California ISO
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Issue Paper

Analysis of Real-Time Imbalance Energy Offset

(CC 6477)

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Real-Time Imbalance Energy Offset

1 Background

In response to inquires by market participants regarding the real-time imbalance energy offset (Charge Code (CC) 6477) for the month of April, the California Independent System Operator (the ISO) conducted a review of the first monthly invoice published under the new market model launched April 1, 2009. The real-time imbalance energy offset for the month of April amounted to a $14.13 million charge to Measured Demand, consistent with Section 11.5.4.2. The imbalance energy offset is calculated by summing the settlement dollar values for the following charge codes: real-time instructed imbalance energy (CC6470), real-time uninstructed imbalance energy (CC6475), real-time unaccounted for energy (CC6474) and the HASP energy, congestion and loss pre-dispatch (CC6051), less real-time congestion offset (CC6774). As stated in the Tariff, allocation of CC6477 is based on measured demand in *pro rata* share to all scheduling coordinators (SCs) including Metered Sub-System (MSS) operators that are not load following and have elected gross settlement.[1]

2 Issue Statement

The ISO has identified two key drivers for the imbalance energy offset (CC6477) based on its evaluation of the settlements outcomes for the month April:

- Significant difference between HASP and RTD energy prices combined with substantial amount incremental and/or decremental HASP imbalance energy; and
- The effect of using an average hourly price for RT demand imbalance energy settlement.

2.1 Divergence Between HASP and RTD Energy Prices

In the ISO's new market design, the hour-ahead hourly inter-tie energy is scheduled through the HASP process and settled using the HASP Intertie LMP. On the other hand, uninstructed imbalance energy of load and generating resources as well as the instructed imbalance energy of generating resources of real-time are settled using the imbalance energy weighted average of the two applicable five-minute energy prices determined in RTD.[2] When the HASP Intertie LMP

[1] For MSS operators that have elected load following or net settlement or both, allocation of CC6477 is based on the MSS Aggregation Net Measured Demand. MSS Aggregation Net Measured Demand is defined in the tariff as "The sum of the net metered CAISO Demand from all the Net-Load MSSs in the MSS Aggregation plus any exports out of the CAISO Balancing Authority Area from the MSS Aggregation. Net metered CAISO Demand of an MSS is defined as the algebraic difference between the gross CAISO Demand and Generation internal to the MSS."

[2] *See* ISO Tariff definition for Resource-Specific Settlement Interval LMP.

and the real-time prices differ significantly, and a significant amount of imbalance energy is scheduled in HASP, there is also a significant disparity in the cost of settling supply in HASP versus the settlement of real-time demand. This appears to be the main driver of the real-time imbalance energy offset charges observed in April.

Over-Scheduling in DA IFM (Day-Ahead Integrated Forward Market)

Over-scheduling of energy – that is, a final IFM energy schedule that exceeds the ISO's load forecast – occurred frequently in the April Day-Ahead (DA) market, especially for certain operating hours. In anticipation of over-generation in real-time, operators act to reduce import energy and/or increase export energy in HASP through market mechanisms such as load forecast downward biasing and exceptional dispatch in the HASP. This puts downward pressure on the HASP energy prices relevant to the inter-tie imbalance energy settlement. However, RTD energy prices are not always low as compared to HASP energy prices. As a result, the settlement dollar amounts that the ISO charges inter-ties for HASP imbalance energy do not always cover net payments to the imbalance energy relevant to RTD including imbalance energy associated with the downward deviations of load and balancing generation. The impact of this disconnect between the HASP and RTD energy price when combined with substantial amount of HASP energy sold to market participants has driven the charges in the imbalance energy offset Charge Code (CC6477).

Under-Scheduling in IFM and Under-Forecasting in RUC

Under-scheduling in the DA market and under-forecasting of load in the execution of the Residual Unit Commitment (RUC) run were rare in April. Under such conditions market mechanisms such as load forecast upward biasing and/or exceptional dispatching in the HASP to increase import schedules and/or reduce export schedules at high prices, especially when large volumes of positive instructed imbalance energy are necessary for real-time operation. However, in real-time, the RTD energy price has not always risen as high as the energy price in HASP. As a result, the payments made to the inter-ties could not be recovered from the net charges to the imbalance energy relevant to RTD including the upward deviation of load and the balancing generation. Again, the difference between HASP and RTD energy prices has led to charges incurred in imbalance energy offset charge code (CC6477). This phenomenon was much less than IFM over-scheduling, and therefore its total impact for April has been much smaller.

Matching Supply to Load Variation in Real-Time

While energy schedules coming out of the DA Integrated Forward Market (IFM) and inter-tie schedules out of HASP are fixed on an hourly basis, the actual load in real-time ramps up and down continuously throughout the hour. During early morning hours of load pick-up and late evening hours of load drop-off, the ISO load moves as much as 2000 MW per hour in up-ramp and as much as 3000 MW per hour in down-ramp. Lack of available downward dispatch capacity in generation to follow load variation within the hour has posed a challenge for real-time operation. In order to avoid over-generation in real-time, in the HASP timeframe the market solution tends to decrease import and/or increase export schedules and subsequently to increase internal generation levels and creates more room for generators for following downward deviation of loads from their DA schedules.

To illustrate the discussion above, consider a generator scheduled at 110 MW in DA where its minimum load level is 100 MW. Imports are scheduled at 50 MW and DA load is 160 MW so that supply in total is equal to the demand in DA market. Consider that in real-time, load ramps from 130 MW to 190 MW during the hour. Though the hourly UIE of load is zero for this hour (i.e., no over-scheduling), should the HASP schedule for import remain unchanged from DA schedule, the room for generation downward dispatching is 110 -100 =10 MW, less than the 30 MW downward deviation of load from its DA schedule. Thus the system is in over-generation by 20 MW when the load is at 130 MW. To prevent over-generation from happening at any time during the hour, imports must be reduced by 20 MW and scheduled at 30 MW in HASP. As such, generator will have to move up 20 MW to counter the reduction of import schedule in HASP, resulting in 30 MW of dispatch room for balancing downward deviation of load.

The April DA schedules show that many generating resources were scheduled at levels only slightly above their minimum loading levels. For steep load ramping hours, the ISO market therefore needed to sell significant volumes of HASP energy to market participants, possibly driving down the HASP price. Therefore, selling energy in HASP was not only due to DA over-scheduling, but also due to a lack of downward dispatching capacity of generation in DA schedules. This additional HASP energy sold to market participants could also result in offset charges if a significant differential in energy prices between HASP and RTD were to exist. Since ramping of system load is the underlying cause of this portion of offset charge, the related costs may be viewed as appropriately allocated to metered demand.

2.2 Averaging effect from the use of hourly prices for RT load energy settlement

Real-time settlement for load and generation is based on 10-minute intervals. However, load is metered on hourly basis, and thus the 10-minute interval energy consumption is not available from the meter data submitted by SCs. For this reason, settlement of the load UIE is calculated on an hourly basis and equally distributed among the 6 settlement intervals within the hour. Moreover, the energy price for settling the hourly UIE of load is an hourly price calculated by simple averaging of the energy prices from the 12 RTD dispatches within the hour. As a result of using the simple averaging in deriving the hourly price for settlement results in load being charged less when deviating upward than it would be charged based on an interval by interval basis, and being paid more when deviating downward. The effect of price averaging becomes more pronounced when the actual energy consumption of load and RTD energy prices fluctuate widely between different settlement intervals within the hour. The following two-interval examples demonstrate the settlement distortion caused by this price averaging.

Example 1

Consider that load deviates up by 50 MWh for first interval at $10/MWh and deviates up by 100 MWh in the second interval at a price of $20/MWh. In this example, the higher energy-price is assigned to the second interval because of larger upward deviation. If load were metered separately for each of the 2 intervals and settlement were based on individual intervals using the actual energy consumption within the interval, load would have been charged \$10*50 + \$20*100 = \$2,500. On the other hand, under the price-averaging scheme for settling load deviations, the average price is \$15/MWh and load is charged for \$15*(50+100) = \$2,250 over the two intervals in total. Thus, load is charged \$250 more than if the more granular meter data was used.

Example 2
Consider that load deviates down by 50 MWh for the first interval at \$20/MWh and deviates down by 100 MWh for the second interval at \$10/MWh energy price. In this example, the lower energy-price is assigned to the second interval because of larger downward deviation. If load were metered separately for each of the 2 intervals and settlement were based on individual intervals using the actual energy consumption within the interval, load would have been paid by \$20*50 + \$10*100 = \$1,500. On the other hand, under the price-averaging scheme for settling load deviations, the average price is \$15/MWh and load is paid for \$15*(50+100) = \$2,250 over the two intervals in total. Thus, load would have paid \$750 less than if more granular meter data was used.

We have observed that the cost shifting effects discussed above are more prominent during those hours with significant amounts of load ramping.

The above discussion suggests that using the settlement interval actual imbalance energy of load with the interval energy prices for settlement amount calculation would reduce the cost distortion. Though load is metered on hourly basis rather than on settlement interval basis, an estimate of the settlement interval MWh quantity can be derived through state estimation results, and these ten-minute values could alternatively be used in the settlement calculations. One potential solution to mitigate the averaging effect contribution to the real time imbalance energy offset would be to increase the accuracy of RT load settlement by utilizing the 10-minute MWh values provided by the state estimator results.

3 Data Analysis

The CAISO has conducted analysis for the month of April using data from the settlement system for energy MWh quantities and settlement dollar values relevant to CC6477 and data from the EDRP system for HASP and RTD energy prices. For April, \$14.13 million in net charges was accrued to the RT imbalance energy offset.

Within the 720 hours in April, offsets were charged in 604 hours (or 83.89% of hours). Ranking the hours from smallest amount charged to CC6477 to the largest payment amount, we have found that the top 36 hours (or 5% of hours) account for \$10 million in the offset charges. This indicates that the bulk of the offset distortion occurred in a small number of hours.

Analysis of the differences between RTD and HASP energy prices within these 36 hours showed that RTD prices were all higher than the HASP prices by an amount ranging from \$38 to over \$600. For 64% of the 36 hours, the ISO market was net in HASP energy exporting (net in selling to market participants) in the amount of 1,500MWh or higher.

A good measure of the cost of the ISO selling low-price HASP energy can be calculated by taking the difference of the RTD and HASP energy prices and multiplying this value by the net amount of HASP energy sold to market participants through inter-ties. For the majority of the 36 hours in which the offset charge amounts were largest, we find that this calculation accounts for 70% or more of the offset amount.

The observations from the above analysis are that the practice of selling HASP energy when there is a significant price differential between RTD and HASP is a key factor in the large offset charge. While this happened in only a small number hours within the month, when is did happen it had a large impact on the settlement amount. Investigation of the large differences in prices is currently in progress.

Additionally, RTD 5-minute energy prices and load from the Enterprise system is used to evaluate the offset distortion effect of averaging RTD prices for hourly prices in settlement. In doing this analysis, it is found that price averaging can account for up to 20 to 30% of the offset charge for many hours among the worst 36 hours described above.

4 Potential Methodology for Two-Tier Allocation of Imbalance Energy Offset

The hourly offset can be a charge or a payment to market participants. For hours where the offset is a payment, it may be appropriate to retain the single tier allocation scheme based on measured demand of SCs as stated in the tariff.

For hours where the offset is a charge, a two-tier scheme with tier-1 allocation based on net positive imbalance energy of SCs and tier-2 allocated to measured demand of SCs could be used.

Referring to the discussion in previous sections, positive net UIE is the main factor behind the HASP negative instructed imbalance energy, resulting in large offset charges when RTD energy price is much higher than HASP price. Visualizing such, the total tier-1 offset charge is calculated as:

Tier-1 Offset Charge total = min (A, B) * max (RTD energy price minus HASP energy price, 0)

A = total of net positive UIE of all SCs
B = absolute value of the net negative imbalance HASP energy netted among all SCs.

In determining the total amount of tier-1 offset charge, the energy amount used in calculation on the RHS of the equation is lesser between the total of net positive UIE of different SCs and the HASP energy sold to SCs in net quantity. This is the energy amount that incurs charges into the offset associated with DA over-scheduling. The $/MWh value for the calculation is RTD and HASP price difference but will be restricted to no less than zero. For RTD price below HASP price, tier-1 offset charge total is zero and will not become negative.

The tier-1 offset charge total is limited to no greater than the original offset charge. The tier-1 offset charge total is allocated to the net positive uninstructed imbalance energy of SCs. The rate that is charged to SCs would not be greater than the difference between the RTD price and the HASP price if the difference is positive. Otherwise the rate would be zero.

Tier-1 offset charge total is allocated to the net positive uninstructed imbalance energy of SCs. The remaining balance of the offset charge is tier-2 offset charge total, allocated to measured demand of SCs.

5 Options

- Implement the above-described two-tier allocation scheme (or something similar) to allocate a portion of the offset charge on UIE basis, in accordance with the factors discussed in this paper that contribute significantly to the size of the offset.

- Identify, and to the greatest extent possible, mitigate the causes of the large energy price differentials between RTD and HASP that occur in a small number of hours within a month. As these causes are identified and corrected, the Tier 1 portion of the offset charge allocated to UIE will become appropriately small under the formula of the previous section.

- Align the time intervals used for the settlement of RT load UIE and generation. To do this the ISO needs to estimate the actual UIE of load within each settlement interval based on state estimator results, and then settle that interval's UIE using the RTD price of the settlement interval. This will fix the offset distortion problem caused by the price averaging of RTD prices under current settlement paradigm.

- Use the RTD price to settle the hourly ties. For import energy would be provided BCR to the extent the RTD prices do not support the bid. However for exports BCR is not provided and exports must accept the risk. This is similar to what the NYISO has been working on to reduce their price difference between their hourly process and RTD.

- Do nothing.

6 Conclusion

If questions, comments or concerns arise with respect to this analysis of the Real-Time Imbalance Energy Offset, please address them to Greg Cook at gcook@caiso.com or Edward Lo at elo@caiso.com.