Evaluating the value of probabilistic forecasts in power systems

Lueder von Bremen, Bruno Schyska, Hauke Bents, Clara Buller

DLR, Institute of Networked Energy Systems, Oldenburg

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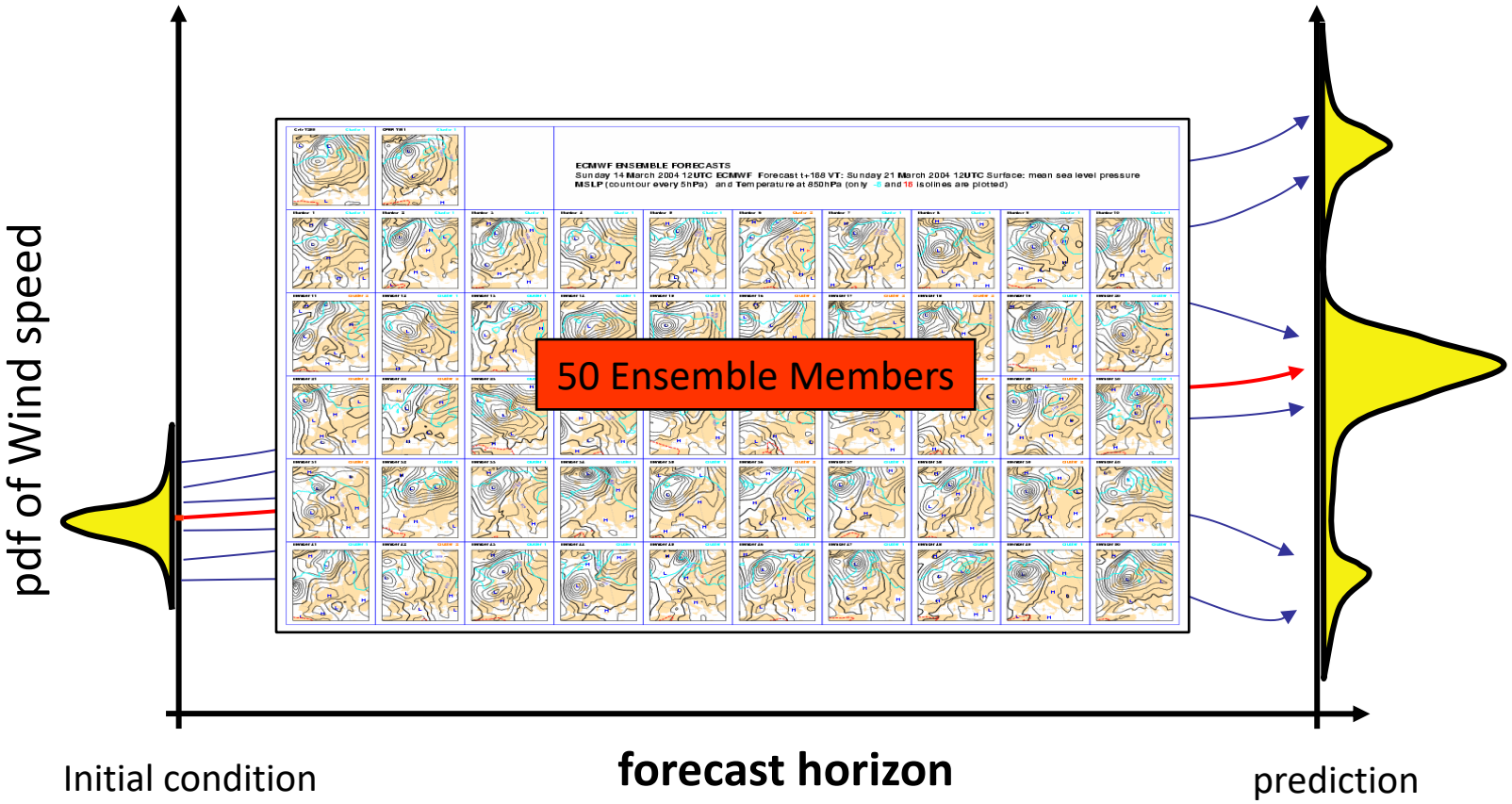
How to evaluate the value of uncertain weather forecasts?

Solution from Numerical Weather Forecasting: Ensemble Prediction



Source: European Centre for Medium-Range Weather Forecasts (ECMWF)

- Lorenz Paradigm: Numerical Weather Forecasting is an initial state problem
- Quantify the uncertainty in the forecast to be aware of forecast errors
- **Major task:** Combine probabilistic forecasts with power dispatch model

How to evaluate the value of uncertain weather forecasts ?

- **<u>Solution from power system modelling:</u> Stochastic Dispatch modelling including optimal power flow with transmission restrictions, ramping constraints and prices**

Current practise: Conventional/Deterministic Clearing	Novel idea: Stochastic clearing
Without forecast uncertainty	Forecast uncertainty is considered by implementing **expected balancing costs** in optimization problem
Deterministic (best) forecast is used	50 ensemble member are used as potential occuring weather scenarios
Potentially high system costs due to expensive balancing and expensive load shedding	System improves dispatch using uncertainty information. Less balancing is needed

Optimization problem

Current practise: Conventional clearing at the stock exchange

12:00 on previous day

Day-ahead (DA) Market

min Day-ahead Dispatch Costs

$$\min_{g,g^{+/-}} \sum_{n,s} \left(C_{n,s} g_{n,s,t}\right)$$

Novel idea: Stochastic clearing

min Day-ahead Dispatch Costs + Expected Balancing Costs

Continously up to 5 min ahead delivery
Here:
Only once 15min ahead

Intra-day (ID) Market

min Intra-day Correction Costs + Expected Balancing Costs

$$\min_{g^{+/-},s} \varrho \cdot \left(\sum_{n,s} \left(C^{+}_{n,s} g^{+}_{n,s,t} + C^{-}_{n,s} g^{-}_{n,s,t} \right) \right) + \mathbb{E}_{\omega} \left[C^{\mathrm{BM}}_{\omega} \right]_t$$

time of delivery t_0

Balancing (BM) Measures

min Balancing Costs

$$\min_{g^{+/-}} \sum_{n,s} \left(C^{+}_{n,s} g^{+}_{n,s,t} + C^{-}_{n,s} g^{-}_{n,s,t} \right) + \sum_{n,i} \left(C^{shed}_{n,i} s_{n,i,t} \right)$$

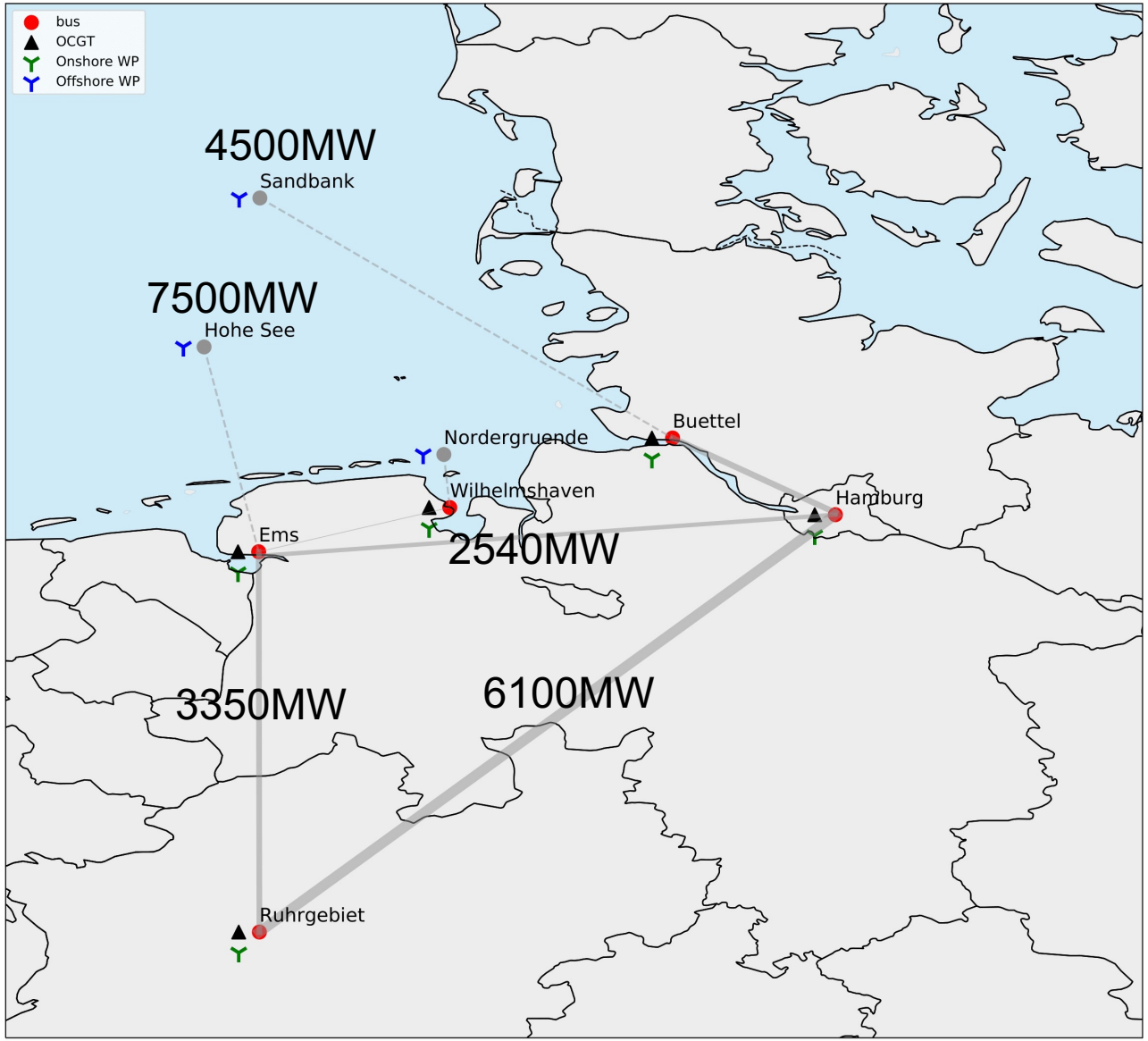
(6) J. M. Morales et al., “Electricity market clearing with improved scheduling of stochastic production”, *European Journal of Operational Research*, vol. 235, pp. 765-774, 2014. doi.org/10.1016/j.ejor.2013.11.013

(7) T. Brown, J. Hörsch and D. Schlachtberger, “PyPSA: Python for Power System Analysis”, *Journal of Open Research Software*, Jan. 2018.

Studying Network

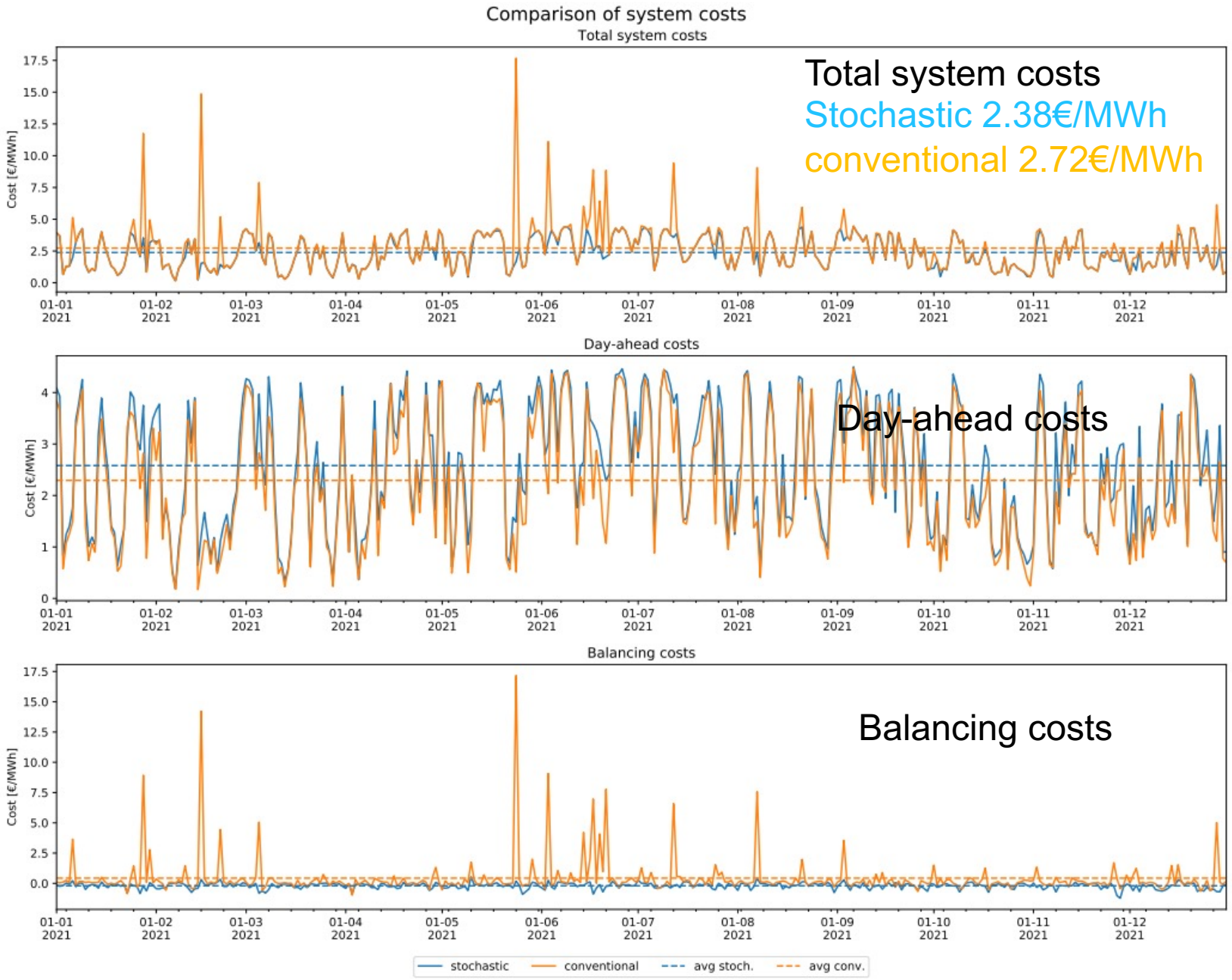
Properties:

- 3 generator types:
  - 5xOCGT (flexible open-circle gas turbines)
  - 5xOnshore wind parks
  - 3xOffshore wind parks
- 5 Buses:
  - Load profile for each sector (Industry, CTS, Households)
  - Load shedding up to 200€/MWh
- 13 Generators:
  - Nominal generator capacity
  - Marginal costs (0€/MWh for Wind, 4.50€/MWh for OCGT)
  - Flexibility/balancing premium up↑: +14%
  - Flexibility/balancing premium down↓: +3%
- 5 Links:
  - Nominal link capacity



Results: Comparison of system costs

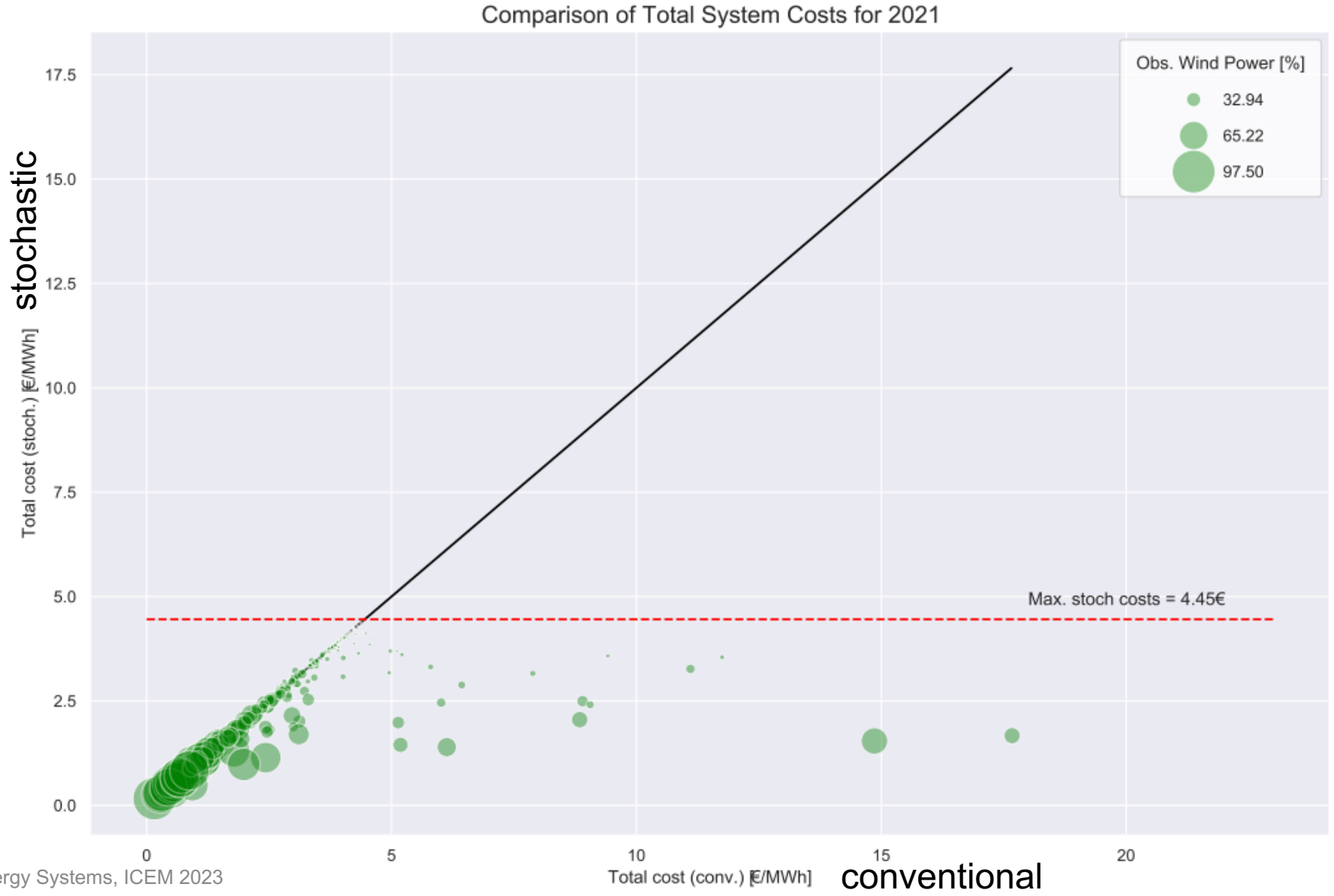
- Total system costs = day-ahead costs + balancing costs
- Stochastic model yields overall price reduction
- Higher day-ahead market costs for stoch. model as more OCGT is dispatched than in conventional clearing
- Hence, very low balancing costs at time of delivery



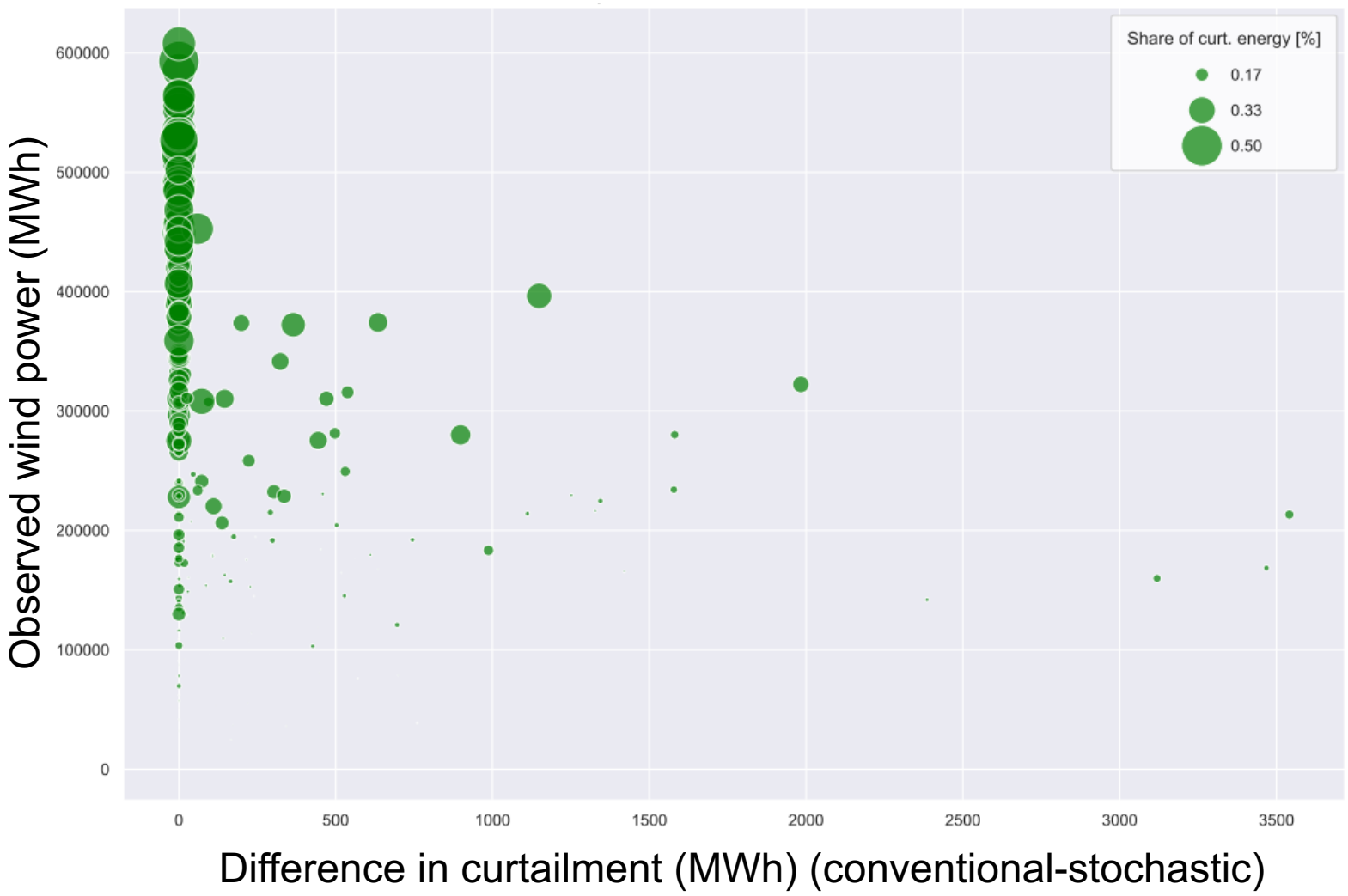
Half of balancing costs due to shedding, half due to higher balancing energy usage

Comparison of total average daily total system costs

- Negative correlation between total system costs and observed wind power
- Cap of costs in stochastic model of 4.46€ ~ marginal costs of conventional generators

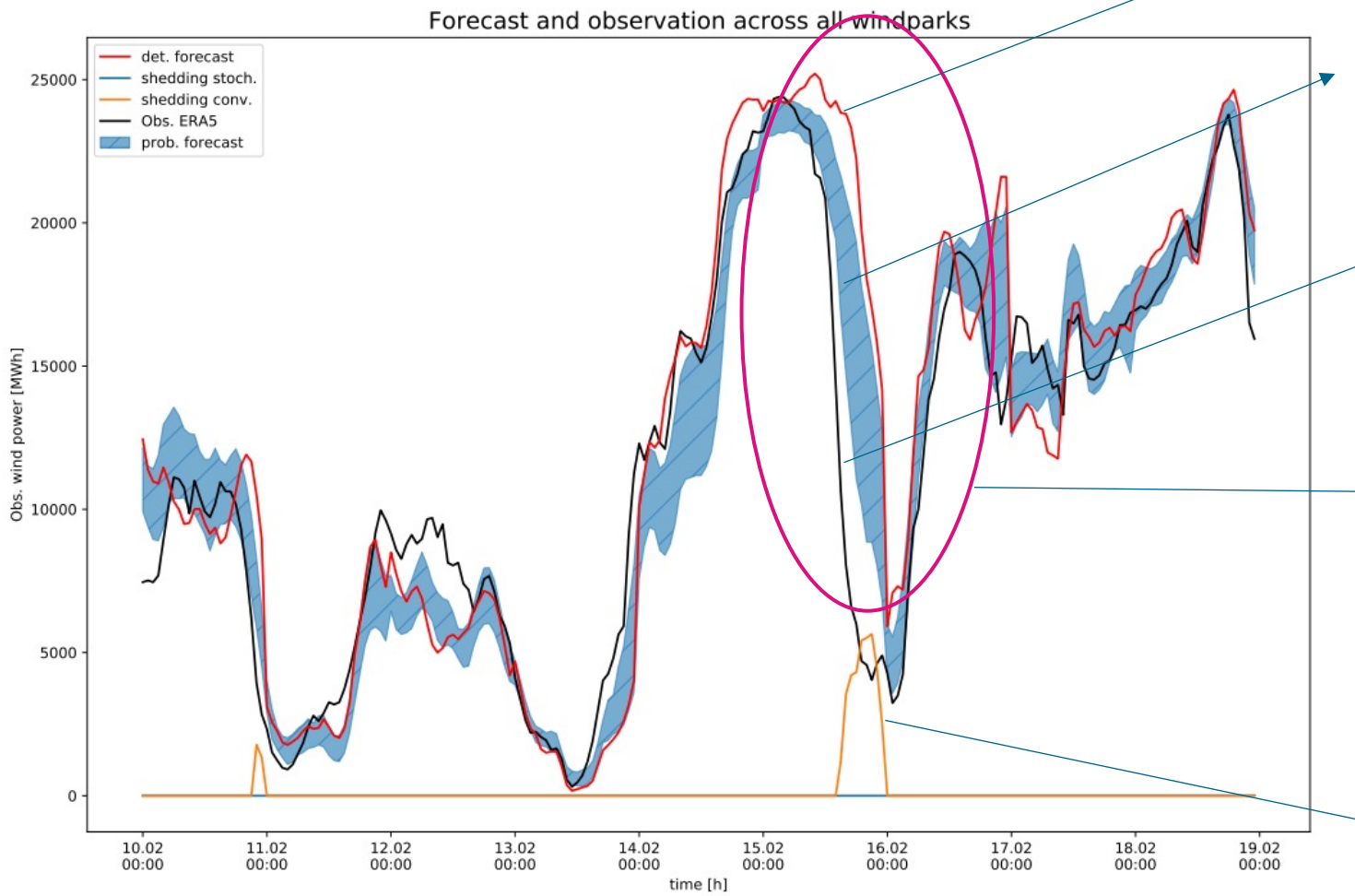


Comparison of daily wind curtailment



With obs. wind power the share of curtailed wind energy increases.
Slighly more curtailment in conventional clearing for medium obs. wind power due to „unplanned“ congested lines
Grid strenghening reduces curtailment by ~30%. But more shedding occurs.

Avoid load shedding when considering forecast uncertainty



Deterministic forecast

Prob.forecast (inner quartile)

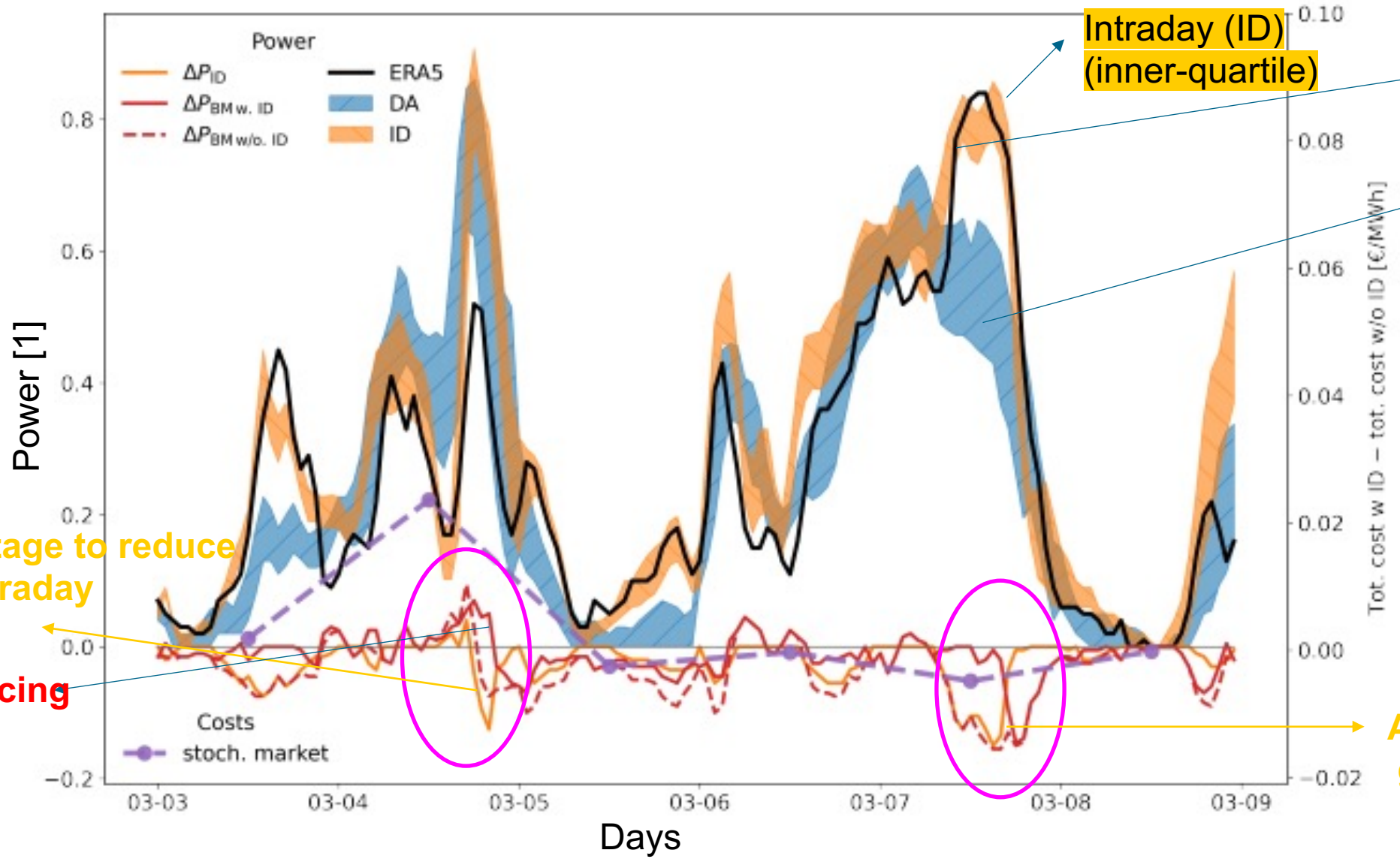
observation

Ramp earlier than expected

Load shedding

Ramping constraints are too strict to balance the sudden lack of wind power in the conventional clearing 2021: Shedding reduction from 318GWh (conventional) to 1.5GWh (stochastic). Total load: 140 TWh

Include updated forecast for intraday (ID) clearing



Intraday (ID) (inner-quartile)

observation

DayAhead (DA) (inner-quartile)

Disadvantage to reduce gas at Intraday

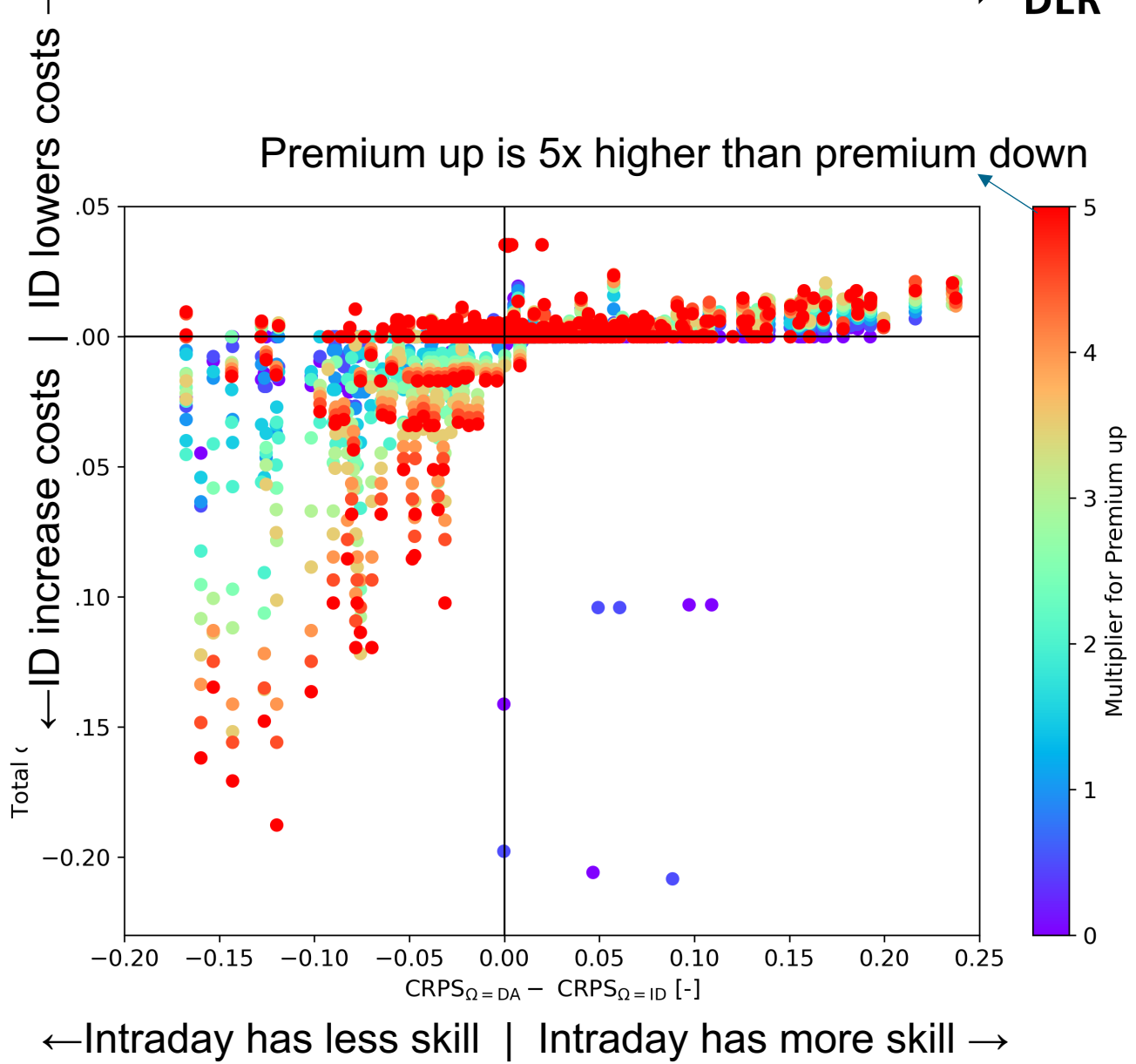
Buy balancing

Advantage to reduce gas at Intraday

It is expensive when intraday forecast is even slightly worse than day-ahead forecast

Sensitivity of Intraday (ID) corrections to forecast skill and to premium up/down price spread

- CRPS as skill measure
- High premium spread lead to high extra costs in case Intraday is worse than DayAhead forecast
- Overestimation of wind power at Intraday is most expensive



Take home messages

- Impact of forecast uncertainty can be modelled in an (idealized) power system including power flow optimization, prices and ramping constraints
- Total system costs decrease when considering weather forecast uncertainty due to reduced curtailment, load shedding and balancing costs
- Updated forecasts at the intraday-market can reduce costs further, but premiums and forecast skill play an important role
- Next steps: expand the network for higher realism, include storages, investigate complementarity between storage and forecast skill

THANK YOU FOR YOUR ATTENTION.

Contact: lueder.von.bremen@dlr.de

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