Markets Overview

Mark Rothleder
Vice President, Market Quality & Renewable Integration

Oregon Public Utility Commission
April 11, 2019
The role of the grid operator and market operator

<table>
<thead>
<tr>
<th>A grid operator maintains reliability by:</th>
<th>A market operator supports reliability by providing:</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Balancing supply and demand</td>
<td>• A larger operational footprint</td>
</tr>
<tr>
<td>• Operating transmission system within limits</td>
<td>• Cost minimization to balance supply and demand</td>
</tr>
<tr>
<td>• Ensuring grid is secure in case of a contingency event</td>
<td>• Non-discriminatory grid access to supply and demand</td>
</tr>
<tr>
<td>• Orchestrating restoration in case of a system outage</td>
<td>• Price transparency reflective of system conditions</td>
</tr>
<tr>
<td></td>
<td>• Compensation for grid services</td>
</tr>
</tbody>
</table>
## How transmission use varies in different market environments

<table>
<thead>
<tr>
<th>Function</th>
<th>RTO/ISO</th>
<th>OATT (Bilateral)</th>
<th>EIM</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Balancing Authority Area (BAA)/Transmission Provider (TP) responsibility</strong></td>
<td>CAISO/Market Operator (MO) is the BAA for all market participants and manages the high-voltage transmission grid, including operational management of transmission that is owned by multiple Participating Transmission Owners (PTOs)</td>
<td>Each BAA/TP retains operational control of its grid and provides transmission service through its OATT</td>
<td>Each BAA/TP (or “EIM Entity”) retains operational control of its grid and provides transmission service through its OATT; CAISO/Market Operator (MO) receives market inputs (including available transmission for EIM transfers) and issues market outputs - dispatch signals to participating resources and market settlements</td>
</tr>
<tr>
<td><strong>Transmission scheduling and congestion management</strong></td>
<td>Market participants provide bids and self-schedules for generation and load; MO uses bid-based, security-constrained economic dispatch and related monitoring tools to manage transmission congestion; transmission capacity in the CAISO is not reserved and cannot be purchased</td>
<td>Transmission Customers reserve and schedule transmission from their TP through submission of transmission schedules (or “e-tags”); TP curtails transmission schedules to manage congestion</td>
<td>CAISO/Market Operator (MO) monitors EIM transfers, which are adjusted to accommodate OATT (bilateral) transmission schedules; when congestion occurs on an EIM transfer path, congestion “rent” is calculated and is distributed to the EIM Entity BAA/TP that made the transmission available (?)</td>
</tr>
<tr>
<td><strong>Recovery of transmission revenue requirement</strong></td>
<td>Transmission revenue is recovered by CAISO by applying a single volumetric charge to all load and to export (or wheel-through) schedules. PTOs in CAISO receive an allocation of this transmission revenue for the transmission facilities they own under CAISO's operational control</td>
<td>Transmission customers pay transmission at a set rate to each TP/BAA with whom they reserve and schedule transmission (this can involve multiple transmission rates across multiple BAA/TP areas, or “pancakes” for a single transaction)</td>
<td>There is no additional, incremental charge for transmission used in real-time for the EIM; EIM Entities and CAISO allow transmission to be shared and used on a reciprocal basis in the EIM. Some transmission used in the EIM has already been procured while some comes from Available Transfer Capacity that would have gone unused.</td>
</tr>
</tbody>
</table>
The balancing of supply and demand

- Supply
- Demand
- Inter-Regional Interchange
- Sales
- Sales
- Inter-Regional Interchange
- Purchases
- Load
- Losses
- Load
- Load
- Losses
- Frequency
- Frequency
- 60
- Decrease
- Increase
- Power Generated
Most demand is met in advance of the market through utility-owned or bilaterally procured resources.
Products and services

Energy

- Physical supply and demand
- Virtual supply and demand

Other Products

- Ancillary services: Regulation Up & Down Spin & Non-spin
- Residual unit commitment
- Flexible ramping product

Energy Imbalance Market
SCED and SCUC

• Security Constrained Economic Dispatch (SCED)
  – Simultaneously clears energy supply bids including self-schedules against the demand forecast to determine dispatch instructions.

• Security Constrained Unit Commitment (SCUC)
  – An optimization that determines commitment status and day-ahead schedules and awards for selected resources and minimizes start up and minimum load costs while respecting physical operating characteristics.
Clearing price is where supply and demand cross

Demand price takers

Self-scheduled supply and are modeled as price-takers at beginning cost curves

Supply bids

Demand price takers

Supply price takers

Clearing price is where supply and demand cross

Total cleared demand

Energy $/MWh

Market clearing price

MW

Demand bids

Total cleared demand
Example 1: No Congestion

If the need for energy is 300 MW and two generators are offering at $40 and $60, what is the least cost solution? (Assume no losses)

Node 1

G1

Bid: 500 MW @ $40

Node 2

G2

Demand: 300 MW

Node 3

Demand: 0 MW

Limit = 1000 MW
Example 1: No Congestion

The most economic choice is 300 MW at $40 from G1.

Node 1

LMP = $40

Limit = 1000 MW

Node 2

LMP = $40

Node 3

LMP = $40

Demand: 300 MW

Bid: 500 MW @ $60

Bid: 500 MW @ $40

Demand: 0 MW

G1

G2
Example 2: Congestion

If the need for energy is 300 MW and two generators are offering at $40 and $60, EXCEPT the transmission line between G1 and the demand is limited to 150MW, what is the most economic solution? (Assume no losses)

Node 3
LMP = $60

Demand: 300 MW

Node 1
LMP = $40
Limit = 150 MW

Node 2
LMP = $60

G1
Bid: 500 MW @ $40
150 MW

Demand: 0 MW

G2
Bid: 500 MW @ $60
150 MW

Demand: 0 MW
Components of the locational marginal price

- Energy
- Congestion
- Losses

LMP
Pre-Market Processes

- Resource Adequacy
- Congestion Revenue Rights
- Full Network Model
- Load Forecast
- Process outage information
- D-2 Pre-market run
  - Address transmission constraints
  - Adjust models
Full Network Model

- Models network topology, resources and load covering entire WECC
- Accounts for parallel flow impacts on ISO
- Supports modeling of EIM flows and transfers
- Updated approximately every 6 weeks
Forecasting

Neural-Network Forecast

- HVAC KW
- Day Type
- Time of Day
- Exterior Temperature
- Humidity

Input Layer → Hidden Layer → Hidden Layer → Output Layer

Supply and Demand
Current System Demand: 29998 MW
Forecast Peak Demand: 36820 MW

Available Resources  Day-Ahead Demand Forecast
Actual Demand  Hour-Ahead Demand Forecast

Megawatts in thousands

0  5  10  15  20
Hour Beginning

0  25  30  35  40  45
Outage Management

- Generator interface for reporting planned and forced generation outages and de-rates
- Transmission owners interface for reporting transmission outages and switching
- Feed outage information to full network model
- Reports outages to Peak Reliability Coordinator
Summary of day-ahead and real-time markets

Market timeline:

**Day-ahead market (DAM)**

- T - 7 days
- 10:00
- DAM process begins
- 13:00
- Clear the market
- Publish results CMRI
- Triggers the real-time market

**Real-time market (RTM)**

- T-1 after 13:00
- T-75min
- RTM process begins
- Clear the market
- Receive dispatches ADS
- Settlements MRI-S

Bids submitted SIBR

SIBR/BSAP

ADS

MRI-S
Day-Ahead Market Processes

- Step 1 - Market Power Mitigation (MPM)
- Step 2 - Integrated Forward Market (IFM)
- Step 3 - Residual Unit Commitment (RUC)
Day-ahead market process

Market opens 8 days before the trade date

10:00 am – Market closes

Run residual unit commitment

Run market power mitigation

Run integrated forward market

Publish results
Real-Time Market Processes

- Mitigate market power
- Procure needed ancillary services
- Pre-dispatch intertie resources
- Commit or de-commit resources against forecast
- 15-Minute dispatch
- 5-Minute dispatch
- Flex requirements
Real-time market processes

Market power mitigation (MPM)
Mitigates market power applies to 15 and 5-minutes market

Hour-ahead scheduling process (HASP)
Produces HASP advisory schedules and advisory AS awards; Binding HASP intertie schedules with hourly block bids

Short term unit commitment (STUC)
Issues start-up instructions to medium and short start units

Real-time unit commitment (RTUC)/15-minute market (FMM)
Issues start-up/shut down instructions to short and quick start units; Procures ancillary services as needed
Real-time market processes

Real-time economic dispatch (RTED)
- 5 minute dispatch to meet energy imbalances

Real-Time Contingency Dispatch (RTCD)
- Dispatches of energy in real-time to respond to a grid disturbance or a system emergency

Real-Time Manual Dispatch (RTMD)
- Backup process in case RTED fails and is expected to continue to fail to converge/solve

Exceptional Dispatch
- To prevent an imminent system emergency or a situation that threatens system reliability
Real-time market processes

- Exceptional dispatch
  - As needed

- MPM
  - Hourly

- STUC
  - Every 15 mins.

- RTUC/FMM
  - Every 15 mins.

- RTMD

- RTCD
  - Every 5 mins

- RTED

* HASP is embedded in RTUC as the first of the four runs
Hourly process for real-time market

- **T-75**: Real-time bid submission deadline
- **T-20**: Intertie hourly transmission profile and energy schedule for market 1 e-tag deadline
- **T-22.5**: 15-minute scheduled awards published
- **T-37.5**: Start of market 1 optimization
- **T-45**: Results from hourly process to accept block schedules published (HASP)

**Market participants**

**Market operator**

**T** = Start of the hour
Fifteen minute market timeline

T-22.5: Market 2 optimization starts
T-7.5: Market 2 energy schedule awards
T-5: Market 2 energy schedule e-tag deadline

20 minutes

T-22.5: Self schedule changes for market 2

37.5 minutes

T = Start of the hour
RTD market timeline

- RTD provides operational instruction to all generation and demand response resources

- T = Start of the hour

- T-7.5: RTD 4 optimization starts

- T-2.5: RTD 4 dispatch, RTD 5 optimization begins

- 7.5 Min

- Financially binding

- Market 1

- Market 2

- RTD 2

- RTD 3

- RTD 4

- RTD 5

- RTD 6
EIM economic benefits result from optimization of bids and transfer capability between areas

Prior to EIM:
Each BA must balance loads and resources w/in its borders.

In an EIM:
The market dispatches resources across BAs to balance energy

- Limited pool of balancing resources
- Inflexibility
- High levels of reserves
- Economic inefficiencies
- Increased costs to integrate wind/solar

- Diversity of balancing resources
- Increased flexibility
- Decreased flexible reserves
- More economically efficient
- Decreased integration costs
A balancing area with no transfer capability can still benefit from EIM automated optimal dispatch

- EIM benefits can occur due to fuel cost savings of more optimal dispatch compared to base schedules

- Settlement of imbalance volumes between hourly base load and generation schedules and 15-minute schedules offset
Economic displacement between balancing areas provides EIM benefits to both balancing areas

- Balancing Area 1 benefits from saving on generation cost due to access to lower cost supply from area 2
- Balancing Area 2 benefits from selling excess supply to area 1 by dispatching internal generation up
EIM optimization achieves benefits by minimizing cost of meeting forecast demand and flex requirements.

- **Base Schedules**
- **Fifteen Minute Forecast**

EIM does **NOT** optimize the difference between hourly base schedule and forecast demand. EIM objective minimizes cost of meeting total forecast demand every 15- and 5-minutes.
Tests ensure balancing area has sufficient capacity and bid in capability to meet its forecast demand and uncertainty.
Supply and ramp from provides benefits to both areas

Supply Curve

Price

$60

$50

$40

Quantity

Balancing Area 1

Demand

Balancing Area 1

Supply Curve

$50 supply from balancing area 2 displaces $60 supply in balancing area 1

BAA1 Load benefits serving load at lower cost

BAA2 supply benefits by being able value $50 supply

BAA1 Load

Benefits serving load at lower cost

BAA2 supply benefits by being able value $50 supply

California ISO

ISO PUBLIC – © 2018 CAISO
A suite of solutions are necessary

<table>
<thead>
<tr>
<th>Storage</th>
<th>Western EIM expansion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increase the effective participation by energy storage resources.</td>
<td>Expand the western Energy Imbalance Market.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Demand response</th>
<th>Regional coordination</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enable adjustments in consumer demand, both up and down, when warranted by grid conditions.</td>
<td>Offers a more diversified set of clean energy resources through a cost effective and reliable regional market.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Time-of-use rates</th>
<th>Electric vehicles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Implement time-of-use rates that match consumption with efficient use of clean energy supplies.</td>
<td>Incorporate electric vehicle charging systems that are responsive to changing grid conditions.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Renewable portfolio diversity</th>
<th>Flexible resources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Explore procurement strategies to achieve a more diverse renewable portfolio.</td>
<td>Invest in fast-responding resources that can follow sudden increases and decreases in demand.</td>
</tr>
</tbody>
</table>