Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Executive Director, Market Monitoring

Date: July 18, 2018

Re: **Department of Market Monitoring Update**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

This memo provides an update on market performance during the first half of 2018. Highlights include the following:

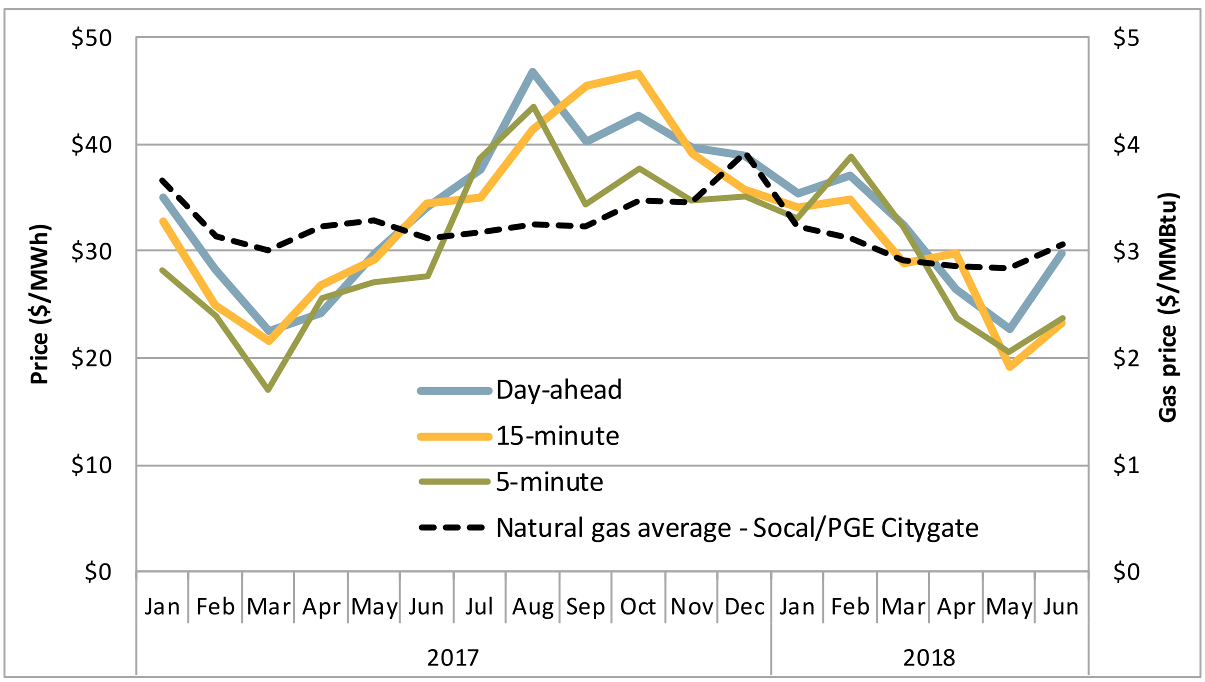
- Prices in the ISO's energy markets remained stable and competitive in the first half of 2018. Day-ahead system energy prices have risen about 5 percent compared to 2017, driven in part by lower hydroelectric production.
- Average day-ahead prices are also higher in 2018 due to a decrease in the number of very low and negative prices during the mid-day hours of peak solar output. The frequency of negative prices have also dropped substantially in the 15-minute and 5-minute markets compared to the first half of 2017.
- The decrease in negative prices in the real-time market in 2018 has also led to a reduction in the total quantity and percentage of solar and wind energy that has been decremented. During the first half of 2018, about 1.5 percent of forecasted solar and wind output has been decremented, compared to about 2.1 percent in the same months of 2017.
- Operating reserve requirements during off-peak hours have increased significantly due to modifications made in response to new FERC-approved reliability requirements (BAL-002-2). The increase in requirements has not lead to a significant increase in ancillary service costs due to the low cost of reserves during off-peak hours.
- At the start of the second quarter of 2018, the EIM was expanded to include two new participants: Idaho Power and Powerex. Prices in these two areas have been tracked closely with prices in adjacent EIM areas in the Northwest.

Energy prices remained stable and competitive

Prices in the ISO's energy markets remained stable and competitive in the first half of 2018 (see Figure 1). Day-ahead prices in the first half of 2018 have risen 5 percent from 2017 levels, driven in part by lower hydroelectric production. Day-ahead prices have also increased due to a drop in the frequency of very low and negative prices during the mid-day hours of peak solar output. Prices for next day gas at PG&E Citygate also dropped 15 percent, while prices for SoCal Citygate rose 1 percent.

In the real-time market, average 15-minute market prices remained about equal while 5-minute prices increased 15 percent in the first half of 2018 compared to last year. Real-time prices continued to be lower than day-ahead prices during most hours in the first half of 2018, with average prices in the 15-minute market and 5-minute market about 8 percent and 7 percent lower than day-ahead prices, respectively.

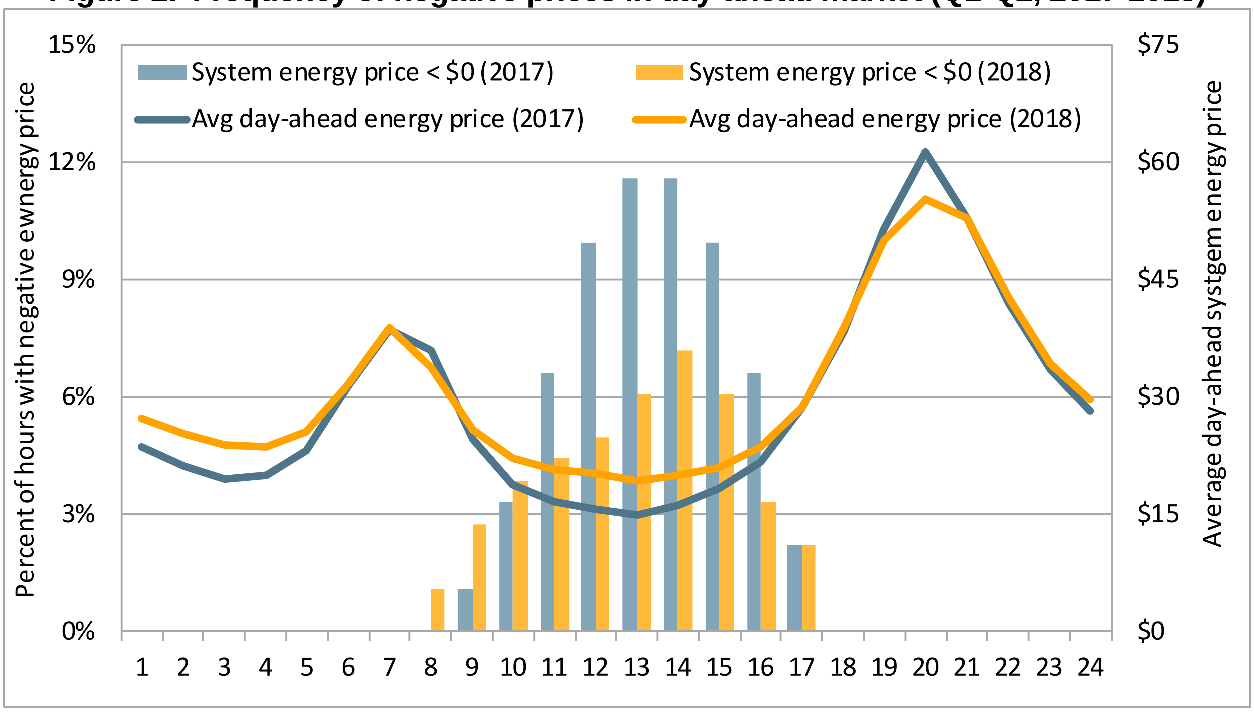
Figure 1. Average monthly system energy prices (2017-2018)



As shown in Figure 2, the frequency of negative prices in the day-ahead market has dropped substantially in 2018 compared to the first half of 2017. In the first half of 2018, negative day-ahead prices occurred about 4 percent of the time during hours ending 8 through 17, compared to about 6 percent in Q1-Q2 2017.

The frequency of $0 or negative prices has also dropped substantially in the 15-minute and 5-minute markets compared to the first half of 2017. In the 15-minute market, prices at or below $0/MW occurred in less than 3 percent of intervals compared to more than 8 percent of intervals in Q1-Q2 2017. In the 5-minute market, prices at or below $0/MW occurred in less than 5 percent of intervals during Q1-Q2 compared to more than 11 percent of intervals in 2017.

Figure 2. Frequency of negative prices in day-ahead market (Q1-Q2, 2017-2018)



Renewable energy curtailments

The lower frequency of negative prices in 2018 has also led to a decrease in the total quantity and percentage of solar and wind energy that has been decremented in the CAISO real-time market. During the first half of 2018, about 1.5 percent of forecasted solar and wind output has been decremented, compared to about 2.1 percent in the same months of 2017 (see Figure 3). The total amount of wind and solar decremented has dropped 20 percent during the first half of 2018 compared to 2017. Almost all of the wind and solar reductions (99.7 percent) have resulted from the dispatch of negatively priced bids, with curtailment of self-scheduled wind and solar accounting for only less than 0.3 percent of reductions.

Figure 3. Decremental dispatch and curtailment of wind and solar in CAISO

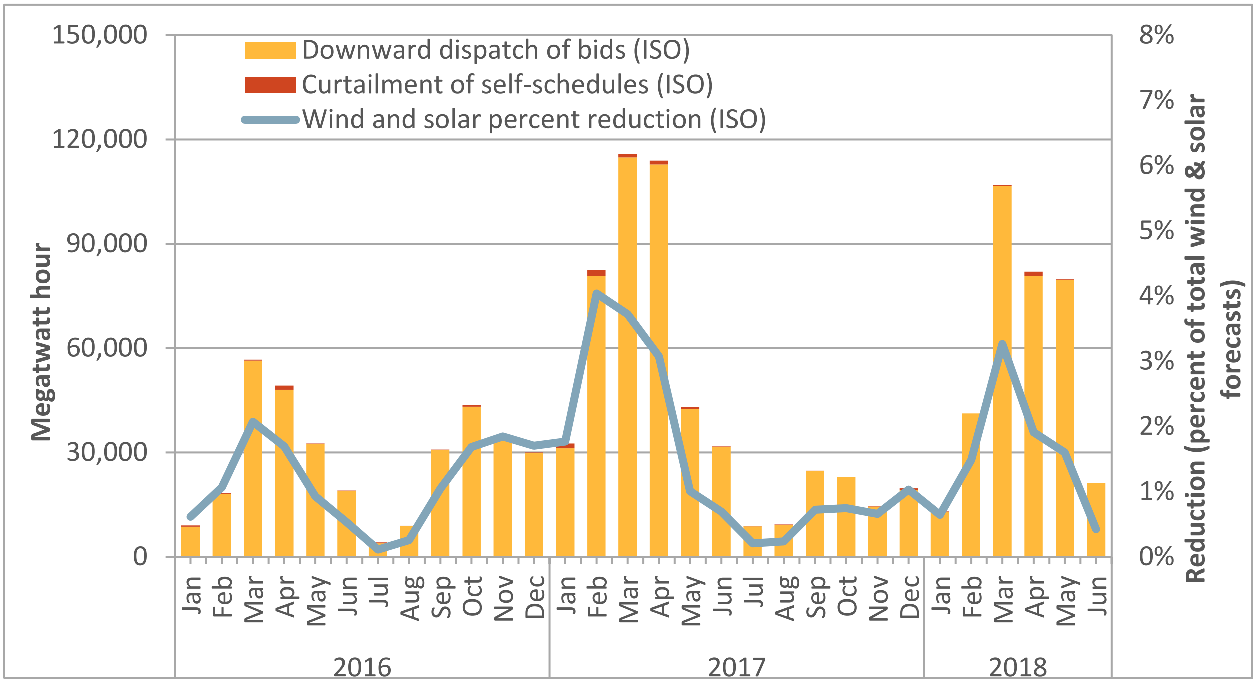
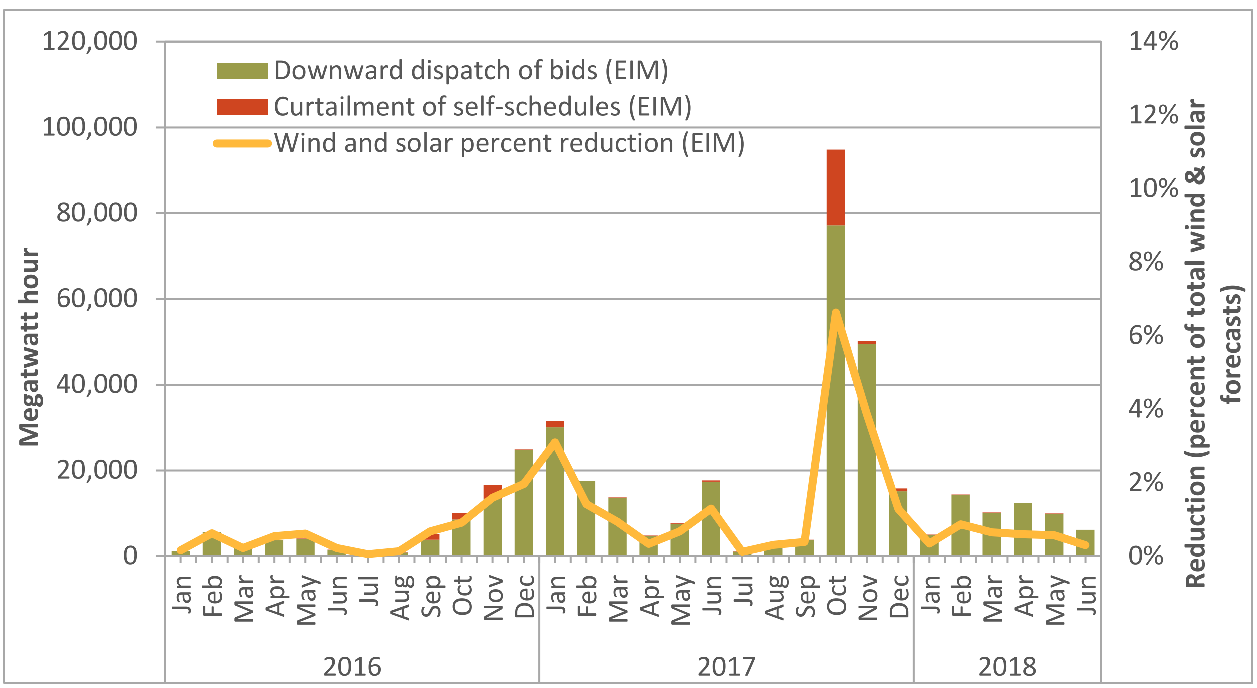


Figure 4. Decremental dispatch and curtailment of wind and solar resources in EIM



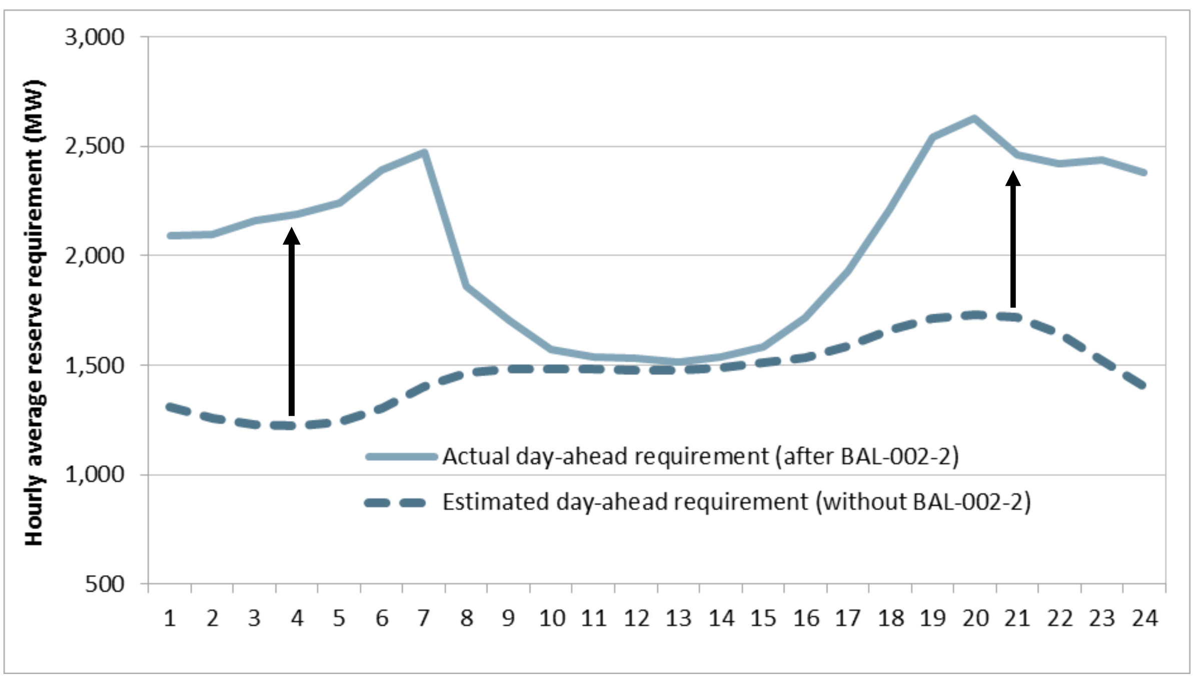
The total quantity of solar and wind energy that has been decremented in the EIM has also decreased in 2018 (see Figure 4). During the first half of 2018, the total amount of intermittent renewable energy decremented has dropped by about 38 percent compared to 2017. All reductions in the EIM are from wind resources. In 2018, the majority of reductions (over 99 percent) in the EIM have resulted from the dispatch of negatively priced bids, rather than curtailment of self-scheduled wind (.05 percent).

Operating reserve requirements and costs

FERC approved new definitions effective January 1, 2018, that required the ISO to reevaluate the most severe single contingency for purposes of calculating operating reserve requirements (BAL-002-2). This change resulted in a significant increase to the operating reserve requirements after January 1, 2018, to cover the potential sudden loss of scheduling on the Pacific DC Intertie. The increase in requirements has not lead to a significant increase in ancillary service costs due to the low cost of reserves during off-peak hours.

Figure 5 shows actual hourly average operating reserve requirements during the first six months of 2018 as well as *estimated* hourly average operating reserve requirements had the changes associated with BAL-002-2 not been implemented. Average operating reserve requirements increased less than 100 MW during the peak solar period (hours ending 9-16). However, during the other 16 hours of the day, average requirements have increased from about 1,500 MW to about 2,300 MW – an increase of about 800 MW.

Figure 5. Average Operating Reserve Requirements (January – June, 2018)

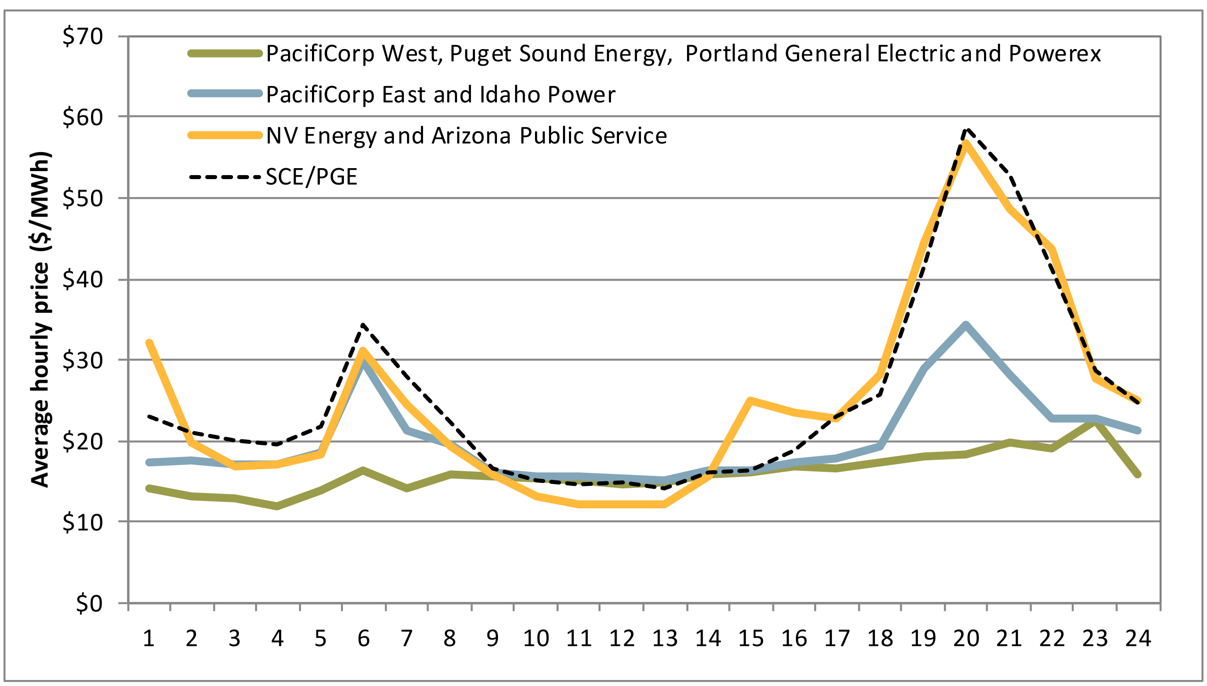


Energy Imbalance Market

At the start of the second quarter of 2018, the EIM was expanded to include two new participants: Idaho Power and Powerex.

- Prices in the Idaho Power area have been very closely correlated with prices in PacifiCorp East. As shown in Figure 6, prices in these areas are significantly lower than prices in NV Energy, APS and the ISO during the evening (hours ending 18 to 24). This price difference reflects frequent north to south congestion between these areas during these hours, which lowers the price in Idaho Power and PacifiCorp East.
- Prices for Powerex have been very closely correlated with prices for the other EIM areas in the Pacific Northwest (Puget Sound Energy, Portland General Electric and PacifiCorp West). As shown in Figure 6, prices in these areas is significantly lower than prices in the rest of the EIM and ISO most hours, except for the mid-day hours of peak solar output (hours ending 9 to 14). The lower prices for the EIM areas in the Pacific Northwest during other hours reflects congestion limiting supply that can be exported. This lowers the price in these areas.

Figure 6. Average hourly 15-minute market prices (Q2 2018)

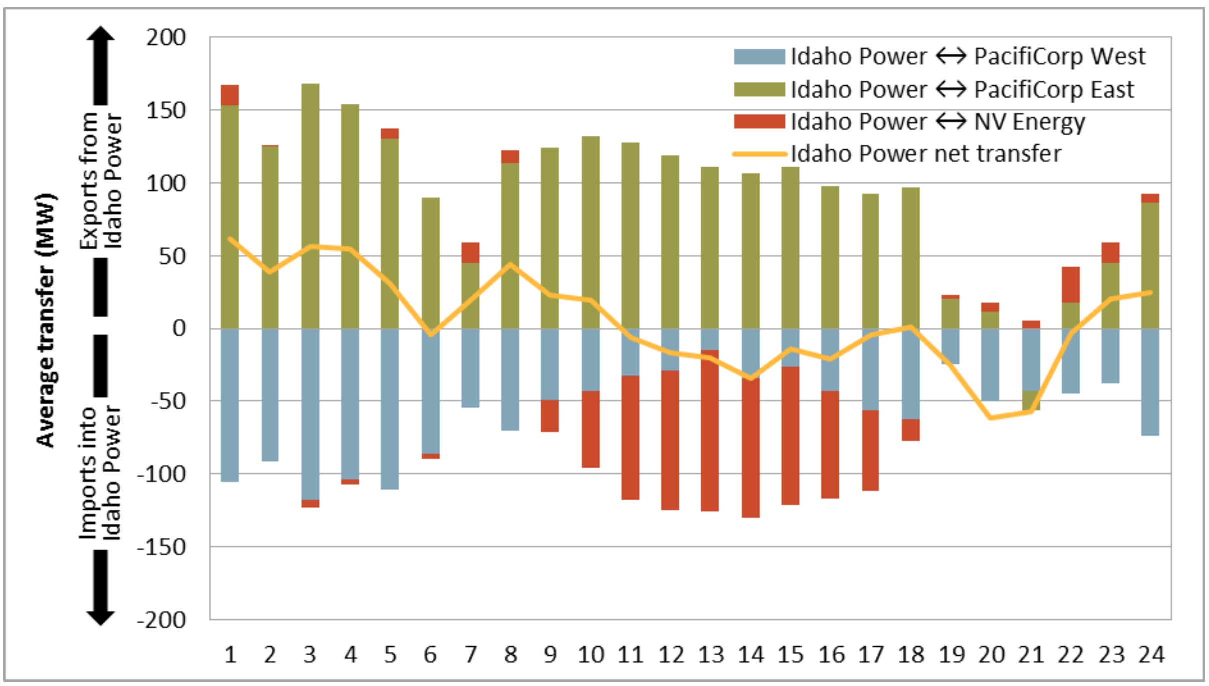


Idaho Power area

The addition of the Idaho Power area beginning in April 2018 added substantial additional transmission to the EIM. This transmission has been used to meet Idaho's internal imbalance need and to transfer power through the Idaho Power area to the EIM areas. As shown in Figure 7, Idaho has tended to import power during peak hours 11 to 21 with average hourly net imports of about 25 MW during these hours. During other hours of Q2, Idaho tended to be a net exporter in the EIM with average transfers out of about 30 MW per hour.

In addition, transmission through Idaho has been utilized to transfer power from the PacifiCorp West and Nevada Power areas into the PacifiCorp East area. Transfers into Idaho from PacifiCorp West and Nevada Power have averaged 60 MW and 25 MW, respectively, while an average of about 94 MW per hour has been transferred from Idaho into the PacifiCorp East area.

Figure 7. Average hourly EIM transfers from Idaho Power area (Q2 2018)

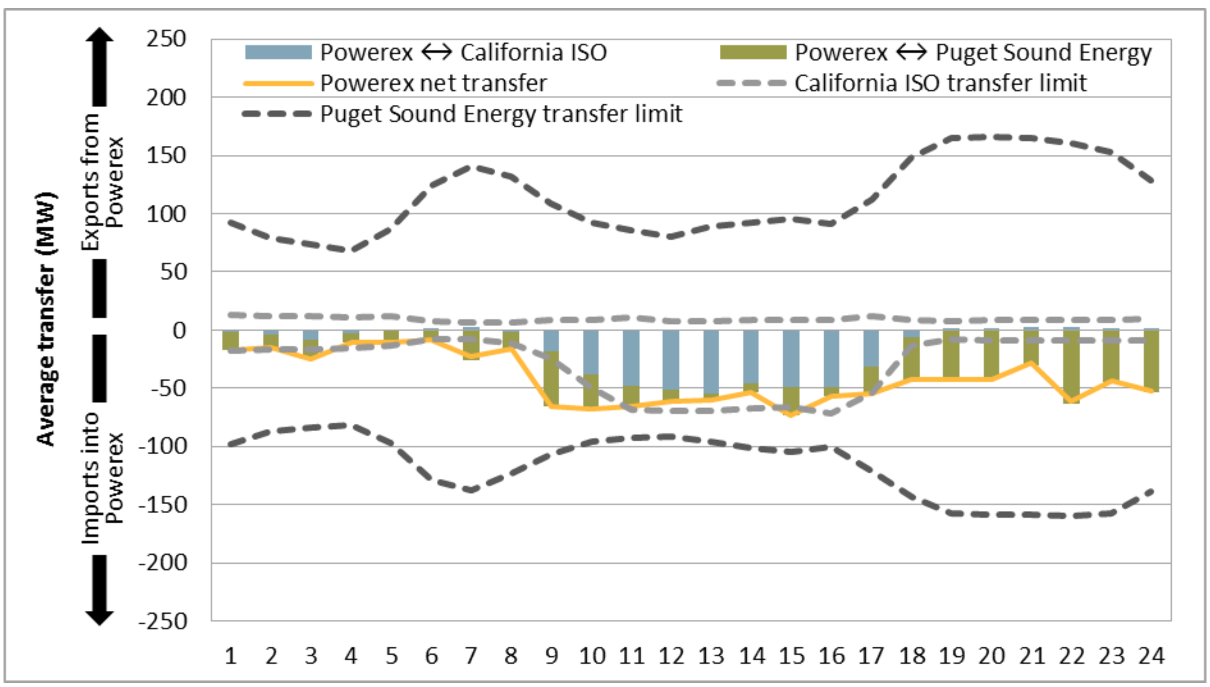


Powerex

Powerex's participation in the EIM has consisted of imports from the EIM during almost all hours. As shown in Figure 8, Powerex has imported an average of about 17 MW per hour from the ISO (mostly during the peak solar hours) and an average of about 25 MW per hour from the Puget Sound Energy area – for a total average imports of about 42 MW.

Exports from Powerex have been negligible. The lack of exports from Powerex is primarily the result of relatively low prices in the EIM relative to supplier offers in Powerex. During many hours, Powerex has also limited the amount of transmission capacity available to export power into the ISO to 0 MW. Powerex has explained that it has limited exports during many hours due to its concern that if bid mitigation is in effect, exports may be scheduled from Powerex at mitigated prices less than its market bid price. DMM has provided analysis of this issue and recommendations for addressing this issue to the ISO and stakeholders.[1]

Figure 8. Average hourly EIM transfers from Powerex (Q2 2018)



[1] *Market Monitoring Update,* Eric Hildebrandt, Department of Market Monitoring EIM Governing Body Meeting General Session July 12, 2018 https://www.westerneim.com/Documents/DepartmentofMarketMonitoringUpdate-Presentation-Jul2018.pdf