1 Power System Operations

2 Power Market Operations
Outline

1. Power System Operations

2. Power Market Operations
Actors

Transmission/independent system operator

Utility or producer

Utility or consumer + aggregator

Distribution system operator

Utility + aggregator
Uncertainty

- Rainfall (affects hydro)
- Load forecast errors
- Renewable supply forecast errors
- Generator failures
- Transmission line failures
- Load failures

**Contingency**: failure of any system element (generator, line, transformer, load)

- Which of these uncertainties are short-term (hours-ahead or real-time)?
- Which of these uncertainties are continuous/discrete?
System frequency is an indicator of supply-demand balance
**Primary reserve** (a.k.a. primary control, frequency containment reserve) is the first line of defense

1. Change of inertia in generator rotors: immediate

2. Frequency-responsive governors (automatic controllers): reaction is immediate, may take a few seconds reach target

3. Automatic generation control (AGC, a.k.a. load frequency control, regulation): updated once every few seconds up to a minute
Secondary Reserve

Secondary reserve (a.k.a. automatic frequency restoration reserve, frequency responsive reserve, secondary control, operating reserve): second line of defense

- Reaction in a few seconds, full response within 5-10 minutes
- Classified between spinning and non-spinning reserve
  - **Spinning reserve**: generators that are on-line
  - **Non-spinning reserve**: generators that are off-line but can start rapidly (or imports)
- Requirements dictated by capacity of greatest generator in the system and peak load
**Tertiary Reserve**

Tertiary reserve (a.k.a. manual frequency restoration services, tertiary control, tertiary reserve, replacement reserve): third line of defense

- Available within 30 to 60 minutes
Sequential Activation of Reserves

Failure occurs

Spinning and non-spinning reserve

Replacement reserve

Frequency-response reserve

Minutes
Consider $n$ generators, operating cost $f_i$, capacity $C_i$

$$\min \sum_{i=1}^{n} f_i(p_i)$$

s.t. $p_i + r_i \leq C_i$

$$\sum_{i=1}^{n} r_i \geq \max_{i=1,...,n} C_i$$

$p_i, r_i \geq 0$

What have we ignored?
Sequential Electricity Markets

Derivative market & OTC
Long and mid term (years/months)

Day-ahead market
Short term (1 day)

Intraday market
Very short term (hours)

Reserve markets
Real time (minutes/seconds)

Actual load
Time (24 hours)

Time (24 hours)
Time (24 hours)
Time (24 hours)
Flow Chart of Operations

Begin operations

Open Day-Ahead Market

Create Outage Schedules

Prepare/Publish Demand Forecasts & AS Requirements

TD-7

TD-3

TD-2

Day-Ahead

Collect 7-Day Wind Forecast

TD-1 0530

Close Day-Ahead Market

TD-1 1000

Run Market, Residual Unit Commitment

TD-1 1300

System Load Forecast

TD-1 1300

Open Real-Time Market for 0100 to 2400 on Trading Day

TD-1 1500

Commit Extremely Long Start Units

Real-Time

Close Real-Time Market

TD TH-75'

Run Hour-Ahead Scheduling

TD TH-67.5'

Run Real-Time Unit Commitment to Commit Fast Short Start Units

TD TH-67.5'

Run Short-Term Unit Commitment to Commit Medium Short Start Units

TD TH-52.5'

Publish AS Awards

TD TH-45'

Update Demand Forecast

TD every 30 minutes

Run RTED

TD every 5 minutes

After Markets
Analyzing the Flow Chart

- Which decisions are binding before day-ahead/in the day-ahead/in real time?
- What happens if system operator demand forecast is much higher than traded power in day-ahead market?
- What parts of the supply chain are not actively controlled, according to the flow chart?
- Where would demand response enter in this flow chart?
- How many optimization models are shown in the flow chart?
- What would happen if each optimization model ignored future time periods?
Looking Ahead in Operations

Consider the following example:

- **Real-time economic dispatch:** solved every 5 minutes for the next 5 minutes
- **Three generators**
  - Expensive: 1 MW/minute ramp rate, 10 $/MWh marginal cost
  - Moderate: 5 MW/minute ramp rate, 80 $/MWh marginal cost
  - Cheap: no ramp rate limit, 20 MW capacity limit, zero marginal cost
- **Initial conditions:** 50 MW from expensive and 50 MW from moderate
- **Demand:** Gaussian with mean 100 MW, standard deviation 15 MW
Cost 5-minute lookahead: 1738 $
Cost 10-minute lookahead: 1406 $

Why is the second policy doing better?
1. Power System Operations

2. Power Market Operations
The Motivation for Markets

- Information: each agent uses only private information
- Short-run efficiency (Adam Smith’s "invisible hand"):
  profit-maximizing agents behave optimally from a global point of view if "the price is right"
- Long-run efficiency: correct investment incentives
Bilateral (least centralized) → Exchange → Pool (most centralized)

- **Bilateral trade**: traders exchange in pairs
- **Exchanges**: traders submit simple bids to auctions with simple rules
- **Pools**: traders submit multi-part bids to auctions with complex rules

Can electricity be traded bilaterally in real time?
Example: Exchange Versus Pool

Consider generator with startup cost of 2400 $, capacity of 10 MW, fuel cost of 20 $/MWh who wants to sell energy for 24 hours

- Exchange: at least how much should the generator bid in order not to lose money?
- Pool profit for energy price $P$:
  \[
  \max((P - 20) \cdot 10 \cdot 24 - 2400, 0) \text{ $}
  \]
- Pool side payment: \[
  \max(2400 - (20 - P) \cdot 10 \cdot 24, 0) \text{ $}
  \]
Generator bids: price-quantity pairs \((P, Q)\), representing price \(P\) at which suppliers are willing to produce quantity \(Q\).

Consumer bids: price-quantity pairs \((P, Q)\) representing price \(P\) consumers are willing to pay for quantity \(Q\).

Obligations and payoffs
- Market clearing price \(P^*\): intersection of supply and demand curves
- *In the money* supply bids: produce and receive \(P^* \, \$/MWh\)
- *In the money* demand bids: consume and pay \(P^* \, \$/MWh\)
Example

The following bids are submitted for 5-minute power in a uniform price auction

- Supplier 1: 30 MW at 12 $/MWh
- Supplier 2: 35 MW at 28 $/MWh
- Supplier 3: 25 MW at 80 $/MWh
- Consumer 1: 10 MW at 90 $/MWh
- Consumer 2: 40 MW at 40 $/MWh
- Consumer 3: 25 MW at 20 $/MWh

- What is the uniform price?
- What is each supplier’s profit?
- What is each consumer’s profit?
- How much money is left to the auctioneer?
$P = 28$
Second-Price Auctions

Auctions for selling one item

- Lowest bidder (supplier) paid for supplying the auctioned item
- Supplier is paid price bid by cheapest losing bidder

Induces truthful bidding

- Why would you want to understate cost?
- Why would you want to overstate cost?
Uniform prices are a natural generalization of second-price auctions to multiple items, 'losing' bid is $k + 1$.
Meanwhile, in Texas (February 24, 2013)
Pay-As-Bid Auctions

**Pay-as-bid pricing:** Bids are accepted in order to maximize benefit from trade, each agent pays/receives the price they bid.

Criticisms of uniform pricing:
- Price volatility
- Hockey-stick bidding
- Unfair profit margins for infra-marginal suppliers. This argument is wrong.

Criticisms of pay-as-bid pricing:
- Discriminatory (different price for the same product)
Is this a uniform or pay-as-bid auction?
Example

The following bids are submitted for 5-minute power in a pay-as-bid auction

- Supplier 1: 30 MW at 12 $/MWh
- Supplier 2: 35 MW at 28 $/MWh
- Supplier 3: 25 MW at 80 $/MWh
- Consumer 1: 10 MW at 90 $/MWh
- Consumer 2: 40 MW at 40 $/MWh
- Consumer 3: 25 MW at 20 $/MWh

- What is the price?
- What is each supplier’s profit?
- What is each consumer’s profit?
- How much money is left to the auctioneer?
Which of the blue dots are losing money?

Which of the blue dots would be suspect of keeping power out of the market?
Blueprint of an Electricity Market
What would the following mean?

- an ‘Energy’ arrow from generators to utilities
- an ‘Ancillary Services’ arrow from system operator / generators to utilities
- a ‘Capacity’ arrow from generators to utilities
- an ‘Ancillary Services’ arrow from utilities to the system operator
Example: California and Central Western Europe

- Pool versus exchange
- Coordination
- Nodal versus zonal pricing
Day-Ahead Markets

California:

- Pool: detailed bids and uplift payments
- Uniform price for energy (different between nodes)
- Each generator bids individually
- Determines energy, reserve, transmission usage simultaneously

Central-Western Europe:

- Exchange: simple bids
- Uniform price for energy (different between zones)
- Each firm (not generator) bids individually
- Determines energy, cross-border transmission usage (not reserve)
- Ignores Kirchhoff’s laws (for the time being)
A System Without a Market-Clearing Price [Stoft, 2001]

- Fixed demand: 100 MW
- Identical generators
  - Startup cost: 3000 $
  - Marginal cost: 20 $/MWh
  - Capacity: 200 MW
Ignoring Kirchhoff’s Laws

All lines have identical characteristics

What is the optimal dispatch if we ignore Kirchhoff? if we account for Kirchhoff?
Real-Time Operations

California:
- Real-time market: replica of day-ahead market model with certain decisions fixed
- Uniform price

Central and Western Europe:
- Re-dispatch: change of generator schedule in order to prevent violation of transmission constraints (pay-as-bid)
- Balancing: use of reserve in order to correct forecast errors/contingencies (pay-as-bid)
Nodal Pricing Versus Zonal Pricing

California

- **Node**: physical connection point of the network
- **Nodal pricing**: transmission capacity is bought indirectly by differentiating price of energy at each *node*

Central and Western Europe

- **Zone**: collection of nodes at which electric energy is sold at the same price
- **Zonal pricing**: motivation is to simplify the trading of energy by reducing the number of markets
Nodal Pricing in PJM (February 15, 2014)

Figure: 05:40 (upper left), 08:40 (upper right), 09:20 (lower left), 09:55 (lower right).