Operation of Wholesale Electricity Markets

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Operation of Wholesale Power Markets

1. Historical context – why markets? (5 min)
2. Markets for what? (10 min)
3. Energy markets (15 min)
4. Balancing (ancillary services) markets (15 min)
5. Forward markets (15 min)
6. What is the geography of markets? (5 min)
7. Other considerations (5 min)
8. Questions? (20 min)
Historical context – why markets?
History: People

- Thales: identified the phenomenon of electricity (600 BC)
- Michael Faraday: electric generator and motor (1838)
- Thomas Edison: light bulb (1879)
- George Westinghouse: transformer (1880s)
- J. Pierpont Morgan: financed Edison
- Nicola Tesla solves the AC transformation problem
History

- Werner von Siemens: first electric street light in UK in 1881
- Samuel Insull: modern electric grid
- Thomson-Houston Electric Company of Lynn, Massachusetts bought Edison’s company and his patents for $1.75 million. Changed its name to General Electric
Issue 1: AC versus DC

- Alternating Current – Direct Current
- Amount of electricity a transmission line can carry is a function of the voltage and the size of the conductor
- DC = lower voltage and safer
- AC = higher voltage and more efficient
- Development of transformer technology favored AC
Issue 2: Centralized versus Decentralized Power

- 1895-1908 there were hundreds of small electric companies, each with different voltages and frequencies
- GE produced small generators for residences and commercial buildings. Strongly opposed large central generating plants
- Believing the company was wrong, Samuel Insull quit GE and signed on as Manager of the Chicago Electric Company – one of approximately 40 companies in Chicago
Issue 2 (con)

- Insull: Demand patterns constantly changing across the day. It made no economic sense to meet those patterns separately (transit, commercial, and street lighting). Central stations plus a grid would allow power stations to “follow demand” across a 24 hour period.

- Insull reduced demand risk by buying the transit companies and obtaining exclusive rights to sell power in specific franchise areas.

- By developing central generating stations and then connecting them to a grid system, Insull was able to lower the price of power from 20 cents per KWh to 2.5 cents per KWh.

- Improved efficiency of generating facilities from 4% to 10%.
Hierarchy of the Power System

- **Generation**: 2,000–24,000 Volts
- **Transmission**: 69,000–765,000 Volts
- **Distribution**: 23,000 Volts
- **Load**: 4.16 kv – 34.5 kv

- **Generation** diagram includes factories, hydroelectric dam, and wind turbines.
- **Transmission** diagram includes high voltage towers and substations.
- **Distribution** diagram includes substations and residential, commercial, and industrial buildings.
- **Load** diagram includes residential, commercial, and industrial buildings.
Why Markets? From natural monopoly to competition

What happened?

- Diseconomies of scale: 1970s - competition overtakes benign consolidation as the ideal structure of the wholesale generation industry

- Market-based withdrawal of governments from investment, planning and control of industries in 1980s and 1990s

- Financial distress in the regulated utility industry in the late 1970s and 1980s opened the door to non-regulated/non-government owned competitors
Why Markets?
From natural monopoly to competition

Diseconomies of scale: Completed costs of large nuclear plants built in the United States

Bottom line: Natural monopoly or markets?

- Traditional power system components: generation, transmission, distribution

- Transmission and distribution remain natural monopolies – one big supplier is always a more efficient use of resources than multiple competing suppliers – *requires effective regulation*

- In most power systems generation is no longer a *natural* monopoly – *assuming effective competition enforced by regulation*, having multiple competing suppliers is a more efficient use of resources

- That said, there are many ways to introduce competition into the generating sector, and there are other issues to be considered (e.g., resource planning) – competitive wholesale power markets is one option

- The new “wild card”: demand as a wholesale power market resource

Source: Market Monitoring Analytics (PJM)
Markets for what?
Electricity: Voltage, Frequency, Current and Power

AC Electricity:

Frequency = Cycle/second (called “Hertz” or “Hz”)

Grid Frequency (e.g., N. America, Japan) = 60 Hz
(e.g., Europe, India) = 50 Hz

Voltage = Height of waterfall (Volts)
Current = Amount of water (Amperes or “amps”)
Power = Voltage x Current (Watts)
Energy = Power x time (e.g., Watt-hours)
All Networked Power Systems Require

Continuous Balance of Supply and Demand over all timescales
Reliability:
Frequency Regulation is Key for an AC Grid

Balanced Load (60 hertz)
Supply = Demand

Load Increase

Load Decrease
What “out of balance” might look like…
Dimensions of wholesale market function

• Four major functions
  – Investment in new resources when/as needed
  – Deployment of existing resources to serve expected demand
  – Allocation of transmission capacity and management of transmission congestion
  – Response of supply (and demand?) to actual conditions in real time
• Responsibility for the first three can be:
  – Central government agency
  – Government-regulated vertically integrated utility company
  – Competing private buyers & sellers, overseen by a market operator
• Responsibility for the last one always rests with the system operator

The regulators’ challenge? In all four dimensions, to find the right balance among economic efficiency, service reliability, environmental sustainability and social policy
Wholesale Electricity Markets

The purchase and sale of electricity from generators to resellers (marketers and retailers), along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Wholesale Competition

A system whereby a marketer or distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of marketers and distribution companies.

Source: R. Coutu, ISO New England
In practice, markets are rarely all one or all the other, but:
- where there is an organized pool, pooled trades have tended to dominate
- where there is no organized pool, bilateral trading has tended to dominate
Markets and timelines

• Short-term energy markets (day ahead and real time)
  - Length of daily schedule intervals – an important issue!

• Short-term services markets (real time to months)

• Forward markets (in some regions) (months to years)
  – Firm production capacity (or demand-side equivalent)
  – Transmission “rights”
  – Ancillary services/reserves
  – Bilateral long-term contracts for [ ]
Example: ISO New England

Real-Time Energy Market (RTM)

Source: R. Coutu, ISO New England
Short-term (spot) energy markets
Economic Dispatch
Day-ahead or of real-time committed resources

- Objective is to minimize the total cost of producing electricity while keeping the system in balance

- Economic dispatch uses least-cost resources in a single interval (e.g., hourly in the Day-Ahead Market, 5-10 minutes in the Real-Time Market) to meet the demand

- System/market operator assesses resource costs in each scheduling interval and establishes the wholesale cost of energy based on a uniform clearing price auction

Source: R. Coutu, ISO New England
Electricity Supply and Demand Curve

“Normal” Supply and Demand

Electricity Supply and Demand

- Some “must run” plants
- Small Supply Margin
- Inelastic Demand
- Can Get Large Price Swings
- Can’t store electricity
NOTE: These are the prices at which the resources are prepared to sell, not their marginal production costs (though they must disclose their costs subject to audit)
Bidding into the Market

Houston Zone Supply Stack

Bosque CC1

ERCOT Supply Stack

Bosque CC2

Cumulative Capacity (MW)

Full Load Costs ($/MWh)

Median Load 34,821 MW

Max Load 65,531 MW

Min Load 21,385 MW

Note: GED Supply Curve for the region based on GED Energy Intelligence database, Winter, 2006. Natural Gas price is assumed to be $7/MMBtu.
Day-ahead spot market steps (without transmission)
Day-ahead spot market steps (with transmission)
Locational pricing reflects congestion

- Multiple physical locations (tens to hundreds) each with its own wholesale price
- Prices are determined by energy price, transmission constraints (“congestion”) and related losses
- Highlights value of efficiency, distributed production & energy storage, demand response
Example: ISO New England – nodal market

**Nodes**
- 900+ specific pricing locations across New England
- Generators are paid at their individual nodal price, which is unique for each modeled generator

**Zones**
- Eight load zones
- Vast majority of load settles at zonal price
- Zonal price is load-weighted average of nodal prices within a zone

**Hubs**
- Predefined node; straight average of 32 nodal prices
- Hub was created to support bilateral trading

Source: R. Coutu, ISO New England
Load Zones and Pricing Hub
Elements of LMP

Energy, Congestion, and Losses Reflect Local System Conditions

Energy
$32.00 / MWh
(same across all New England)

Congestion
$4.25 / MWh

Losses
$0.75 / MWh

Locational Marginal Price
$37.00 / MWh

Same price across all of New England; established as the load-weighted average LMP within New England

The Cost impact, due to transmission constraints, to operate one or more expensive, local power plant to meet local demands

The added cost due to the energy that is lost as power flows across the transmission system

Source: R. Coutu, ISO New England
Example: Nordpool – zonal market
Example: New York ISO – zonal market
ERCOT (Texas) – switched from zonal (5 zones) to nodal within the past 2 years
Intra-day market steps (schedule meets reality)

Day D-1 → Day D

- Generation & demand balancing
- Feasible schedule for day D
- Balancing bids

INTRADAY MARKETS
Hourly clearing. Day-ahead schedule updating

GATE CLOSURE

Final hourly program

Generation & demand imbalances

Real-time functioning

Ancillary services (operation reserves)

SYSTEM OPERATOR

Source: C. Batlle
Real-time (intra-day) example: ISO New England

- **Inputs – Reoffer Period between 4:00 - 6:00 p.m. (day before)**
  - Actual system operating conditions
    - Metered load, generation, tie-line flows, etc.
    - Actual External Transactions

- **Outputs**
  - RT Hourly Commitment Schedules are produced after 6:00 p.m. (day before)
  - RT Dispatch signals are sent to generators (and dispatchable load) throughout the day (as often as 10-minute updates)
  - RT hourly LMPs based on actual operating conditions
  - RT Settlement
    - Based on deviations between DA schedule and actual operations

Source: R. Coutu, ISO New England
Short-term (spot) ancillary services markets
What “services” are we talking about?

Day D-1 ➔ Day D

- Generation & demand balancing
- Feasible schedule for day D
- Balancing bids

INTRADAY MARKETS
Hourly clearing. Day-ahead schedule updating

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Generation & demand imbalances

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SYSTEM OPERATOR
Power System Operation Impacts

Time Scales of Interest:

- **Regulation** -- seconds to a few minutes -- similar to variations in customer demand
- **Load-following** -- tens of minutes to a few hours -- usage follows predictable patterns
- **Scheduling and commitment of generating units** -- one to several days
Source: C. Batlle
Balancing needs are the same – but the categories are different in different regions

<table>
<thead>
<tr>
<th>EU:</th>
<th>North America:</th>
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</table>
| - Primary regulation  
  Inertia; speed regulators | - Frequency response |
| - Secondary regulation  
  Automatic generator control | - Regulation reserves |
| - Tertiary regulation  
  Manual by system operator | - Ramping |
| | - Load following |
| | - Supplemental reserves |

Others: Voltage regulation  
Black start (resources able to restore the system after a black-out)
These various services are created by actual system resources, including *inter alia*:

- Power plants running at part load, able to “ramp up” on command
- “Loads” (consumers) able to change their consumption level or pattern on command
- Storage (either grid-connected or end-use/distributed)

The combination of these choices with *economic* dispatch choices and *local grid constraints* produces what is called “security-constrained economic dispatch”

The end result is how a market tries to address *both* least-cost and reliability objectives
Forward capabilities/resources markets
Forward capacity markets

- Many markets (ERCOT, many EU markets) rely on the energy and ancillary services markets to send the price signals necessary for market participants to decide when and how much to invest in new resources.
- Other markets have decided not to rely on this and have added various “capacity mechanisms” that pay specifically for firm capacity needed to provide “resource adequacy”.
- These take different forms, but all rely on a forecast of peak demand (a) on the overall system and (b) in transmission-constrained areas.
- Either administratively or through an auction mechanism they then determine what resources are available to meet the forecasted peak, how much the resources will cost, and how much the market is prepared to pay over the relevant period (from 1 year in some markets to many years in others).
Most markets today rely on short-term ancillary services markets to provide the balancing services they need.

A very few markets (e.g., ISO New England’s forward reserves market, Great Britain’s Short Term Operating Reserves market) have adopted longer-term mechanisms to value and pay for critical services over a longer period of time (typically 1 year at the moment) to ensure “system security.”
Forward services markets

• As production from renewable resources like wind and solar grows on all power systems, it is expected that the importance and the size of the balancing services market will expand significantly.

• As a result, the use of forward services markets is likely to expand as well – these may take the form of separate, longer-term services auctions along the lines of those that already exist in ISO New England and Great Britain.

• Since these services originate in most cases from system capacity resources, another option is to combine system security needs and resource adequacy needs into a single forward market for resource capabilities.
Forward transmission “rights” markets

• In some markets (like the EU) physical transmission capacity is still controlled by forward auctions – but actual transfer capacities are quite fluid in real time

• This can lead to significant inefficiencies in the utilization of existing transmission resources and unnecessary congestion for market participants
In a fully integrated market (e.g., PJM or Nordpool) transmission capacity is scheduled and traded day-ahead and within day in conjunction with the scheduling of energy and services.

To allow participants to hedge their exposure in advance, some regions have adopted trading in “financial transmission rights”, allocated through periodic auctions.

Sellers guarantee compensation to buyers for differences on the day between what they can deliver to “cross border” customers and what they were obligated or intended to deliver.
The geography of markets
“Synchronized” physical interconnects (US)
Regional Transmission Organizations:
Where Electricity is Bought and Sold on the Wholesale Market
“Synchronized” physical interconnects (Europe)

Source: UCTE Network Development Plan 2008
Europe is still country-by-country (except for the Nordic market) but the Internal Electricity Market Target Model is intended to address that
One vision of how regionally integrated energy markets could emerge from the IEM process
### Summary: Tasks and Market Tools

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<th>Market Tools</th>
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<td><strong>Electric Energy Market</strong></td>
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<tr>
<td>• Day-to-day power</td>
<td>• Day-Ahead Energy Market &amp; Real-Time Energy Market</td>
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<td><strong>Reliability</strong></td>
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About RAP

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- Allocate system benefits fairly among all consumers

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