Integration of Contracted Renewable Energy and Spot Market Supply to Serve Flexible Loads

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Load Flexibility

3 fundamental approaches to deal with renewable energy variability via demand response

1. Centralized co-optimization of dispatchable supply resources and flexible loads by system operator

2. Price response:
   - Renewable producers bid in centralized real-time market
   - Consumers can communicate with system through instantaneous response to price

3. Coupling aggregated load with renewables:
   - Flexible loads communicate basic needs to renewable suppliers
   - Flexible loads follow dynamic supply signal from renewable resources, system operator faces reduced variability
Want to quantify:

- Renewable energy utilization
- Cost of unit commitment and economic dispatch
- Capital investment in generation capacity

Stochastic unit commitment an appropriate model:

- Quantifies renewable energy utilization (decision variable)
- Quantifies operating costs (objective function)
- Endogenously determines reserves (as opposed to ad hoc rules)
Two-Stage Stochastic Unit Commitment

1. In the first stage we commit slow generators:
   \[ u_{gst} = w_{gt}, \quad v_{gst} = z_{gt}, \quad g \in G_s, \quad s \in S, \quad t \in T \] (corresponds to day-ahead market)

2. Uncertainty is revealed: net demand \( D_{st} = \) firm demand + deferrable demand - wind power supply

3. Fast generator commitment and production schedules are second stage decisions: \( u_{gst}, g \in G_f \) and \( p_{gst}, g \in G_f \cup G_s \) (corresponds to real-time market)

4. Objective:
   \[
   \min \sum_{g \in G} \sum_{s \in S} \sum_{t \in T} \pi_s (K_g u_{gst} + S_g v_{gst} + C_g p_{gst})
   \]
Integrating Demand Response in Stochastic Unit Commitment

Decision support

Wind and firm load outcomes → Scenario selection

Net load representative outcomes → Centralized stochastic UC

Centralized vs Coupling

Centralized economic dispatch

Min load, startup, fuel cost, renewables utilization → Bid-based economic dispatch

Centralized economic dispatch

Flexible load outcomes → Coupling-based economic dispatch

Price outcomes → Coupling algorithm

Evaluation

Wind outcomes

Firm load outcomes

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Stochastic unit commitment with demand satisfaction

\[ \sum_{t=1}^{N} p_{gst} = R \]

Assumptions of centralized load control:
- Central co-optimization of generation and demand (computationally prohibitive)
- Perfect monitoring and control of demand

Centralized load control represents an idealization that can be used for:
- Quantifying the cost of decentralizing demand response
- Estimating the capacity savings of deferrable demand
Demand Bids

Based on retail consumer model of (Borenstein and Holland, 2005), (Joskow and Tirole, 2005), (Joskow and Tirole, 2006)

State contingent demand functions used in economic dispatch

\[ D_t(\lambda_t; \omega) = a_t(\omega) - \alpha b \lambda R - (1 - \alpha) b \lambda_t \]

Note that the demand function model has to:

- Be comparable to the deferrable demand model in terms of total demand \( R \)
- Be consistent with the observed inflexible demand in the system
Implementation of Coupling

- Match renewable power suppliers to aggregations of flexible consumers
- Consumers specify deadlines for flexible consumption tasks (EV charging, water pumping, refrigeration etc.)
- Aggregators serve deferrable loads primarily from renewable generation assets, possibly resorting to real-time market purchases
- Two types of real-time market participation constraints:
  - Quantity (fuse size)
  - Threshold price (callable forward)
Coupling

Available wind → Real-time price → RT market payments and load-shedding penalty

Decision algorithm: how much to buy from RT market → Charge rate constraint → RT market purchase constraint

State which tells us how far we are
Dynamic Programming on Recombinant Lattices

1-D process

Period t+1
Period t+2

2-D process

cross-section

Period t+2

Period t+1

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Model Summary

- 124 units (82 fast, 42 slow)
- 53665 MW power plant capacity
- 225 buses
- 375 transmission lines
- 15 scenarios
- Two studies
  - Deep wind integration (14% energy integration, 2020)
  - Moderate wind integration (7% energy integration, 2012)
Day Types

- 8 day types considered, one for each season, one for weekdays/weekends
- Day types weighted according to frequency of occurrence
Data Sources

- Wind power production:
  - California ISO interconnection queue lists locations of planned wind power installations
  - NREL Western Wind and Solar Interconnection Study archives wind speed - wind power for Western US

Calibration

1. Remove systematic effects:

\[ y^S_t = \frac{y_t - \hat{\mu}_{mt}}{\hat{\sigma}_{mt}}. \]

2. Transform data to obtain a Gaussian distribution:

\[ y^{GS}_t = N^{-1}(\hat{F}(y^S_t)). \]

3. Estimate the autoregressive parameters \( \hat{\phi}_j \) and covariance matrix \( \hat{\Sigma} \) using Yule-Walker equations.
Data Fit

- Price ($/MWh)
  - Data
  - Lattice

- Wind (MW)
  - Data
  - Lattice
Firm Demand Uncertainty

- Second order autoregressive model
- Data: California ISO 2004 Oasis database
- Single-area model without transmission constraints
### Study Cases

<table>
<thead>
<tr>
<th></th>
<th>Zero</th>
<th>Moderate</th>
<th>Deep</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind capacity (MW)</td>
<td>0</td>
<td>6,688</td>
<td>14,143</td>
</tr>
<tr>
<td>DR capacity (MW)</td>
<td>0</td>
<td>5,000</td>
<td>10,000</td>
</tr>
<tr>
<td>Daily wind energy (MWh)</td>
<td>0</td>
<td>46,485</td>
<td>95,414</td>
</tr>
<tr>
<td>Daily DR energy (MWh)</td>
<td>0</td>
<td>40,000</td>
<td>80,000</td>
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<tr>
<td>DR/firm energy (%)</td>
<td>0</td>
<td>6.1</td>
<td>12.2</td>
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</tbody>
</table>
## Operating Costs and Lost Load

<table>
<thead>
<tr>
<th></th>
<th>Daily Cost ($)</th>
<th>Daily Load Shed (MWh)</th>
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<tbody>
<tr>
<td>No wind</td>
<td>9,012,031</td>
<td>17.301</td>
</tr>
<tr>
<td>Centralized Moderate</td>
<td>8,677,857</td>
<td>1.705</td>
</tr>
<tr>
<td>Bids Moderate</td>
<td>211,010</td>
<td>609.914</td>
</tr>
<tr>
<td>Coupled Moderate</td>
<td>265,128</td>
<td>2.217</td>
</tr>
<tr>
<td>Centralized Deep</td>
<td>8,419,322</td>
<td>10.231</td>
</tr>
<tr>
<td>Bids Deep</td>
<td>578,909</td>
<td>1221.492</td>
</tr>
<tr>
<td>Coupled Deep</td>
<td>705,497</td>
<td>112.452</td>
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</tbody>
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## Summary

<table>
<thead>
<tr>
<th></th>
<th>Capacity (MW)</th>
<th>Daily Spillage (MWh)</th>
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<tbody>
<tr>
<td>No wind</td>
<td>26,123</td>
<td>N/A</td>
</tr>
<tr>
<td>Moderate</td>
<td>26,254</td>
<td>0</td>
</tr>
<tr>
<td>Deep</td>
<td>26,789</td>
<td>2</td>
</tr>
</tbody>
</table>
Conclusions

- **Capacity requirements**: For the studied cases, increased load demand is almost fully absorbed by installed wind power capacity.

- **Cost of anarchy**: The cost of anarchy increases from 3.06% to 8.38% as the integration level increases.

- **Demand bids**: Price-responsive demand achieves better cost performance than coupling (2.43% - 6.88% cost increase relative to centralized dispatch) but violates the 1-in-10-years reliability of the system 3.4 to 6.8 times.

- **Wind spillage**: Negligible spillage of wind power.
Perspectives

- Price-responsive smart charging
- Stochastic dual dynamic programming algorithm with state-contingent real-time bids
- Transmission constraints
- Parallelization of the model in Lawrence Livermore National Laboratory high performance computing cluster
References


Thank you

Questions?

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http://www3.decf.berkeley.edu/~tonypap/publications.html