Electricity Market Solutions for Generator Revenue Sufficiency with Increased Variable Generation

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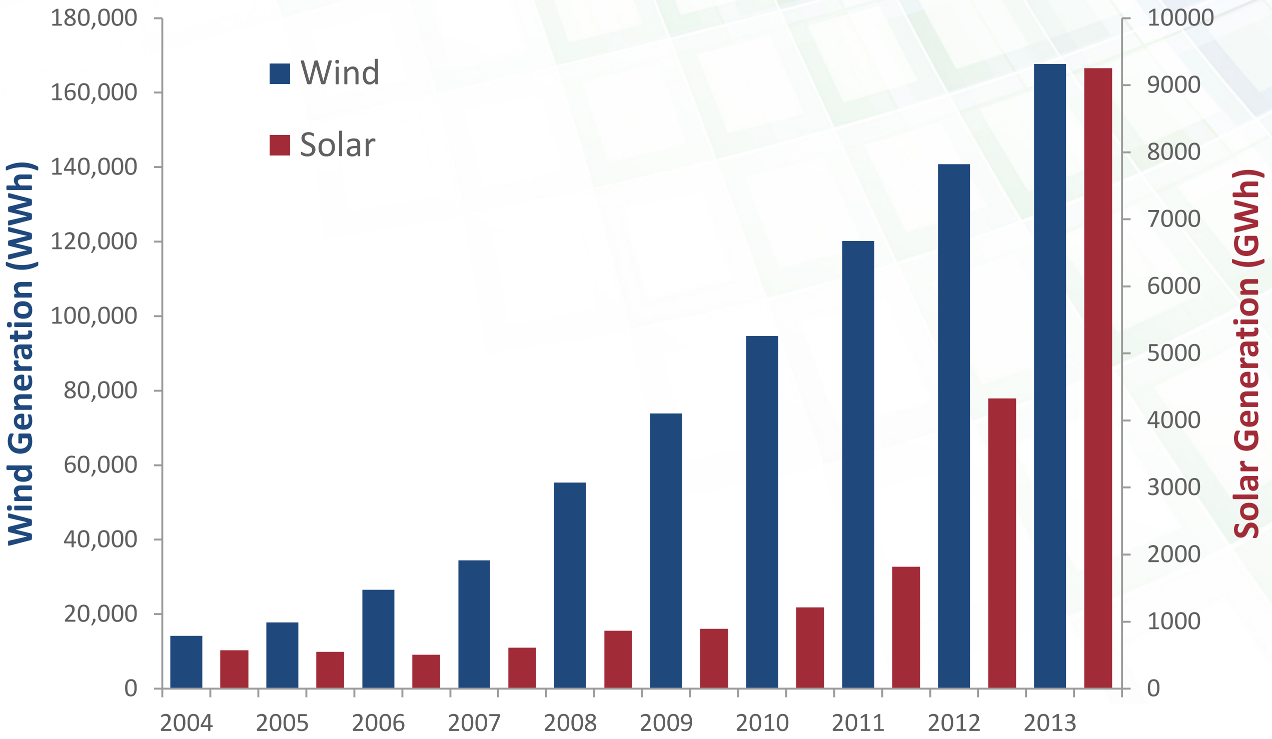
Motivation

- There is *a rapid shift towards more renewable resources* in the U.S. power grid
  - State and federal incentives
    - 38 states with RPS or RPG
  - U.S. wind capacity: 65 GW
  - U.S. solar capacity: 20 GW



Source: EIA Electric Power Monthly Table 6.2B

Characteristics of Renewables

1. Variability and uncertainty

- Increased reserve requirements

⇨ More flexible capacity needed

2. Zero marginal cost of generation

- Reduction in LMPs/wholesale electricity prices

⇨ Generators lose revenue

Research Questions

1. How will wind power affect **prices of energy and reserves**?

2. What are implications for **revenue sufficiency**?

3. Are new market designs needed to ensure **resource adequacy**?

Approach

- Model three different market polices to value reserves, energy and capacity
  1) Operating Reserves Demand Curve
  - ERCOT

  2) Fixed Reserves Scarcity Pricing
  - Used in most U.S. markets
  - We assume:
    - $100/MW-h spin-up
    - $500/MW-h total reserve

  3) Capacity Payments
  - $40/kW-year
  - No reserve scarcity pricing

Approach

- **Case study application to "ERCOT" system**
  - 4 thermal unit types (Nuclear, Coal, NGCC, NGCT)
  - 2013 ERCOT wind and load profile
  - 2024 total load projection (15% growth)
  - Wind varies from 10% to 40% of total demand
- **Cost Minimizing MIP**
  - Unit expansion
  - Commitment
  - Generation/Reserves
  - Integer unit representation
  - 8760 hourly periods
- **Sensitivities**
  - No PTC
  - No Wind Reserves
  - High Natural Gas Prices

Parameter	Value
Peak Load (MW)	77,471
Existing Generation Capacity (MW)	73,380
Nuclear	4,400
Coal	19,500
NGCC	43,600
NGCT	5,880
Maximum Wind Resource Capacity Factor	33.0%

Parameter	Nuclear	Coal	NGCC	NGCT	Wind
Capacity (MW)	2,200	1,300	400	210	-
Max. Output (MW)	2,046	1,214	378	202	-
Min. Output (MW)	2,046	520	160	84	-
Overnight Cost ($/kW)	5,501	2,925	1,021	673	1,630
Fixed OM ($/kW)	93.28	31.18	15.37	7.04	39.55
Annualized Fixed and Investment Cost ($/MW)	373,595	297,416	78,186	51,537	164,371
Var OM ($/MWh)	2.14	4.47	3.27	10.37	-
Heat Rate (btu/kWh)	10,464	8,740	6,333	10,450	-
Fuel Cost ($/MMbtu)	0.50	2.34	4.96	9.60	-
Marginal Generation Cost ($/MWh)	7.37	23.80	30.64	55.00	-
No Load Cost ($/MW)	-	1.10	4.78	8.86	-
Max Spinning-up Reserve (% of Max. Output)	-	20%	50%	80%	-
Ramp Up Limit (% of Max. Output/hr)	-	35%	50%	100%	-
Ramp Down Limit (% of Max. Output/hr)	-	35%	50%	100%	-
Start-Up Cost ($/MW)	-	131.35	61.80	40.60	-
Shut-Down Cost ($/MW)	-	1.31	0.62	0.41	-
Forced Outage Rate	7.0%	6.6%	7.7%	7.7%	-

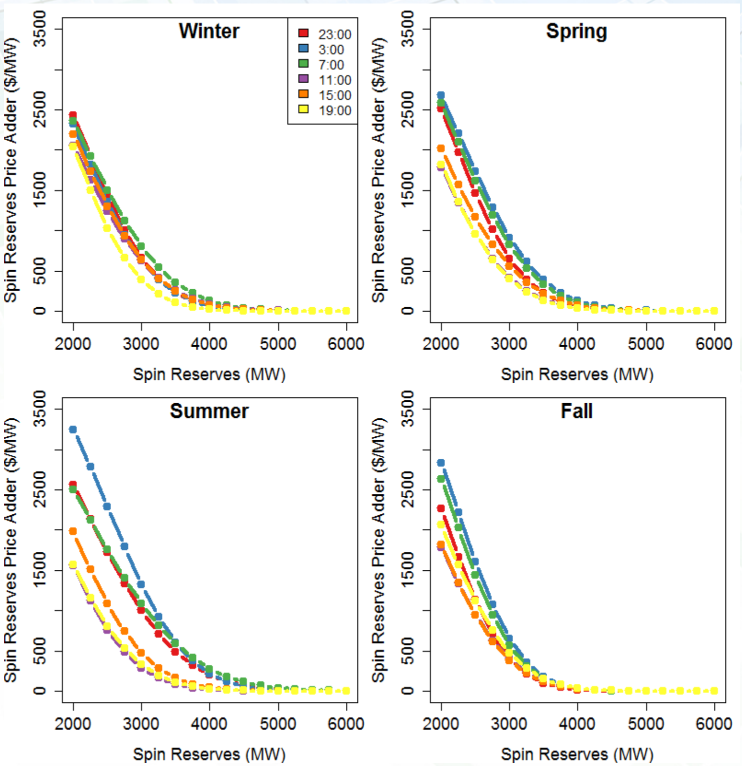
ERCOT ORDC

- ORDC derived from recent ERCOT implementation
  - 24 distinct PWL curves for month/hour pairs

Table 1 LOLP distributions by season and time-of-day block for 2011 and 2012

Season	For Hours	μ	σ
Winter (Month 12, 1, 2)	1-2 and 23-24	185.14	1217.89
	3-6	76.28	1253.93
	7-10	136.32	1434.64
	11-14	-218.26	1441.00
	15-18	-53.67	1349.52
	19-22	-183.00	1129.31
Spring (Month 3,4,5)	1-2 and 23-24	245.76	1174.61
	3-6	460.41	1313.46
	7-10	348.16	1292.36
	11-14	-491.91	1332.05
	15-18	-253.77	1382.60
	19-22	-436.09	1280.47
Summer (Month 6,7,8)	1-2 and 23-24	374.88	1503.97
	3-6	1044.81	1252.25
	7-10	339.01	1679.70
	11-14	-695.94	1251.05
	15-18	-270.54	1284.96
	19-22	-730.33	1331.49
Fall (Month 9, 10,11)	1-2 and 23-24	15.90	1044.88
	3-6	478.97	1014.02
	7-10	322.65	1036.07
	11-14	-473.16	1293.83
	15-18	-422.21	1246.49
	19-22	-177.76	1231.14

+ VOLL ⇒



$$P_{ns} = 0.5 \cdot (VOLL - \lambda) \cdot \left(1 - CDF\left(\mu_{h,m,w}, \sigma_{h,m,w}, rs + rns - X\right)\right)$$

$$P_s = P_{ns} + 0.5 \cdot max(VOLL - \lambda, 0) \cdot \left(1 - CDF\left(\frac{\mu_{h,m,w}}{2}, \frac{\sigma_{h,m,w}}{\sqrt{2}}, rs - X\right)\right)$$

Formulation

ORDC

Expansion (Integer)

Commitment (Integer)

$$\min \sum_{i\in I} u_i \cdot (C_i + F_i)\cdot \overline{P_i} + \sum_{i\in I}\sum_{t\in T} MC_i \cdot g_{i,t} + SUC_i \cdot y_{i,t} + SDC_i \cdot x_{i,t} + NLC_i \cdot z_{i,t}\cdot \overline{P_i}$$

$$+ \sum_{t\in T} VOLL \cdot es_t - PTC \cdot wg_t \boxed{- \sum_{t\in T} RBS_t[Rs_t] + RBNS_t[Rns_t]}$$

FRSP/CP

$$\min \sum_{i\in I} u_i \cdot (C_i + F_i \boxed{- CP)} \cdot \overline{P_i} + \sum_{i\in I}\sum_{t\in T} MC_i \cdot g_{i,t} + SUC_i \cdot y_{i,t} + SDC_i \cdot x_{i,t} + NLC_i \cdot z_{i,t}\cdot \overline{P_i}$$

$$+ \sum_{t\in T} ESC \cdot es_t + SRSC \cdot srs_t + NRSC \cdot nrs_t$$

$$\sum_{i\in I} rs_{i,t} + wr_t + rss_t = RRs_t \quad \forall\ t \in T$$

$$\sum_{i\in I} (rs_{i,t} + rns_{i,t}) + wr_t + rnss_t = RRs_t + RRns_t \quad \forall\ t \in T$$

Shadow Price

Reserve targets are based on ORDC results.
Spin: $15/MW-h
Non-Spin: $.01/MW-h

Energy/reserve prices in each period are set equal to the marginal cost/benefit of their provision

Formulation

Load Balance

$$\sum_{i \in I} g_{i,t} + wg_t + es_t = D_t \xrightarrow[\text{Shadow Price}]{} \text{LMP}$$

Reserves

$$rs_{i,t} \leq z_i \cdot \overline{P_i} \cdot SPR_i \qquad \forall\ i \in I, s \in S, t \in T$$

$$rns_{i,t} \leq (u_i - z_i) \cdot \overline{P_i} \cdot NSR_i \qquad \forall\ i \in I, s \in S, t \in T$$

Thermal Output

$$g_{i,t} + rs_{i,t} \leq z_{i,t} \cdot \overline{O_i} \qquad \forall\ i \in I, t \in T$$

$$g_{i,t} \geq z_{i,t} \cdot \underline{O_i} \qquad \forall\ i \in I, t \in T$$

Wind Balance

$$wg_t + wr_t + wc_t = W_t \qquad \forall\ t \in T$$

Ramping

$$g_{i,t} \leq g_{i,t-1} + z_{i,t} \cdot RU_i \qquad \forall\ i \in I, t \in T \neq 1$$

$$g_{i,t} \geq g_{i,t-1} - z_{i,t-1} \cdot RD_i \qquad \forall\ i \in I, t \in T \neq 1$$

Unit Commitment

$$z_{i,t} = z_{i,t-1} + y_{i,t} - x_{i,t} \qquad \forall\ i \in I, t \in T \neq 1$$

$$z_{i,t} \leq u_i \qquad \forall\ i \in I, t \in T$$

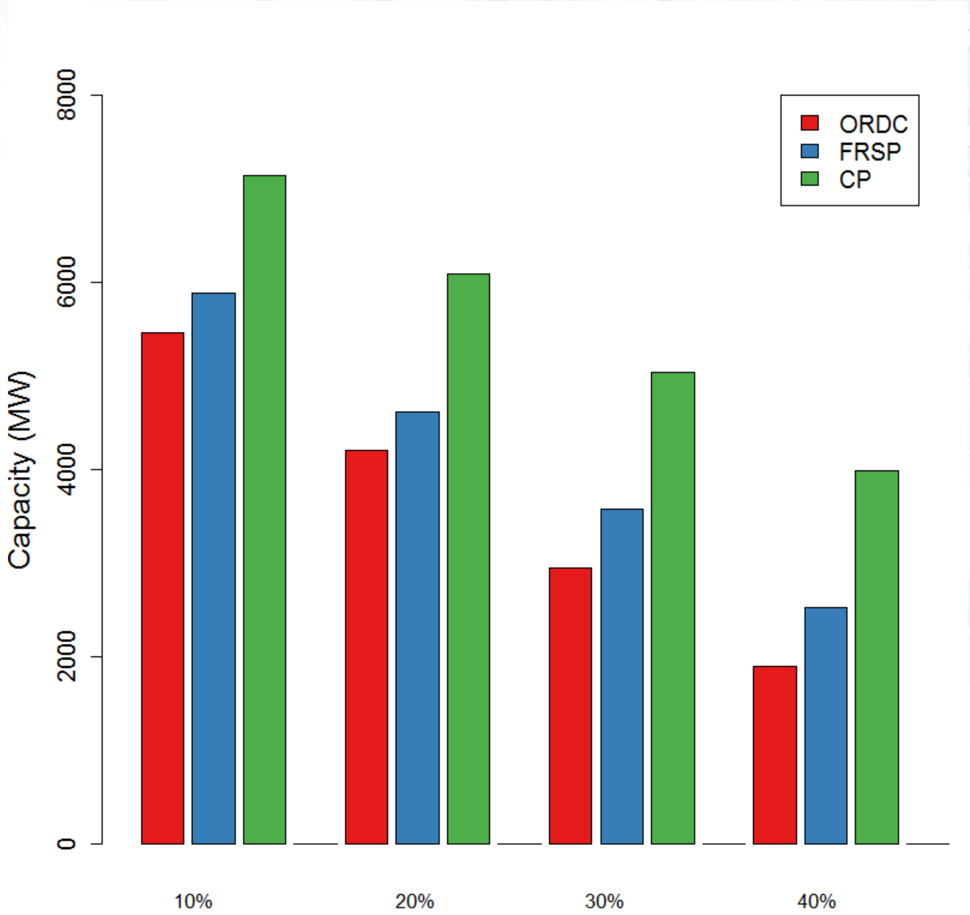
$$x_{i,t},\ y_{i,t},\ z_{i,t} \geq 0 \quad \forall\ i \in I, t \in T$$

- **Integer variables for expansion and commitment**
- **Significant reduction in computation time (up to 5000x*)**
- **Enables solving for full year of operations (8760 hourly periods)**

* B. Palmintier and M. Webster, "Impact of unit commitment constraints on generation expansion planning with renewables," in *2011 IEEE Power and Energy Society General Meeting*, 2011, pp. 1–7.

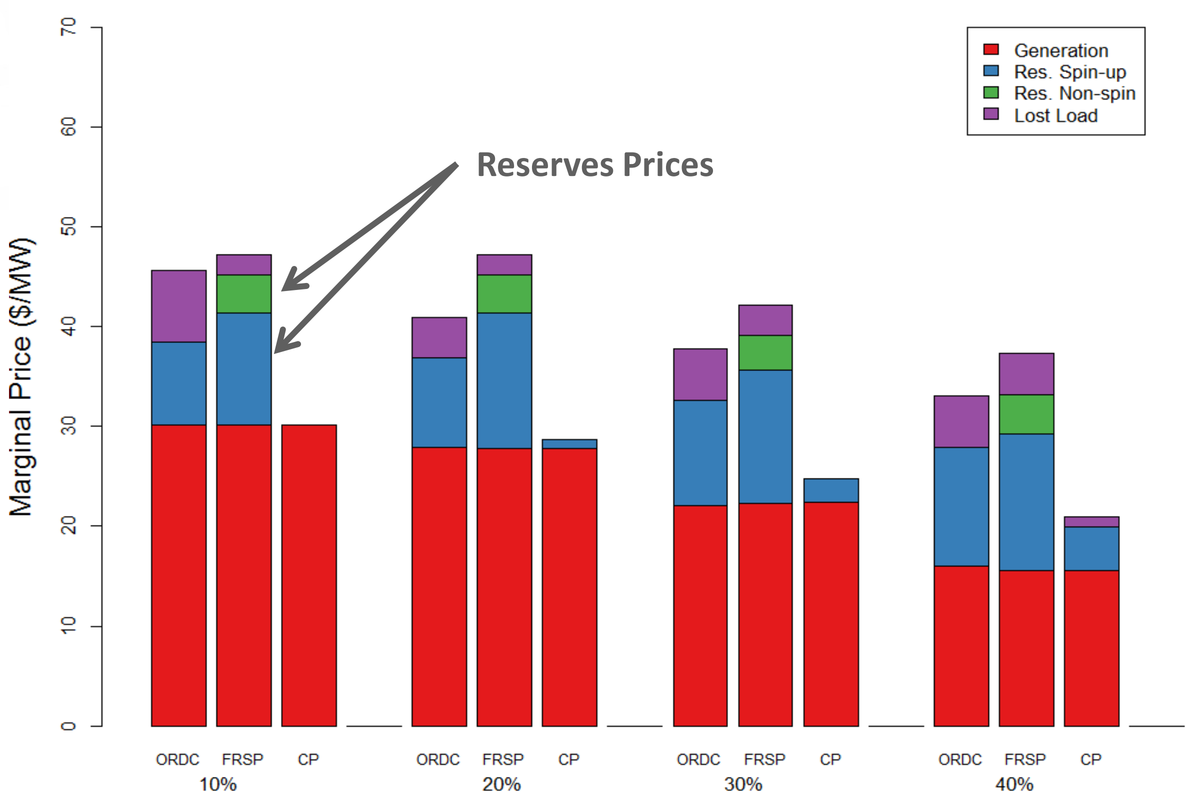
Results: Capacity Expansion

- Only new NGCT capacity is developed
  - CP results in most new capacity
  - ORDC and FRSP are comparable



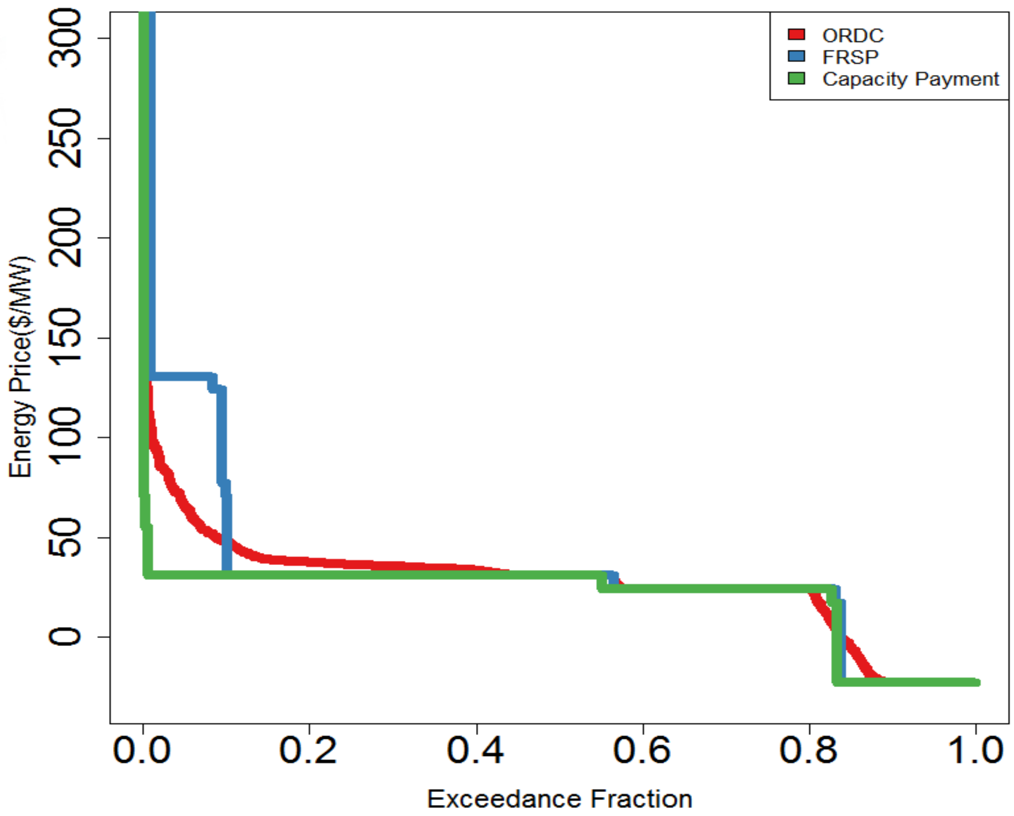
Results: Prices

- **Prices drop with increasing wind**
- **ORDC > CP**
  - CP has no reserves pricing mechanism
    - Lower prices
  - Extra capacity developed
    - Essentially no lost load
- **FRSP > ORDC**
  - Higher reserve prices
    - Scarcity price spikes
    - Mostly non-spin
  - Less frequent lost load
    - Few hours = large price impact



Results: Exceedance Curve

- For full 8760 hour year
- ORDC -> More continuous price spectrum

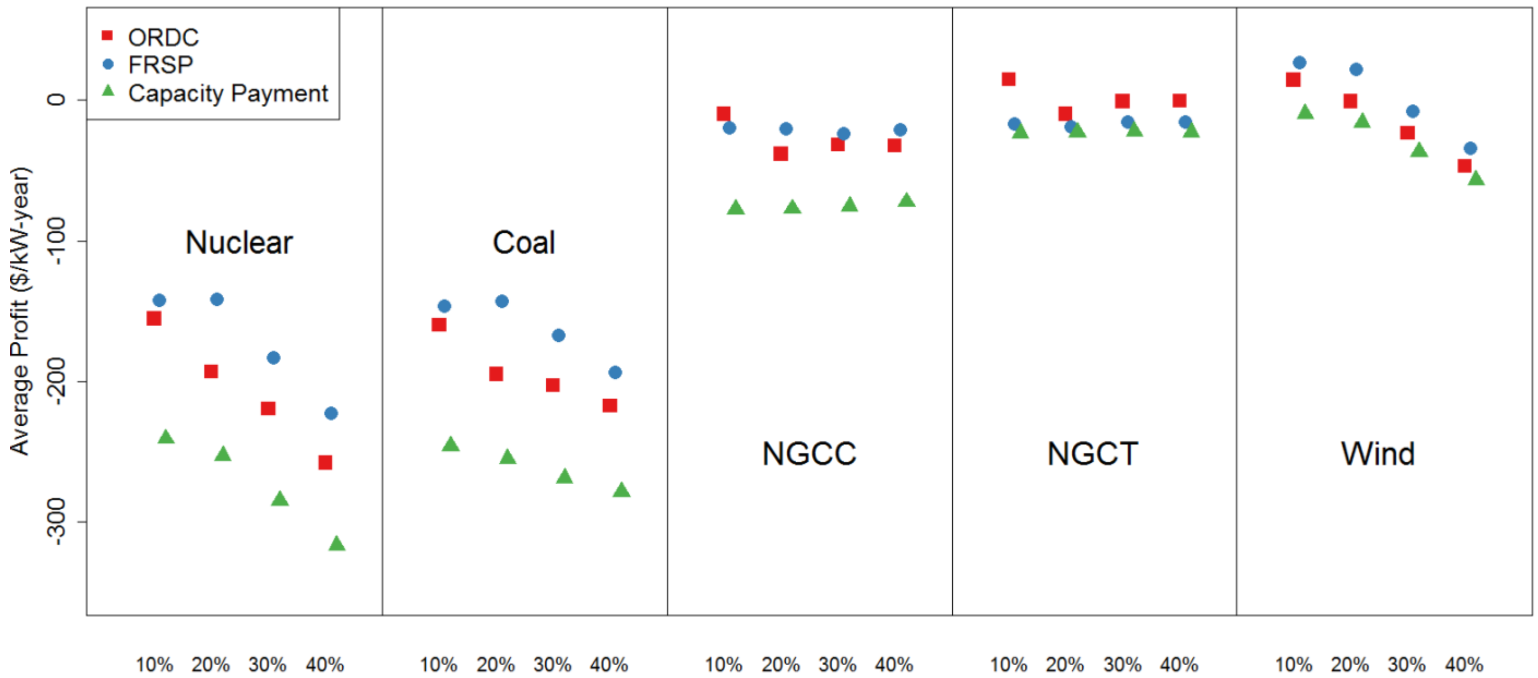


Hourly Generation and Reserves

- Summer week with 40% wind penetration
- High wind and spinning reserves at night

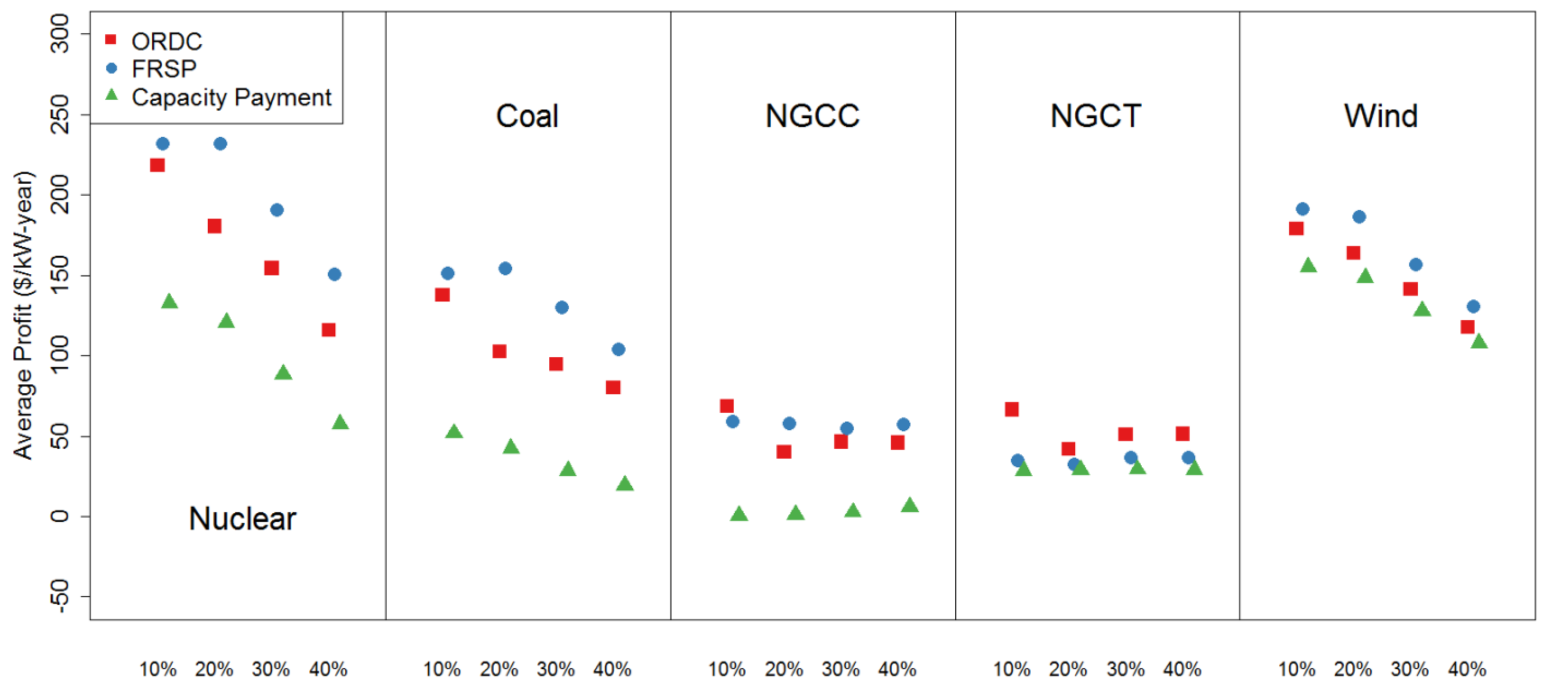
Results: Generator Profits

- Nuclear, Coal and Wind profits decrease with increasing wind
  - More exposed to lower off-peak prices
- Gas units receive additional revenues from providing reserves
- $40/kW-year capacity payments provide less revenue than ORDC/FRSP
  - Assumption that there is no reserve scarcity pricing



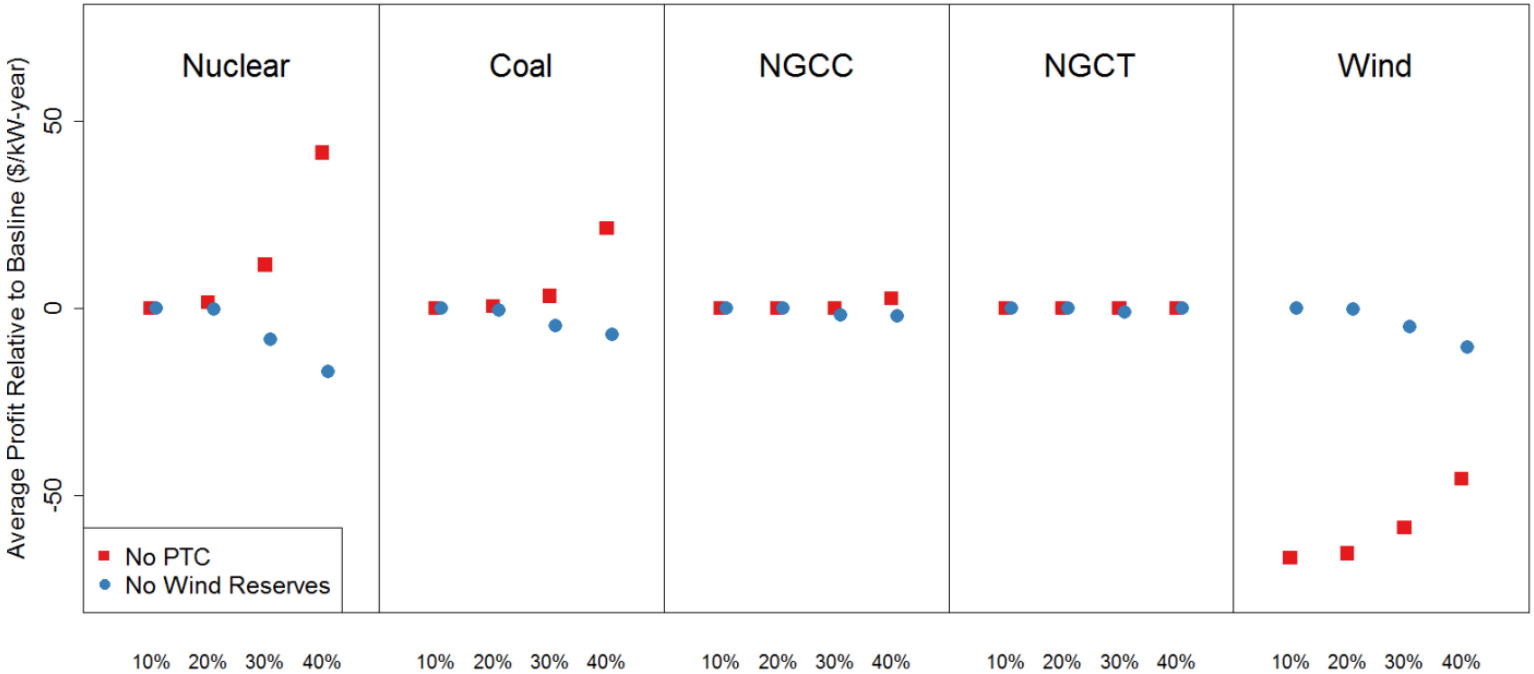
Results: Generator Profits w/o Capital Costs

- Most units are profitable without capital costs



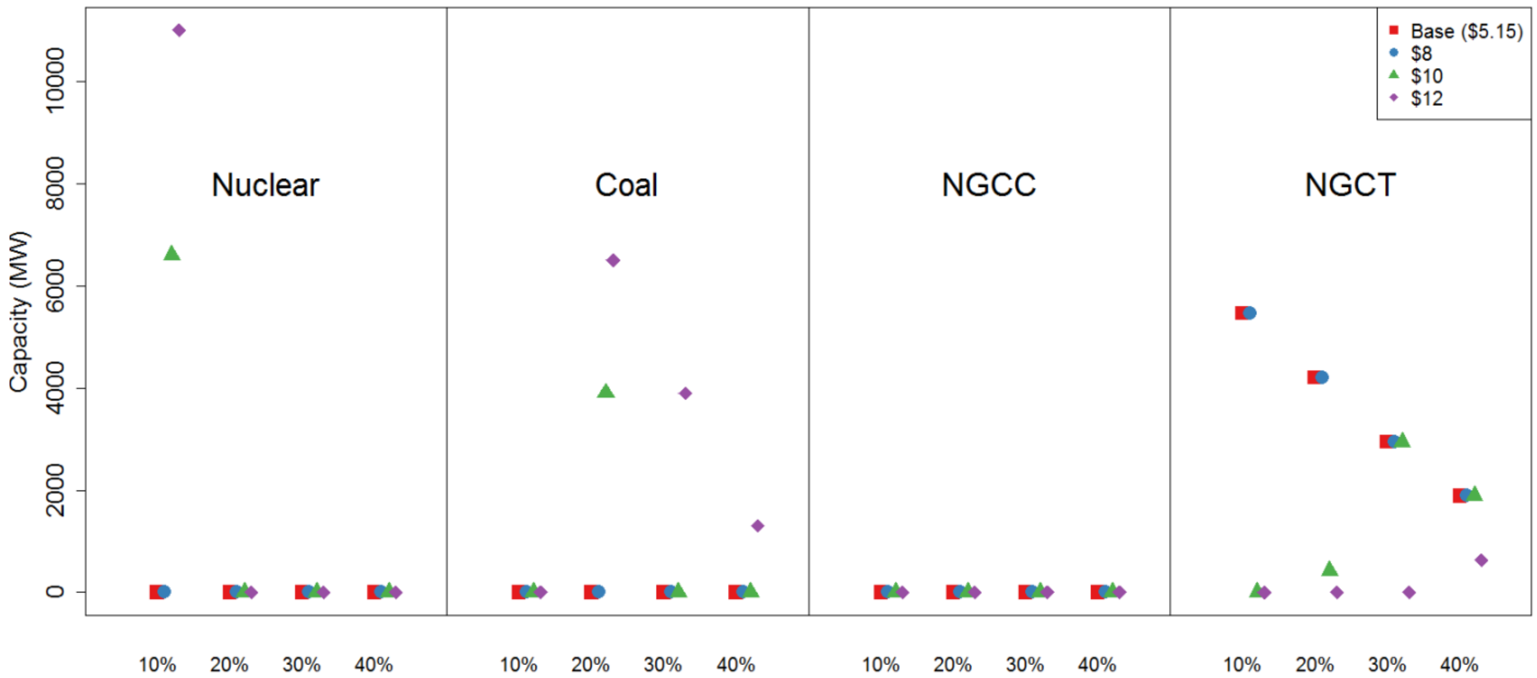
Results: Policy Sensitivity

- Eliminating the PTC
  - Raises energy prices and baseload revenues
  - Reduces wind profits
- No wind reserves
  - More gas capacity is kept for reserves
  - Baseload units provide the marginal unit more often



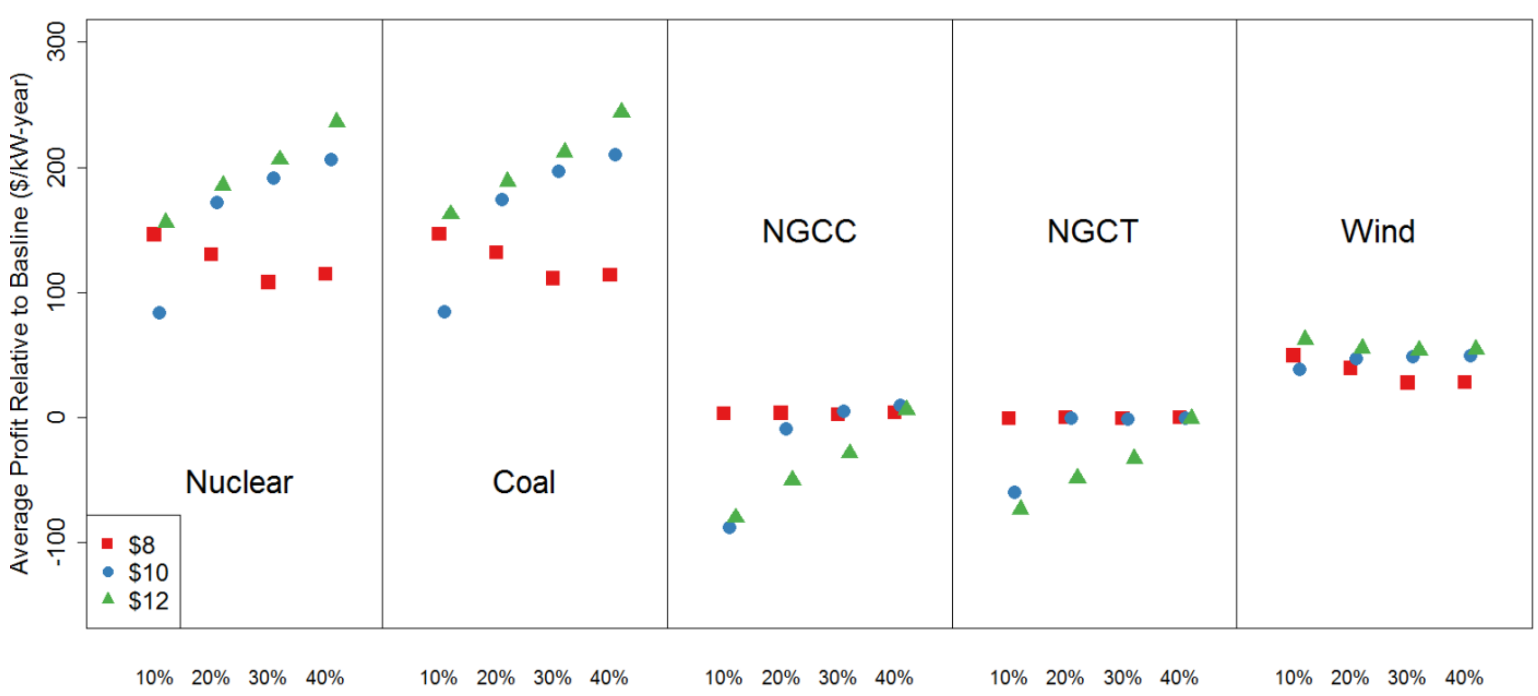
Results: NG Price Sensitivity

- $10/MMbtu – New nuclear is developed for 10% and 20% wind
- $12/MMbtu – New coal is developed up to 40% wind
- NGCC is still never developed, NGCT expansion decreases



Results: NG Price Sensitivity

- Higher NG prices increase energy prices and wind/baseload profits
- When wind penetration is high, NGCC and NGCT profits are relatively unchanged
  - Increased revenue streams from reserves products



Conclusions

- **How will wind power affect prices of energy and reserves?**
  - Energy prices decrease
  - Reserves prices increase
- **What are implications for revenue sufficiency?**
  - Revenues decrease for nuclear, coal and wind units with more wind
  - Natural gas units are less impacted
    - Increased revenues from reserves
  - ORDC and FRSP can be structured to provide similar revenues
    - ORDC has advantage of less variable prices, fewer large spikes, less risk to investors
  - $40/kW-year capacity payments
    - Less revenue but more capacity
  - Low natural gas prices contribute to baseload revenue sufficiency issues
- **Are new market designs needed to ensure resource adequacy?**
  - Our analysis ensures resource adequacy through system cost-minimization
  - Without long term revenue sufficiency, there likely will not be resource adequacy
  - Alternative solutions
    - Hybrid CP/ORDC model

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