2020 Q3 Report on Market Issues and Performance

February 10, 2020

Department of Market Monitoring, California ISO
Amelia Blanke, Ph.D., Manager of Monitoring and Reporting

Highlights of Q3 2020 market performance

- Load curtailment (August 14-15)
- Prices and wholesale energy costs increase
  - lower hydro
  - high regional demand
  - slightly higher gas prices
- Average load decreases, but peak loads increase
- Generation outages increase
- Congestion increases
- Offset costs, ancillary service costs, bid cost recovery, and losses to ratepayers from congestion revenue rights sold in the auction also increase.
Western energy imbalance market highlights

• Peak prices in NV Energy, Arizona Public Service, and Salt River Project exceeded the rest of the system

• Northwest prices regularly lower than the rest of the system due to limited transfer capability

• Sufficiency test failures and power balance violations drove prices up, particularly in NV Energy

• Significant transfer capability between the ISO and south western BAAs energy to flow with little congestion.
Special issues covered in Q3 market report

- Load curtailment eventd
- Load under-scheduling
- Hourly block import compensation
- Resource adequacy showings and performance
- System market power
  - Structural competitiveness
  - Bidding behavior
  - Market power had very limited effect on system prices
Total CAISO Q3 wholesale costs increased ~60% to $3.8 billion compared to Q3 2019 -- driven by lower hydro, periods of high load and slightly higher gas prices.
Gas prices declined across major gas trading hubs in the west compared to the first half of 2019.

Load weighted Q3 gas prices up 4% from Q3 2019
Day-ahead prices ($47/MWh) exceed 15-minute prices ($44/MWh) and 5-minute prices ($36/MWh)
High day-ahead prices more than twice as frequent as high real-time prices (IFM, FMM, RTD)
In 2019, average hourly loads continue to decrease due to behind-the-meter solar generation and energy efficiency initiatives, plus lower statewide temperatures.
COVID impact to lower overall load, but higher peaks
Renewable generation decreased by 16 percent over Q3 2019 due to lower hydro production (down 38 percent)
Average prices up – with highest average prices in net load peak hours,
Average, minimum and maximum hourly net load (2018-2020)
Generation outages increase relative to prior years

![Generation outages chart](chart_image.png)

- **Other forced outages**
- **Forced maint. and plant trouble**
- **Other planned outages**
- **Planned maintenance**

<table>
<thead>
<tr>
<th>Quarter</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q1</td>
<td>12,000</td>
<td>10,000</td>
<td>8,000</td>
<td>6,000</td>
<td>4,000</td>
</tr>
<tr>
<td>Q2</td>
<td>14,000</td>
<td>12,000</td>
<td>10,000</td>
<td>8,000</td>
<td>6,000</td>
</tr>
<tr>
<td>Q3</td>
<td>16,000</td>
<td>14,000</td>
<td>12,000</td>
<td>10,000</td>
<td>8,000</td>
</tr>
<tr>
<td>Q4</td>
<td>18,000</td>
<td>16,000</td>
<td>14,000</td>
<td>12,000</td>
<td>10,000</td>
</tr>
</tbody>
</table>
Day-ahead ISO and bilateral market prices (Jul – Sep)

Average monthly peak prices

<table>
<thead>
<tr>
<th>Month</th>
<th>ISO</th>
<th>MIDC</th>
<th>PV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jul</td>
<td>$32</td>
<td>$19</td>
<td>$40</td>
</tr>
<tr>
<td>Aug</td>
<td>$97</td>
<td>$38</td>
<td>$205</td>
</tr>
<tr>
<td>Sep</td>
<td>$49</td>
<td>$39</td>
<td>$68</td>
</tr>
</tbody>
</table>
Average hourly net interchange by quarter

- **Import day-ahead**
- **Export day-ahead**
- **Net interchange before EIM**
- **Net Interchange after EIM**

**Legend:**
- Blue line: Import day-ahead
- Orange line: Import 15-minute market
- Light blue line: Export day-ahead
- Yellow line: Export 15-minute market
- Black dotted line: Net interchange before EIM
- Dark grey line: Net Interchange after EIM
Congestion increased in the third quarter. The $220 million day-ahead congestion rent was more than double the third quarter of 2019 ($79 million).
Congestion revenue rights auction revenues were $38 million less than payments made to non-load-serving entities, about 17 percent of day-ahead congestion rent.
Real-time offset costs increased to $104 million, almost as high as the total offset cost in 2019.

<table>
<thead>
<tr>
<th></th>
<th>2018</th>
<th>2019</th>
<th>Q1-Q3'20</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy</td>
<td>$20</td>
<td>$8</td>
<td>$43</td>
</tr>
<tr>
<td>Congestion</td>
<td>$117</td>
<td>$97</td>
<td>$84</td>
</tr>
<tr>
<td>Loss</td>
<td>-$2</td>
<td>-$0</td>
<td>-$3</td>
</tr>
<tr>
<td>Total</td>
<td>$135</td>
<td>$105</td>
<td>$124</td>
</tr>
</tbody>
</table>
Ancillary service payments increased significantly during the third quarter to about $97 million.
Bid cost recovery payments rose to $62 million, about $14 million more than the third quarter of 2019.
Average hourly energy from exceptional dispatch

In-sequence energy
Out-of-sequence energy
Commitment energy
Percent of load

Q1  Q2  Q3  Q4  Q1  Q2  Q3
2019 2020

Average hourly exceptional dispatch energy (MWh)
Exceptional dispatch energy as percent of load

0.0% 0.2% 0.4% 0.6% 0.8% 1.0%
Above market exceptional dispatch costs total $7.5 million
Operator adjustment a growing determinant of residual unit commitment procurement
Peak prices in southwest (NV Energy, Arizona Public Service, and Salt River Project) exceeded the rest of the system.
Peak prices in southwest (NV Energy, Arizona Public Service, and Salt River Project) exceeded the rest of the system.
Frequency of upward failed sufficiency tests by month

![Bar chart showing frequency of upward failed sufficiency tests by month for different utilities from 2019 to 2020. The chart includes bars for California ISO, PacifiCorp East, PacifiCorp West, NV Energy, Puget Sound Energy, Arizona Public Service, California ISO (PacifiCorp East), Nevada Power, Puget Sound Energy, BANC, Portland General Electric, Powerex, Idaho Power, Seattle City Light, and Salt River Project. The y-axis represents the percent of intervals, and the x-axis represents months from January to September. The bars for each month are color-coded to represent different utilities, with the height indicating the frequency of upward failed sufficiency tests.]

---

**Utilities**
- California ISO
- PacifiCorp East
- PacifiCorp West
- NV Energy
- Puget Sound Energy
- Arizona Public Service
- Portland General Electric
- Powerex
- Idaho Power
- Seattle City Light
- Salt River Project

---

**Years**
- 2019
- 2020
### Energy Imbalance Market Transfer Limits

<table>
<thead>
<tr>
<th>Operator</th>
<th>15-minute Market</th>
<th>5-minute Market</th>
</tr>
</thead>
<tbody>
<tr>
<td>Congestion Frequency</td>
<td>Price Impact ($/MWh)</td>
<td>Congestion Frequency</td>
</tr>
<tr>
<td>BANC</td>
<td>1%</td>
<td>-$2.89</td>
</tr>
<tr>
<td>Arizona Public Service</td>
<td>2%</td>
<td>-$2.33</td>
</tr>
<tr>
<td>NV Energy</td>
<td>6%</td>
<td>$15.06</td>
</tr>
<tr>
<td>Idaho Power</td>
<td>7%</td>
<td>-$3.97</td>
</tr>
<tr>
<td>PacifiCorp East</td>
<td>7%</td>
<td>-$3.98</td>
</tr>
<tr>
<td>Salt River Project</td>
<td>10%</td>
<td>-$2.40</td>
</tr>
<tr>
<td>PacifiCorp West</td>
<td>38%</td>
<td>-$9.18</td>
</tr>
<tr>
<td>Seattle City Light</td>
<td>43%</td>
<td>-$9.66</td>
</tr>
<tr>
<td>Puget Sound Energy</td>
<td>43%</td>
<td>-$9.08</td>
</tr>
<tr>
<td>Portland General Electric</td>
<td>50%</td>
<td>-$9.08</td>
</tr>
<tr>
<td>Powerex</td>
<td>61%</td>
<td>-$13.88</td>
</tr>
</tbody>
</table>

Map boundaries are approximate and for illustrative purposes only. Copyright © 2021 California ISO.
## Average 15-minute market energy imbalance market limits (July – September)

<table>
<thead>
<tr>
<th>From Balancing Authority Area</th>
<th>To Balancing Authority Area</th>
<th>Total export limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>California ISO</td>
<td>CISO 1,310 BANC 3,370 NEVP 860 AZPS 1,480 SRP 0 PACE 20 PACO 0 PACW 100 PGE 0 PSEI 7,140 SCL 930 PWRX 250</td>
<td>7,140</td>
</tr>
<tr>
<td>BANC</td>
<td>1,310</td>
<td>1,310</td>
</tr>
<tr>
<td>NV Energy</td>
<td>3,850</td>
<td>5,610</td>
</tr>
<tr>
<td>Arizona Public Service</td>
<td>2,230</td>
<td>11,060</td>
</tr>
<tr>
<td>Salt River Project</td>
<td>2,660</td>
<td>7,560</td>
</tr>
<tr>
<td>PacifiCorp East</td>
<td>630</td>
<td>2,540</td>
</tr>
<tr>
<td>Idaho Power</td>
<td>530</td>
<td>3,140</td>
</tr>
<tr>
<td>PacifiCorp West</td>
<td>130</td>
<td>1,660</td>
</tr>
<tr>
<td>Portland GE</td>
<td>30</td>
<td>350</td>
</tr>
<tr>
<td>Puget Sound Energy</td>
<td>0</td>
<td>800</td>
</tr>
<tr>
<td>Seattle City Light</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Powerex</td>
<td>0</td>
<td>230</td>
</tr>
<tr>
<td>Total import limit</td>
<td>10,210</td>
<td>1,310</td>
</tr>
</tbody>
</table>

The table above shows the average 15-minute market energy imbalance market limits for each market participant from July to September. The limits are expressed in megawatts and represent the maximum allowed energy imbalance for each balancing authority area.
Special issues covered in Q3 market report

• Load curtailment event
• Load under-scheduling
• Hourly block import compensation
• Resource adequacy showings and performance
• System market power
  – Structural competitiveness
  – Bidding behavior
  – Market power had very limited effect on system prices
Key findings are consistent with CAISO/CPUC/CEC report

Load curtailments due to a series of contributing factors:

- **Extreme temperatures and energy demand** across the West, electricity demand well in excess of current resource planning targets.
- **California state resource adequacy requirements** based on 1-in-2 year loads plus a 15 percent planning reserve margin, insufficient to reflect actual system conditions.
- **Counting rules for resource adequacy capacity** which overestimate the actual capacity that is available from many resources during the early evening hours.
- **Transmission capacity from Pacific Northwest de-rated by about 650 MW** as a result of a weather-related forced outage which prevented additional available supply from being imported into the CAISO.
- **The sudden loss of several large gas fired units** contributed to curtailment events, although the overall level of gas capacity on outage was not unusually high.
- **Self-scheduling of relatively large volumes of exports** in the day-ahead market, which reduced net imports into CAISO.
- **Residual unit commitment (RUC) process and related real-time bid processing design**. Detailed discussion of this to follow.
Additional findings

• The Western energy imbalance market functioned well and helped facilitate transfers of available capacity in real-time across the west.

• DMM has carefully reviewed major outages which occurred on August 14-15 – and found no indication of false outages/manipulation.

• Contrary to some suggestions in the media, DMM has found no evidence that market results on these days were the result of market manipulation.
DMM Recommendations

- **Resource adequacy**: Place high priority on key recommendations in CAISO/CPUC/CEC report:
  - Increase resource adequacy requirements to more accurately reflect risk of extreme weather events.
  - Continue to work with stakeholders to clarify and revise the counting rules for resource adequacy capacity.

- **Exports/imports**: Further changes and clarifications in the rules and processes for limiting/curtailing exports should be discussed and pursued by CAISO in conjunction with other balancing areas.

- **Demand Response**: Ensure a higher portion of demand response used to meet resource adequacy requirements is available during critical net load hours.
Self-scheduled, bid-in, or cleared load as a percent of actual load (all load)

<table>
<thead>
<tr>
<th></th>
<th>Average actual load (MW)</th>
<th>Average % cleared</th>
</tr>
</thead>
<tbody>
<tr>
<td>IOUs</td>
<td>25,390</td>
<td>98%</td>
</tr>
<tr>
<td>CCAs</td>
<td>10,497</td>
<td>91%</td>
</tr>
<tr>
<td>Munis</td>
<td>3,347</td>
<td>100%</td>
</tr>
<tr>
<td>DA</td>
<td>3,060</td>
<td>105%</td>
</tr>
<tr>
<td>All load</td>
<td>42,607</td>
<td>97%</td>
</tr>
</tbody>
</table>
Under-scheduled load by entity type

- IOU
- CCA
- Direct Access
- Muni
- Net underscheduled load

13-Aug to 19-Aug
2020 Q3 intertie hour-ahead versus 15-minute compensation ($ million)

- **Positive Revenue**: $\sum((\text{HASP Price} - \text{FMM Price}) \times (\text{HASP MW} - \text{IFM MW})) > 0$
- **Negative Revenue**: $\sum((\text{HASP Price} - \text{FMM Price}) \times (\text{HASP MW} - \text{IFM MW})) < 0$
- **Net settlement**: sum of negative and positive revenue comparing hour-ahead market prices to hourly average 15-minute market prices ($\sum (\text{Negative Revenue}, \text{Positive Revenue})$)
Overall resource adequacy availability was not unusually low during hours of load curtailments.

<table>
<thead>
<tr>
<th>Resource type</th>
<th>Date</th>
<th>Hour ending</th>
<th>Total resource adequacy capacity (MW)</th>
<th>Day-ahead market</th>
<th>Real-time market</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Adjusted for outages</td>
<td>Bids and self-schedules</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>MW</td>
<td>% of total RA Cap.</td>
</tr>
<tr>
<td>Total</td>
<td>8/14/2020</td>
<td>19</td>
<td>51,373</td>
<td>49,313</td>
<td>96%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>20</td>
<td>51,373</td>
<td>49,373</td>
<td>96%</td>
</tr>
<tr>
<td></td>
<td>8/15/2020</td>
<td>19</td>
<td>51,333</td>
<td>48,894</td>
<td>95%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>20</td>
<td>51,333</td>
<td>48,955</td>
<td>95%</td>
</tr>
</tbody>
</table>

Availability = Total MW self-scheduled and/or bid into CASO day-ahead and real-time market.

Source: DMM Report, Table 3-1, p. 27
Overall resource adequacy availability was not unusually low during highest load hours of Q3, similar to 2019

<table>
<thead>
<tr>
<th>Resource type</th>
<th>Total resource adequacy capacity (MW)</th>
<th>Day-ahead market</th>
<th>Real-time market</th>
<th>Other:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total resource adequacy capacity (MW)</td>
<td>Adjusted for outages</td>
<td>Bids and self-schedules</td>
<td>Adjusted for outages/availability</td>
</tr>
<tr>
<td></td>
<td>MW</td>
<td>% of total RA Cap.</td>
<td>MW</td>
<td>% of total RA Cap.</td>
</tr>
<tr>
<td>Must-Offer:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas-fired generators</td>
<td>19,659</td>
<td>18,572</td>
<td>94%</td>
<td>18,571</td>
</tr>
<tr>
<td>Other generators</td>
<td>1,441</td>
<td>1,361</td>
<td>94%</td>
<td>1,361</td>
</tr>
<tr>
<td>Subtotal</td>
<td>21,100</td>
<td>19,933</td>
<td>94%</td>
<td>19,932</td>
</tr>
</tbody>
</table>

Other:

| Imports                  | 4,475 | 4,437 | 99% | 4,135 | 92% | 4,463 | 100% | 3,783 | 85% |
| Imports - MSS            | 331   | 331   | 100% | 109 | 33% | 331   | 100% | 119   | 36% |
| Use-limited gas units    | 8,206 | 7,923 | 97% | 7,890 | 96% | 7,788 | 95% | 7,729 | 94% |
| Hydro generators         | 6,491 | 5,836 | 90% | 5,531 | 85% | 5,720 | 88% | 5,422 | 84% |
| Nuclear generators       | 2,818 | 2,776 | 99% | 2,769 | 98% | 2,776 | 99% | 2,769 | 98% |
| Solar generators         | 2,937 | 2,923 | 100% | 2,034 | 69% | 2,907 | 99% | 2,043 | 70% |
| Wind generators          | 1,191 | 1,177 | 99% | 802 | 67% | 1,174 | 99% | 786   | 66% |
| Qualifying facilities    | 984   | 973   | 99% | 819 | 83% | 964   | 98% | 830   | 84% |
| Other non-dispatchable   | 519   | 511   | 98% | 471 | 91% | 488   | 94% | 468   | 90% |
| Subtotal                 | 27,952 | 26,887 | 96% | 24,560 | 88% | 26,611 | 95% | 23,949 | 86% |
| Total                    | 49,052 | 46,820 | 95% | 44,492 | 91% | 46,151 | 94% | 43,456 | 89% |
Aggregate performance of all demand response (self-reported)

[Graph showing demand response resource adequacy value, real-time availability (bids), real-time schedules (dispatch), and reported response (not capped at dispatch or resource adequacy value) over dates from 8/14/2020 to 9/6/2020.]
Average real-time battery schedules (August 14-18)

- Energy (Charging)
- Energy (Discharging)
- Reg Down
- Reg Up
- Spin Reserves
- Flex Down

Average hourly schedule (MW)

Hour

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24

(150)
(100)
(50)
0
50
100
150
200
250
300
350
Although market was structurally uncompetitive many hours, overall market results were competitive in the third quarter.

Quarterly average price-cost markup was about $1.42/MWh (2.6 percent)
The CAISO market was structurally uncompetitive during the high load days in August

Number of hours with residual supply index less than one

- One pivotal supplier test (RSI1)
- Two pivotal supplier test (RSI2)
- Three pivotal supplier test (RSI3)
Comparison of potential scarcity and non-competitive hours

- Hours failing 1 pivotal supplier test
- Hours failing 2 pivotal supplier test
- Hours failing 3 pivotal supplier test

Potential scarcity hours based on DMM analysis

Price ($/MWh) vs. Reserve margin (supply/demand)
Comparison of day-ahead market bids vs marginal costs for gas-fired units (August 18, hour-ending 19)