.78	12.33	3.84	0.87	0.03	0.84	4.33	0.30	0.85	0.002

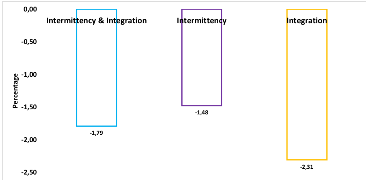
- 1000 demand (Q_D) and renewable production (Q_G) realizations were drawn from a multivariate normal distribution were:.
  - Distribution characteristics, such as means, variances, and covariance, adjust in response to a 1% increase, as calibrated from the data.

- **Current Scenario**: We calculate the $E(S)$, F, and RP for each drawing based on the estimated parameters.
- **Three New Scenarios:**
  1. "Intermittency Scenario": σ_G adjusts in response to a 1% increase in intermittent power within the energy mix.
  2. "Integration Scenario": $Corr(Q_D, Q_G)$ adjusts in response to a 1% increase in intermittent power within the energy mix.
  3. "Intermittency and Integration Scenario": both $Corr(Q_D, Q_G)$ and σ_G change.

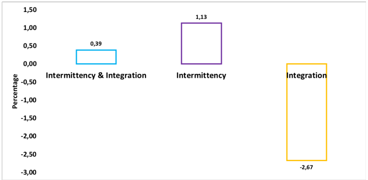
Simulation Results



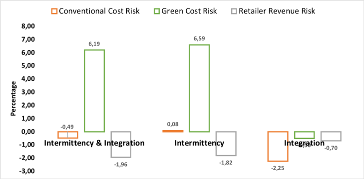
(a) Percentage change in S



(b) Percentage change in F



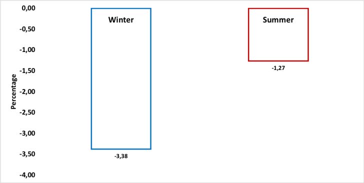
(c) Percentage change in RP



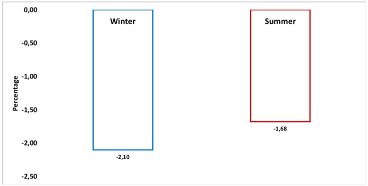
(d) Percentage change in Non-Diversifiable risks

- Intermittency and Integration: $S\downarrow$ by 1.89%, RP $\uparrow$ by 0.39%.
- Driven by $\uparrow$ in σ_G, not offset by $Corr(Q_D, Q_G)$

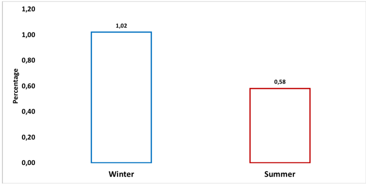
“Intermittency and Integration scenario” in Winter/Summer



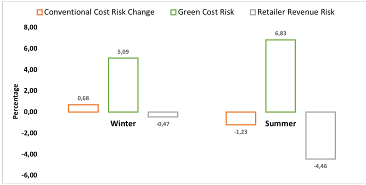
(a) Percentage change in S



(b) Percentage change in F



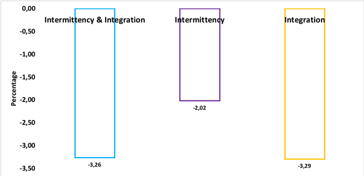
(c) Percentage change in RP



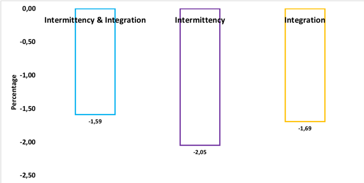
(d) Percentage change in Non-Diversifiable risks

- RP increases much less in Summer than in Winter

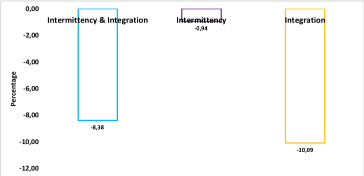
Wind vs Solar



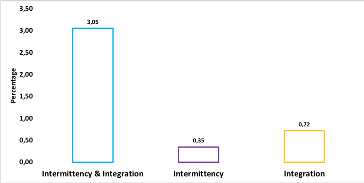
(a) Percentage change in S, solar



(b) Percentage change in S, wind



(c) Percentage change in RP, solar



(d) Percentage change in RP, wind

- Wind has a positive impact on RP, while solar has a negative impact
- Driven by the fact that solar ↑ $corr(Q_D, Q_G)$ while wind ↓ it. Details

Conclusion

We examine the impact of intermittent power on risk exposures and premia.

1. Proposed market equilibrium model highlights:
    - Risk premium depends on covariance between intermittent power production and spot price.
2. Model parameters estimated for the German-Austrian market (2013-2018).
3. Counterfactual analysis:
    - Risk premium decreases as $Corr(\tilde{Q}_D, \tilde{Q}_G)$ increases, and increases as $\sigma_{\tilde{Q}_G}$ increases.
    - Intermittent power's impact varies with its demand correlation, which might explain differing empirical results across countries.
    - Risk premia show more sensitivity to wind than solar power.
    - Solar power generation seems better integrated than wind.

Thank you!

Appendices

FIRST STAGE	SOLAR POWER (1)	WIND POWER (2)	SOLAR POWER (3)	WIND POWER (4)
SUNSHINE DURATION	0.0119***		0.0126***	-0.00751
	(6.163)		(5.152)	(-1.281)
WIND VELOCITY		5.738	-1.123	3.288
		(0.968)	(-0.433)	(0.531)
WIND SPEED		-3.094	1.132	-0.763
		(-0.526)	(0.442)	(-0.125)
PRECIPITATION		-0.00894	0.00257	-0.0113*
		(-1.424)	(0.944)	(-1.735)
SRMC_COAL	-0.0505**	0.0911*	-0.0493**	0.0839
	(-2.455)	(1.801)	(-2.328)	(1.660)
SRMC_GAS	0.0171	-0.0179	0.0197	-0.0145
	(1.080)	(-0.445)	(1.170)	(-0.360)
SMRC_OIL	0.00875	-0.0328**	0.00929	-0.0301*
	(1.349)	(-2.011)	(1.358)	(-1.840)
SRMC_RNW	-1.350***	2.664***	-1.429***	2.251***
	(-3.756)	(2.963)	(-3.595)	(2.371)
Feed_in_tariffs FIT	0.00560	0.123***	0.00520	0.131***
	(0.509)	(4.124)	(0.411)	(4.328)
Dummy SUMMER	-0.279	0.0122	-0.307	-0.104
	(-1.492)	(0.0246)	(-1.465)	(-0.208)
Dummy FALL	-0.905***	0.902*	-0.859***	0.487
	(-4.217)	(1.885)	(-3.567)	(0.847)
Dummy WINTER	-1.005***	0.669	-0.958***	0.464
	(-5.363)	(1.474)	(-4.783)	(0.969)
TEMPERATURE	0.0781***	-0.0116	0.0677**	0.0342
	(3.149)	(-0.198)	(2.380)	(0.503)
Dummy_ 2014	0.447*	-0.174	0.503*	-0.150
	(1.872)	(-0.288)	(1.995)	(-0.249)
Dummy_ 2015	3.224***	-3.602**	3.413***	-2.553
	(4.394)	(-2.011)	(4.163)	(-1.304)
Dummy_ 2016	2.722***	-1.427	2.912***	-0.673
	(4.293)	(-0.900)	(4.138)	(-0.400)
Dummy_ 2017	3.741***	-0.462	3.884***	0.528
	(4.958)	(-0.256)	(4.757)	(0.271)

Equilibrium and the futures risk premium

Market clearing condition: Futures price F^* such that $\sum_i q_i^F = 0$

- Each $Cov(\tilde{\rho}_i, \tilde{S})$ can be decomposed into two parts: revenue risk and cost risk
- Retailers' cost risks offset producers' revenue risks (no risk once aggregated)

$$\underbrace{F^* - E(\tilde{S})}_{\text{Risk Premium}} = \overline{A} \left(\begin{array}{l} \underbrace{N_B \alpha_1 Cov \left(\frac{c^L}{\gamma^L} . e^{\left(\gamma^L \left(\frac{\widetilde{Q}_N}{N_B} \right) \right)}, \tilde{S} \right) + N_B \alpha_2 Cov \left(\frac{c^M}{2} \left(\frac{\widetilde{Q}_N}{N_B} \right)^2, \tilde{S} \right) + N_B \alpha_3 Cov \left(\frac{c^R}{\gamma^R} . e^{\gamma^R \left(\frac{\widetilde{Q}_N}{N_B} \right)}, \tilde{S} \right.}_{\text{Conv. Prod. Cost Risks}} \\ + \underbrace{Cov \left((\delta - \theta) \widetilde{Q}_G, \tilde{S} \right)}_{\text{Green Prod. Cost Risks}} \\ - \underbrace{Cov \left(P_R \widetilde{Q}_D, \tilde{S} \right)}_{\text{Retailers Revenue Risks}} \end{array} \right.$$

where $\overline{A} = \frac{A}{N_B + N_G + N_R}$ is a weighted risk-aversion coefficient.

→ Risk premium is a function of producers' cost risks and retailers' revenue risks that contribute to **aggregate risk**.

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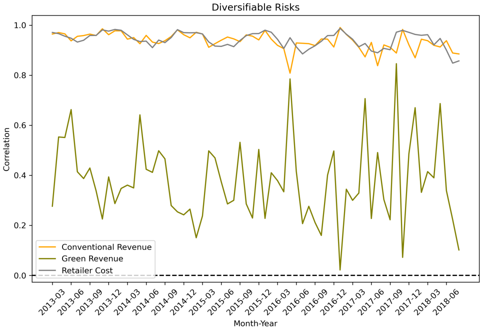
Diversifiable risks: Producers' revenues and retailers' costs



Producers' revenues and retailers' costs

- Correlations are all positive (even for green producers)
- Corr(Conv. Rev, S) and Corr(Green Rev, S) are higher in summer, but Corr(Retailer Cost, S) is higher in winter.

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Data

1. **Electricity spot demand and supply curves**. Epex Spot hourly snapshots of the LOB for the German/Austrian day-ahead electricity market 2013-2018
    - 24 hourly aggregated supply curves
    - Compute (S, Q^W)
2. **Electricity Phelix futures prices.**
    - 66 contracts with daily prices from six months before the maturity date
3. **Renewable generation**.
    - Hourly solar and wind generation day-ahead forecasts from the German Transmission System Operators (TSOs)
4. **Short Run Marginal Costs**
    - We construct the marginal costs of the three main fossil fuels (gas, coal, and oil) from the formulas reported by Refinitiv (including CO2 prices)
5. **Other data**
    - Feed-in-tariffs
    - Retail prices

Marginal costs: construction

We construct the marginal costs of the three main fossil fuels

- We base our computations on the formula provided by Refinitiv.

$$\text{SRMC[eur/MWh]} = \frac{\text{Commodity price[eur/ton or eur/therm]}}{\text{heat value[GJ/t or GJ/therm]} \times \text{efficiency}} \times 3.6\text{[GJ/MWh]}+$$
$$+ \frac{\text{emission intensity[tCO2/GJ]} \times \text{carbon emission price[eur/tCO2]}}{\text{efficiency}} \times 3.6\text{[GJ/MWh]}+$$
$$+ \text{O\&M costs[eur/MWh]}$$

- We obtain efficiency percentages from an ECOFYS report (2018) and emission intensity factors from EIA (2005).
- We keep the operation and maintenance costs for coal and gas from Refinitiv. For oil, we employ those reported by DIW Berlin (2013). Details

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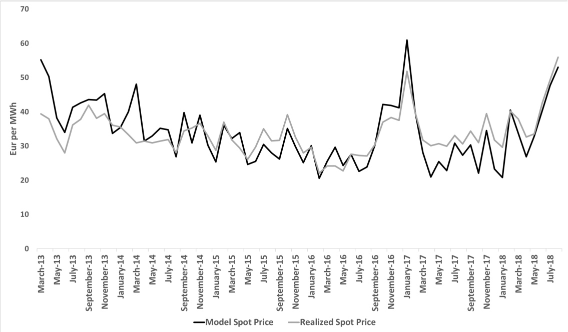
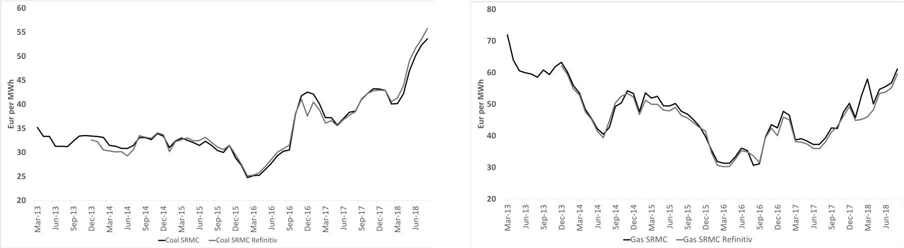
STEP 2 Objective: Use futures prices regressed on non-diversifiable risks to recover other model parameters $(a_G, \overline{A})$. Formula



Model spot prices vs Realized Spot Prices

Robustness: Marginal costs of oil



Comparison between the Coal Short Run Marginal Cost provided by Refinitiv and our own time series.

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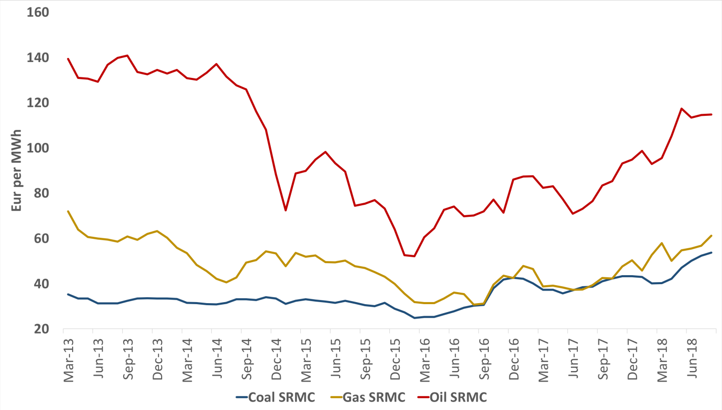
Marginal costs of oil, gas and coal power plants



Goodness of fit: consistency with cost components

	g_B parameter	b_B parameter
Gas Marginal Cost	-0.00792**	-0.0142
	(0.00332)	(0.0212)
Oil Marginal Cost	0.00448***	0.0006
	(0.00143)	(0.00912)
Coal Marginal Cost	-0.00674	0.0290
	(0.00449)	(0.0287)
Residual Load in TWh	-0.00791	0.0468
	(0.0000119)	(0.0000758)
Time dummies included?	Yes	Yes
Observations	68	68

Standard errors in parentheses

* ($p<0.1$), ** ($p<0.05$), *** ($p<0.01$)

- g_B (convex part): Convexity increases with marginal cost of oil (last in merit order), decreases with marginal cost of gas
- b_B (concave part): As expected, no impact

Data on efficiency

	Coal	**Gas**	**Oil**
Heat value Gj/MWh	7.2	10	
Efficiency [%]	44	48.5	38
Emission intensity [t CO2/Gj]	0.0946	0.0561	0.0741
O&M costs [eur/MWh]	4.4	3.2631 [GBP/MWh]	3

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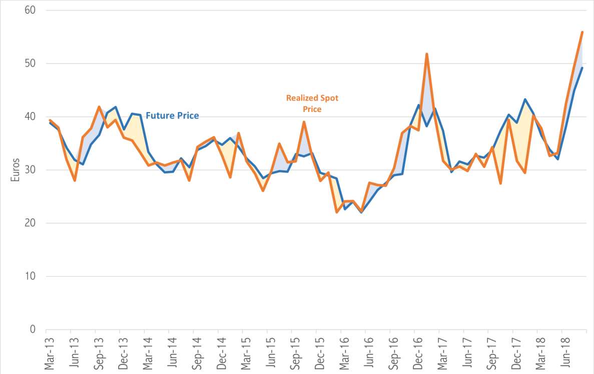
Descriptive statistics

We close the calibration of the model using data on Futures prices



One month-ahead futures prices vs realized spot prices from the German-Austrian market/ Blue=bacwardation, yellow=contango