Integrating Wind Power: A potential Role for Controllable Demand

Alberto J. Lamadrid and Tim Mount

Seventh Annual Carnegie Mellon Conference on the Electricity Industry, 2011

Cornell University

Outline

1. Motivation and Outline
2. Structure of the SuperOPF
3. Sequential Run Setup
4. Parameters
   - Test Network
   - Wind Characterization
   - Cases Simulated
5. Results of the Case Study
6. Conclusions

Cornell University

Outline

Cornell University

Motivation

Adoption of renewables = change in marketplace for generators

- Wholesale customer Rate Payments

$$\text{Bill Cost} + \lambda_i \times d_i + cp_i \times q_i \tag{1}$$

- More Stochastic generation:
  Lower income from energy (lower λ_i) + Higher capacity Prices
  = More Missing Money

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2006 through September 2010 (See 2009 SOM, Figure 2-14)

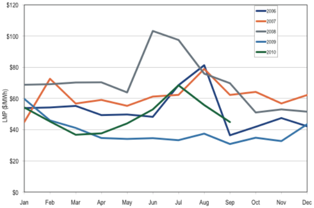
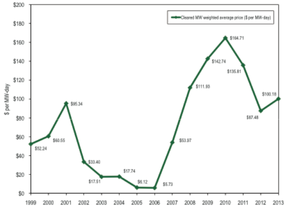


Figure 5-1 History of capacity prices: Calendar year 1999 through 2013[28] (See 2009 SOM, Figure 5-1)



Cornell University

How to compensate services that help maintain reliability?

Outline

Cornell University

Simplified Objective Function

$$\min_{G_{ik},R_{ik},\mathrm{LNS}_{jk}} \sum_{k=0}^{n_c} p_k \Bigg\{ \sum_{i=1}^{I} \Big[C_{G_i}(G_{ik}) + \mathrm{R}_i^+ (G_{ik} - G_{t-1,i0})^+ + \mathrm{R}_i^- (G_{t-1,i0} - G_{ik})^+ \Big]$$
$$+ \sum_{j=1}^{J} \mathrm{VOLL}_j \mathrm{LNS}(G_k, R_k)_{jk} \Bigg\} + \sum_{i=1}^{I} [C_{R_i}(R_i^+) + C_{R_i}(R_i^-)] \quad (2)$$

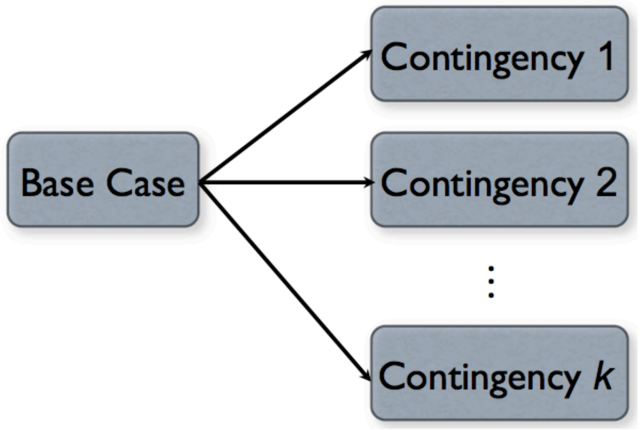
Subject to meeting Load and all of the nonlinear AC constraints of the network.

$k = 0, 1, \ldots, n_c$	Contingencies in the system
$i = 0, 1, \ldots, I$	Generators
$j = 0, 1, \ldots, J$	Loads
p_k	Probability of contingency k occurring
G_i	Quantity of apparent power generated (MVA)
$C_G(G_i)$	Cost of generating G_i MVA of apparent power
$\mathrm{R}_i^+(G_{ik} - G_{t-1,i0})^+$	Cost of increasing generation from previous hour
$\mathrm{R}_i^-(G_{i0} - G_{t-1,ik})^+$	Cost of decreasing generation from previous hour
VOLL_j	Value of Lost Load, (\$)
$\mathrm{LNS}(G, R)_{jk}$	Load Not Served (MWh)
$R_i^+ < \mathrm{Ramp}_i$	$(max(G_{ik}) - G_{i0}))^+$, up reserves quantity (MW)
$C_R(R_i^+)$	Cost of providing R_i^+ MW of upward reserves
$R_i^- < \mathrm{Ramp}_i$	$(G_{i0} - min(G_{ik})^+$, down reserves quantity (MW)
$C_R(R_i^-)$	Cost of providing R_i^- MW of downward reserves

Cornell University

Cooptmization

Co-optimization → Minimize the Expected Cost of Dispatch over Different States of the System



Outline

Ramping and reserve costs

Fuel name (t)		Generation Cap. MW (bus cap. MW)	Fuel Cost (\$/MW)	Res. Cost (\$/MW)	Ramp Cost ($\$\cdot t$/MW)
Oil	(p)	65: b1(35), b2(30)	95	10	0
GCT	(p)	45: b1(20), b2(25)	80	10	0
CC Gas	(s)	40: b22(20), b27(20)	55	20	30
NHR	(s)	65: b20(30), b27 (35)	5	20	30
Coal	(b)	70: b13(35), b23(35)	25	30	60
NHR	(b)	50: b13(20), b23(30)	5	30	60

Setup ramping costs

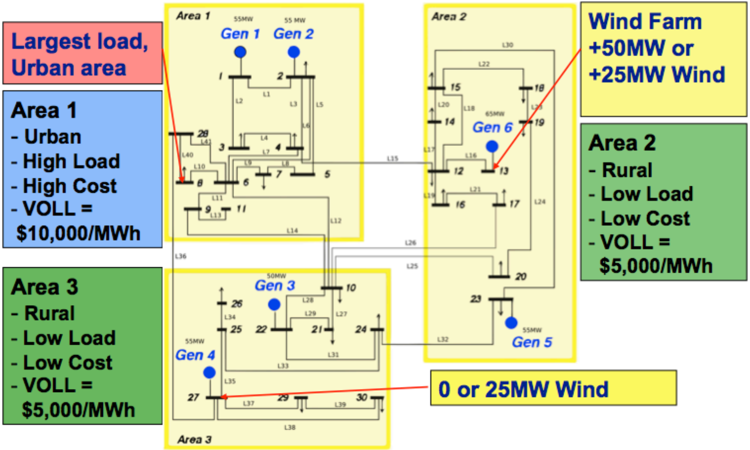
For every hour, a two-stage optimization problem was solved.

- First stage (hour-ahead), the dispatches for the next time period ($t+1$) were determined
- Second stage (real-time), wind realization is known $\rightarrow$ dispatches for the present time period ($t+1$) were determined with reserves from results of first stage.
- Outputs of each hour were interlinked $\Rightarrow$ set second-stage dispatches for hour t as initial conditions for the dispatch in hour $t+1$.
- Any deviations above or below previous hour dispatch priced according to the ability of generators to move from their current operating point.

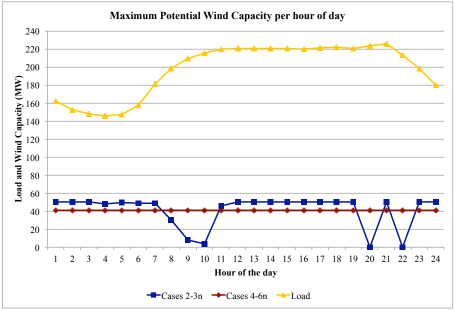
Outline

Cornell University

30 Bus test network



Specifications for a Windy Day



1. Representative demand shown
2. Wind covers around 35% of demand
3. Three wind cuts occur.

Research Questions

- How Much potential wind is dispatched?
- How much capacity is needed for reliability?

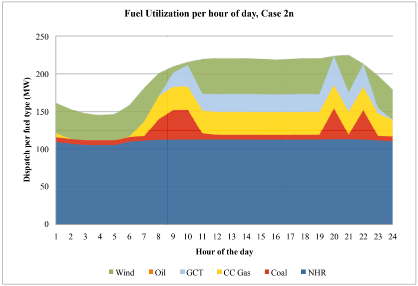
Cases studied

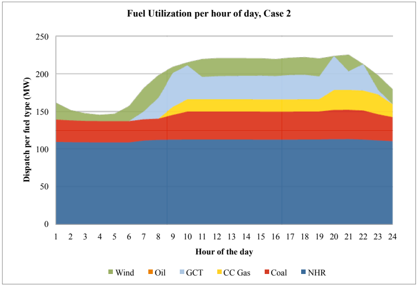
1. Case 1: NO Wind.
2. Case 1n: NO Wind + No Ramping Cost
3. Case 2: Wind.
4. Case 2n: Wind + No Ramping Cost.
5. Case 3: Wind + No Congestion.
6. Case 3n: Wind + No Congestion + No Ramping Cost.
7. Case 4: Constant Potential Wind.
8. Case 5: Wind geographically distributed, Negatively Correlated.
9. Case 6: Wind geographically distributed, Constant Potential.
10. Case 7: Baseline Distributed wind.
11. Case 8: Distributed Wind, Load Response in daily profile.
12. Case 9: Distributed Wind, load response as flat load.

Cornell University

Outline

Effects of Adding Ramping Costs





- No ramping costs **Wind Variability mitigated by Coal**, *MORE* wind dispatched
- Ramping costs **Wind Variability mitigated by GCT**, *LESS* wind dispatched

Cornell University

Effects of Adding Ramping Costs

Typical day with 0MW/50MW of Wind Capacity

50MW Wind Capacity	Case 1 No Ramping Costs	Case 1 With Ramping Costs	Percentage Change
Operating Costs: $1000/day	109	118	8.26
Conventional Capacity Committed: MW	224	224	0

Adding Wind:

50MW Wind Capacity	Case 2n No Ramping Costs	Case 2 With Ramping Costs	Percentage Change
Operating Costs: $1000/day	80	92	15
Conventional Capacity Committed: MW	273	255	-6.59
Potential Daily Wind Dispatched: %	88	43	-51.14

Effects of constant wind and geographic distribution

Typical Day with Ramping costs.

50MW Wind Capacity	Case 2 Normal Wind	Case 4 Constant Wind	Percentage Change
Operating Costs: $1000/day	92	83	-9.78
Conventional Capacity Committed: MW	255	225	-11.76
Potential Daily Wind Dispatched: %	43	74	72.09

Lower Operating costs → More wind dispatched
Less Capacity Needed → Cutouts eliminated

50MW Wind Capacity	Case 2 Normal Wind	Case 7 Two Wind Sites	Percentage Change
Operating Costs: $1000/day	92	81	-11.96
Conventional Capacity Committed: MW	255	265	3.92
Potential Daily Wind Dispatched: %	43	60	39.53

No Congestion and geographic offsets

50MW Wind Capacity	Case 7 Two Wind Sites	Case 5 Offset Wind Sites	Percentage Change
Operating Costs: $1000/day	81	79	-2.47
Conventional Capacity Committed: MW	265	230	-13.21
Potential Daily Wind Dispatched: %	60	79	31.67

Lower Operating costs → Slightly lower than constant wind.
Less Capacity Needed → Cutouts are present.

50MW Wind Capacity	Case 7 Two Wind Sites	Case 3 No Congestion	Percentage Change
Operating Costs: $1000/day	81	58	-28.4
Conventional Capacity Committed: MW	265	271	2.26
Potential Daily Wind Dispatched: %	60	62	3.33

Cornell University

Demand Response and Flat Demand

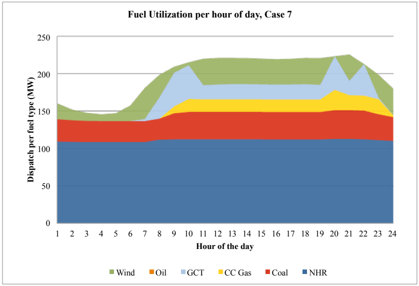
50MW Wind Capacity	Case 7 Two Wind Sites	Case 8 Two Sites + DR	Percentage Change
Operating Costs: $1000/day	81	77	-4.94
Conventional Capacity Committed: MW	265	242	-8.7
Potential Daily Wind Dispatched: %	60	65	8.33

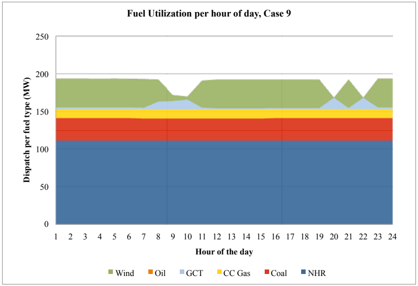
Lower Operating costs → Substantial gains
Less Capacity Needed → Cutouts mitigated and peak load reduced

50MW Wind Capacity	Case 7 Two Wind Sites	Case 9 Two + Flat +DR	Percentage Change
Operating Costs: $1000/day	81	55	-32.1
Conventional Capacity Committed: MW	265	206	-22.26
Potential Daily Wind Dispatched: %	60	77	28.33

Cornell University

Effects of flat demand + Demand Response





- **Lower Operating Costs/ More Wind Dispatched** → Substantial gains
- **Much lower capacity Needed** → Cutouts Mitigated and peak load reduced.

Cornell University

No Congestion vs. Flat Demand

	Case 1 *No Wind*	Case 2 *Normal W.*	Case 3 *Transm. W.*	Case 4 *ESS + Wind*	Case 9 *Load Resp. W.*
Conv. Capacity Committed *MW*	224	255	271	225	206
Wind Dispatched *% of Available Wind*	0	43	62	74	77
Operating Costs *$/MWh*	23	19	12	17	12
Capital Cost *$/MWh*	38	46	52	53	45
Total Operating+Capital Cost *$/MWh*	61	65	64	70	57

Similar Operating costs → Merit order dispatch, mitigated variability Much less Capacity Needed → Cutouts mitigated and peak load reduced

50MW Wind Capacity	Case 3 No Congestion	Case 9 Two + Flat +DR	Percentage Change
Operating Costs: $1000/day	58	55	-5.17
Conventional Capacity Committed: MW	271	206	-23.99
Potential Daily Wind Dispatched: %	62	77	24.19

Cornell University

Outline

Conclusions

- Ramping costs and the high probability of cutouts results in less wind dispatched.
- Eliminating network congestion does not eliminate the adverse effects of wind variability (more wind dispatched but the same capacity needed).
- The main benefit of using controllable demand to mitigate wind variability is to reduce the capacity needed.
- Using controllable demand (electric vehicles and thermal storage) to flatten the daily pattern of demand and mitigate wind variability is the big winner. More wind is dispatched and less capacity is needed.