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Electricity markets with high RES shares - Price formation and cost recovery

WinGrid Scientific Workshop on Power System Balancing and Operation with Large Shares of Wind Power

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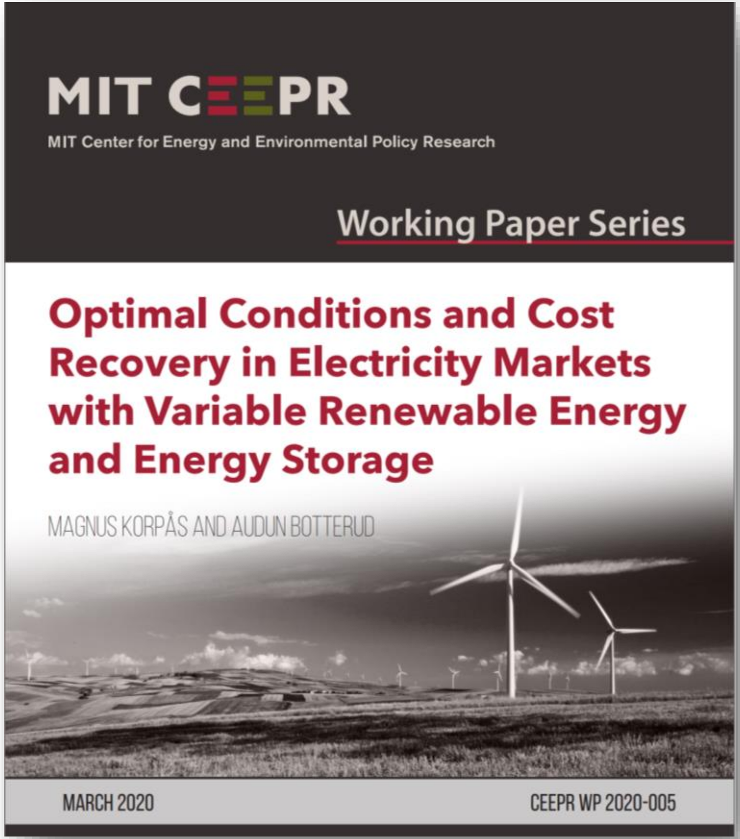
Common hypohesis:

- Traditional electricity markets fail under large-scale penetration of wind and solar
  - Wind and solar have zero marginal cost
- Prices collapse and costs are not recovered in the long run

Our main result:

- All plants recover their costs in (perfect) energy-only markets with wind and solar
  - Holds true with and without energy storage
- Think twice before embarking on complete re-design of electricity markets



Variable Renewable Energy (VRE) and prices

Europe

Merit order effect estimates of wind and PV in Germany, 2006–2012

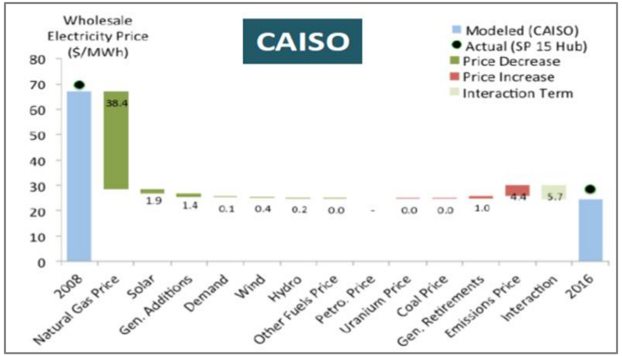
	2006	2007	2008	2009	2010	2011	2012
	Euros/MWh						
Sensfuß et al. (2008)	-7.8						
Weigt (2009)	-6.2	-10.4	-13.0				
vbw (2011)					-8.0		
Sensfuß (2012)		-5.8	-5.3	-6.0	-5.2	-8.7	-8.9
Speth, Stark (2012)					-5.6	-5.6	
Cludius et al. (2013)			-10.8	-7.8	-6.0	-7.7	-10.1

Data source: Federal Ministry of Economic Affairs and Energy (2014), p. 38.

- Merit Order Effect: 5-13 €/MWh (Praktiknjo, Erdmann (2016))
- VRE an important factor for overall price decline, at least since 2011/2012
- Price decline 0-1 €/MWh in relative terms for 1% VRE increase (Welisch et al. (2016))

Praktiknjo, Erdmann (2016)

United States

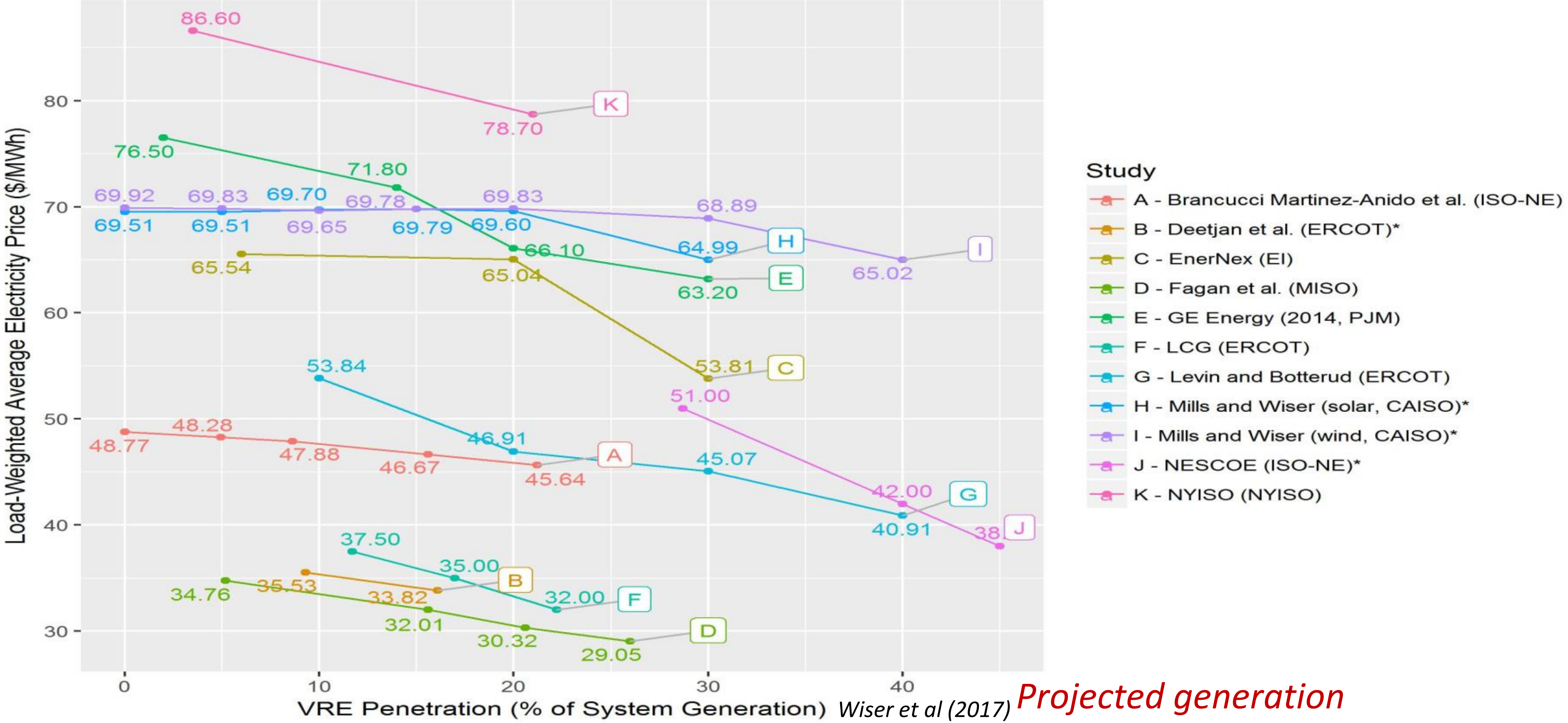


- Merit Order Effect: 0-9 $/MWh (Wiser et al (2017))
- But: <5% VRE contribution to overall price decline between 2008-2016 in CAISO and ERCOT (85-90% gas)

Mills et al (2020)

Negative prices occur more frequently

Prediction of future price impacts of VRE



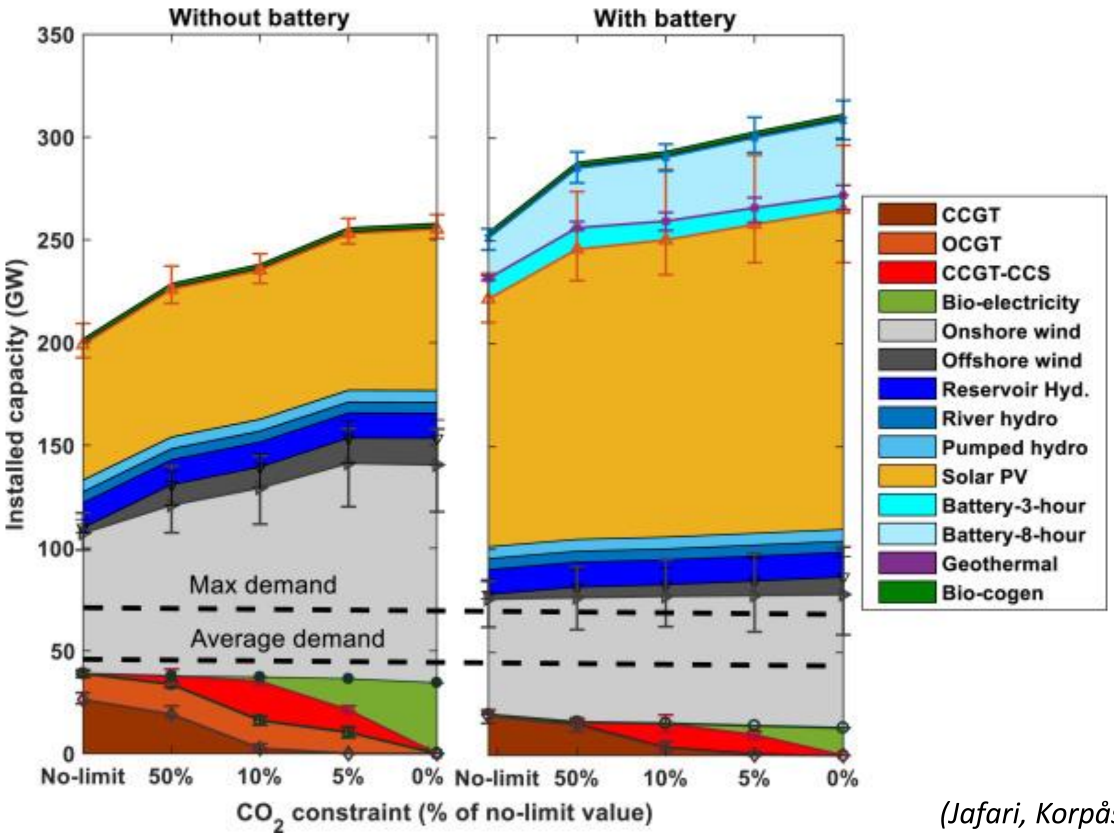
Wiser et al (2017)

Projected generation portfolios usually not in economic equilibrium!

Investments in VRE and Storage

- Investments in VRE and energy storage have been driven, in part, by incentive schemes and policies
  - Feed-in tariffs/premiums, auction schemes, carbon pricing, net metering (Europe)
  - Production and investment tax credits, renewable portfolio standards, net metering, energy storage mandates (United States)
- Rapid reduction in costs for VRE and Storage
- How do these technologies influence thermal generation investments and market equilibrium in a competitive market?
  - Schmalensee, MIT (2019)
  - Joskow, MIT (2019)

The future brings high VRE penetrations



- The figure shows result from a recent power system decarbonization study: Italy 2050
- Cost reductions makes VRE and EES competitive, even without carbon caps
- EES triggers more VRE investments
- Thermal capacity is pushed out
- Approach: Minimize system costs
- But how does this work in a competitive (perfect) market?

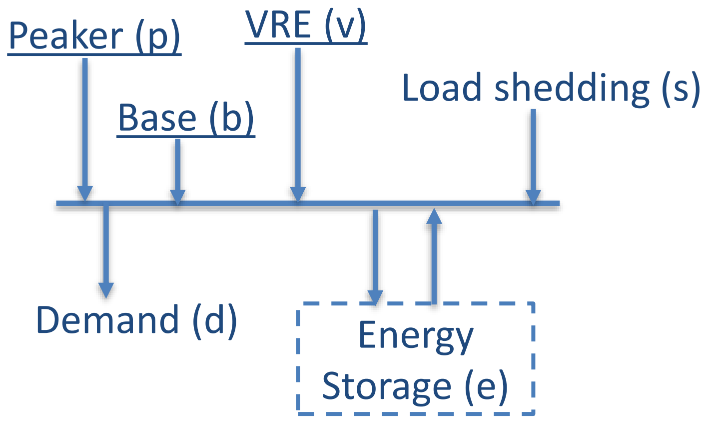
(Jafari, Korpås, Botterud, Renewable Energy, Aug. 2020)

System Optimality and Market Equilibrium

- Most electricity markets are based on marginal cost pricing
- Gives the optimal solution for the system in theory
  - System demand is met at minimum costs
  - All GenCos (price-takers) maximize their profits and recover their costs (Green 2000, Stoft 2002)

- We assume energy-only markets
  - Scarcity pricing ensure cost recovery of peaker (and all other) plants
  - No explicity capacity remuneration mechansism considered
    - They do influence market outcomes and prices (Kwon et al. 2019)
  - No direct incentive schemes for VRE and EES
    - Competing on equal terms as other technologies

Minimization of system costs



Problem: Find the plant capacities and operation which minimizes cost of delivered energy

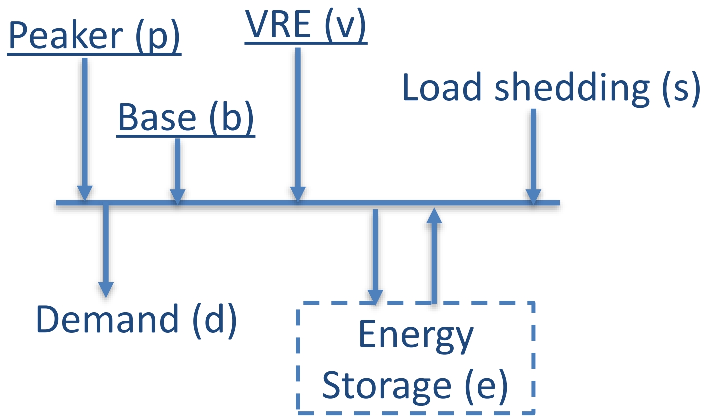
Min C = Annualized Inv Cost + Annual Operating Cost

Subject to

- Plant constraints
- Load balance constraint
- Energy Storage constraints
- Availability of VRE
- (Grid constraints)

Load shedding is set to Value of Lost Load (VOLL) or a high scarcity price

Profit maximization



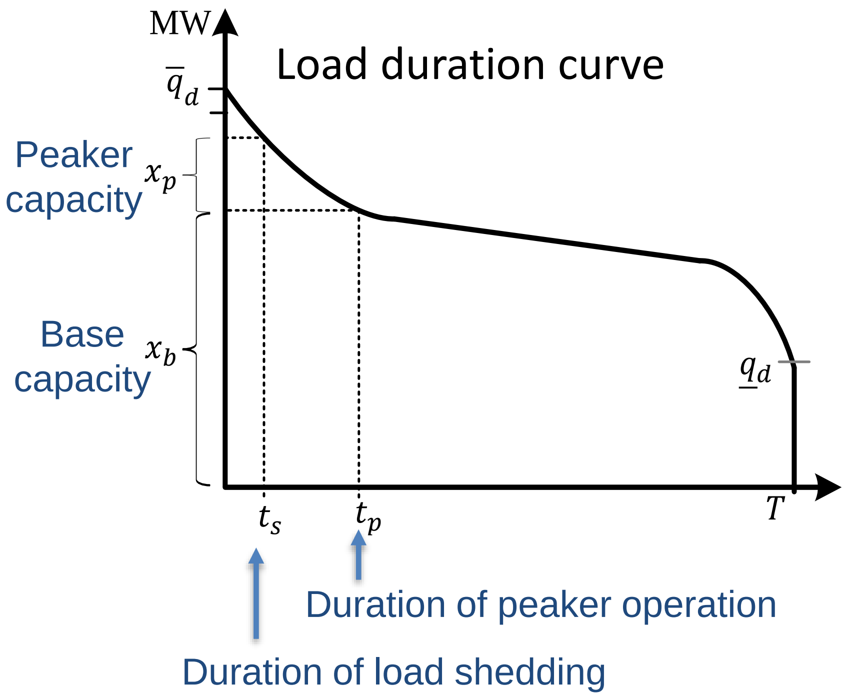
Problem: Find the plant capacities and plant operation which maximizes individual profits

Max π = Annual Market Revenues - Annual Operating cost – Annualized Inv Costs

Perfect market is assumed

- Each plant owner is too too small to influence the price individually
- Generators bid their marginal cost
- Storage owner bid marginal cost of generation and marginal value of consumption (opportunity cost)

Market Equilibrium with Thermal Generation



- System optimality conditions gives optimal durations of all generators i

$$\min C \Rightarrow \frac{\partial C}{\partial x_i} = 0$$

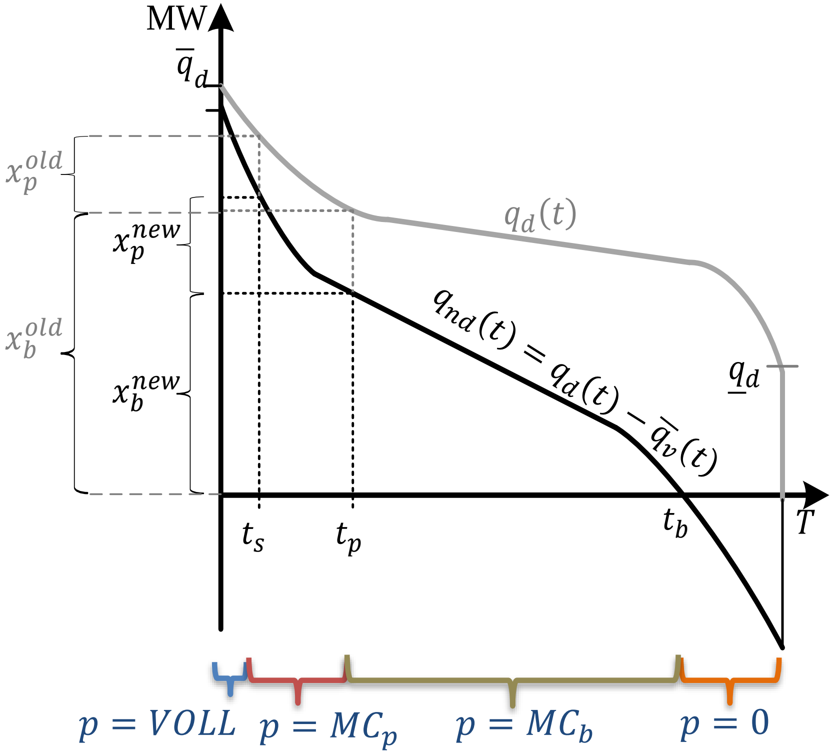
- Profit maximization gives the same result

$$\max \pi_i \Rightarrow \frac{\partial \pi_i}{\partial x_i} = 0$$

- Cost recovery is ensured in optimum

$$\pi_i = 0$$

Market Equilibrium with VRE



- Net demand = Demand – VRE output
- Cheap VRE will give negative Net demand
- Optimal t_s and t_p are independent of VRE level (Cost recovery)
- Base duration t_b is determined from the VRE optimality condition
- VRE is the marginal generator for $t > t_b$
  - Price p = 0

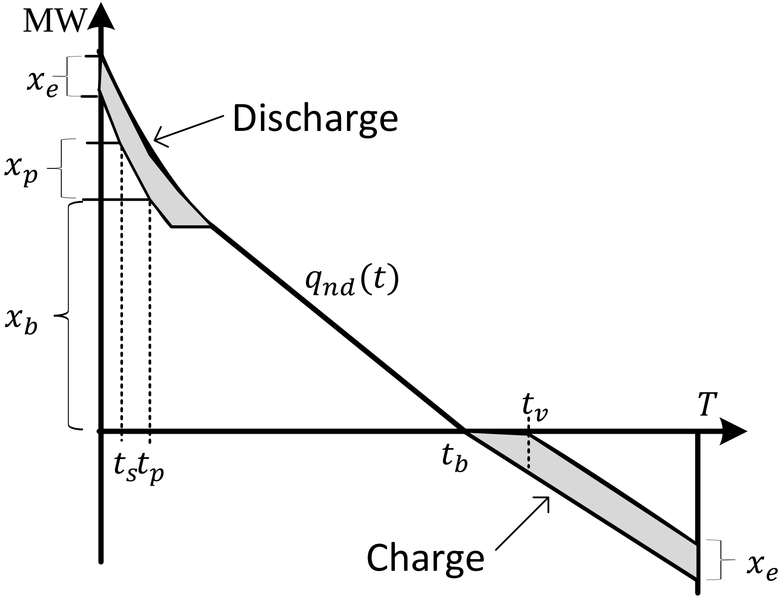
- Introduction of (competitive) VRE tends to give
  - Less baseplant capacity and energy
  - Slightly more peaker capacity
  - Slightly more load shedding
  - Some VRE curtailment

Market equilibrium with EES

- EES is challenging to include in duration curve modelling due to the storage level constraint
- We can model power capacity x_e and round-trip efficiency η_e explicitly, but not kWh constraint

- We have derived optimality conditions for different (simplified) EES operating assumptions

EES for surplus VRE. «Unlimited storage»



- Optimality condition for EES determines the duration of maximum charging
  - $t \leq t_b$: Price set by most expensive generator in operation.
  - $t_b < t < t_v$: Price set by the storage opportunity cost. It is the value of one more kWh stored energy. $p = \eta_e \cdot VC_b$
  - $t \geq t_v$: Price set by VRE. $p = v_v = 0$
- Introduction of EES creates a new price segment where EES is the marginal load
  - This increases the optimal amount of VRE in the market
  - Thermal is reduced further

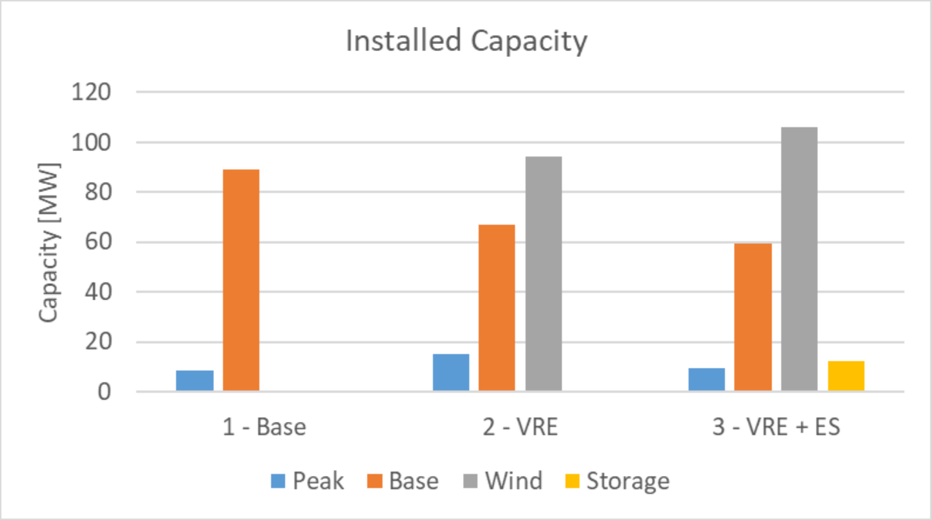
Numerical Example

- European aggregated hourly time series for 1 year
  - Wind and solar
  - Load scaled to 100MW
- Costs mainly based on EU Reference Scenario 2050
  - Technology cost and plant data
  - Fuel and carbon prices
- Duration curve model based on optimality conditions for all plants

- Key assumptions
  - Peaker p: OCGT
  - Baseplant b: CCGT
  - VRE plant v: Offshore wind
  - Energy Storage e: Li-Ion or Pumped hydro
  - Price during load shedding: 3000 $/MWh

- Three main cases
  - Case 1 - Base: Only peaker and baseplant
  - Case 2 - Add VRE
  - Case 3 – Add VRE and EES

Results: Capacities and Prices

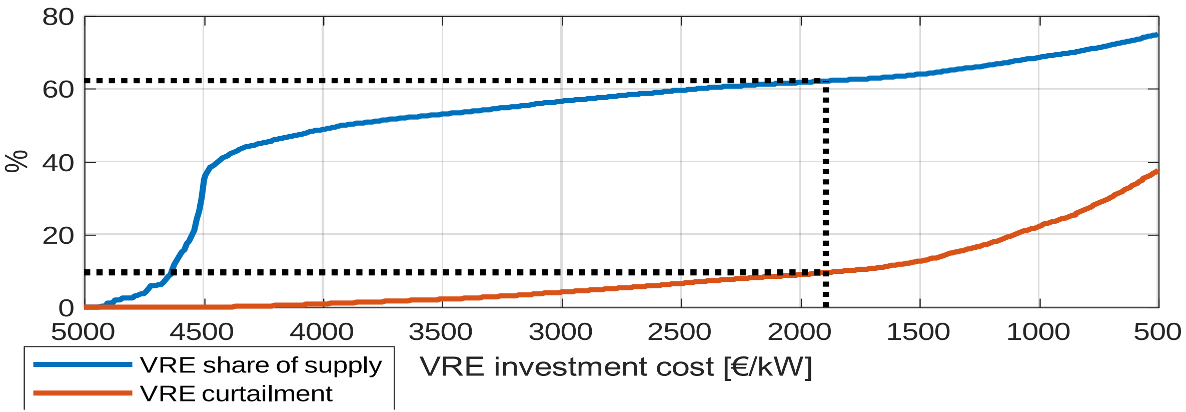


- VRE gives less base, more peak plants
- EES gives more VRE, less base and peak
- VRE and EES give much lower emissions

	1 - Base	2 - VRE	3 - VRE + EES
Weighted avg. price	114.9	81.6	81.4

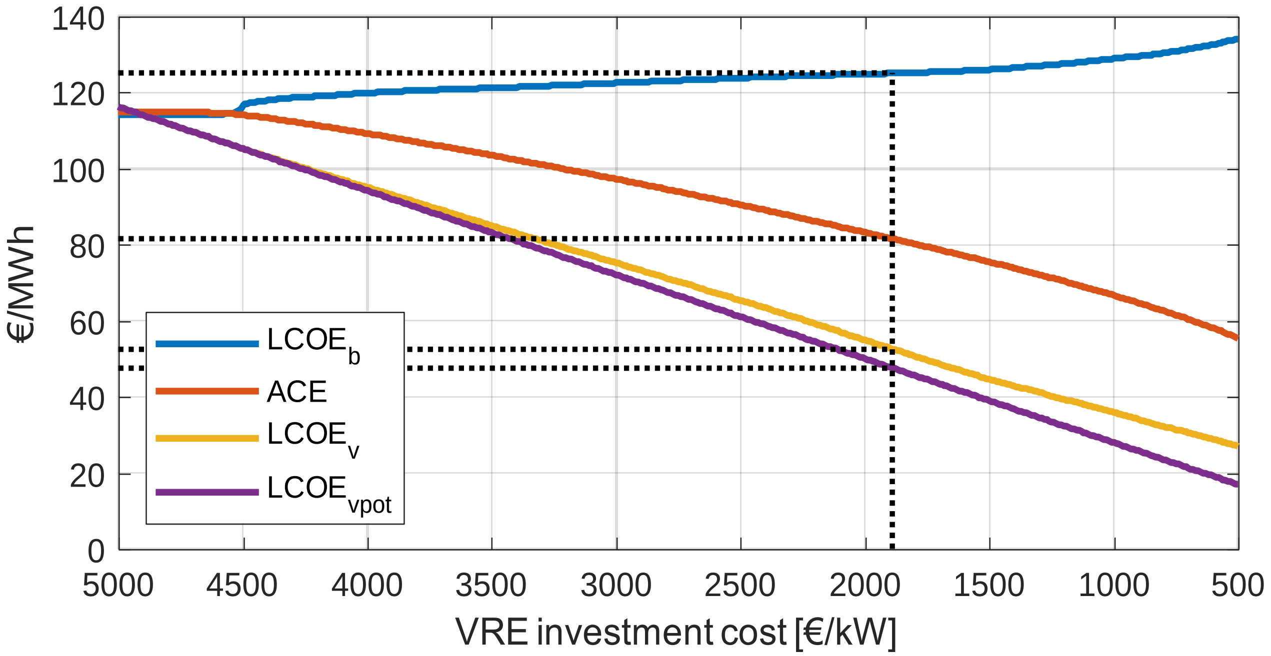
All technologies break even in all cases

Saturation of wind energy penetration in the market without storage



LCOE and ACE

Average electricity costs decreases as wind and solar becomes more competitive.
In this perspective, the «system cost» of wind and solar can be considered **negative**.



Concluding remarks from analytical model I/II

- All plants recover their costs in a perfect market with VRE and EES
  - Gives optimal generation mix to minimize system cost
  - The result is identical to profit mazimization of price-taker firms
  - ***Analytic and numeric analyses indicate that thermal generators, VRE, and ES can co-exist in regular energy-only markets***

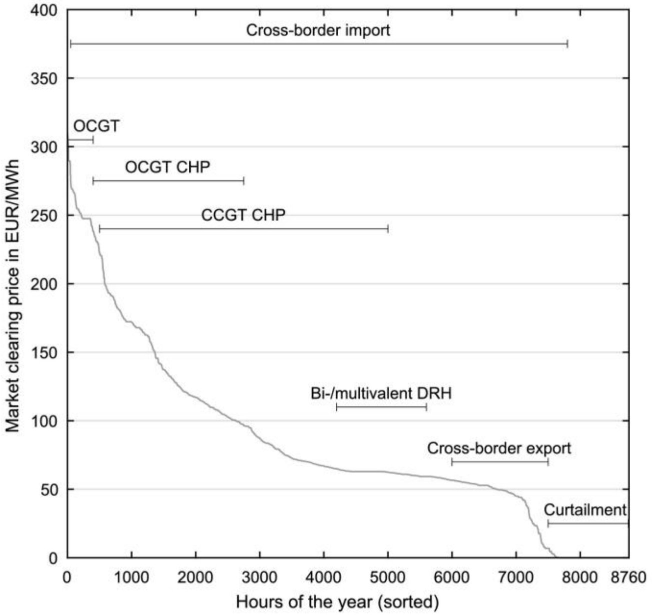
- The merit-order effect of VRE changes the capacity mix so that all (remaining) generators recovers their costs
  - Just as when new, cheaper thermal generators enters the marked

Concluding remarks from analytical model I/II

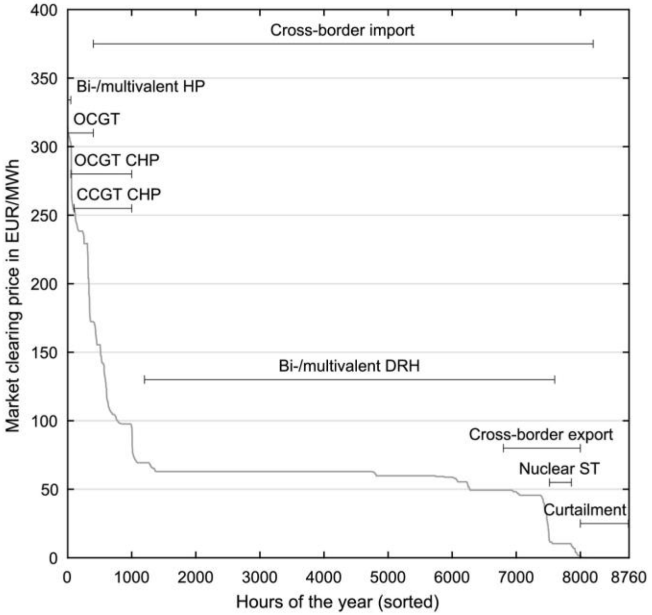
- EES triggers more VRE capacity in equilibrium,
  - EES creates a new price segment based on the marginal value of storage, where the VRE gains additional profits.
- This result has several implications for the market equilibrium:
  - 1) EES pushes more thermal capacity out of the market, both because of its balancing ability and because it triggers more investments in VRE
  - 2) EES leads to lower total amounts of curtailed VRE in equilibrium, although it triggers more VRE investments
  - 3) The main benefit of EES is to increase the VRE share in the system and consequently further reduce emissions caused by thermal generation. The emission benefit is much more evident from the results than the impacts on electricity cost
- Limitations of study
  - Inflexible demand
  - Deterministic approach – Uncertainty not accounted for
  - Out-of-market arrangements such as long-term contracts

Demand-side flexibility will influence price formation in low-carbon markets

Demystifying low-carbon electricity market clearing



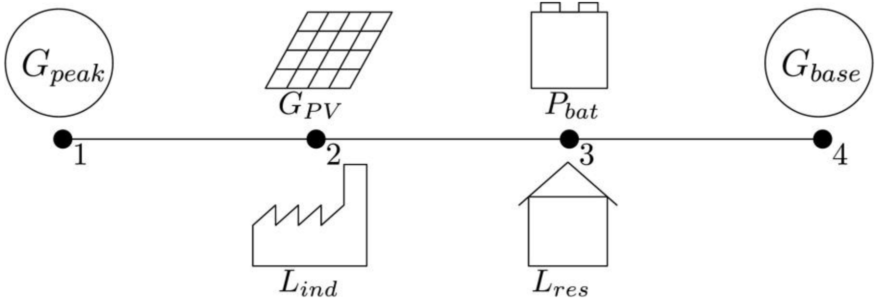
(a) DEU market area (significant cross-border exchange)



(b) FIN market area (limited cross-border exchange)

Härtel, Korpås (2020)
https://doi.org/10.1016/j.eneco.2020.105051

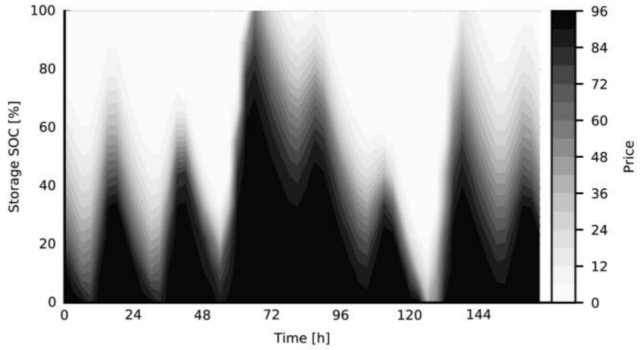
Pricing of storage will depend on forecasts and value of stored energy



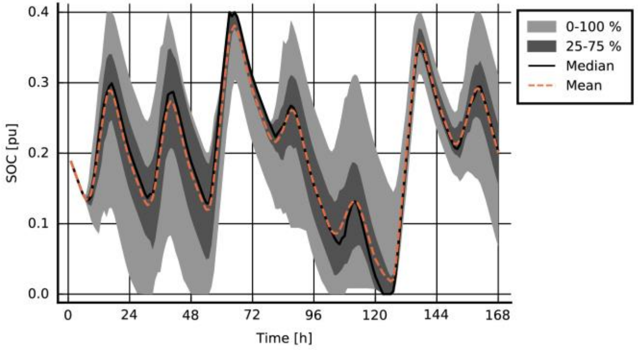
- (Local) Market model based on Stochastic Dynamic Programming for optimal dispatch of system with storage
- Determines the expected value of stored energy – similar to long-term hydropower planning
- Price in the (perfect) market is influenced by the marginal cost of thermal generation and the probability of energy deficit (related to VOLL)

Aaslid, Korpås, Belsnes, Fosso (2021)
https://doi.org/10.1016/j.epsr.2021.107169

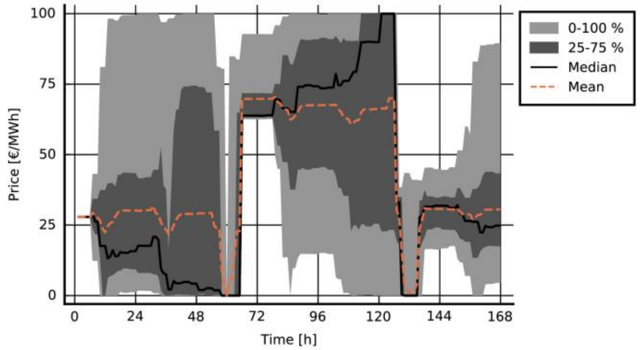
System with only PV and EES



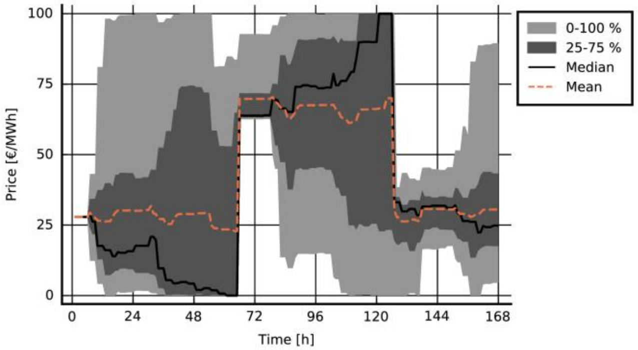
(a) Storage marginal value.



(b) Storage state-of-charge.



(c) LMP at industrial bus.



(d) LMP at residential bus.

Aaslid, Korpås, Belsnes, Fosso (2021)
https://doi.org/10.1016/j.epsr.2021.107169

Long-term contracts for RES

- Long-term contracts are attractive for
  - Customers: Securing green electricity
  - Producers: Securing the price for its product
- But how will long-term contracts influence
  - Prices in the energy-only market
  - Investments in flexibility
- Is it sufficient to balance the contracted energy on a yearly basis?
- What happens in the market if «all» green producers are supposed to get long-term contracts?

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