Wind Energy and Electricity Markets

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June 9, 2009

Abstract

- Many jurisdictions are greatly increasing the amount of wind production, with the expectation that increasing renewables will reduce greenhouse emissions.
- Discuss the interaction of increasing wind, transmission constraints, production tax credits, wind and demand correlation, intermittency, and electricity market prices using the particular example of the ERCOT market.

Outline.

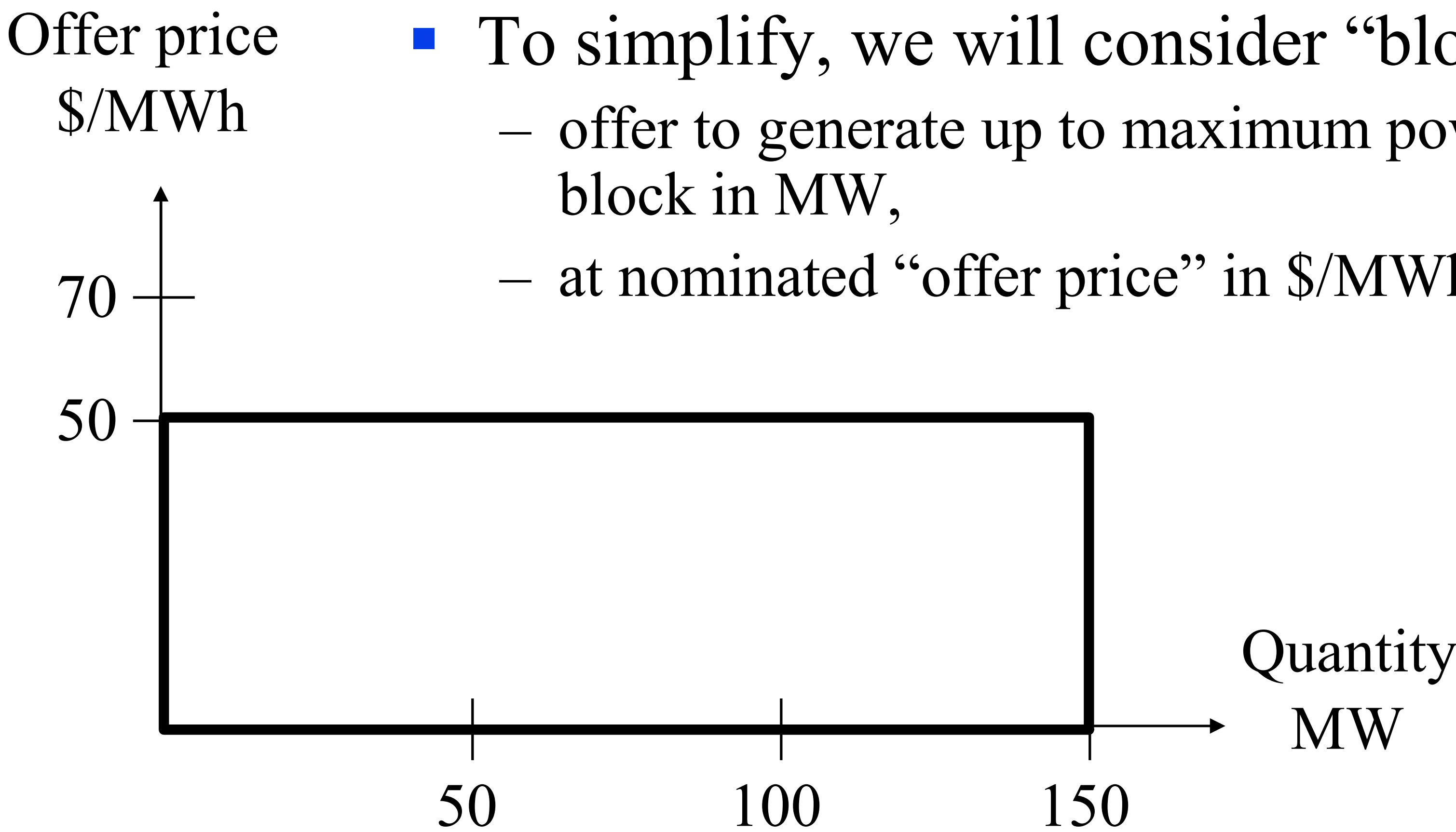
- Offer-based economic dispatch.
- Real-time market and examples.
- Transmission limitations.
- Production tax credits and renewable energy credits.
- Transmission price risk.
- Wind and demand correlation.
- Intermittency.
- Putting the cost estimates together.

Offer-based economic dispatch.

- Generators offer to sell:
  - energy,
  - reserves and other Ancillary Services (AS),
- The ISO selects the offers to meet demand:
  - "day-ahead," for tomorrow, based on anticipation,
  - "real-time," to cope with actual conditions.
- Focus on real-time energy market since:
  - will illustrate the main issues,
  - ERCOT does not currently have a day-ahead market,
  - wind generators are unlikely to offer reserves and may not participate in the day-ahead market.

Offer-based economic dispatch.

- An offer by a generator is a specification of price versus quantity:
  - Applies for a particular hour or range of hours.
- To simplify, we will consider “block” offers:
  - offer to generate up to maximum power in the block in MW,
  - at nominated “offer price” in $/MWh.



Real-time market.

- ISO selects the offers to meet its short-term forecast of demand based on offer prices:
  - Use offer with lower offer price in preference to higher offer price.
- Examples are "organized markets" of Northeast US (PJM, ISO-NE, NYISO), Midwest, California, Southwest Power Pool (SPP), and Texas (ERCOT):
  - ERCOT market called the "balancing market."

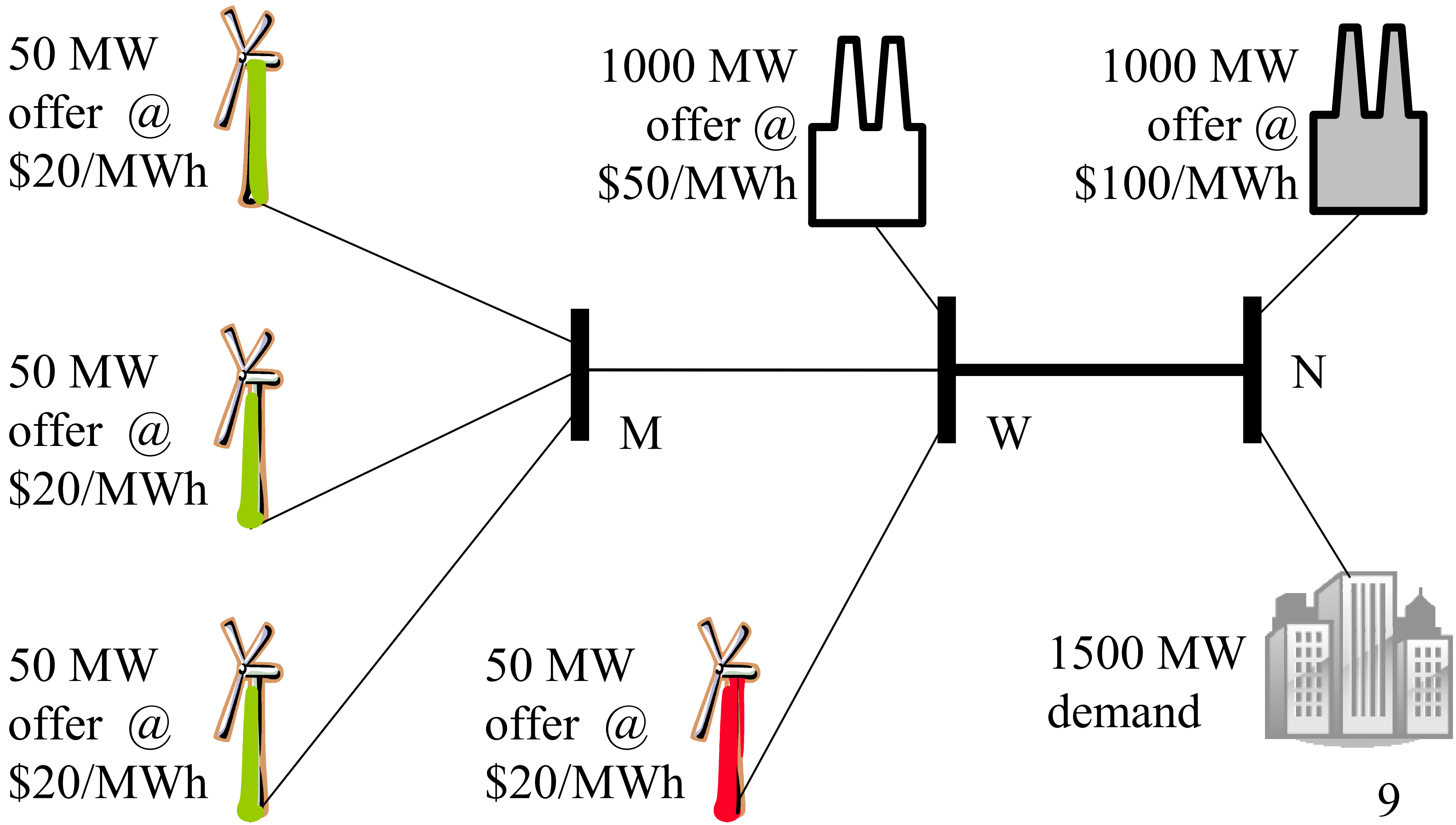
Real-time market.

- How is the price set?
- Roughly speaking, highest *accepted* offer price or, equivalently, the offer price that would serve an additional MW of demand, sets the price for all energy sold:
  - Need more careful definition if insufficient offers to meet demand,
  - Need more careful specification if at a jump in prices between blocks,
  - As we will see, will need to modify in the case of limiting transmission constraints (“congestion”).

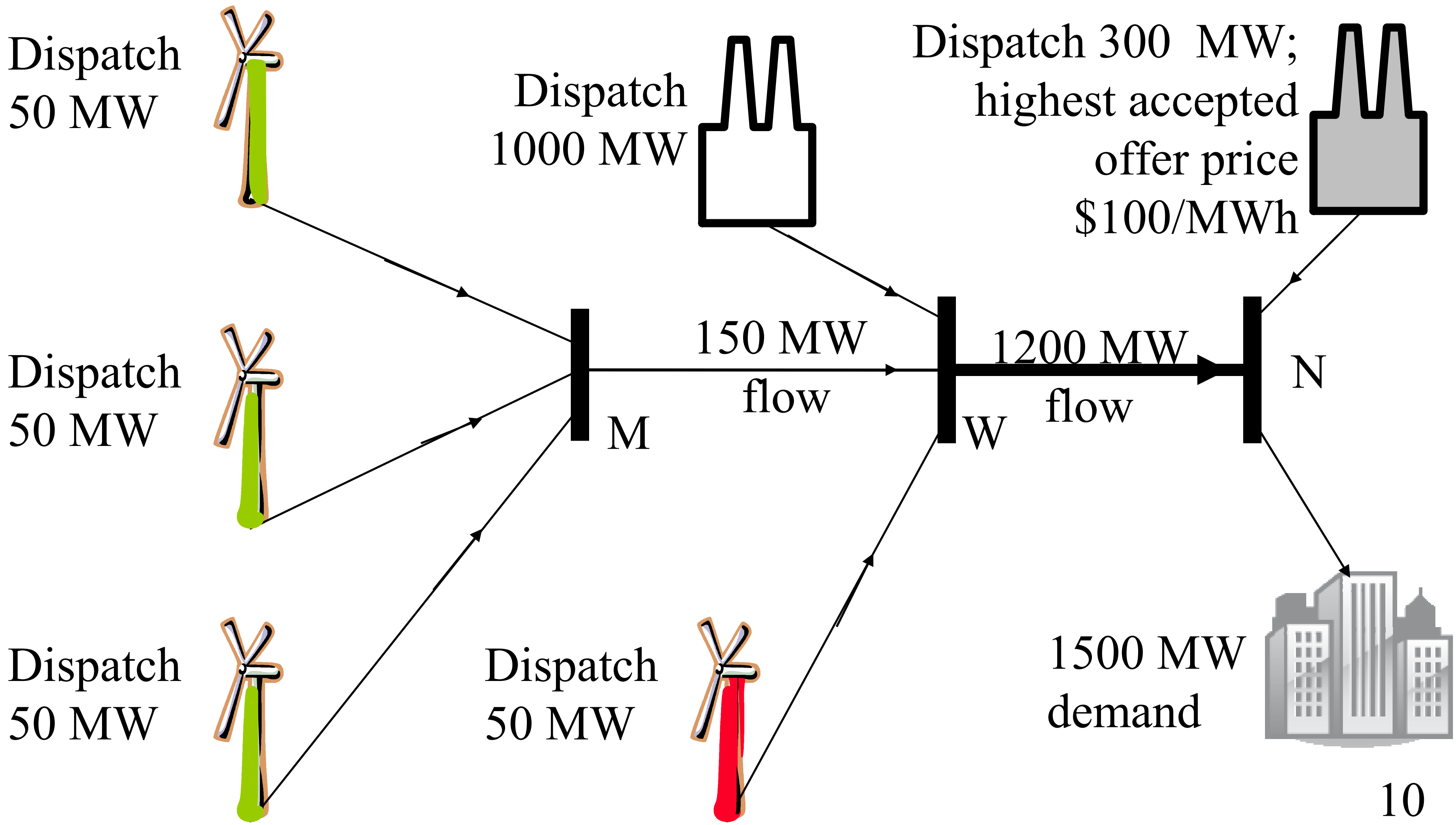
Examples of real-time market with wind resources.

- We will consider a very simple system.
- Transmission will be just two lines joining three "buses," M, W, and N:
  - Simplifies situation compared to reality, but useful as a start,
- Wind (at M and W) and thermal (at W and N) offer into the real-time market to meet demand (at N).
- Start with unlimited transmission (Example 1) & then consider limited transmission (Example 2).

Example 1: unlimited transmission, 1500 MW demand at N, block offers.



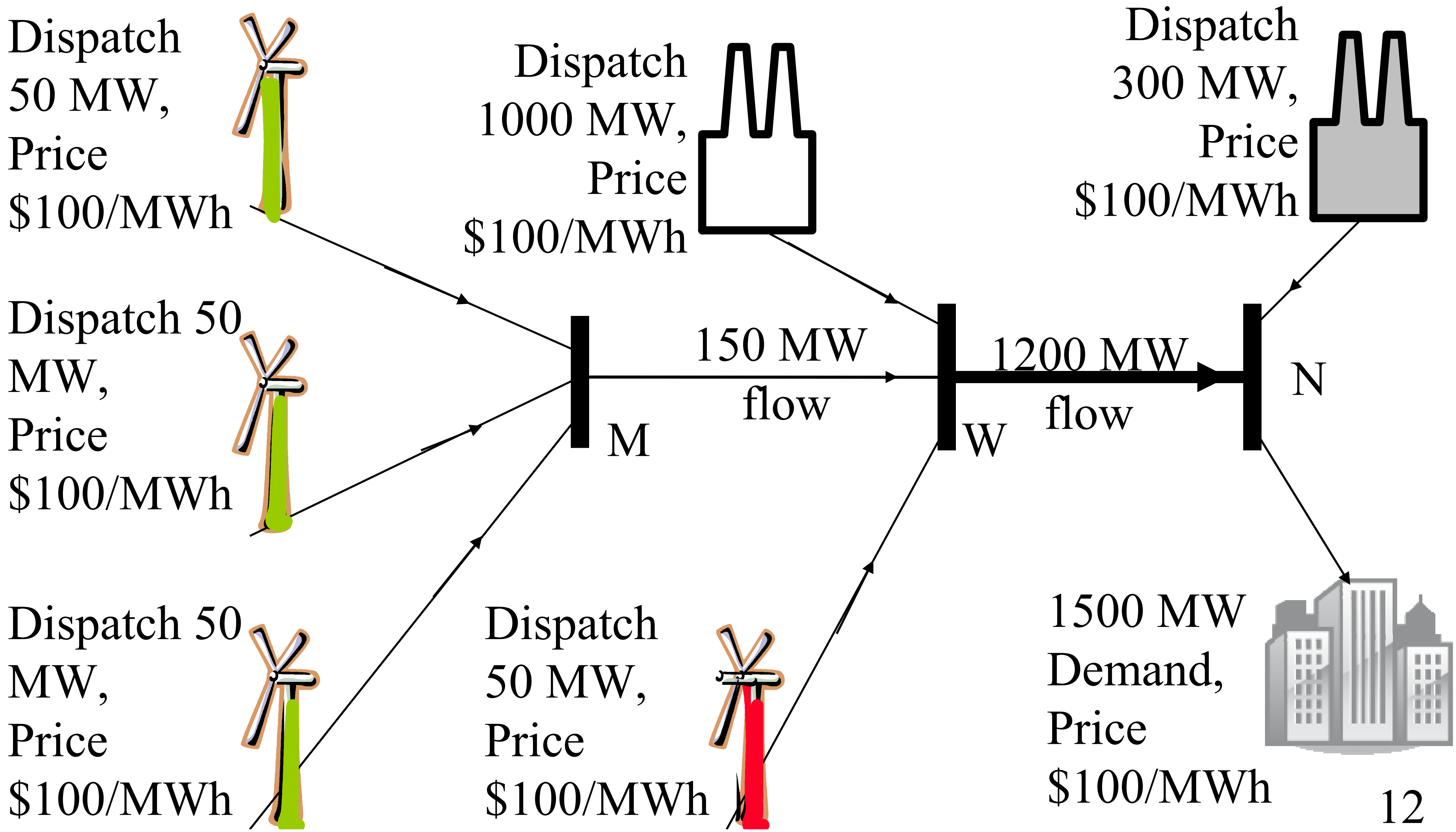
Dispatch for 1500 MW demand, unlimited transmission capacity.



Prices for 1500 MW demand, unlimited transmission capacity.

- Highest accepted offer price was \$100/MWh from "gray" thermal generator at bus N:
  - To serve an additional MW of demand at any bus would use an additional MW of "gray" generation.
- "Green" and "red" wind and "white" thermal generator all fully dispatched.
- Price paid to all generators and paid by demand is \$100/MWh.

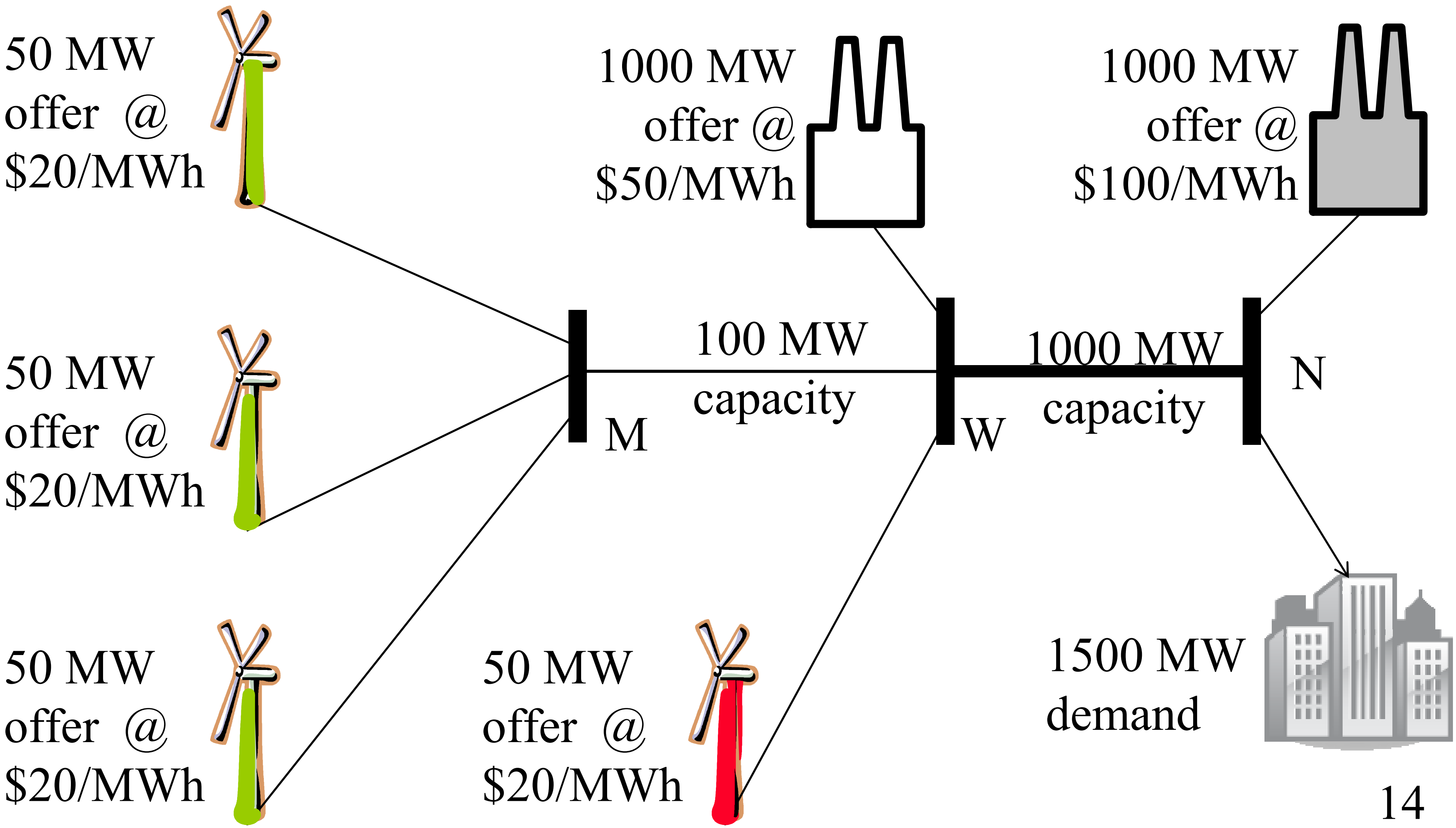
Dispatch and prices for 1500 MW demand, unlimited transmission capacity.



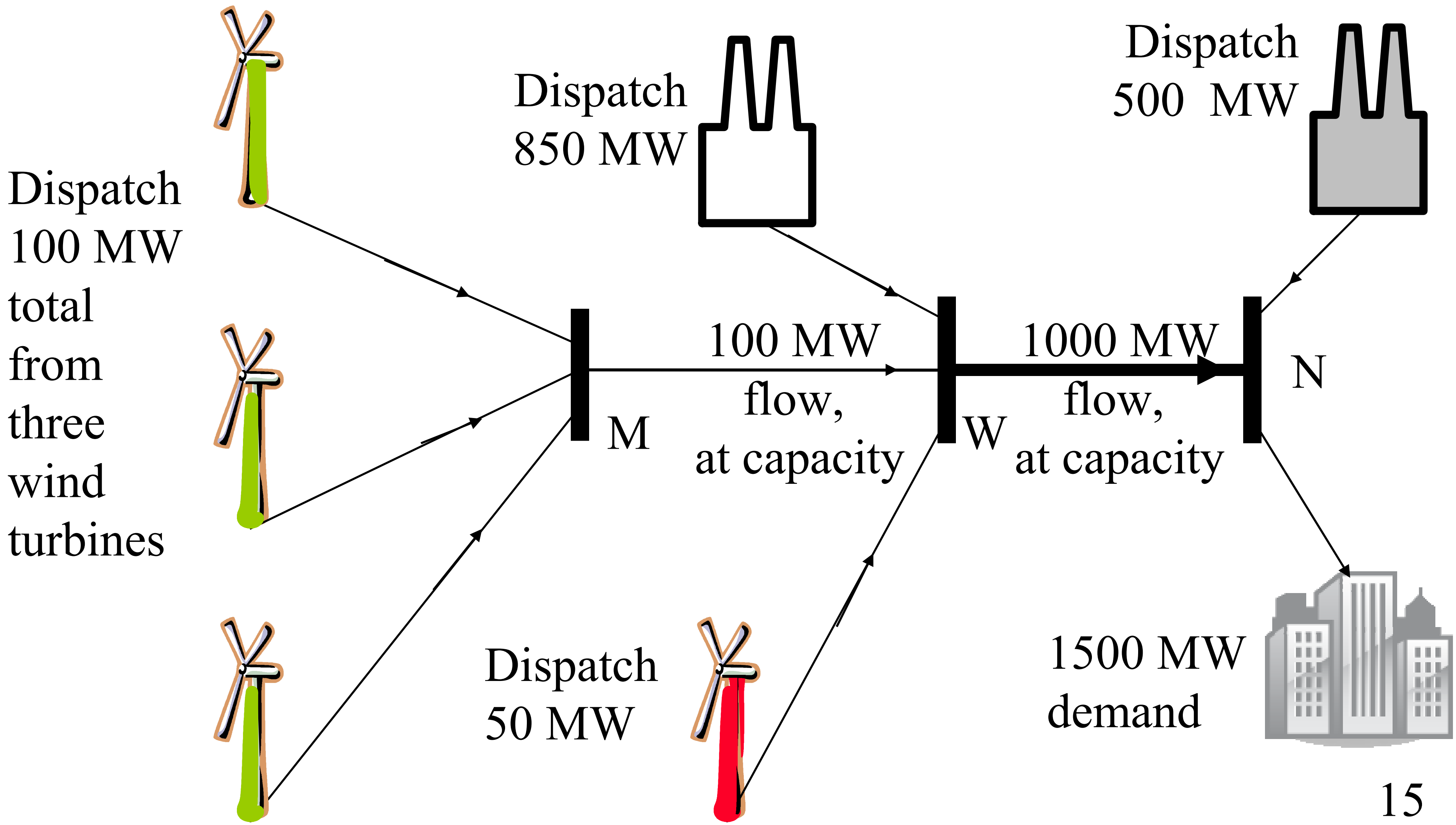
What is the effect of transmission limitations?

- If the limited capacity of transmission prevents the use of an offer with a lower price then the highest accepted offer can be thought of as *varying* with the location of the bus.
- Nodal or "locational marginal prices" reflect this variation:
  - Roughly speaking, the price at each bus is based on the offer price to meet an additional MW of demand *at that bus*.
  - In ERCOT, currently have coarser "zonal" representation of transmission.

Example 2: transmission limits, 1500 MW demand at N, block offers.



Dispatch for 1500 MW demand, limited transmission capacity.



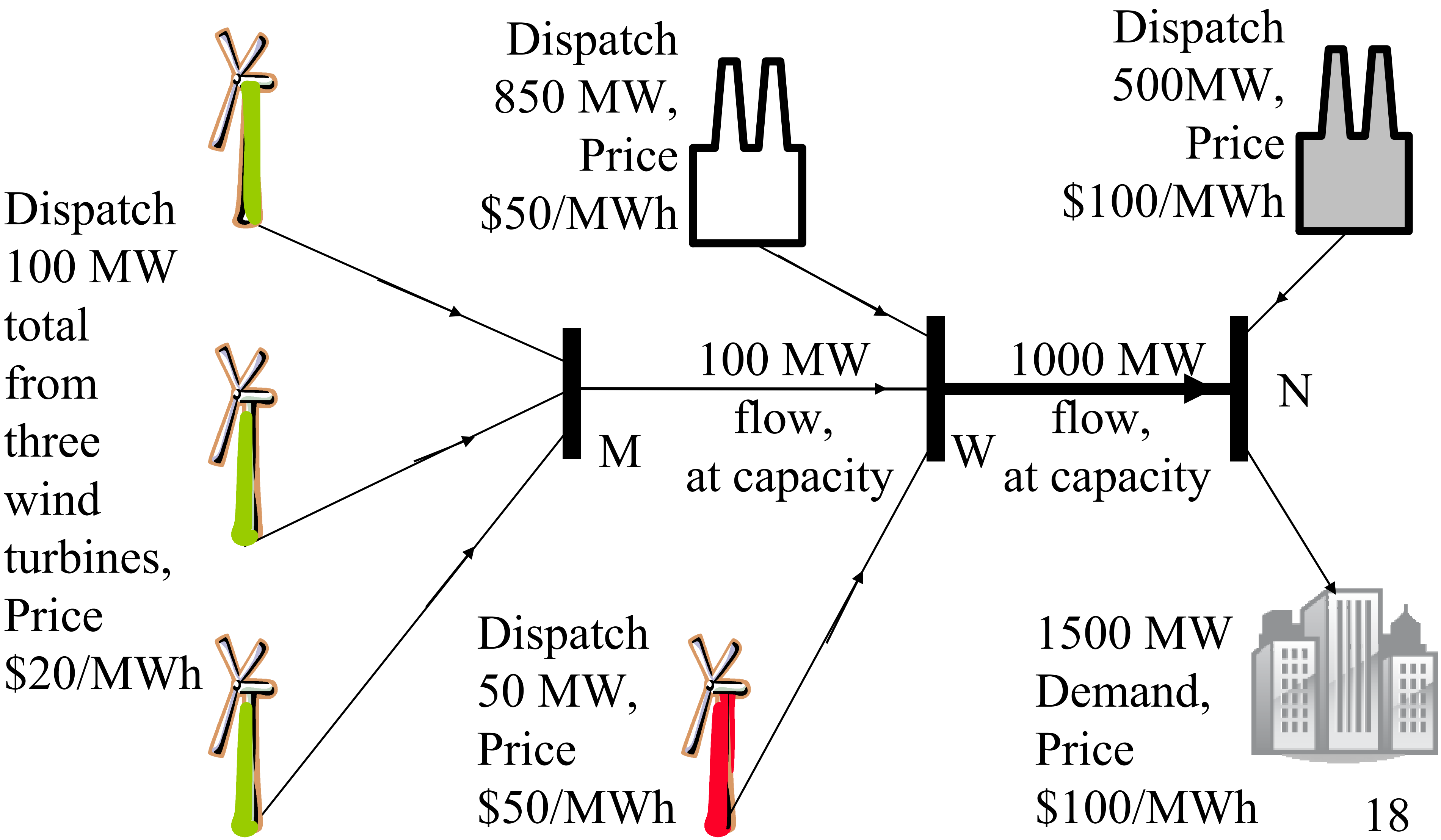
Prices for 1500 MW demand, limited transmission capacity.

- Highest accepted offer price was \$100/MWh from “gray” thermal generator at bus N.
- “Red” wind fully dispatched at bus W.
- “White” thermal generator at bus W not fully dispatched.
- “Green” wind at bus M not fully dispatched.
- “Price-based” curtailment of “white” thermal and “green” wind generation.

Prices for 1500 MW demand, limited transmission capacity.

- What are the LMPs?
  - To meet an additional MW of demand at N would dispatch an additional MW of \$100/MWh “gray” thermal generation, so LMP_N = \$100/MWh at N,
  - To meet an additional MW of demand at W would dispatch an additional MW of \$50/MWh “white” thermal generation, so LMP_W = \$50/MWh at W,
  - To meet an additional MW of demand at M would dispatch an additional MW of \$20/MWh “green” wind generation, so LMP_M = \$20/MWh at M.
- “Green” wind paid \$20/MWh, “red” wind paid \$50/MWh.

Dispatch and prices for 1500 MW demand, limited transmission capacity.



How do PTCs and sales of RECs affect this?

- Federal production tax credits (PTCs) and state renewable energy credits (RECs) only accrue when actually generating.
- What if one of the “green” wind farms at M wanted to generate 50 MW?
- To get preference in the dispatch process, wind farm must reduce its offer price:
  - Ignoring “dispatch priority,”
  - Dispatch priority in ERCOT will affect issues in Texas when final rule is decided.

How do PTCs and sales of RECs affect this?

- If one of the “green” wind farms at M dropped its offer below \$20/MWh then the lowest price offer would be fully dispatched.
- But maybe the other “green” wind farms want to be fully dispatched as well!
- How low will the “green” wind farms go?
  - This requires a model of competitive interaction, which has a host of assumptions,
  - But we will estimate a bound on LMP_M.

How do PTCs and sales of RECs affect this?

- Suppose that the total value of PTCs and RECs etc is \$35/MWh,
- Suppose that the variable operation and maintenance costs of the wind farm are \$5/MWh.
- Suppose quantity q is sold by wind farm at price LMP_M then operating profit will be:

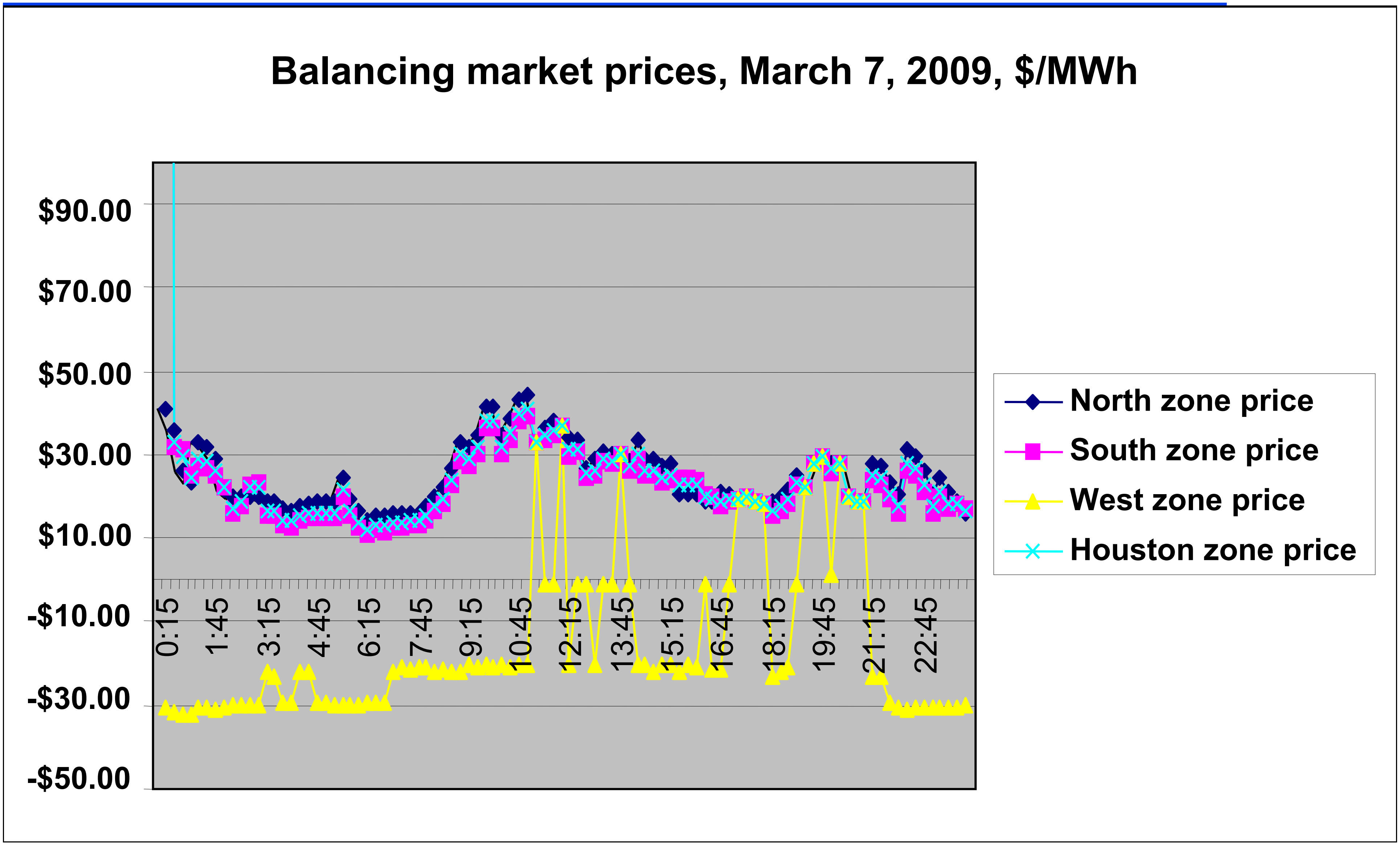
$$(LMP_M - \$5/MWh + \$35/MWh) \times q.$$

- Only positive if $LMP_M > \$5/MWh - \$35/MWh$.

How do PTCs and sales of RECs affect this?

- With limited transmission, LMP_M at M is set by the highest accepted wind offer at M.
- If intense competition, wind farms may undercut each other, decreasing highest accepted offer price.
- LMP_M could go as low as *minus* $30/MWh!
- Concurs with recent experience in ERCOT balancing market in West zone:
  - Represents transfer from Federal taxpayers to market for taking wind power at unfavorable *locations*.

How do PTCs and sales of RECs affect this?



Transmission price risk.

- Differences in zonal (or nodal) prices represent the (short-term) opportunity cost to transmit power from one location to another in limited system:
  - When transmission constraints bind, opportunity cost (and therefore transmission price) can be high,
  - As high as $40/MWh or more from West zone to demand centers in ERCOT,
  - Risk of high transmission prices can be hedged by financial instruments issued by ISO (but clearing price for financial instruments reflects average expected values of prices being hedged).

Transmission price risk.

- In longer-term, investment in transmission increases capacity to transmit power and reduces short-term transmission prices:
  - In principle, socially optimal investment to bring energy from remote generation resources would trade-off the cost of new transmission against production cost savings (possibly including cost of greenhouse emissions),
  - In practice, production cost savings can only be roughly estimated from offers, and transmission planning may be driven by many goals.

Transmission price risk.

- Wind tends to be far from demand:
  - Transmission constraints often limit transfers from wind to demand centers, as in West zone wind in ERCOT,
  - Transmission capacity increases require considerable investment.
- ERCOT "competitive renewable energy zones" involve about $5 billion in transmission investment for increase in capacity of 11 GW from West:
  - Approximately $10/MWh average cost.

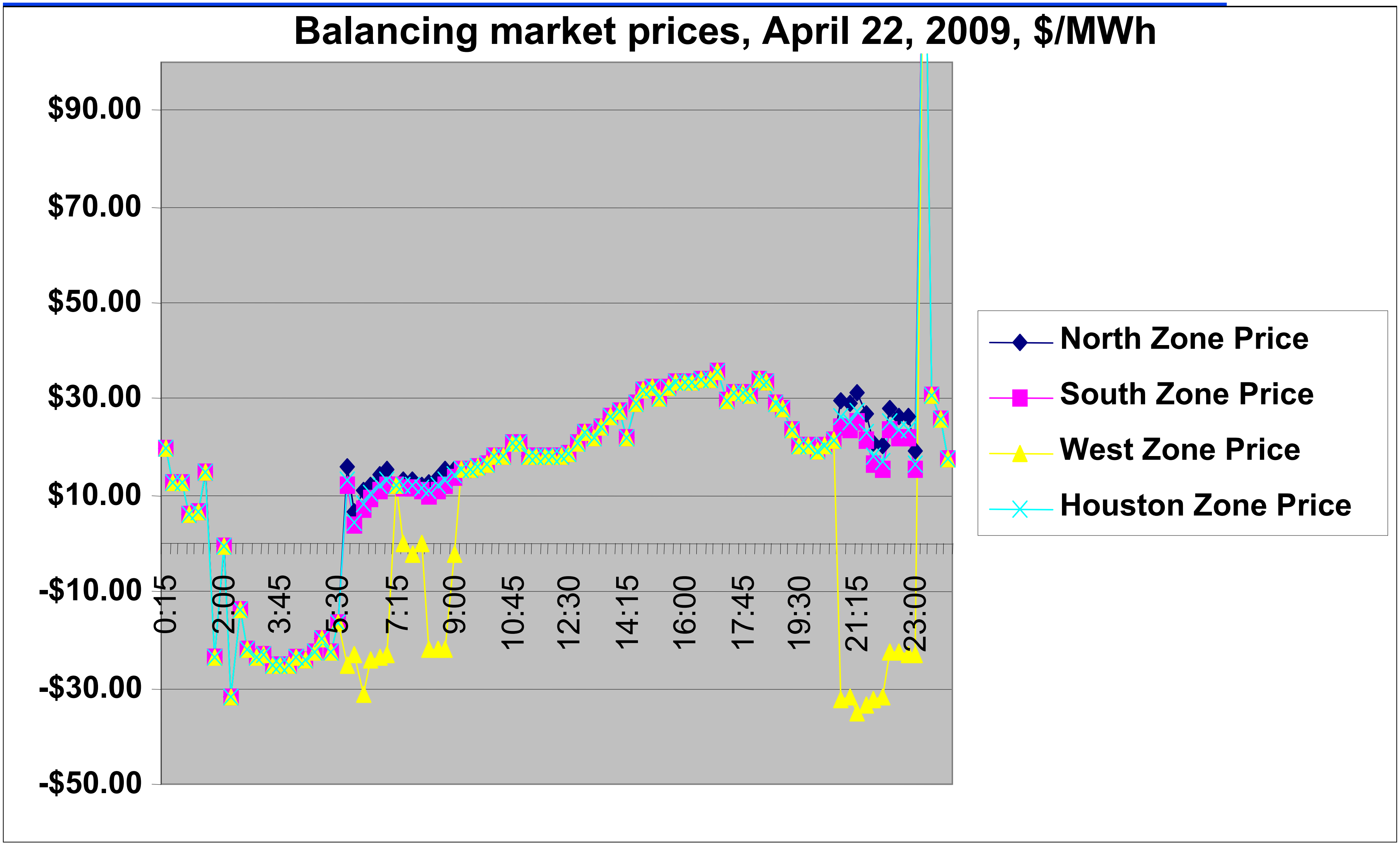
Wind and demand correlation.

- What happens when transmission upgrades are completed and more wind is built?
- Much more wind power will be produced!
- However, West Texas wind is anti-correlated with ERCOT demand:
  - Wind tends to blow more in Winter, Spring, and Fall than Summer and more during off-peak hours than on-peak.

Wind and demand correlation.

- Off-peak wind production tends to decrease need for thermal generation off-peak.
- Again, if there is intense competition off-peak, prices may be set negative by wind.
- Concurs with recent experience in ERCOT balancing market:
  – Represents transfer from Federal taxpayers to market for taking wind power at unfavorable *times*.

Wind and demand correlation.

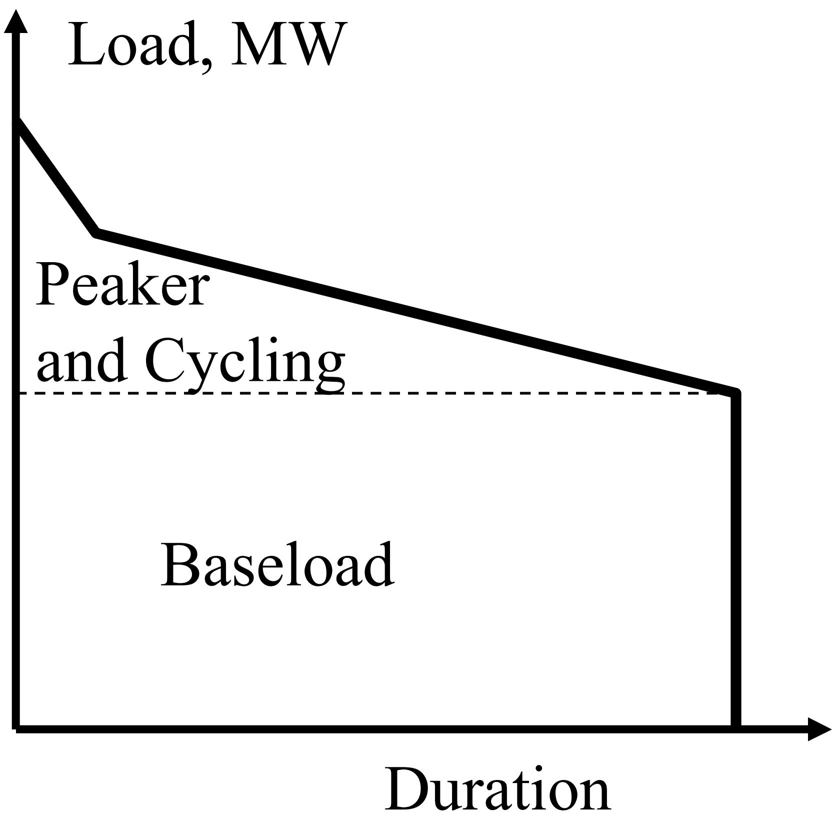


Wind and demand correlation.

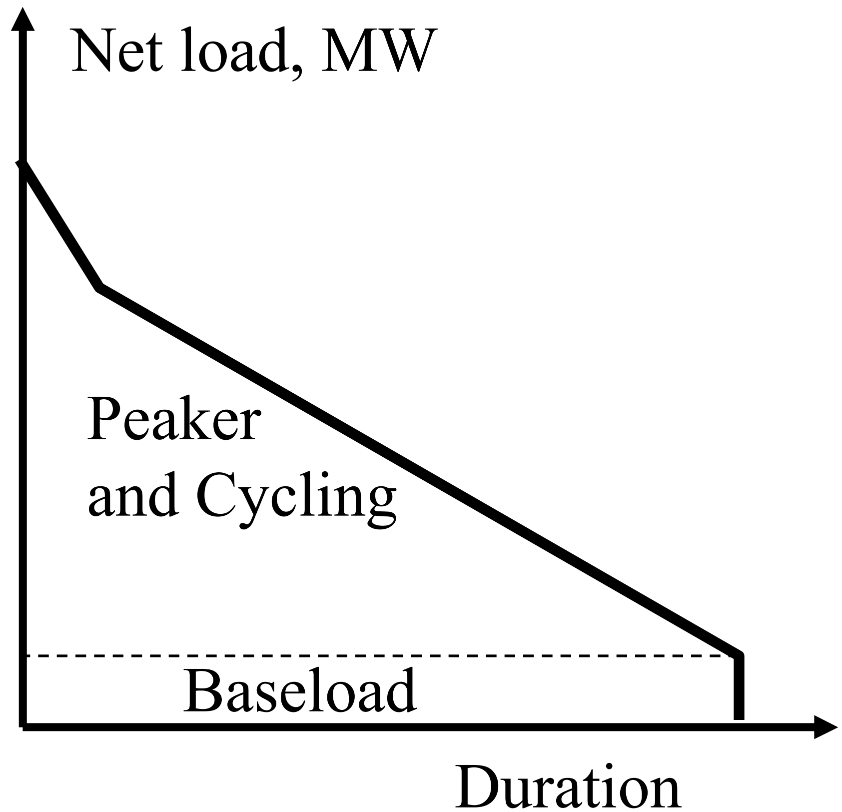
- If off-peak wind can be anticipated in forecast, centralized unit commitment could reduce wind curtailment by de-committing thermal:
  - Current ERCOT market does not have centralized unit commitment, but
  - ERCOT nodal market will have centralized unit commitment.
- In longer-term, generation portfolio might adapt to "peakier" net load by increasing fraction of peaker and cycling capacity.

Wind and demand correlation.

Load-duration without wind.



Net Load-duration with wind.
Net load = load minus wind.



Intermittency.

- Electricity demand and supply must be matched essentially continuously.
- Matching is achieved at various timescales:
  – Short-term, by adjustment of generation resources in response to system frequency, "governor action" and "regulation,"
  – Medium-term, through offer-based economic dispatch of resources to match average demand over 15 or 60 minute periods in organized markets and to acquire reserves.
- Meeting demand involves more than load-duration issues.

Intermittency.

- Historically:
  - demand for energy is uncontrollable (but somewhat predictable), while
  - generation is controllable (and mostly predictable).
- Wind generation is intermittent at various timescales:
  - "negative demand."
- Integration of wind involves more than net load-duration issues!

Intermittency.

- Intermittency of wind imposes requirements for additional ancillary services:
  - Short-term, increased regulation,
  - Medium-term, increased reserves and utilization of thermal resources with ramping capability,
  - Longer-term (as regulation, reserve, and ramping capabilities of existing thermal generation portfolio become fully utilized), additional flexible thermal resources or storage.

Intermittency.

- Increasing penetration of wind means less thermal resources may be on-line to provide ancillary services.
- On-line thermal will operate at lower fractions of capacity and will be required to ramp more:
  - Possibly worsened heat rates and emissions.
- Driver for more storage and more controllable demand.

Intermittency.

- Various studies have estimated the "wind integration" AS costs, with estimates varying from a few to a few tens of $/MWh:
  - Proxy upper bound to energy-related AS costs provided by cost of lead-acid battery based energy storage, around $40/MWh.
- Variation in estimates reflect:
  - Variation in particulars of systems,
  - Lack of standardization in estimating costs, and
  - Lack of representation of intermittency in standard generation analysis tools.

Intermittency.

- Requirements for increased resources due to intermittency can be reduced by deliberately spilling wind:
  - Operate at below wind capability to enable contribution of “inertia” and regulation,
  - Ramp from one power level to another at limited rate.
- But since wind turbine costs are primarily capital, this will increase cost of wind power:
  - Trade-off between integration costs and increased cost of wind.

Intermittency.

- Aggressive portfolio standards in the 20% to 30% range for energy will almost certainly involve significant changes in operations of both wind and thermal to cope with intermittency.
- Example (assuming all renewables are wind):
  - 30% renewable portfolio standard by energy,
  - 30% wind capacity factor (ratio of average production to wind capacity),
  - 55% load factor (ratio of average to peak demand),
  - Ignoring curtailment, wind capacity would be 55% of peak demand and would exceed minimum demand!!

Intermittency.

- ERCOT peak demand is about 62 GW.
- 30% renewable portfolio standard for energy would require around 34 GW of wind capacity.
- But even with 8 GW of wind capacity today, prices are occasionally negative during off-peak in Spring in ERCOT, with minimum demand around 25 GW.
- With 34 GW of wind, would need major changes to: operations; portfolio of generation; storage; and demand!

Intermittency.

- Multiple possible changes to accommodate intermittency:
  - Increased reserves,
  - Relatively more agile peaking and cycling generation,
  - Wind spillage,
  - Compressed-air energy storage,
  - Controlled charging of millions of PHEVs.
  - Using off-peak coal generation to power carbon dioxide separation and sequestration.
- Hard to estimate capital and operating cost of optimal portfolio of changes!

Intermittency.

- As a *rough* ballpark proxy for energy-related AS cost due to intermittency:
  - consider lead-acid battery storage for 25% of wind energy production,
  - Would add 25% times \$40/MWh = \$10/MWh to cost of wind.

Putting the cost estimates together.

- ERCOT charges most costs of transmission construction to demand.
- North American markets generally charge all AS costs to demand, regardless of cause.
- But we will add the wind-related transmission and wind-related AS costs to the cost of wind power:
  - Needs care when comparing to similar figures for other generation assets,
  - These costs are not necessarily reflected in market prices.

Putting the cost estimates together.

- Typical unsubsidized cost of wind energy is around \$80/MWh,
- Assume \$10/MWh incremental transmission for wind,
- Assume \$10/MWh proxy to cost of intermittency,
- Total is about \$100/MWh.
- Average balancing energy market price in ERCOT is around \$50/MWh to \$60/MWh.
- Wind adds about \$50/MWh to costs.

Putting the cost estimates together.

- Total annual ERCOT retail energy sales are around 3 times 10^8 MWh, retail bill around $30 billion.
- To achieve 30% renewable energy from wind would increase retail bill by *very roughly*:

  0.3 times 3 times 10^8 MWh times $50/MWh,

  $4.5 billion.

Summary

- Offer-based economic dispatch.
- Real-time market and example.
- Transmission limitations.
- Production tax credits and renewable energy credits.
- Transmission price risk.
- Wind and demand correlation.
- Intermittency.
- Putting the cost estimates together.