Co-Optimization of Energy and Reserves

Anthony Papavasiliou

FPM Meeting, 04/10/2016

Some Reflections on Today's Discussion

- Market monitoring and compulsory participation in real time: Pacific Gas & Electric submits their resources in real-time markets for fear of market monitoring
- Networks in US intra-day auctions: yes (plus reserve)
- Optimality of day-ahead clearing: Euphemia does not provide certificates of optimality, neither does US-type centralized unit commitment
- Uplifts: allow for more stable pricing, small fraction of market and of somewhat secondary concern
- Reactive power and inertia: not part of market clearing
- The role of Independent System Operators: operation **and** market clearing
- Complexity of multi-part bidding: it is in some ways quite simple, one can simply bid technical and economic data truthfully, **including location**, and let market engine take over
- Frequency of intra-day: there are hour-ahead auctions, but not two-/three-/… hour ahead markets

US-Style Day-Ahead / Hour-Ahead / Real-Time Market Model

- Objective: min $\sum_{g,t}(K_g u_{gt} + S_g v_{gt} + C_g p_{gt})$
- Load balance: $\sum_{g \in G} p_{gt} = D_t, \forall t$
- Min / max capacity limits: $P_g^- u_{gt} \leq p_{gt} \leq P_g^+ u_{gt}, \forall g, t$
- Ramping limits: $-R_g^- \leq p_{gst} - p_{gs,t-1} \leq R_g^+, \forall g, t$
- Min up times: $\sum_{q=t-UT_g+1}^{t} v_{gq} \leq u_{gt}, \forall g, t \geq UT_g$
- Min down times: $\sum_{q=t+1}^{t+DT_g} v_{gq} \leq 1 - u_{gt}, \forall g, t \leq N - DT_g$
- State transition: $v_{gt} \geq u_{gt} - u_{g,t-1}, \forall g, t$
- Integrality: $v_{gt}, u_{gt} \in \{0, 1\}, \forall g, t$
- Kirchhoff voltage/current laws
- Transmission line thermal constraints

- Unit specific
- Integrated
- No opportunity costs
- Technical and economic information

PJM Example

Day-ahead Market – Average Daily Volumes

- 1,210 generators, 3 part offers (startup, no load, 10 segment incremental energy offer curve)
- 10,000 - Demand bids – fixed or price sensitive
- 50,000 - Virtual bids / offers
- 8,700 - eligible bid/offer nodes (pricing nodes)
- 6,125 - monitored transmission elements
- 10,000 - transmission contingencies modeled

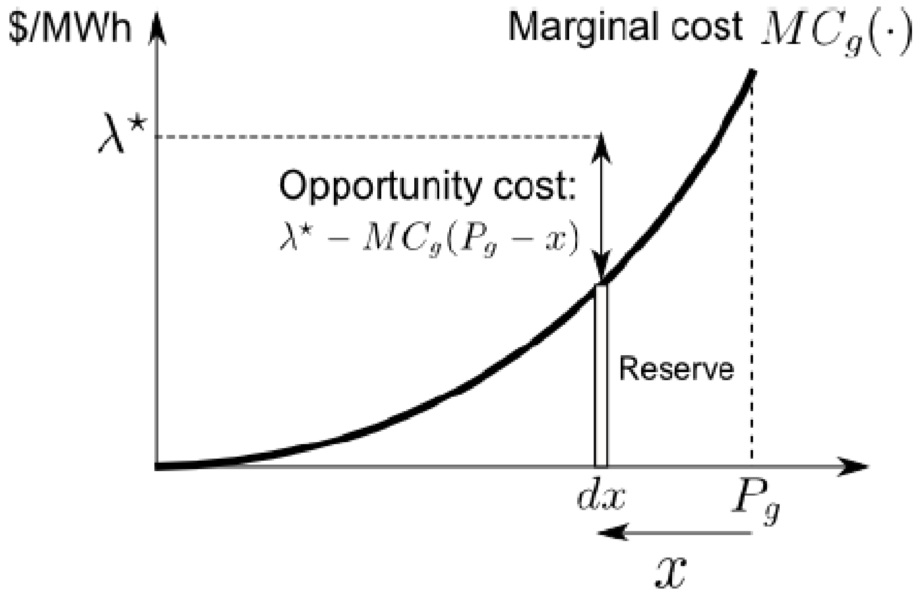
Co-Optimization

- Forward (day-ahead, hour-ahead) and <u>real-time</u> multi-product auctions for simultaneous clearing of energy and reserves => forward and real-time reservation and activation are priced *simultaneously*
- Sequence of events:
  - Agents bid technical/cost data *by unit*
  - ISO solves co-optimization
  - Prices are obtained as dual multipliers (sensitivities) of market clearing constraints
- Two-settlement system
- Transmission is also handled in the co-optimization
- Rules for setting reserve *requirements* are similar to Europe

Sequential Clearing

- Forward (month-/week-/day-ahead) reservation followed by real-time activation
- How does the design differ from co-optimization?
  - Sequential -> reserve auctions rely on opportunity cost bidding
  - Portfolio bidding (for energy)
  - No real-time market for reserve capacity
- Considerations
  - In a system with dynamic and uncertain conditions, can a decentralized design discover prices?
  - If there is no real-time market for reserve capacity, how can real-time markets signal scarcity?
  - If we wish to co-optimize in the day ahead, how can we reconcile that with EUPHEMIA and portfolio bidding?

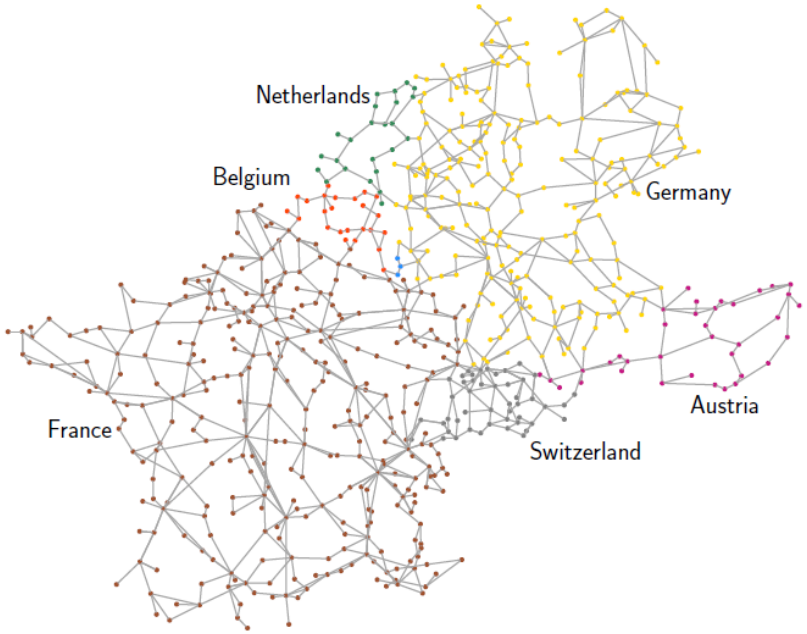
Opportunity Cost

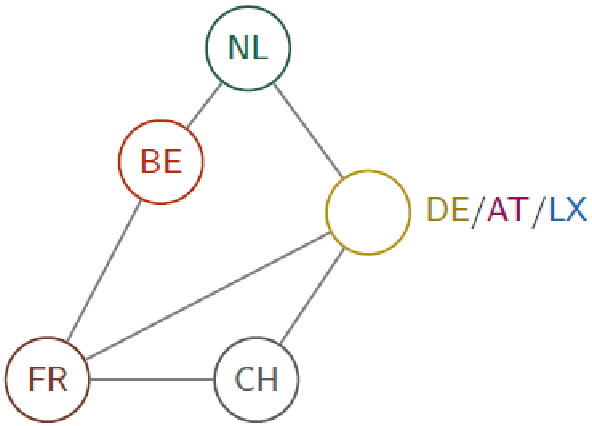


Allocate slice *dx* for reserves, instead of using it to sell energy at a price $\lambda^\star \Rightarrow$ opportunity cost:

$$\max(0, \lambda^\star - MC_g(P_g - x))$$

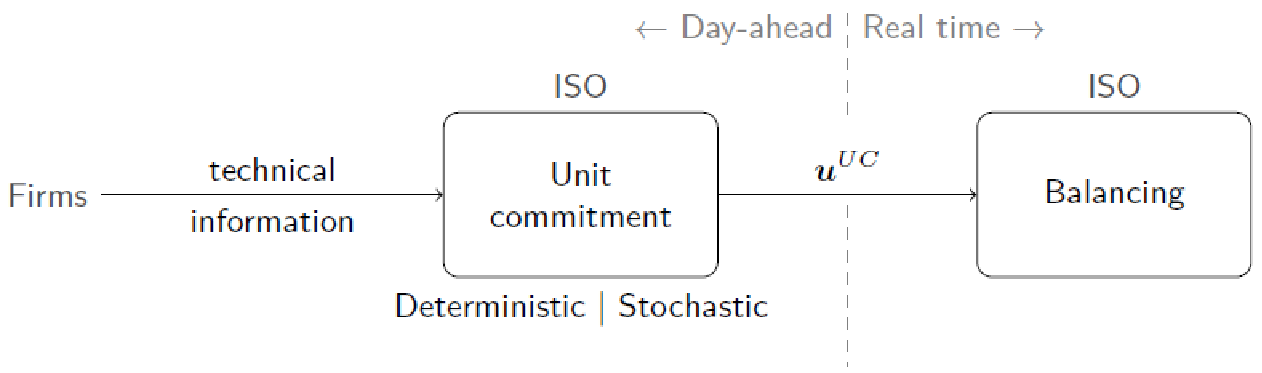
Sequential versus Coordinated Clearing in CWE

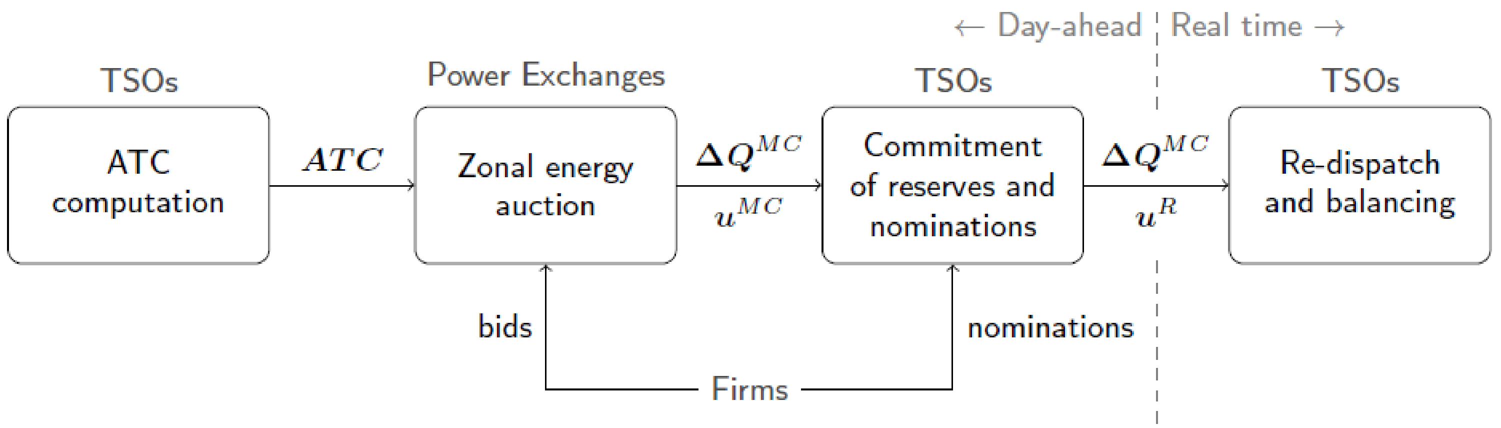




I. Aravena, A. Papavasiliou, ‘Renewable Integration in Zonal Markets’. Forthcoming in *IEEE Transactions on Power Systems*.

Coordinated versus Sequential Clearing





Simulation Setting

- Commitment of slow resources decided in day ahead, commitment of fast units decided in real time. Production of all units decided in real time.
- 656 thermal generators
- Multi-area renewable production with demand and 15’ resolution
- Comparing performance of 3 policies:
  - Market coupling respecting net positions, **MCNetPos**
  - Fully coordinated real-time operation, **MCFree**
  - Fully coordinated day-ahead and real-time operation, **DetermUC**
- Interpretation
  - MCNetPos - : benefits of

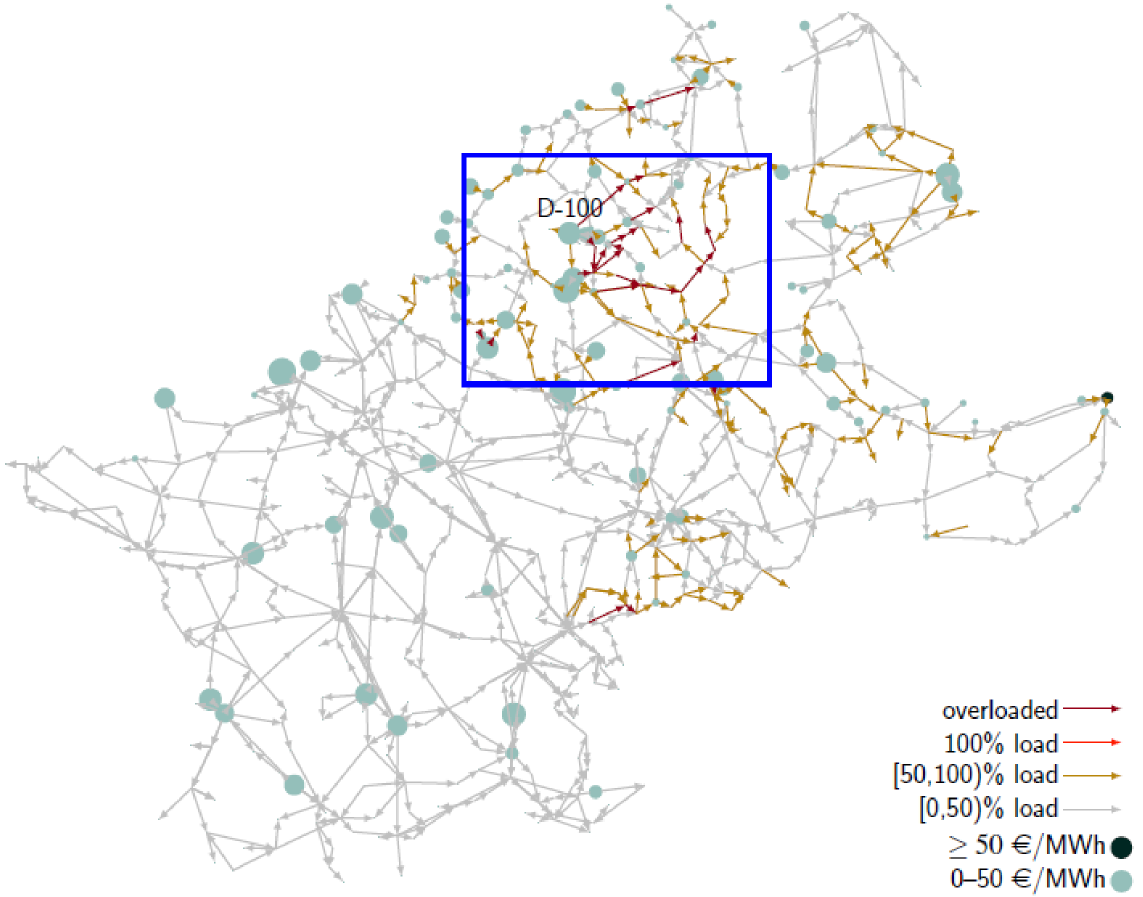
Policy Comparison

Policy	Expected cost [MM€/day]	Efficiency losses [%]	Efficiency losses [MM€/year]
MCNetPos	30.42	6.2	650
MCFree	29.45	2.8	294
Deterministic UC	28.64	-	-

- Deterministic UC – MCFree: benefits of improved day-ahead congestion management
- MCFree – MCNetPos: benefits of improved cross-zonal real-time coordination

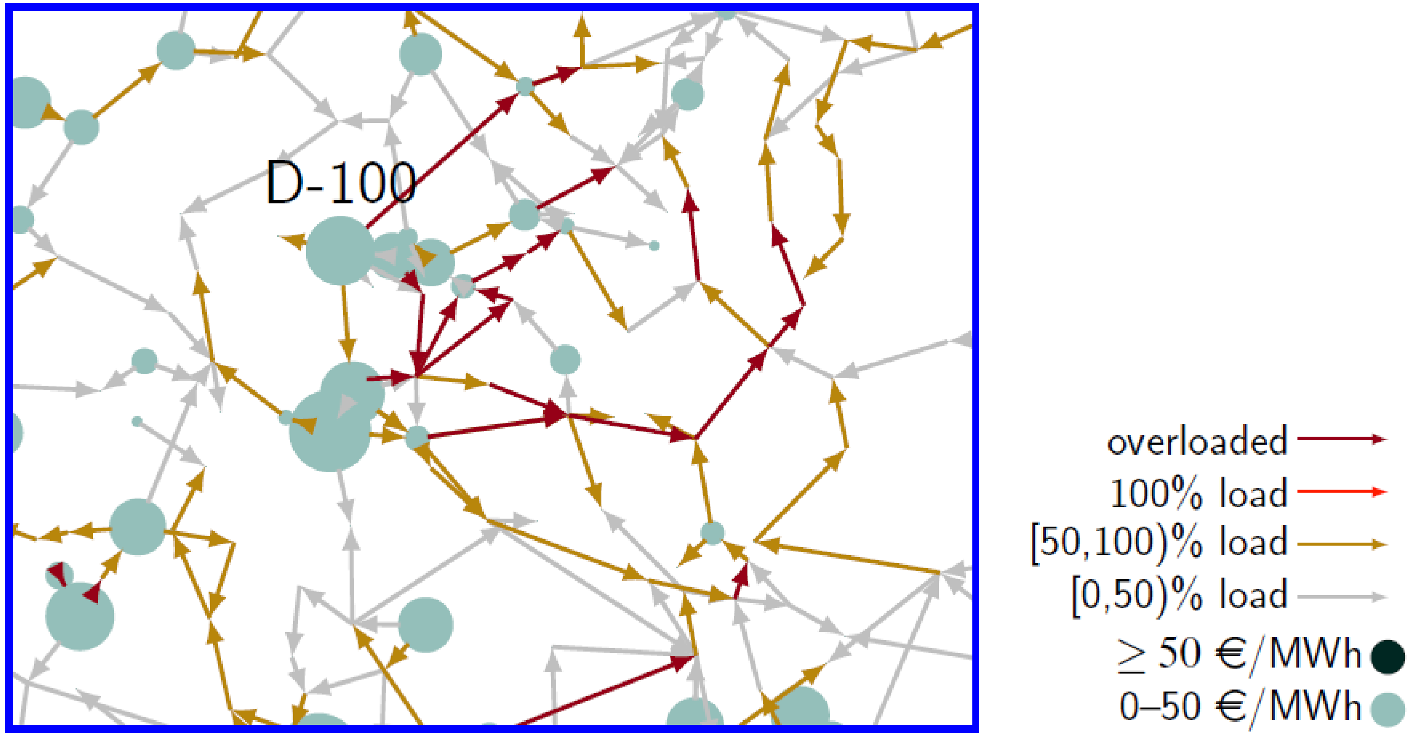
Benefits of Day-Ahead Coordination (Deterministic UC vs MCFree)

MCFree day-ahead schedule for spring weekday at 17:00-18:00



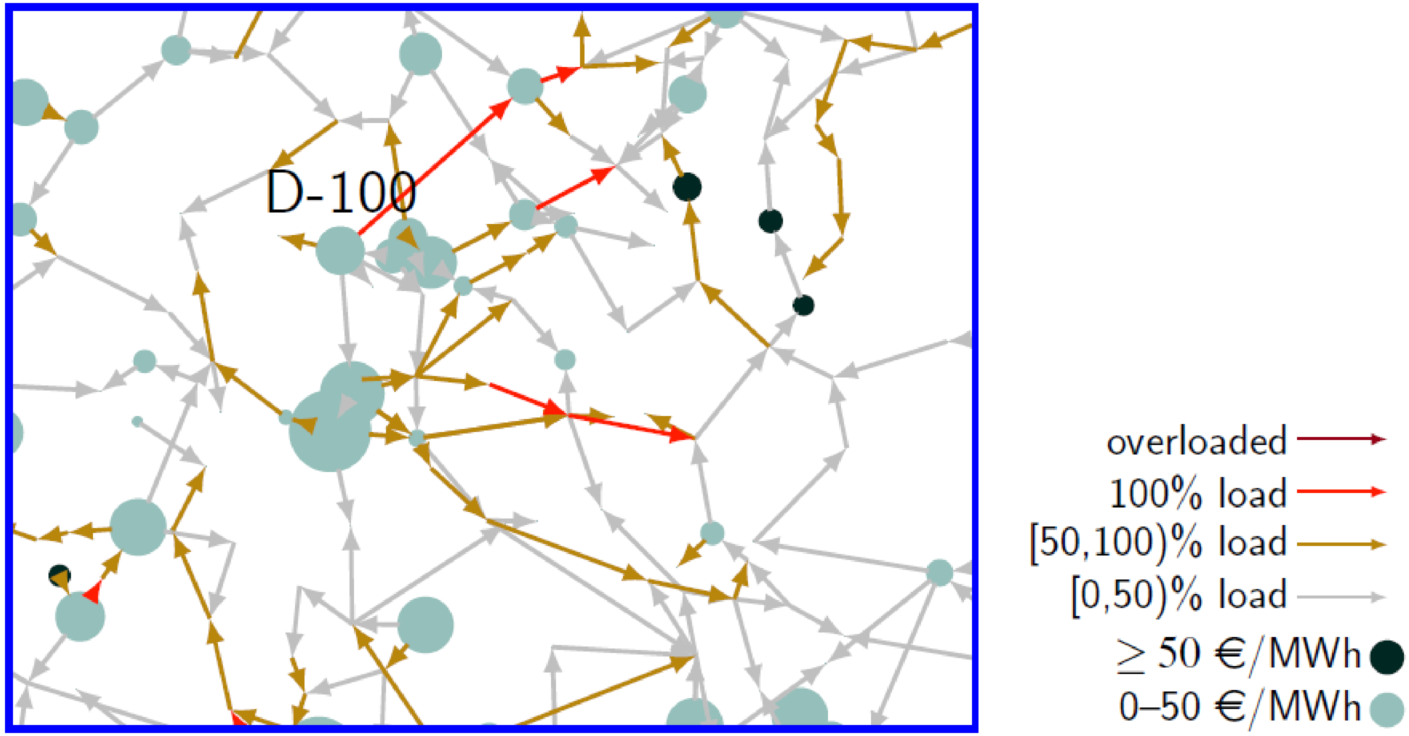
Benefits of Day-Ahead Coordination (Deterministic UC vs MCFree)

MCFree day-ahead schedule for spring weekday at 17:00-18:00

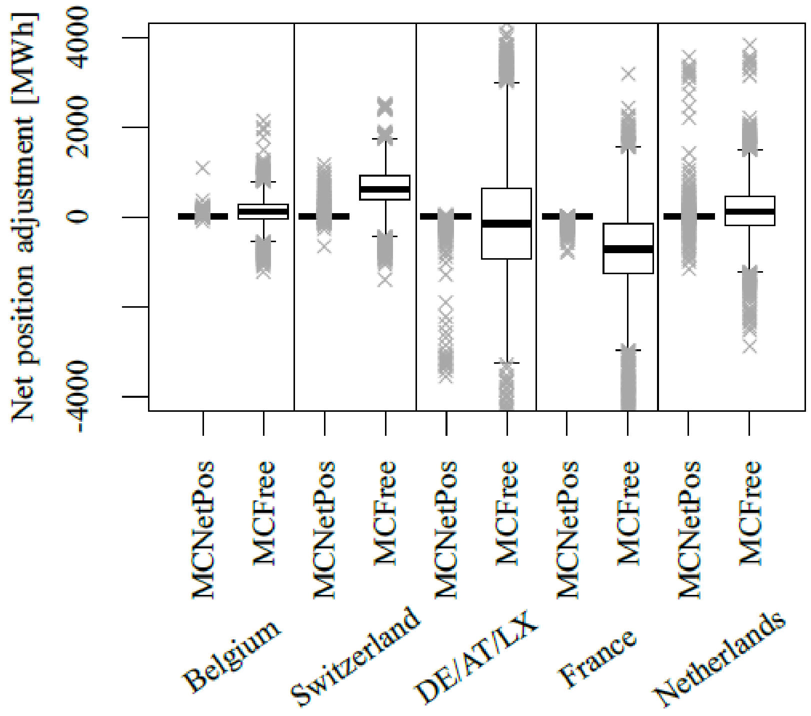


Benefits of Day-Ahead Coordination (Deterministic UC vs MCFree)

MCFree real-time operation for a sample of spring weekday at 17:30-17:45



Benefits of Real-Time Coordination (MCFree vs MCNetPos)



- Adjustment of net positions is driven by renewable forecast error for DE / AT /LX, limited by zonal net demand and day-ahead net position
- Superior performance of fully coordinated balancing (MCFree) relative to zonal balancing (MCNetPos): sharing of shortage and excess of renewable supply across zones

Appendix

$$
\begin{aligned}
(EDR): \quad & \max \sum_{l \in L} \int_0^{d_l} MB_l(x)dx - \sum_{g \in G} \int_0^{p_g} MC_g(x)dx \\
(\lambda): \quad & \sum_{l \in L} d_l - \sum_{g \in G} p_g = 0 \\
(\mu): \quad & R \leq \sum_{g \in G} r_g \\
& r_g \leq R_g \\
& p_g + r_g \leq P_g \\
& p_g, d_l, r_g \geq 0
\end{aligned}
$$

An Illustration

- Three generators
  - $P_1 = 100$ MW, $R_1 = 1$ MW/minute, $MC_1 = 10$ \$/MWh
  - $P_2 = 100$ MW, $R_2 = 5$ MW/minute, $MC_2 = 80$ \$/MWh
  - $P_3 = 100$ MW, $R_1 = \infty$, $MC_3 = 0$ \$/MWh
- Inelastic demand $D = 100$ MW
- Secondary reserve (10 minutes) $R = 100$ MW

Prices:

- Power: $\lambda^\star = 10$ \$/MWh
- Reserve: $\mu^\star = 10$ \$/MWh

An Illustration

- Three generators
  - $P_1 = 100$ MW, $R_1 = 1$ MW/minute, $MC_1 = 10$ \$/MWh
  - $P_2 = 100$ MW, $R_2 = 5$ MW/minute, $MC_2 = 80$ \$/MWh
  - $P_3 = 100$ MW, $R_1 = \infty$, $MC_3 = 0$ \$/MWh
- Inelastic demand $D = 100$ MW
- Secondary reserve (10 minutes) $R = 100$ MW

Suppose all agents believe the energy price will be $\lambda^\star$ and bid truthfully, generator g bids **opportunity cost**:

$$\max(\lambda^\star - MC_g, 0) \text{ \$/MWh}$$

An Illustration

Reserve uniform price auction:

- Generator 2 cleared for 50 MW
- Generator 1 cleared for 10 MW
- Generator 3 cleared for 40 MW

Energy uniform price auction:

- Generator 1: 90 MW at 10 $/MWh
- Generator 2: 50 MW at 80 $/MWh
- Generator 3: 60 MW at 0 $/MWh

Energy market clearing price: $\lambda^\star = 10$ $/MWh

Returning to reserve auction, we find that $\mu^\star = 10$ $/MWh