POTSDAM INSTITUTE FOR CLIMATE IMPACT RESEARCH

The economics of variability and implications for IAMs

Falko Ueckerdt

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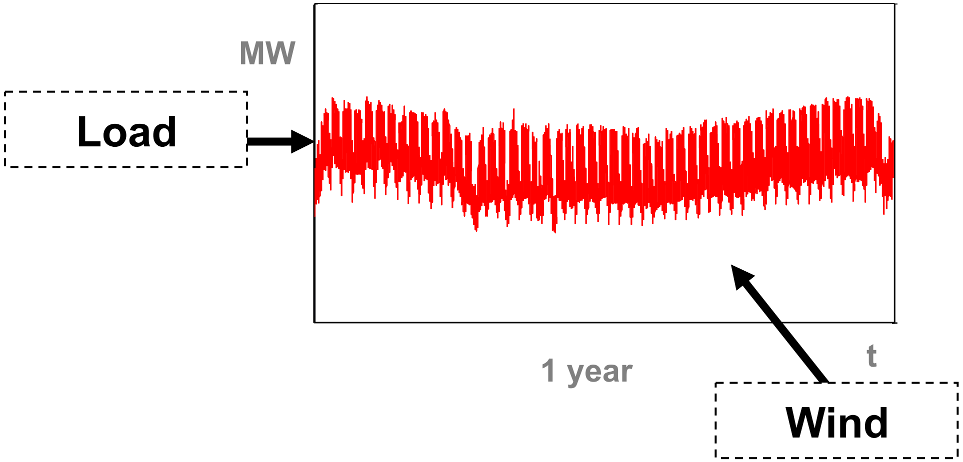
falko.ueckerdt@pik-potsdam.de

The challenge ahead: bridging the scales

Integrated assessment models:

Hybrid model of energy-economy-climate optimizing long-term investments decisions until 2100 in a **~5 years temporal resolution**

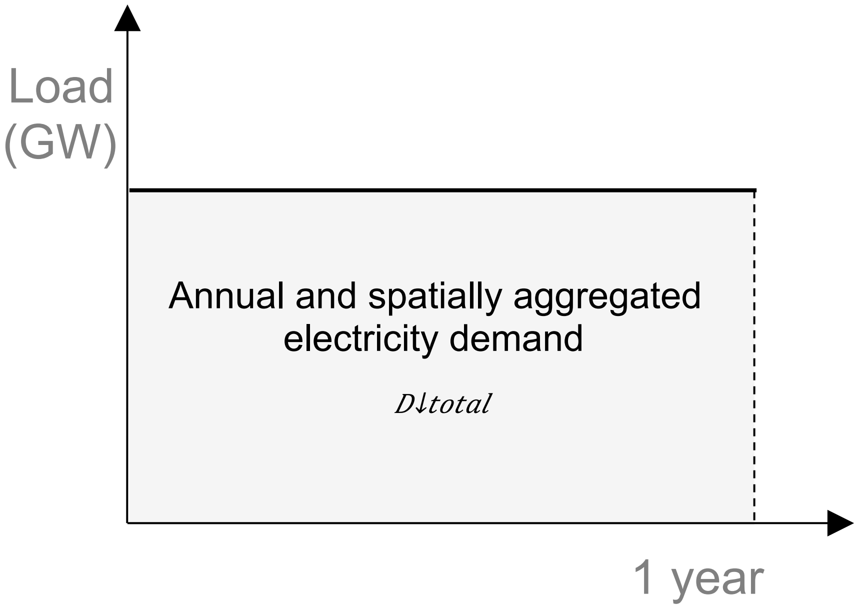
Short-term variability
(German data)



long-term investments

short-term variability

Coarse resolution of IAMs potentially induces a bias



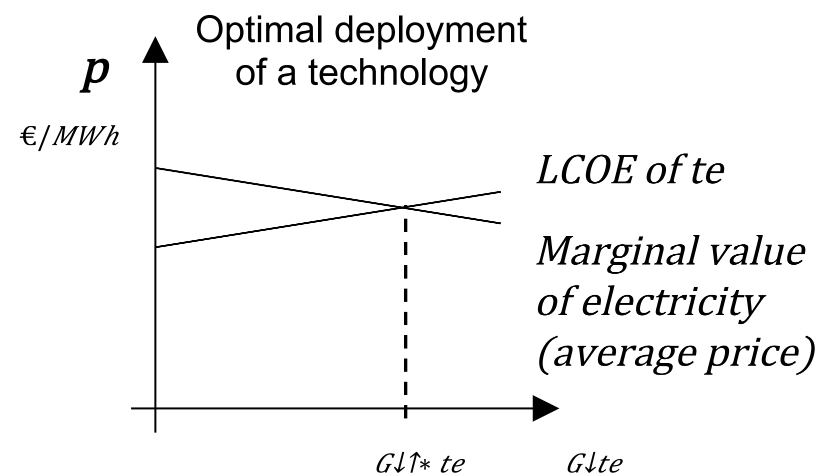
Balance equation: $D_{total} = \sum_{te} G_{te}$

G_{te}: *Annual generation from technology te*

Strong implicit assumption:

Electricity is a homogenous economic good

→ Only levelized costs of electricity (LCOE) of a technology determine its economic efficiency and optimal deployment



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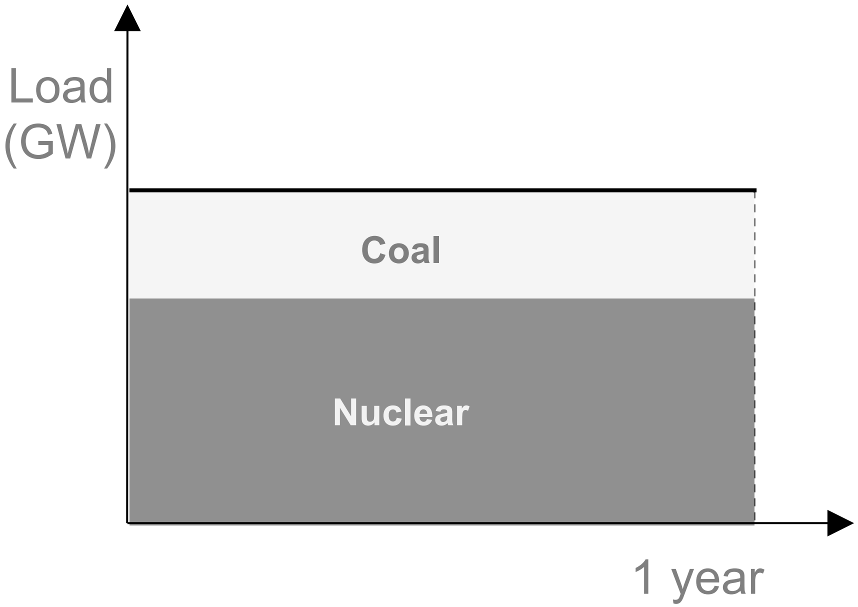

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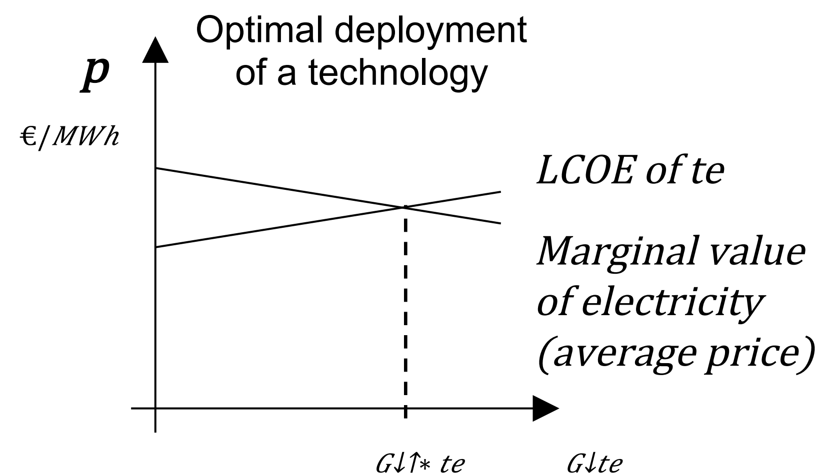
Strong implicit assumption:

Electricity is a homogenous economic good

→ Only levelized costs of electricity (LCOE) of a technology determine its economic efficiency and optimal deployment

→ Results biased towards baseload technologies



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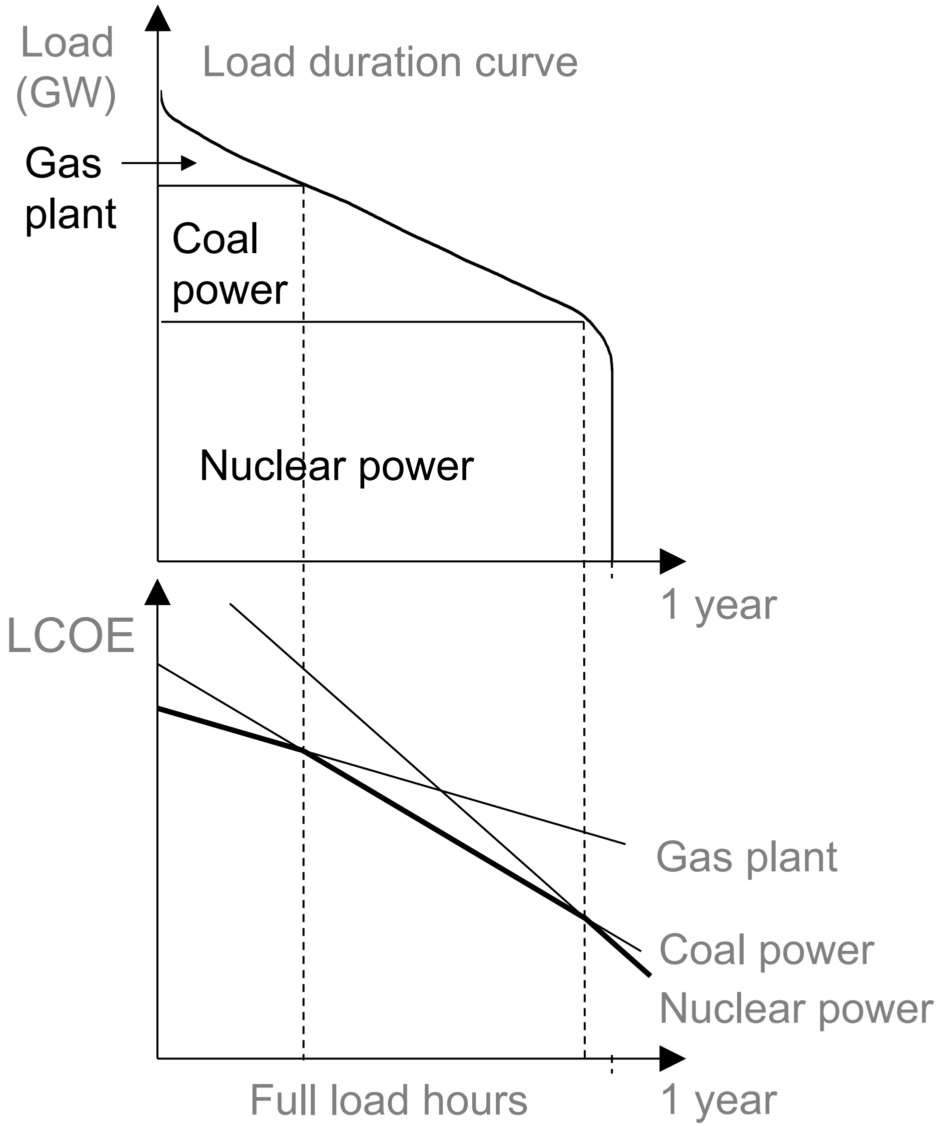
Actually, electricity is a heterogenous good



Demand is **variable**, storage is costly

The value (price) of electricity varies over **time**

Electricity is a **heterogeneous** good over time

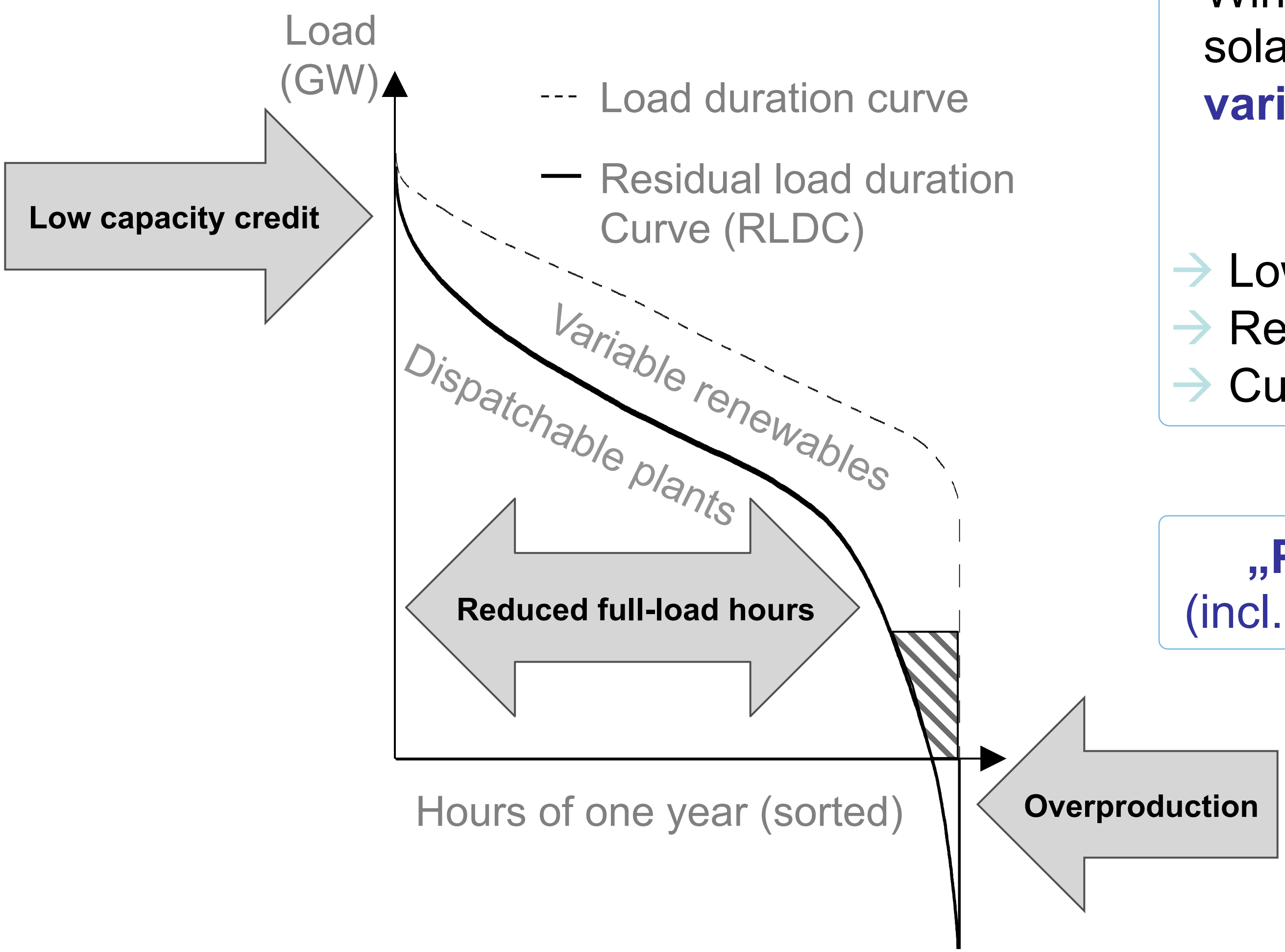
Actually, electricity is a heterogenous good

Demand&supply are **spatially distributed**. Transmission is costly	Demand is **uncertain** and **short-term variable**	Demand is **variable**, storage is costly
↓	↓	↓
The value of electricity varies between **locations**	The value of electricity depends on its **uncertainty/variability**	The value (price) of electricity varies over **time**
Heterogeneous across space	**Heterogeneous** w.r.t. uncertainty and short-term variability	Electricity is a **heterogeneous** good over time

→ Technologies are no perfect substitutes. LCOE comparison is not sufficient

→ IAMs should account for variable demand (capacity constraint, flexibility constraint, load duration curves)

Variable renewables increase the modeling challenge

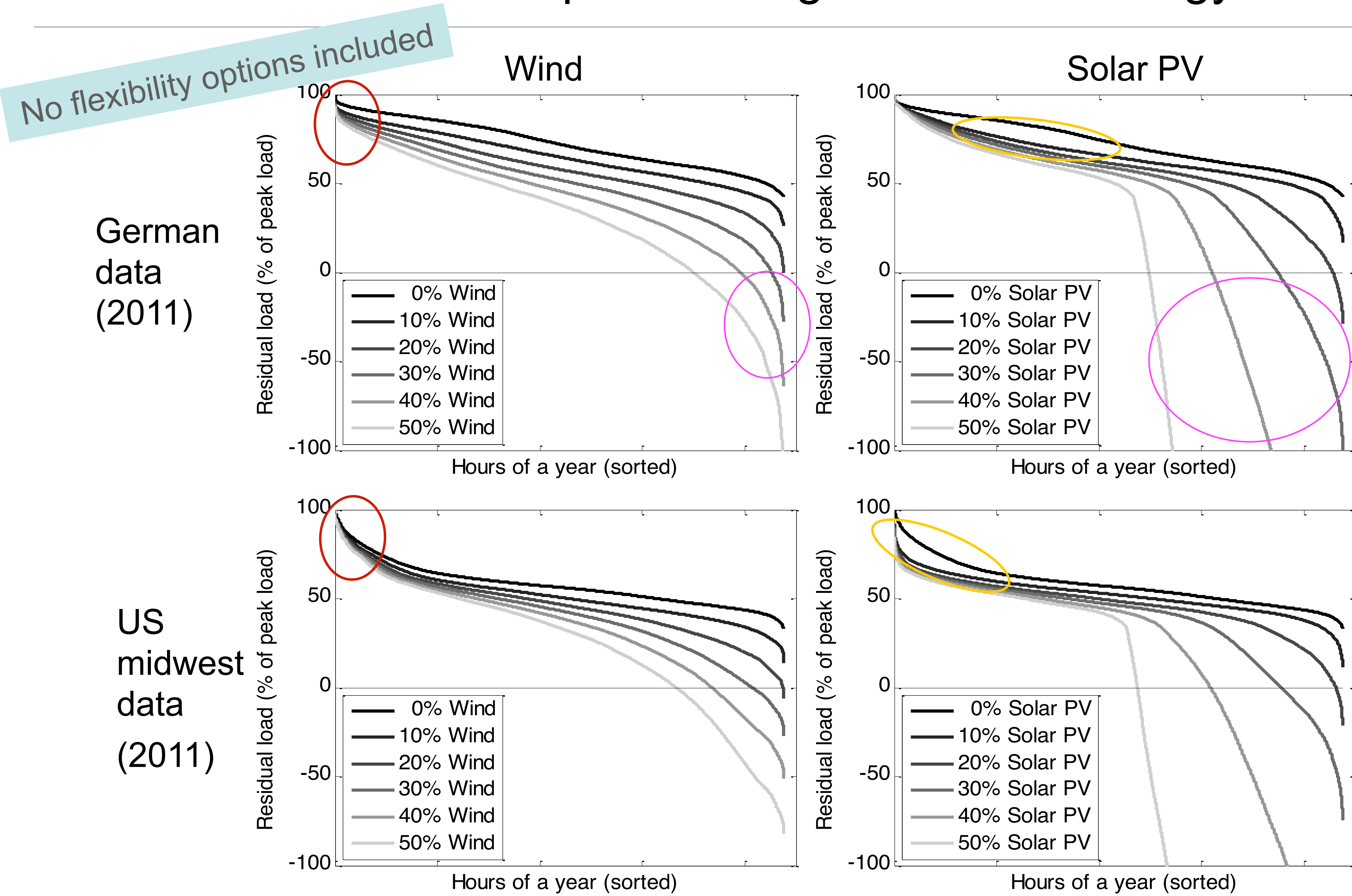


- Wind speeds and solar radiation are **variable over time**

→ Low capacity credit
→ Reduced FLH
→ Curtailment

„Profile costs“
(incl. adequacy costs)

Profile costs depend on region and technology



Variable renewables induce different costs on a system level

- Resource quality is **spatially variable**

→ Additional transmission is costly

- Winds and radiation is **uncertain** day-ahead and **short-term variable**

→ Short-term dispatch adjustments are costly

- Wind speeds and solar radiation are **variable over time**

→ Low capacity credit
→ Reduced FLH
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„Grid-related costs"

„Balancing costs"

„Profile costs"
(incl. adequacy costs)

Integration costs

(are neglected in LCOE comparison)

falko.ueckerdt@pik-potsdam.de

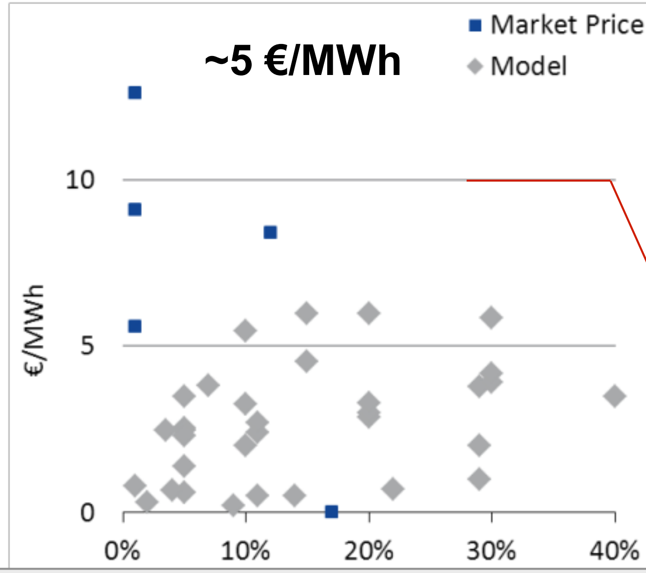
Cost divisions can be found in Milligan et al. 2009, Holttinen et al. 2011, SRREN 2011, Borenstein 2012, Hirth 2012 (submitted), Ueckerdt 2013 (submitted)

Quantification for wind: profile costs are most important

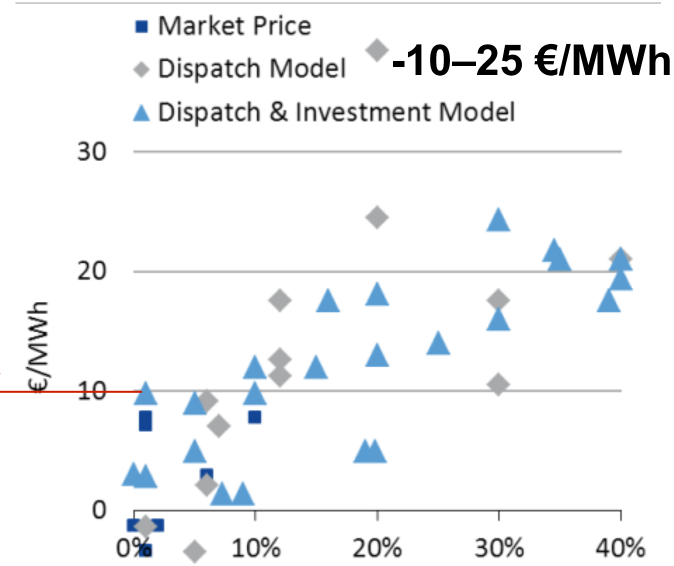
Grid-related costs

- **2-13 €/MWh** (shares of 15-40%, dena 2010, NREL 2012, Holttinen et al. 2011, Schaber et al. 2012)
- Scarce and inconclusive data

Balancing costs



Profile costs



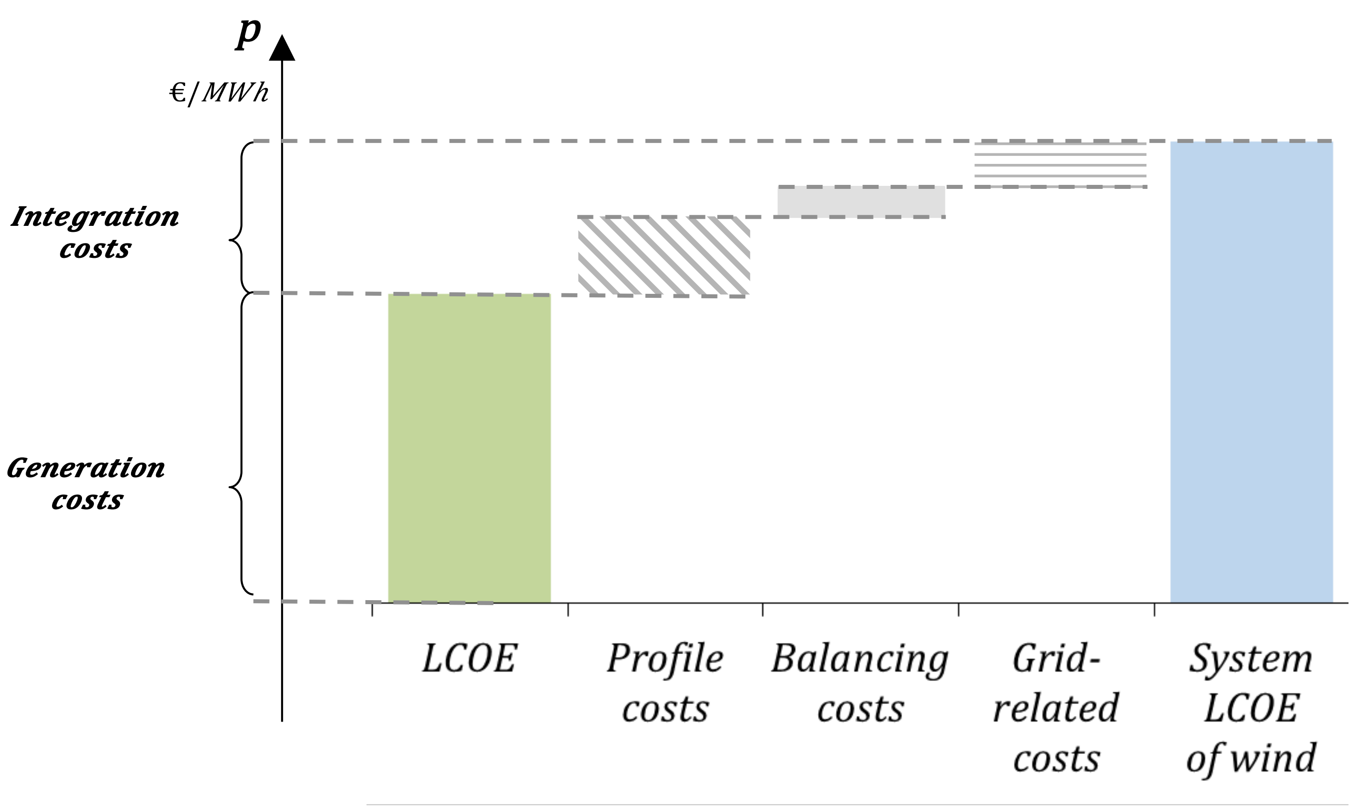
1. Integration costs of wind power can be in the same range as generation costs at high shares
2. A significant driver of integration costs are profile costs, especially the reduced utilization of capital-intensive thermal plants.

Koreneff, 2012; Mills and Wiser, 2012). To improve comparability, the system base price has been normalized to 70 €/MWh wherever possible.

dispatch and investment modeling (triangles). To improve comparability, the system base price has been normalized to 70 €/MWh in all the studies.

all numbers in marginal terms per MWh of VRE

We define System LCOE as the sum of generation and integration costs



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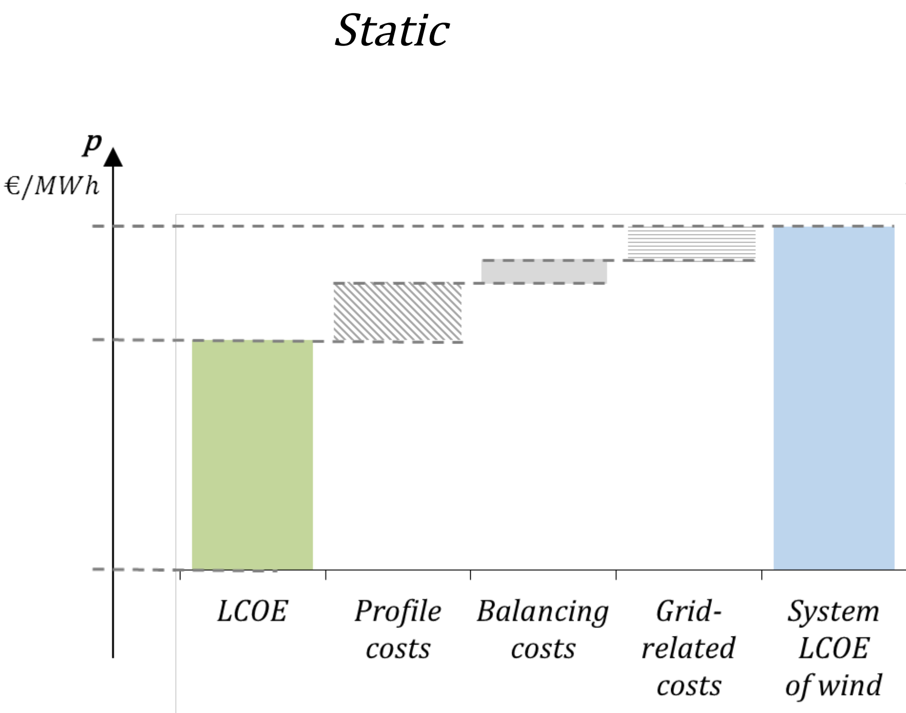

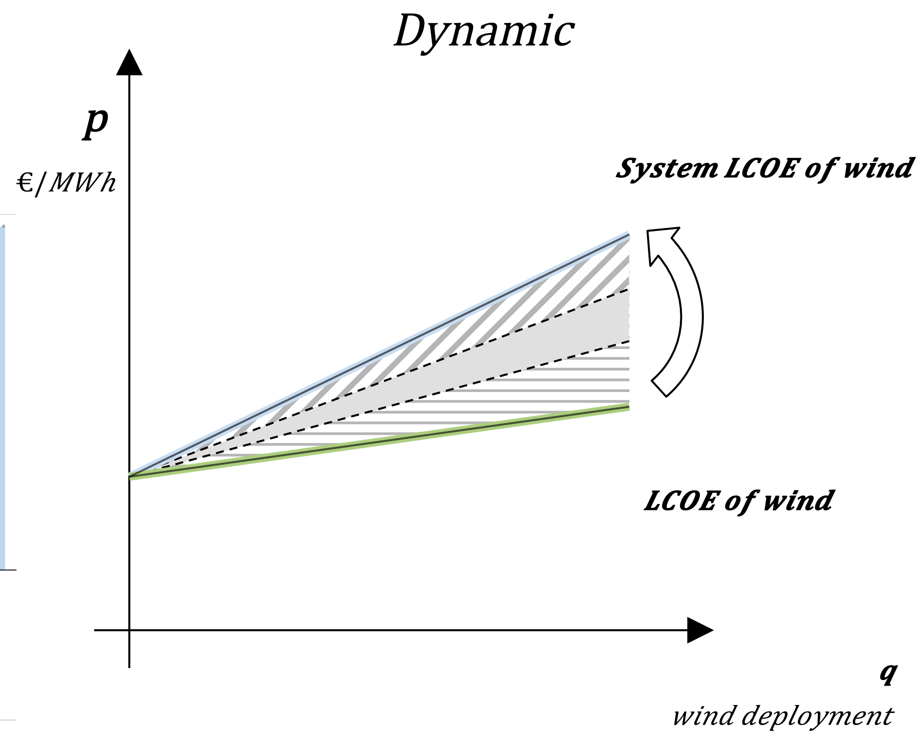

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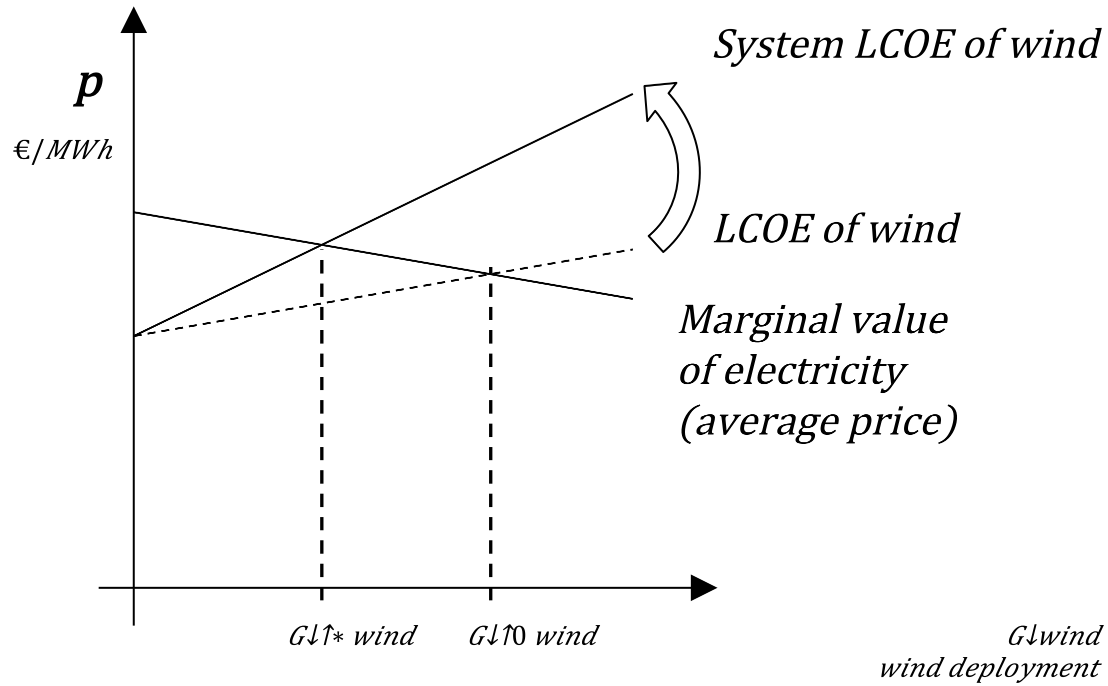
Ueckerdt et al. (submitted)

Variability changes economic evaluation of VRE

What is the optimal amount of wind?



Note, high integration costs of VRE do not imply that optimal shares are low.

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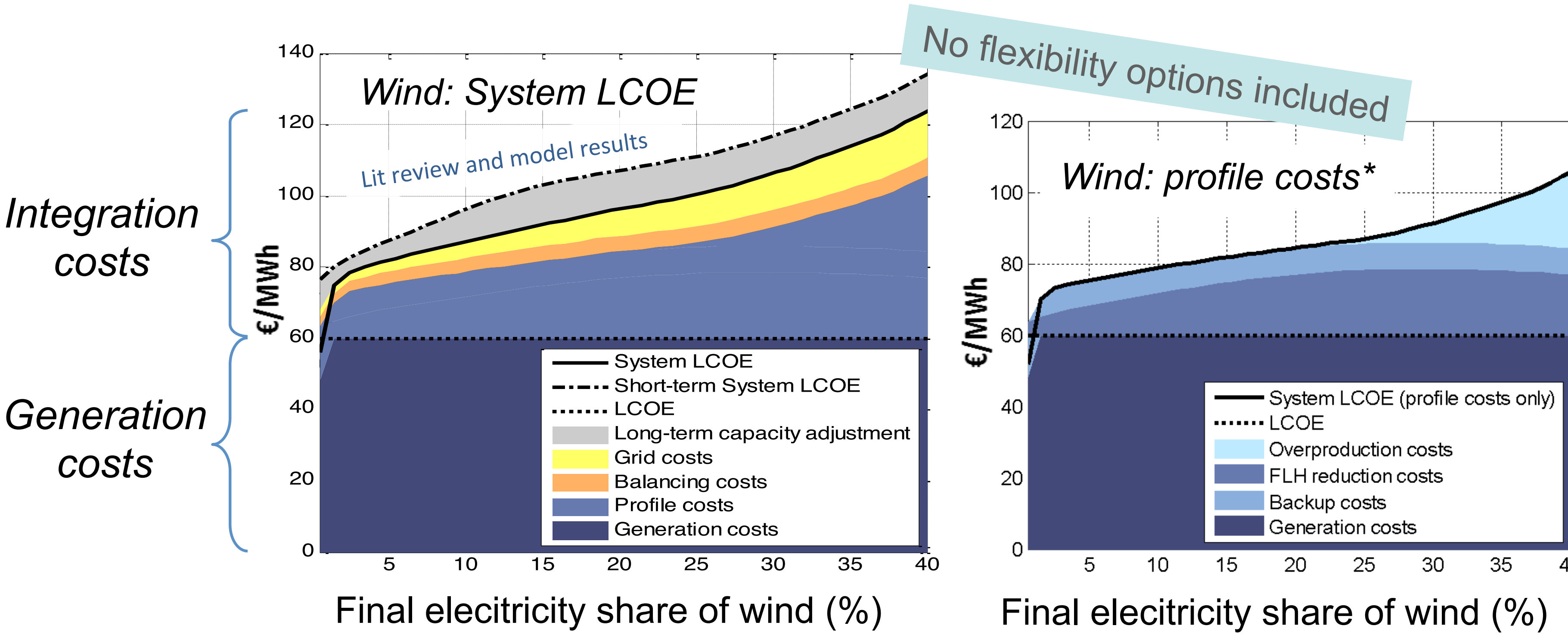
System LCOE can be implemented in IAMs

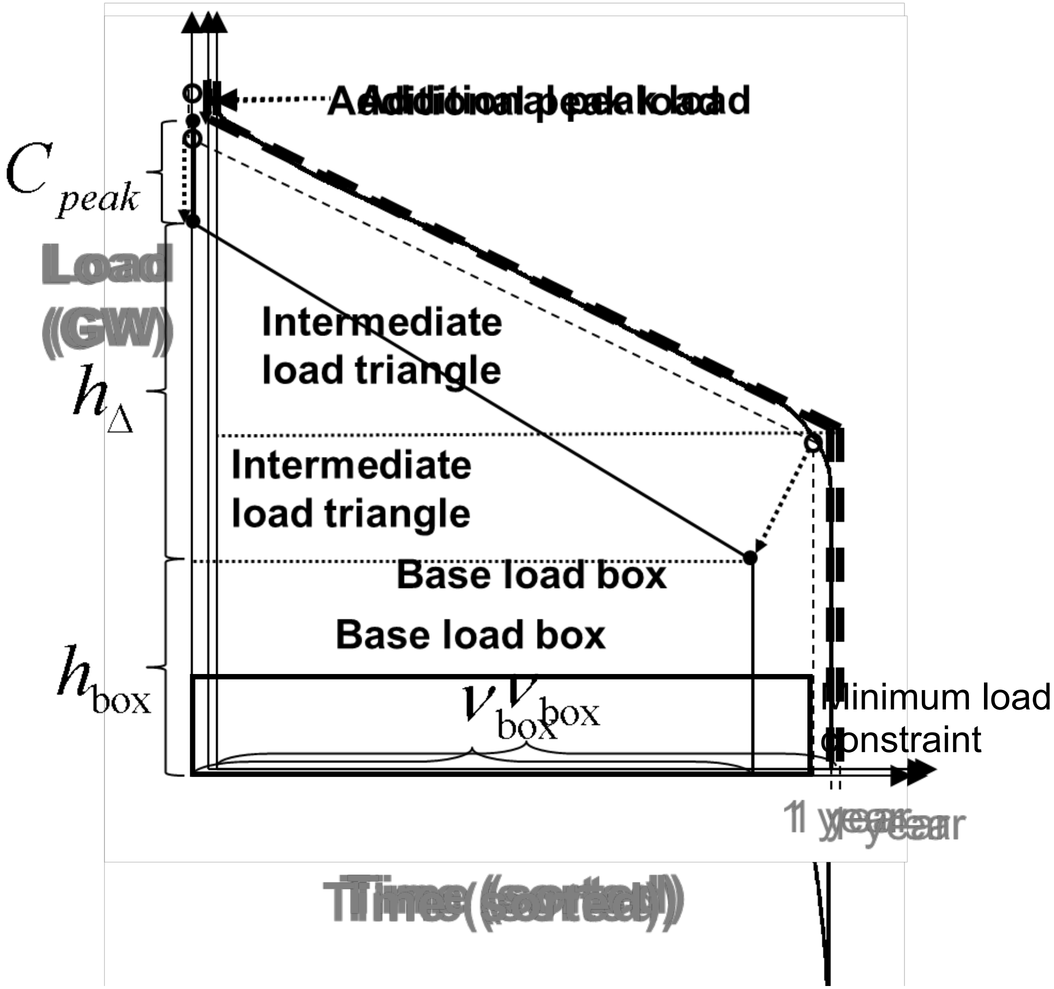


- System LCOE can be implemented as a function of VRE penetration
- It needs bottom-up studies for parameterization (depending on flex.options)
- Cost adders are a good solution for balancing and grid costs
- Conventional plants also imply integration costs
- Profile costs can also be accounted for endogenously

**no minmimum load constraint*

falko.ueckerdt@pik-potsdam.de

Acounting for profile costs endogenously: RLDC approach



- A stepwise linear function approximates the (R)LDC data
- The RLDC endogenously changes within the optimization
- 4 Parameters depend on penetration and mix of variable renewables
- Dispatchable power plants cover residual load

→ Low capacity credit is considered

→ Full-load hours of dispatchable power plants are endogenously reduced

→ Curtailment is considered

→ Important flexibility option: Adaptation of the residual capacity mix is modeled

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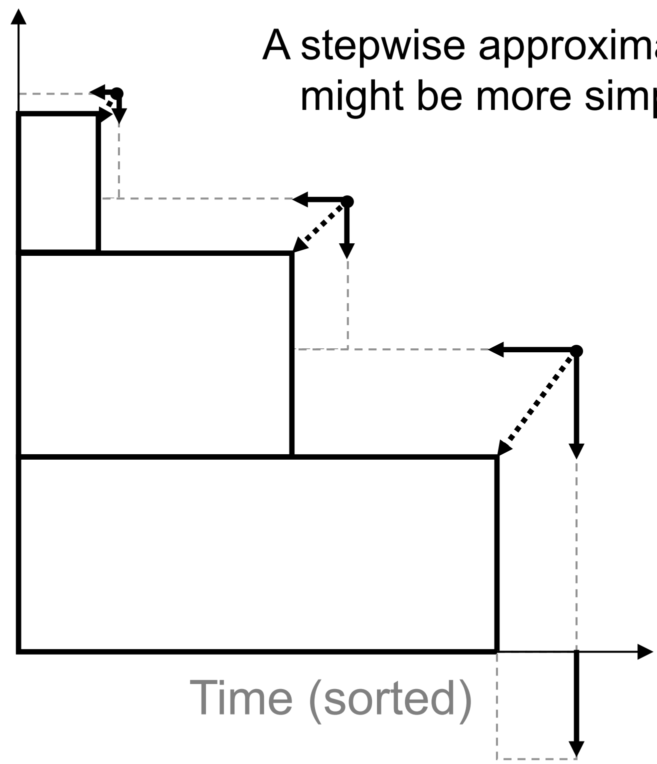

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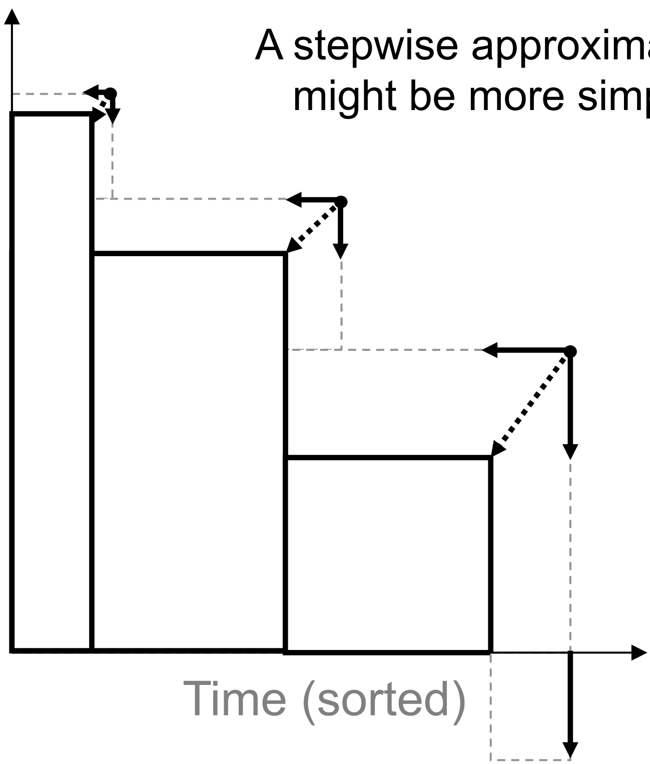


Could be implemented similar as representative time slices

- A stepwise linear function approximates the (R)LDC data
- The RLDC endogenously changes within the optimization
- 4 Parameters depend on penetration and mix of variable renewables
- Dispatchable power plants cover residual load

→ Low capacity credit is considered

→ Full-load hours of dispatchable power plants are endogenously reduced

→ Curtailment is considered

→ Important flexibility option: Adaptation of the residual capacity mix is modeled

Flexibility options can be structured along the challenges

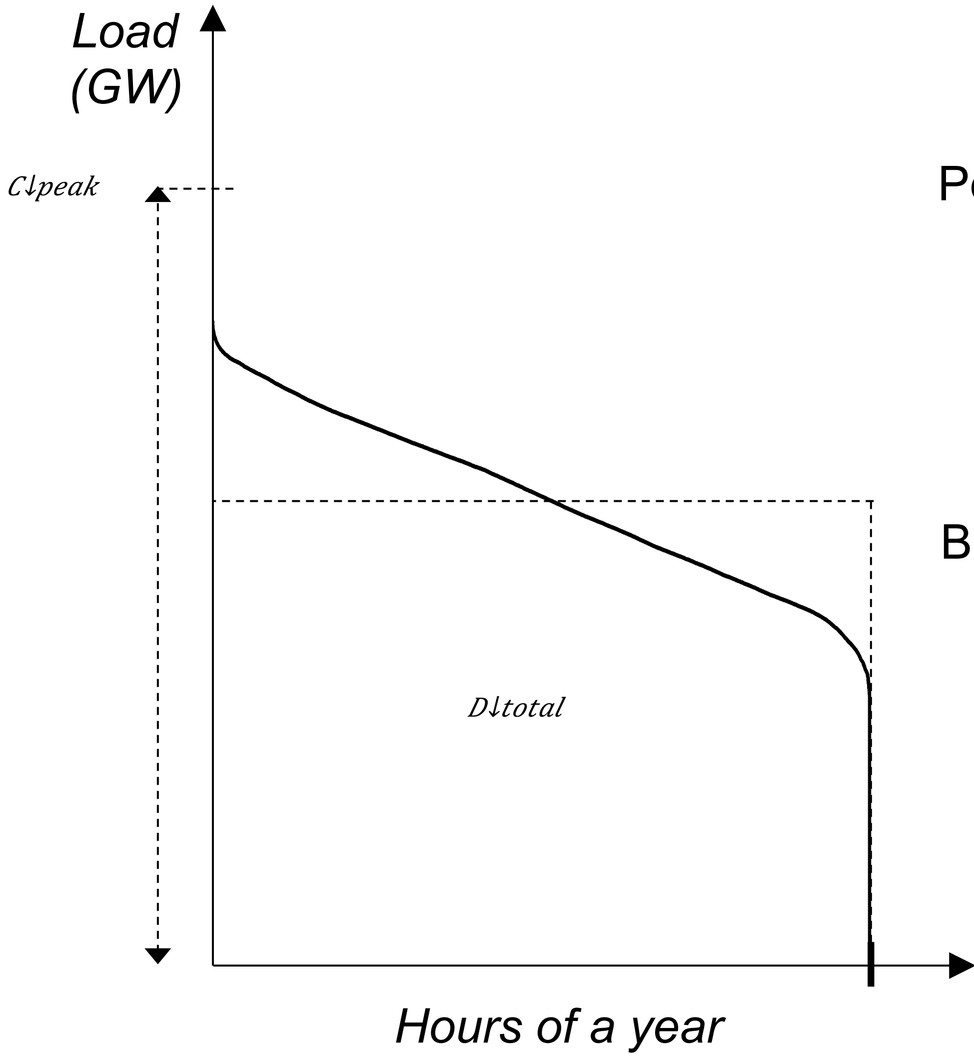
Grid-related Costs	Balancing Costs	Profile Costs
• Grid investments (no regret) • *Shift generation/load geographically* • *Locational price signals on spot markets*		

Bottom-up research required on long-term role of flexibility options and integration costs at high VRE shares

Summary

1. IAMs tend to model electricity as a homogenous good, though it is not
2. IAMs should account for demand variability e.g. by representing a LDC
3. VRE induce integration costs (grid, balancing and profile costs)
4. Integration costs of wind power can be in the same range as generation costs at high shares
5. A major driver of integration costs are profile costs
6. We suggest a metric ‘System LCOE’ that can be implemented in IAMs (it needs bottom-up models for parameterization)
7. Profile costs can directly be represented in IAMs via RLDC
8. Bottom-up research on long-term role of flexibility options and integration costs at high VRE shares needed

Acounting for profile costs endogenously



Peak capacity constraint

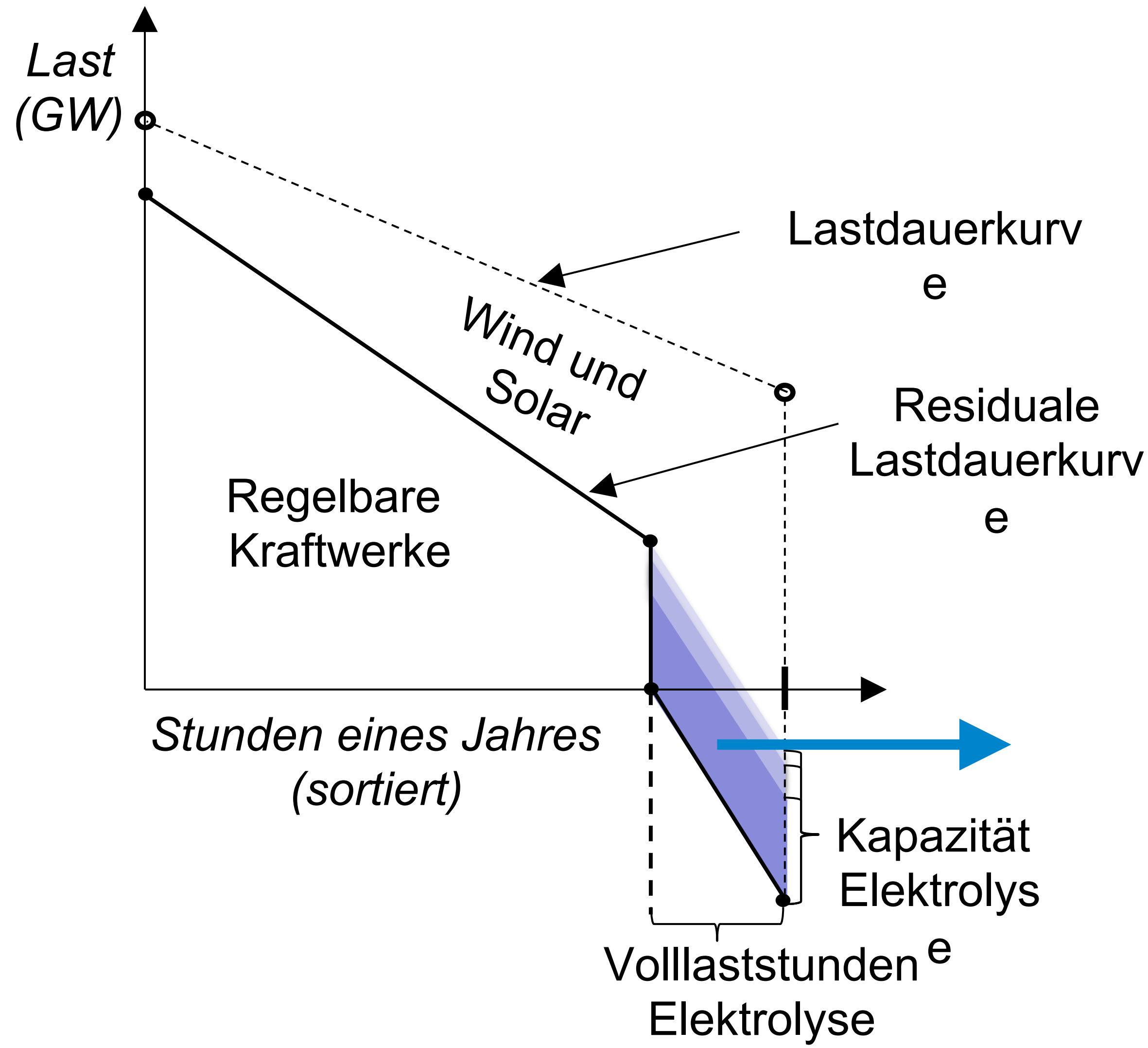
$$C_{peak} = \sum_{te} \gamma_{te} C_{te}$$

Balance equation:

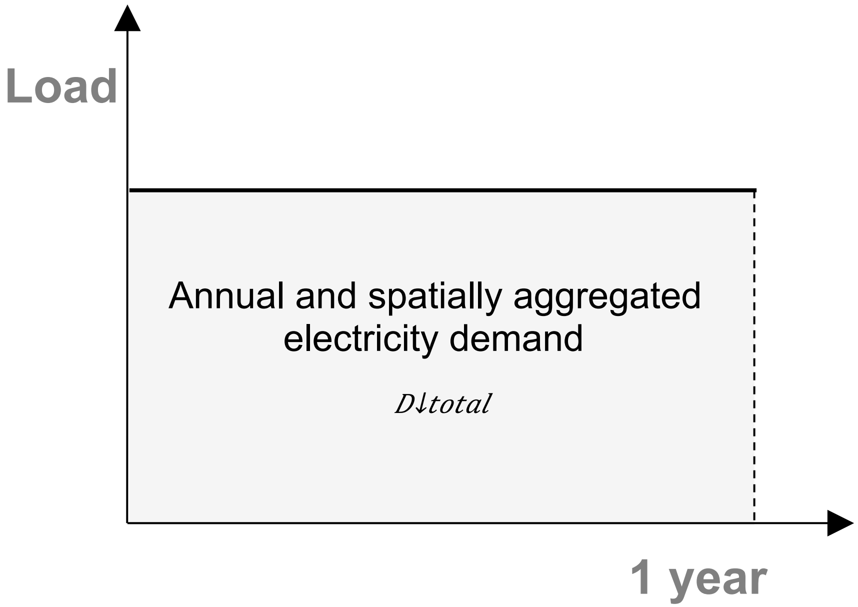
$$D_{total} = \sum_{te} G_{te}$$

G_{te} ; C_{te} ; γ_{te} Generation; capacity; capacity credit from technology te

Modeling hydrogen storage in the RLDC approach



Acounting for profile costs endogenously



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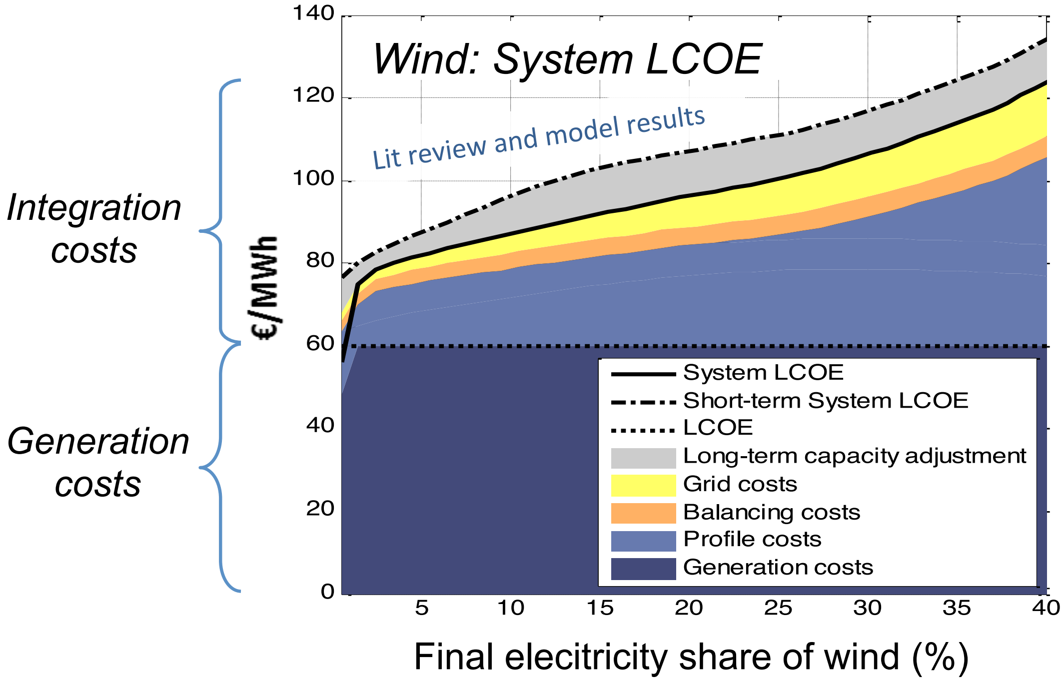
Outlook

System LCOE – magnitude and shape



- From literature: Grid and balancing costs (Holttinen et al. 2011; Gross et al. 2006; Hirth 2012a, dena 2010)
- From a simple model: profile costs.
- Parameterized from German data, representative for thermal systems in Europe
- Caveats that increase integration costs
  - No import/export
  - No demand elasticity
  - No storage
  - Power sector only

- Integration costs of wind power can be in the same range as generation costs at high shares
- A significant driver of integration costs are profile costs, especially the reduced utilization of capital-intensive thermal plants.

→ Integration costs can become an economic barrier to deploying VRE at high shares.

→ An economic evaluation of wind and solar power must not neglect integration costs.

What are integration costs?

- Integration costs have been defined as
  - *“the additional costs of accommodating wind and solar” (Milligan et al., 2011, p.51)*
  - *“the extra investment and operational costs of the non-wind part of the power system when wind power is integrated“ (Holttinen et al., 2011, p. 180).*
  - *“comprising variability costs and uncertainty costs” (Katzenstein & Apt 2012, p* ***XX****)*

- However, there is no formalised definition

  → no agreement on how to calculate them (Milligan et al., 2011)

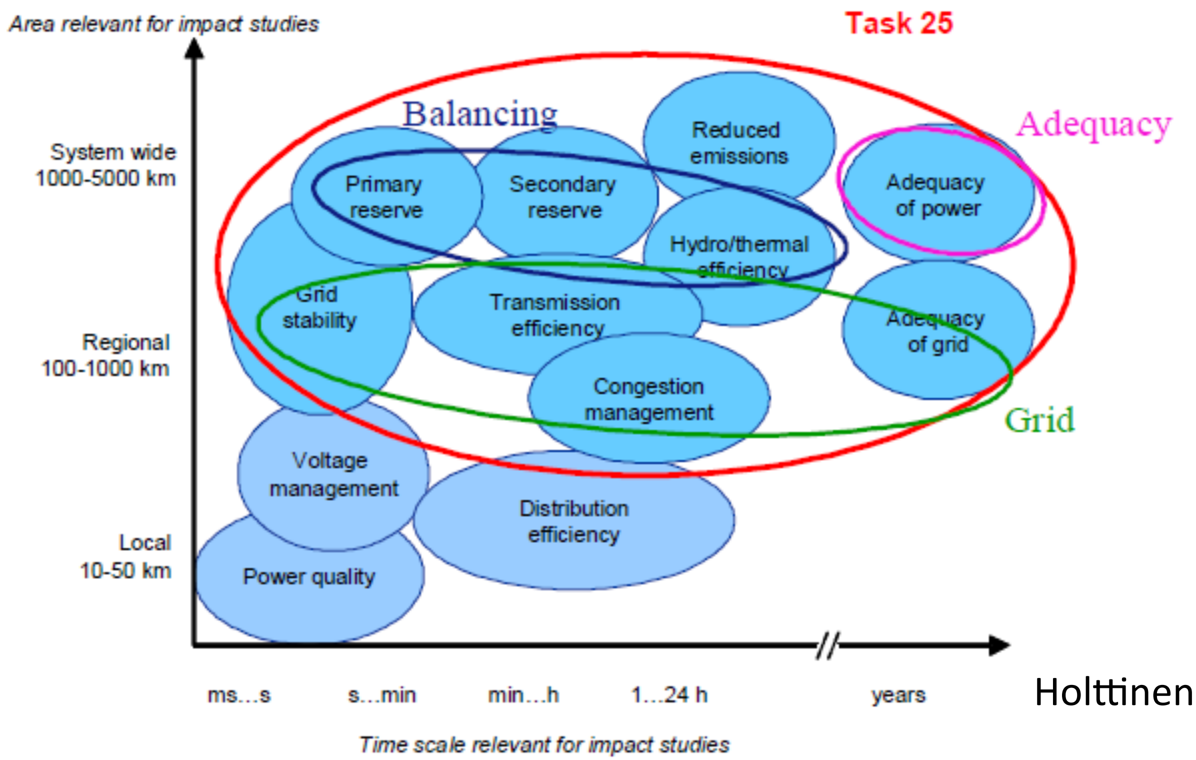
- Integration studies operationalize integration costs as the sum of integration cost components, assuming that this division is exhaustive

A taxonomy of integration costs for variable renewables

„Adequacy costs“
(„capacity costs“)

„Balancing costs“

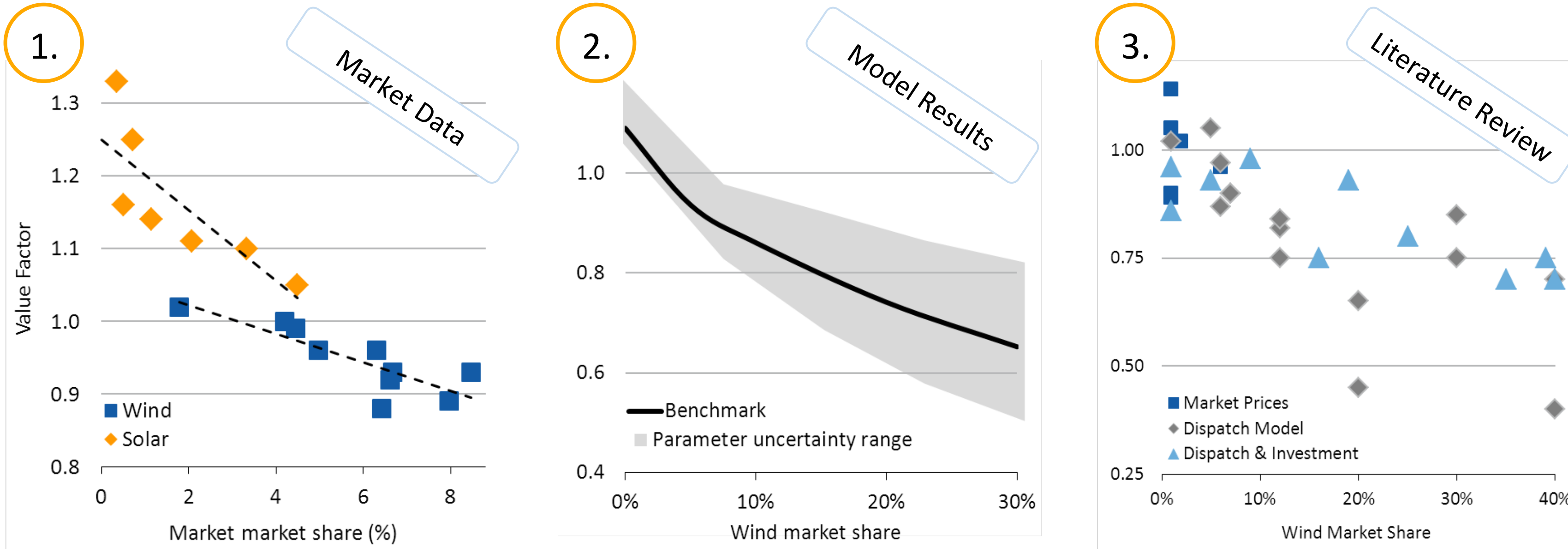
„Grid costs“



Holttinen et al. 2011

Integration costs

The market value (here value factor) reduces: Market Data, Model Results, Literature Review



At 30% penetration, the value factor of wind falls to 0.5 – 0.8 of the base price. In Germany, it has already fallen from 1.02 to 0.89 as penetration increased from 2% to 8%.

Hirth, Lion (2013): "The Market Value of Variable Renewables", Energy Economics 38, 218-236.