Efficiency Losses of Zonal Network Management under Large-Scale Renewable Energy Integration: A Case Study of Central Western Europe

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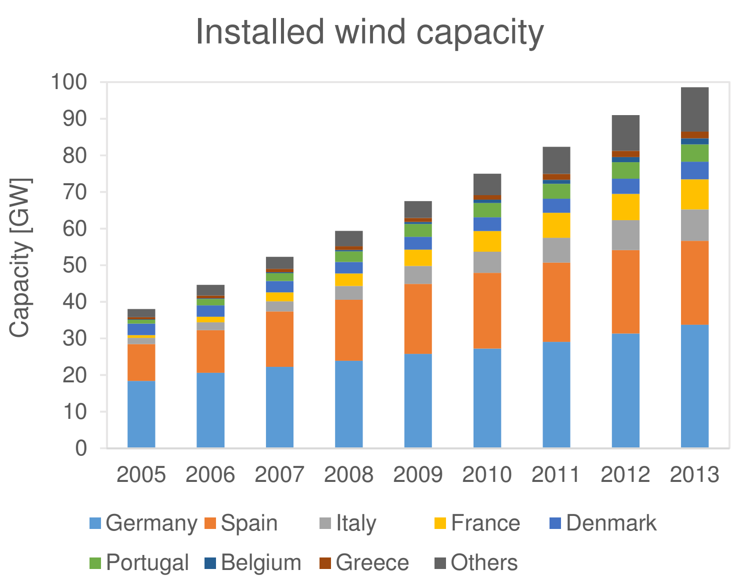
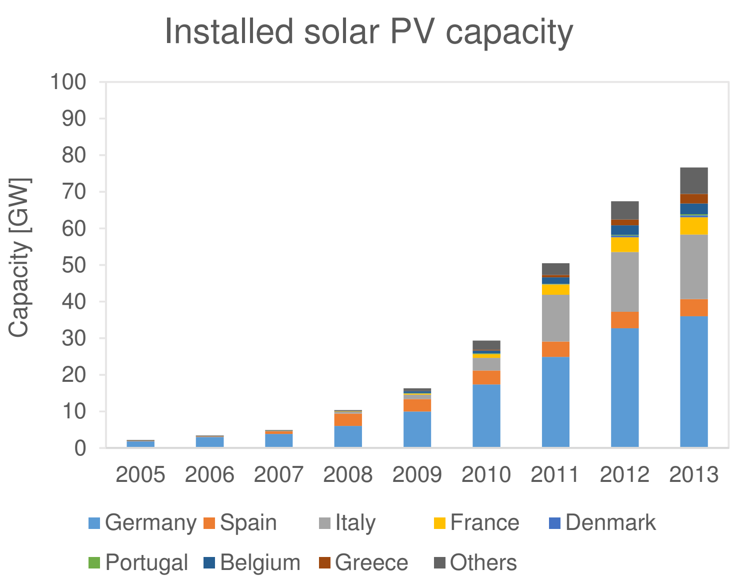
Motivation

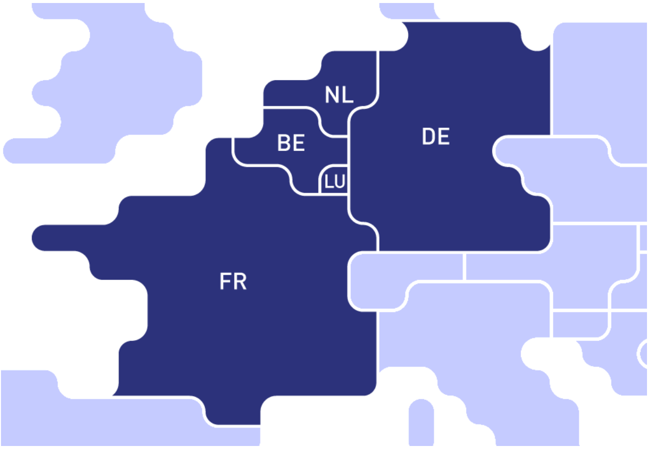
- Day-ahead market clearing (commitment) in Europe introduces inefficiencies
  - Omission of Kirchhoff's law from market design
  - Lack of coordination during operation
- Inefficiencies are exacerbated by renewable energy integration





Goal

- Compare 3 paradigms for day-ahead unit commitment in the Central Western Europe (CWE) system
  - Market Coupling: status quo
  - Deterministic Unit Commitment: perfect coordination of TSOs, representation of Kirchoff laws
  - Stochastic Unit Commitment: endogenous representation of uncertainty



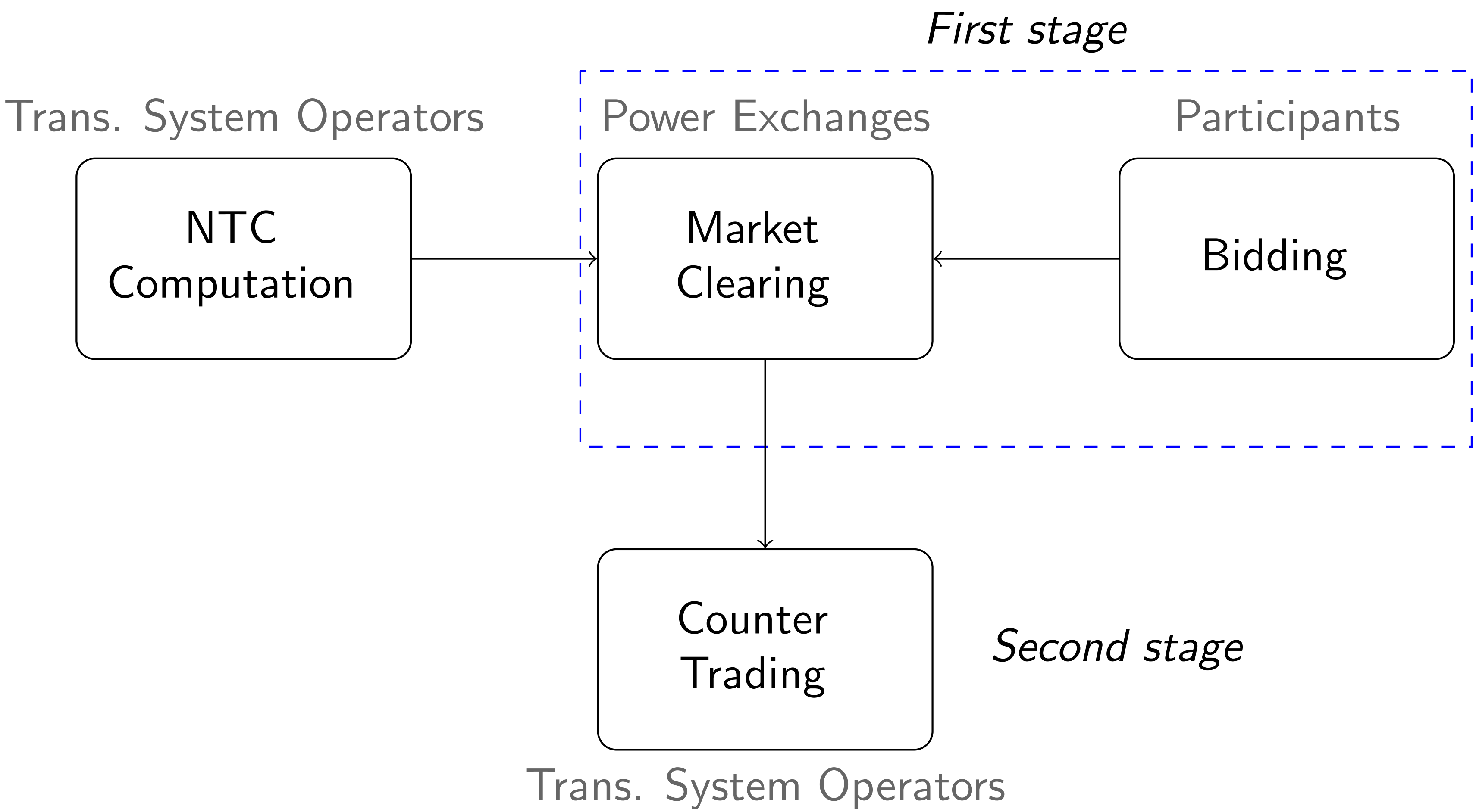
Policy Modeling

Common Modeling Framework

- Relevant literature: (van der Weijde and Hobbs 2011 [2]), (Oggioni, Murphy and Smeers 2014 [3])
- Contribution: quantify inefficiencies of European day-ahead power exchanges while accounting for uncertainty and unit commitment on a system of realistic size
- Two-stage process
  - First stage: commitment of slow thermal units in the day-ahead market
  - Realization of uncertainty ξ : wind and solar power production
  - Second stage: commitment of fast thermal units and dispatch of all units in real time
- Second stage (real-time) costs evaluated via Monte Carlo simulation

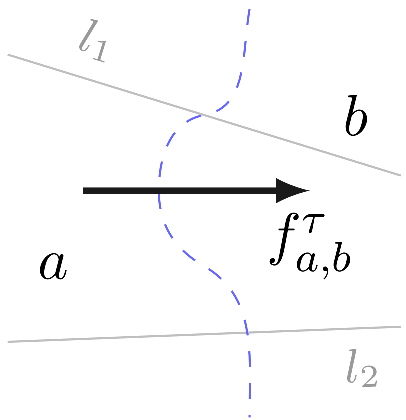
Market Coupling Organization Model

The day-ahead European power exchange represents transmission constraints through a **transportation model**



Computation of Net Transfer Capacity (NTC)

- Net Transfer Capacity (NTC) = Total Transfer Capacity (TTC) - Transmission Reliability Margin (TRM)
- For each hour τ the TTC from region a to b, $\mathsf{TTC}^{\tau}_{a,b}$, is computed as the maximum feasible cross-border flow
- Computation considers real network model and unit commitment constraints for the pair of areas



$$
\begin{aligned}
\mathsf{TTC}^{\tau}_{a,b} = \max \quad & f^{\tau}_{a,b} \\
\text{s.t.} \quad & f^{\tau}_{a,b} \in UC_{a,b}(\mathbb{E}_s[\boldsymbol{\xi}_s])
\end{aligned}
$$

ENTSO-E. Procedures for cross border transmission capacity assessments, 2001.

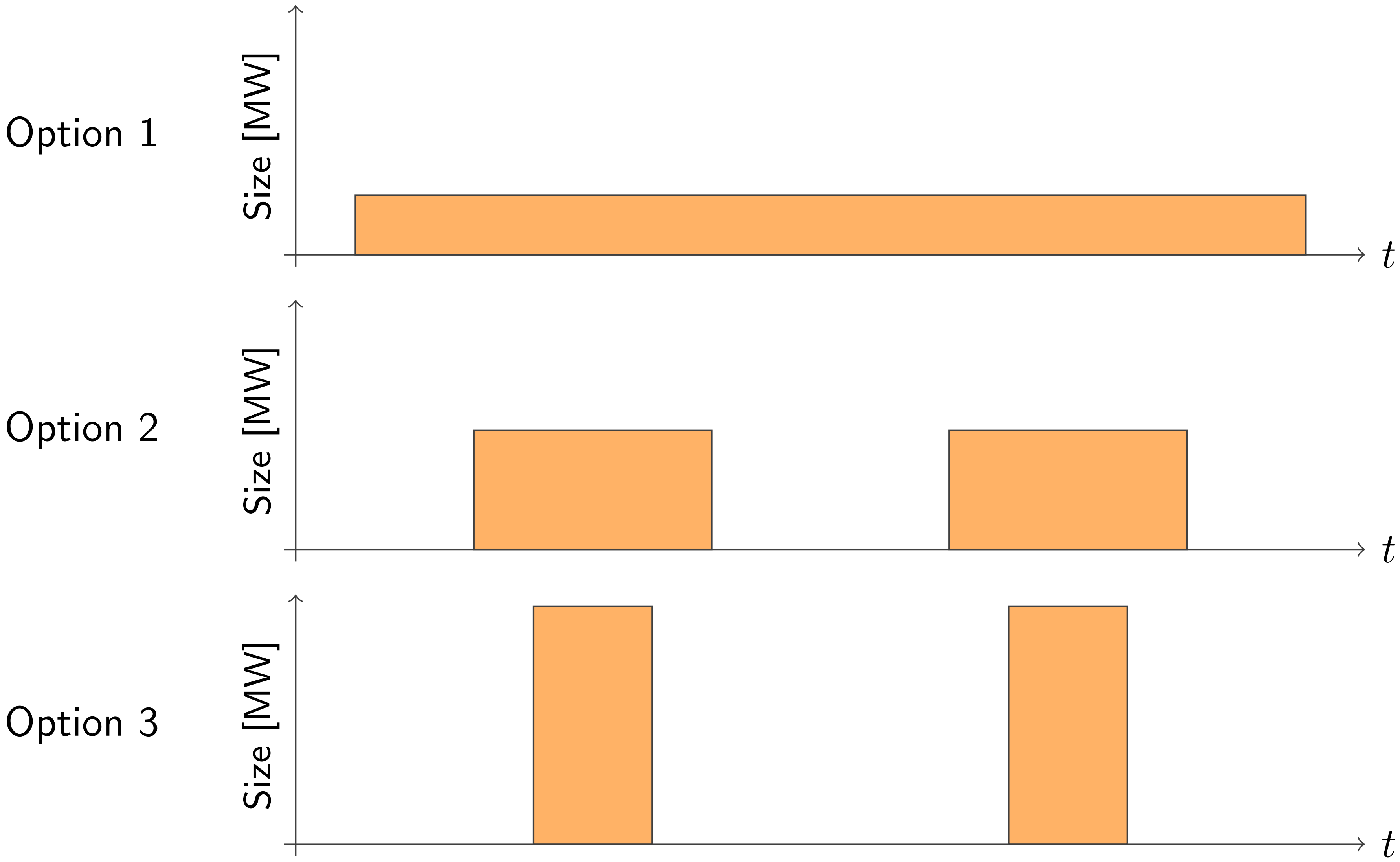
Market Clearing

- COSMOS, EUPHEMIA, **Madani and Van Vyve, 2013** [1]
- Continuous orders, block (fill-or-kill) orders, linked block orders and exclusive block orders, with strict linear pricing
- Unit commitment constraints (DT, UT, ramps) not included in the market clearing model $\Rightarrow$ generators assumed to only bid realizable orders

$$\begin{aligned} \max \quad & \textit{Welfare}(x_i, y_j) \\ \text{s.t.} \quad & \textit{Welfare}(x_i, y_j) \geq \textit{Surplus}(s_i, s_j) \\ & (x_i, y_j, n_{k,t}) \in \textit{PrimalFeasibleSet} \\ & (s_i, s_j, p_{l,t}, v_{k,t}) \in \textit{DualFeasibleSetLR'}(y_j) \end{aligned}$$

where x_i, y_j are order acceptance/rejection variables, s_i, s_j the corresponding orders surplus, $p_{l,t}$ the zonal prices, $n_{k,t}$ the exchanges and $v_{k,t}$ the corresponding congestion dual variables

Exclusive Block Orders



Constructions of Orders

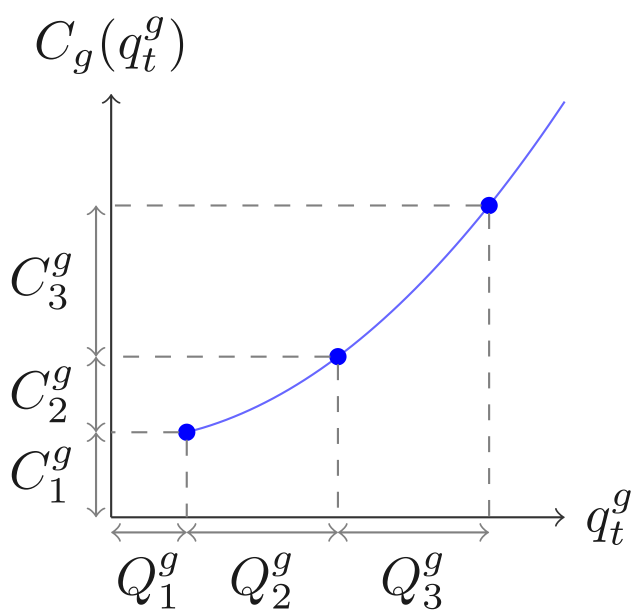
- General principle: **agents bid truthfully**
- Imports, renewable energy sources, demand represented as continuous orders
- Pre-committed thermal generators (nuclear) bid continuous orders at their marginal cost
- Other thermal units modeled as bidding **large groups of exclusive block orders**, each order being a power output profile
- Surplus of the exclusive group for generator g given by

$$s_g \geq -\bar{C}_g(\boldsymbol{q}^g) + \sum_t q_t^g p_{l,t}, \quad \boldsymbol{q}^g \in UC_g(\boldsymbol{q}_0^g), \quad \boldsymbol{q}^g = (q_1^g, q_2^g, \ldots, q_T^g)$$

where $UC_g(\boldsymbol{q}_0^g)$ is the feasible set of power outputs ($\boldsymbol{q}_0^g$ is the vector of initial conditions)

Embedding Unit Commitment Constraints

- q_t^g approximated with n discrete bins, leading to



$$q_t^g \approx \sum_{k=1}^{n} Q_k^g u_{k,t}^g$$

$$C_g(q_t^g) \approx \sum_{k=1}^{n} C_k^g u_{k,t}^g$$

$$u_{1,t}^g \in SUSD_g(\boldsymbol{q}_0^g) \quad \text{(UT \& DT)}$$

$$u_{k,t}^g \in RURD_g(\boldsymbol{q}_0^g) \quad \text{(ramps)}$$

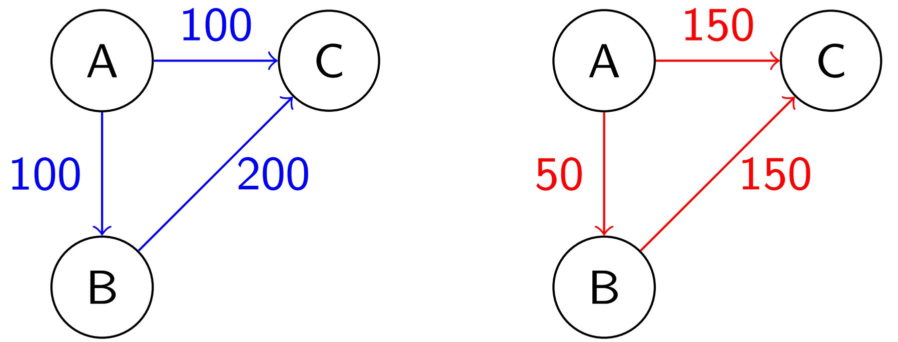
$$u_{k+1,t}^g \leq u_{k,t}^g,\ u_{k,t}^g \in \{0,1\}$$

- Products of $u_{k,t}^g$ with continuous variables (e.g. $p_{l,t}$) can be replaced with a linearized big-M formulation, Glover 1975
- Feasible day-ahead schedule consistent with linear pricing

Counter trading

- Second stage model, maintaining first stage commitment decisions (slow units)
- International energy exchange
  1. Maintaining cross-border flows, van der Weijde and Hobbs 2011 [2]
  2. Maintaining country net-positions, Oggioni, Murphy and Smeers 2014 [3]

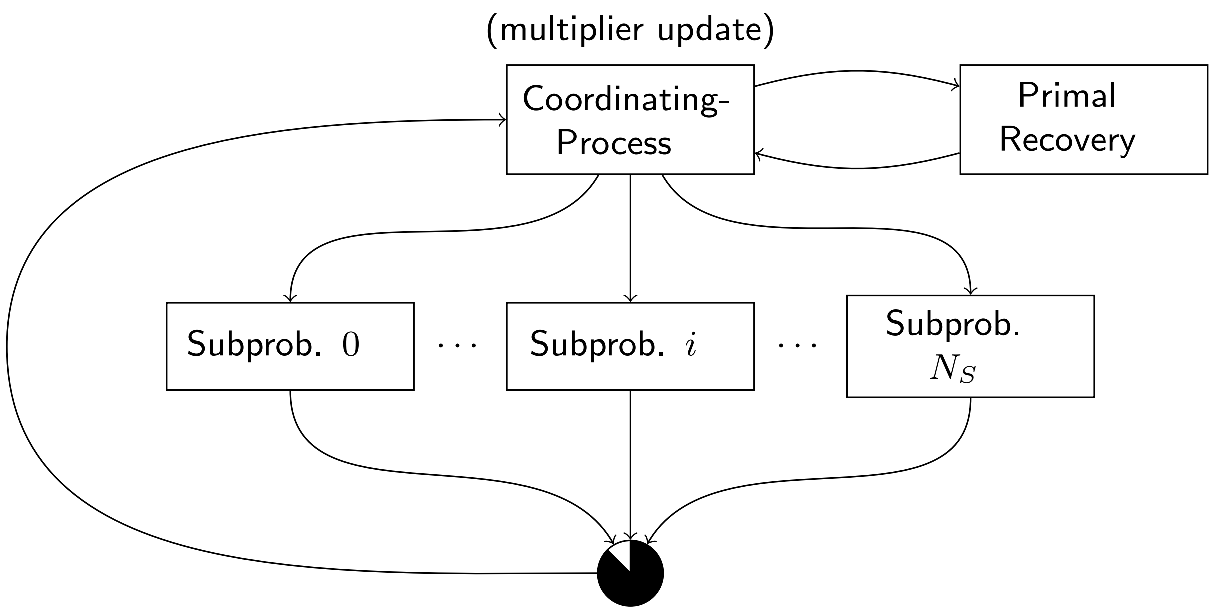
same net positions,
different cross
border flows



- Deviations penalized through an L1 penalty function, with cost $CL = \max_{g \in G} \mathit{MarginalCost}_g$

Stochastic Unit Commitment

- Endogenous modeling of uncertainty through a discrete probability distribution
- Problem solved using dual decomposition and subgradient method, Papavasiliou, Oren and O'Neill 2011 [4]
- Upper bound convergence accelerated by recovering $N_S + 1$ feasible first stage schedules at each subgradient method iteration

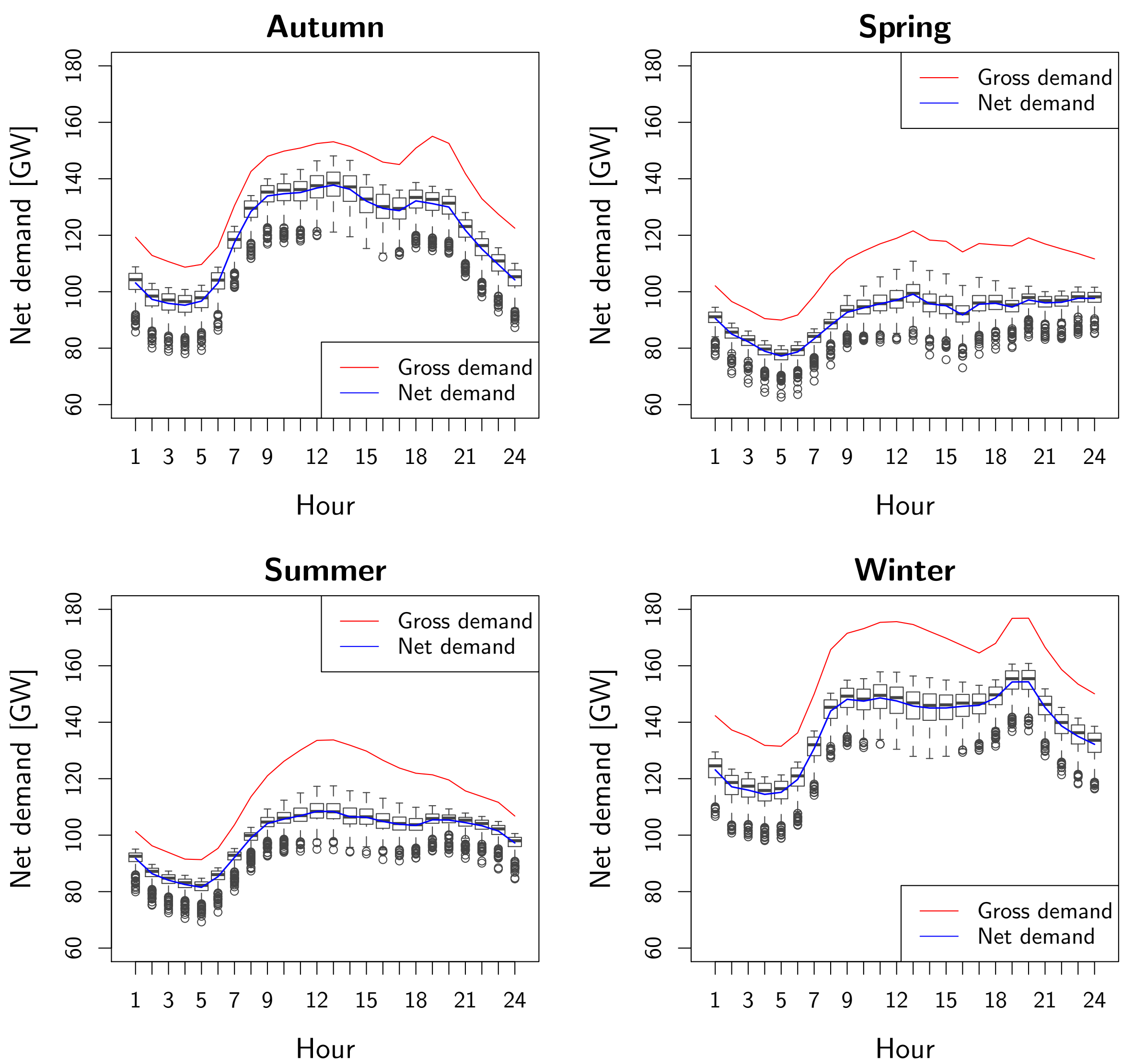


Results

CWE System Data

- Belgium, France, Germany, the Netherlands and Luxembourg
- CWE Phoenix database (shared by GDF Suez) ∼ Generators
- Oggioni, Murphy and Smeers 2014 [3] ∼ Transmission system (15 nodes, 28 lines)
- ENTSO-E and Transmission System Operators
  - ∼ Demand
  - ∼ Cross-border physical flows (imports/exports)
  - ∼ Wind and PV power production time series

Net Demand in the CWE System on Weekdays



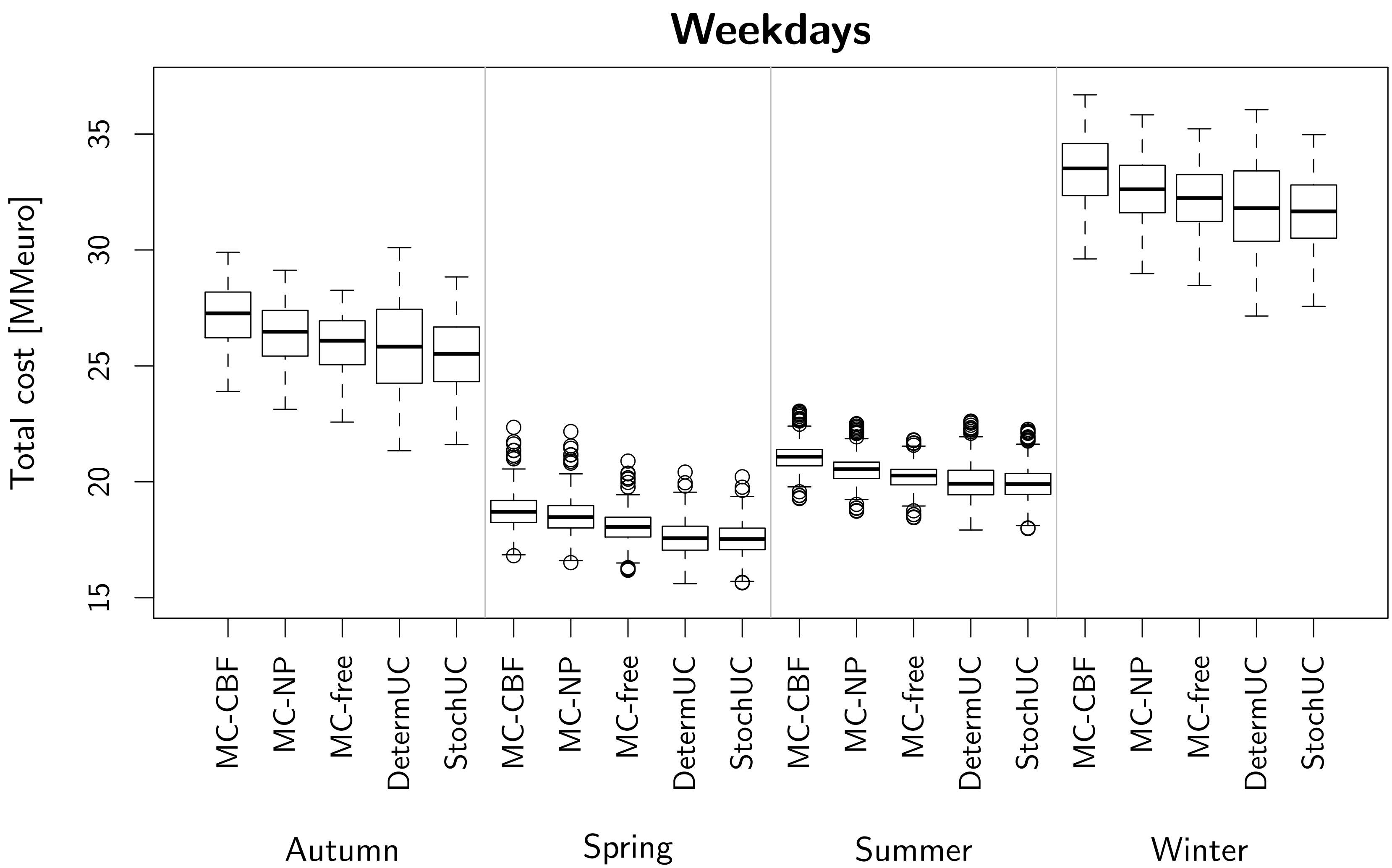
Simulation Settings

- Slow generators: 114.2GW ($+91.0$GW of nuclear generators)
- Fast generators: 7.1GW ($+26.9$GW of aggregated CHP generators)
- Wind and solar power production are uncertain only in Germany
- 8 typical days: 4 seasons $\times$ weekdays/weekends
- Initial conditions from 2-week deterministic UC solution
- Second stage (real-time) costs estimated using 200 Monte Carlo samples (per season) from past realizations
- Stochastic unit commitment solved using 20 scenarios (per season), selected using scenario reduction technique proposed by Heitsch and Römisch, 2007 [5]

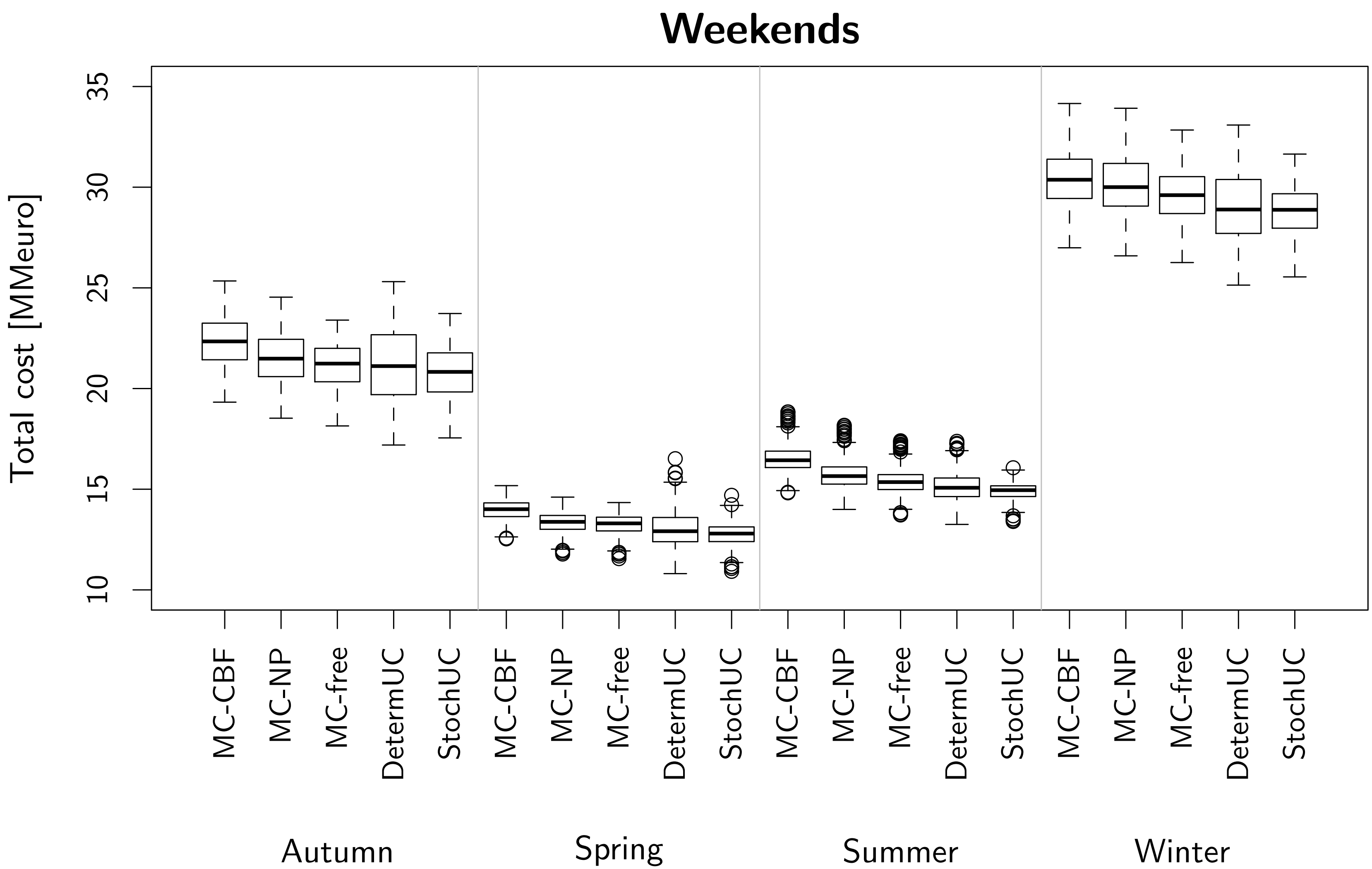
Model Comparison Overview

- Compare 5 policies:
  - Market coupling enforcing cross-border flows, TRM 15% (*MC-CBF*)
  - Market coupling enforcing net positions, TRM 15% (*MC-NP*)
  - Market coupling with international re-dispatch, TRM 15% (*MC-free*)
  - Deterministic UC without reserves (*DetermUC*)
  - Stochastic UC (*StochUC*)
- In terms of expected costs: *MC-CBF* $(100\%) \succ$ *MC-NP* $(97.4\%) \succ$ *MC-free* $(95.8\%) \succ$ *DetermUC* $(94.7\%) \succ$ *StochUC* (93.8%)

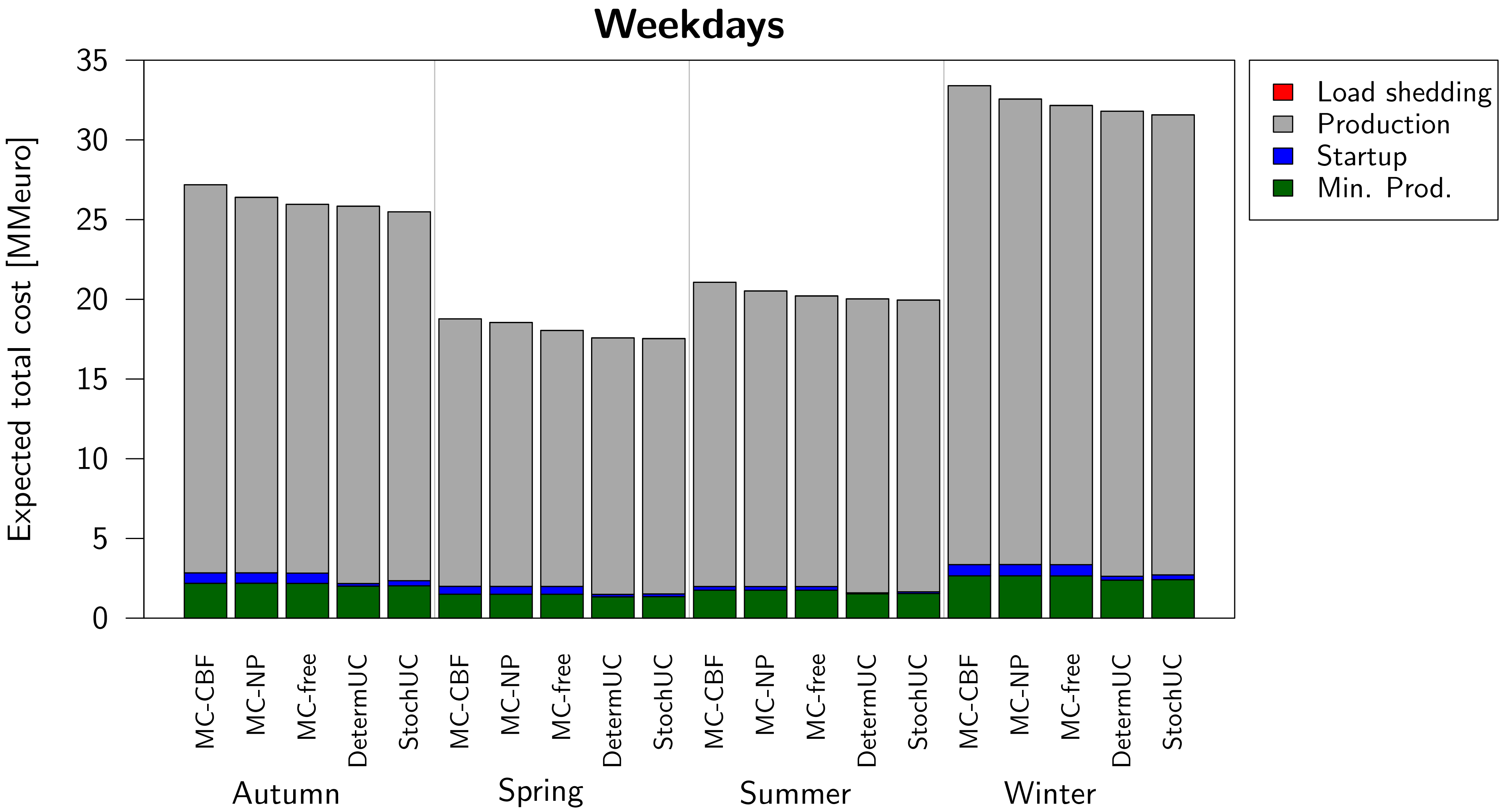
Cost Distribution Weekdays



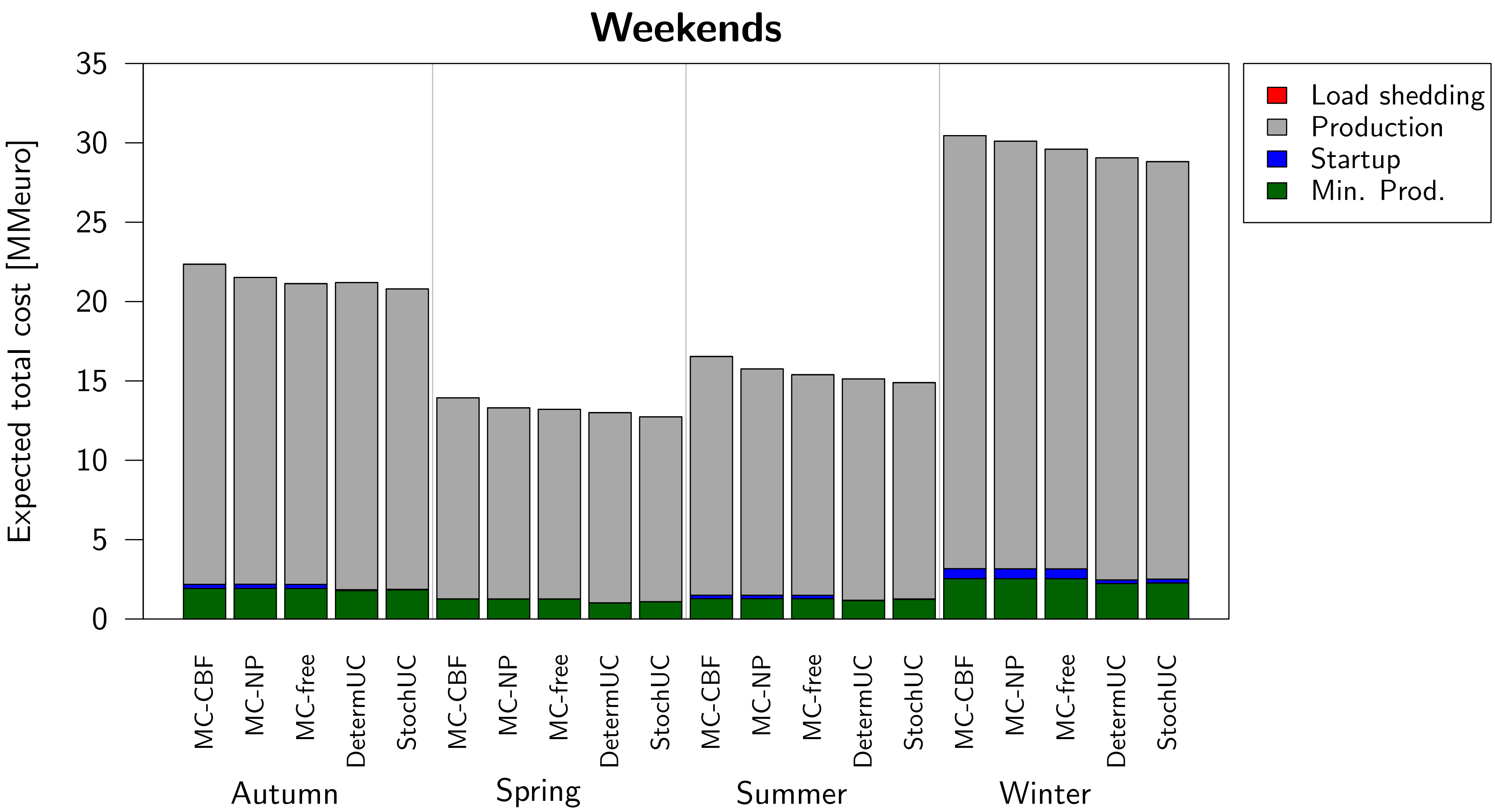
Cost Distribution Weekends



Expected Cost Composition Weekdays



Expected Cost Composition Weekends



Conclusions

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- Efficiency gains of stochastic unit commitment relative to current practice: *MC-CBF* - *StochUC* ~ 1.48MM€ per day
- Benefit of relaxing cross-border flows: *MC-CBF* $-$ *MC-free* ~ 1.00MM€per day
- Benefit of relaxing net positions: *MC-free* $-$ *MC-NP* ~ 0.39MM€per day
- Benefit of accounting for network physical constraints: *MC-free* $-$ *DetermUC* ~ 0.27MM€per day
- Benefit of endogenously modeling uncertainty: *DetermUC* $-$ *StochUC* ~ 0.21MM€per day

Thank you!

References

[1] Mehdi Madani and Mathieu Van Vyve. A new formulation for the European day-ahead electricity market problem and its algorithmic consequences. *CORE Discussion Paper* 2013/74.

[2] Adriaan Hendrick van der Weijde and Benjamin F. Hobbs. Locational-based coupling of electricity markets: benefits from coordinating unit commitment and balancing markets. *Journal of Regulatory Economics*, Volume 39, Issue 3, pp 223-251, June 2011.

[3] Georgia Oggioni, Fred H. Murphy and Yves Smeers. Evaluating the impacts of priority dispatch in the European Electricity Market. *Energy Economics* 42: 183–200, 2014.

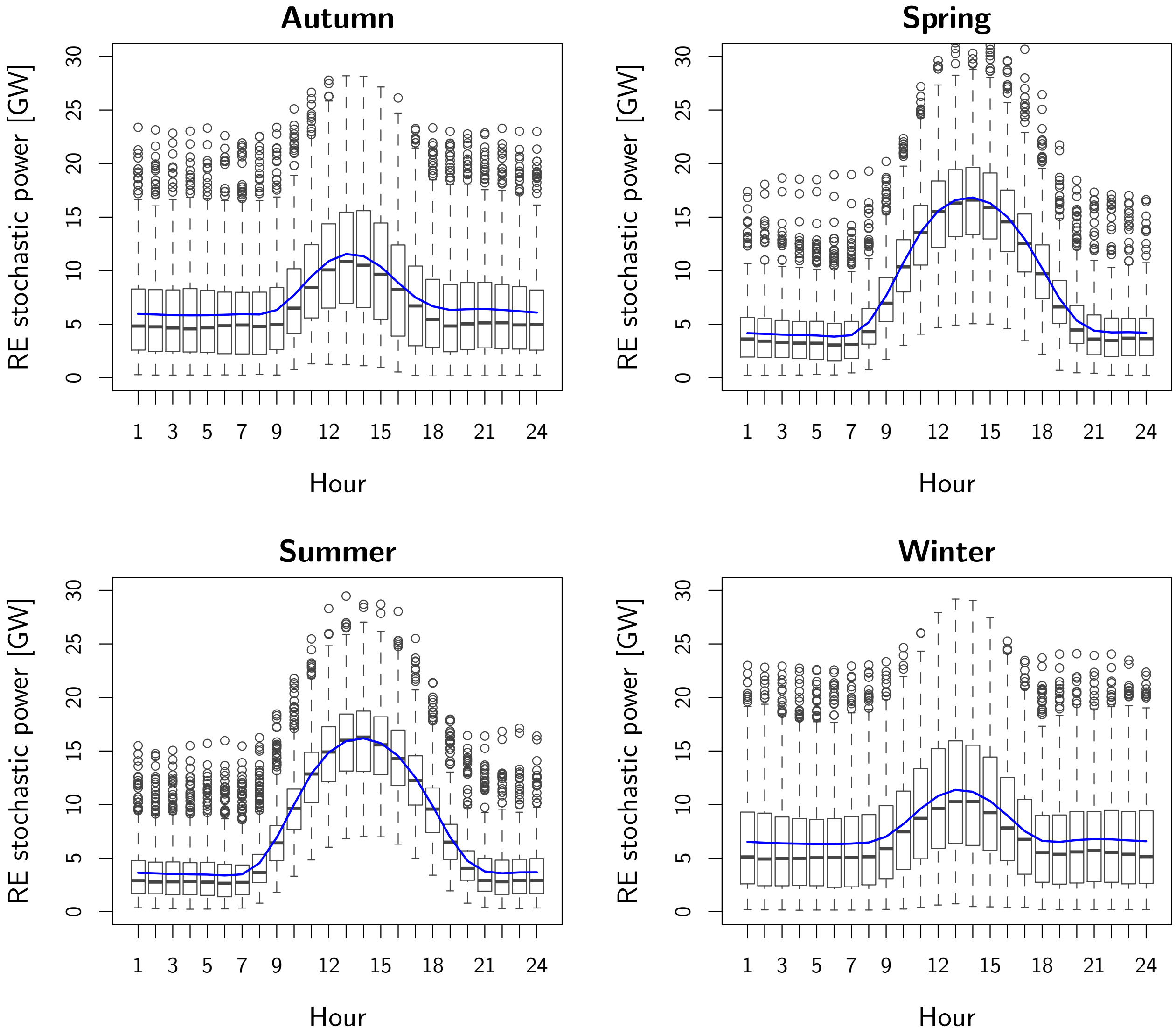
[4] Anthony Papavasiliou, Shmuel S. Oren and Richard P. O'Neill. Reserve Requirements for Wind Power Integration: A Scenario-Based Stochastic Programming Framework. *IEEE Transactions on Power Systems* vol. 26, no.4, pp. 2197–2206, Nov. 2011.

[5] Holger Heitsch and Werner Römisch. A note on scenario reduction for two-stage stochastic programs. *Operations Research Letters* 35(6): 731–738, Nov. 2007.

Appendix

Stochastic renewable energy supply

(wind and solar power inside Germany)



Cost Distribution

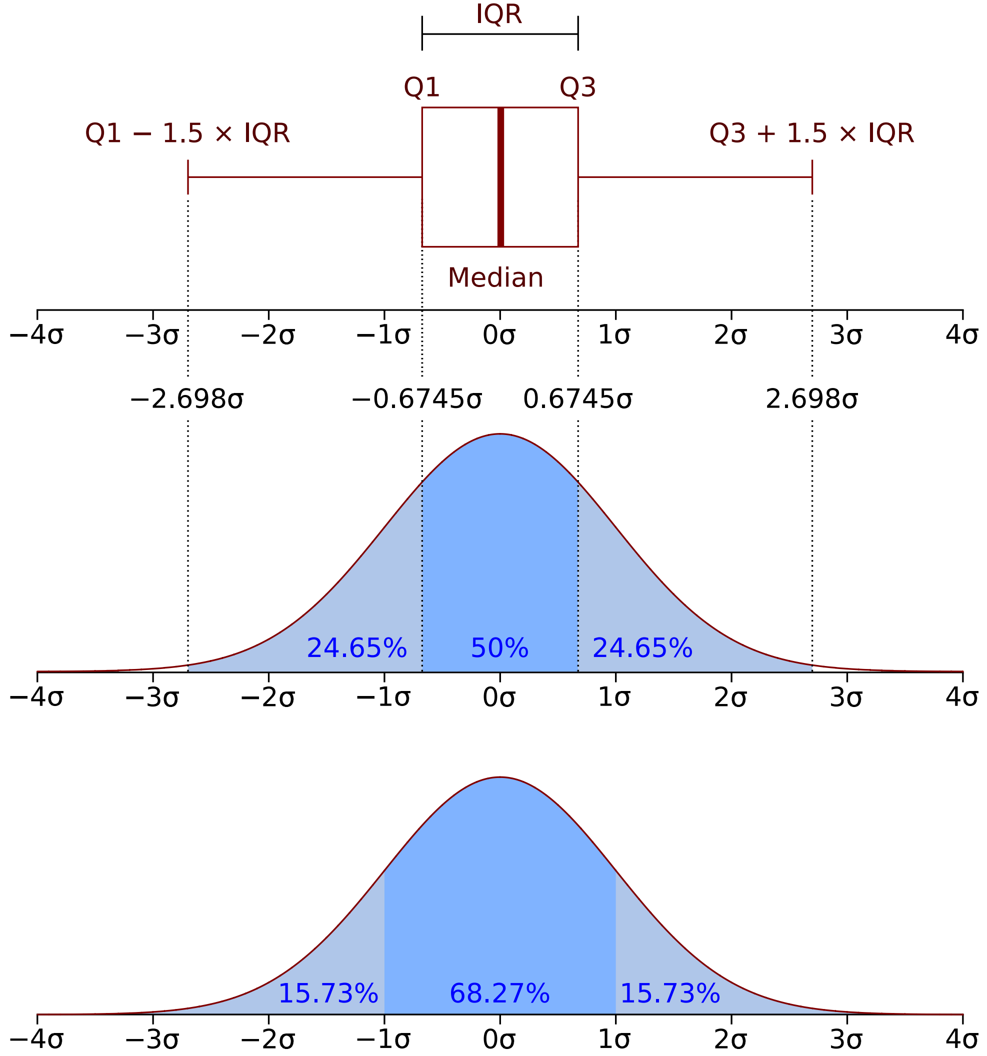
- At an aggregate level, the net demand determines the distribution of the operation costs:
  - Autumn and winter, similar aggregate weather conditions:
    - Partial to complete cloudiness, with wind blowing at different hours, but blowing every day
    - Even in clear days, due to solar light incidence angle, solar power does not increase much

    The hourly net demand distribution is flat, leading to flat distributed operation costs with no extreme values
  - In spring and summer we observe the opposite weather conditions, leading to peaky distributed operation costs, with extreme values

Expected Cost Composition

- Start-up and minimum production cost differences are explained by the different models used in the first-stage:
  - Market coupling models with strict linear pricing and zonal transmission, v.s. global minimization with the actual grid
  - Additional first-stage unit started up due to conservativeness of transport model in market coupling policies (Net-Transfer-Capacities)
- Production cost differences are mostly explained by the restrictions imposed over cross-border flows or net-positions in real operation

Box Plot, Gaussian Standard Distribution



Source: Wikipedia. Box plot. http://en.wikipedia.org/wiki/Box_plot