NHH

Does intermittent generation require stochastic dispatch models?

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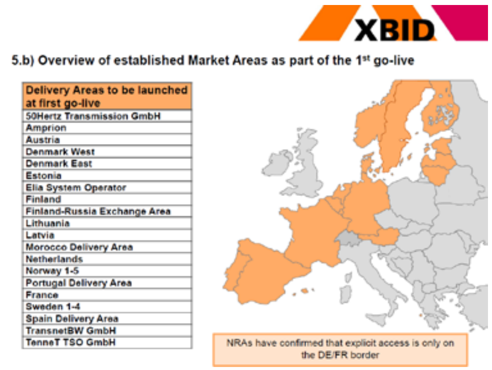
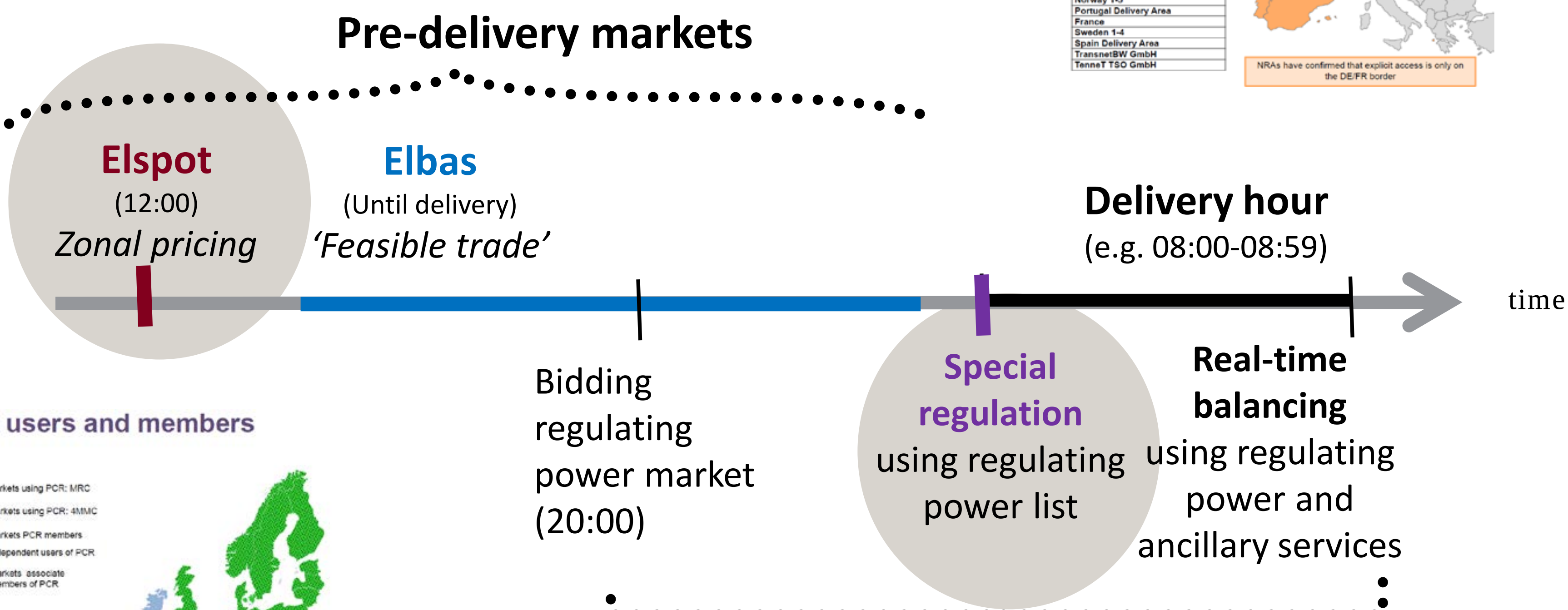
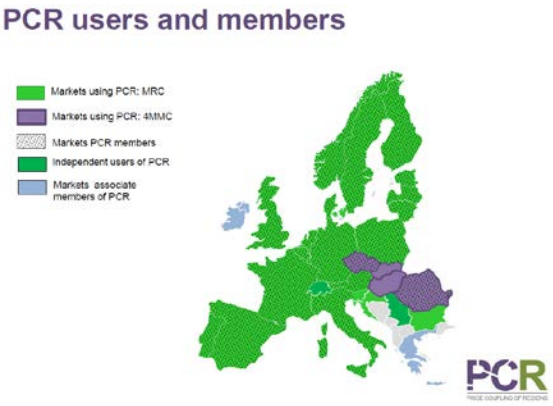
Background – European target model

- Energy only day-ahead market
  - Supplemented by intraday and balancing markets
- Market coupling between regional markets
  - Zonal pricing – Available Transfer Capacity (ATC) model
  - Zonal pricing – Flow-based Market Coupling (FBMC) model
  - (Nodal pricing – Benchmark)
- Intermittent renewables are variable and uncertain (and subsidized)
- Need for changes in market design?

European and Nordic Market





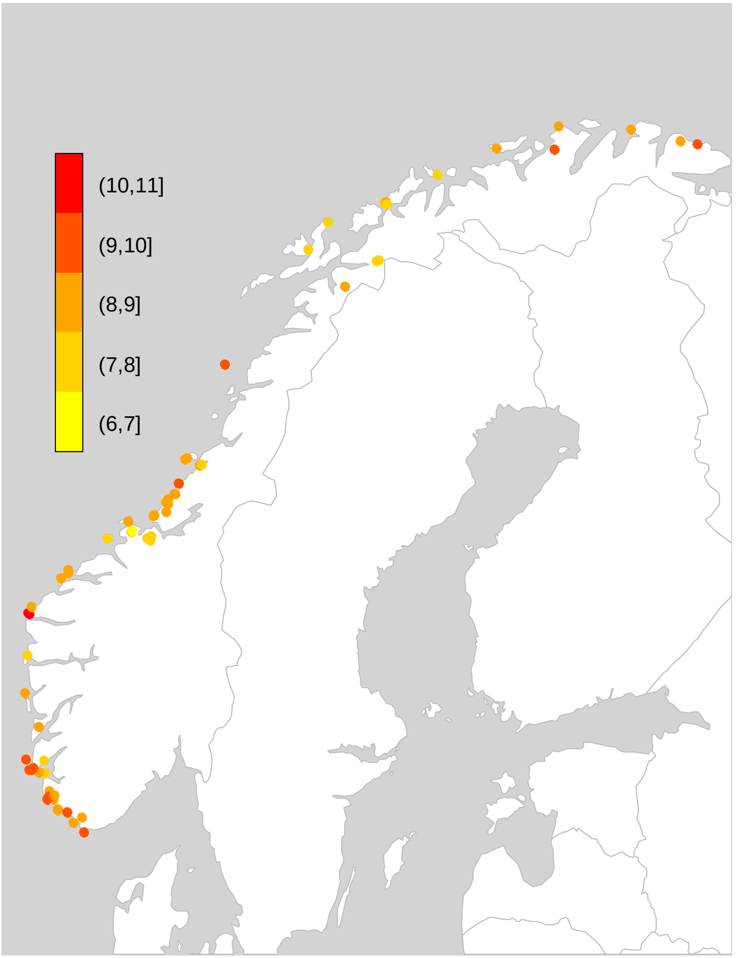


Markets and systems for:

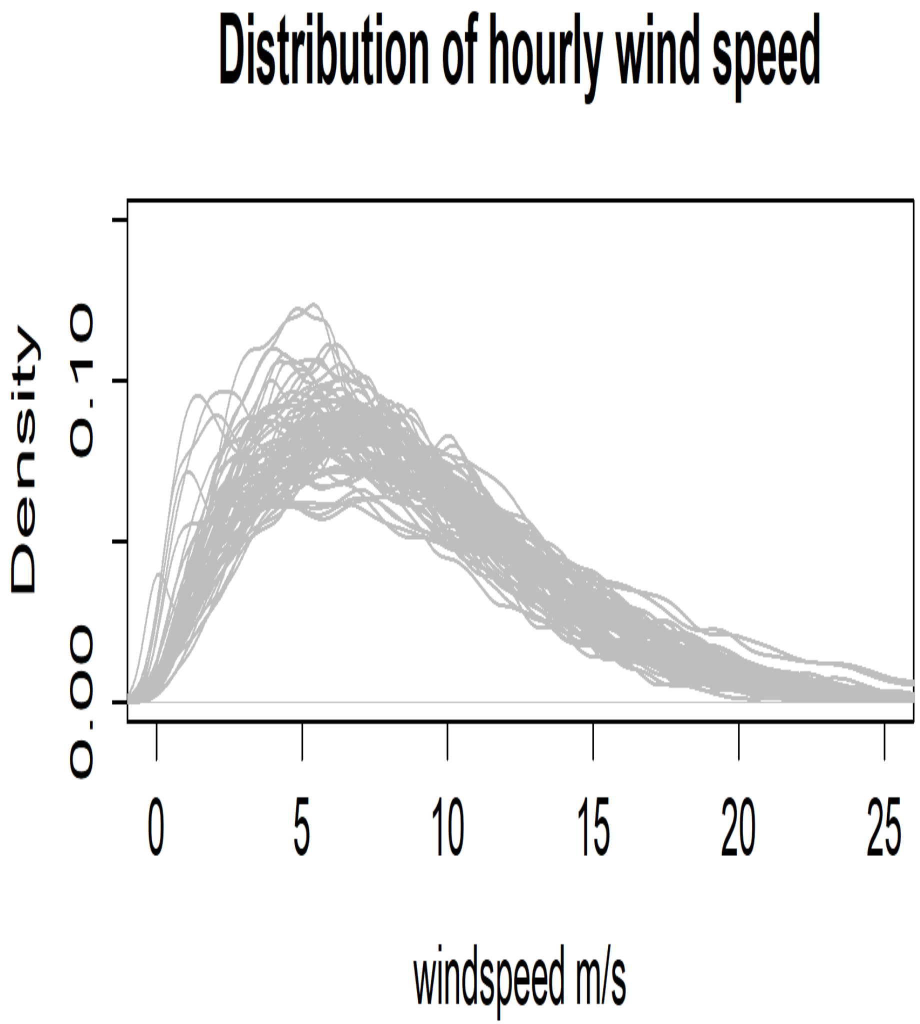
- **Real-time balancing** (Regulating power market, and other ancillary services)
- **Congestion alleviation**

Wind power data

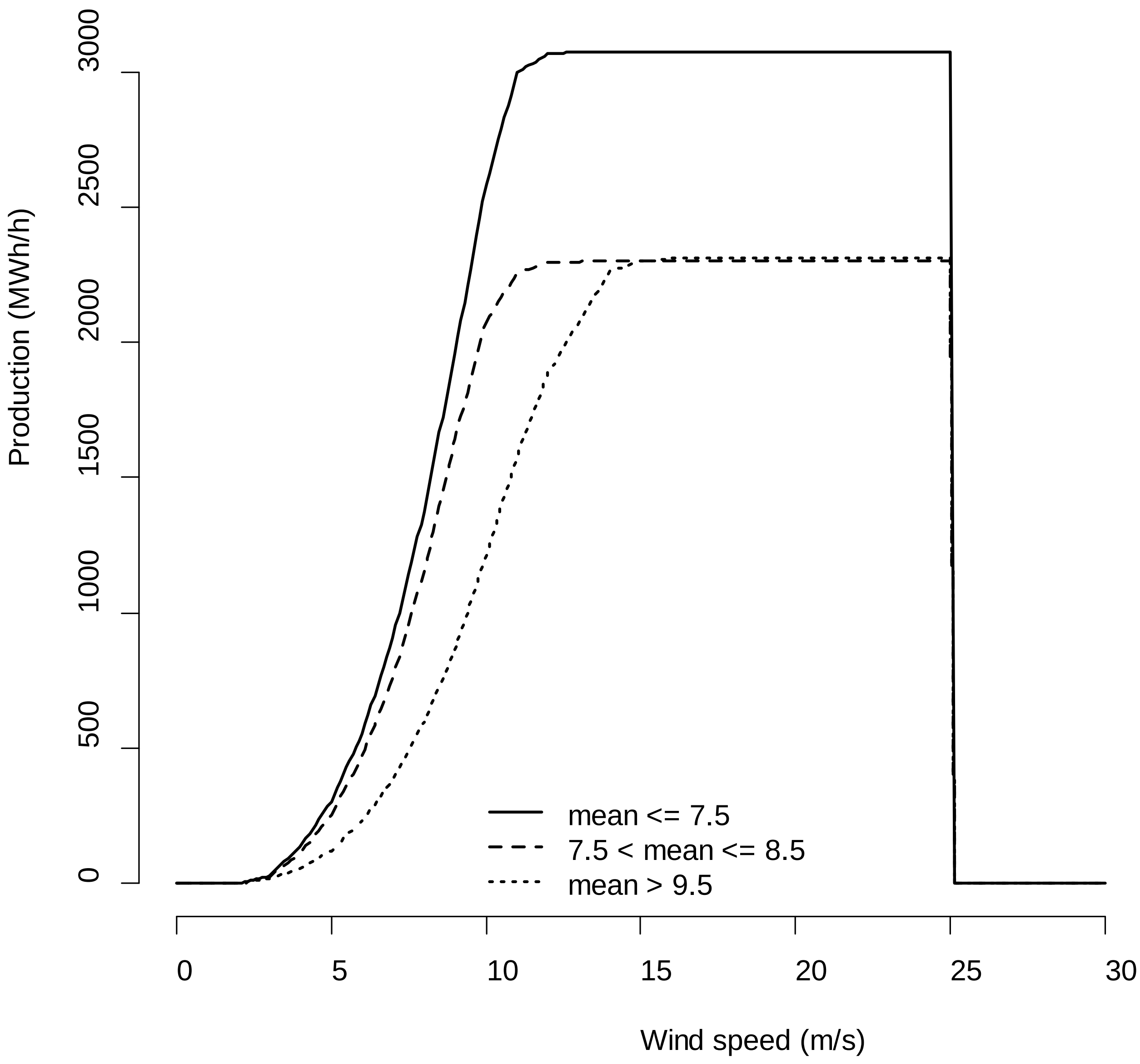
(The Norwegian Meteorological Institute and Kjeller Vindteknikk, KVT)



Average wind speed for individual locations

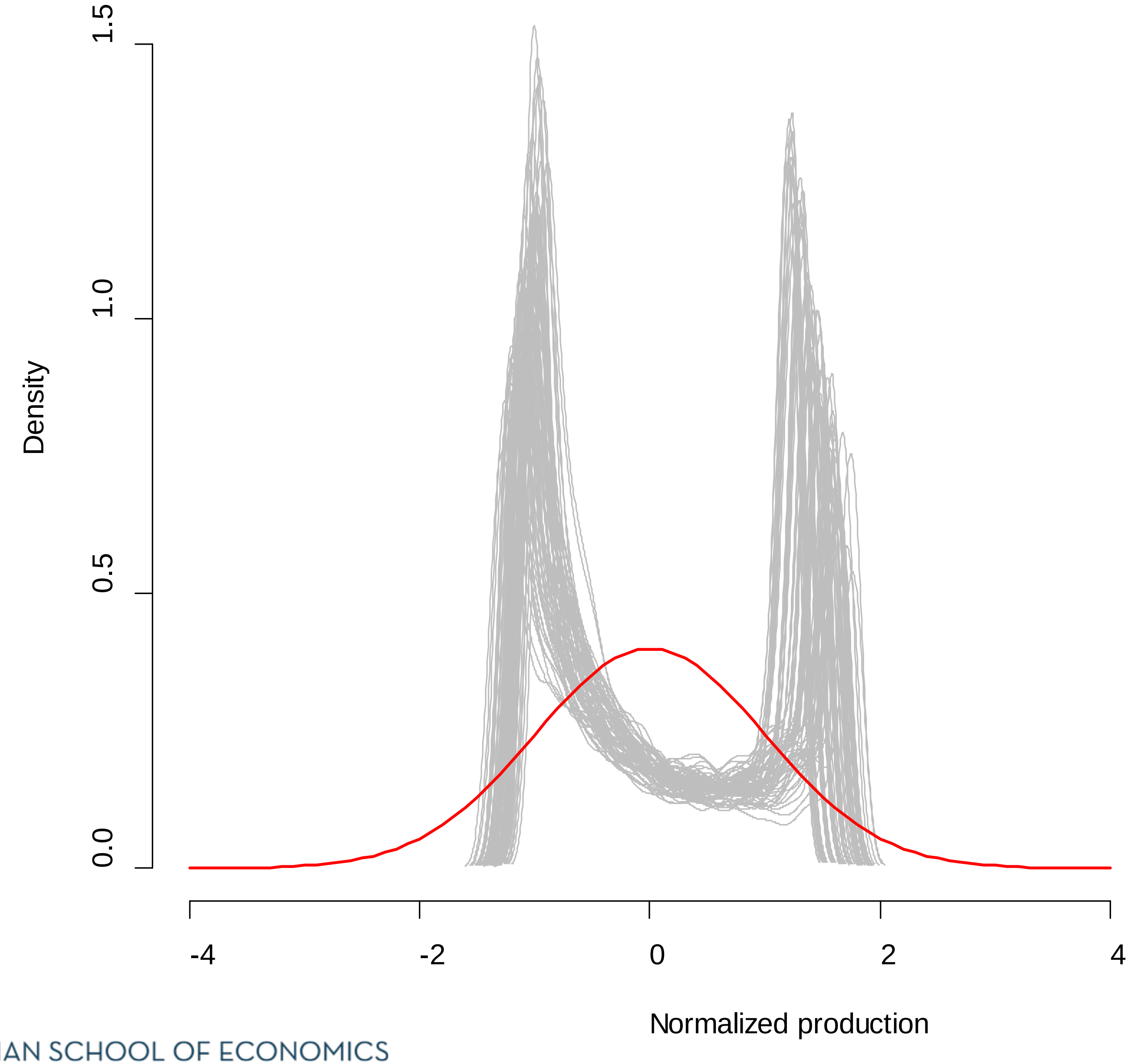


Wind turbine assumptions

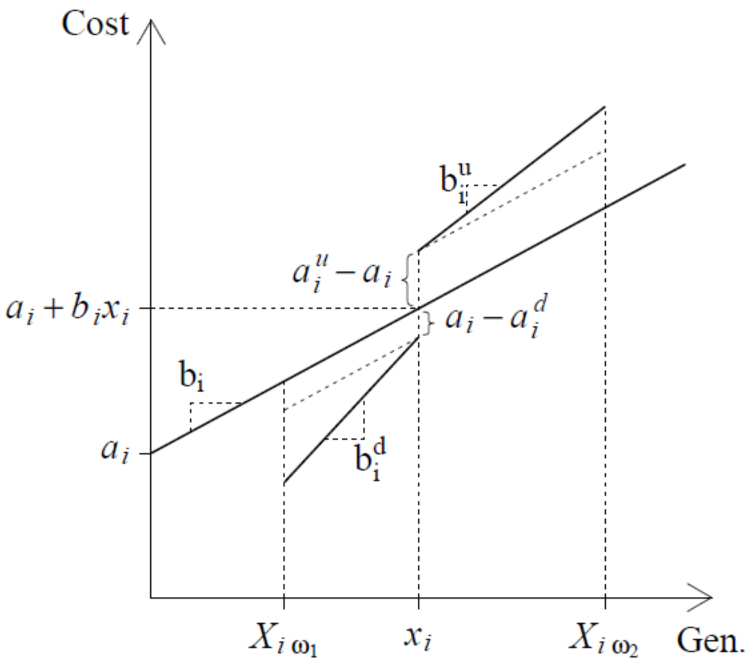


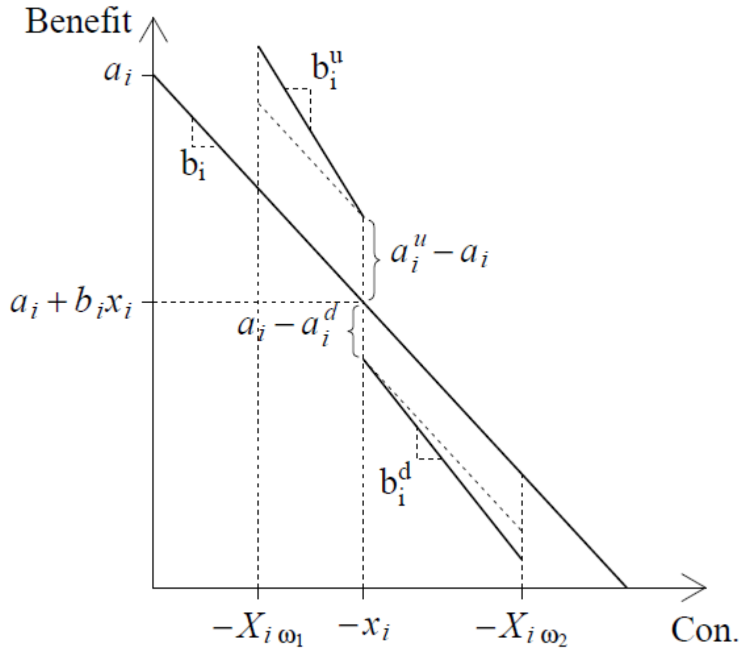
Source: KVT (WindPRO)

Distribution of hourly production



Cost and benefit curves



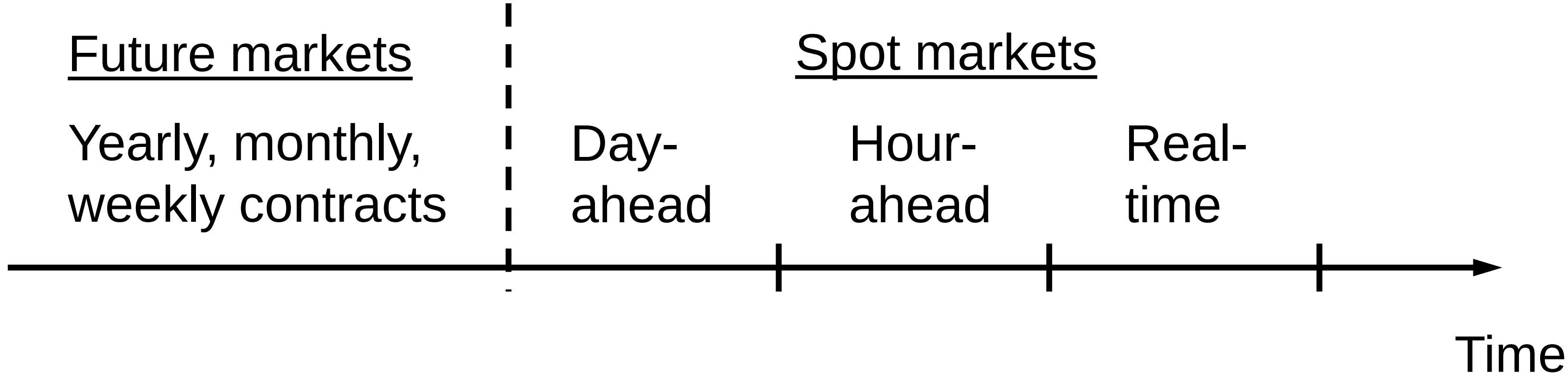


Re-dispatch:

«Up-regulation»
i.e. increase production
or reduce consumption

«Down-regulation»
i.e. reduce production
or increase consumption

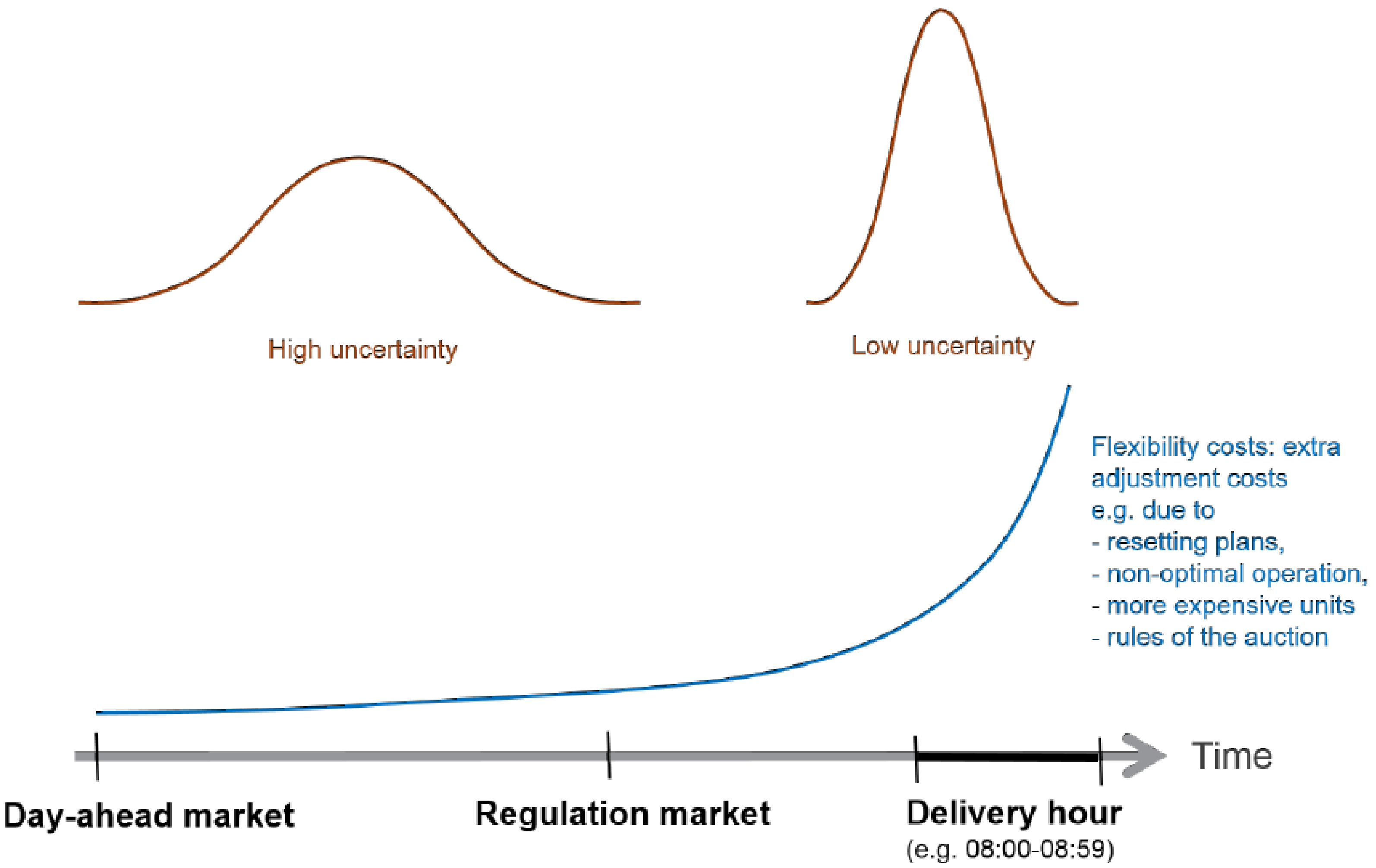
Future and Spot Markets



"In most industrialised countries, scheduling and dispatching electricity generation is carried out by solving an optimal power flow model. When one attempts to solve this model in practice, a difficulty arises because intermittent generators, as well as many consumers, cannot accurately predict the quantity of power they will produce or consume in advance. A solution that accurately represents reality can thus be computed only in real time, or in hindsight. On the other hand, some types of power plant are so slow to change their output that they have no hope of implementing the optimal solution to this model unless it is computed several hours (at least) beforehand."

Prichard et al., "A Single-Settlement, Energy-Only Electric Power Market for Unpredictable and Intermittent Participants", *Operations Research* 58, 1210-1219.

Flexibility cost and uncertainty



Stochastic dispatch models

$$\min_{x,f,X,F} \mathbb{E}\left[\sum_{i\in I}\Big(c_i(X_i) + \tilde{c}_i(x_i, X_i)\Big)\right]$$

s.t.

$$x_i \in C_i^1 \qquad \forall i \in I$$

$$X_{i\omega} \in C_i^2(\omega, x_i) \qquad \forall i \in I,\ \omega \in \Omega$$

$$\tau_n(f) + \sum_{i\in I(n)} x_i = 0 \qquad \forall n \in N \qquad [\pi_n]$$

$$\tau_n(F_\omega) + \sum_{i\in I(n)} X_{i\omega} = 0 \qquad \forall n \in N,\ \omega \in \Omega \qquad [p_\omega \lambda_{n\omega}]$$

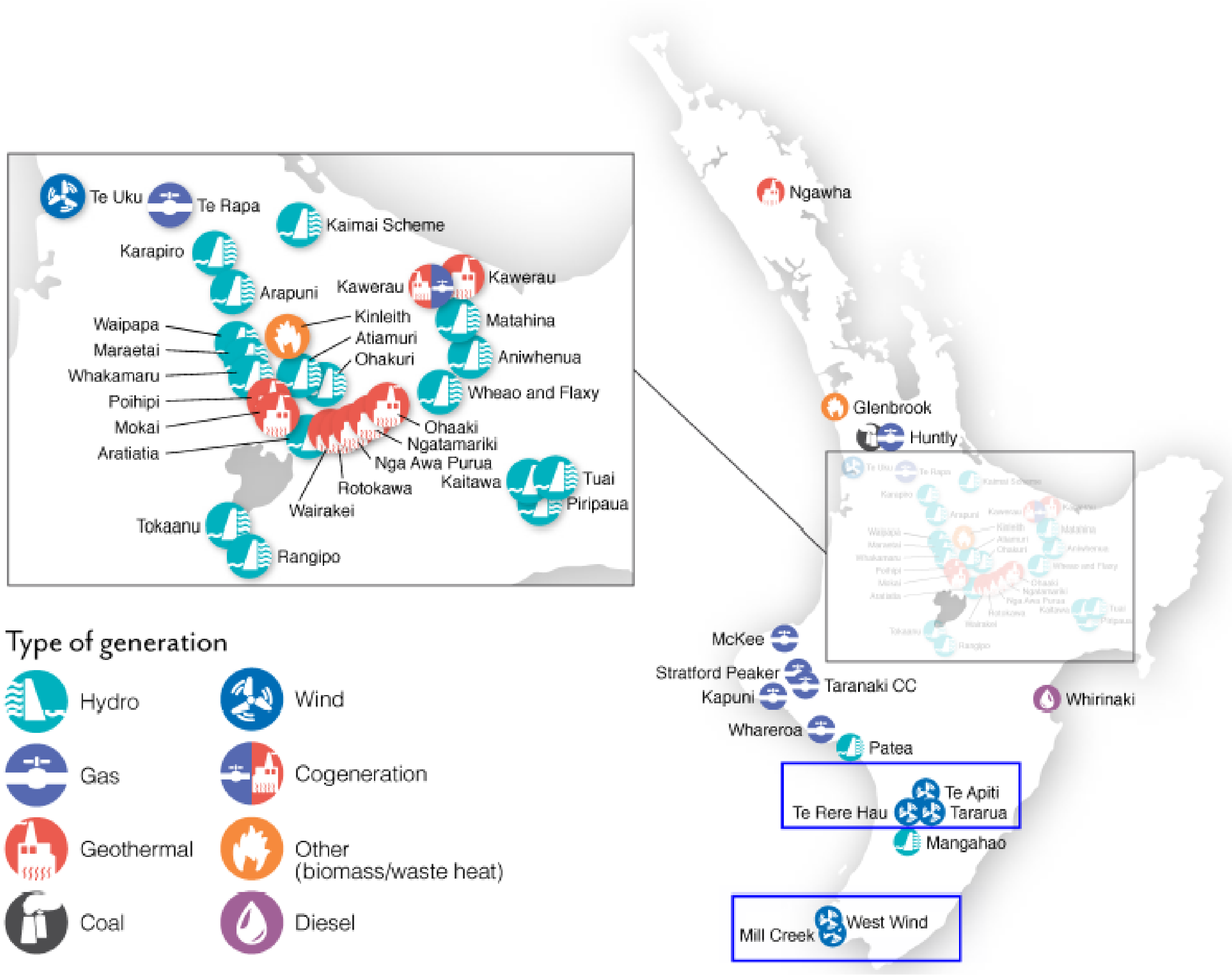
$$f \in U^1$$

$$F_\omega \in U^2 \qquad \forall \omega \in \Omega$$

Stochastic dispatch models

- Our starting point is an energy-only stochastic market clearing as in Pritchard et al. (2010)
    - Compare to a sequential market clearing model with myopic clearing of the day-ahead part of the market
- Organization of bidding and information responsibilities (Bjørndal et al., 2016a)
- How should the day-ahead part of the market be modeled? (Bjørndal et al., 2016b)
    - Network flow and balance constraints
- Pricing (Zakeri et al., 2016)
    - Revenue adequacy for the system operator
    - Cost recovery for generators

Simulation of New Zealand market



- 255 nodes
- 500 links
- Over 90% of the 4032 periods examined (during Jan – April 2014) demonstrated full cost recovery
- Cost recovery in all cases by aggregating over ≈14 days

Conclusions

- Stochastic market clearing models are potentially more efficient and possible to implement
  - Ref. discussion of integrated or unbundled systems (Wilson, 2002)
- May require new or different roles and bidding formats
  - Bids from uncertain resources
  - Optimization over time
- Alternatives
  - More frequent auctions?
  - Improving intraday markets?