CAISO Energy Markets Price Performance Report

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California Independent System Operator

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Acronyms

BAA	Balancing authority area
CB	Convergence bid
DAM	Day-ahead market
DOT	Dispatch operating target
ED	Exceptional dispatch
EIM	Energy imbalance market
FMM	Fifteen-minute market
FRP	Flexible ramp product
FRU	Flexible ramp upward
HASP	Hour ahead scheduling pre-dispatch
IFM	Integrated forward market
LMP	Locational marginal price
MCC	Marginal congestion component
MLC	Marginal Losses component
RTD	Real-time dispatch
RUC	Residual unit commitment
SMEC	System marginal energy component
VER	Variable energy resource

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Background and Scope

Early 2019, in response to stakeholder requests, the CAISO committed to analyze price formation in its electricity markets. Stakeholders asked that the CAISO evaluate i) whether real-time prices adequately reflect constrained system conditions, ii) why real-time prices have trended lower than day-ahead prices, and iii) whether intertie energy deviation settlements are setting the correct incentives. The CAISO analyzed the performance of the locational marginal prices (LMPs) in order to respond to these questions.

The CAISO analyzed the drivers of price performance in the CAISO day-ahead market (DAM) and real-time markets (RTM) from January 2017 to March 2019. The CAISO selected this period to account for seasonal variations and capture trends over a longer horizon, including conditions that may have been affected by natural gas prices. The CAISO focused only on the markets within the CAISO balancing authority area (BAA). However, the results of the analysis of price performance in the real-time market may be instructive to other Energy Imbalance Market (EIM) areas because the EIM is part of the overall real-time market.

Earlier this year, the CAISO solicited stakeholder input on the scope and nature of the analysis and later provided an updated and preliminary results in June 2019. The CAISO held a conference call with stakeholders on June 21 to discuss the content of the preliminary report and solicited additional written stakeholder comments. This final report provides the complete results of the CAISO's analysis and responds to stakeholder comments (see Appendix D). The CAISO also discusses potential enhancements to address any price performance findings discussed in this report.

Executive Summary

The CAISO analyzed different aspects of price performance, considering and evaluating multiple drivers of price formation in its day-ahead and real-time energy markets. The analysis primarily consisted of two complementary analytical efforts. First, the CAISO identified and evaluated persistent trends and patterns from January 2017 through March 2019. Second, the CAISO evaluated several case studies that considered different system and pricing conditions to identify the cause and effect of the price performance drivers. In some instances, the CAISO reran the original market case with controlled changes in conditions to evaluate counter-factual case scenarios. These counter-factual cases provide insights into how inputs and conditions influence market outcomes. The first analytical approach in several cases identified specific cases that were further evaluated under the second analytical approach.

From all the items identified in this effort, the main findings are summarized as follows:

- Market uncertainty, in either the day-ahead or real-timeframes, is estimated based only on load, wind and solar resources, and is measured with net load error defined as load minus solar and wind supply. The most significant level of uncertainty in the CAISO markets materializes between the day-ahead and the real-time markets, and has generally well-defined hourly and monthly profiles. Day-ahead uncertainty, estimated as the difference of net loads between the DAM and RTM, can be as much as 6,000 MW, while the real-time uncertainty may reduce to about 1,500 MW. The level of uncertainty does not vary significantly when using either the bid-in demand/supply from the integrated forward market (IFM) or the load and variable energy resource (VER) forecast from the reliability unit commitment (RUC) process; and also does not vary significantly regardless of whether it is compared to either the fifteen-minute market (FMM) or real-time dispatch (RTD). This uncertainty reflects variations of the load forecast (accuracy) compounded with the variations in VERs performance. On some extreme days, load forecast error was driven by temperature changes (error) of more than 10 degrees. Days like July 25, 2018 or June 10, 2019, during which the system experienced peaking conditions, were also days in which rapidly changing temperatures led to large forecast errors.

- CAISO system operators may conform the load forecast to account for changing conditions in the system and to position the system to projected needs. The load conformance applied in the real-time market tends to increase the uncertainty between DAM and RTM and typically maxes out in the peak hours of the day because the load conformance will tend to increase the real-time load requirements.

- Convergence bids, or virtual bids, help converge the day and real–time market prices by taking on arbitrage opportunities. The analysis of the effect of virtual bids provides mixed results. In some periods of time, convergence bids narrowed the gap between DAM and RTM prices, but in other cases they increased the gap. Convergence bids are not the only force impacting price convergence between the two markets and the analysis confirms that uncertainty between the DAM and RTM, as estimated by the net load errors between the markets, is a contributing factor to price divergence. For instance, the relationship between net load error and price divergence between markets shows that generally when the net load error is positive (net load in real time is higher than the day-ahead net load) prices in real-time tend to be higher than day-ahead prices. Conversely, when FMM net load is lower than the IFM net load, FMM prices tend to be lower.

- Manual dispatches on interties consist of a relatively small portion of the overall volume of exceptional dispatches (EDs), but they tend to be used on peak days when supply is tight. Manual dispatches on interties may settle at a negotiated price. When import energy from manual interties is actually made available to FMM and RTD, it will displace more expensive energy bids that otherwise could have set prices. The inclusion of that additional energy from manual interties at the bottom of the bid stack will tend to lower the price paid to the rest of the market.

- The flexible ramping product (FRP) considers a capacity requirement for each EIM BAA, including the CAISO BAA, as well as one requirement for the system-wide EIM area as a whole. The FRP requirements for a given BAA can be met with resources internal to that area or if more efficient, with resources from other areas. When the FRP requirement is met with resources external to the EIM entity's BAA, the amount of EIM transfers that can occur between areas is bounded by each area's net import/export capability, while ensuring each area can fulfill its own FRP requirements first. The effective FRP requirements applicable to each EIM BAA can be significantly lower than the original FRP requirement. When the effective FRP requirement is lower than the original requirement, each EIM area's flexible ramp can be met from other EIM BAAs through the EIM transfers respecting EIM transfer limits. This outcome can be observed in any EIM BAA. As a result, the overall system-wide EIM area requirement is effectively enforced and may set the FRP procurement for the entire EIM footprint. At times it is economic to procure FRP capacity from internal resources of each EIM BAA, which naturally will meet, to some extent, the original EIM BAA requirement. For the CAISO BAA, the market design provides for additional optimized imports at the CAISO inter-tie scheduling points in the FMM that could provide the ability to increase flexibility on internal resources by unloading their energy dispatch. However, the amount of fifteen-minute import bids offered in practice appears be fairly limited.

- FMM is part of a series of fifteen-minute intervals (*i.e.,* the real-time unit commitment (RTUC) process). The RTUC runs every fifteen minutes to make commitment decisions for fast and short start units for the next four to seven subsequent fifteen-minute intervals, depending on when during the hour the run occurs. The second interval of each RTUC run horizon is designated as FMM run and is the binding interval for energy prices and schedules used for settlements. The first interval in an RTUC run horizon, or the interval preceding FMM, is referred to as the *buffer* interval. The RTUC in the buffer interval, in addition to commitment of fast and short-start units, produces advisory schedules and prices that are not financially binding. FRP procurement is set based on uncertainty and movement between two adjacent FMM intervals and is associated with the first of these two intervals. FRP procurement associated with the binding interval can be utilized between the binding interval and the subsequent advisory interval when uncertainty realizes between FMM runs or between an FMM run and the corresponding RTD runs. Currently, the FRP requirement is not enforced in the buffer interval of each market run. Because the FRP has already been procured for that interval in a previous FMM run, the lack of FRP requirement for the buffer interval implies that any FRP procured in the previous FMM run can be fully released. If uncertainty realizes in the subsequent FMM run, the FRP previously procured will be readily utilized in that FMM, which is considered to be an optimal market solution. However, fully releasing that previously allocated FRP capacity means there may no longer be any capacity available for the RTD intervals within in that timeframe; or, even worse, the flexible capacity may be actually lost, which is the case when projected start-ups of certain units necessary to carry flexible ramp are re-optimized in subsequent intervals and no longer determined as needed because of the additional flexible capacity resulted from the release of the FRP in the buffer interval. This may be one condition leading to real-time price spikes even though prices for flexible ramp capacity during the affected intervals were $0.

- Flexible ramp capacity can be allocated to multiple types of resources, including proxy demand resources (PDR). Recent trends show multiple PDR resources with bids at or close to the bid cap of $1,000/MWh are awarded FRP. The real-time market may procure FRP from PDRs because it is economic to do so, and it can happen frequently at low or zero-dollar FRP prices since procurement is based on the opportunity costs between providing energy or FRP. Because PDRs with high bids will generally not be dispatched for energy, they will not have a tradeoff between energy and FRP capacity and, thus, the market may find that the most optimal solution is to allocate FRP to all PDR resources. That FRP capacity then cannot be utilized or delivered when uncertainty realizes in FMM or RTD, unless the clearing prices for energy reach the bid cap of $1,000/MWh. In such cases, the FRP capacity procured from PDRs with high energy bids leads to a systemic underutilization of FRP. Furthermore, even when FRP capacity procured from PDRs is used the real-time market, if PDRs are unable to follow five-minute real-time dispatches the procured FRP is not materialized. Therefore, utilization of flexible ramp from PDRs does not currently translate into an operational reality.

- Procurement of FRP capacity is based on opportunity costs, which arise from the trade-offs between energy and the need for FRP capacity. Because there is only one area-wide requirement per each BAA within the EIM area or the entire EIM area as a whole, the market does not consider locational constraints when procuring FRP. This presents two complications regarding the effectiveness of the current FRP design, which results in under-utilization or under-deployment of FRP. The first complication relates to FRP in the context of the EIM. Because the FRP requirements for the CAISO BAA are effectively zero and the need is fulfilled with the enforcement of the system-wide EIM area requirement only, a large volume of the procurement may end up allocated in other EIM areas. However, transfer capability between these EIM areas and the CAISO can become limited or fully utilized for energy, stranding that flexible ramp capacity behind EIM transfer constraints. Thus, even when uncertainty materializes and resources in other EIM areas carry the flexible capacity, this capacity cannot be utilized for meeting CAISO's area needs.

  The second complication relates to congestion from internal constraints within any BAA participating in the EIM. The CAISO enforces transmission constraints within each EIM BAA, which allows the market to economically manage congestion. As part of the congestion management process resources can move up if they help to mitigate the congestion, or down if they exacerbate congestion. This optimal dispatch is matched with the corresponding price signal through the marginal congestion component at the LMP of each resource's location. Since FRP is not locational-based, this part of congestion management does not explicitly account for the FRP procurement. As a result, the market can procure flexible ramp capacity from resources that are dispatched down for congestion management, then in the following market run when uncertainty materializes, congestion will prevent the flexible ramp capacity from being deployed. This interplay between congestion and FRP procurement can be further complicated because the market may find it optimal to allocate FRP capacity precisely to resources dispatched down for congestion management. However, the market has no mechanism to avoid this outcome. Based on the analysis performed, this has happened in other EIM areas as well as the CAISO area.

- Losses associated with PDCI may create a systemic difference between the DAM and HASP versus FMM and RTD. Currently, the CAISO models this type of in-kind losses only in FMM and RTD markets as export transactions, and does not consider them in the HASP or DAM because they are not known by the time DAM and HASP are run. Thus, this losses consideration effectively increase the demand that the CAISO market must clear in FMM and RTD, which may drive the market to clear at a higher-price point in the supply. Secondly, there may be cases where losses can lead to losing the congestion signal on the intertie associated with the export record.

- There are cases in which the HASP observes the need for congestion management and therefore creates a congestion signal for a given intertie in addition to securing the schedule feasibility at the intertie. Subsequently, when FMM and RTD run, if conditions do not change, both FMM and RTD will start with an already feasible solution. Because the intertie schedules will remain fixed, there will be no need for further congestion management and the congestion price signal will no longer show up in FMM and RTD. Conversely, there are scenarios in which the HASP did not observe congestion, but system conditions change afterwards, such as a participant tagging higher than HASP schedules, and then the intertie binds in FMM or RTD as a result of congestion management. This is the right outcome in terms of how the market sequencing and clearing processes work, given the incremental nature of settling the markets. The complication resides in the intertie settlements in which hourly interties are cleared in the HASP market at certain prices but that price signal may not be preserved in the subsequent FMM.

- Under current functionality, VERs have the flexibility to economically bid into the IFM. However, the CAISO has observed that VERs are consistently under-scheduling in the IFM relative to their forecasted amounts. The CAISO has since implemented a true-up process in RUC, where IFM bids for VER resources are increased to the forecast values. This allows RUC to consider VERs forecast values to avoid over-committing generation in RUC. However, this true-up process is in place only for resources that participate in IFM. There may be cases in which VERs do not bid (with either an economical bid or a self-schedule) in IFM and this true-up process will not apply. Consequently, there may be VERs supply still not considered in the RUC process that is projected to be available in the real-time market based on the VERs day-ahead forecast; this may lead to excess of generation in the real-time market.

- In certain cases, VERs appear to be bidding in the IFM beyond their natural capability. In IFM the VER bids are not capped by the day-ahead forecast. A clear example is a set of solar resources bidding up to their maximum capacity for hours in which solar resources clearly cannot produce due to the lack of irradiance; *i.e.*, from 10pm through 5am. Whether this bidding is intended or inadvertent, it introduces noise to measures of VERs under-scheduling in DAM. However, this may not have an impact on pricing performance because the same outcome would be achieved by having a convergence bid for that capacity.

- In January 2019, The Market Surveillance Committee (MSC) submitted a written opinion on the CAISO's Intertie Deviation Settlement initiative. The opinion of the MSC expressed concerns[1] that, the proposed intertie settlement rule would not be effective in incentivizing delivery and performance if intertie real-time pricing did not accurately reflect system conditions. The MSC reached this conclusion based on analysis from specific examples using the CAISO's previously released data. However, this data incorrectly characterized manual intertie dispatches (a type of EDs) as intertie deviations. Following the publication of the MSC opinion, the CAISO recognized and corrected the misclassified data and informed the MSC of the corrected data.[2]

- Using the corrected data – correctly classifying manual EDs in comparison to intertie deviations -- the CAISO has reviewed the specific examples identified by the MSC and can confirm the market prices on these dates/hours appropriately reflected system conditions. When more supply is made available to FMM and RTD by means of issuing manual dispatches on interties, the resulting prices in both FMM and RTD were lower than in HASP. This conclusion supports the proposed intertie deviation settlement.

- The volume of intertie deviations associated with EIM entities is fairly small compared to the overall volume of deviations. This addresses the MSC's concern that the volume of intertie deviations could be actually motivated by entities participating in the EIM.

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1 *See* MSC – Final Opinion on Intertie Deviation Settlement, January 18, 2019, http://www.caiso.com/Documents/MSC-OpiniononIntertieDeviationSettlment-Jan18_2019.pdf.

2 The CAISO analyzed the corrected data and determined it had no material impact on the proposed settlement rule. Therefore, there were no changes made to the Intertie Deviation Settlement proposal. A revised draft final proposal was published in February 2019 to reflect the corrected data analysis. http://www.caiso.com/Documents/DraftFinalProposal-IntertieDeviationSettlement-UpdatedFeb13-2019.pdf

Possible Enhancements to Improve Price Performance

The analysis highlights certain areas where price performance can be improved. The discussion of these potential enhancements and their implications are provided below. The CAISO will engage stakeholders in the evaluation of the possible solutions discussed below and will pursue any changes to either its business practice manuals (BPMs) or Tariff, or both, as necessary.

1. Current performance of FRP in real-time market.

In 2016, the CAISO implemented the FRP to address the growing presence of uncertainty in the real-time markets, in part driven by the increased integration of VERs in the CAISO BAA. The FRP was tailored to address the uncertainty observed in the real-time markets only, which considers uncertainty between FMM and the RTD. With respect to the various areas of potential enhancements discussed in this report, the FRP items have the highest priority. The CAISO is exploring the following FRP solutions:

a. **Effective FRP requirements for EIM BAAs.**
Currently, the original FRP requirements for each EIM BAA can be significantly offset due to the credit consideration of EIM transfers when transfer capability into are area is large relative to the BAA requirements. The permissible EIM Transfers are bounded by the net import/capability of each BAA, which is purely based on the transfer capability that may exist for a given EIM area. However, this capability does not reflect nor is bounded by the actual capacity that the adjacent EIM areas can provide based on actual resource capacity and bids made available for the EIM market. Consequently, the current use of the import/export capability will generally be insufficient to provide the flexible ramp capability that individual EIM areas may need. This can become more s significant for EIM BAAs that can observe higher level of uncertainty comparable to the uncertainty of EIM areas combined.

The CAISO is exploring other internal mathematical approaches to limit the impact of NIC/NEC on each of the EIM areas.

b. **FRP requirement for the buffer interval in FMM.**
The lack of a FRP requirement between the (first) buffer interval and the (second) binding interval leads to the full release of the flexible ramp that was previously procured In some cases, this leads to the loss of flexible capacity that is dispatched as energy in FMM and not reserved for uncertainty that may materialize RTD.

The CAISO is exploring alternatives to ensure the FRP procured in the previous FMM is not fully released in the subsequent FMM so that the awarded FRP is reserved for RTD to use when uncertainty materializes in RTD.

c. **Non-deliverability of procured FRP.**
Procurement of flexible ramp capacity does not take into account the location of the procured capacity. Under the current market design, flexible ramp capacity can be procured from resources that are subject to congestion. The congestion from either EIM transfers or internal constraints to a BAA may prevent the utilization of the flexible ramp capacity when uncertainty materializes in the real-time markets. To some extent the solution of item

a: Effective FRP requirements for EIM BAAs (described above) will address this issue. However, the CAISO is considering whether further enhancements that explicitly address congestion-based non-deliverability of FRP are necessary. These possible enhancements will be considered as part of the incorporation of a FRP in the DAM enhancements, including the consideration of a regional deliverability requirement or locational procurement of FRP in the day-ahead as well as in the real-time market.

d. Flexible ramp allocated to PDRs.
Since these resources are not currently able to follow RTD instructions, rendering the procurement of FRP of no use, the CAISO has explored to not allow PDR resources to be eligible for flexible ramp capacity schedules and awards. In the short term, the CAISO is exploring options making PDRs that do not respond to five minute dispatch ineligible for FRP under its current tariff authority. For the long term, once the enhancements for the Energy Storage and Distributed Energy Resource (ESDER Phase 3) initiative[3] are fully implemented, PDRs that are not five-minute dispatchable should not be registered as such in the master file because they will have the option to elect hourly or fifteen minute scheduling. This will make such resources not-eligible for FRP and will address this issue in part.

2. Managing uncertainty from the DAM to RTM.

The CAISO is currently exploring market enhancements to address the uncertainty that materializes from DAM to RTM[4] Such as the creation of a new DAM product. Market mechanisms that address uncertainty reduce the need for operator intervention to procure additional RUC capacity, operator imbalance energy conformance or EDs. This is a high priority item for the CAISO.

3. Divergence between HASP and FMM/RTD markets.

Because the CAISO must execute the various components of the real-time market (*i.e.*, the HASP, FMM and RTD) sequentially, there will naturally be a delay between the execution time of each market. During that lapse, system conditions may change and naturally lead to price divergence between markets. This may be further complicated by the fact that although hourly intertie resources are cleared in HASP they are still settled at FMM prices, which can also create inconsistencies between schedules and prices for hourly interties.

There are some areas identified for potential enhancement

a. **Market timing.**
The timing of the real-time market is rooted in the market structure and data and system changes will inherently happen across markets. Thus, there is no specific enhancement that can target this timing concern. As the market progresses towards real-time, the market will have more up to date

[3] *See* Tariff Amendment - Energy Storage and Distributed Energy Resource (ESDER Phase 3) September 3, 2019 (FERC Docket No. ER19-2733) http://www.caiso.com/Documents/Sep3-2019-TariffAmendment-EnergyStorageandDistributedEnergyResource-ESDER-Phase-3-ER19-2733.pdf.

[4] *See* Day-Ahead Market Enhancements Stakeholder Initiative. http://www.caiso.com/informed/Pages/StakeholderProcesses/Day-AheadMarketEnhancements.aspx

information and the market solution will reflect these conditions. There is no expectation at this point to reconsider the settlements for hourly interties, in which hourly resources are settled at FMM prices.

b. **Treatment of PDCI losses.**
The CAISO is evaluating whether to model the expected PDCI losses in the HASP (later considered in FMM and RTD) in order to minimize the gap.

c. **Reservation of transmission in HASP for existing rights or transmission ownership rights.**
Some holders of existing rights or transmission ownership (ETC/TOR) rights may have the right to reserve their transmission capacity reserve up to 20 minutes before the hour. Today, the CAISO reserves the ETC/TOR rights when it clears the HASP so that it can avoid curtailing other HASP schedules should ETC/TOR rights later exercise their rights.

The CAISO is exploring whether it may continue to holding these rights by executing the HASP without such reservations and curtailing other non-ETC/TOR rights when ETC/TOR rights holders later exercise their rights.

4. Consideration of VERs.

The CAISO is considering an enhancement related to VERs that could reduce the uncertainty that materializes between DAM and RTM. VERs, like all resources, have the flexibility to economically bid in IFM. The CAISO has implemented a true-up process in RUC, where the CAISO increases the IFM bid-in amounts for VERs up to the forecast values. The CAISO is considering extending this logic to all VERs even if they do not have a bid or self-schedule in IFM.

With regards to VERs bidding in the DAM beyond its natural capability, the CAISO believes its tariff already prohibits such behavior and will take appropriate actions to ensure such behavior does not continue. This does not have an impact on pricing performance but it may impact the allocation of RUC commitment costs that would otherwise apply to convergence bids that are appropriately submitted as such and not physical bids.

Market Structure and Price Performance

Based on the CAISO market design, the CAISO expects prices between the Day-Ahead Market (DAM) and the Real-Time Market (RTM) to converge to a reasonable degree, subject to changes in system conditions. The level of price convergence across markets, and the degree to which prices reflect actual system conditions are indicators of robust price performance in the CAISO markets.

The RTM is composed of three sequential sub-market processes that are executed sequentially at different times, granularities, and for different forward looking horizons: Hour Ahead Scheduling Process (HASP), the Real-Time Unit Commitment (RTUC), the Fifteen Minute Market (FMM), and Real-Time Dispatch (RTD). The RTUC runs every fifteen minutes to commit fast and short start units for the next four to seven subsequent fifteen-minute intervals, depending on when during the hour a particular RTUC run occurs. The second interval of each RTUC run horizon is designated as the FMM run and is the binding interval for energy prices and schedules used for settlements. FMM runs for a horizon of up to four and a half hours ahead and as short as one hour ahead, and begins running approximately 37.5 minutes ahead of the binding interval. The FMM solution is financially binding for both internal and intertie resources. The HASP runs about 75 minutes in advance of the binding hour and is conducted on one of the fifteen-minute RTUC runes. The RTD runs for a horizon of up to one hour and five minutes and runs 7.5 minutes ahead of the binding interval.

For intertie resources participating on an hourly basis, the financially binding schedules are determined in the HASP instead of FMM. However, the FMM clearing prices are used to settle hourly resources. For internal resources, the FMM schedules are financially binding, but they do not set physical operational instructions for energy because they are ultimately re-optimized in the five-minute RTD. FMM commitment instructions -start-ups, shutdowns and transitions- are, however, physically and financially binding. In the RTD, both dispatches and prices are operationally and financially binding.

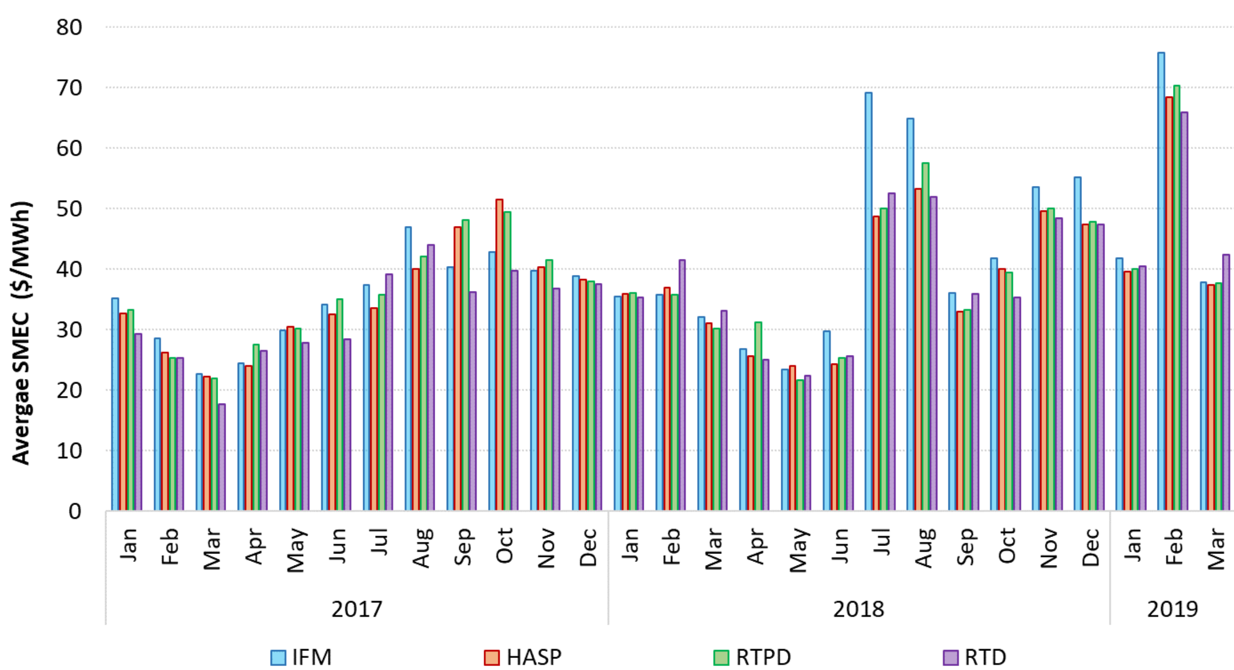
The CAISO follows a standard multi-step settlements process, in which the DAM is settled fully and subsequent markets are settled incrementally; *i.e.*, FMM schedules settle with respect to IFM awards, and RTD settles with respect to schedules and dispatches set in FMM. The CAISO settles the volumetric difference of hourly schedules relative to IFM schedules, based on real-time prices (either FMM or RTD prices). When prices diverge persistently across the multi-step settlements, resources could arbitrage across markets. Convergence bidding is intended, in part, to help converge prices between the DAM and RTM.

Energy prices in the CAISO market consist of three main components – the system marginal energy cost (SMEC), the marginal congestion cost (MCC), and the marginal cost of losses (MCL). The SMEC reflects the marginal cost of meeting the system-wide demand. The MCC is based on the binding transmission constraints in the system and varies by location. The MCL reflects the sensitivity of a location to system losses. Price performance, such as convergence, at the system level can be measured using the SMEC, which will illustrate price convergence to meet system-wide supply and demand. Although the price decomposition of locational marginal prices is relative to the selection of the slack node, the SMEC can generally provide a reasonable reference of the power balance (supply equals demand) at the system level.

Another option is to rely on a different construct that is independent of the slack selection, in this case taking the full locational marginal prices. Typically, Default Load Aggregation Points (DLAP) or Trading Hubs (THs) have been used as a reference. In this report, a reference price is constructed by taking a weighted average of the four DLAPs in the CAISO system, namely, DLAP_PG&E, DLAP_SCE, DLAP_SDG&E and DLAP_VEA. The weights are the amount of load cleared at each DLAP. Such price will be referred to as the system- weighted price. The difference between the SMEC price and the system-weighted price will reflect the marginal losses and congestion observed at the DLAP level.

Figure 1 through Figure 4 show the simple averages of system weighted prices compared across the various CAISO markets[5]. Figure 1 shows a monthly trend, while Figures 2 through 4 show the averages on an hourly profile broken out by calendar year. Overall, IFM prices in 2018 tended to be higher than real-time prices for most times of the day, with the largest divergence observed in the summer months. Within the various runs of the real-time market, the trend of price divergence is less pronounced and has a less persistent trend as compared to the IFM. The Appendix shows the same metrics using instead the SMEC component only.

Figure 1: Monthly comparison of average system- weighted prices across the CAISO markets



[5] RTD dispatches can be issued intermittently on five minute basis to PDR resources based on system changing conditions. In some cases, these dispatches are not feasible since some PDR resources need notice to deploy. Furthermore, in some cases, once the programs are triggered, they need to remain on for a minimum period of time. Consequently, when the CAISO dispatches these resources, they will not follow the instructions.

In comparison to the statistics with the weighted average price, those based on SMEC prices and presented in the Appendix show similar trends of price convergence, even though some months generally show a larger divergence using SMECs. The monthly trend also shows an interesting factor of the market dynamic fairly influenced by the gas-system dynamic. Months like July 2018, or February and March 2019 are a reflection of higher and more volatile gas conditions. With the CAISO market relying substantially on gas resources, the electric prices –either SMEC or DLAPs- will move accordingly, with higher electric prices when gas prices increased.

Figure 2 illustrates the price convergence on an hourly profile, which shows that IFM prices are persistently higher than real-time prices starting in 2018 and continue in 2019. This divergence is more pronounced during peak hours when the system is naturally tighter in supply. As discussed in subsequent sections, the CAISO markets are experiencing the highest prices during the net load peak hours, instead of during the gross peak hours.

Figure 2: 2017 hourly comparison of average system-weighed prices across the CAISO markets

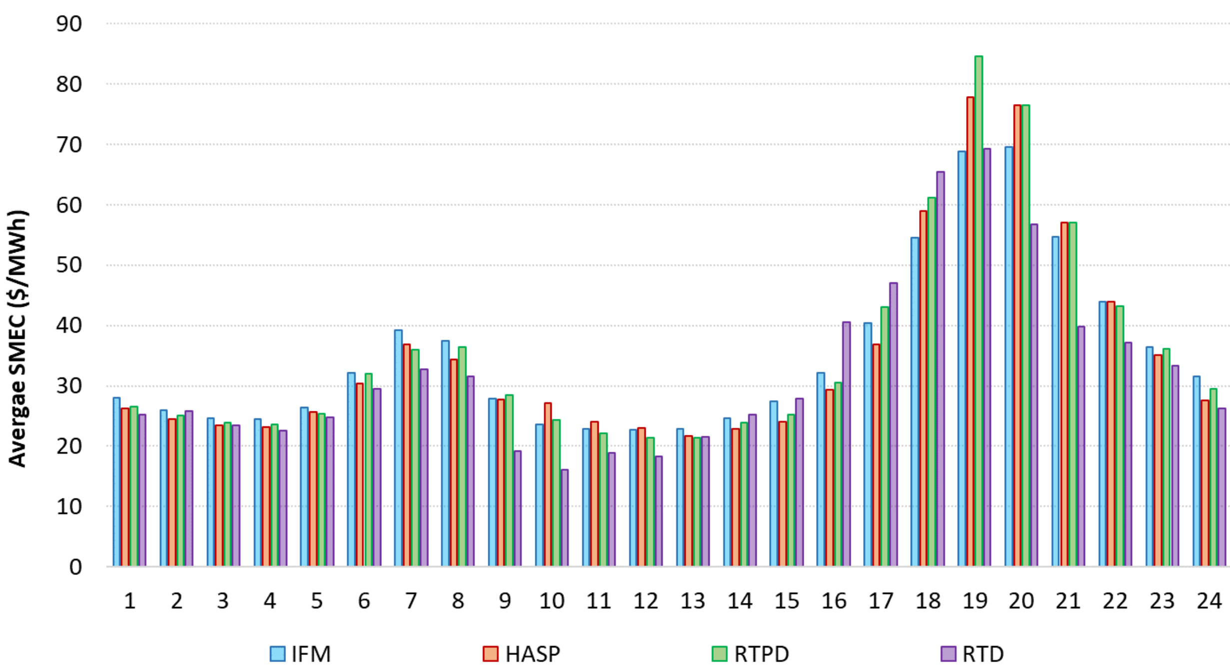


Figure 3: 2018 hourly comparison of average system-weighted prices across the CAISO markets

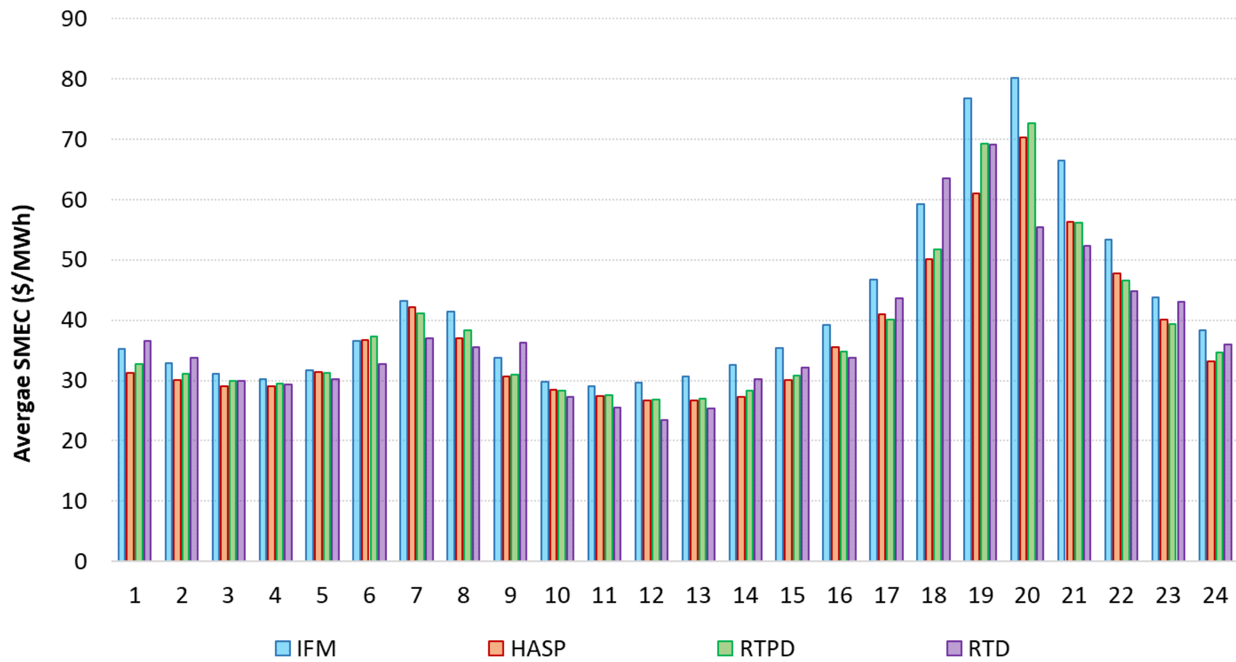
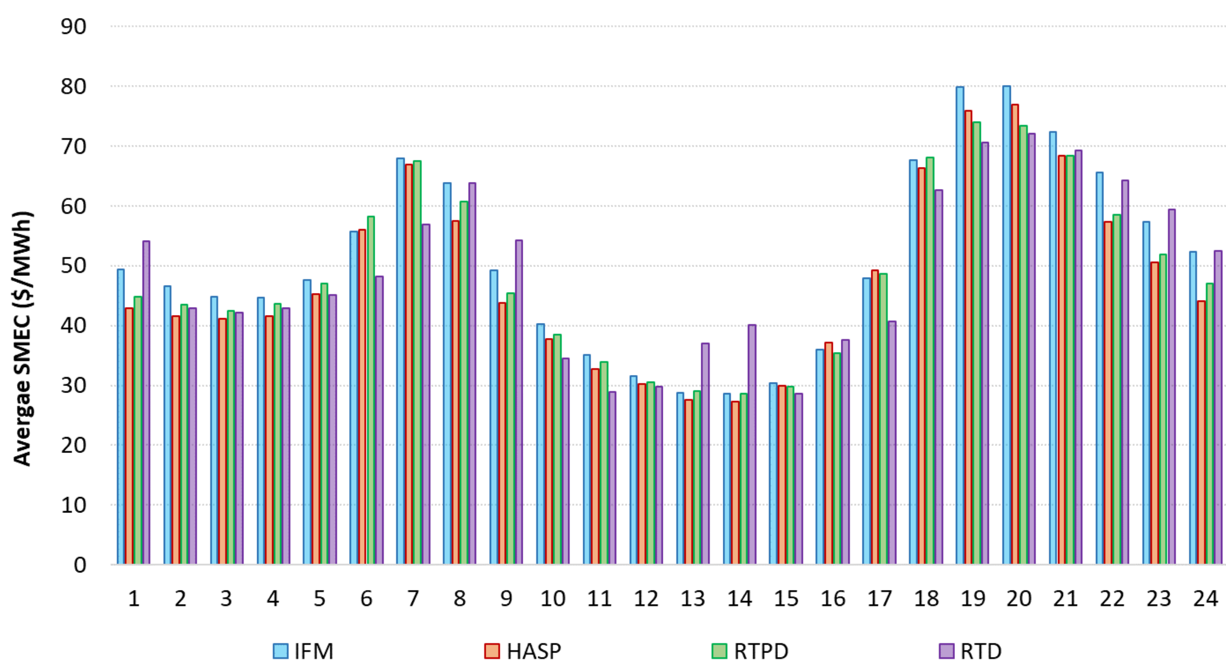


Figure 4: 2019 hourly comparison of average system-wide prices across the CAISO markets



Either SMEC or the system weighed price can provide an accurate reference of price performance at the system level. However, the price performance at scheduling points of interties may be different from the system-based performance. This is because there are market design features related to the treatment of interties, discussed throughout this report, which may lead to congestion differences among markets that metrics on either SMEC or DLAPs will not capture explicitly. Figure 5 through Figure 7 illustrate price convergence at representative scheduling points for the Malin, NOB and Paloverde interties. These three interties are taken as a proxy reference for intertie performance since they are the main interties at which a significant volume of energy is traded within the CAISO system.

Although HASP prices are not used to financially settle interties, this market produces financially binding schedules for hourly intertie resources, which are then settled at the FMM prices. Intertie resources can participate in the CAISO markets under different formats. They can opt to use i) hourly interties, which means they are scheduled with a flat hourly profile in the HASP; ii) fifteen-minute resources which are scheduled in FMM on a fifteen-minute basis, and for which their schedule may vary from interval to interval within the hour; and iii) one-time adjustments, which allows resources to make adjustments to their hourly schedule through FMM. Regardless of these scheduling options, intertie schedules are all settled based on the FMM prices. Hourly interties are, by and large, the main type of interties participating in the CAISO markets. Thus, divergence between HASP and FMM prices have direct implications in the real-time markets. Both the Paloverde and Malin interties reflect similar trends to the system weighed prices during some of the most pronounced periods, like the summer of 2018 when IFM prices were fairly higher than real-time prices. However, the NOB intertie in particular shows a more pronounced divergence mainly within the HASP. Generally, the NOB intertie has observed fairly lower prices in HASP relative to the other CAISO markets. Unlike other interties, NOB has only hourly intertie bids.

Figure 5: Monthly average LMP at Malin scheduling point

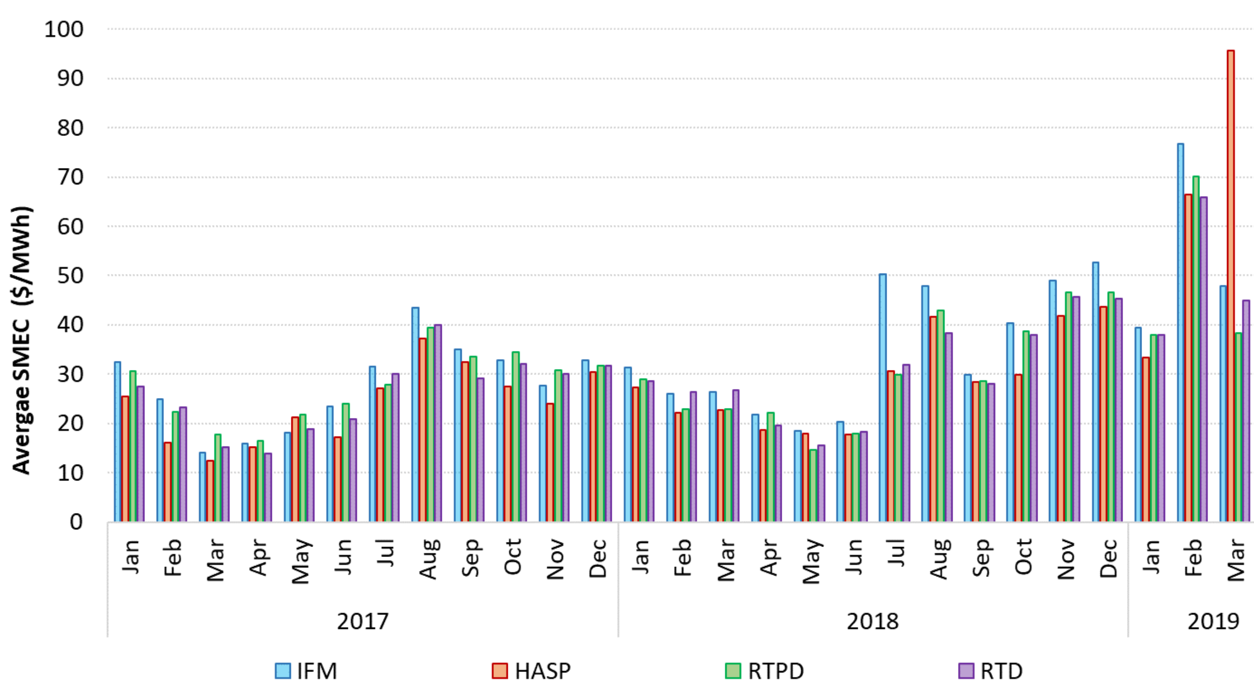


Figure 6: Monthly average LMP at NOB scheduling point

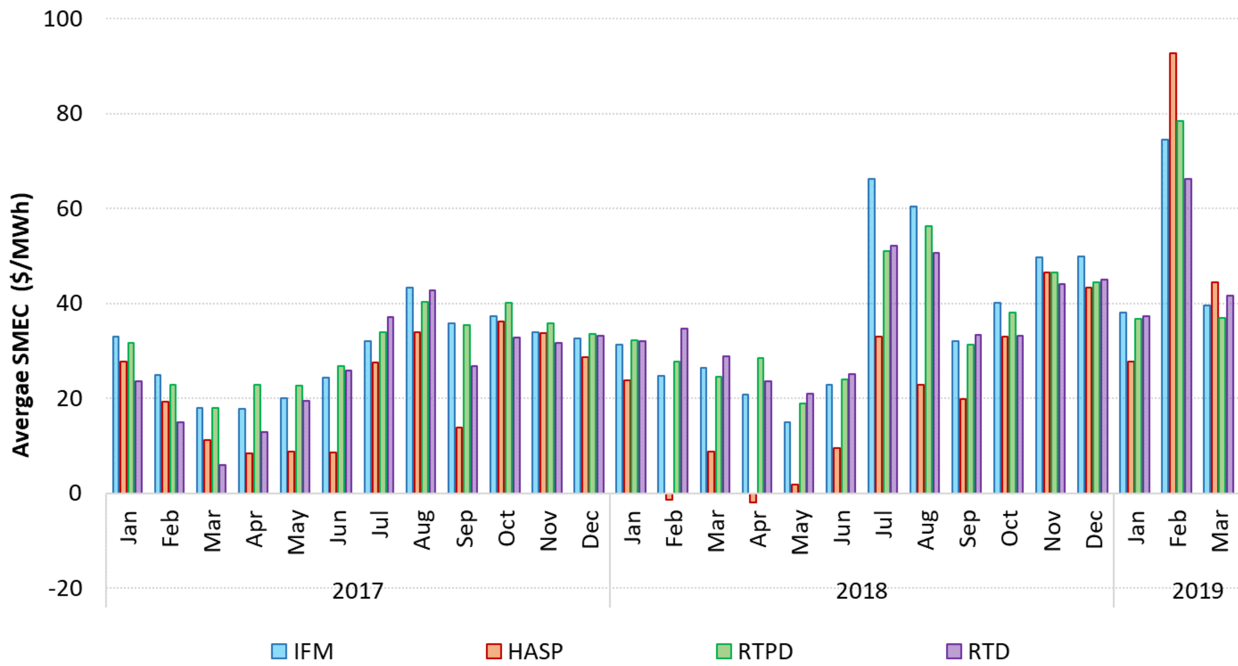
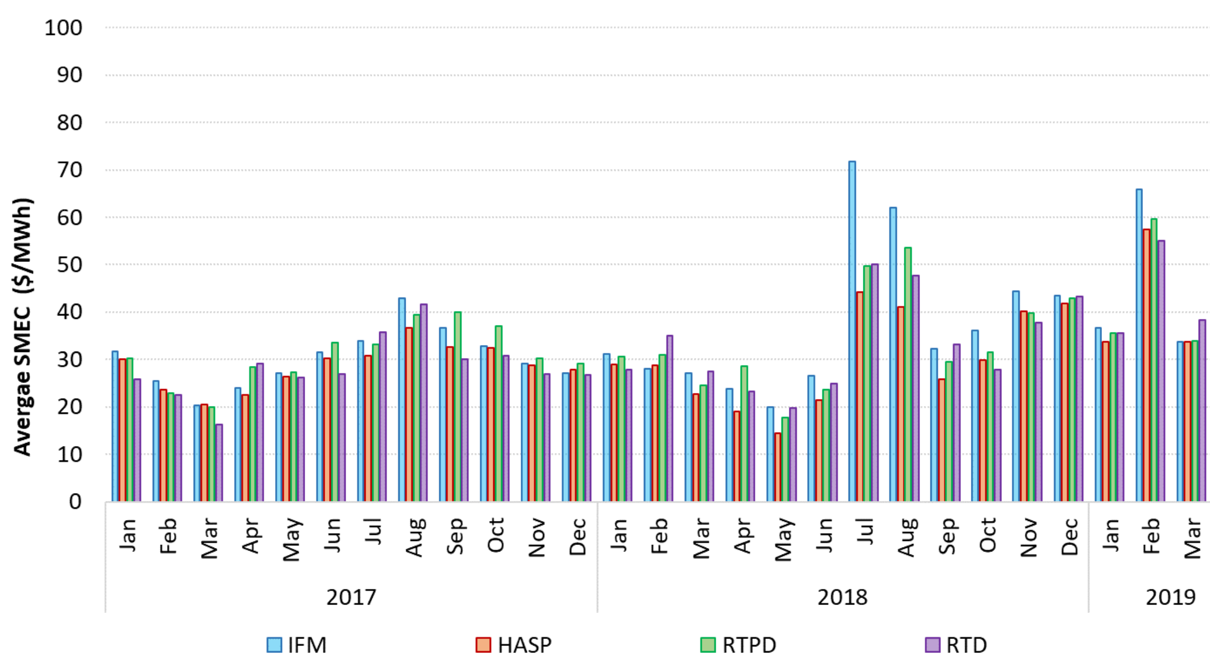


Figure 7: Monthly average LMP at Palo Verde scheduling point



Although averages can provide a rough visualization of how prices may be evolving overtime, they are too coarse to capture the frequency and magnitude of the price spreads across CAISO markets. Figure 8: through Figure 11: show the price distribution of each market using box-whisker plots. The boxes represent the samples within the 10th and 90th percentile and the whiskers represent the samples from the minimum value to the 10th percentile, and from the 90th percentile to the maximum value respectively. The blue marker in the box represents the median (50th percentile), while the red marker represents the simple average price. In order to show a meaningful level of prices in a graph, these figures have been limited to a price range between -$50/MWh and $150/MWh. The plots with a full price range are shown in Figure 154 through Figure 157 in the Appendix.

There are certain months in which the price variation increased significantly: July and August 2018, when peaking conditions combined with high gas prices occurred system-wide, and February and March 2019, when volatile gas conditions were observed in the Western United States. In these months, 80 percent of the prices move within a range of $90/MWh, in comparison to the price window of $35/MWh observed in other months.

Figure 8: Averaged system-weighted prices in IFM

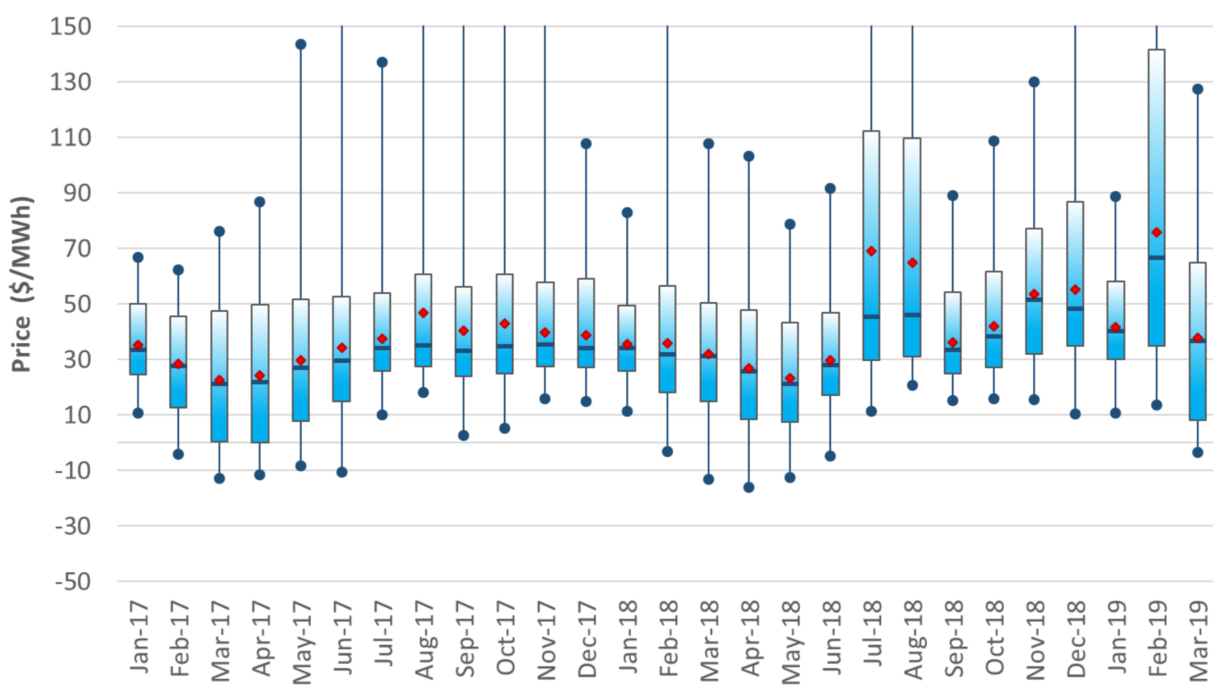


Figure 9: Averaged system-weighted prices in HASP

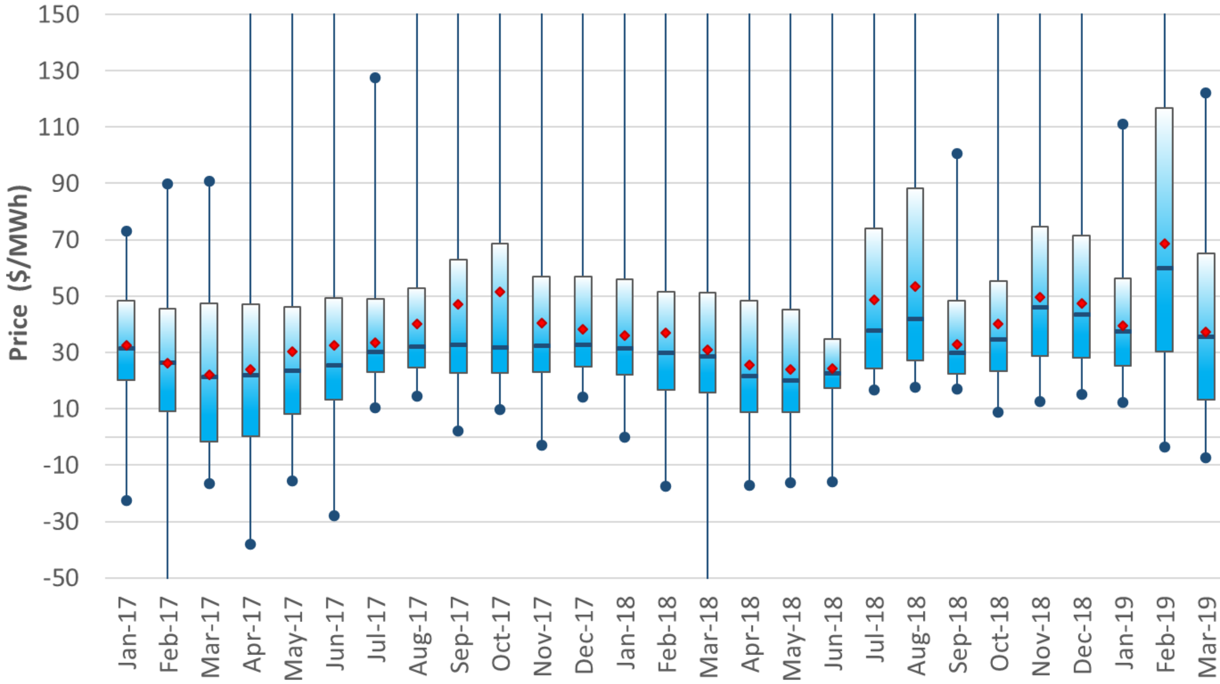


Figure 10: Averaged system-weighted prices in FMM

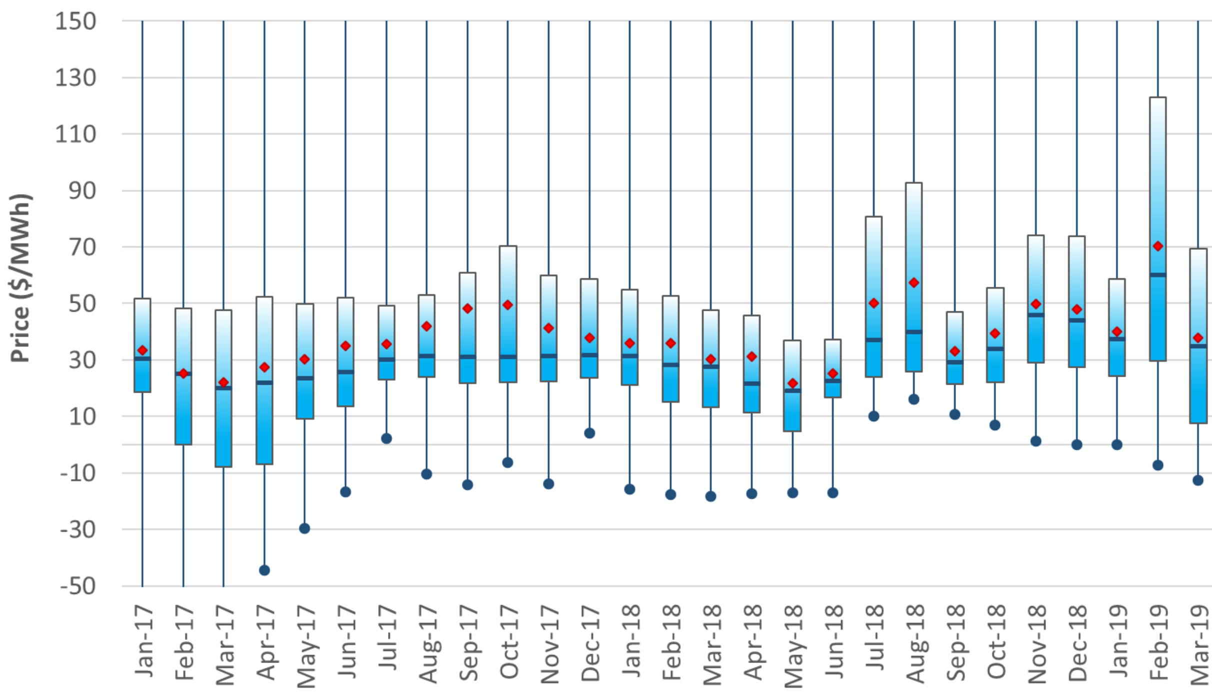


Figure 11: Averaged system-weighted prices in RTD

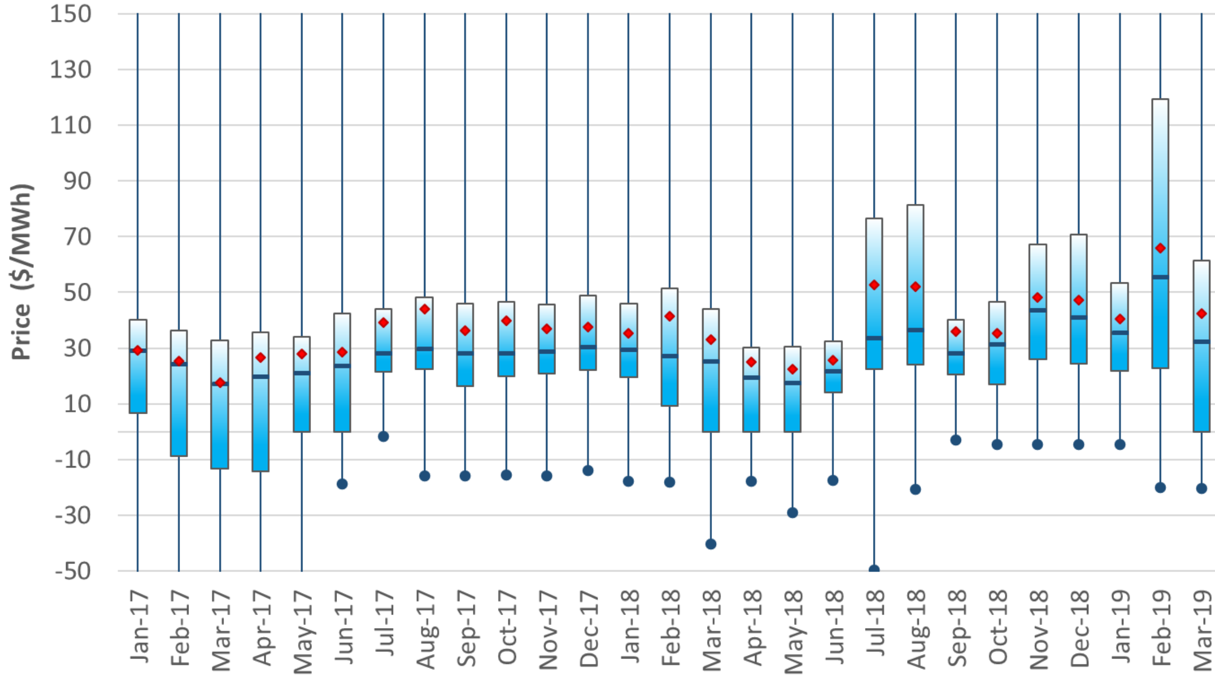
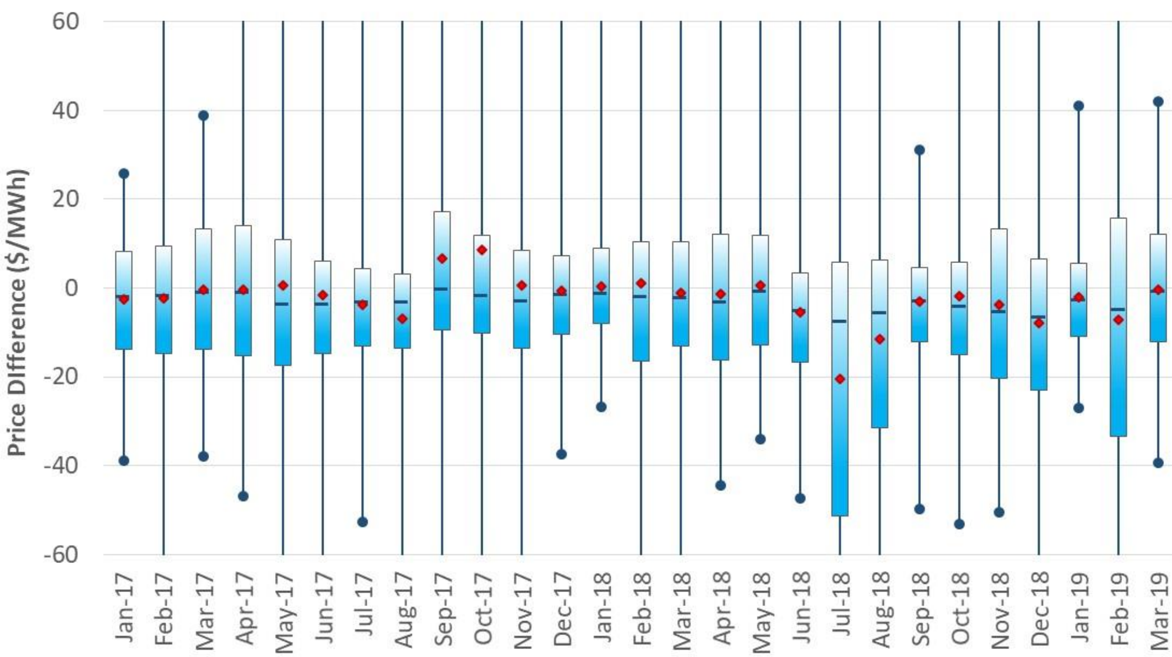


Figure 12 through Figure 15 show the distribution of price spreads between different sets of CAISO markets. These spreads are calculated with the system-weighted average prices from DLAPs[6].

Figure 12: Price spreads between IFM and HASP



[6] The spreads are calculated as (HASP-IFM) , (FMM-IFM), (FMM-HASP) and (RTD-FMM).

Figure 13: Price spreads between HASP and FMM

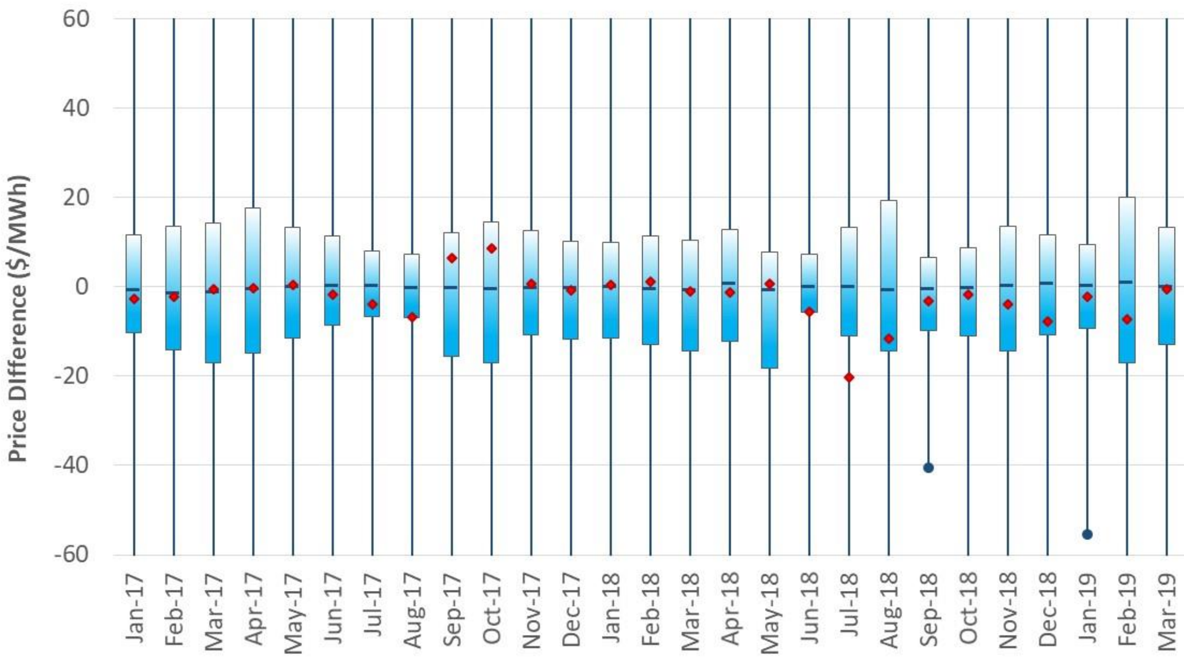


Figure 14: Price spreads between FMM and RTD

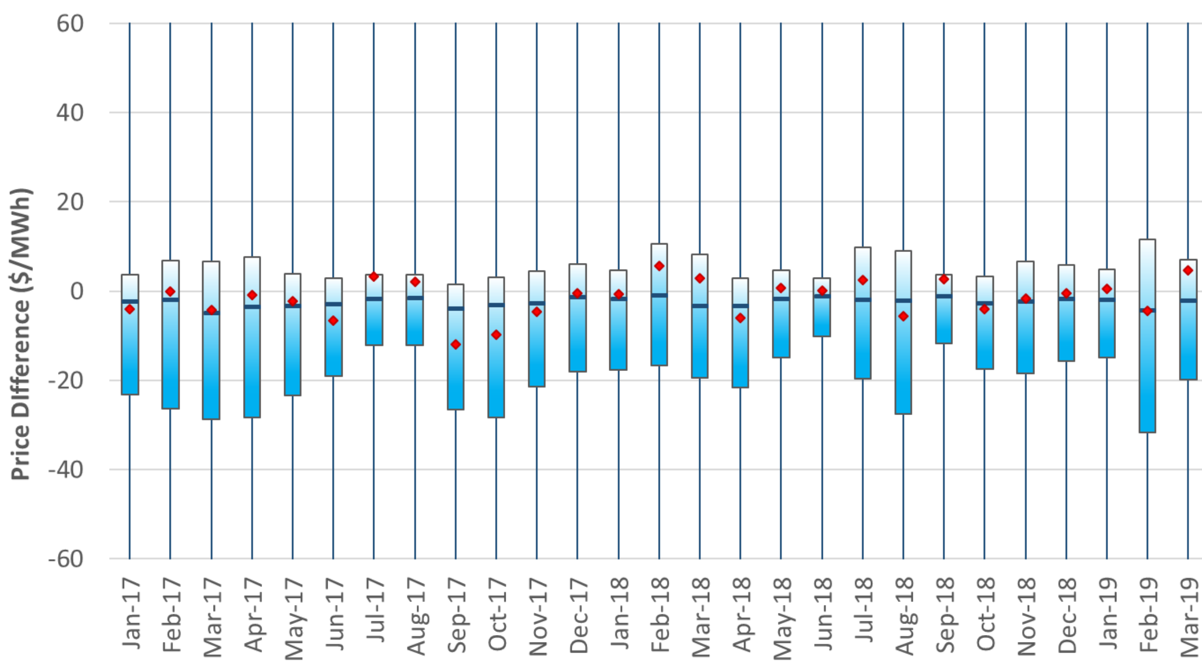
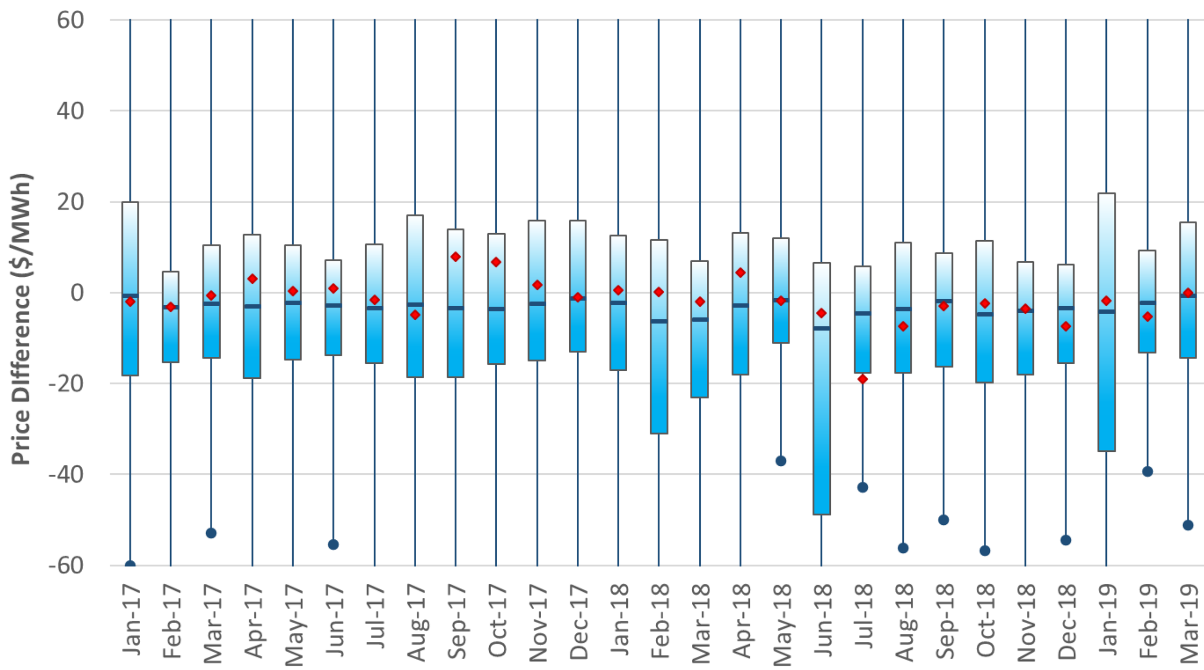


Figure 15: Price spreads between IFM and FMM

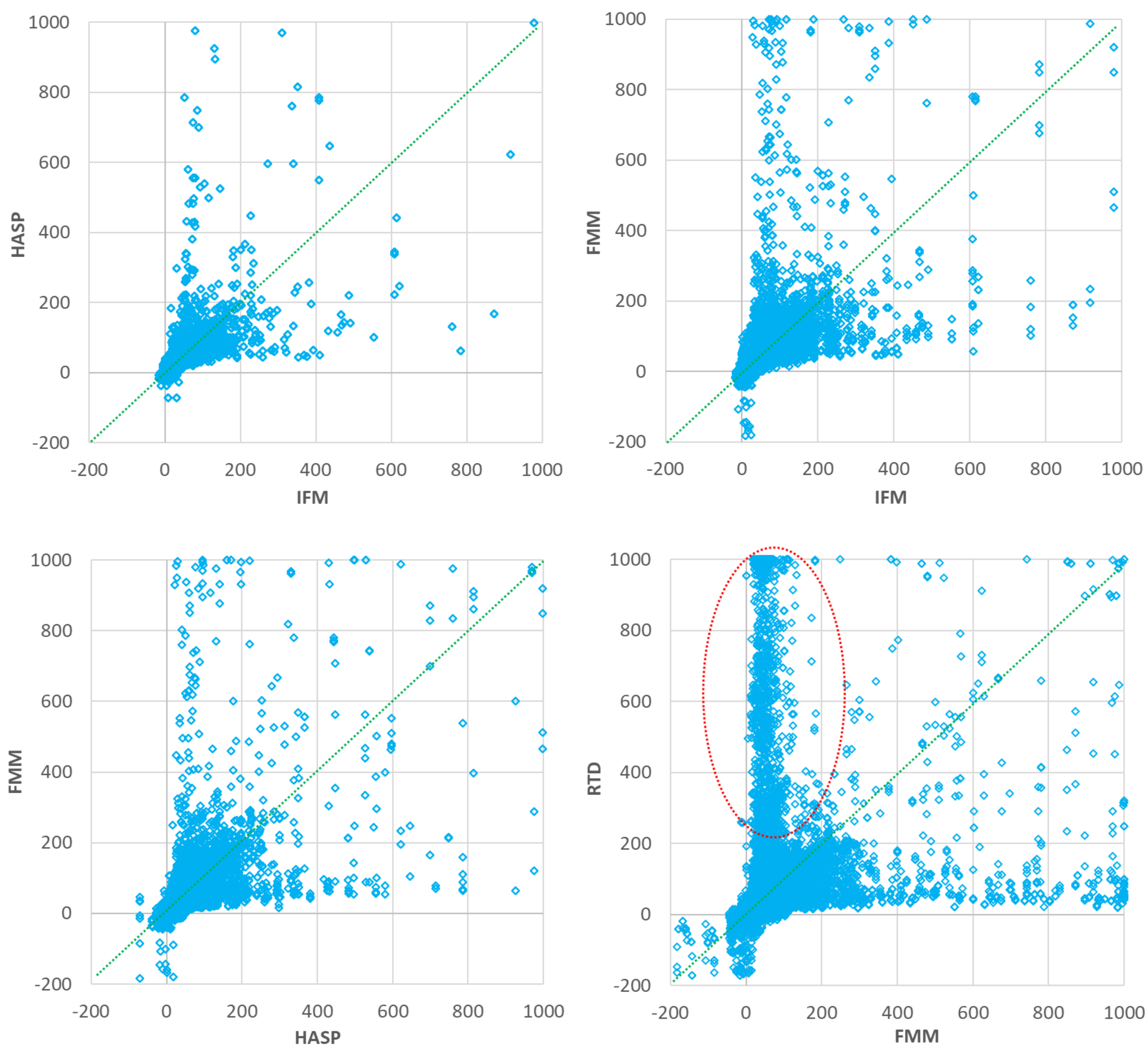


In order to see a meaningful trend, these plot diagrams display prices in the range of ±$60/MWh. The full range of price distributions are provided in Figure 158 through Figure 160 in Appendix A.

The largest spreads are observed between the IFM and HASP, and IFM and FMM, and in the month of July 2018. These two spreads (HASP-IFM and FMM-IFM) are more concentrated in the negative range, which indicates a higher frequency of price divergence between these two markets when IFM prices are higher than HASP or FMM prices. This is the same pattern observed with simple averages introduced in earlier metrics. Across the months, FMM-HASP spreads are more evenly distributed, which would reflect a better performance than HASP-IFM spreads. These spreads also show that the simple averages may not be as effective in measuring price convergence. For the RTD-FMM spreads, a larger volume is concentrated in the negative range, which indicates that a higher frequency of spreads shows higher prices in FMM. In this comparison, the simple averages may not properly show the price dynamic as well.

Figure 16 shows a simple correlation plot for the price spreads between CAISO markets. A large volume of the spreads is concentrated in the low-price range; as the spreads become larger, correlation weakens, with price spreads scattered mainly in the positive quadrant of the price spread graphs. This is significant in the RTD-FMM spreads. Some price spreads can reach $1,000/MWh and typically happen when the price in one market spikes to the scarcity price signal while the price in the other market stays low or even negative.

Figure 16: Correlation of System Weighted Prices (in $/MWh) between CAISO markets



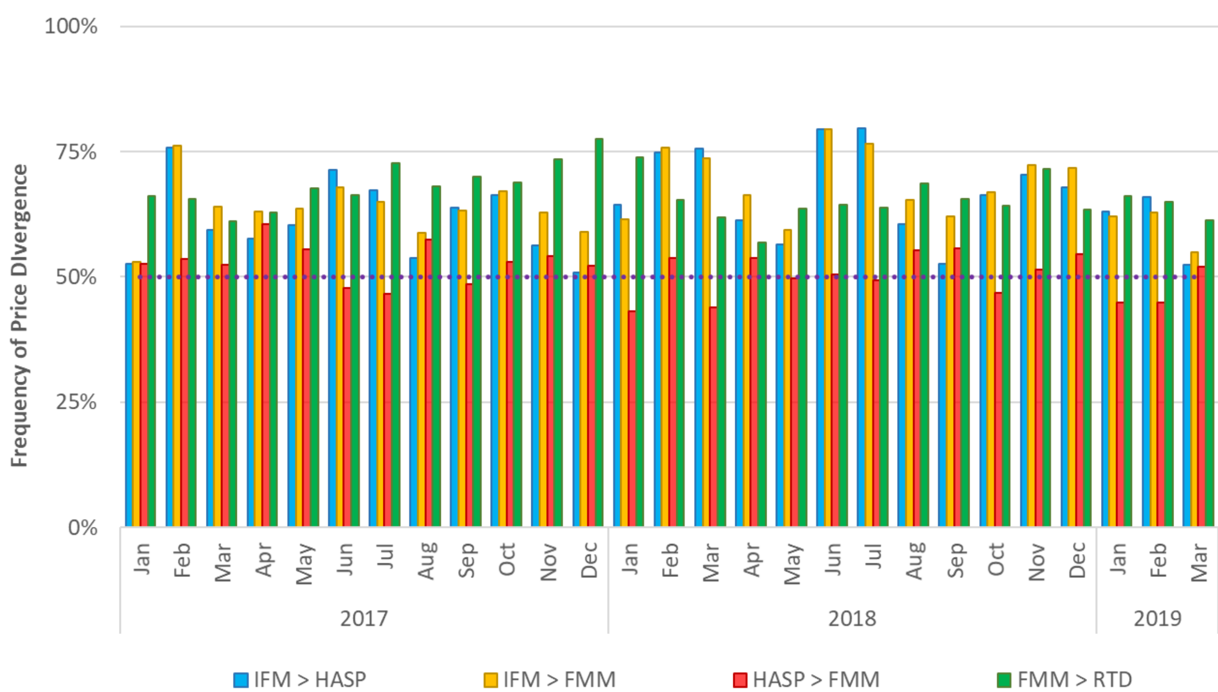
In addition to the magnitude, the frequency of price divergence conveys important information. Figure 17 shows the frequency when the price in one market is higher than the price in other market used in the spread calculation. Under this metric, prices are compared side-by-side between markets for each interval[7]. For instance, the hourly price observed in a given hour of the IFM is compared against the hourly price of the HASP. Similarly, the hourly price in the HASP is compared against the four prices of the four FMM intervals contained within the hourly HASP run. For the correlation between FMM and RTD markets,

[7] In order to avoid very small price differences distorting the metric, price difference within 25 cents –positive or negative- are not included in this metric.

there is a marked area of divergence along the y–axis; these points reflect instances where FMM prices are within the normal price range but RTD prices are spread up to $1,000/MWh. To some extent, this is expected because the RTD may experience temporary ramping constraints which typically arise due to the inherent changing conditions in the RTD. This condition is not as pervasive in the other markets, which are optimized over longer periods (fifteen minutes or hourly), because the longer horizon can absorb the ramping and changing conditions, lowering their exposure to volatile conditions.

For example, in July 2018, the blue bar below in Figure 17 represents the price divergence between the IFM and HASP at about 80 percent. This means that for approximately 80 percent of the hours in that month, the price in IFM was higher than the price in the HASP. The red bar indicates that for about 50 percent of the FMM intervals in that month, the prices in the HASP were higher than the prices observed in FMM. The frequency of divergence between IFM and HASP track closely with the frequency of divergence between the IFM and FMM.

Figure 17: Monthly frequency of price divergence between markets



Frequencies of about 50 percent are expected, which would mean that half of the time, prices in one market are higher than prices in the other market. This indicates a normal distribution of price spreads. Frequency values divergent from 50 percent indicate that the price divergence between markets is more systemic and persistent. For the period under analysis, the frequency of price differences between HASP and FMM are evenly distributed in each month, at about 50 percent. This is not the case for the price differences between IFM and HASP, and FMM and RTD, which occurred approximately 62 percent of the time, and in some specific months, was as high as 80 percent. This frequency alone still does not provide a meaningful information regarding the magnitude of such price divergence but serves to highlight how pervasive the price divergence in various markets may be.

Regarding interties, a similar frequency of price divergence is illustrated with a duration curve in Figure 18 through

Figure 20 in 2018. For the Malin and Palo Verde interties, such curves illustrate that the price spreads are more evenly distributed between positive and negative spreads. However, the NOB intertie shows a significant divergence between markets, mainly driven by prices in the HASP. To fully understand the drivers of this divergence, some specific intervals were examined more closely, discussed further in subsequent sections.

Figure 18: Duration curve for prices at Malin scheduling point

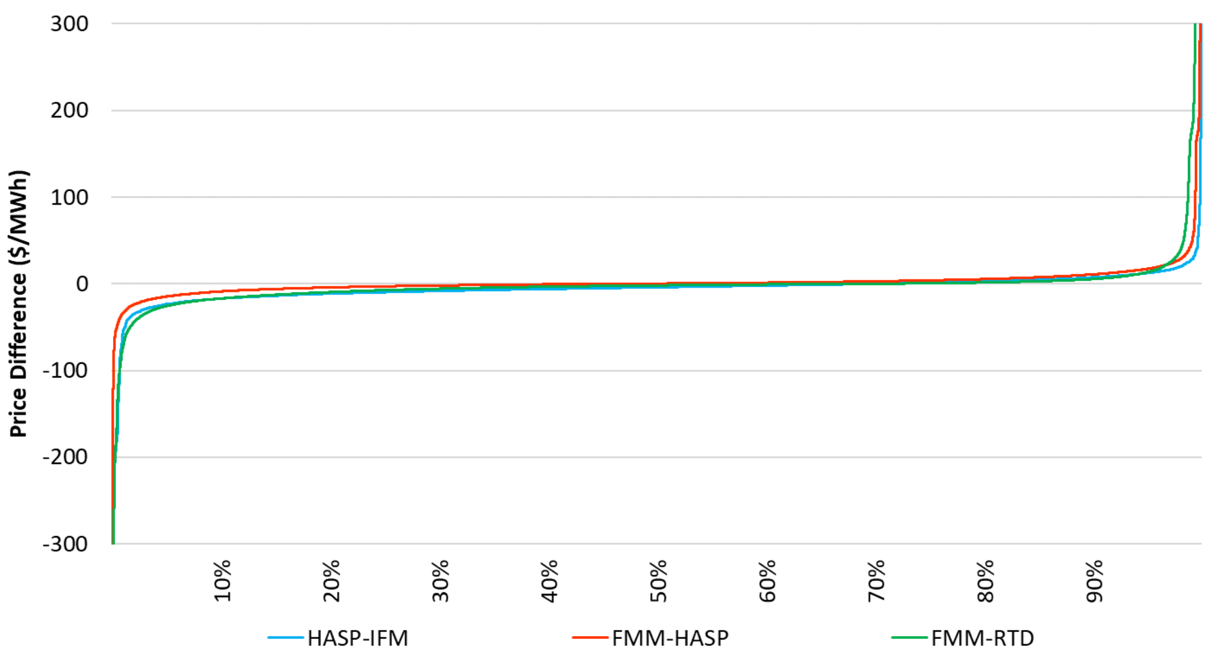


Figure 19: Duration curve for prices at NOB scheduling point

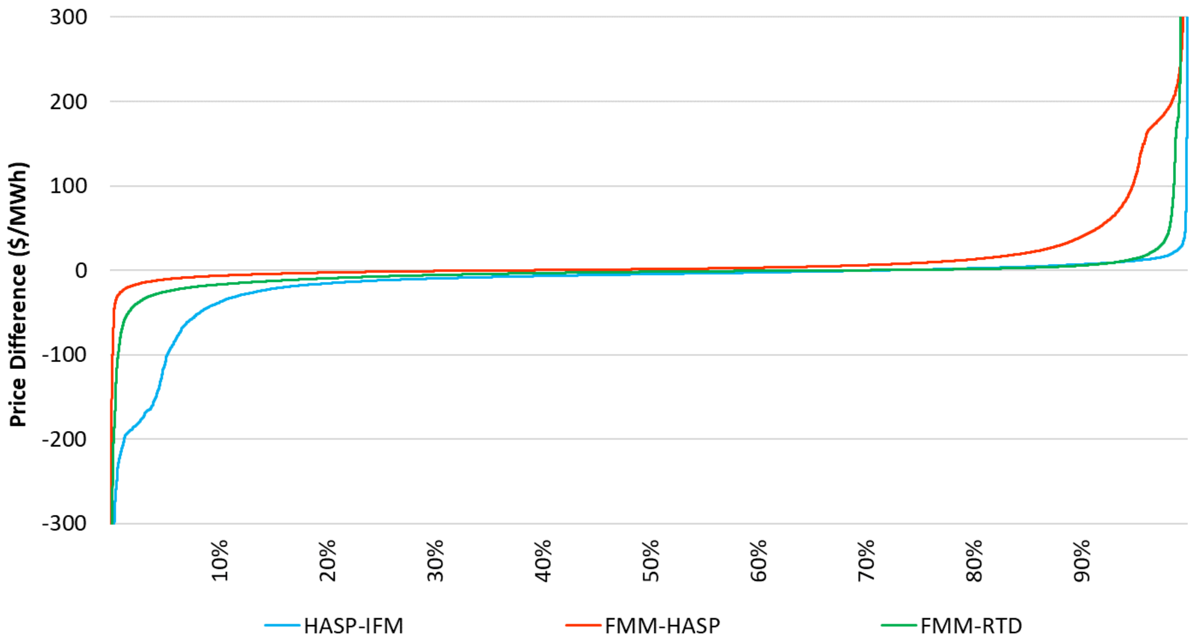
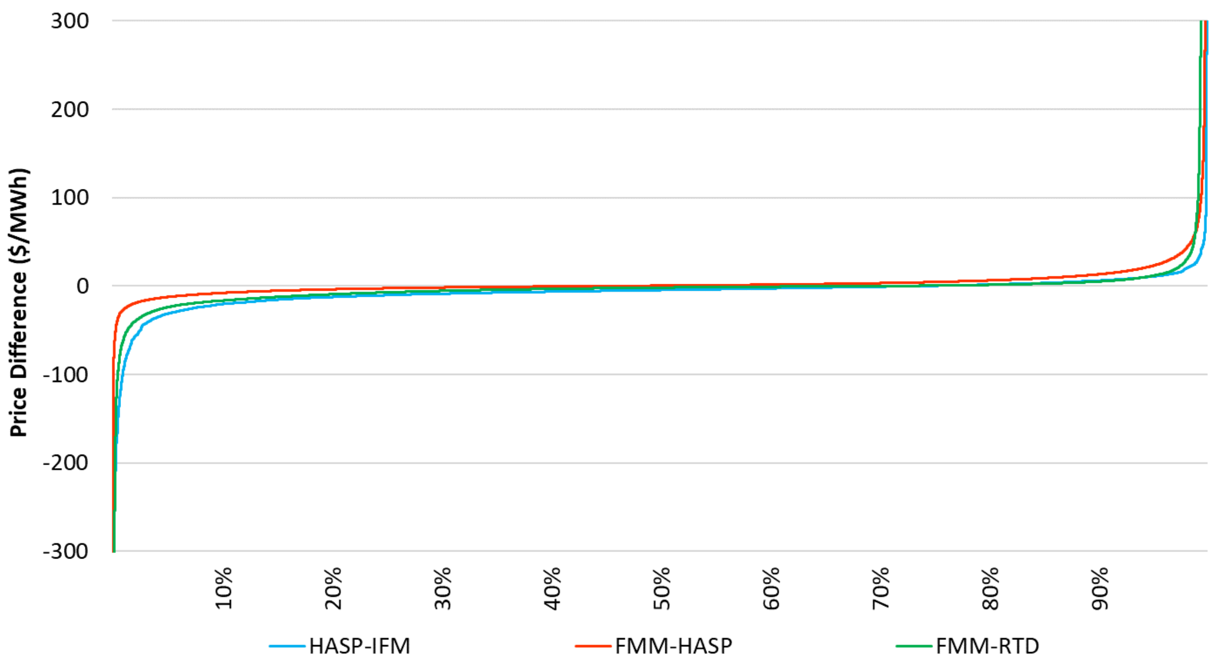


Figure 20: Duration curve for prices at Palo Verde scheduling point



Gas-Electric Price Dynamics

Currently, the CAISO relies on gas prices to calculate caps on commitment costs and default energy bids (DEBs). For resources using the proxy-cost option for commitment costs, the CAISO uses next-day gas prices from up to three vendors (NG, Platts and SNL). The CAISO uses the gas indices for the hubs at SoCal Citygate, PG&E Citygate, and Kern River delivery pool. These gas indices, along with transportation costs and other miscellaneous costs, are used to calculated different fuel region prices, which in turn are used to estimate the commitment costs and the DEBs. This calculation is performed daily and overnight, so that it can be used in the RTM for the next trading date. Without the Aliso Canyon provisions temporarily in place, this same index would be used for DAM, which is run the next morning for the subsequent trading date. Under the Aliso Canyon provisions, each morning (when gas trades occur) the CAISO takes the estimated weighted average price from the Intercontinental Exchange (ICE) and replaces the previous night's calculated index as described above to determine the fuel price for that day's DAM. This temporary procedure eliminates the one-day lag in the price index that would otherwise exist and the DAM runs with the most recent price trends. For weekends and holidays, when there are no gas trades on ICE, the system falls back to the most recent index available, which is the index calculated the previous night. Note that the market participant can bid in their variable cost for gas resources up to the bid cap ($1,000/MWh). If any resource is mitigated as part of the market power mitigation process, its variable-energy bids will be mitigated to the highest of the competitive locational marginal price or the resource's DEB.

Figure 21: Trend of gas prices between the DAM and RTM

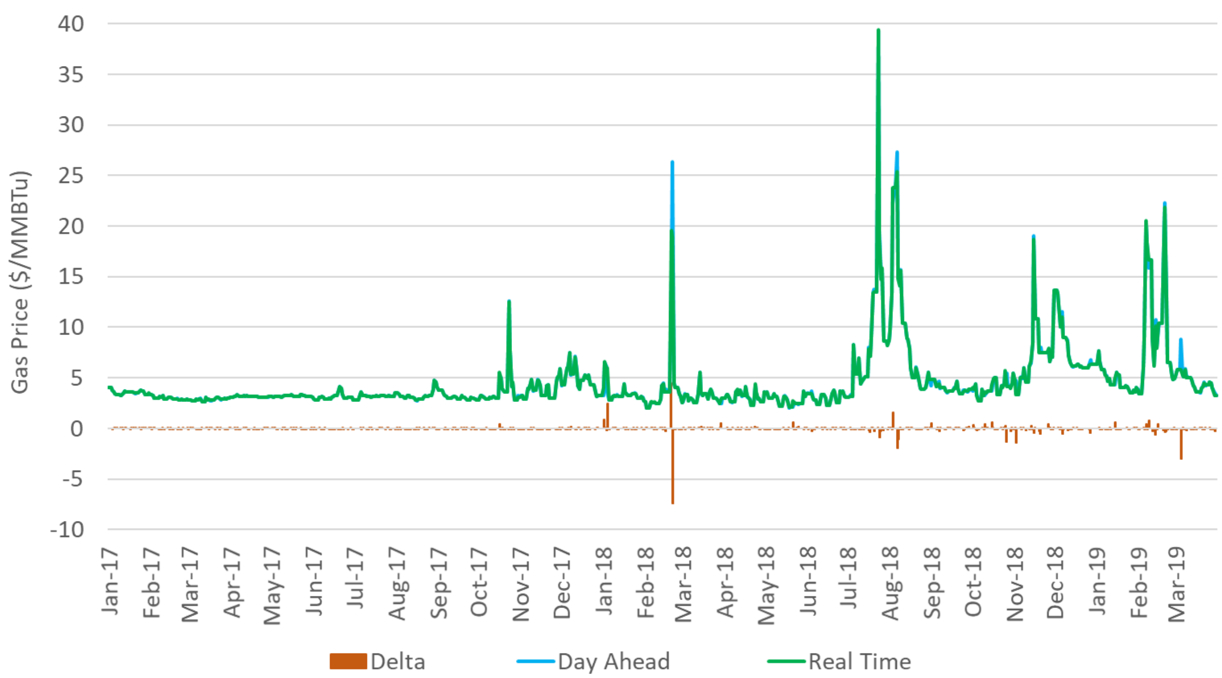


Figure 21 shows the comparison of the commodity price used for SoCal resources, which is derived from the SoCal City gas hub. For RTM, it reflects the blended index from the gas prices available from the various vendors; for DAM, it reflects the estimated ICE weighted price obtained in the morning just prior to the DAM run. These prices also reflect any price that may have been applied by using the internal CAISO fallback logic, when the next-day gas price was not available for any reason. As expected, the majority of time, the day-ahead price tracks closely to the real-time price because the manual update process that updates the gas price every morning has eliminate the additional one-day lag. There is a relatively small set of days with divergence in gas prices between DAM and RTM, as shown by the red bars in Figure 21. This is observed when there is volatility in the gas market.

There are two main ways gas market dynamics drive electric price divergence. First, gas price differences in the day-ahead and real-time gas prices will be reflected in resources' commitment costs and DEBs, which will in turn be reflected in the market clearing prices in the electric market. Secondly, market participants will factor the fuel prices in their economic bids and will internalize the price differentials, which also be reflected in the market clearing prices in the electric market. Because of the price divergence, even if the same quantity of supply is bid in real time, it may come at higher bid prices. Therefore, either commitment costs, DEBs, or variable energy bids may drive the market clearing prices and the price divergence between markets.

Figure 22: Trend of gas and electric prices in DAM

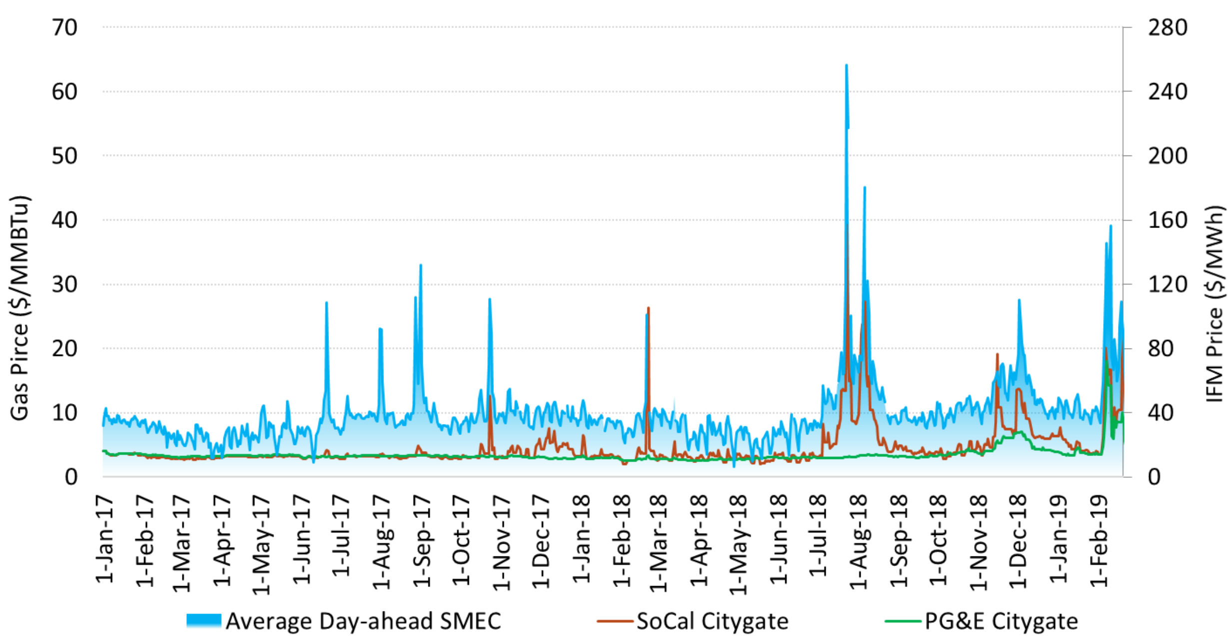
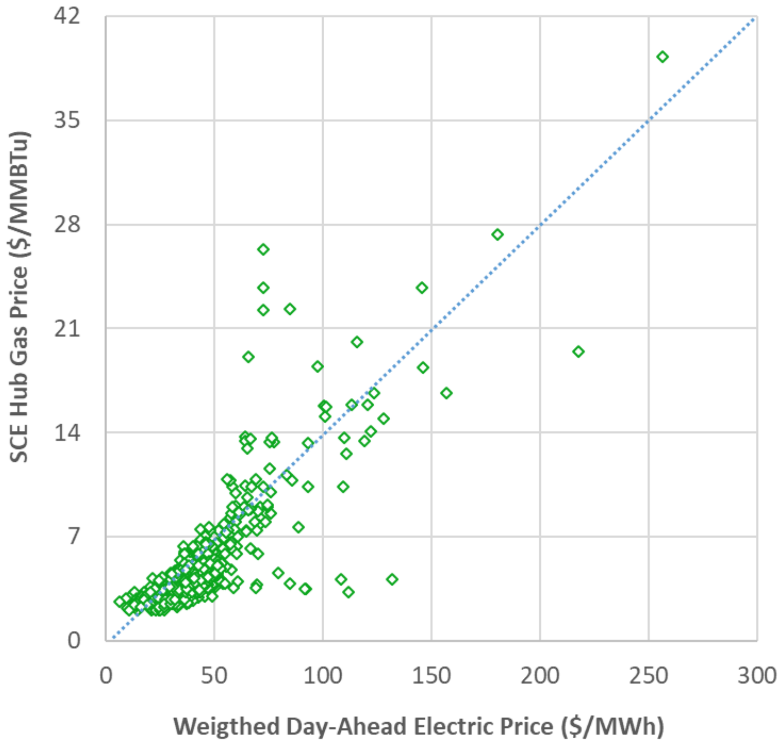


Figure 22 shows both day-ahead gas and electric prices for the analysis period for the PG&E and SoCal Citygate gas hubs since these are the two main hubs used to define the fuel regions in the CAISO markets. With a significant amount of generation based fueled by gas, gas prices will heavily influence electric prices. For the analysis period, there was gas price volatility in the SoCal region that directly translated into electric price volatility. Figure 23 shows a strong correlation between gas and electric prices across a full ranges of prices. The electric prices are simple daily average prices in order to match the daily nature of the gas prices.

Figure 23: Correlation of gas and electric prices in DAM

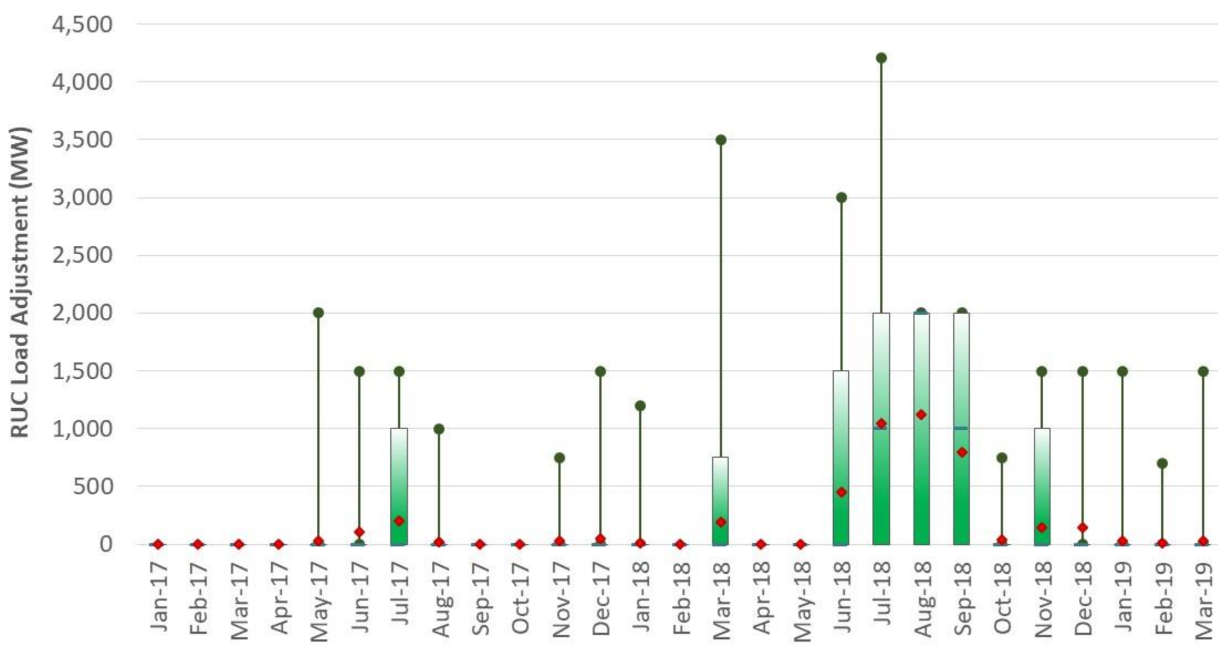


Load Adjustments

The SMEC reflects the marginal cost to meet supply and demand. In all CAISO markets except the IFM, system operators can adjust either demand (through conformance) or supply (through EDs) based on expected system conditions, which results in changes to market inputs which in turn can influence market clearing prices. System demand typically refers to the market requirements, which in the IFM accounts for bid-in demand, bid-in exports, and virtual demand. In the RUC process, demand considers the CAISO forecast for CAISO demand, exports, and any adjustments performed by system operators based on expected system conditions and system losses. The adjustment to the load forecast in the day-ahead timeframe is referred as *RUC net short,* while in the real-time market it is referred to as *Load conformance*.

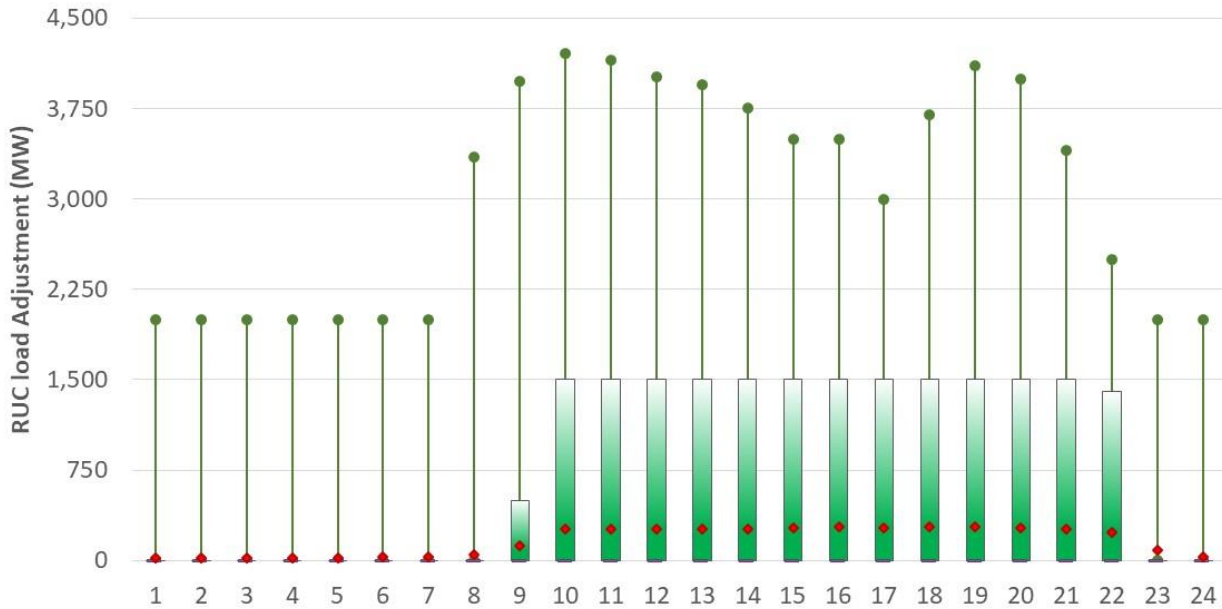
Figure 24 shows the monthly trends for load adjustments made to the RUC forecast, while Figure 25 shows the same data organized in an hourly profile. During July 2018, when the system experienced load peaking conditions, and ramp and load forecast uncertainties, the RUC adjustment maxed at 4,205 MW.

Figure 24: Monthly profile of RUC load adjustments



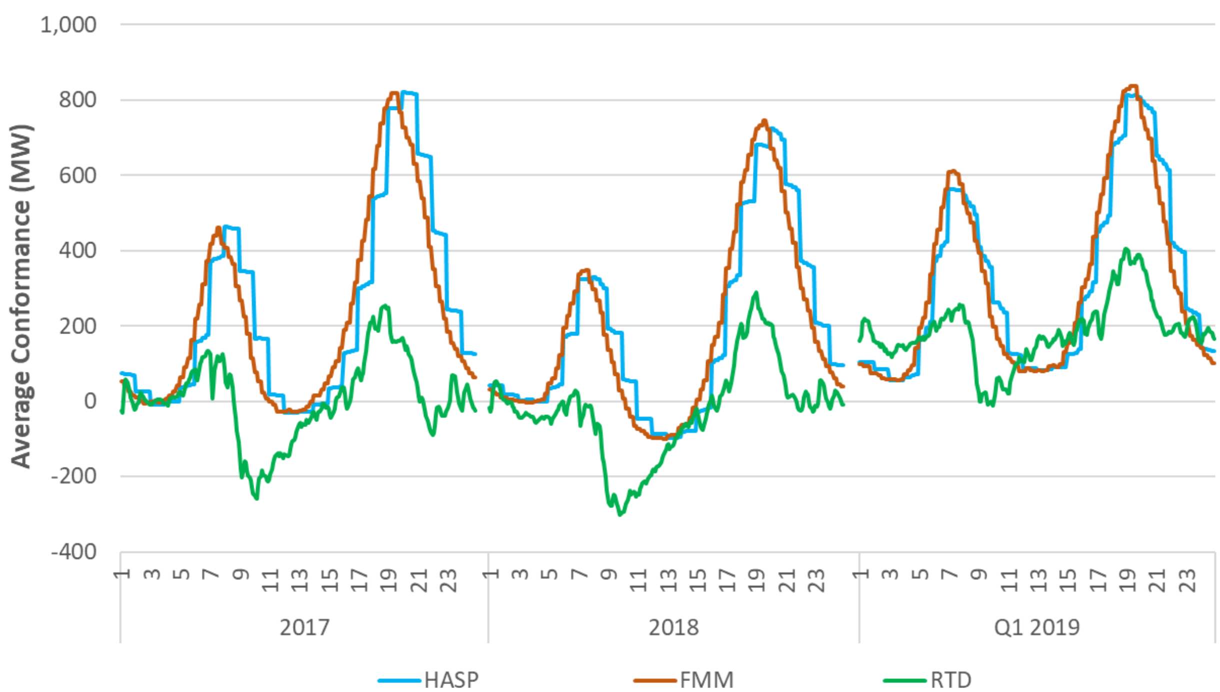
These additional requirements imposed by the load adjustments will be met with supply scheduled in RUC. Some resources –internal generation and interties– will be incrementally scheduled above the IFM schedules. In other cases, such RUC adjustments may lead to additional unit commitments that may be binding for the trading day in RTM; *i.e.,* they will be committed per RUC instruction, since there is not sufficient time for re-optimization in the RTM. In such cases, the RUC adjustment will have a material impact on the commitment of supply resources in RTM. The summer months have seen the majority of the RUC adjustments and they typically apply during the ramp and peak hours of the day.

Figure 25: Hourly RUC adjustments



In the real-time markets, the overall load requirements include the CAISO load forecast, exports, any load conformance, and system losses. Figure 26 illustrates the simple average of load conformance applied to the real-time markets in an hourly profile and with a real-time interval granularity.

Figure 26: Hourly profiles of load conformance in the real-time markets



These adjustments can effectively increase or decrease the overall demand requirements that the market optimization uses to clear against supply. Operators may use load adjustments to true up the market to the real-time system based on projected or observed system conditions.

Figure 27: Monthly distribution of load conformance used in the HASP

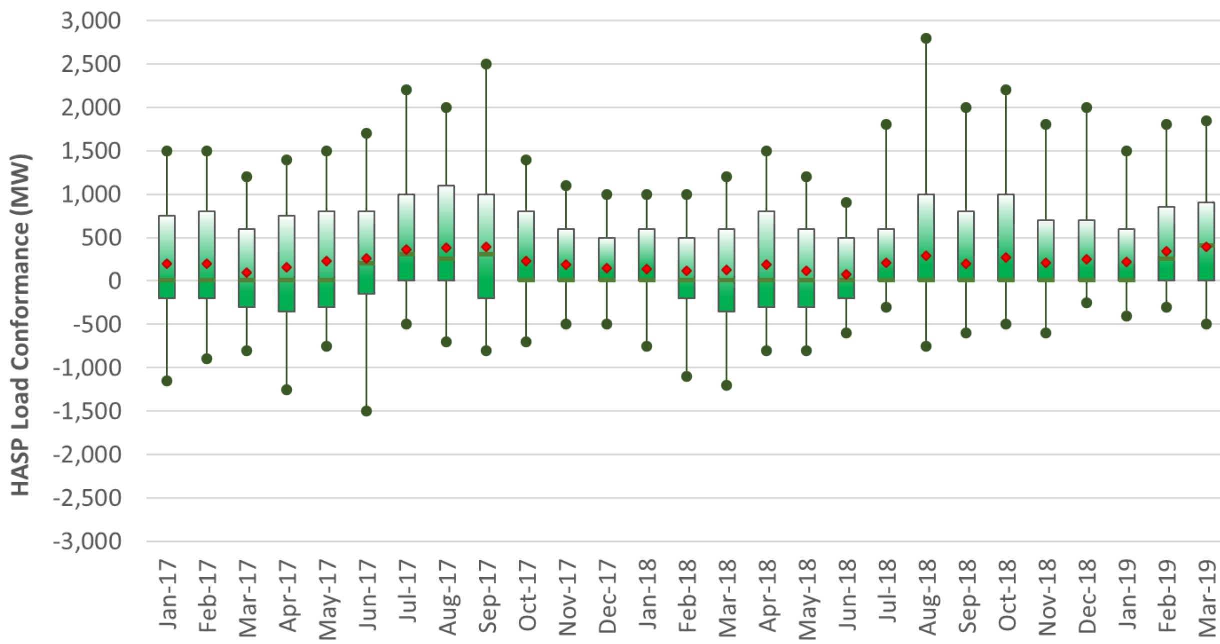


Figure 27 through Figure 32 show the pattern of load conformance imbalance in FMM and RTD markets for 2018, organized by month and by hour. Like the previous price discussion, simple averages may not show the more complex dynamics of conformance. In the box-whisker charts below, the box represents the 10^{th} to the 90^{th} percentile while the whiskers represent the minimum value to the 10^{th} percentile, and the 90^{th} percentile to the maximum value of the samples. The line marked within the box shows the 50^{th} percentile while the red dot shows the simple average[8]. This trends show that the real-time markets have been frequently clearing with an adjustment to the load forecast; these adjustment effectively imposed additional requirements to meet with available supply.

The load conformance applied to HASP and FMM align very well and follow a close profile mimicking the load profile. In contrast, the load conformance applied to the RTD market divergence from HASP and FMM and has a less defined hourly profile. The profile of the HASP and FMM conformance may suggest the main driver is to position these markets to the real-time conditions while the RTD conformance serves more to manage the minute-to-minute imbalances in the real-time system. In each of the markets, the spread of the load conformance is wide, ranging from -2,500 MW to 3,000 MW.

These figures show that HASP conformance is applied predominantly in the upward direction. For instance, it shows that from July 2018 through March 2019, the HASP conformance increased the load

[8] The data sample used to determine the percentiles includes also the data points in which the load conformance was zero MW, which effectively means there was no conformance applied to that interval.

forecast more than 90 percent of the time. Only in the transitional months, such as March and April, a higher frequency of conformance was applied in the downward direction, which may be attributed to handle the low-load conditions, high penetration of hydro, and VERs coming to full production. FMM observes a similar pattern of conformance.

Figure 28: Monthly distribution of load conformance used in FMM

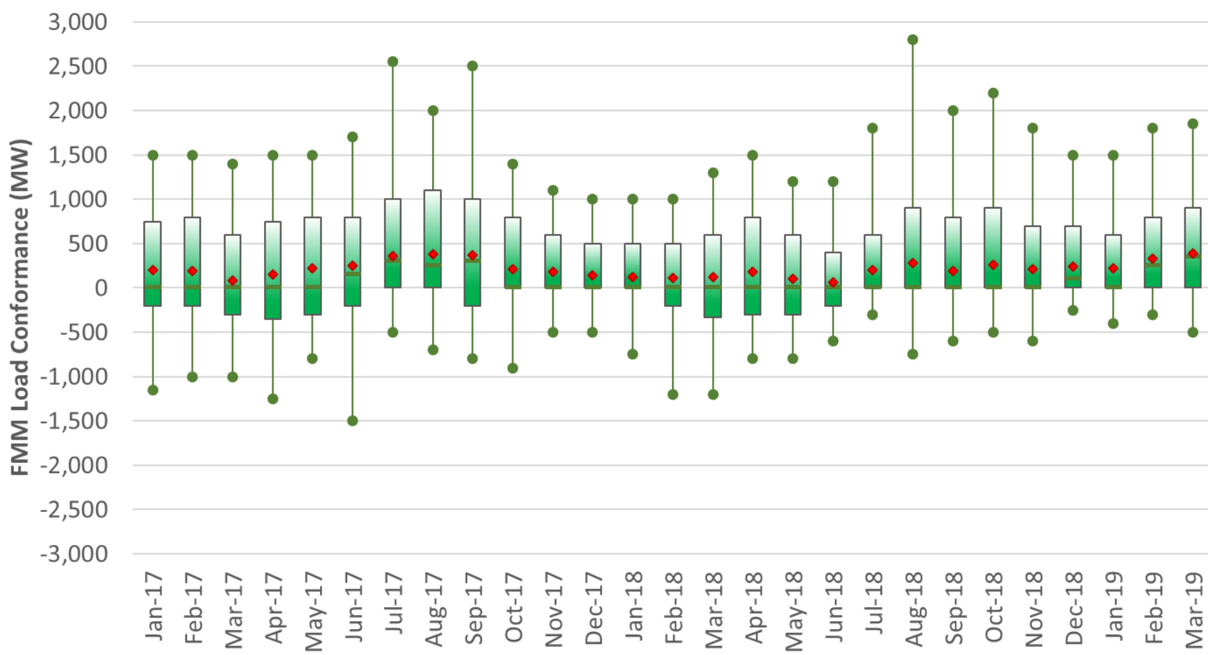


Figure 29: Hourly spreads of load conformance in the RTD market

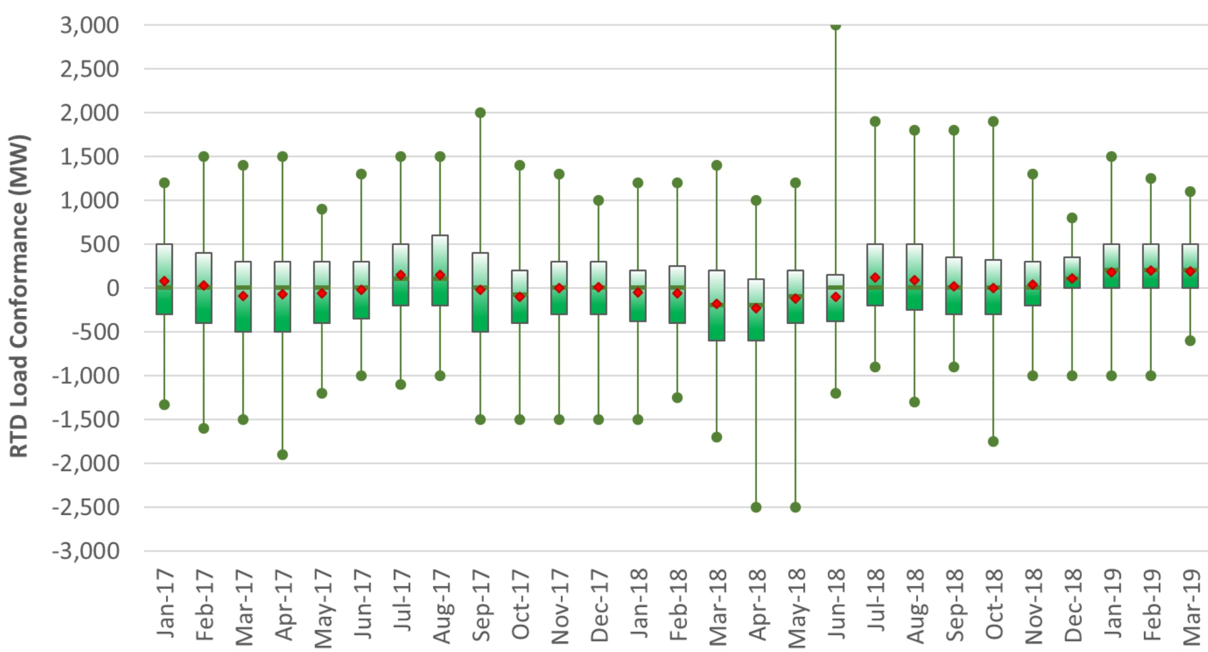


Figure 30: Hourly spreads of load conformance in the HASP

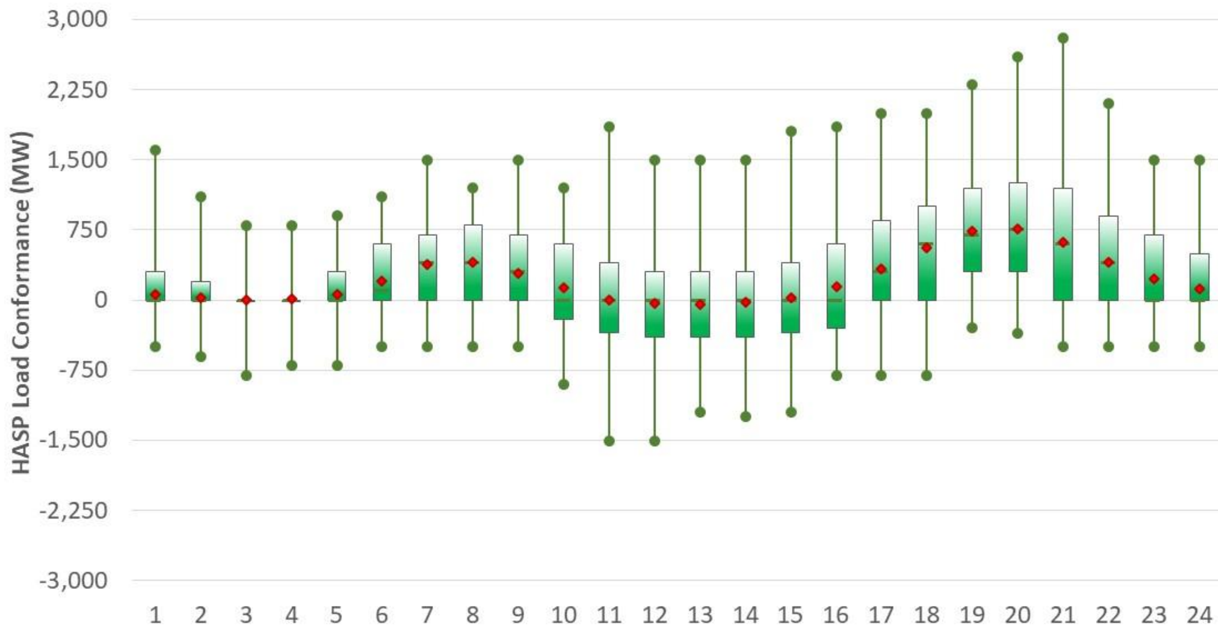


Figure 31: Hourly spreads of load conformance in FMM

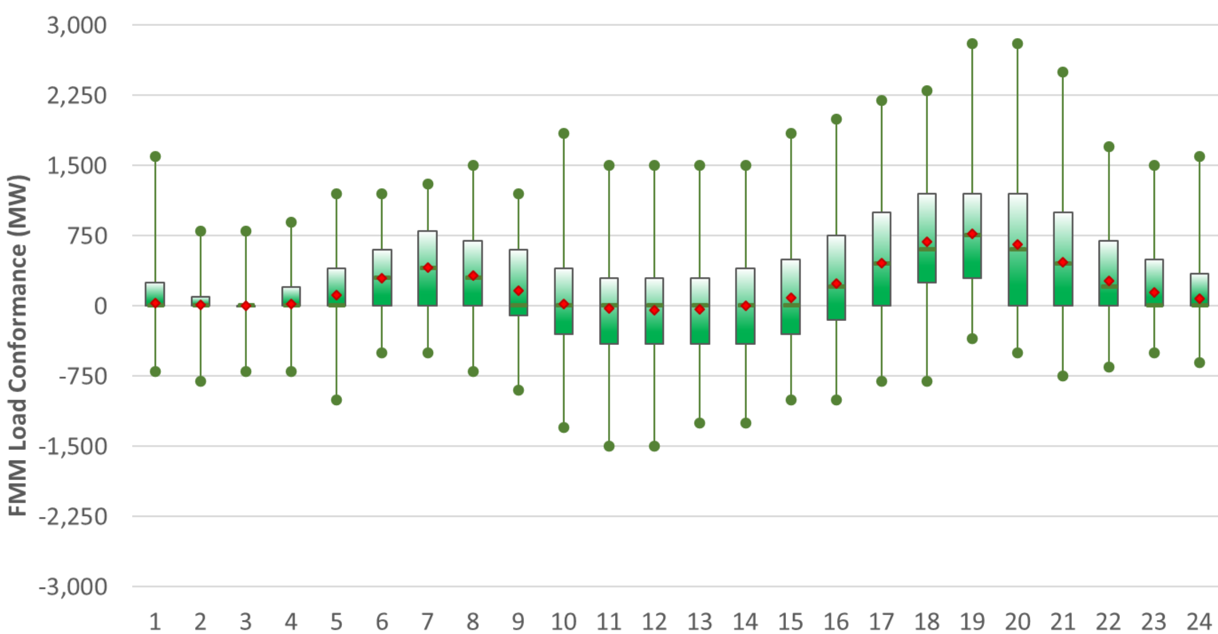
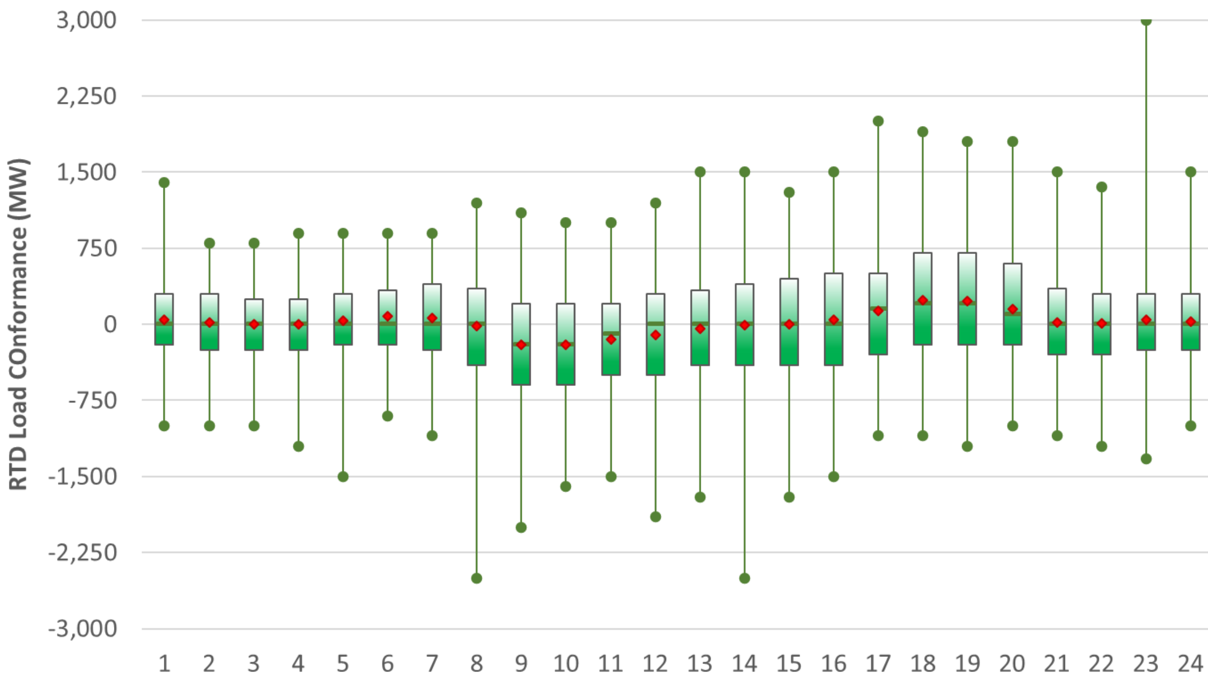


Figure 32: Hourly spreads of load conformance in the RTD market



Load and Market Requirements

Changes to the load forecast itself can lead to misalignments between markets given the fact that different markets use different look-ahead horizons. In cases of poor weather forecasts leading to inaccurate load forecasting, the divergence between DAM and RTM could be significant. In the past, the CAISO has analyzed extreme days, when missed temperatures forecast had a significant impact on the load forecast accuracy. These inaccuracies, in turn, may lead operators to conservatively mitigate such risks and uncertainties by securing more capacity through different operator actions, such as load conformance or EDs. Figure 33 through Figure 36 show the load forecast error for both DAM and RTM, organized by month and by hourly profile for the period of January 2017 through March 2019. The error is calculated as Load forecast minus actual, with a positive error indicating an over-forecast. Not surprisingly, some of the most significant errors, both under-forecasting and over-forecasting, have been observed when the system experienced peaking conditions like September 2017 and July 2018.

In addition, these forecast errors appear to be more concentrated around the peak hours of the day, which under extreme weather conditions are the more uncertain periods of the day. In some cases, the forecasting error may be over 3,000 MW. As expected, the forecasting error is more significant in the DAM, when there exists an inherent time lag between when the market is run and when actual conditions and rapid weather occur. For the RTM, with more certainty of weather conditions and load evolution, the forecast errors will be inherently smaller.

Figure 33: Load forecast error in DAM

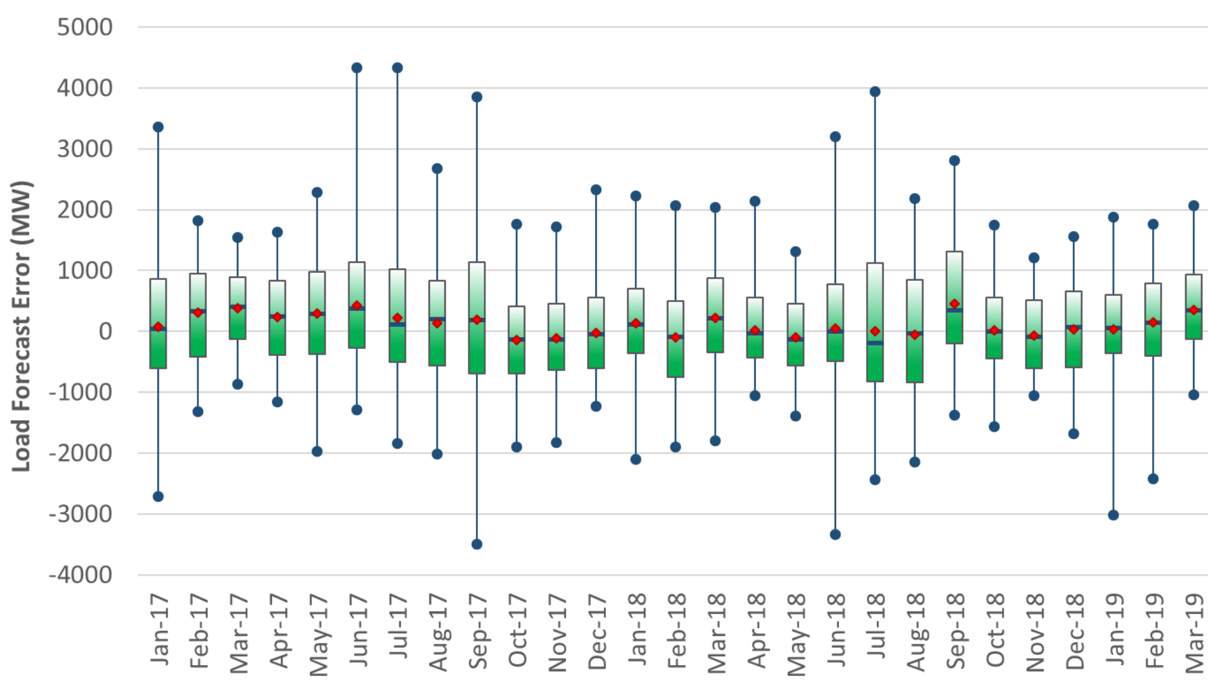


Figure 34: Load forecast error in the real-time market

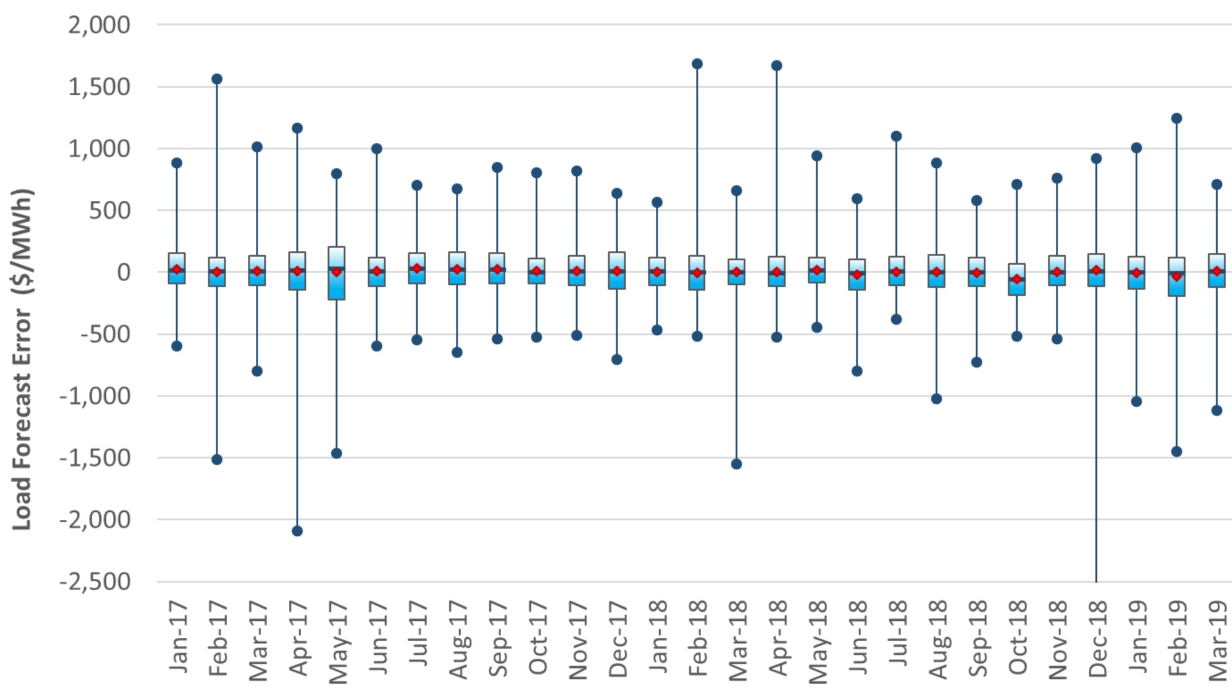
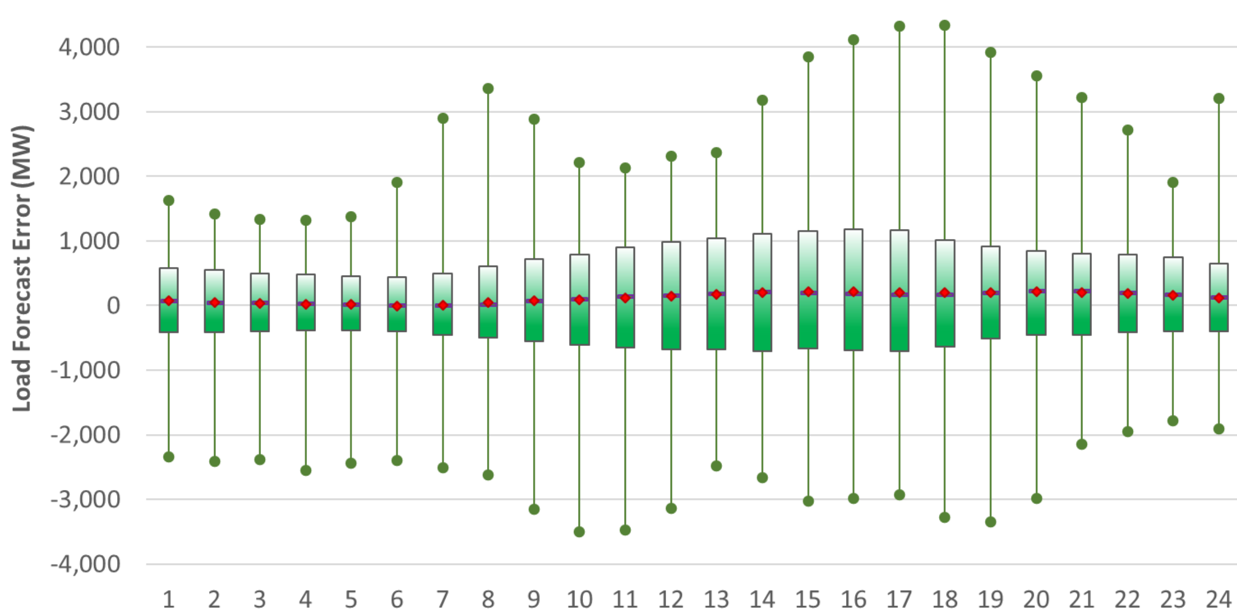
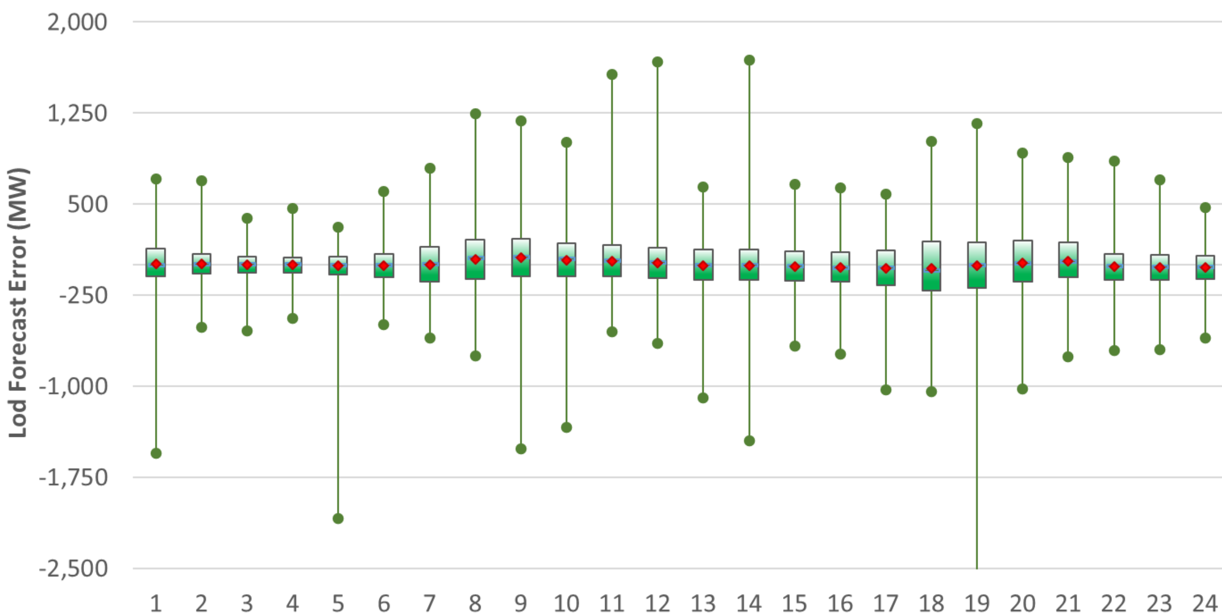


Figure 35: Hourly load forecast error in the DAM



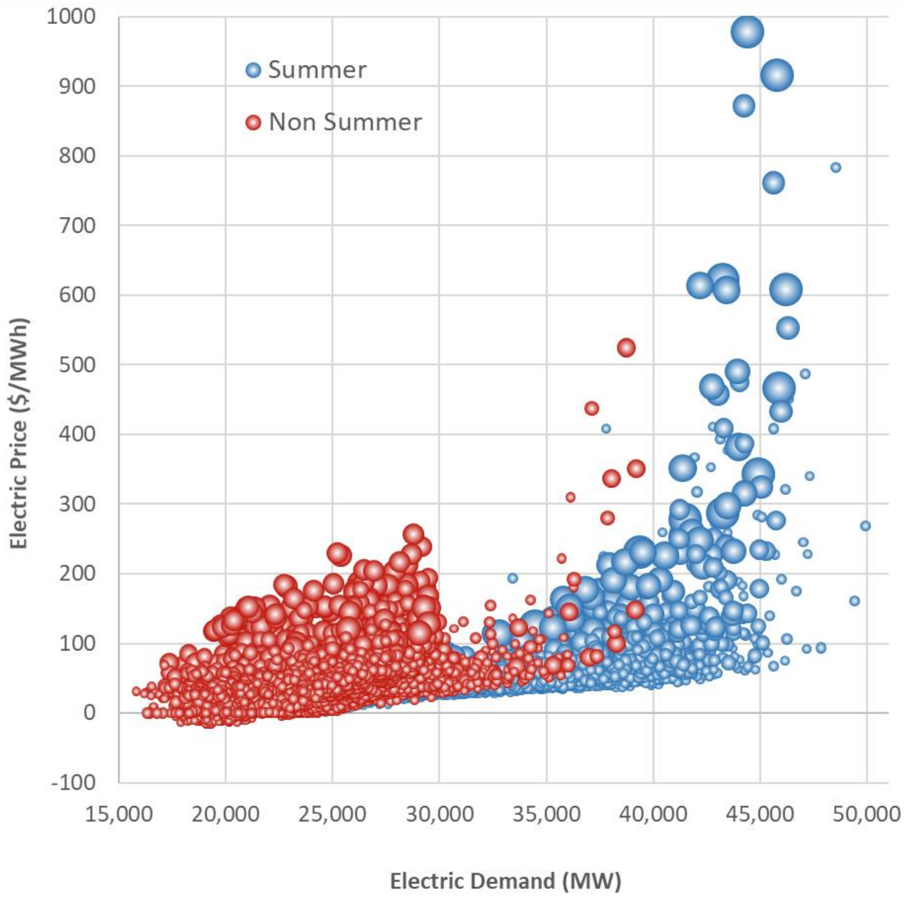
The DAM forecast errors tend to be in the over-forecast direction for the afternoon hours. One reason for this may be attributed to the impact of the behind-the meter production, which tend to impact the gross load of the system. Currently the ISO is exploring alternatives to improve the accuracy of the behind the meter forecast that will in turn help to reduce the load forecast error.

Figure 36: Hourly load forecast error in the real-time market



As demand increases, the system may rely on higher-priced bids to meet such levels of demand and, thus, prices may be expected to rise accordingly to reflect the demand needs. While in the DAM, the higher price is often attributed to scarcity-driven conditions, in the RTM, high prices are associated with more volatile system conditions from interval-to-interval, temporal, and ramp limitations. Figure 37 shows a correlation between day-ahead prices and demand levels. For prices below \$300/MWh, a positive correlation is observed between prices and demand. At a higher range of prices, such correlation becomes weaker, since there are cases in which prices can vary significantly for similar levels of demand. This is expected as demand level is only one of the factors which define the clearing prices. Higher and more volatile gas prices are another factor. For similar levels of demand, if gas prices are different, it is expected that electric prices will be different. For instance, the highest prices observed in DAM occurred on July 24 and 25, 2018. In addition to being the peak days of the year with relatively high loads, these days also observed the highest gas prices, reaching up to \$39/MMBtu. In contrast, many other instances exist with load levels within same range but with much lower gas prices, resulting in lower day-ahead prices. The correlation between electric prices, load levels and gas prices is shown in Figure 37. The size of the bubble stands for the value of the gas prices, with the largest bubble reflecting gas prices of about \$40/MMBtu; the higher the gas price, the larger the bubble depicted in the plot.

Figure 37: Day-ahead prices correlated to CAISO demand level and gas prices

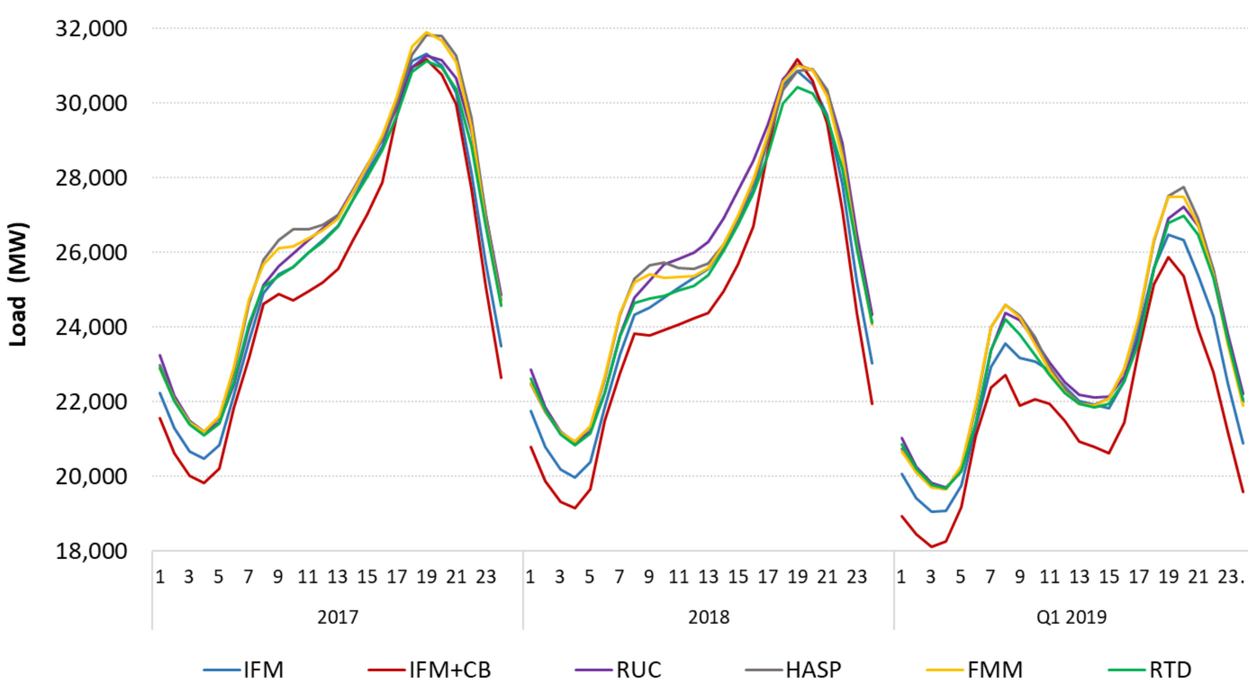


The high energy prices observed in the market coincide with both higher load levels and high gas prices. Hours with the highest load levels, like those of September 1, 2017, did not coincide with extreme gas prices but still saw relatively high electric prices because meeting that high level of load naturally requires to clear in a higher-priced level of the supply stack. There are other instances with milder load levels but relatively high electric prices due mainly to higher gas prices. The data set is clearly defined in two groups that turn out to fall into the peak months (June through September labeled as summer) with higher loads and the other months gathered in the *Non-Summer* group. For the non-summer months, loads are relatively low in the range of up to 30,000MW, with the upper region with higher energy prices are mainly driven by higher gas prices as reflected with large bubbles.

All of the CAISO markets optimally dispatch supply to meet the overall system load or bid-in demand. For the RUC, HASP, FMM and RTD processes, the overall load needs to be met with all available physical supply (internal generation and imports). The overall load is drawn mainly from the CAISO load forecast but also from system losses and any load adjustments done by system operators. The difference between the load forecast and the actual market requirements can vary from interval to interval and typically ranges within a few thousand MWs. This overall market requirement is effectively what the market clears and relies on to set the prices. The divergence of these market requirements between markets can naturally lead to price divergence because, for different market requirements, the market will clear at different price levels in the supply stack.

Figure 38 compares the overall market requirements across the different markets. For the IFM, there are two variations of these requirements: one version for physical supply, and a second version including the contribution of virtual bids (which are presented as net between supply and demand). The former version is useful when comparing against the other markets that were based only on physical supply, while the latter provides a reference of how much displacement (or convergence) the virtual bids introduced to the IFM. The remainder of the markets also include any load forecast adjustments done by operators. These hourly trends are based on simple averages for each calendar year under analysis. The market requirements diverge the most during the morning and evening peak hours. Both IFM and RUC tend to diverge more from the real-time markets in the first hours of the day. One potential driver for this is explained in a subsequent section below.

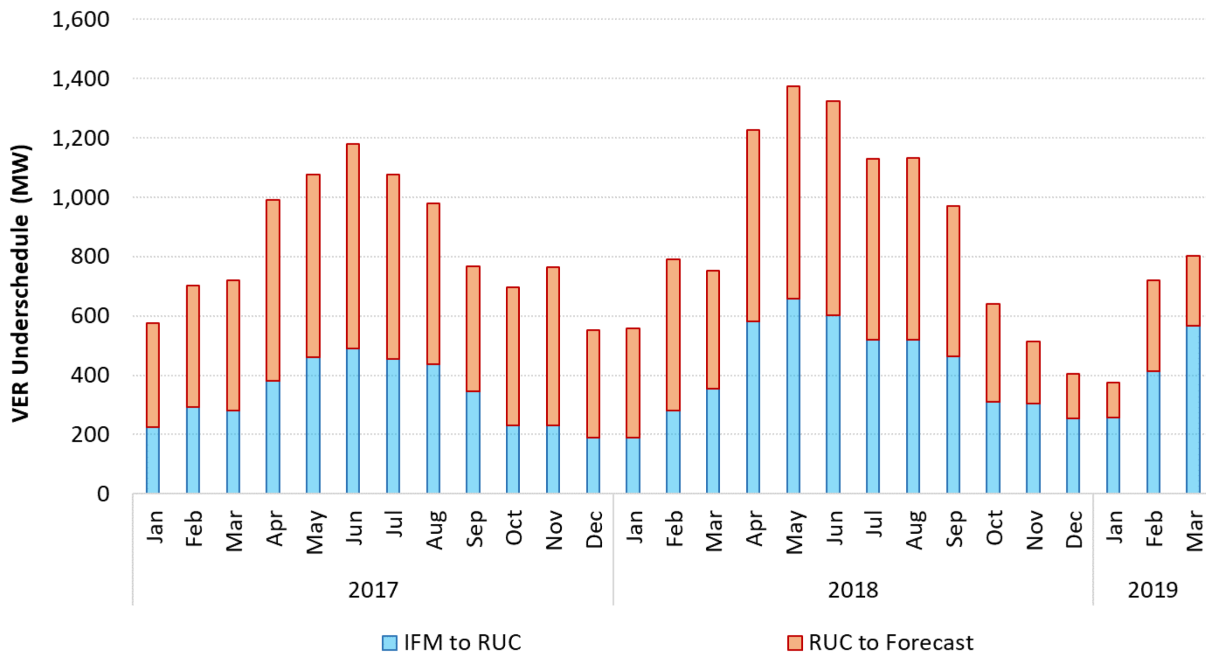
Figure 38: Total load across the various CAISO markets



Currently, VERs have the flexibility to economically bid into the IFM. However, the CAISO has observed that VERs are consistently under-scheduling in the IFM when compared to the capacity made available by these same resources in the RTM. The CAISO has since developed and implemented a true-up process in RUC, where IFM bids for VERs are increased to the forecasted generation values to avoid over-committing generation in RUC. This functionality prevents over-generation conditions in the RTM arising from the under-scheduling of VERs generation in IFM that eventually will materialize in RTM. However, this functionality depends on of the accuracy of the day-ahead VERs forecast.

Figure 39 shows, on average, the difference between the VERs supply considered in RUC compared to the VERs scheduled in IFM[9]. The additional supply available in the RUC process to meet the day-ahead load forecast is represented with blue bars below.

Figure 39: Average VERs true-up up in the RUC process

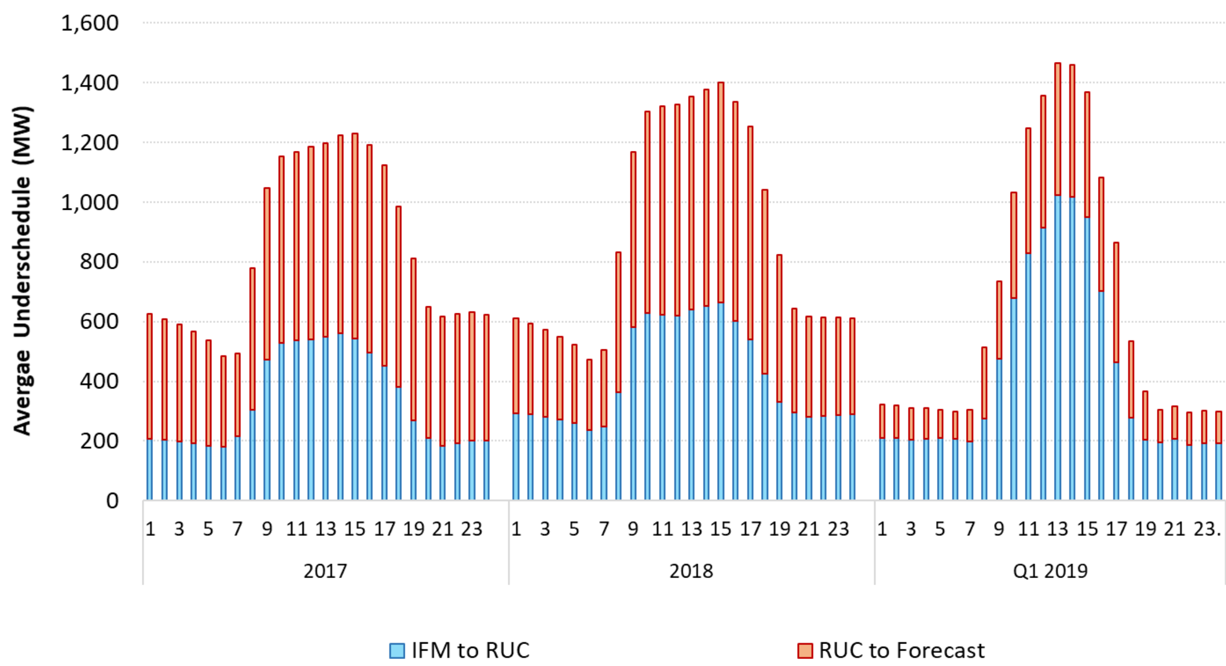


Currently, this true-up process is in place only for resources that bid into IFM. There may be cases in which VERs do not bid in IFM and this true-up process will not apply. Thus, there may be VERs supply still not considered in the RUC process that is projected to be available in the real-time market based on the VER day-ahead forecast; that additional capacity is identified with bars in red. Both types of capacity followed the production pattern of renewables over the seasons.

Figure 40 provides an hourly profile on an annual basis for these two types of capacities associated with VERs under-scheduling. Note that all quarters of the year are considered for 2017 and 2018, but only the first quarter is considered for 2019, due to when the analysis has been performed.

[9] This average applies to both solar and wind and may be skewed on the conservative side since it is over all hours of the day, while solar may have no capacity for the first and last hours of the day. This metric will also be revised in a subsequent version to take the maximum bid from IFM instead of the IFM schedule for VER. This current version compares IFM schedules against VER day-ahead forecast; however, VER resources with economical bids in IFM may be actually dispatched downward economically. The current metric does not differentiate between under-bidding and dispatched downward economically in IFM.

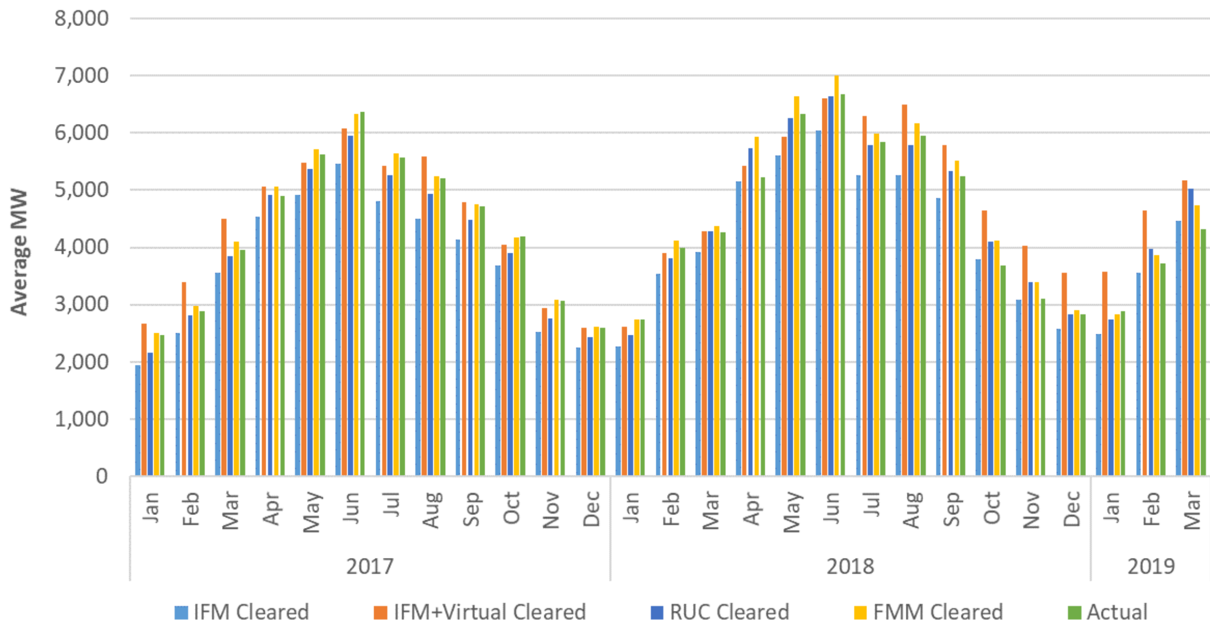
Figure 40: Net load across the various CAISO markets



Convergence bids[10] are only submitted in the IFM and then are liquidated in the real-time market at FMM prices because there are no physical resources to back them up. The main goal of virtual bids is to help converge DAM and RTM by identifying a price difference to arbitrage, which may lead to more efficient market outcomes. The RUC process does not consider virtual bids, but virtual bids can effectively influence the commitment in DAM by displacing generation or creating additional requirements for demand. One identified gap between the IFM and the RTM is the VERs under-scheduling described above, so it is natural to expect that virtual bids can fill in that gap. Figure 41 compares the average MW level of VERs production across the different markets and timeframes[11]. This shows the consistent pattern of VERs clearing below both the day-ahead forecast and real-time dispatches. The column in orange stands for the summation of VERs cleared and the net virtual supply to show how well virtual supply can fill in the gap. For most of 2017 and half of 2018, virtual bids were converging the cleared VERs to both the day-ahead VERs forecast and real-time dispatches, but the trend for the last part of 2018 and the first quarter of 2019 shows that VERs cleared closer to real-time dispatches, and virtual bids generally over-corrected. This is shown with the bar in orange exceeding the real-time bars in green.

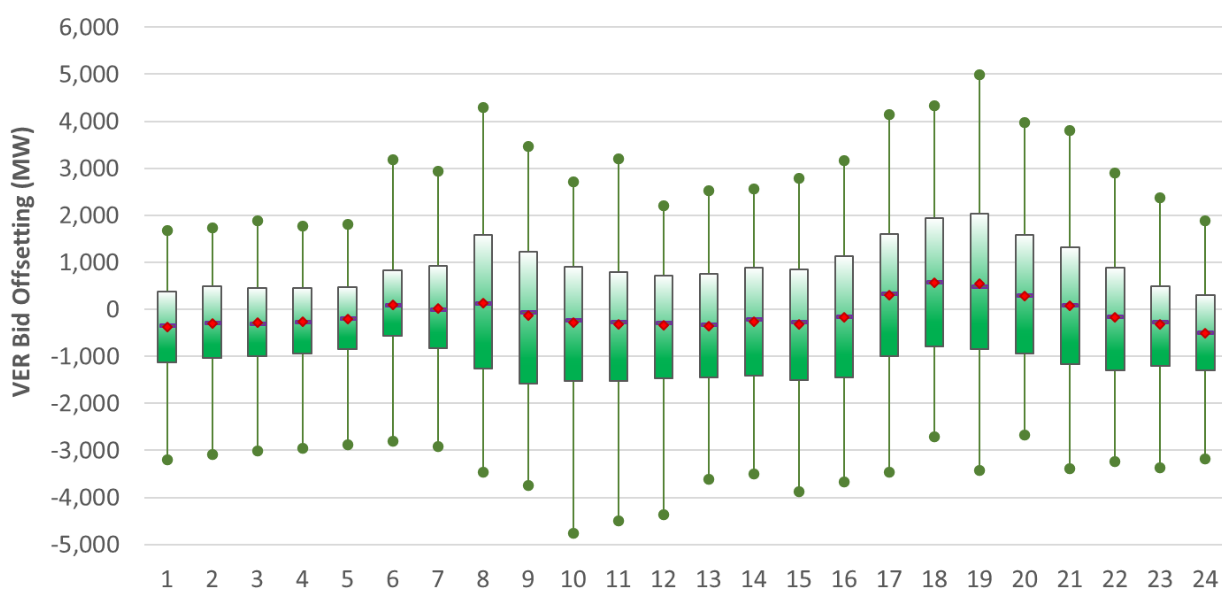
[10] The terms convergence bids or convergence bids are used interchangeably in this document.
[11] A variation of this metric is provided in Appendix A with an hourly breakdown by year.

Figure 41: Average production of VERs



In this comparison, the VERs MWs cleared in FMM is used as a reference since virtual bids are liquidated against FMM prices. Thus, the price convergence is expected to happen primarily between the IFM and FMM[12].

Figure 42: Hourly difference between IFM under-schedule and net virtual supply

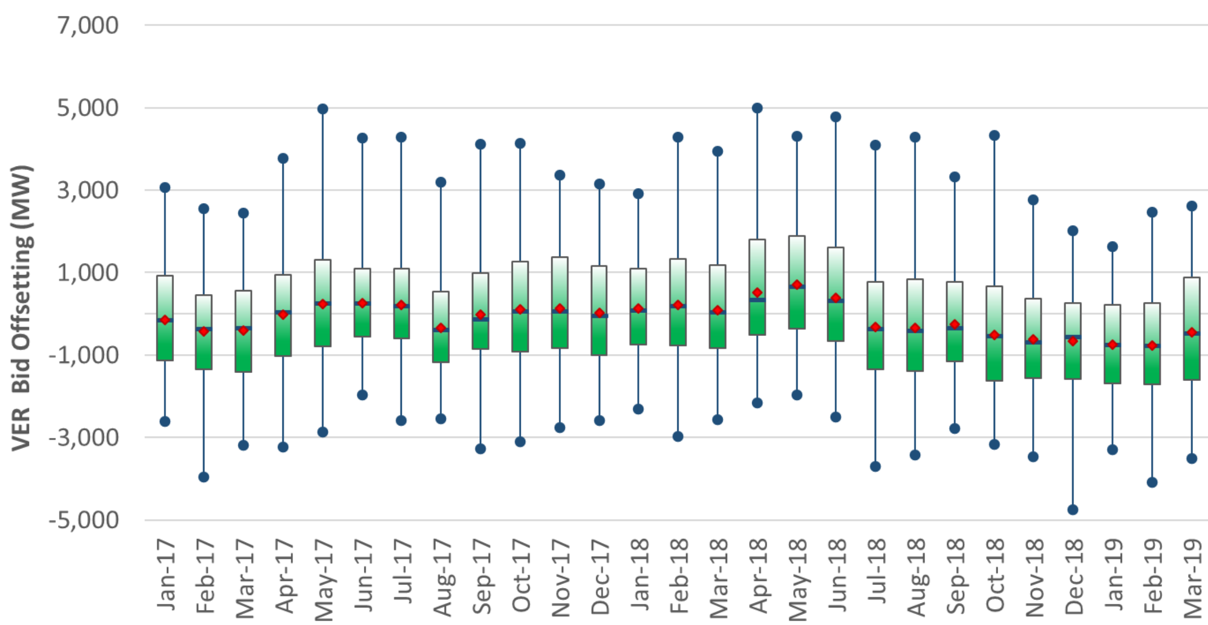


[12] The volumes cleared in the RTD market are not significantly different than the FMM cleared values.

Figure 42 provides the spreads of such convergence. This metric takes the difference in VERs under-scheduling of 1) what was cleared for VERs in IFM and FMM and 2) the net virtual supply cleared in IFM[13]. A positive value represents a situation where the IFM under-schedule is greater than the cleared net virtual supply. This hourly profile shows that there is a fairly large and symmetrical distribution of how close virtual bids fill in the gap of IFM VERs under-schedule.

Similar spreads can be observed over time as shown in Figure 43. It is important to realize that there may be other drivers, like virtual bids, as discussed in this analysis, that play a role in market divergence.

Figure 43: Monthly difference between IFM under-schedule and net virtual supply



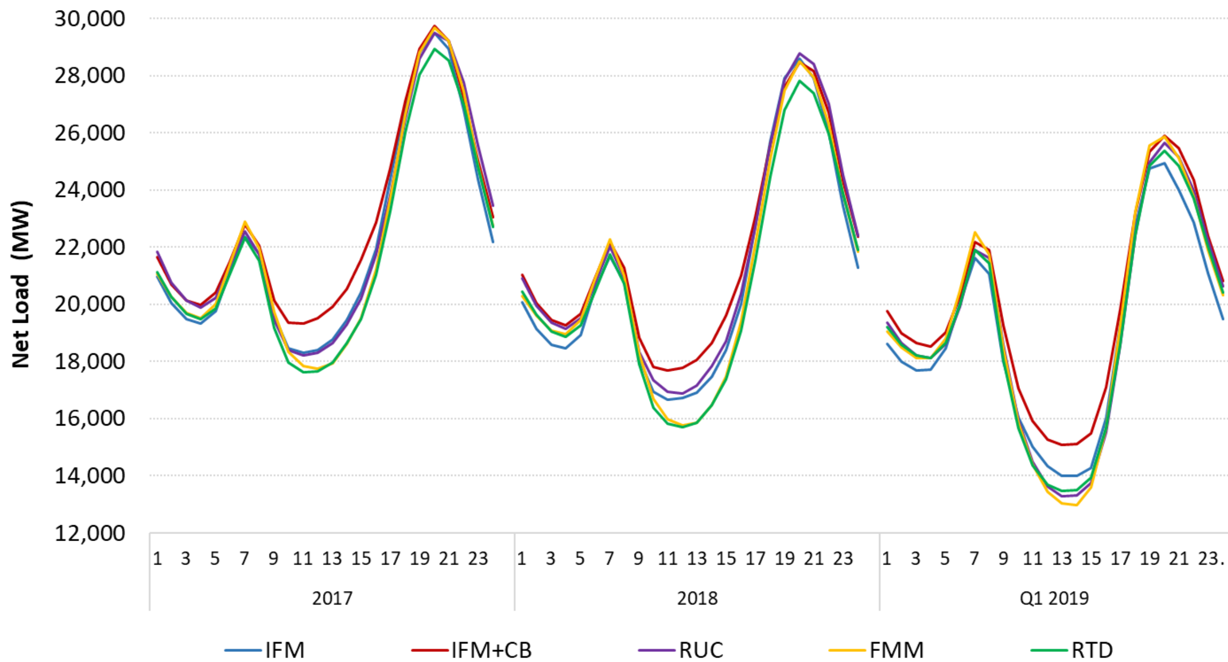
[13] The RTD dispatches are used in this metric because they are the ultimate supplied cleared by the market and that materializes in a dispatch. However, other references can be taken for this metric; one could be the fifteen-minute VER forecast or schedules under the premise that convergence bids are actually liquidated in FMM. The CAISO may further explore these variations in subsequent analysis.

Figure 44: Comparison between IFM under-schedule and net virtual supply

Figure 44 shows the correlation between IFM under-schedule and net virtual supply; the correlation is grouped by calendar year. A large volume of records are concentrated in a small range and, in general, there seems to be a weak correlation between these two variables.

Figure 45 takes this analysis a step further and compares the net load across the various CAISO markets. Net load is calculated as total load less the contribution from VERs, both wind and solar. This measure helps concurrently quantify the variations from both VERs and load. It also helps measure the overall uncertainty that each market has to handle by using historical variations. The calculation of the IFM net load relies on the overall cleared market requirements, the net virtual supply, and cleared VERs schedules. For the RUC net load, the calculation uses the overall market requirements, which include any RUC adjustment from operators and the day-ahead VERs forecast. In real-time, the net load uses the overall market requirements, which include load conformance, as well as the real-time VERs forecasts (fifteen- and five-minute, accordingly). In contrast to gross load, the divergence of net load across the markets reduces in the morning and for peak hours. It appears that the variation of VERs across markets offsets the variations in the gross load among the markets to some extent.

Figure 45: Net load across the various CAISO markets



This metric, however, is a simple average that may hide the more granular variations, which sometimes may be offset between positive and negative values. The relative differences DAM and RTM also provide helpful information to understand the potential drivers for price performance. This metric closely resembles the concept of calculating the differences in net load between markets to determine the uncertainty used for the FRP requirements[14]. Figure 46 through Figure 53 show the net load differences between IFM, RUC, FMM and RTD, in both hourly and monthly trends.

All these trends show that there is significant uncertainty in meeting the net load across the CAISO markets. Maximum values for these uncertainties can be as high as 6,000 MW. Typically, this happens when the variations of the load forecast (accuracy) compounds with the variations of VER resources. Therefore, positioning the supply needs from the day-ahead period in order to meet real-time conditions is challenging. Currently, there is no explicit market mechanism to reconcile such uncertainty from DAM to RTM. To some extent, the RUC process may be a market tool to internalize the uncertainty by using additional load forecast adjustments. It is currently left up to the real-time market and system operators' judgment, to some degree, to ensure the supply is properly positioned to meet the actual system needs. For example, consider hour-ending 19 in 2018. During this hour, the range of variation from IFM to FMM

[14] The use of box-whisker plots allows for an intuitive graphical representation of the distribution of differences. Since these differences are based on multiple data points - namely, load forecast, VERs forecast clear values, dispatches, market adjustments at the interval granularity - some intervals may have a data quality issue as many of these data points are not subject to corrections after the fact. The data used for metrics throughout this report have been clean up to the extent possible. When one data point is not of good quality, the whole data set for that interval is dropped. For instance, if there is a missing value for an RTD dispatch, all data points such as forecast, IFM schedules, VERs forecast, RUC forecast, etc., are also ignored to avoid false differences. About four percent of the overall data set has been omitted in this analysis due to potential data quality issues.

was anywhere between -6,100 MW and +5,700 MW, representing an uncertainty range of more than 12,000 MW at the peak hour.

Figure 46: Hourly profile of net load differences between IFM and FMM

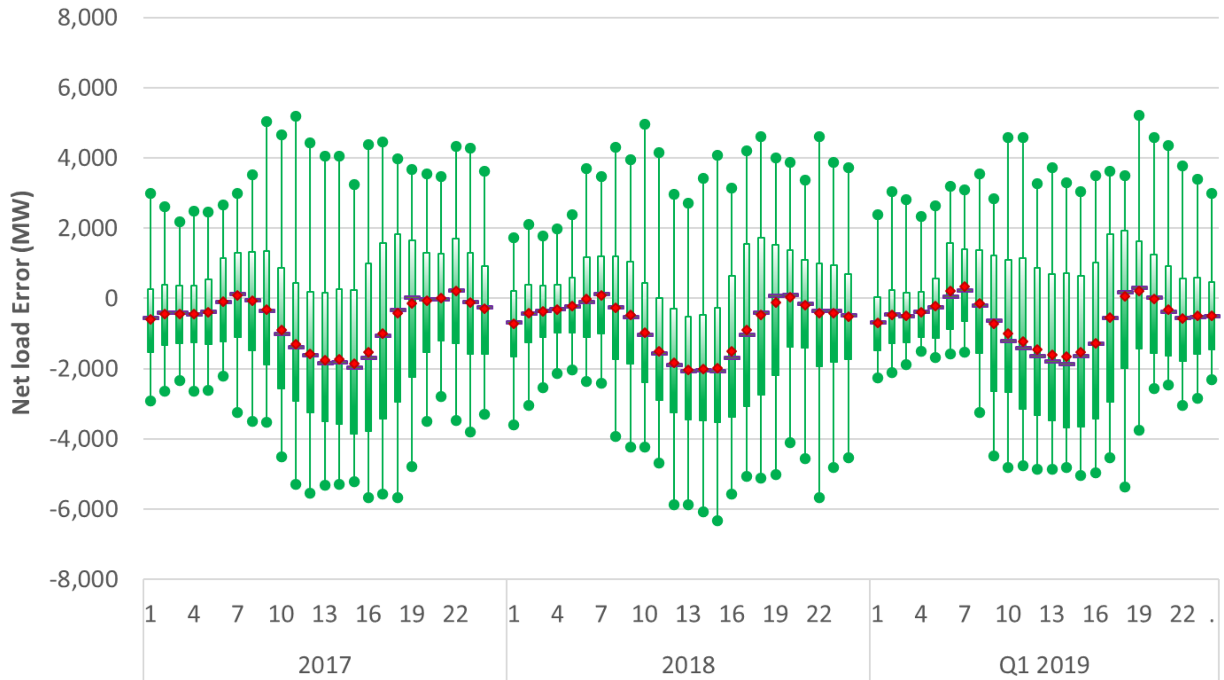


Figure 47: Hourly profile of net load differences between IFM and RTD

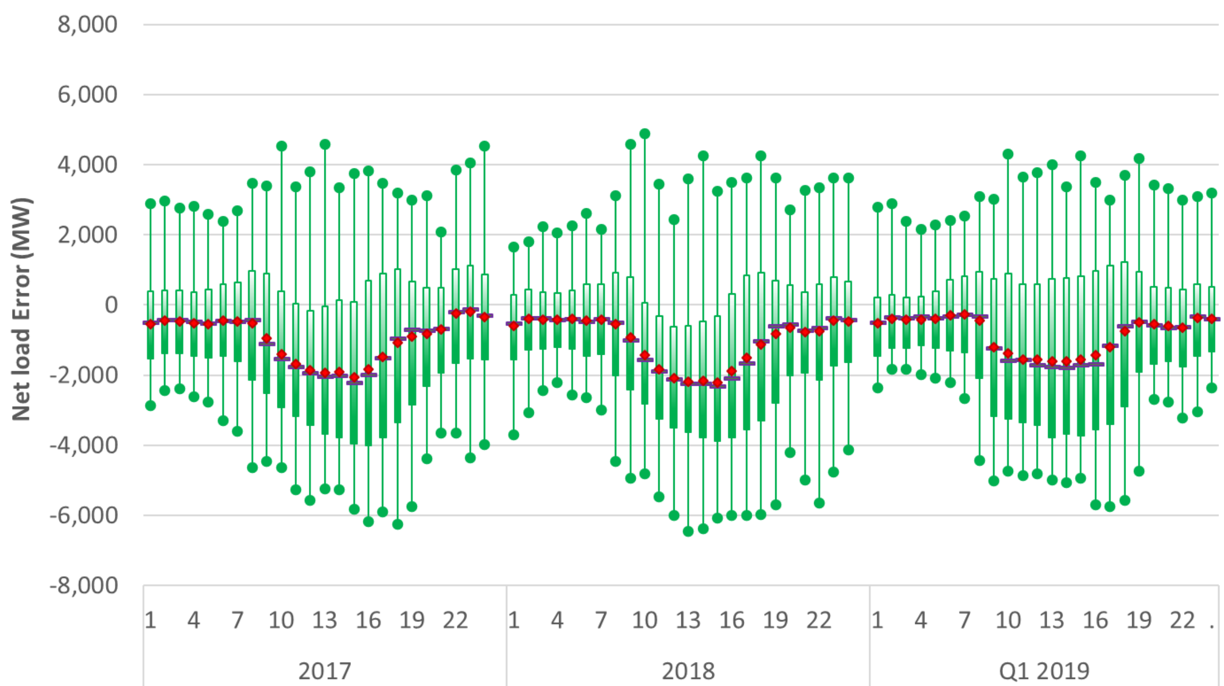


Figure 48: Hourly profile of net load differences between RUC and FMM

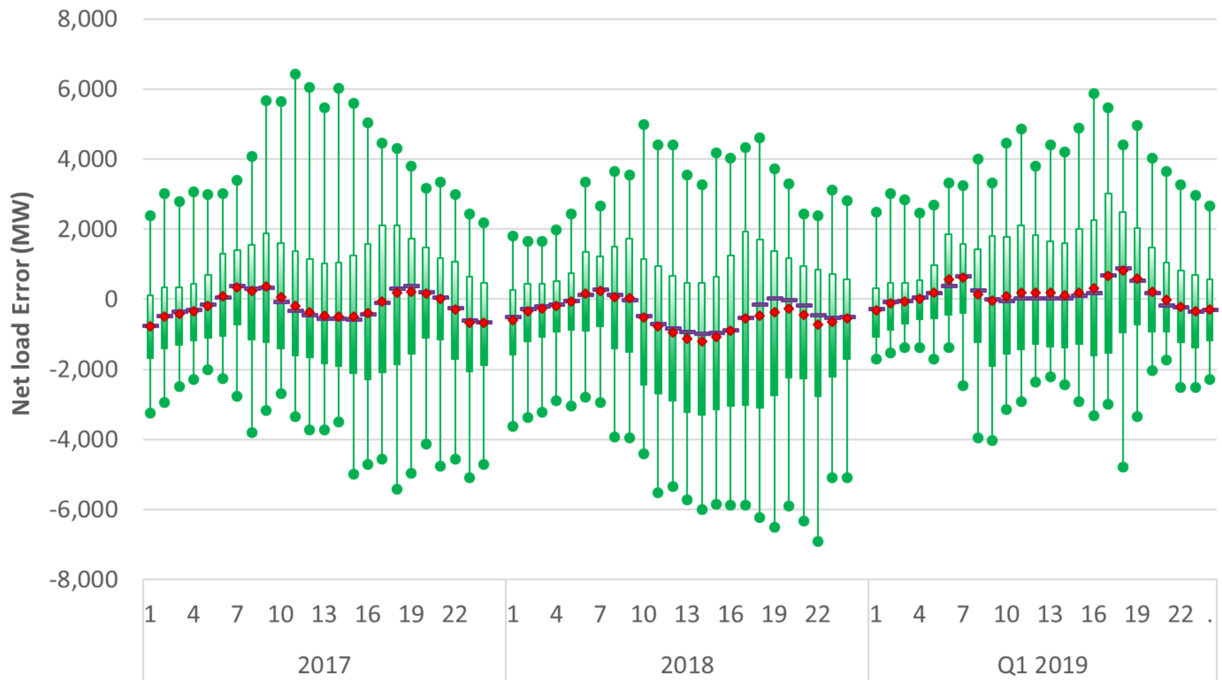


Figure 49: Hourly profile of net load differences between RUC and RTD

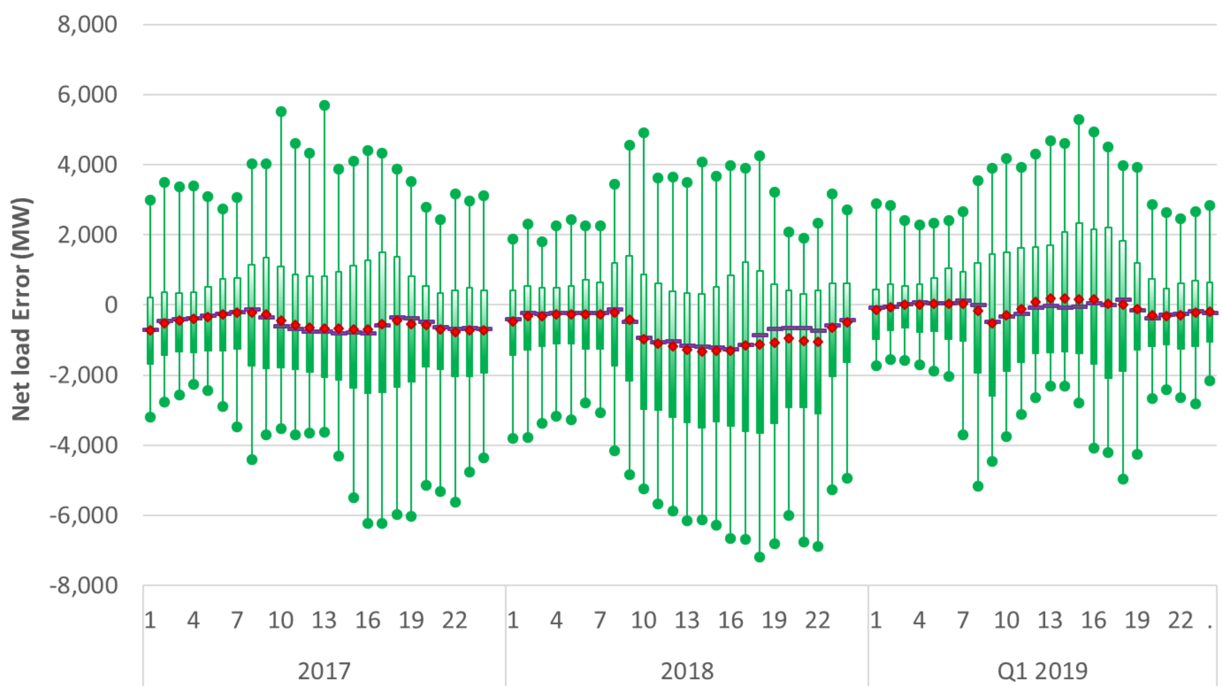
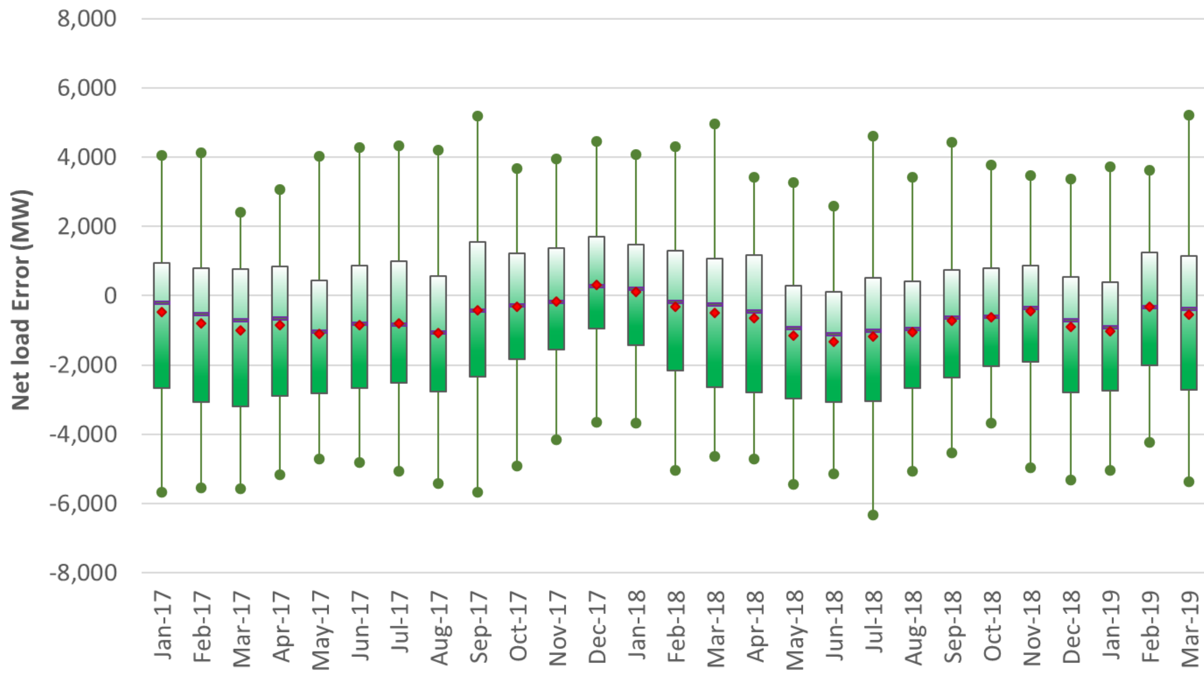


Figure 50: Monthly profile of net load differences between IFM and FMM



In comparing the trends of IFM to real-time versus RUC to real-time, the RUC market tends to get the net error lower than the IFM market.

Figure 51: Monthly profile of net load differences between IFM and RTD

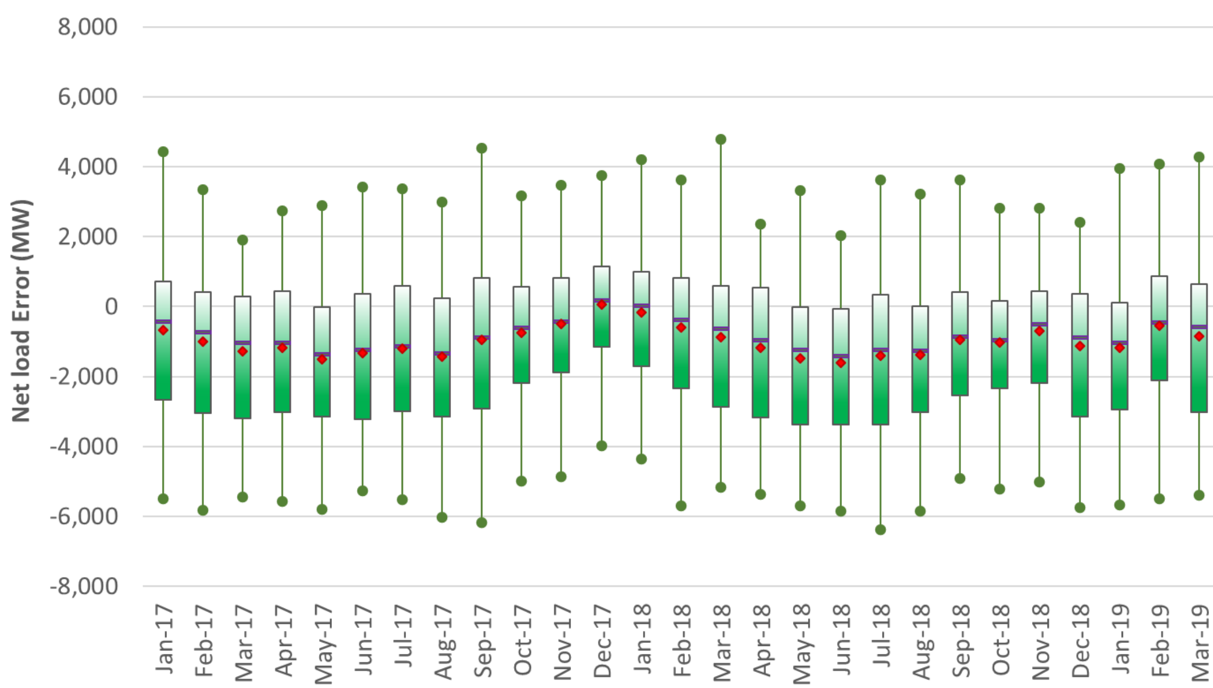


Figure 52: Monthly profile of net load differences between RUC and FMM

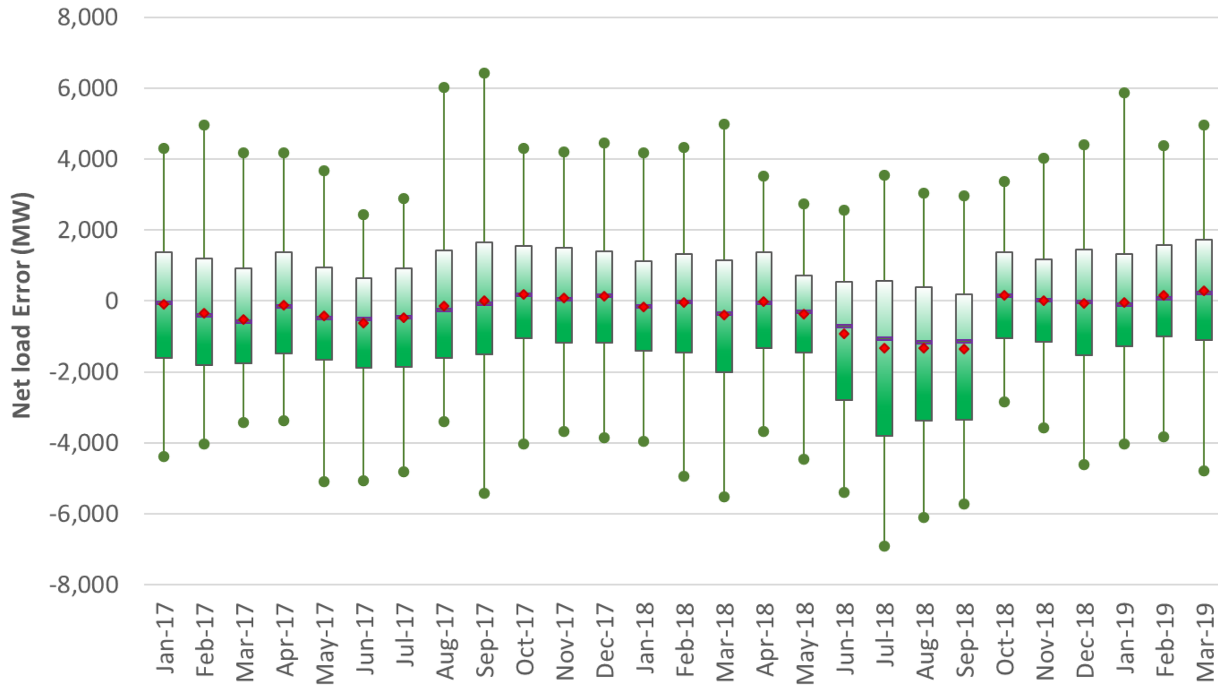


Figure 53: Monthly profile of net load differences between RUC and RTD

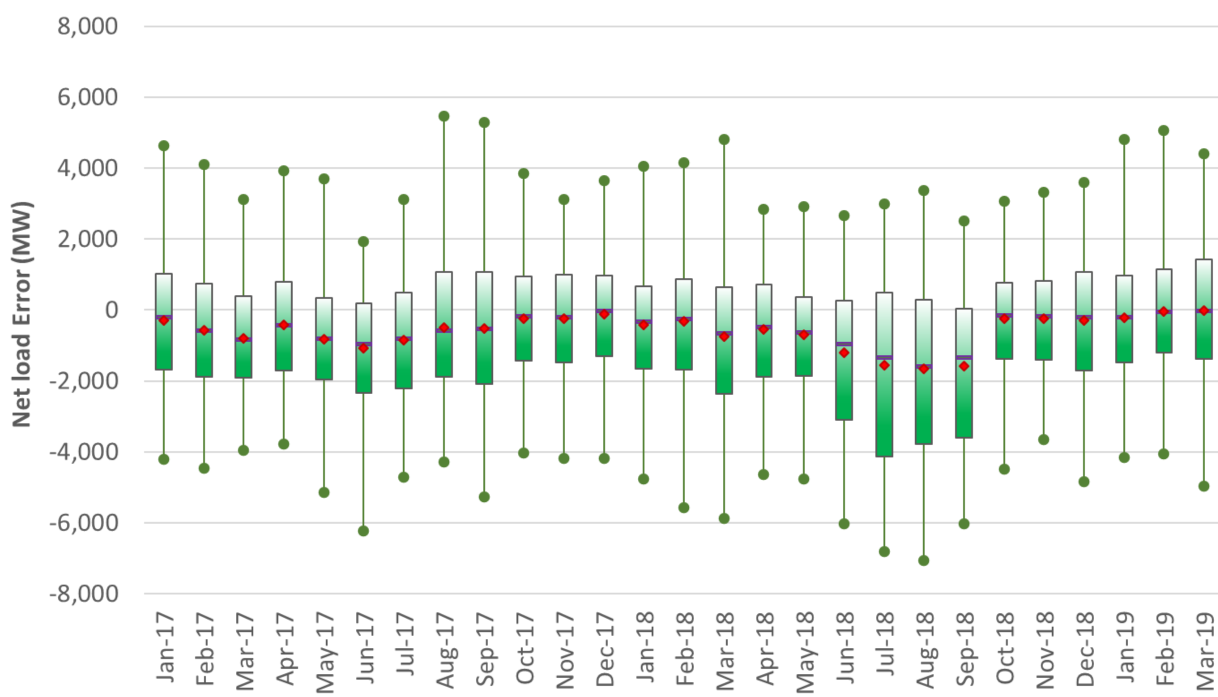
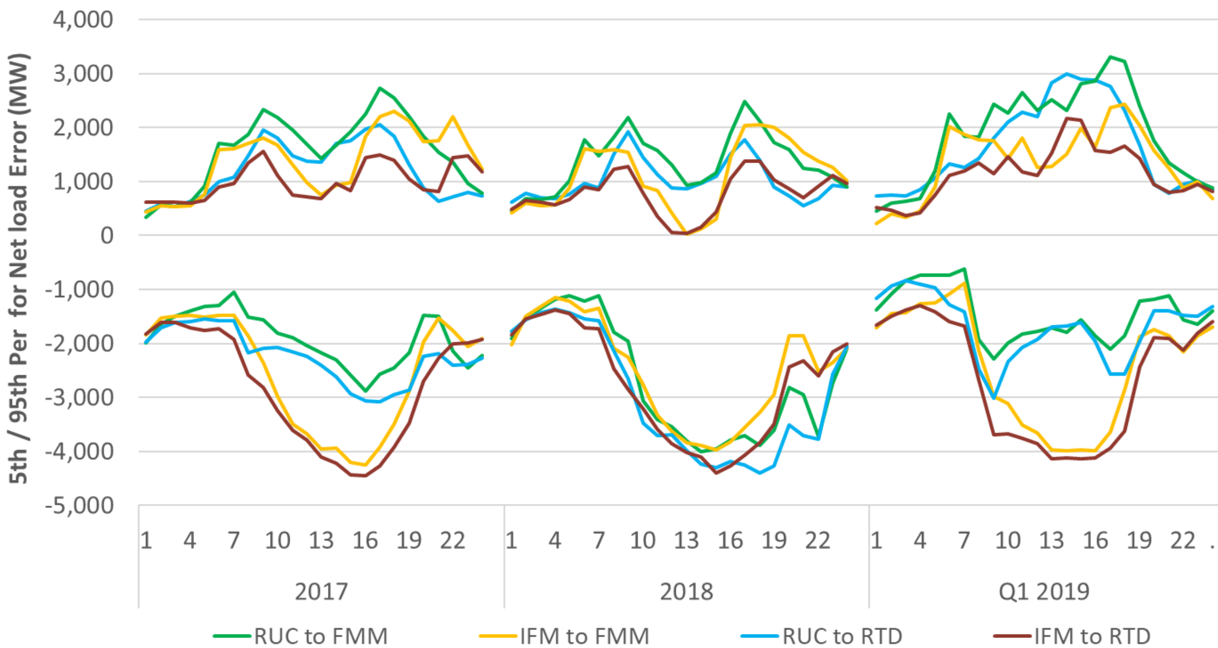


Figure 54 shows the net load errors between CAISO markets at the 5th and 95th percentile, which reflect the downward and upward net load errors between markets. These percentiles are taken as a reference to have a simpler comparison among the various levels of net load errors.

Figure 54: Profile of net load differences between RUC and RTD at P5 and P95



The most marked difference is observed from the IFM market to both FMM and RTD in the downward direction. This is driven largely by the inclusion of virtual bids and is observed mostly during mid-day hours when VER penetration is the highest.

The net load differences between DAM and RTM can be expected to lead to price divergence between markets. For instance, when conditions of load and VER generation lead to higher net load levels in real-time, the market may be more exposed to higher prices since there is a need to dispatch higher levels of generation, which may come with higher bid prices. Figure 55 shows a correlation between the net load errors and the price spreads observed for IFM and FMM. Figure 56 shows the same correlation but depicts only the data points outside the range of -$100/MWh and $100/MWh to narrow the illustration for the cases with the largest divergences.

Figure 55: Correlation between Net load and Price spreads –Full range

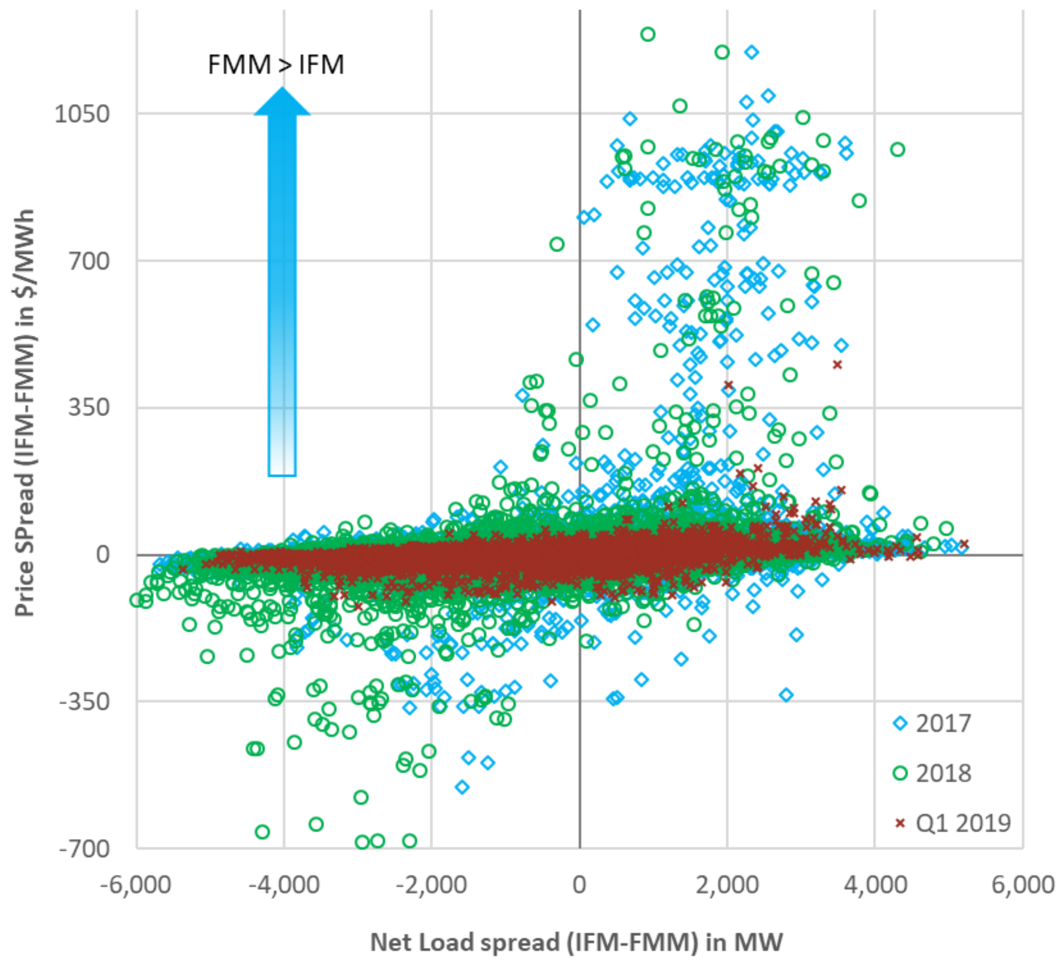
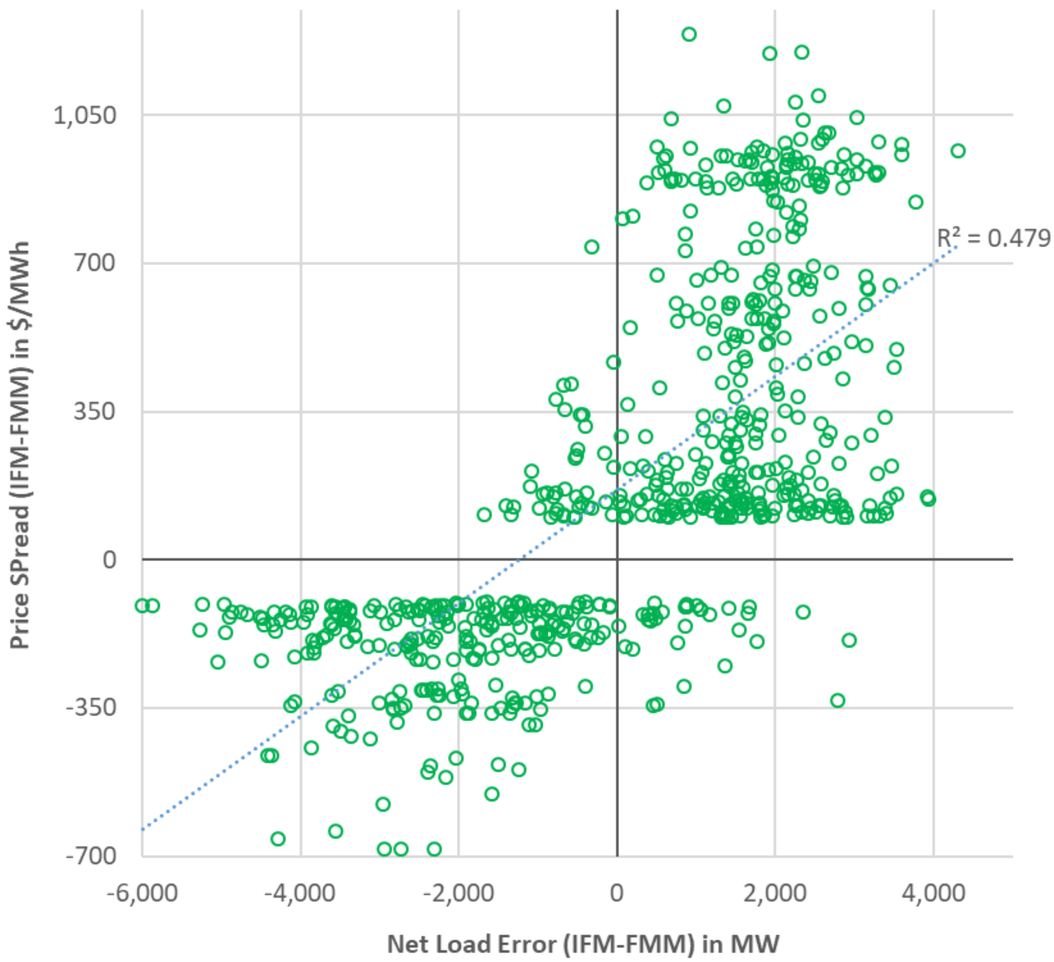


Figure 56: Correlation between Net load and Price spreads –Partial range



Both trends show that some degree of positive correlation exists between the net load error and the price spreads between IFM and FMM. In other words, when the net load is higher in FMM with respect to IFM, the prices tend to be higher in FMM (these are the dots in the top-right quadrant of the correlation plot). Conversely, when the FMM net load is lower than the IFM net load, FMM prices tend to be lower. This is intuitively expected since more demand, which is defined in FMM, will tend to put upward pressure on FMM prices. There are many data points that do not exhibit a strong correlation; this is most likely due to other drivers at play in the market solutions, such as gas price volatility, EIM transfers, intertie dynamics, etc.

The load that is used to derive the net load metric is based on the ultimate supply-demand clearing requirement imposed on each market. This requirement, as described in earlier sections, considers load forecast, transmission losses and any operator adjustments (e.g. load conformance in the real-time market or RUC adjustments in DAM). With the load conformance as the last resort for operators to adjust for system expected conditions, therefore, it is important to understand the effect of operator adjustments on the net load errors estimated in these metrics. The metrics shown in Figure 57 through

Figure 60 are based on the net load errors once operator adjustments are removed. In this case, the net load metric will refer to the natural error caused by the load and VER forecast.

Figure 57: Hourly profile of net load differences between IFM and FMM with no load conformance

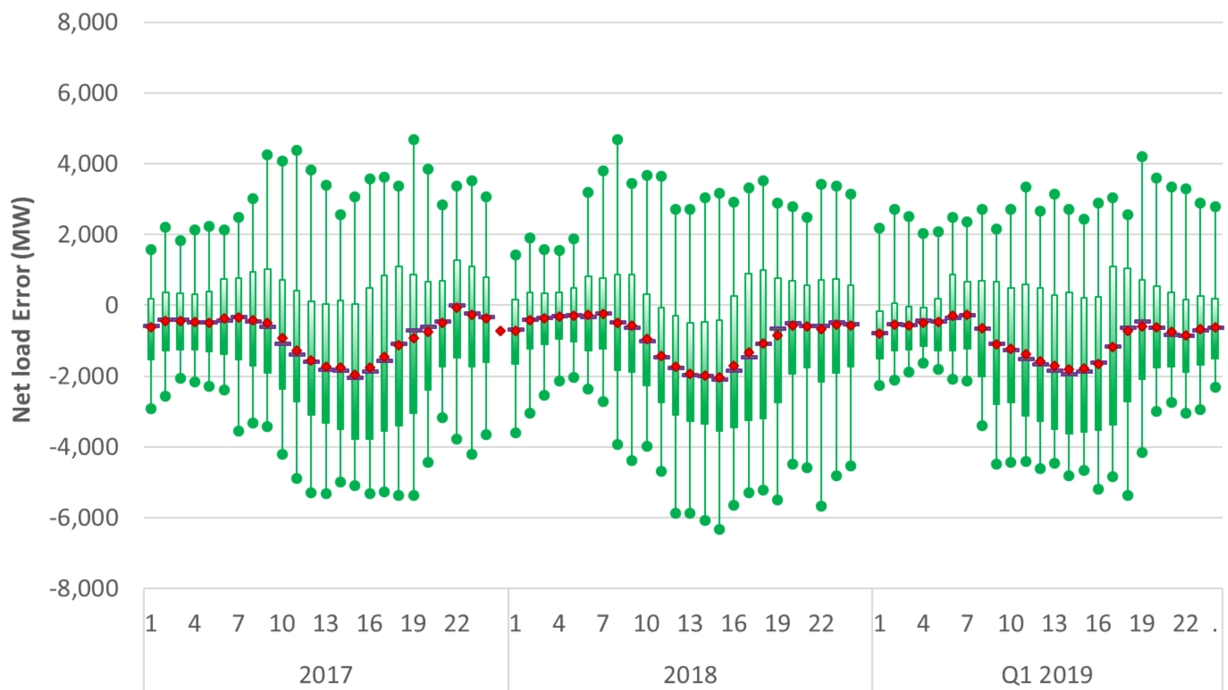


Figure 58: Hourly profile of net load differences between IFM and RTD with no load conformance

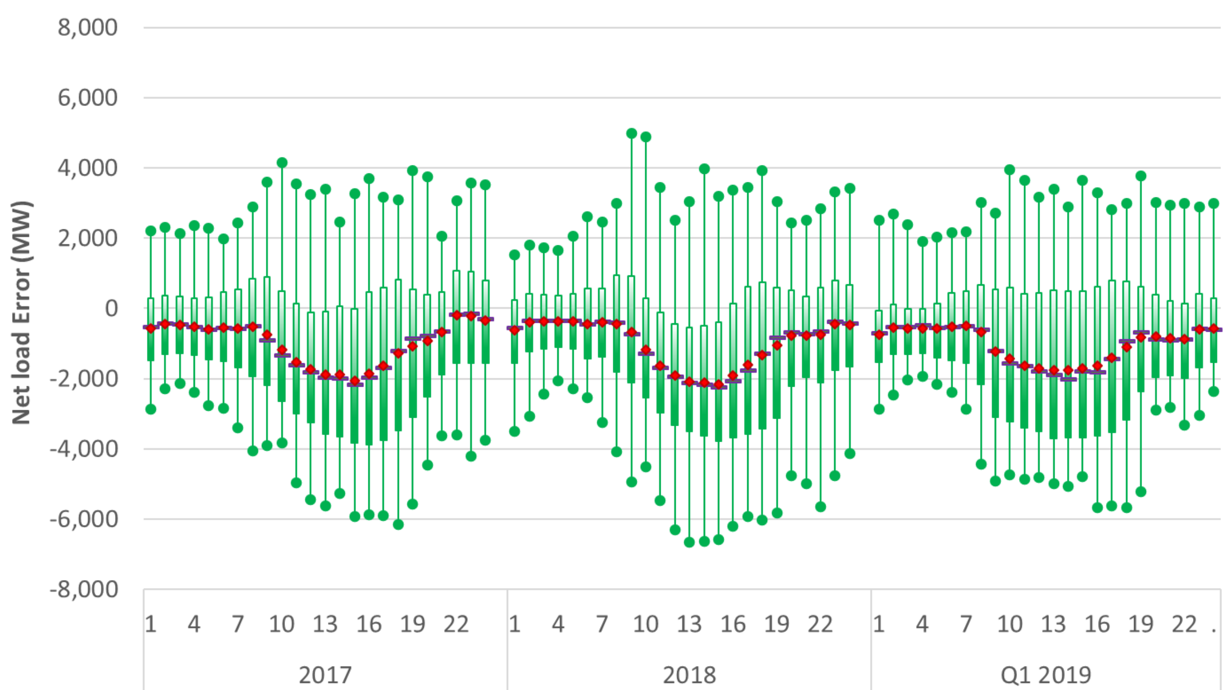


Figure 59: Hourly profile of net load differences between RUC and FMM with operator adjustments

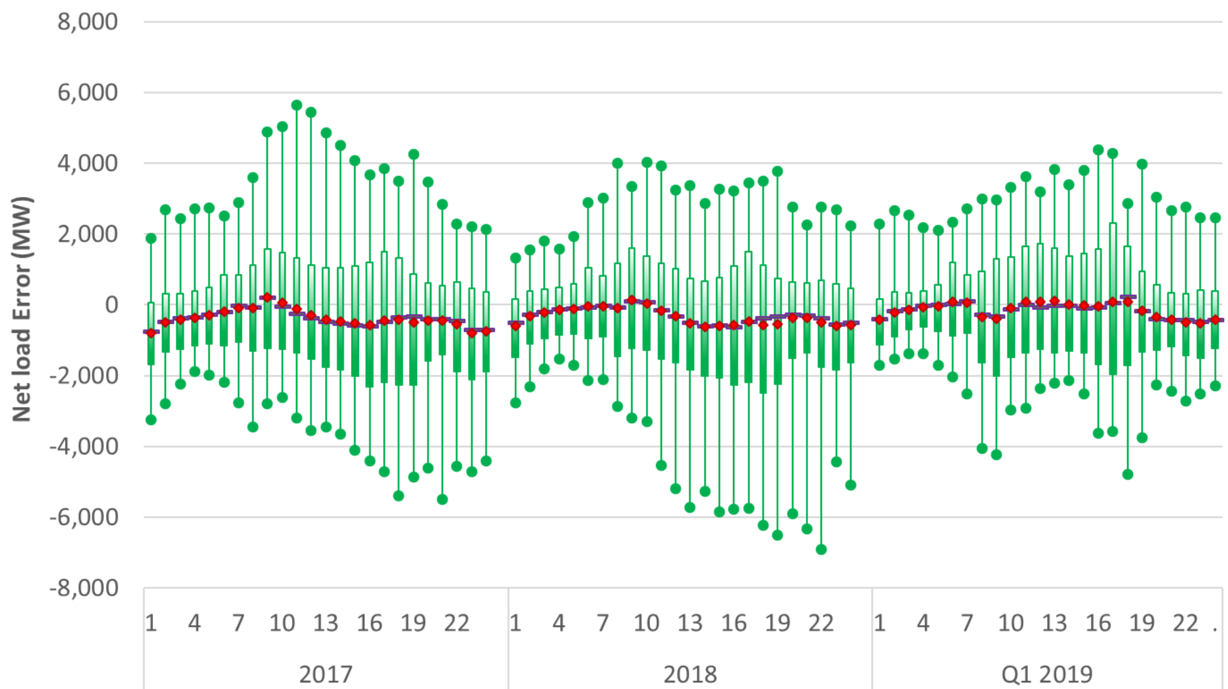
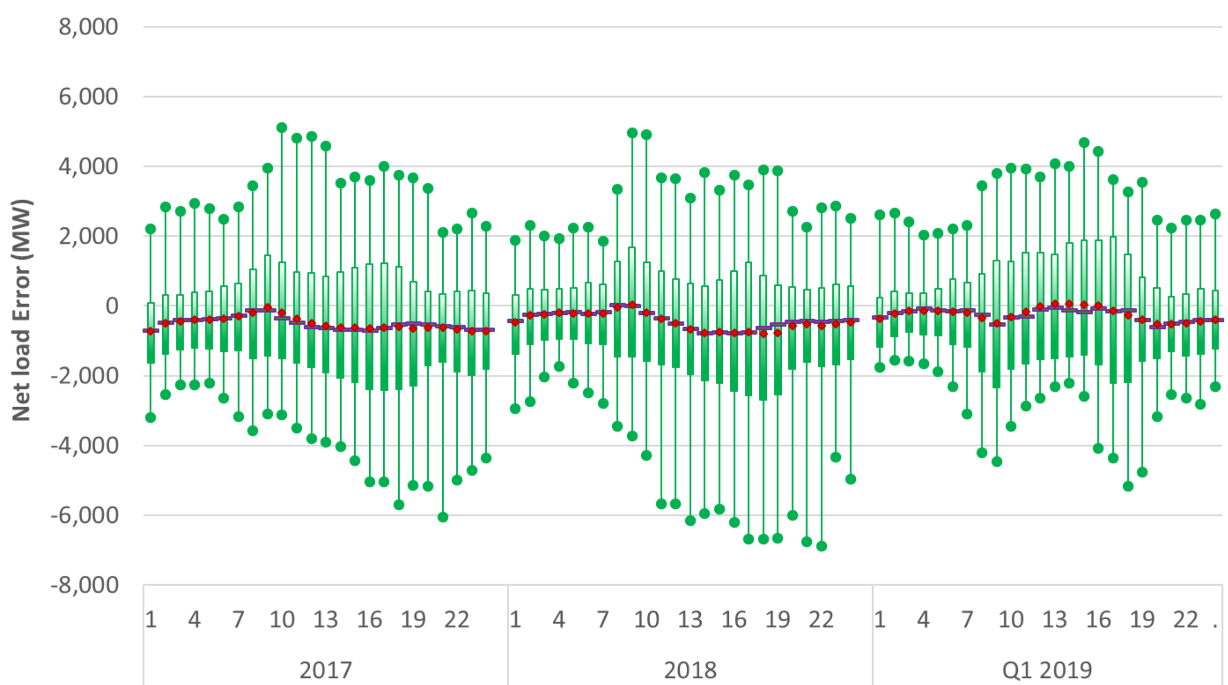


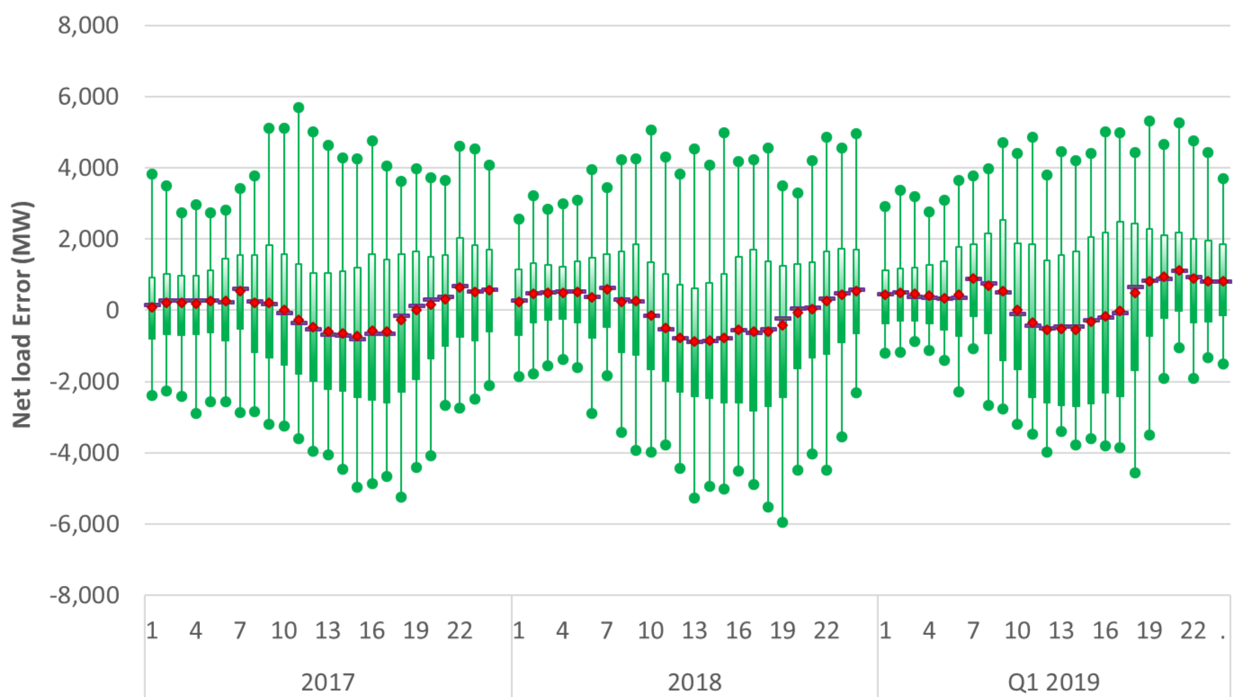
Figure 60: Hourly profile of net load differences between RUC and RTD with no load conformance



In general, the net load errors between markets is smaller when no operator adjustments are considered for the load (*i.e*. load conformance and RUC net short). These metrics also deduct any infeasibilities caused by operator adjustments because these infeasibilities do not lead to more supply being dispatched.

Another factor to consider is the effect of virtual supply in the positioning of the system toward real-time. Figure 61 and Figure 64 show the same hourly profile as previous figures with the difference that they show the outcome when the net virtual supply is disregarded from the IFM market. This effectively shows the net load error from IFM based only on physical resources[15]. This is done only for the net load error between IFM and FMM and the net load error between IFM and RTD. This adjustment does not impact RUC and thus the net load error for RUC does not change.

Figure 61: Hourly profile of net load differences between IFM and FMM with no virtual bids



Effectively, the disregard of virtual supply shows larger net load errors in the upward direction and smaller errors in the downward direction. This is more pronounced during the midday hours, which follow an inverse profile to solar dispatch.

[15] This is a simplistic approach of ignoring the cleared virtual vids in the IFM market in order to illustrate the net load errors based on physical resources only. The convergence bids, however, are cleared concurrently with physical bids. In order for this metric to be accurate, the market would have to be rerun without the consideration of convergence bids to see the shifting on physical resources. This could change not only the IFM resource profile but also the real-time solution.

Figure 62: Hourly profile of net load differences between IFM and RTD with no virtual bids

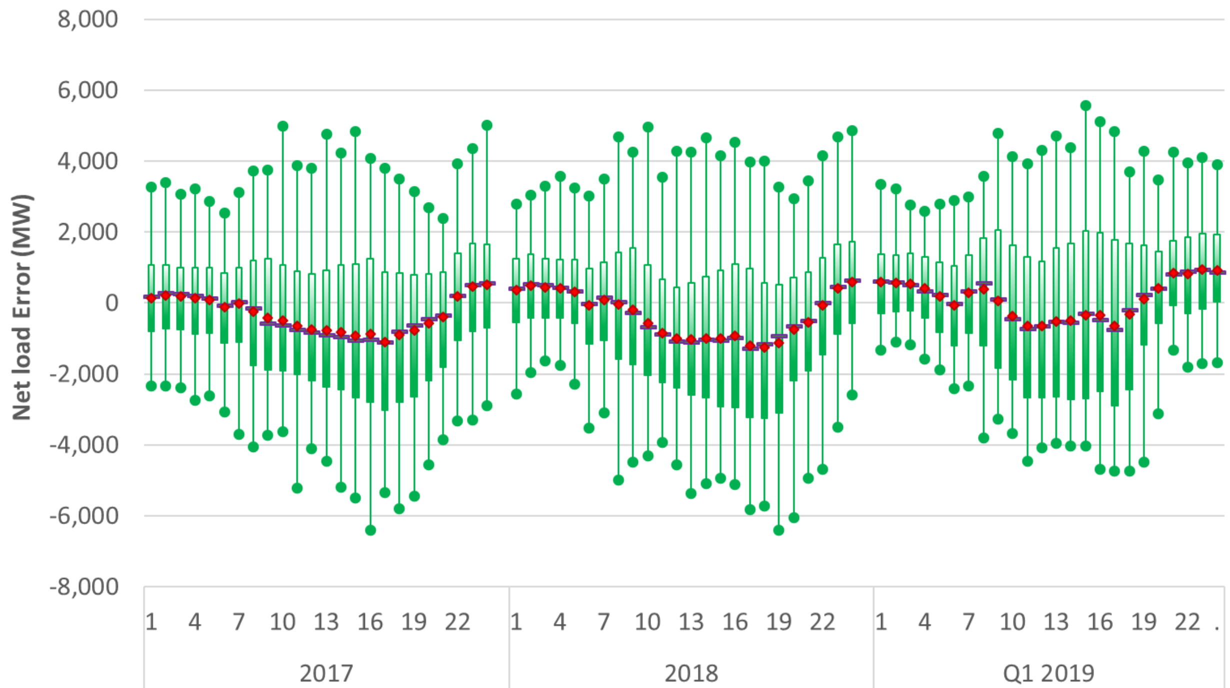
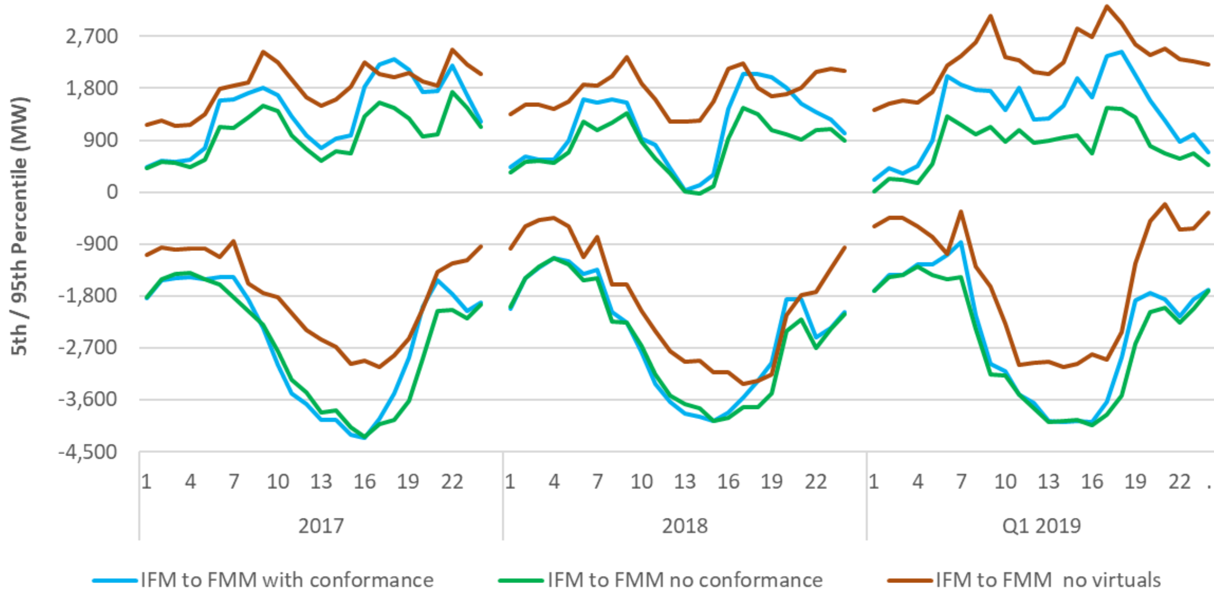


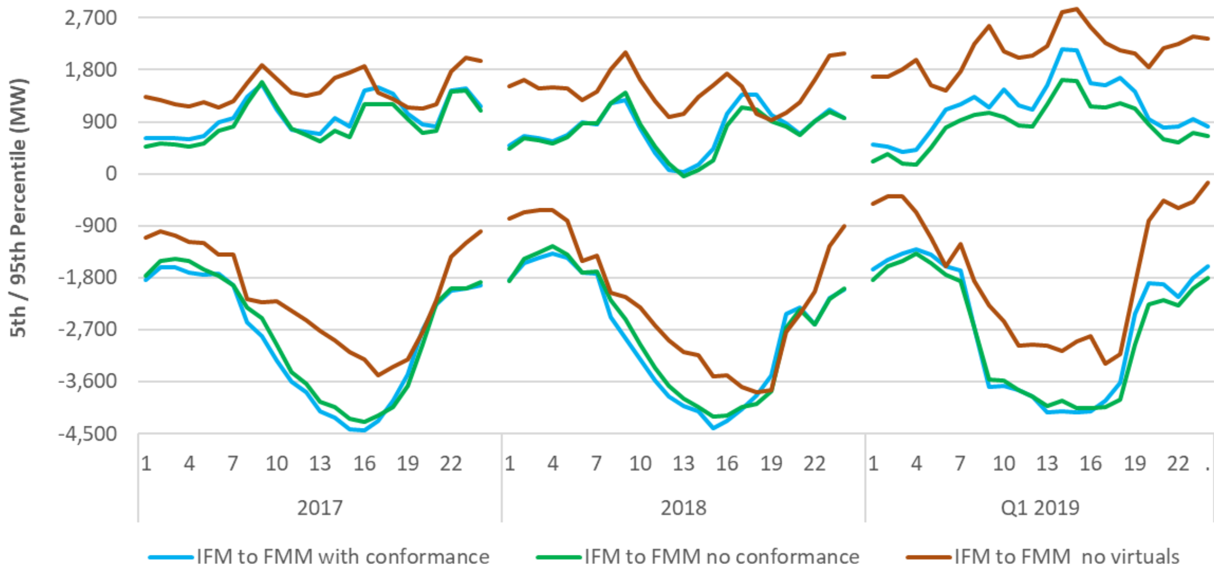
Figure 63 and Figure 64 target certain percentiles of the net load errors to have a specific reference for comparison.

Figure 63: Net load error between IFM and FMM



The 5th percentile is used for comparison of the downward error, while a 95th percentile is used for the upward error[16]. These percentiles are then compared for the error with and without operator adjustments, and also without convergence bids.

Figure 64: Net load error between IFM and RTD



These comparisons show that differences are more meaningful when FMM is used as a reference in contrast to RTD. This is largely due to the higher and frequent load conformance applied to FMM. For the IFM market, there is no change since no operator adjustment is used in IFM, only in RUC.

In the peak hours, the operator adjustments increase the upward error between FMM and IFM market but reduce the downward error. An upward error means that the FMM net load is greater than the net load from IFM. For the real-time market to absorb this type of error, more flexible ramp in the upward direction will be required. When comparing IFM and RTD, the net load errors with the consideration of operator adjustments remain fairly close to the cases with no operator adjustments, indicating the operator adjustments do not have a significant impact on the need for FRP requirement.

Similar to the comparison of net load error and price differences between IFM and FMM, Figure 65 shows the correlation between these two metrics. Generally, there is no significant difference, except for the data points in the second quadrant that are observed when no operator adjustment are in place, which may reflect that the operator adjustment resulted in a better alignment between the FMM net load and the price differences observed between markets (see yellow oval).

[16] The 5th and 95th percentiles are chosen just as a simple reference for comparison. Other percentiles such as the 2.5th and 97.5th will provide similar insights.

Figure 65: Correlation between net load error and price difference for IFM and FMM

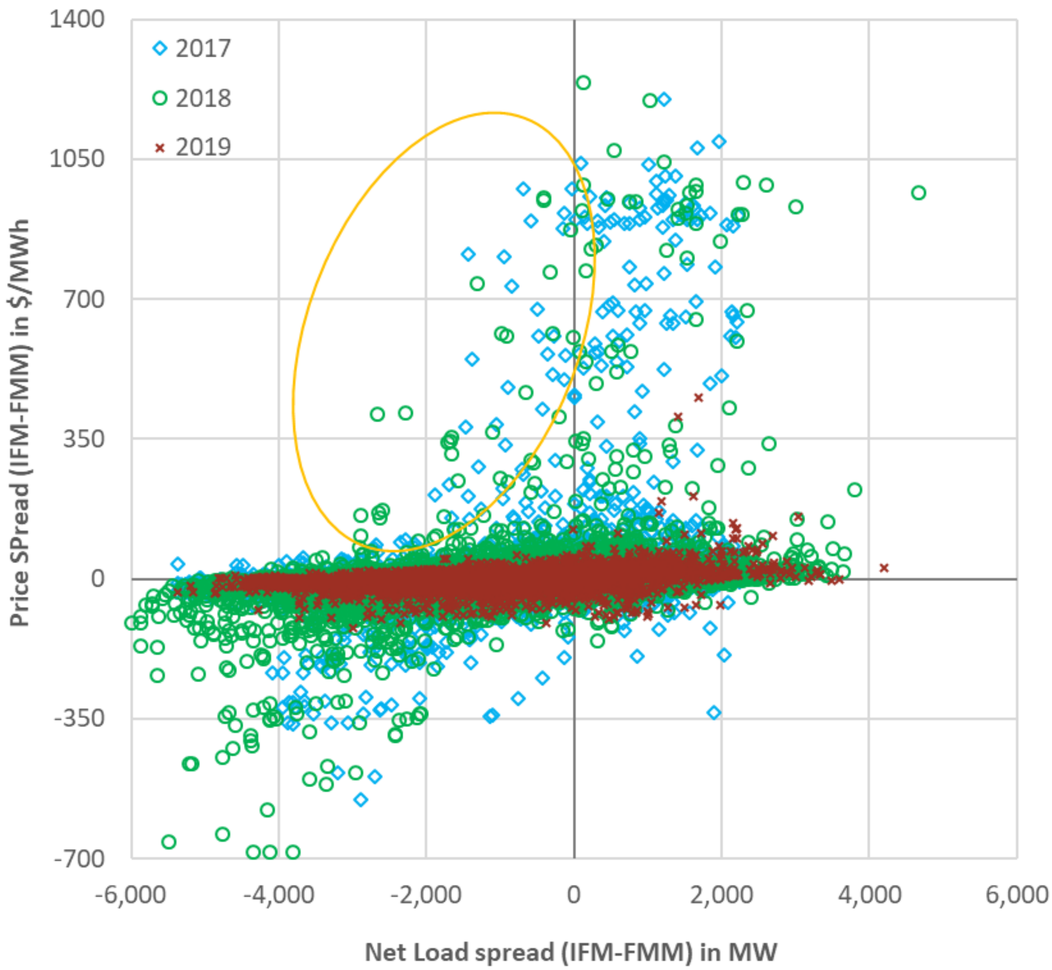
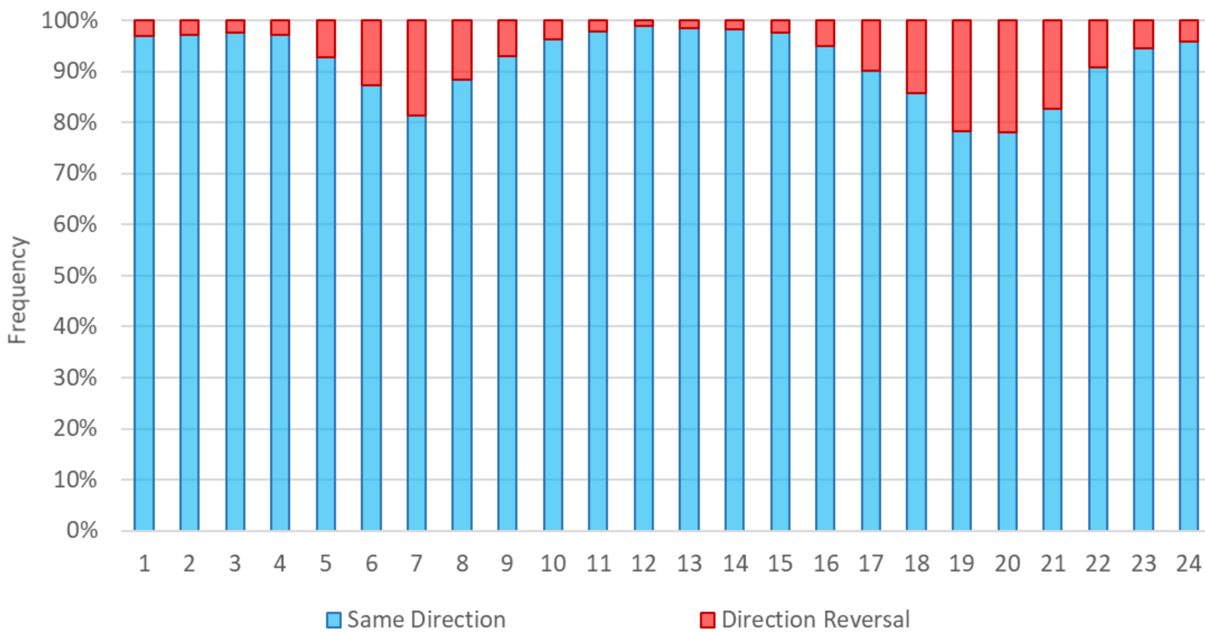


Figure 66 shows how frequently the load conformance to the FMM load forecast is inputted in the same direction of the net load error observed with respect to the IFM market, and how frequently such conformance actually reverses the direction of the net load error. The reversal of the net load error introduced with the load conformance typically maxes in the peak hours of the day and generally happens in the low range of the net load error. Load conformances that reverse the direction of the net load error may have an inefficient impact on the market clearing process. This may be due to the market clearing oppositely to the observed natural net load error which may create a price signal that is counter to the need for supply.

Figure 66: Frequency of direction reversal of net load error due to operator adjustments



Exceptional Dispatches

Operators can instruct specific resources to follow certain dispatch instructions to start up, shut down, transition to a higher or lower configuration in the case of multi-stage generators, operate at a specific MW dispatch, and to not exceed a specific MW value and/or not fall below a specific MW value; these are referred to as exceptional dispatches (EDs). Generally, EDs are issued during the real-time market, *i.e.* in the post-day-ahead market timeframe, but there may be conditions in which EDs can be issued prior to the DAM run.

This type of operator action can insert out-of-merit generation into the supply stack that otherwise would not have been available given the economics of the market. This, in turn, may distort the otherwise economical market clearing price, potentially resulting in lower prices (when more capacity is exceptionally dispatched) or higher prices (when EDs limit the available supply). Furthermore, EDs may cause discrepancy between the capacity cleared in the DAM and the capacity used to clear the RTM, hence driving price divergence.

An out-of-the-market intertie dispatch is a variation of an ED known as a manual dispatch in which operators may agree to buy/sell additional energy with scheduling coordinators. When looking to address system–wide conditions, the operators' reference points are typically bids that did not clear in the HASP and thus may be potentially available and, when looking to address congestion specific interties, may be more appropriate. These dispatches on interties are at a given negotiated price. The negotiated price is paid only to the intertie resources that were dispatched "out of the market" (*i.e.* via a negotiation with an operator), and does not set the price for the rest of the market. The agreed upon intertie energy is made available to the market as tagged (fixed) energy (as opposed to an economic bid that can be cleared based on market prices) and is used in the overall power balance. Generally, such manual dispatches on interties happen after the HASP run. Depending how quickly the participants submits the tag for the negotiated energy, the intertie energy may not be available for some of the intervals of the hour. The dispatch of out-of-market negotiated energy at the ties is a less frequent event than the EDs issued for internal resources and generally occur with constrained system conditions or projected high levels of uncertainty. These situations will lead to a supply discrepancy between the HASP and the FMM/RTD markets, which in turn may influence the clearing prices, with higher prices in the HASP and lower prices in FMM and RTD.

Over the years, the CAISO has developed different metrics and discussed how to quantify the volume of manual interventions in the CAISO markets. For example, the CAISO closely tracks and reports EDs in different forums, including the FERC monthly reports (Table 1 and Table 2), 120-days FERC report, monthly market performance report, and Market Performance Forum Meetings. Anecdotally, the CAISO has discussed implications of EDs and other market interventions. In this analysis effort, the CAISO is seeking to not only more comprehensively quantify the extent of market interventions but most importantly to correlate, identify, and, to the extent possible, quantify their effect on price performance: namely, the impact that the EDs creates on price performance.

Figure 67 shows the monthly volume of energy associated with all EDs, including intertie schedules, during the 2018 calendar year, organized by reason. The largest volume of EDs occurred during the summer months. Figure 68 shows the volume of energy issued with all EDs averaged across hourly intervals during the 2018 calendar year. EDs are issued in higher volumes during peak hours[17].

Figure 67: Volume of EDs in the CAISO market

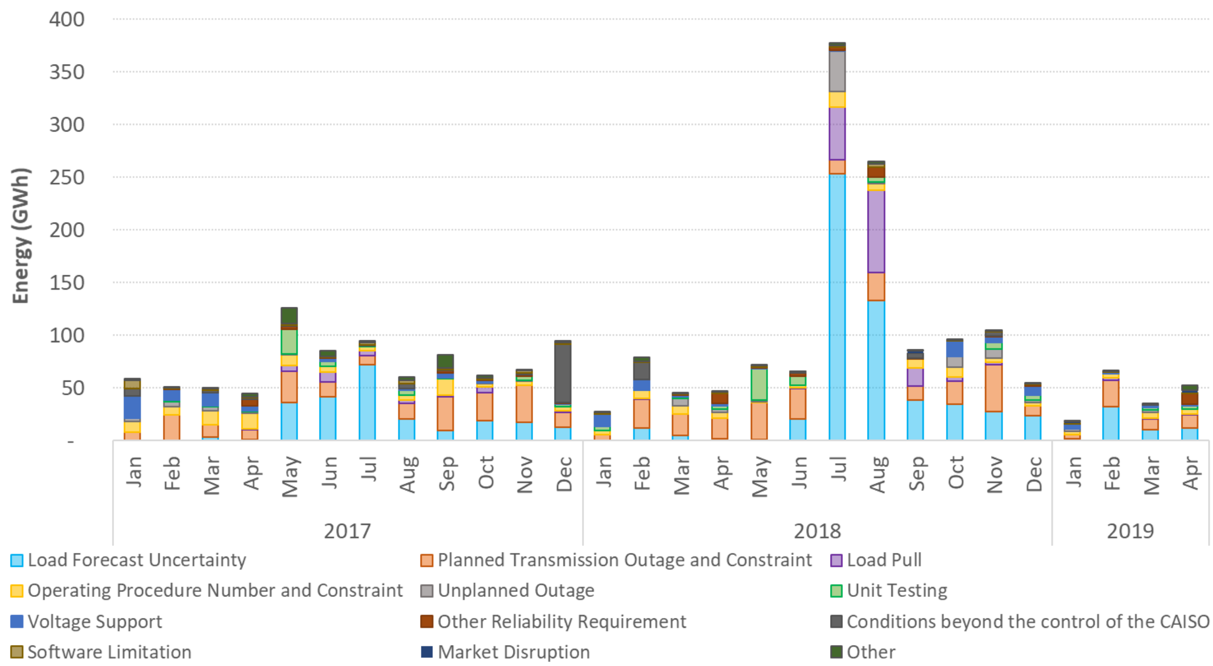


Figure 68: 2018 Volume of EDs in the CAISO market

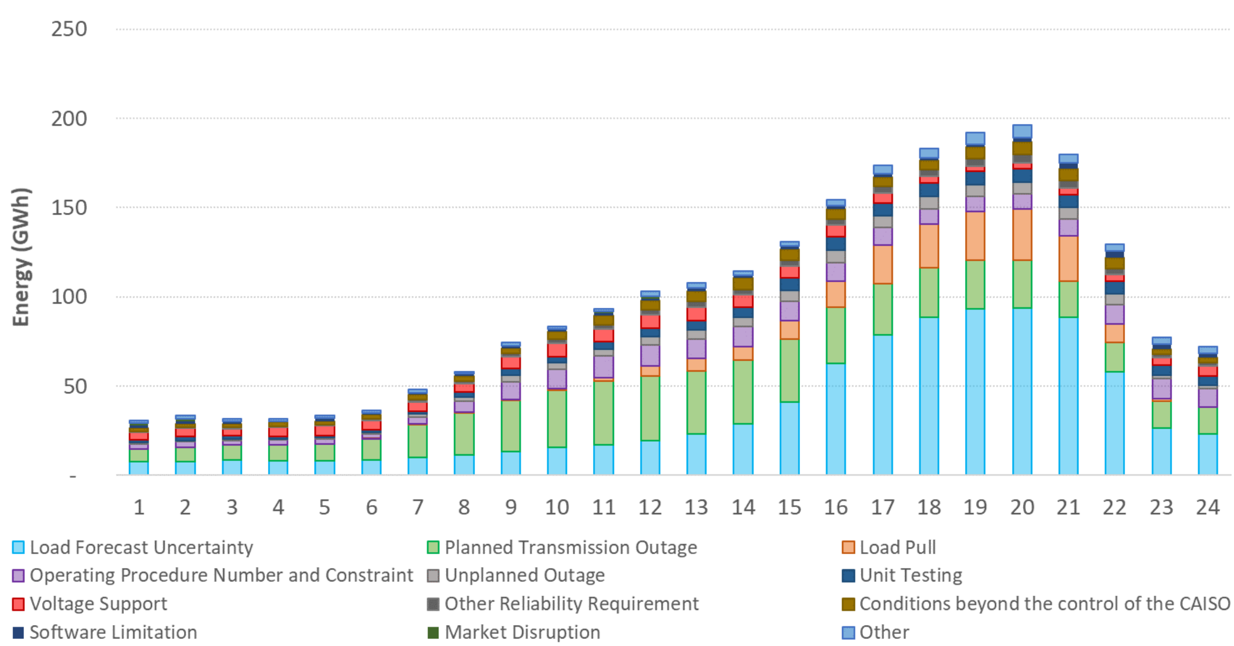
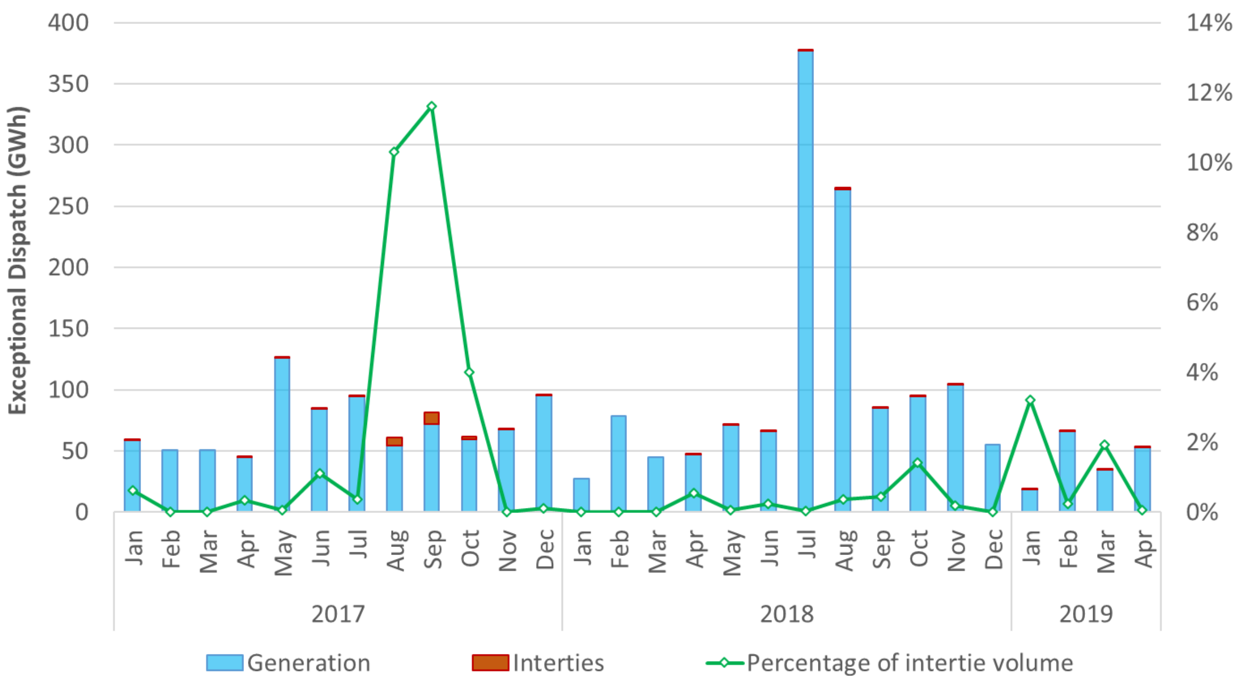


Figure 69 organizes the volume of EDs in two groups, one for internal generation and another for intertie resources. Generally, EDs on interties represent about 1 percent of the overall volume in the reported period, with the exception of the months of August and September 2017, when the interties represented up to about 10 percent of the total volume of EDs. These interties can be for either imports or exports; exports are generally associated with emergency energy to other BAAs.

Figure 69: 2018 Volume of EDs by type of resources



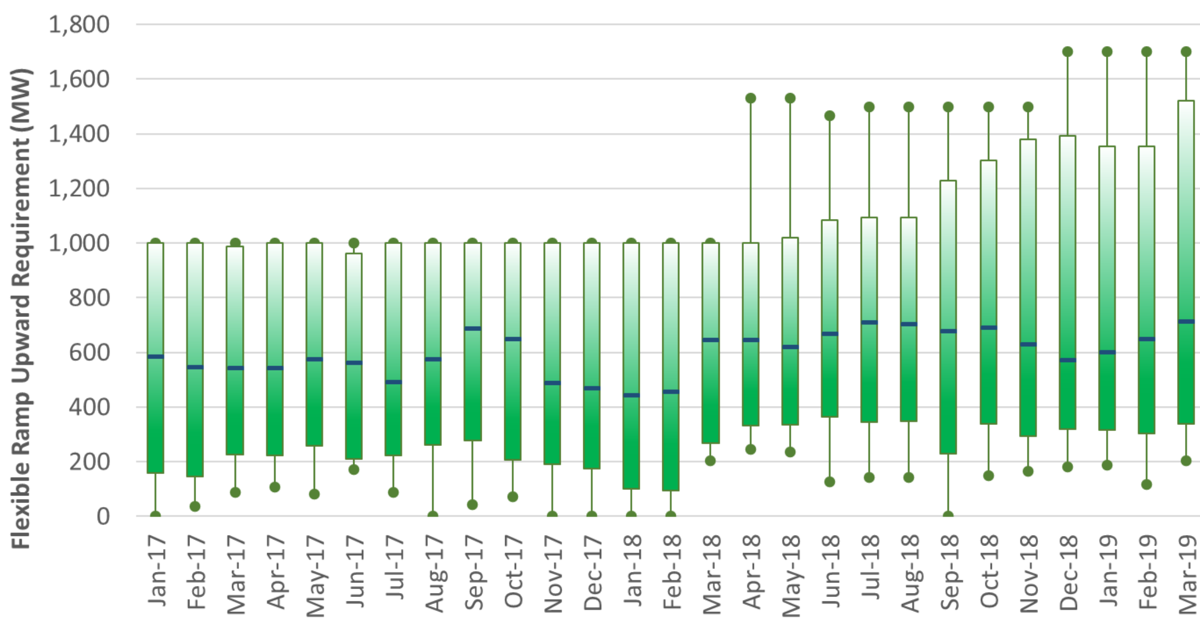
The IFM clears supply with bid-in demand based on the economics of the bids. The cleared IFM demand may not align with the CAISO load forecast for next trading date, thus the RUC process is in place to ensure sufficient capacity is procured to meet the forecasted load[18]. Resources committed in the RUC process or after the IFM, may result in more capacity being available in the RTM than IFM. Consequently, this may lead to lower RTM prices relative to those in IFM.

Flexible Ramp Product

The flexible ramp (FRP) is the existing market functionality in the real-time market that allows the each EIM area to procure for ramp capability in order to meet estimated uncertainty in the real-time markets. Both FMM and RTD optimally clear FRP based on the corresponding requirements in both upward and downward directions. Such uncertainty is estimated based on historical variations from load and VER forecasts using a rolling data set of the last 40 days. The upward and downward requirements are determined based on the 2.5 and 97.5 percentiles of the histograms of the net load errors. For FMM, the errors are estimated between the advisory FMM interval and the binding RTD interval for the same timeframe, while for RTD the net load errors are estimated between the advisory RTD interval and the binding RTD intervals between adjacent RTD markets for the same timeframe. As part of the EIM market, there is a FRP requirement for each BAA, including the CAISO area, plus a system-wide EIM area requirement. The estimated requirements are always capped by a maximum value that is estimated using similar logic to determine the FRP requirement but using a higher percentile.

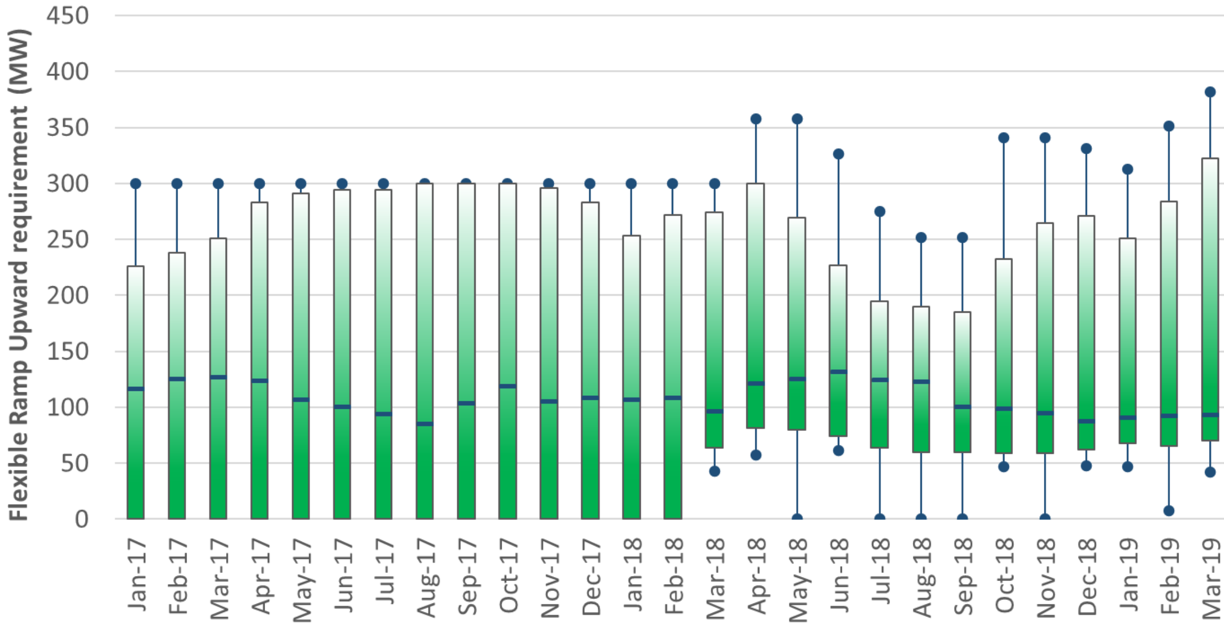
As weather conditions change, the profile of the FRP requirements may change naturally over time. For illustration purposes, Figure 70 and Figure 71 show a distribution of the FRP requirements for CAISO BAA for both FMM and RTD markets for the period under analysis. The flexible ramp upward (FRU) is used for purpose of this analysis.

Figure 70: FRU requirement in FMM



The FRP requirements for FMM will tend to be higher than the requirements for RTD because of the inherent time granularity they cover – fifteen versus five-minute ramp needs - and due to the inherent nature of the uncertainty observed in these two market. The FRP requirements for RTD are expected to be lower than FMM.

Figure 71: FRU requirement in RTD

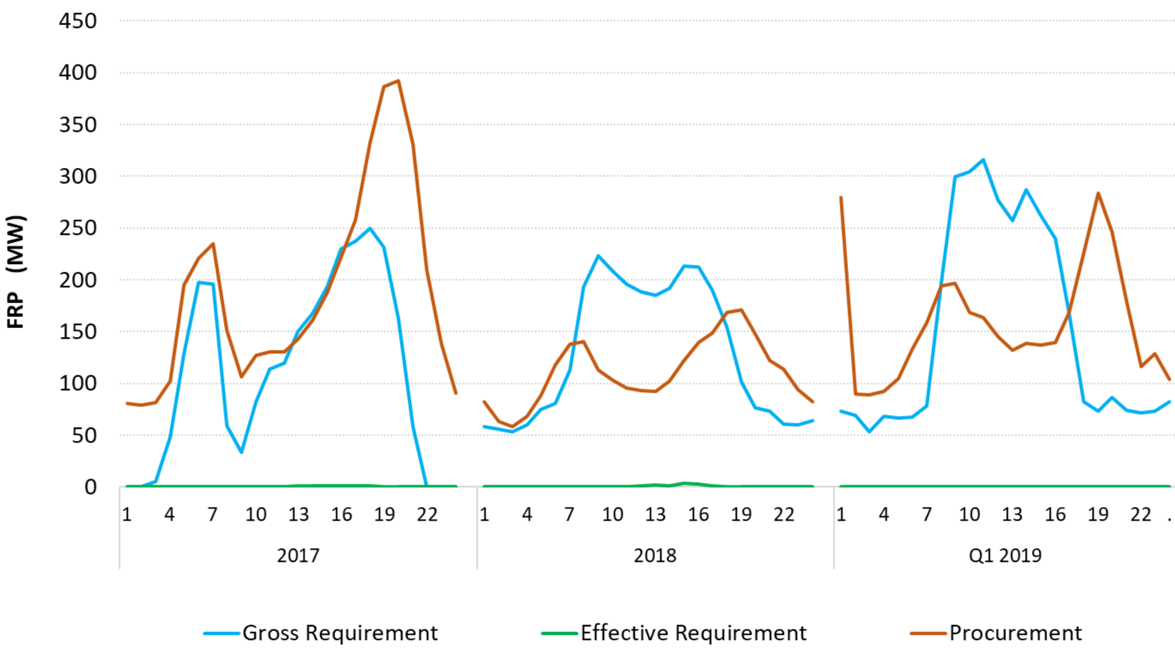


The net import/export capabilities (NIC/NEC) are used as a credit towards an EIM area's requirement. The basic idea is that other area procurement can be supplied through the import or export ETSR transfer capability. If the import capability is higher than the area's requirement, then the effective requirement to enforce for that area is 0 MW. Under typical EIM area conditions, all areas generally have larger import or export limits than their FRU or flexible down requirement. Within an interconnected system with multiple areas, a flexible ramp can be counted towards other areas by wheeling through other areas. Therefore, a case may exist in which the FRP requirements counted towards the credit of imports/export is more than the area's requirement. This means the EIM area requirement may not be enforced effectively since it considers that all of the FRP requirement can be met with FRP procured over the transfers when, in reality, the flexible ramp capability is related to the ramp capability of the available resources and not due to the available transfer capacity. For instance, an EIM area may have an import/export capability of 1,000 MW and its natural FRP requirement based on resources made available may be only 300 MW. This means that if this area can use its flexible ramp capability to meet another area's requirement, only up to 300 MW of FRP requirement is indeed available.

This consideration of credit transfers for FRP procurement is applicable to all EIM areas; this is not a specific attribute for CAISO BAA only. The amount of credit for EIM transfer applicable to each EIM area and, consequently, the effective requirements for a given EIM area depends strongly on the EIM transfer capability with adjacent BAAs. For illustration purposes, consider the CAISO case as shown in Figure 72 and Figure 73. The line in blue stands for the nominal requirement estimated based on historical uncertainty as an input to the market. Then, NIC/NEC is determined at the time the market is cleared. Once all the credit from NIC/NEC is accounted for, each area enforces the effective requirement that the gross requirement must be less the NIC/NEC credit.

Figure 72: CAISO's area FRU requirement and procurement in FMM

Figure 73: CAISO's area FRU requirement and procurement in RTD



The majority of the time, the CAISO area's effective requirement is zero, or very close to zero, as shown with the line in green. With the same logic applying to all EIM BAAs, FRP is effectively required and procured through the system-wide EIM area constraint to more or less extent depending on the specific EIM area. With such a requirement, some resources within a given EIM area may procure flexible ramp capacity in order to meet its FRP requirements; that procurement is shown with the line in red. About half of the gross requirement for the CAISO will be met through the procurement of the EIM area in FMM. The profile for RTD changes to some extent with some peak hours having FRP procurement in the CAISO above the natural CAISO area requirement. Figure 74 and Figure 75 provide a breakdown of the FRP procured throughout the different EIM areas to meet the system-wide area requirement. Because CAISO is the largest area, approximately half of the overall EIM requirements in some hours are procured with CAISO resources.

Figure 74: FRU procurement for system-wide EIM in FMM

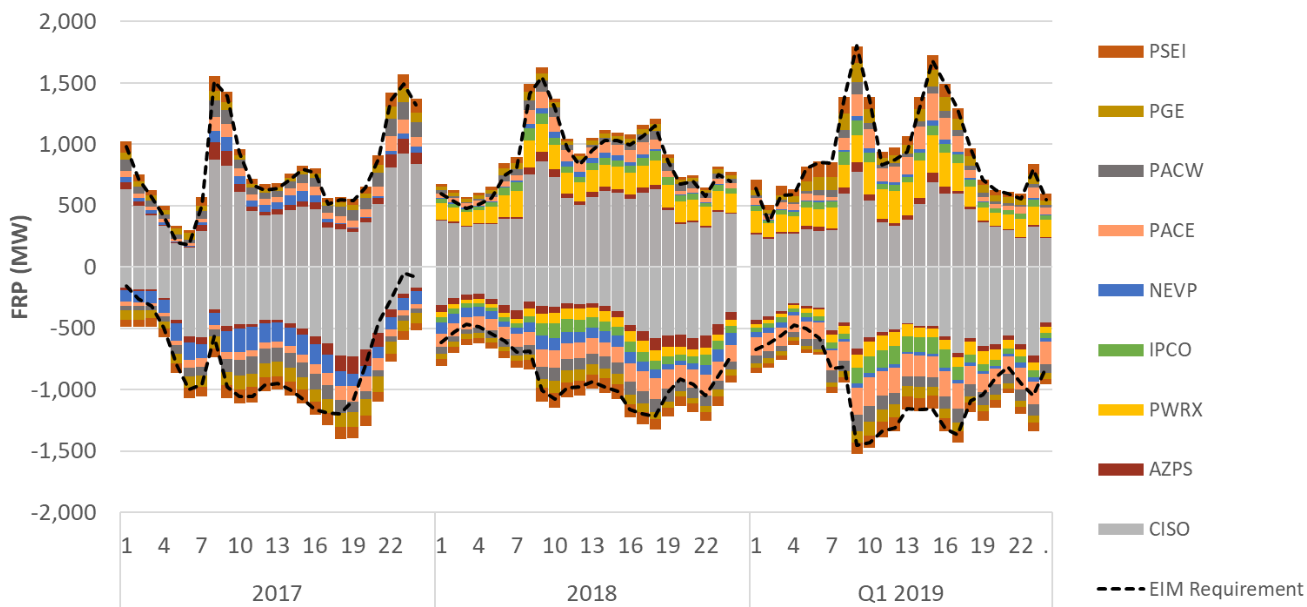
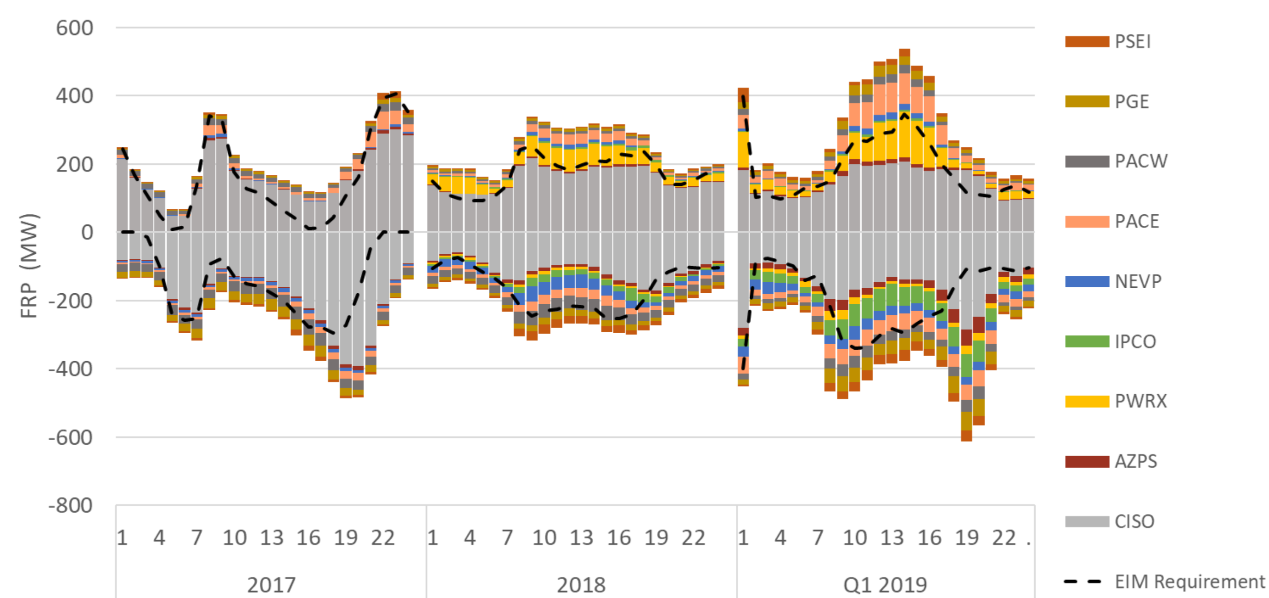


Figure 75: FRU procurement for system-wide EIM in RTD

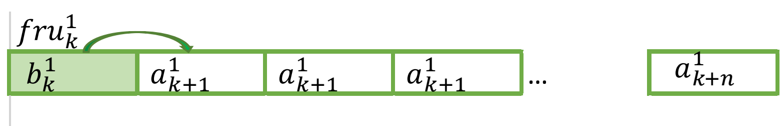


Buffer interval in FMM

The real-time (RTD) markets run every fifteen and five minutes; each market is composed of multiple intervals that have a fifteen- and five-minute granularity. The first interval of the horizon in each RTD market run is the binding interval, since the cleared quantities are used to instruct resources for dispatch and to generate the prices for settlements. The remainder of the subsequent intervals in the RTD horizon are advisory since there is a market solution – for both dispatches and prices - but these subsequent intervals are not used to settled or dispatch resources. For FMM, there is a similar construct with one difference: the first interval of each FMM run is a buffer interval, in which the market clears and determines schedules and prices, but these schedules and prices are not binding. The binding interval is always the second interval in the market horizon of each FMM run. Any subsequent interval is an advisory interval. The logic of the buffer interval was introduced in the market with the implementation of the FERC Order 764 in order to provide sufficient time for tagging purposes once fifteen-minute interties could economically participate in the FMM.

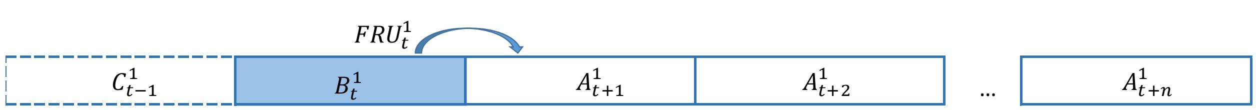
The FRP is intended to procure capacity between intervals to handle the potential for uncertainty. This flexible capacity is assigned to the first interval. The following figure illustrates this construct for the RTD market.

Figure 76: RTD market horizon



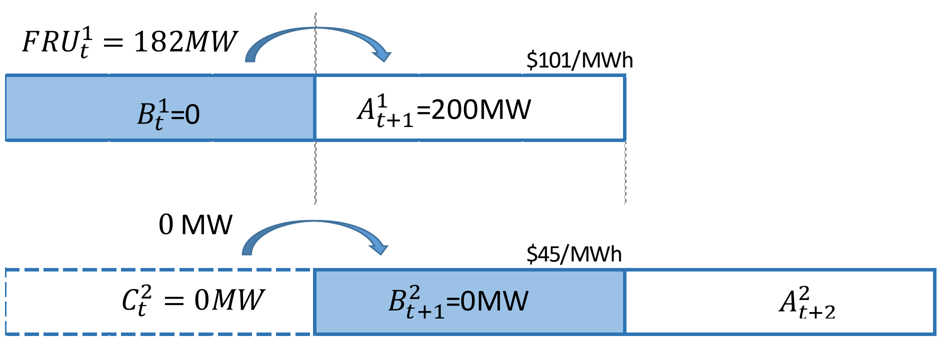
Where k stands for the time interval of the RTD market run *1*; b_k^1 and a_k^1 stand for energy dispatch of a given resource in the binding and advisory interval, respectively; and a_n^1 is the last interval of the RTD market horizon. The binding interval and all the advisory intervals compose the time horizon during which each RTD market runs to clear the market. The fru_k^1 stands for the FRU procurement between the binding and first advisory intervals, and that is assigned to the binding interval. FMM has a similar timeframe as illustrated in the following figure, with the difference of the binding interval being the second interval in the market horizon; thus, the FRU enforced and procured between the binding and first advisory interval is assigned to the binding interval. Currently, there is no flexible ramp capacity required to be procured between the first interval (buffer intervalC_{t-1}^1) and the first binding interval B_t^1. It has been observed that this may lead to instances in which flexible ramp capacity procured in a previous FMM run will be lost in the subsequent FMM run due to the lack of requiring the procurement of FRP assigned to the buffer interval.

Figure 77: FMM horizon



Consider, for instance, the procurement of FRP in a given EIM area in one of the FMM intervals of July 21, 2019 in hour-ending 18. Consider interval t as the reference time. There was a resource that was scheduled for 182 MW of FRU in the binding interval for the first FMM run. In the first FMM run the resource was also expected to start up and be scheduled for 200 MW of energy in the first advisory interval. This resource was originally offline and the FRP requirement was intended to commit the resource. From this perspective, the market and the requirement of flexible ramp properly projected the need for the resource to startup in the first advisory interval *t+1*. In the subsequent FMM run (labeled as FMM run 2) interval *t+1* becomes now the binding interval and the FMM re-optimizes the schedules and procurements, and any unit commitments that can be still revisited, such as the ones for fast-start units . In this second FMM run, this binding interval *t+1* saw energy prices decreasing to about $45/MWh. This was in part due to the FRP procure in the first FMM run being now released for use in the second FMM run for the now binding interval *t+1*. The second FMM run no longer commits the resource for the binding interval t+1 (as previously projected) based on the overall economics of the market. Because there is no requirement for flexible ramp between the first buffer interval *t-1* and the binding interval *t* in the subsequent FMM run, the flexible ramp of 182 MW scheduled from this resource in previous FMM run for interval *t* was lost when the resource is no longer committed[19]. In other words, the flexible ramp is not utilized in interval *t+1* but rather lost. The following figure illustrates this interplay between FMM intervals.

Figure 78: Interplay of buffer interval in FMM



Overall, in addition to the lost flexible ramp, when going from the first FMM run at interval t to the subsequent FMM run at interval t+1, FMM utilized over 400 MW of the 1,062 MW of flexible ramp procured. The utilized flexible ramp helps handle the changes observed between FMM runs.

The FMM uncertainty is actually defined as the changes which happen between the FMM intervals between the corresponding RTD intervals in the same timeframe. The 182 MW of flexible ramp scheduled in the first FMM run, and then lost in subsequent FMM run, negates the flexibility potentially needed later on for the corresponding RTD intervals, since RTD cannot start up this resource. This lost flexible capacity cannot be re-procured in FMM either.

[19] In the first FMM run, this unit was projected for a startup in the first advisory interval of FMM (which is the third interval in the first FMM run horizon and is the interval after the binding interval) in order to provide flexible ramp; however, given the startup time that commitment was not a binding. This is logic in the unit commitment in which if there is time for the market to re-optimize the commitments, the projected startup will only be advisory and subsequent FMM runs may determine if that commitment becomes binding or not.

As a counter-factual study case, the first FMM run was rerun with no FRP requirement to serve as a proxy of the market outcome if there is no FRP required in interval *t+1*. The outcome shows that with no FRP requirement set for interval *t* in the first FMM run from interval t towards interval *t+1* (which is assigned to interval *t* as FRP procurement), the resource no longer gets started up in the advisory interval t+1 in the first FMM run and prices are close to those observed in the second FMM run binding interval.

The fact that there is no FRP requirement imposed in the first interval of the market horizon effectively releases all the flexible ramp capacity procured in the previous FMM run for use in the binding interval of the subsequent FMM run. Thus, if changes happen between these two FMM runs[20], the released flexible ramp capacity will be utilized. This will allow the current FMM run to re-optimize resources to absorb the changes observed in that run. From the FMM perspective, this is a good use of the flexible ramp. For the case described here, the release and utilization of about 40% of the flexible ramp capacity procured in the previous interval allows the market to absorb the changes, resulting in a $45/MWh price instead of a $101/MWh price. The inefficiency arises from the fact that, by fully releasing the flexible ramp capacity in the binding interval for the subsequent FMM run, this may deprive the corresponding RTD intervals in the same timeframe with flexible ramp capacity, as described in the example above. The FRP requirement for FMM is based on the uncertainty estimated between the advisory FMM intervals towards the corresponding RTD intervals.

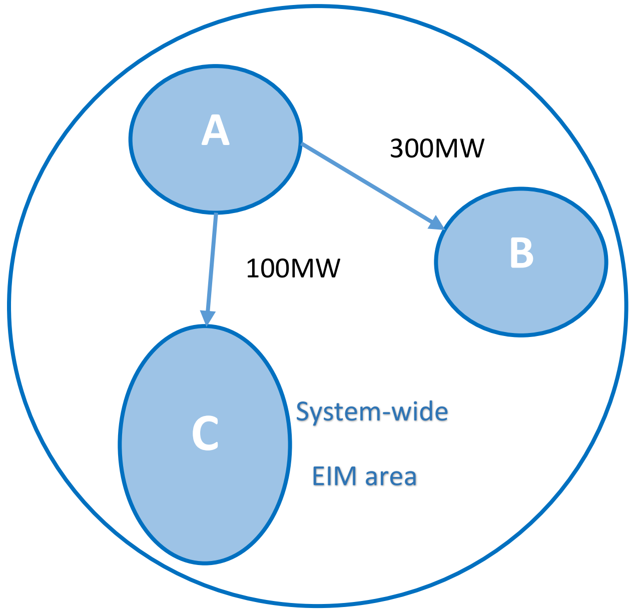
Transfer limitation

Based on the CAISO's previous evaluation of the FRP performance, it was found that credits on imports and exports were beyond levels that an EIM area could feasibly support. In 2018, the CAISO introduced a bound on the amount of flexible ramp capacity that can be assigned to an EIM area and be supported through the import/export transfer capability[21]. With that enhanced formulation, the flex ramp can be scheduled in an EIM area up to the amount of the remaining transfer capacity. Based on the EIM area and the available transfer capacity, the following may still occur: if the majority of the transfer capacity is within an area that does not have ETSR capacity to the area that needs the flexible capacity, the transfer capacity will essentially be stranded and may not be deliverable to the specific area that needs the flexible ramp capacity. Consider the following illustration with three individual EIM areas within a system-wide EIM area. The bound imposed on EIM area A will be the maximum import capability of 400 MW because it is the amount of flexible ramp that can be supported out of this area based on the transfers; based on the economics of meeting the requirement for the system-wide area, it may be that the flexible ramp procured from area A is 400 MW. Now, if area C realizes uncertainty and there is a need for the use of flexible ramp capacity, only 100 MW will be transferable from area A to area C. If area C were to need 400 MW of flexible ramp, 300 MW of that flexible ramp is effectively stranded in area A with no utilization.

[20] The FRP is designed to address uncertainty arising from load, wind, and solar changes. However, when released and utilized in the markets, the flexible ramp capacity can be released and utilized for any type of changes happening across intervals and markets (from FMM to RTD and from FMM interval to FMM interval). Other changes beyond uncertainty, such as load conformance changes/differences and other resource deviations, can also trigger the utilization of flexible ramp capacity.

[21] This enhanced formulation was implemented in April 2019 while the original enhancement was discussed in the Market Surveillance Committee session of February 2018. The presentation is available at http://www.caiso.com/Documents/Presentation-FlexibleRampingProductPerformanceDiscussionFeb22018.pdf

Figure 79: Flex ramp limitation on EIM areas



This situation is again observed in the real-time market. Consider, for instance, the case of June 25, 2019, HE 20, during which an RTD price spike occurred. The system-wide EIM requirement for flexible ramp was 1,032 MW. In the RTD market, uncertainty materialized in this hour because of renewable resource deviation. There were also some losses of resources during this period. Overall, the RTD market was short by 936 MW. So, with the FRP requirement, the available capacity should have been enough to cover the shortfall. However, about 404 MW of flexible ramp capacity scheduled was not deliverable because that capacity was located in the other EIM areas which could not be utilized to absorb the changes because of limited transfer and ramp capability into the EIM BAA observing the uncertainty.

Stranded flexible ramp capacity

The FRP does not rely on explicit bids from participants to determine the optimal procurement and prices for flexible ramp. Instead, flexible ramp capacity is priced at the opportunity cost between procuring flexible ramp and energy in periods when resources become limited. If resources are not capacity-limited for this trade-off to happen between flexible ramp and energy, the value of flexible ramp capacity will be $0 since there is no opportunity cost to withhold capacity from energy to procure more flexible ramp.

Resources in the markets can submit economical bids anywhere between the bid floor of -$150/MWh and the existing bid cap of $1,000/MWh. Resources with bid prices above the clearing prices are not expected to be dispatched for energy simply because they are out of merit; this holds for both power balance conditions and for congestion management.

In recent years, the CAISO has shown that some proxy demand resources may have economical bids close to the bid cap of $1,000/MWh. These resources, or any other type of resources with expensive enough bids, will not normally be dispatched in the market until the real-time market observes undersupply conditions, which may clear these expensive bids and potentially trigger the penalty price for under-supply or congestion. During the analysis of the performance of FRP, the CAISO has identified that flexible ramp may typically be scheduled on resources with expensive energy bids simply because that type of capacity is not used for meeting energy needs. While resources with high energy bids may not be dispatched up for energy because the market clears on cheaper energy prices, their available capacity may be used for flexible ramp because such capacity has no trade off with energy and hence has no opportunity cost to procure flexible ramp. However, when uncertainty materializes in the market, such flexible ramp capacity will only be realized if the energy prices are now high enough to be in merit such that resource moves upward, thus deploying the flexibility.

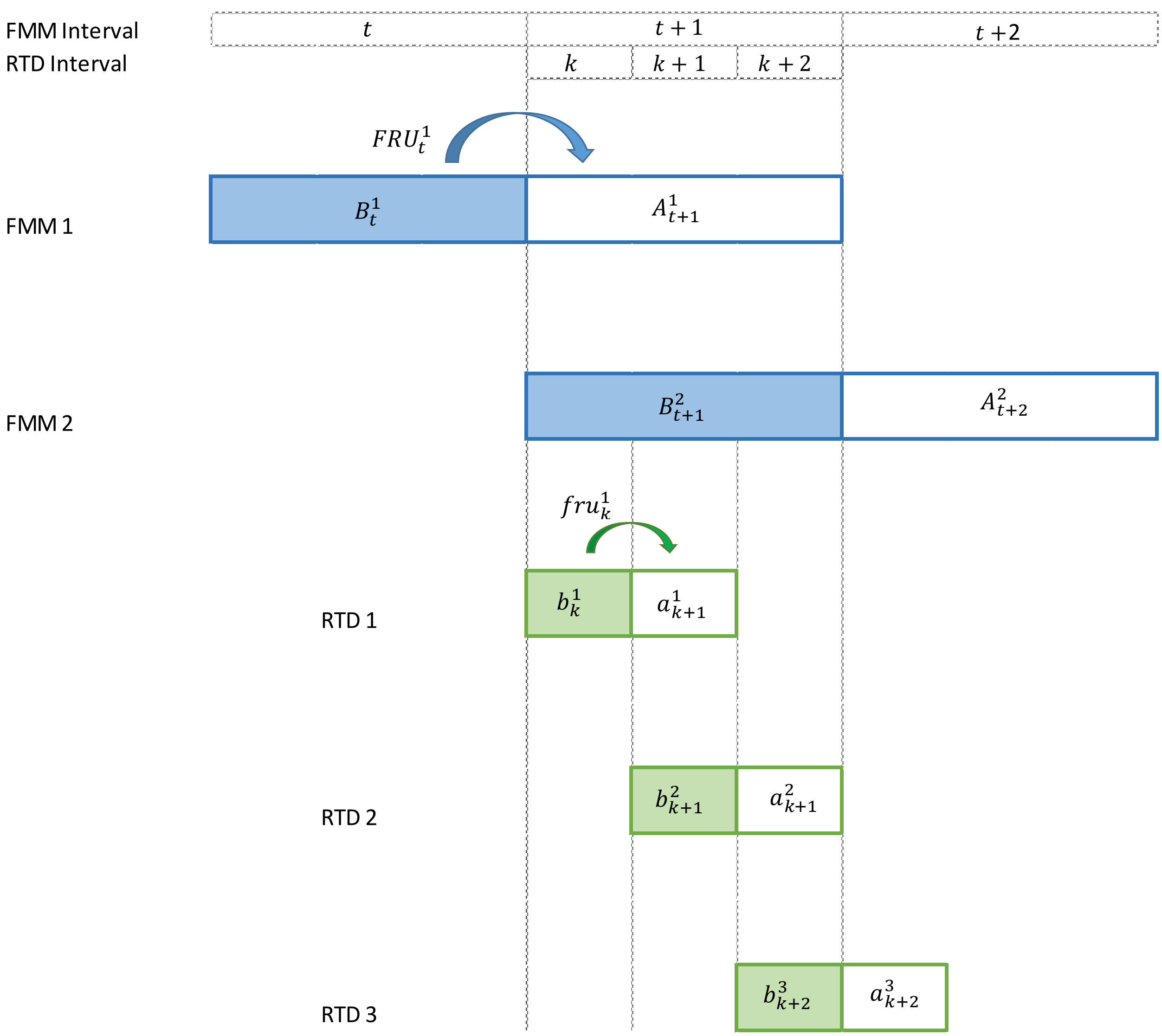
Take, for instance, the case of June 25, 2019 in hour-ending 19, during which flexible ramp capacity was scheduled on proxy demand resources that had bids at $999/MWh. The price for flexible ramp capacity was $0/MWh indicating there was plenty of flexible capacity in the system such that no resource had to be held back for energy to procure flexible ramp. Several proxy demand resources with energy bids at $999/MWh were awarded all of their capacity to flexible ramp, but, unless the real-time market clearing price for energy reach $999/MWh, that flexible ramp capacity will not be utilized even when uncertainty materializes. Another case is June 11, 2019 in hour-ending 17. Flexible ramp capacity was allocated to PDR resources but that capacity was not utilized because the bids on these resources were much more expensive than the real-time energy clearing prices that may be deployed only when the system runs infeasible. Furthermore, even when the market deploys such flexible ramp capacity, PDR are currently not able to follow intermittent five-minute dispatches.

A second scenario for flexible capacity stranded due to congestion is when resources are held back for congestion management of internal constraints within an EIM area. Congestion can be due to internal EIM-area constraint and not only due to EIM transfers limitations. However, certain resources may exacerbate congestion within an EIM area. For congestion management, these resources will be dispatched downward. This will make upward capacity available, which in turn the market can use for procuring flexible ramp capacity. If uncertainty materializes, then that flexible ramp capacity is stranded as its utilization would conflict with congestion management. Thus, the market may have allocated flexible capacity to resources that will not be able to deploy the flexible ramp. Consider the case of June 12, 2019 during peak hours. During FMM interval 3 of hour-ending 18, the system-wide area had a flexible ramp requirement of 1,357 MW, which the market economically procured only up to 1,025 MW at a price of $36.96/MW. Around this time, the real-time market was observing energy prices of up to $1,000/MWh. Approximately 736 MW were procured from CAISO area resources. Out of the 1,025 MW of economically procured capacity, 585 MW of flexible capacity was undeliverable with the majority of the undeliverable capacity (510 MW) due to the flexible capacity conflicting with congestion management. A significant portion of the undeliverable flexible capacity was due to a few resources held back to mitigate congestion on internal constraints – in some cases, that was achieved by having EDs on these resources. There was also flexible ramp which was not utilized in some of the Pacific Northwest EIM areas also due to congestion. In another interval of the same day and hour, the market procured 1,357 MW of flexible ramp capacity with 1,016 MW procured from CAISO area resources. Out of the total requirement, 660 MW were not utilized, with 200 MW lost due to the buffer interval not having a requirement enforced, 240 MW were behind congestion, and 75 MW were from PDR resources that had bids of $999/MWh. In a third interval of that same day and hour, 1,085 MW of FRP requirement were procured, with about 685 MW coming from CAISO area resources. Out of the procured capacity, about 885 MW was not utilized due to being stranded by congestion.

Flexible ramp utilization

The goal of having flexible ramp capacity is to ensure that such ramp-able capability is available for use when uncertainty materializes in the market. One way to measure how effective the product performs is by measuring how the flexible ramp is utilized. The FRP is required and procured in both FMM and RTD. As explained in this section above, the FMM FRP requirement is set based on the uncertainty estimated between the advisory FMM interval towards each of the RTD intervals, while the RTD requirement is estimated as the uncertainty between the advisory RTD interval and the binding interval of the next run. Consider the illustration in Figure 80 for allocating the advisory and binding intervals in a given time reference.

Figure 80: Timeframe for FRP construct in the real-time market



The blocks in blue illustrate the configuration for the FMM, while the blocks in green illustrate the configuration for the RTD market. Binding intervals are filled in blue or green, while advisory intervals have no fill. Each FMM and RTD run is enumerate, with FMM 2 being the market run after FMM 1. Upper case symbols are used for FMM intervals and lower case symbols are used for RTD intervals. For binding intervals, energy dispatches are identified with terms B_{t+1}^{2} and b_{k+1}^{2}. The subscripts stand for the time interval where interval t is used as starting point; the superscripts stand for the market run. Similarly, for advisory intervals, energy dispatches are represented by A_{t+1}^{2} and a_{k+}^{2}, and the flexible ramp awards are represented by FRU_{t+1}^{2} and fru_{k+1}^{2}.

To analyze utilization of the FRU procured in a binding interval t in FMM at the resource level, metric 1 below is used, as one of the metrics.

$$U_t^{FMM} = min\{ FRU_t^1, max(B_{t+1}^2 - A_{t+1}^1, 0)\} \qquad (1)$$

In particular, *ramp change* is defined as the difference between the energy awards of a binding and advisory intervals for the same time reference, $(b_{t+1}^{2} - a_{t+1}^{1})$. For the upward ramp, this change must be positive; this is enforced by the maximum operator in the formula. Any utilization then is bounded by the flexible ramp procured; this is enforced by the minimum operator in the formula.

To calculate FRU utilization in the RTD market, a similar calculation can be applied.

$$U_k^{RTD} = min\left\{ fru_k^1, max\left(b_{k+1}^2 - a_{k+1}^1, 0 \right)\right\} \qquad (2)$$

This calculation of the utilization of flexible ramp is simply based on the changes that happen between two adjacent FMM runs' or RTD runs' energy schedules. This construct is based on the concept that if uncertainty realizes between two market runs, then the flexible ramp capacity will be deployed. For resources that do not have any flexible ramp awards, the minimum operator in the formula will set the utilization to 0 MW since the purpose is to measure only the deployment of flexible ramp.

In addition to Metric 1, for the FRU procured in a binding interval t in FMM, two other metrics can be used to measure its utilization. Following closely the calculation of the FRP requirements, Metric 2 for FRP utilization in FMM can be derived as follows:

$$U_t^{FMM} = \min\left(FRU, max\left(b_k^1 - {A_{t+1}}^1,\ b_{k+1}^2 - {A_{t+1}}^1,\ b_{k+2}^3 - {A_{t+1}}^1, 0\right)\right) \qquad (3)$$

This metric measures the ramp change from the advisory FMM interval to each of the RTD intervals to find the maximum ramp, which then is bound by the flexible ramp award.

Alternatively, Metric 3 considers the cumulative deployment of flexible ramp. The realization of uncertainties of any specific interval can be calculated recursively as below,

$t+1$: $$U_0 = \max(B_{t+1}^2 - A_{t+1}^1, 0)$$

1st five-minute: $$U_1 = \max\left(b_k^1 - \max\begin{pmatrix} B_{t+1}^2 \\ A_{t+1}^1 \end{pmatrix}, 0\right)$$

2nd five-minute: $$U_2 = \max\left(b_{k+1}^2 - max\begin{pmatrix} B_{t+1}^2 \\ A_{t+1}^1 \\ b_k^1 \end{pmatrix}, 0\right)$$

3rd five-minute: $$U_3 = \max\left(b_{k+2}^3 - max\begin{pmatrix} B_{t+1}^2 \\ A_{t+1}^1 \\ b_k^1 \\ b_{k+1}^2 \end{pmatrix}, 0 \right)$$

Subsequently, using auxiliary variables F to define the utilization per interval, the FRU used *until* a specific interval can be calculated as

$t + 1$: $F_0 = U_0$

1st five-minute: $F_1 = \min(U_1 + U_0,\ FRU_t^1)$

2nd five-minute: $F_2 = \min(U_2 + U_1 + U_0,\ FRU_t^1)$

3rd five-minute: $F_3 = \min(U_3 + U_2 + U_1 + U_0,\ FRU_t^1)$

Therefore, for FRU_t^1, which is awarded in interval t, the total FRU utilized is the FRU utilized until the 3rd RTD interval, namely, $k + 2$. Following simple deduction in the Appendix B, this total FRU utilization is estimated as follows.

$$U_{t\to k}^{FMM} = min\left(FRU_t^1,\ max\begin{pmatrix} A_{t+1}^1 \\ B_{t+1}^2 \\ b_k^1 \\ b_{k+1}^2 \\ b_{k+2}^3 \end{pmatrix} - A_{t+1}^1 \right) \quad (4)$$

FRU in the RTD Market

The analysis regarding flexible ramp focuses on the upward capacity since it has been the main concern regarding price performance. To more closely examine the relationship between FRP's deployment and price performance, the data is first selected for RTD intervals when the System Energy Marginal Component (SMEC) is greater than $500/MW for the period of January 2017 through March 2019. Note that the first quarter of 2019 does not have any five-minute intervals of SMEC greater than $500/MW.

Figure 81 and Figure 82 show the frequency of an interval when SMEC is greater than $500/MW in RTD and the FRU procurement price of those intervals. The data is organized on a monthly and hourly basis. Three categories of FRU procurement status are observed: FRU not required (Not Required), FRU required with a FRP price equals to zero (= 0) and less than zero (<0).

It can be seen that there was no FRU requirement throughout the months of 2017. In addition, FRU had negative price in the summer (August, September and October) and during the peak hours, which indicates binding FRU constraints. In contrast, in 2018 FRU is required in almost every interval when SMEC price spiked. FRU requirement was zero in January and February, 2018 and during hours 7, 8, 16 and 17. It was greater than zero in the rest of the year with a $0/MW price.

Figure 81: Monthly frequency of FRU is required and has $0/MW price.

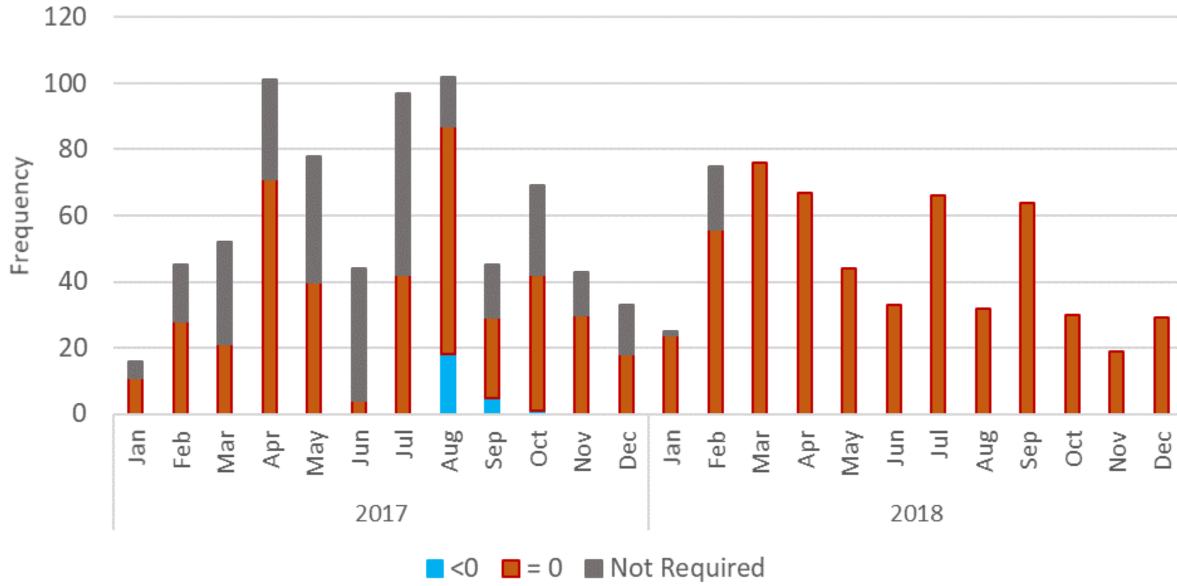
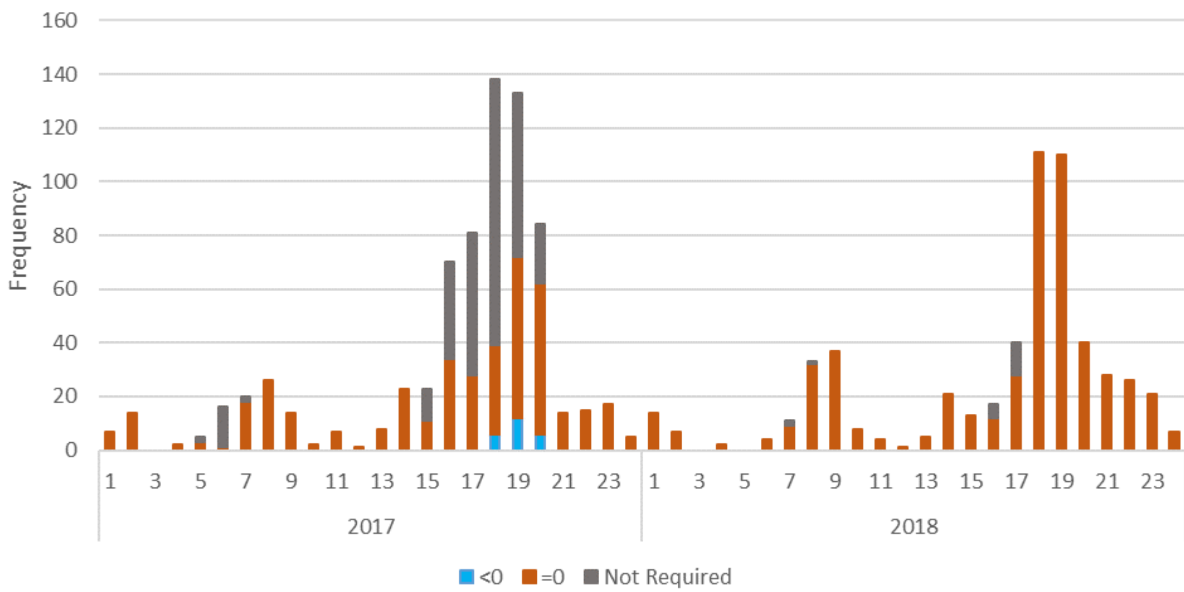


Figure 82: Hourly frequency of FRU is required and has $0/MW price



Knowing the price of FRU procurement, the amount of FRU procurement in MW is compared next. Figure 83 and Figure 84 show the actual procurement versus the requirement of FRU of the studied intervals, which SMEC is greater than $500/MW. The FRU requirement is the raw requirement for CAISO before subtracting NIC/NEC. The same data is stratified into months and hours. The FRU requirement has been increasing since July 2017, with the requirement almost doubled in 2018. In addition, the daily profile shows different patterns between the years.

Figure 83: Monthly FRU requirement and procurement

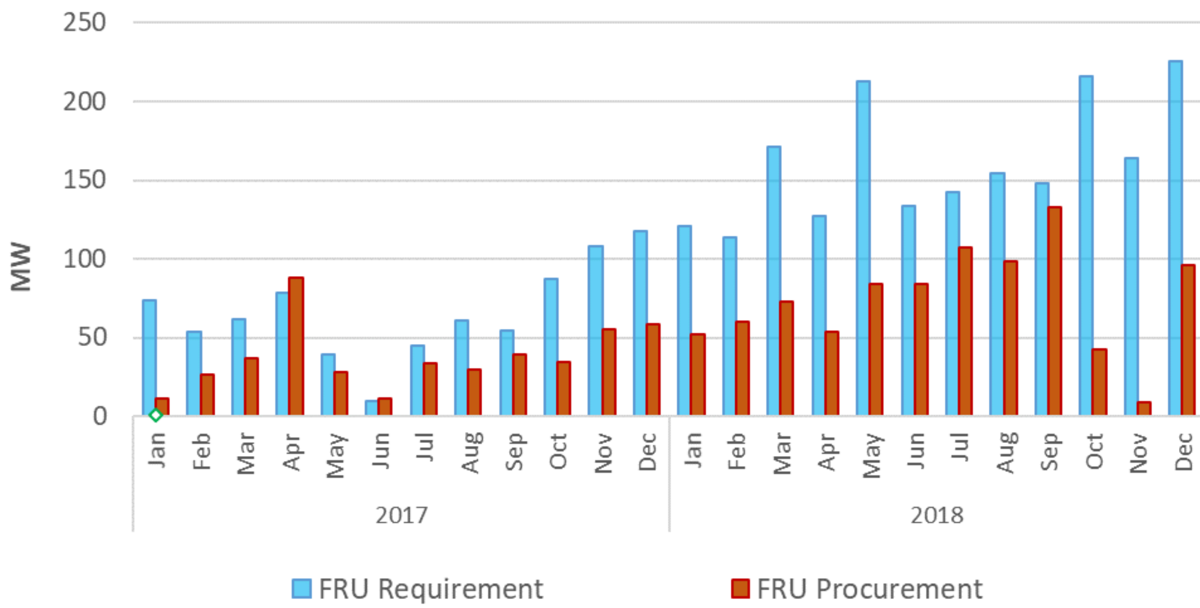
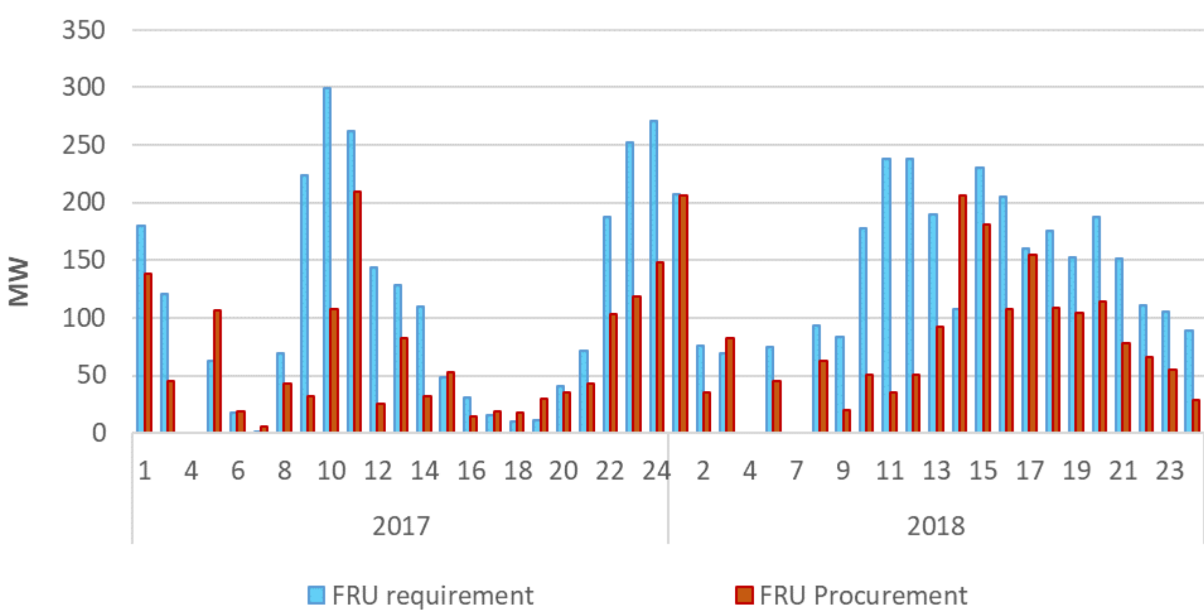


Figure 84: Hourly FRU requirement and procurement



In Figure 85 and

Figure 86, the FRU procurement is decomposed into fuel types and is shown on a monthly as well as an hourly basis. It can be seen that gas and water are dominant fuel types in 2017 and 2018, while resources of 'other' fuel types were awarded at a considerable amount in August and September of 2018. The 'other' fuel types is consist of primarily proxy demand response (PDR) and a small amount of combined cycle (CC) units.

Figure 85: FRU procurement organized by fuel types on monthly basis

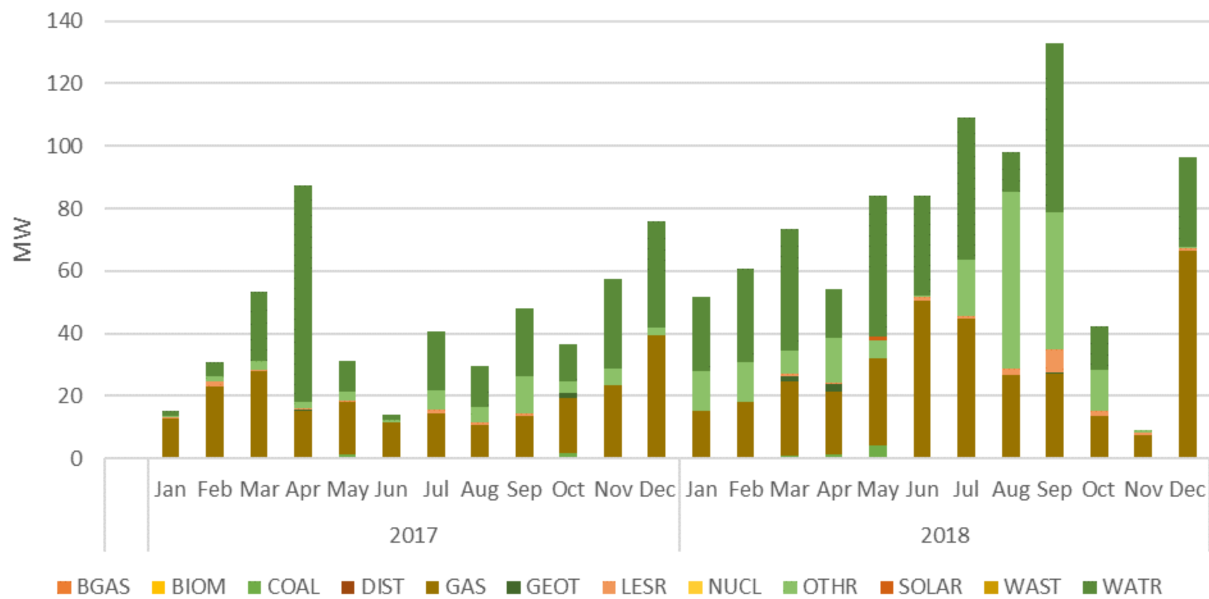


Figure 86: FRU procurement organized by fuel types on hourly basis

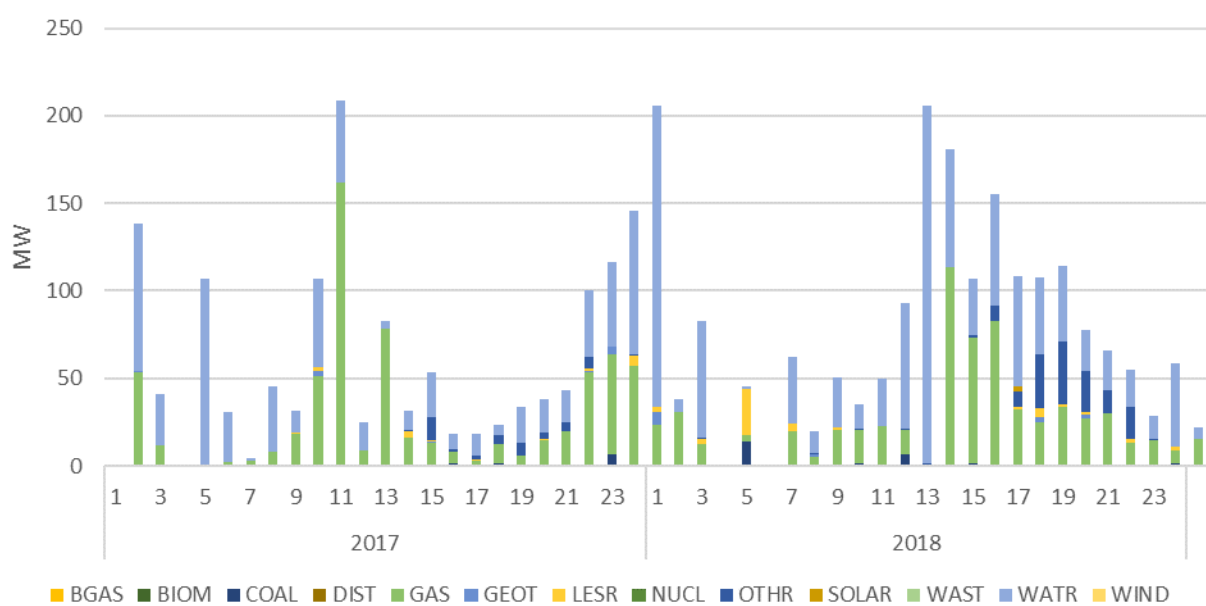


Figure 87 and Figure 88 show the RTD FRU utilization with the metrics described in the beginning of this subsection. The same data is stratified into months and hours. Over time, the amount of FRU not utilized in the RTD market has grown significantly. In early 2017, utilization of FRU was about 86.1%, while in the last months of 2018, utilization has declined to about 22%.

Figure 87: Monthly utilization of FRU in RTD

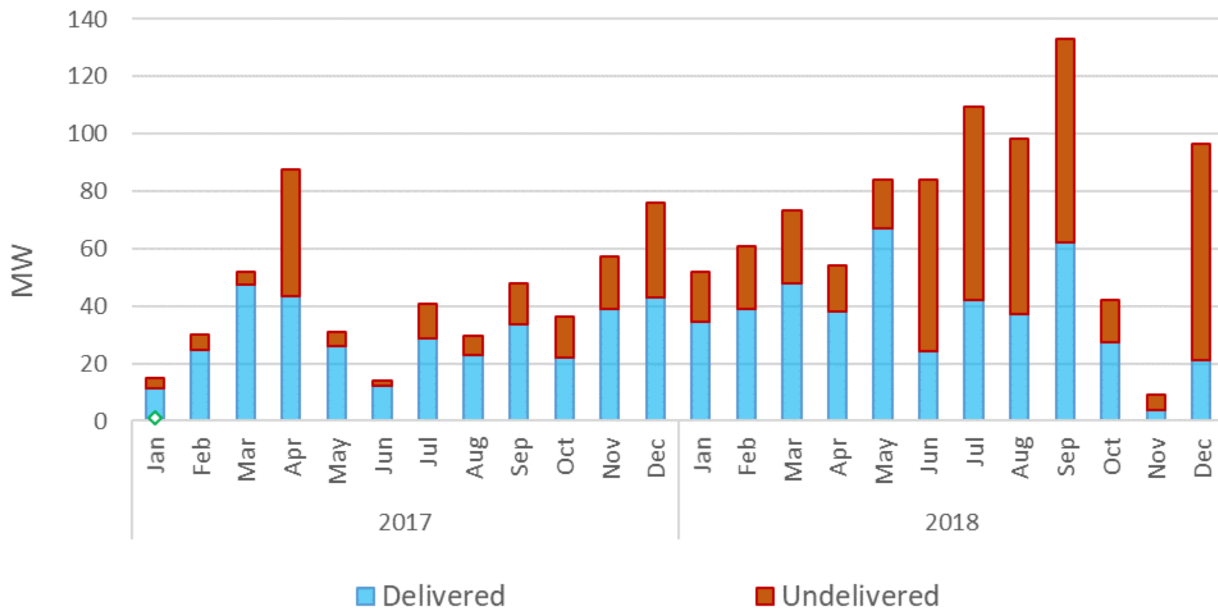
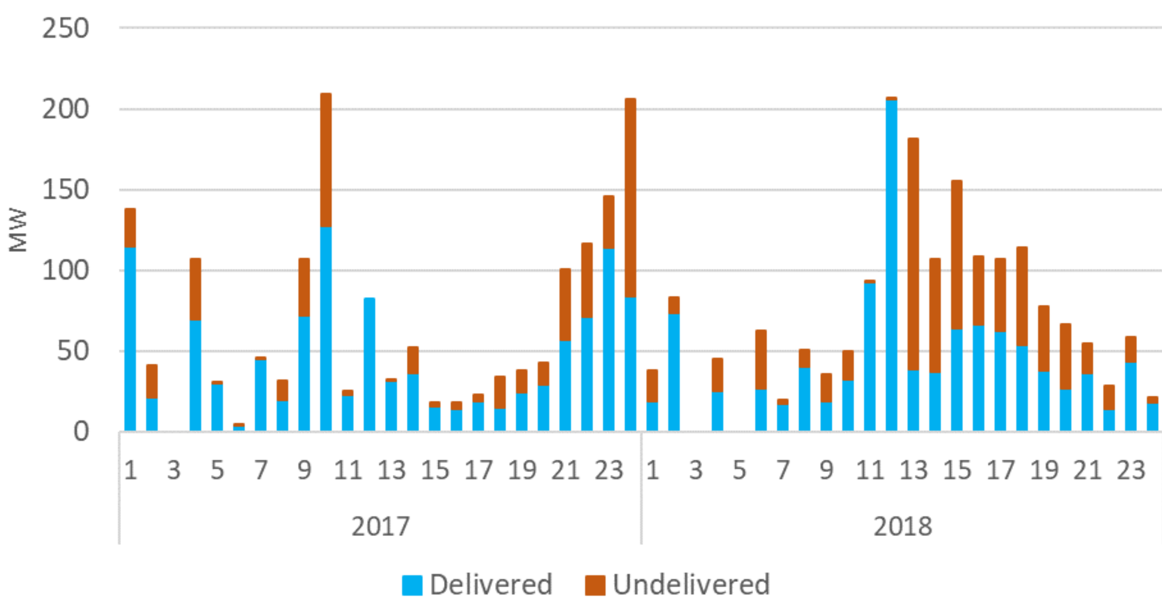


Figure 88: Hourly utilization of FRU in RTD



Furthermore, Figure 89 shows, at the CAISO level, the distribution of the FRU procurement and requirement of all the selected time intervals in which SMEC is greater than $500/MW, and their corresponding ramp change. A black dot represents the total ramp change versus the total FRU procurement of a given time interval in the RTD market. Similarly, a blue dot represents the total ramp change versus total FRU requirement of an RTD interval. Ideally, the FRU requirement should be the same as the award, as well as the ramp change of an RTD interval, meaning that FRU can be fully procured according to the requirement and 100% dispatched in RTD. This ideal case is plotted as a diagonal red line in the figure. Therefore, the closer the dots are clustered to the red line, the higher FRU utilization the time interval has. The region below the red line indicates the 'conservative procurement/requirement,' where the market procured more FRU than the actual ramp change of that market interval. The further away a dot from the red line in this region the lower FRU utilization is for the RTD interval. The region above the red line contains the time intervals when ramp change was greater than the FRU requirement/procurement. It should be noticed that ramp change consists of two parts: naturally realized uncertainties, such as renewable energy output change, and other uncertainties, such as load bias and generation movement. As the current FRU requirement only aims to capture the former, the dots above the red line could be attributed to the latter's occurrence.

Figure 89: FRU utilization at the system level

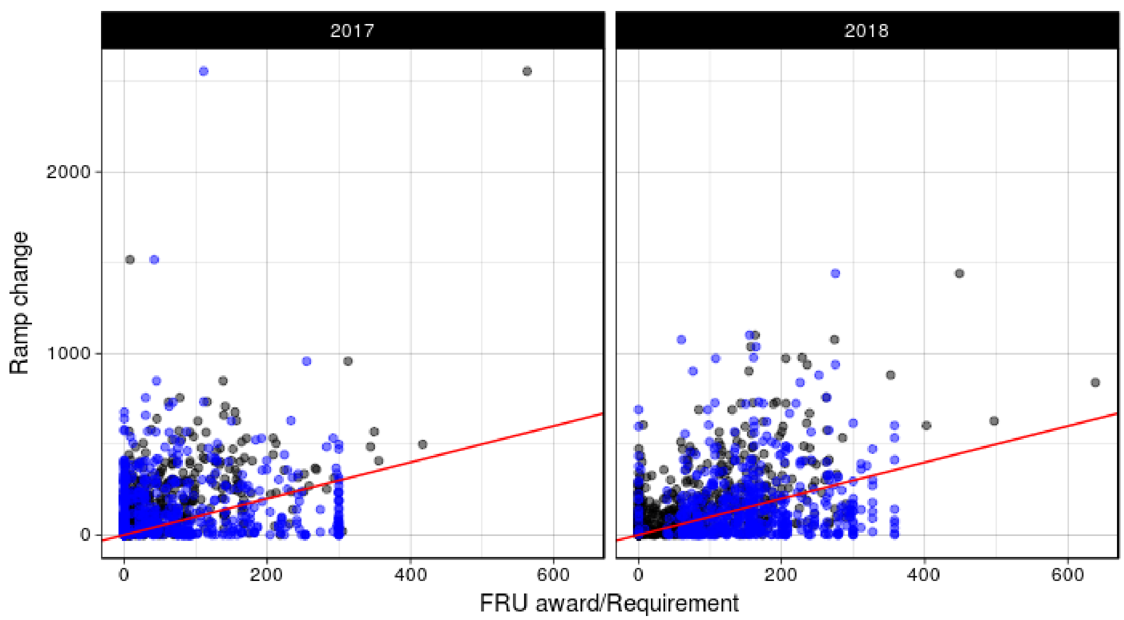
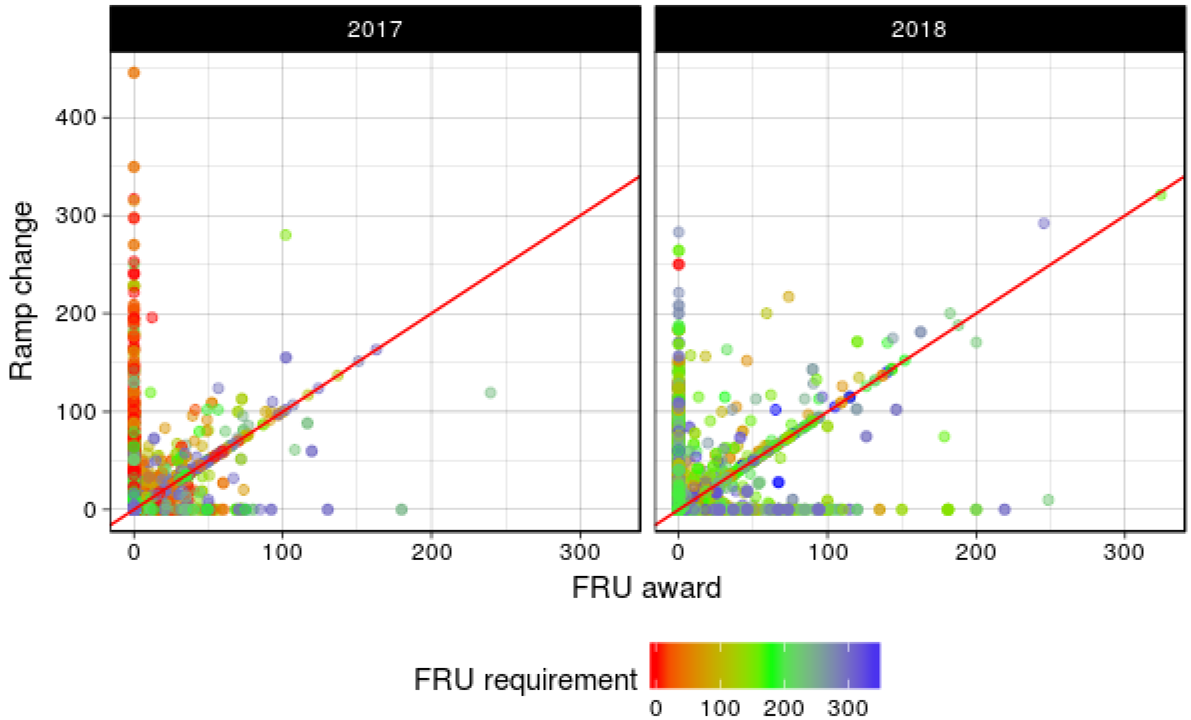


Figure 90 below shows, for each resource, the distribution of the FRU procurement and their corresponding ramp change of an RTD interval. The red line indicate the ideal case when the ramp change equals the FRU awarded to that resource. In addition, the color indicates the magnitude of FRU requirements for a given market interval. In 2017, most of the dots along the vertical axis present warmer colors (trending towards red) in the subfigure on the left, meaning that the resources' low FRU award was correlated to underestimated FRU requirements for those market intervals. In the beginning of 2018, the estimation method for FRU requirement was improved by CAISO. As a result, in 2018, the subfigure on the right shows that the FRU requirement has increased for RTD intervals containing resources of higher ramp changes. Consequently, more FRU was procured under the increased requirements to support the ramp changes. However, there are still dots along the vertical axis of with cooler colors (trending towards blue), representing the resources which uncertainties that were successfully identified by the FRU requirement but were not awarded FRU in the market process.

Figure 90: FRU utilization at the resource level



Data in Figure 90 attempts to identify the cause of insufficient FRU procurement and is further stratified by unit and fuel types. It can be seen that the dots on the vertical axis in Figure 90 are attributed mainly to resources powered by water and gas as well as pump storage or multi-stage generators. Furthermore, Figure 96 and Figure 97 display the actual ramp changes of the resources by fuel types on a monthly and an hourly basis. Similar to the FRU awards, water and gas resources have the greatest ramp change, followed by Limited Energy Storage Resources (LESR) and 'other' fuel types. In particular, water resources experience a significant ramp change at noon (hour 12) in 2018. The 'other' fuel types is consist of primarily proxy demand response (PDR) and a small amount of combined cycle (CC) units.

Figure 91: Flexible ramp utilization organized by resource and fuel type

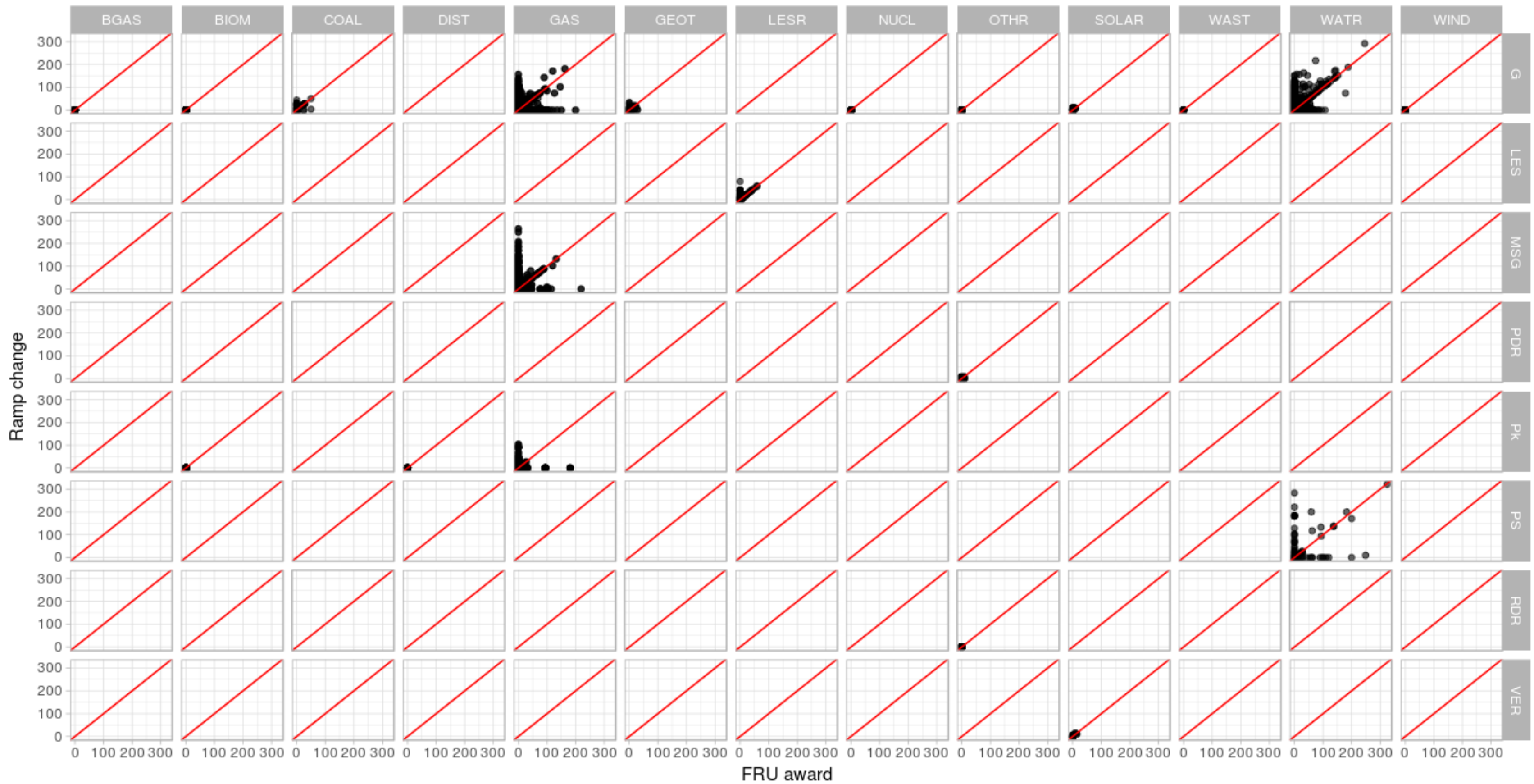


Figure 92: Resources' ramp change organized by fuel types on monthly basis

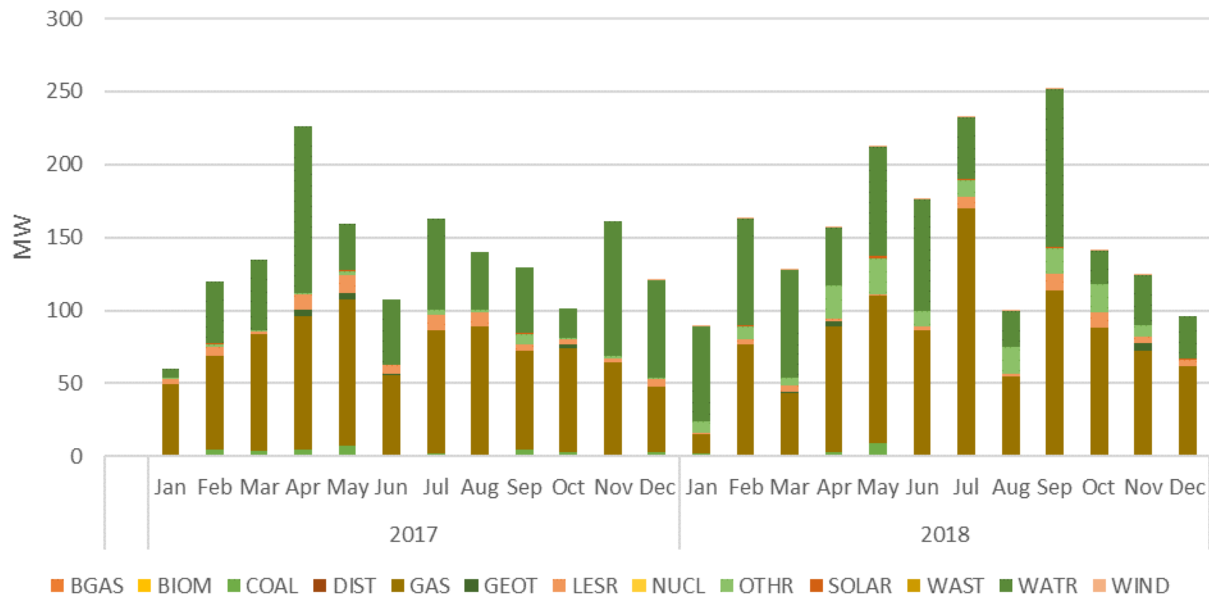


Figure 93: Resources' ramp change organized by fuel types on hourly basis

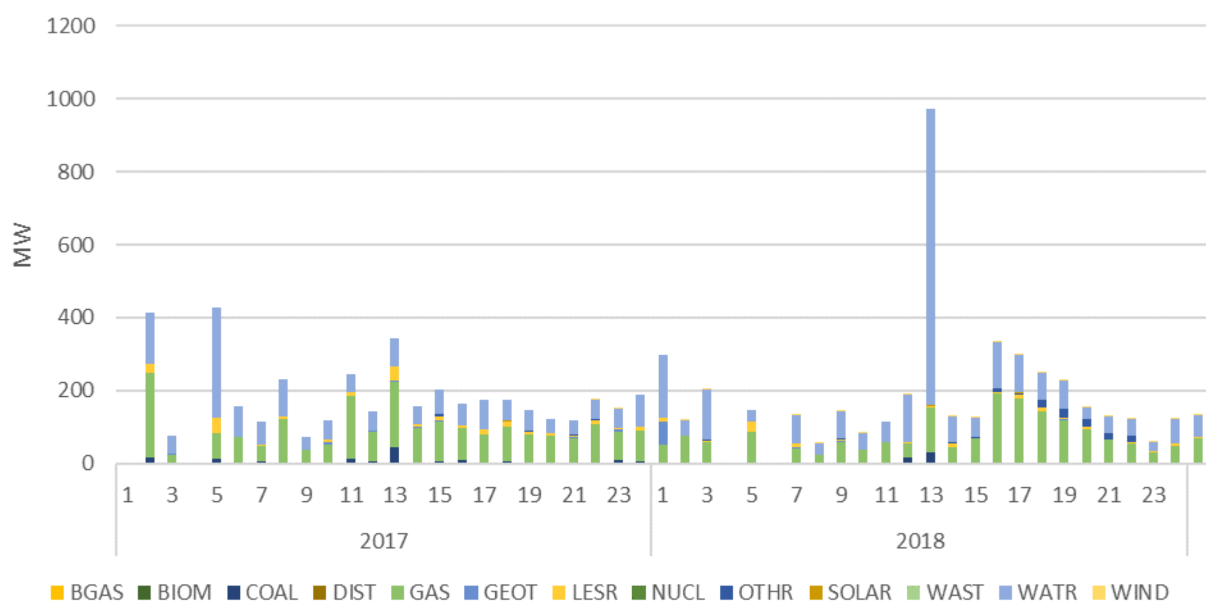
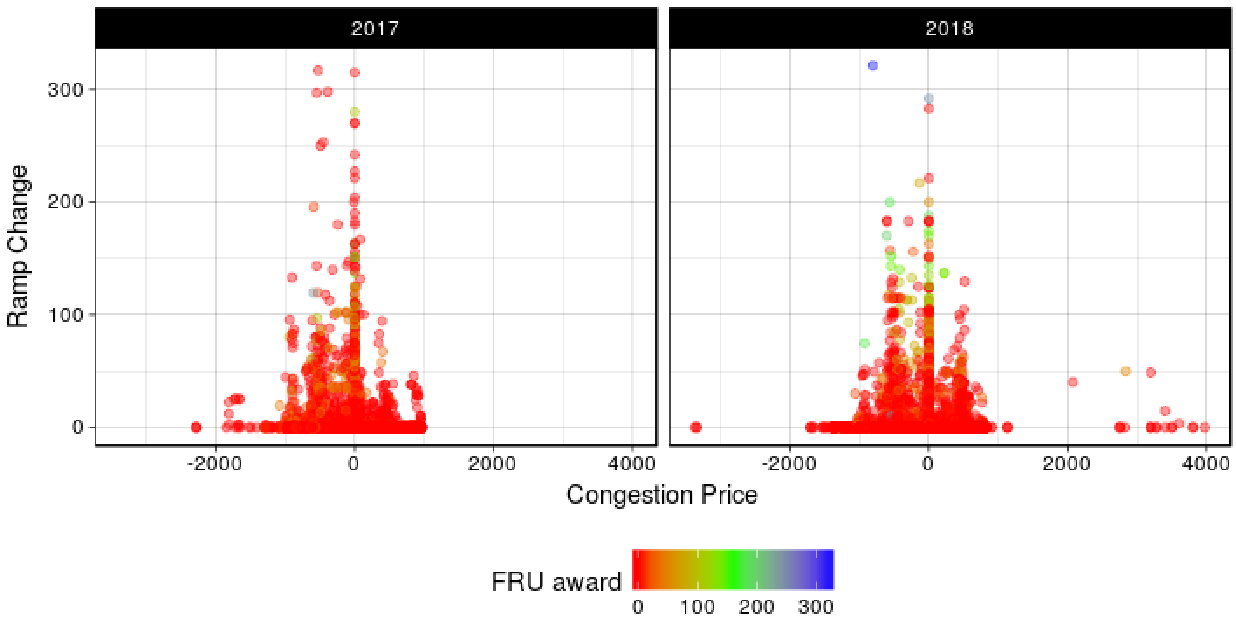


Figure 94 represents the ramp change, while the horizontal axis represents the marginal congestion component of the resources. The color of the dot and the color of a dot represents its FRU award. Ideally, dots should have cooler colors at the upper range of the vertical (ramp change) axis, meaning that a resource with higher FRU award has a larger ramp change; in this case, FRU is well utilized for the resource during the RTD interval. It is observed that the FRU awards are more aligned with the ramp change of resources in 2018 than in 2017. Furthermore, if a dot is found along the negative portion of the horizontal axis, which reflects negative congestion price, the ramp change of the resource may be limited due to congestion. The figure shows that most of the dots that have a higher ramp change also have negative congestion prices. On the contrary, the resources that have a positive congestion price have much less ramp change. This dot distribution indicates that resources that realize the most uncertainties are contained in congested areas. Those resources were awarded much less FRU in 2017 than in 2018, as implied by the dot colors.

Figure 94: Resource's ramp change and congestion price in RTD



FRU in FMM

Similar to the RTD market, the FMM instances with system marginal prices above $500/MWh are analyzed from January 2017 to March 2019. Note that the first quarter of 2019 does not have any fifteen-minute intervals of SMEC greater than $500/MW.

Figure 95 and Figure 96 show FMM intervals when SMEC is greater than $500/MW and the FRU procurement status of those intervals. Four categories are observed of FRU procurement status: no FRU requirement (Not Required), FRU requirement greater than zero and with a price equals to zero (= 0), less than zero (<0), and greater than zero (>0). The same data is stratified into month and hours in the figures.

It can be seen that FRU was not required in December, 2017, despite of the FMM price spike. In 2017, FRU had non-zero prices, positive in March and negative during the peak hours in August, September, October, and November. These non-zero prices are resulted from bounded FRU constraints in the market process and indicate a scarce supply of FRU. In 2018, the FRU was required as regular as FMM hit $500/MW. However, it presented negative price during some time in February, 2018 and during hour ending 20. It was required in the rest of the year with a $0/MW price.

Figure 95: Monthly frequency of FRU required and corresponding price

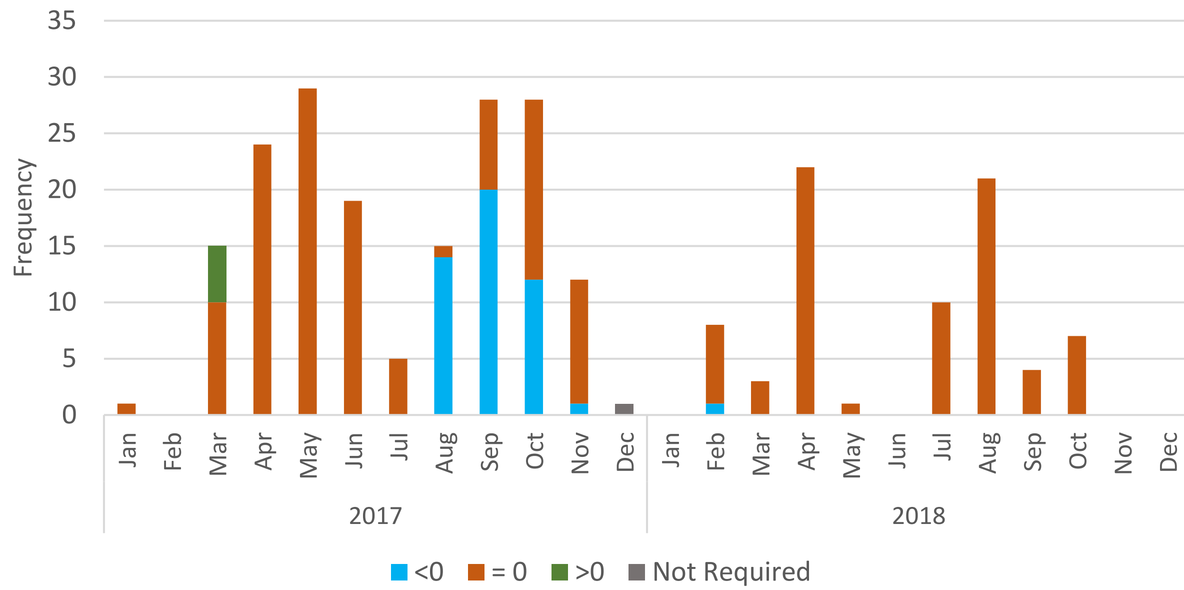


Figure 96: Hourly frequency of FRU required and corresponding price

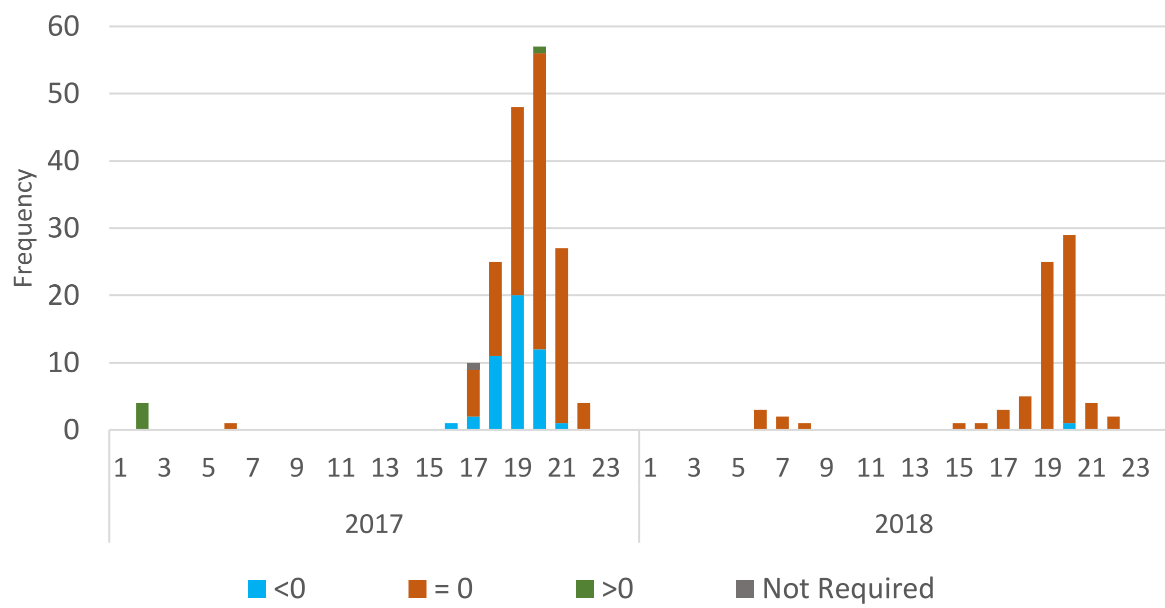


Figure 97 and Figure 98 show the actual procurement versus the requirement of FRU of the studied intervals. The FRU requirement is the raw requirement for CAISO without subtracting Net Import Capacity (NIC) or Net Export Capacity (NEC). The same data is stratified into months and hours. It can been seen that the FRU procured is much less than the requirement in both years, except for during the spring season. Across the duration of a day, the difference between the FRU requirement and procurement is greater during the peak hours.

Figure 97: FRU requirement and procurement

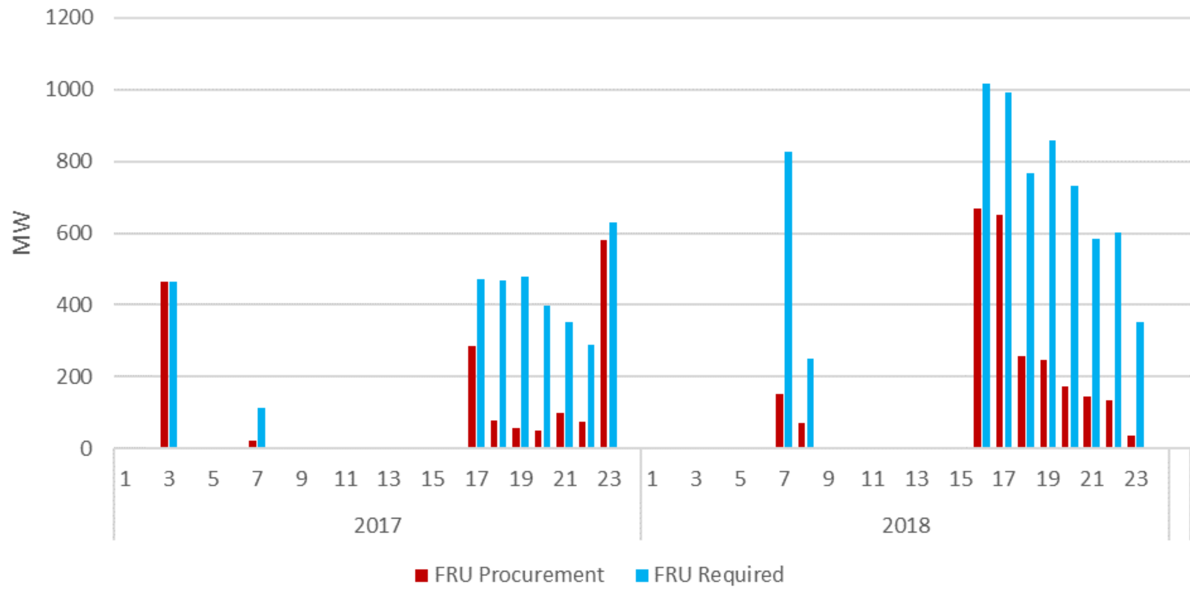
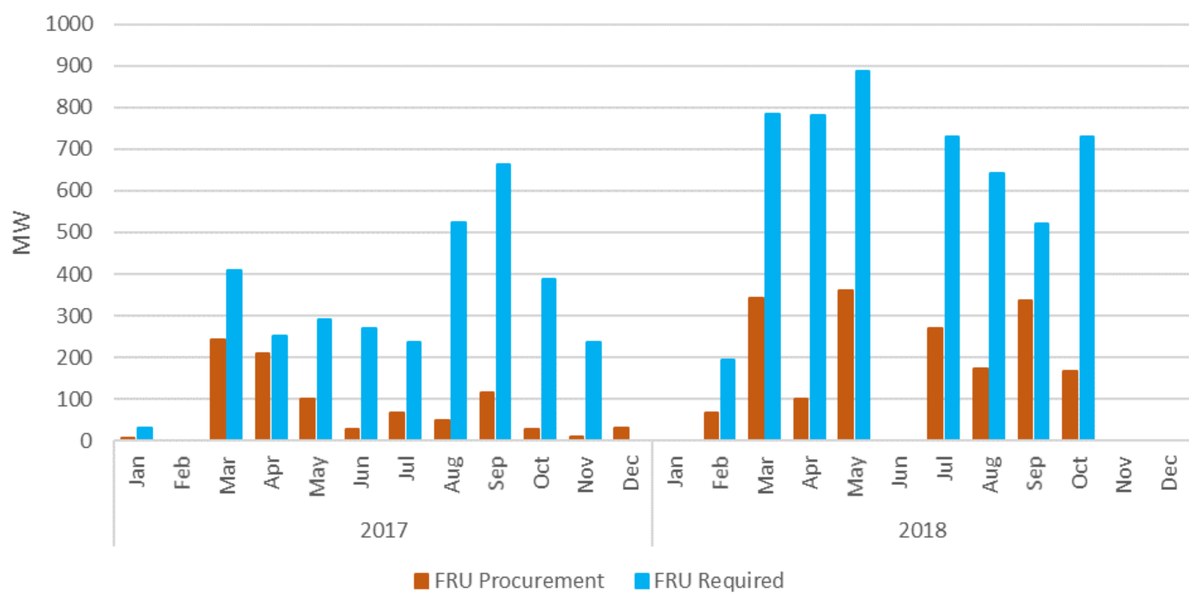


Figure 98: Procured and awarded FRU



In Figure 99 and Figure 100, the FRU procurement is decomposed and shown into fuel types. The figures show that gas and water are the dominant fuel types in 2017 and 2018, while resources of 'other' fuel types were awarded at a considerable amount in 2018. The 'other' fuel type consists primarily of proxy demand response (PDR) and a small amount of combined cycle (CC) units.

Figure 99: FRU Procurement organized by fuel types on monthly basis

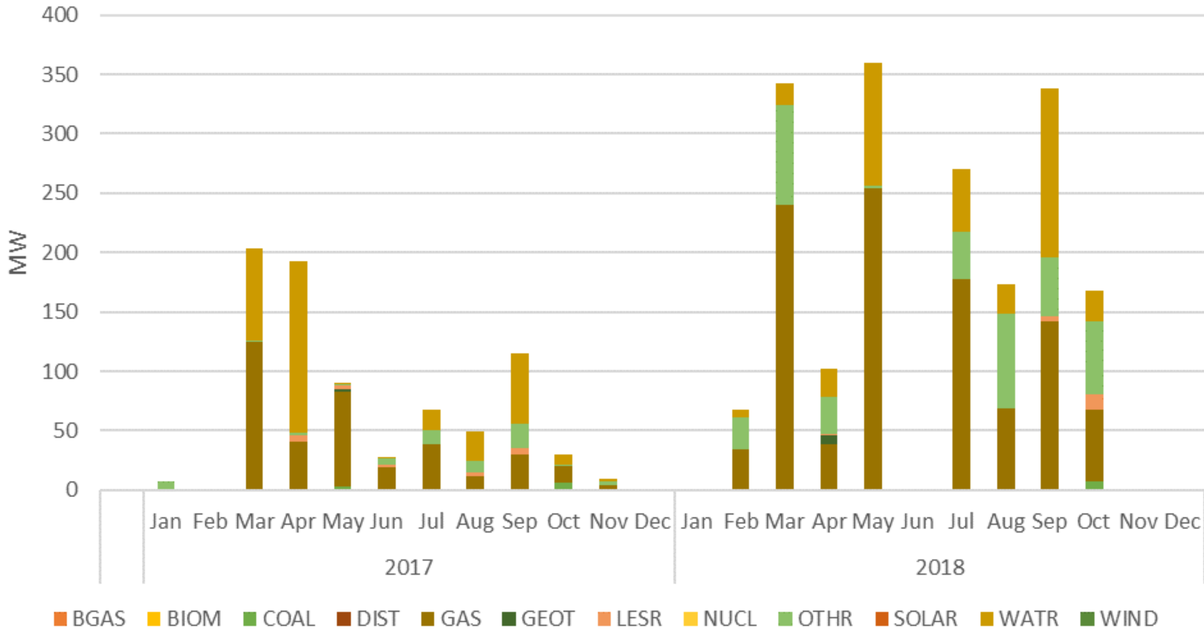


Figure 100: FRU Procurement organized by fuel types on hourly basis

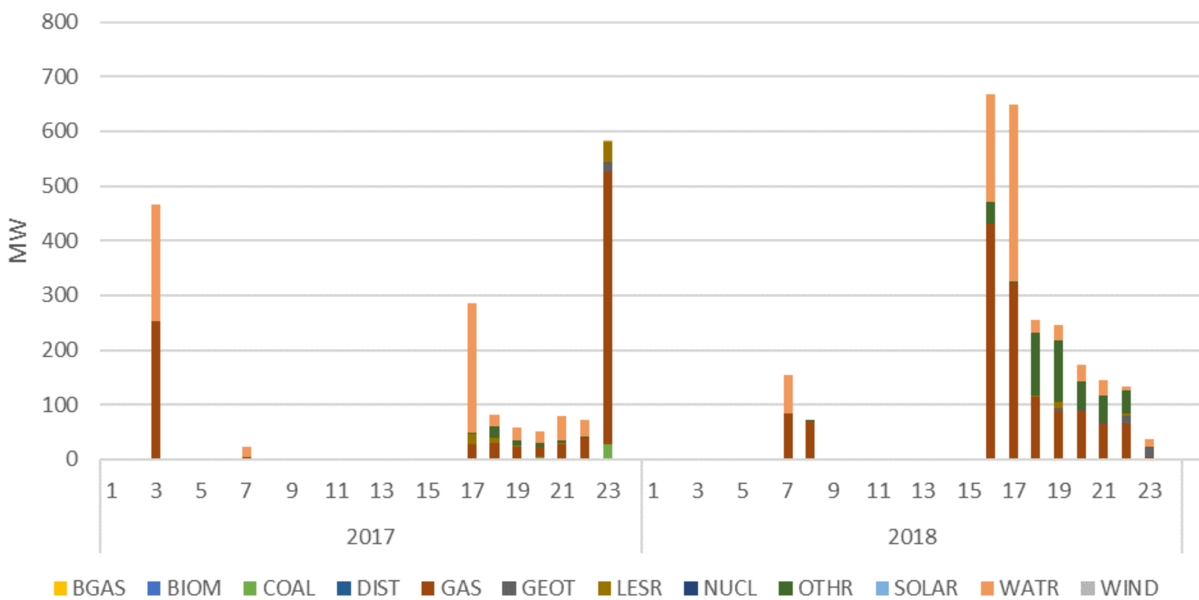


Figure 101 and Figure 102 show the FMM FRU utilization based on formulas (1), (3) and (4) defined above and labeled as *Metric1, Metric2* and *Metric3*, respectively. The same data is stratified into months and hours. When FRU utilization calculated by Metric 1 is greater than by Metric 2, the ramp uncertainties realized in FMM's binding interval is greater than the total ramp uncertainties realized in the three RTD intervals. FRU procurement during those market intervals would be insufficient, since the current FRU requirement is calculated only reflecting Metric 2.

Figure 101: Monthly utilization of FRU in FMM

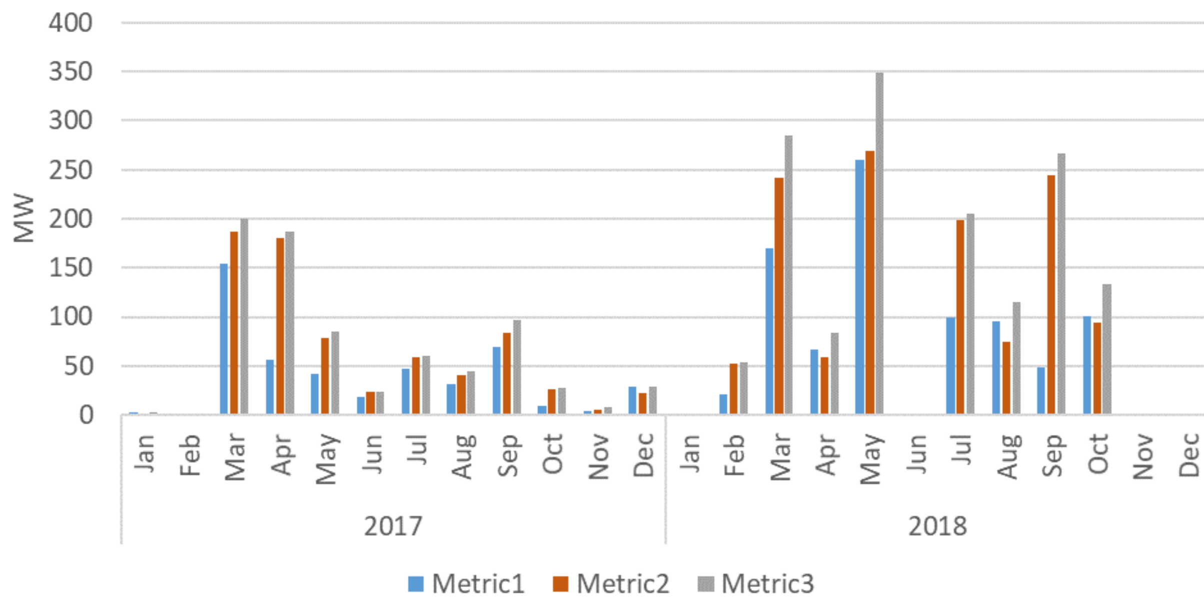
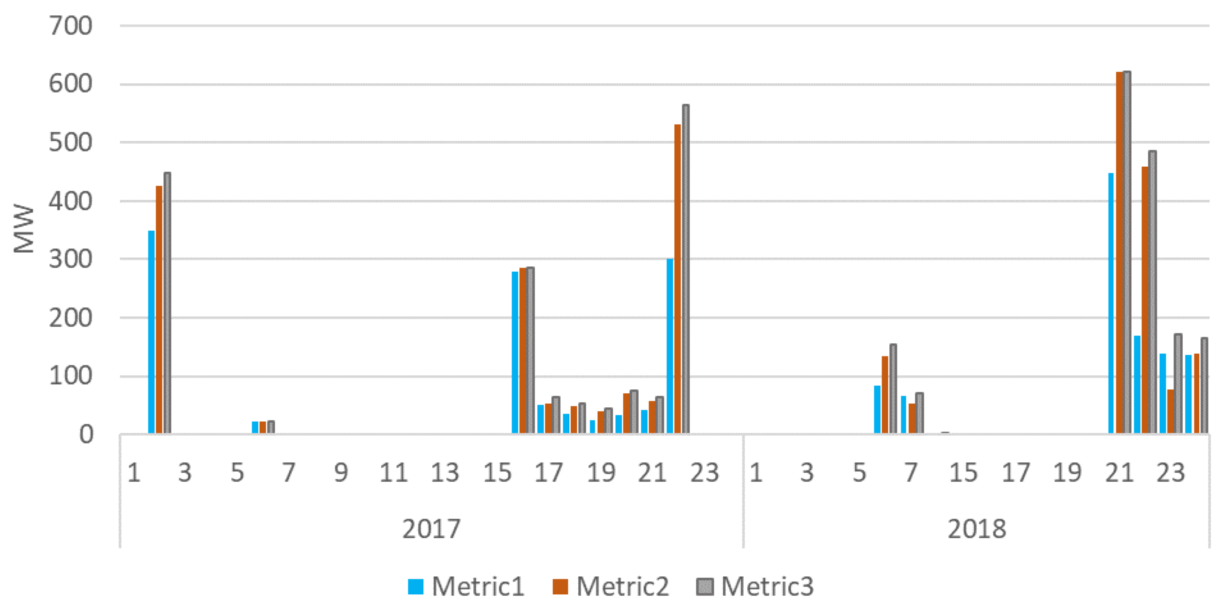


Figure 102: Hourly utilization of FRU in FMM



To identify the market intervals and resources associated with lower FRU utilization, *ramp change* stands for the upward uncertainty realized. For example, in Figure 80, for FMM2, interval $t+1$, the ramp change of FMM is the difference between the energy awards of a binding and advisory FMM intervals, $max(B_{t+1}^2 - A_{t+1}^1, 0)$. Similarly, the ramp change for the *i-th* RTD interval is the difference between the energy awards of that RTD binding interval and the FMM advisory interval, $max(b_i - A_{t+1}^1, 0)$.

Figure 103 through Figure 105 illustrate the relationships of ramp changes and FRU's award and procurement. In those figures, c15 represents the ramp change of the FMM interval, c1, c2, and c3 are the ramp change of the first, second, and third RTD interval.

Figure 103 shows, at the CAISO level, the distribution of the FRU procurement and requirement of all the time intervals under study and their corresponding ramp change. In particular, a black dot represents the total ramp change and the total FRU procurement of a given time interval in FMM. Similarly, a blue dot represents the total ramp change and total FRU requirement within the market time interval. Ideally, the FRU requirement is the same as the award as well as the ramp change, meaning that FRU can be fully procured according to the requirement and 100% dispatched in FMM. This ideal case is plotted as a diagonal red line in the figure. Therefore, the closer the dots are to the red line, the higher FRU utilization the time interval has. The region below the red line indicates the 'conservative procurement/ requirement,' where the market procured more FRU than the actual ramp change of that market interval. The further a dot is away from the red line, the lower FRU utilization of that FMM interval. The dots above the red line are the time intervals when FRU required/procured is less than the actual ramp change. It can be seen that the FRU award is much less than the requirement in both 2017 and 2018.

Figure 104 shows the distribution of the FRU procurement and the corresponding ramp change for each resource in a five-minute interval. The red line indicate the ideal case when the ramp change equals to the FRU awarded to that resource. In addition, the color indicates the FRU requirement for a specific market interval. It can be seen that in 2017, most of the dots near the vertical axis present warmer color, meaning that the low FRU award was correlated to underestimated FRU requirements for those market intervals. In the beginning of 2018, the estimation method for FRU requirement was improved by CAISO. As a result, the right subfigures for 2018 show the FRU requirement for RTD intervals containing resource of higher ramp changes have increased.

Figure 103: FRU utilization at the system level

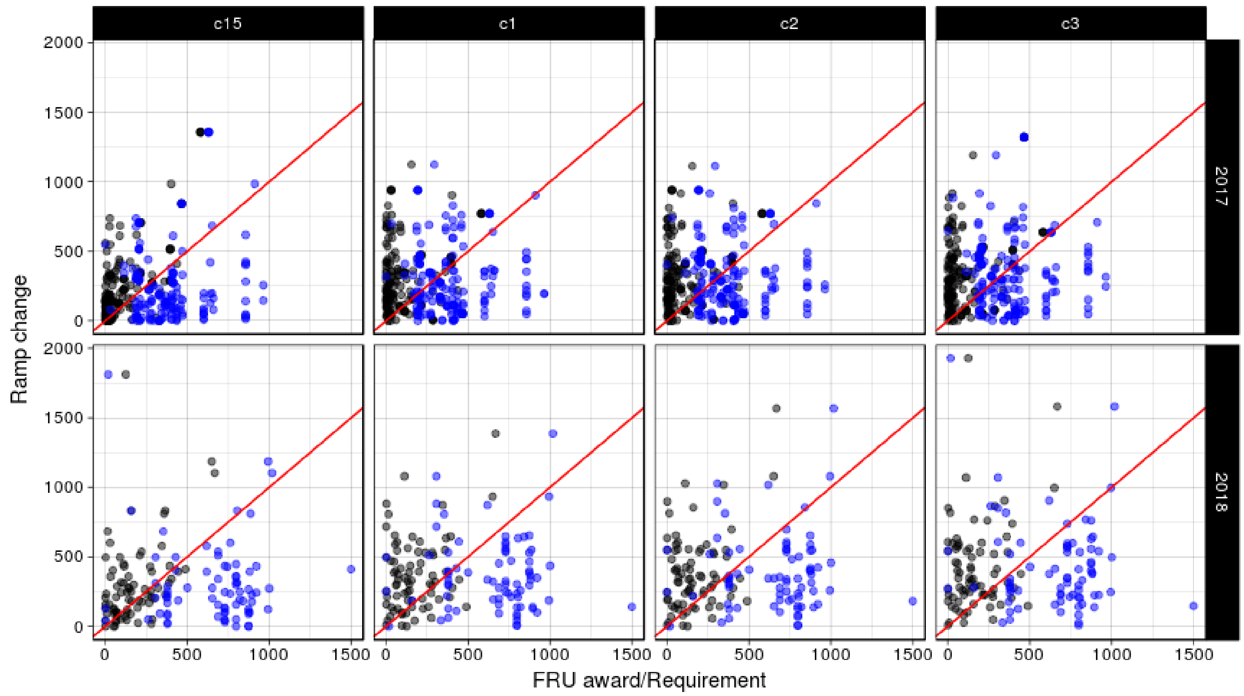


Figure 106 shows resources' ramp change and FRU award by their fuel types. Due to the multiple time intervals involved in FRU deployment in FMM, color coding is used to represent the resources' fuel types instead of matrix in Figure 91 for the RTD market. It can be seen that water and gas were dispatched the most in both 2017 and 2018, and resources that have high ramp change but were awarded little FRU are mostly gas types.

The same data is organized by fuel types and displayed on a monthly and hourly basis in Figure 106 through Figure 109. In particular, Figure 106 and Figure 107 show the actual ramp change of resources in FMM, $\max(B_{t+1} - A_{t+1}, 0)$, and Figure 108 and Figure 109 show ramp change in the RTD market deviating from the FMM advisory interval, $max\big(\, b_k^1 - {A_{t+1}}^1,\, b_{k+1}^2 - {A_{t+1}}^1,\, b_{k+2}^3 - {A_{t+1}}^1, 0\big)$. The gas and water resources made the most ramp changes in both the FMM and RTD markets, while geothermal and other resources had noticeable ramp changes in the RTD market during hour 3 in March of 2017. In addition, some months (May of 2018 in FMM, and January of 2017 and February of 2018 in RTD) and hours (hour 3, 23, 2017 and hour 16 and 17, 2018 in both FMM and RTD) have more significant ramp change as compared to other times.

Figure 110 shows how congestion impacts the resource's ramp change. The vertical axis represents the ramp change, while the horizontal axis represents the marginal congestion component of the resources. The color of the dot represents its FRU award. Ideally, dots should have cooler colors at the upper part of the figures, meaning that a resource of a higher ramp change is awarded more megawatts of FRU. Furthermore, if a dot is associated with a negative congestion price, it means the resource is impacted by congested.

Figure 104: FRU utilization at the resource level

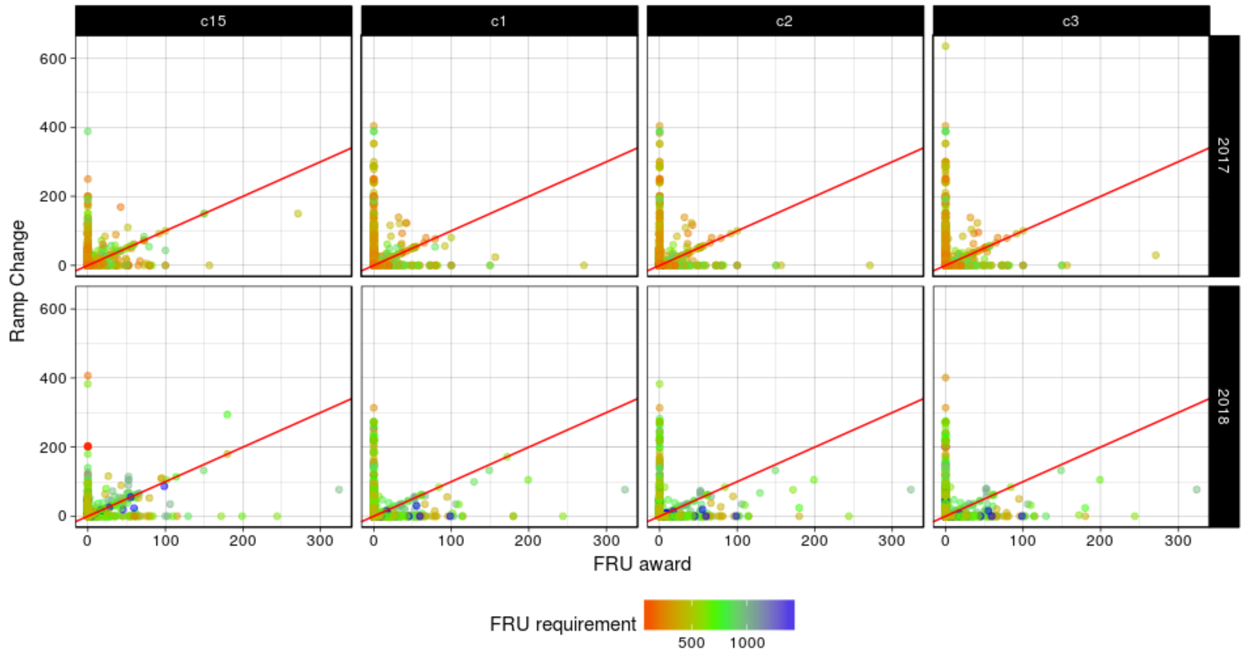


Figure 105: FRU utilization at the resource level by types

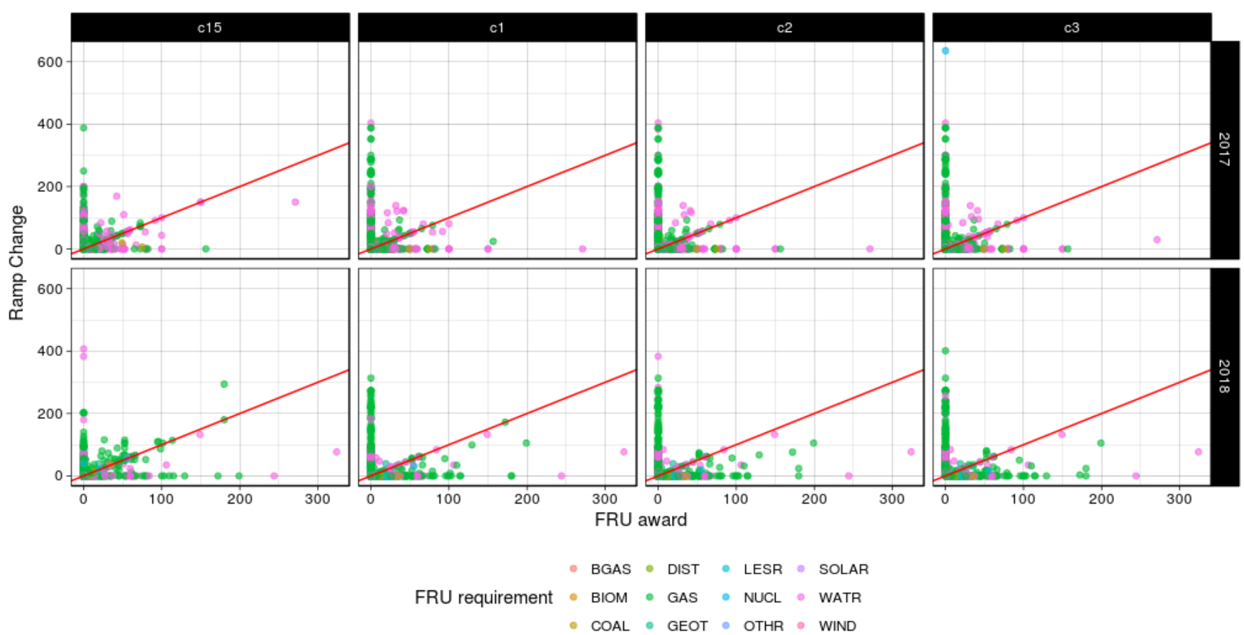


Figure 106: Resources' ramp change in FMM organized by fuel types on monthly basis

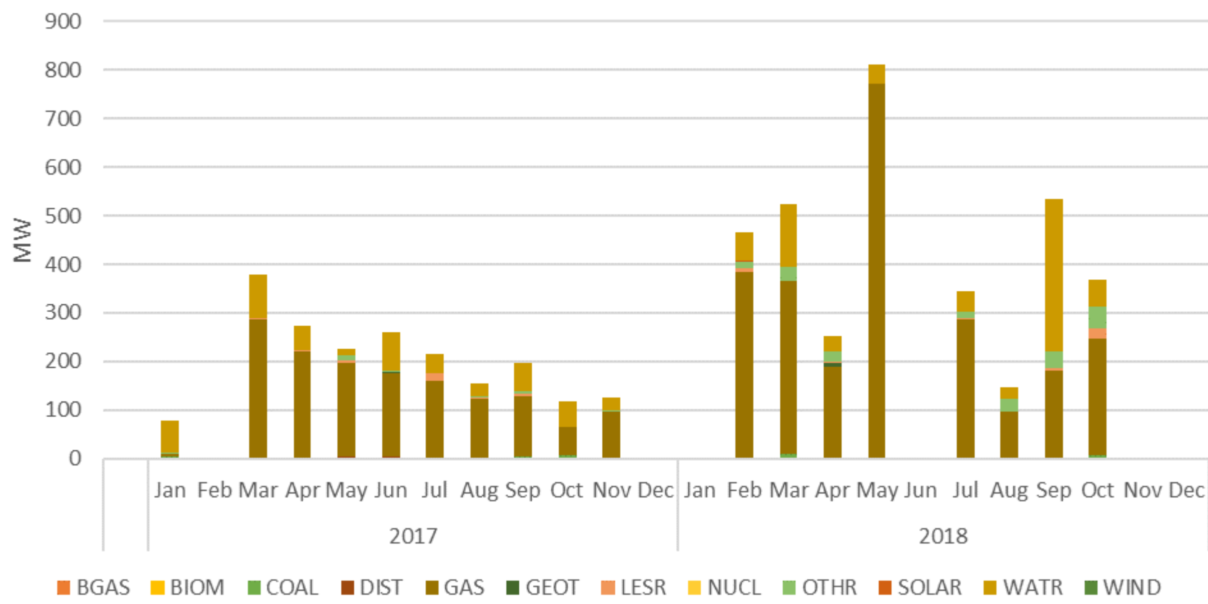


Figure 107: Resources' ramp change in FMM organized by fuel types on hourly basis

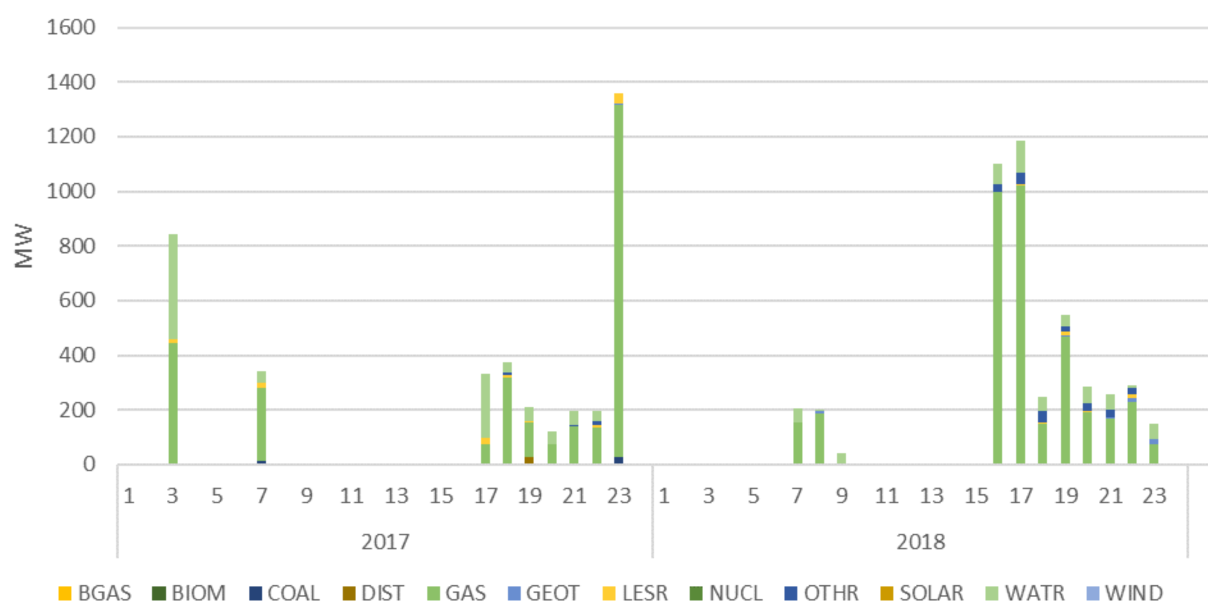


Figure 108: Resources' ramp change in RTD market organized by fuel types on monthly basis

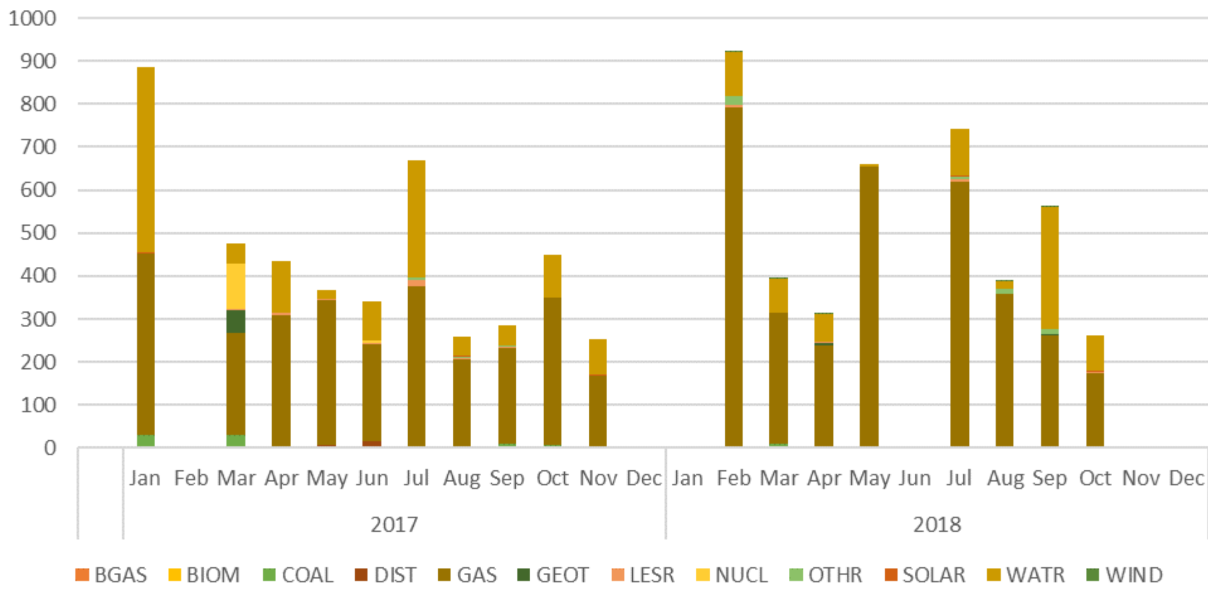


Figure 109: Resources' ramp change in RTD market organized by fuel types on hourly basis

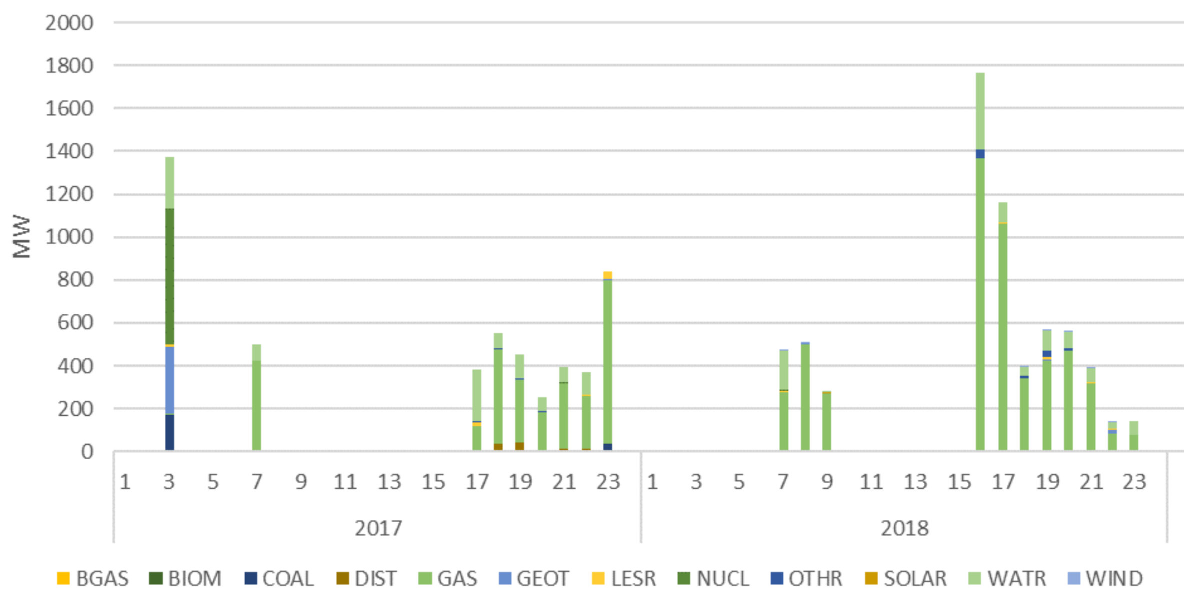
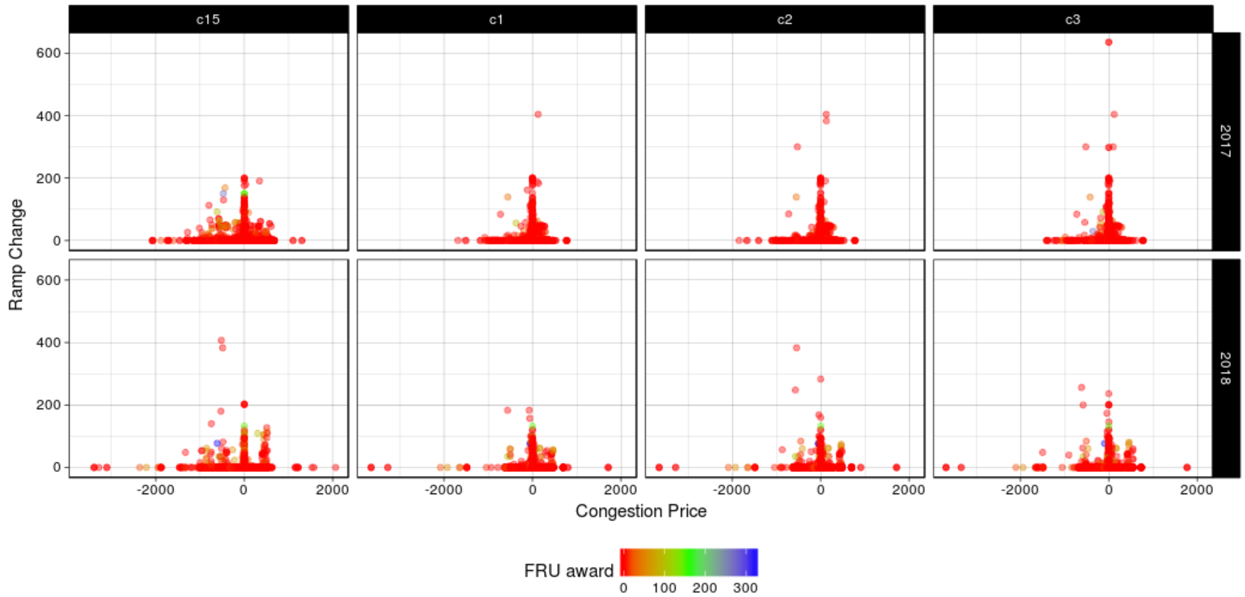


Figure 110: FRU utilization and system congestion at the resource level



In this section, analysis is performed on FRU requirement, procurement and utlization based on RTD and FMM data from 2017 to the first quarter of 2019. For market intervals in which SMEC is greater than \$500/MW, the FRU requirement almost doubled in 2018 as compared to 2017. This change could be attributed to an enhancement made in early 2018 to FRU requirement estimation. However, the procurement of FRU abruptly decreased in late 2018. FRU utilization has presented a decreasing trend. In the RTD market from the first quarter of 2017 to the last quarter of 2018, FRU utilization has decreased by 65%. The decrease is also observed for FRU utilization in FMM, but at a lower magnitude. Three metrics are adopted to measure FMM FRU utilization; these metrics each reflect the uncertainties realized in the FMM market , the RTD market, and culmulatively.

In addition, at both the CAISO market level and the resource level, the analysis highlights the instances in which the realized uncertainties deviate from the FRU that is required as well as the FRU that is procured. FRU is awarded most to gas and water resources, while pump-storage and multi-stage generators have the most actual ramp change.Ramp change is defined to quantify the uncertainties realized among different market intervals for the same reference time. The analysis shows that, in terms of location, most resources that have greater ramp change are located in congested areas while in terms of time, some months and hours present a much higher ramp change than in other times.

Uncertainty realized in the real-time market

The FRP product is in place to provide the market with a mechanism to deal with uncertainty that materializes in the real-time market. The FRP requirement is based on the historical uncertainty observed in the markets. The FRP is designed at the 97.5th percentile for upward flexibility needs, meaning it is not designed to cover every single instance and level of uncertainty realized in the markets. Furthermore, this mechanism considers only uncertainty related to load, wind and solar forecasts; when conditions change in the real-time market, deployment of upward ramp capacity may be required. Table 1 shows a summary of the actual uncertainty realized in the real-time markets for the various EIM BAAs. For all EIM BAAs, the actual uncertainty realized in RTM does marginally exceed five percent, which can serve as a reference for how frequently the FRP requirement set at P95 (2.5th percentile in the downward direction and 2.5th percentile in the upward direction) can cover the actual uncertainty. The second and third columns in the table below show that the direction of the actual uncertainty materialized in the real-time market is evenly distributed between the upward and downward needs.

Table 1: Uncertainty realized in the real-time market

BAA	Actual Uncertainty Exceeds Requirements	Actual Uncertainty>0 (Upward Need)	Actual Uncertainty<0 (Downward Need)
CAISO	6.2%	42.2%	57.8%
PACE	5.6%	53.4%	46.6%
PACW	6.1%	59.6%	40.4%
NEVP	5.2%	52.1%	47.9%
AZPS	6.1%	55.4%	44.6%
PSE	6.2%	46.7%	53.3%
IPCO	6.0%	51.5%	48.5%
PWRX	5.6%	50.0%	50.0%
PGE	7.3%	53.5%	46.5%

Intertie Deviation

For intertie deviation, this report relies on the same timeframe used in the Intertie Deviation initiative in order to address some of the concerns raised during the Policy discussion. In the MSC's opinion, there is a hypothesis that Energy Imbalance Market participants (EIM entities) may be arbitraging between the intertie market in HASP and the EIM market in FMM and RTD. One specific area the MSC's opinion suggests to analyze is whether those interties with deviations belong to EIM entities such that this type of arbitrage could potentially exist. The deviations that originated from EIM entities in the timeframe analyzed are relatively negligible as shown in Figure 111. The total volume of under-deliveries sourced from EIM entities is less than 5 percent, which makes unlikely that the EIM rules are a main driver to incent intertie deviations.

Figure 111: Volume of intertie deviations

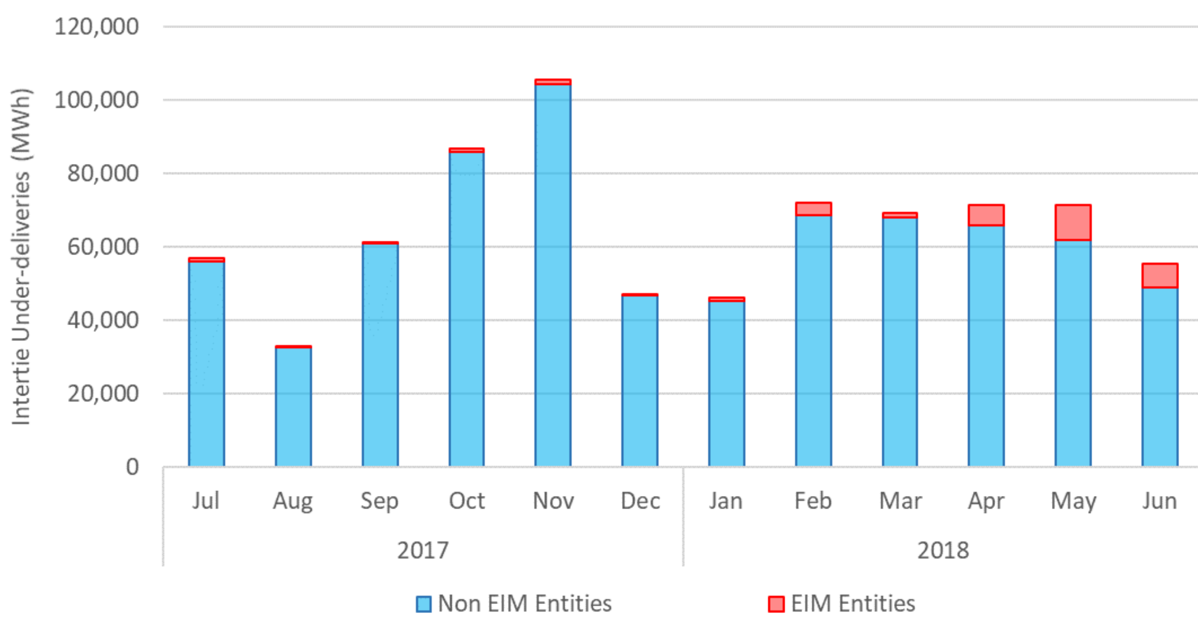
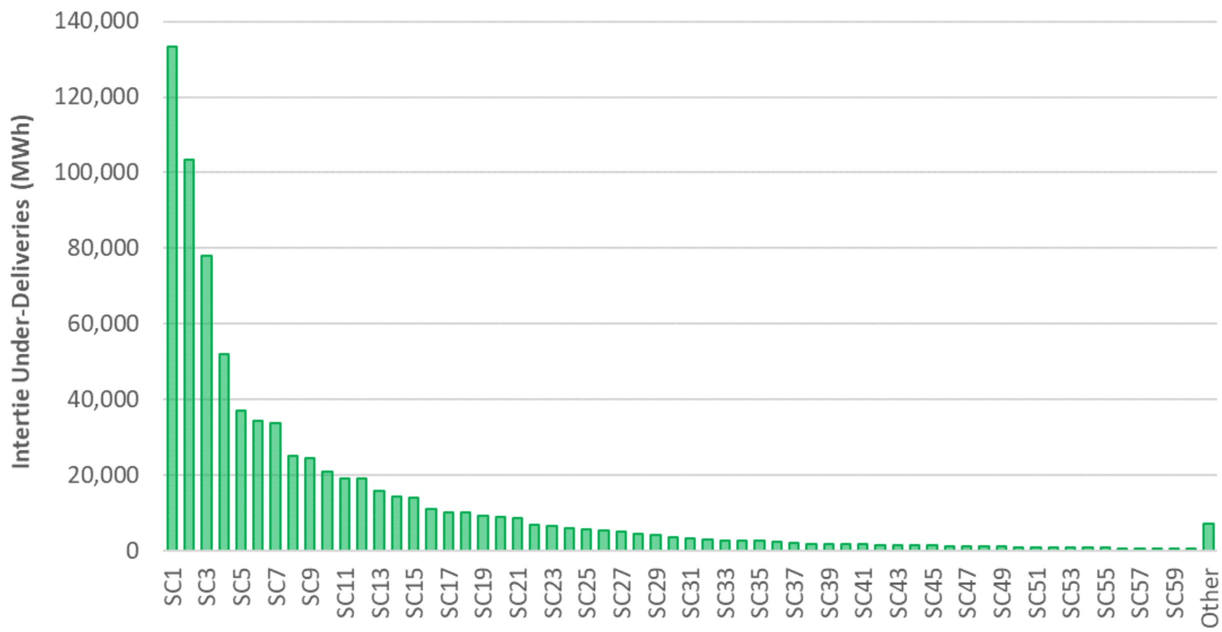


Figure 112 shows the total volume of intertie deviations per scheduling coordinator for the period of July 2017 through June 2018. The top five scheduling coordinators with intertie deviations account for 51 percent of the overall volume of deviations.

When analyzing the type of bids associated with intertie deviations, several scenarios can be observed. For instance, for the scheduling coordinator with the largest volume of deviations, three main scenarios are observed. One is when the scheduling coordinator more than a half of the intertie deviations are related to submitting some type of self schedules in the real-time market.

Figure 112: Volume of intertie deviations by Scheduling Coordinator



In the majority of these cases, there was an economical bid submitted in the DAM, then the scheduling coordinator submitted a self-schedule in the real-time market to protect the day-ahead award; these will clear generally at the nominal self schedule quantity; then the scheduling coordinator partially showed or decline fully the award. In a less frequent scenario the scheduling coordinator did not submit bids in the day-ahead market, then it puts self schedule in the real-time market (which gets lower priority than day-ahead self schedules); with having self schedules, these intertie will generally clear at the self-schedule quantity; then the intertie does not show or is partially showing.

Intertie deviations on August 28, 2017 HE19

On Aug 28, 2017 HE 19-20, the HASP and FMM load conformance was 1700 MW and the FMM/HASP prices were close to $1000/MWh. A counterfactual simulation was run to see the effect of the intertie deviations in subsequent FMM. For HE 19 interval 1, FMM had an under-generation infeasibility of 143 MW driving the $1000 prices. This particular case was selected because it had the smallest undersupply. The market rerun simulated the case in which the intertie deviation did not happen. In FMM, this resulted in effectively having 310 MW more of supply to meet the system demand. The resultant case had zero MW under-generation infeasibility but prices were still as high as $1000/MWh set by economic bids on proxy demand resources.

For HE 19 interval 2, FMM has an under-supply infeasibility of 590 MW, and the simulation of the effect of the intertie deviation only resulted in a smaller under-supply infeasibility of about 280 MW and the prices still clearing at $1000/MWh.

Intertie deviation on April 14, 2018 HE 21

Based on the intertie deviation effort, focuses on an instance in which the market observed one of the largest discrepancies of intertie awards from the HASP to the FMM/RTD market. April 14, 2018 HE 21 saw one of the largest tie deviations. This ~2100 MW deviation is measured between HASP awards and the tie tagged values. This instance indeed relates to operational cuts of interties on a specific intertie due to unscheduled flows. These cuts led to the large difference between the HASP awards and the tagged values[22].

While this case does not reflect an explicit deviation by the scheduling coordinator, it is a good example of how the pricing unfolds for those type of scenarios and has similarities to the questions raised in the MSC paper. The Average DLAP price for the HASP run in this case was $44.35/MWh, FMM DLAP average at $58.97/MWh, and RTD average DLAP price at $29.77/MWh. The prices reflected in FMM show that there was a decrease in supply which increased the prices between HASP and FMM. However, the RTD prices dropped in comparison to the FMM and HASP pricing. This was due to variability between FMM and RTD specifically related to renewables, load forecast, and operator bias for uncertainty. The RTD market had about 750 MW less demand due to 600 MW bias difference between FMM and RTD along with forecast change of 150 MW. This was compounded with renewables under-forecast in FMM for about 200MW in FMM. With this additional supply and diminished demand, the prices decreased in the RTD market, while the tie schedules were relatively consistent due to the timing of the tie schedules. In this case, prices properly reflect the system conditions observed in the markets.

Intertie deviation on September 1 and 2, 2017

The MSC's opinion for the Intertie Deviation Policy raises several hypotheses about pricing leading to incentives for deviation. The MSC's concerns focus on Sep 1, 2017 HE 18 during which FMM and RTD prices were low despite the occurrence of significant under-deliveries. The expectation is that if less interties (supply) are delivered, a tighter supply condition should naturally be observed in these markets, thus giving rise to prices. As explained below, in reality, the RTD market observed an increase of supply from ties and more supply with respect to FMM[23].

When analyzing the intertie deviation data, the under-deliveries of this hour were less than 300 MW, and were fully offset by over-deliveries of more than 700 MW. This was a peak load day with load clearing over 50,000 MW. For this timeframe, there were both additional interties procured in the real-time market and intertie declines from scheduling coordinators. The additional availability of interties in the real-time market after the HASP procurement were due to purchases of additional intertie energy needed

[22] Strictly speaking this is not an instance of an explicit deviation from scheduling coordinators but rather a system condition leading to the deviation. In the metrics developed for the intertie deviation Policy, this type of scenarios were manually screened and filtered out to not inflate the magnitude of intertie deviations. Although this is not an explicit deviation originated by the scheduling coordinator, this instance will still reflect pricing implications for instances in which FMM and RTD had to balance without the interties that the HASP market originally scheduled to meet the demand needs.

[23] It seems that erroneous data may have been provided to the MSC while the Policy discussion took place. That data included manual dispatches for interties incorrectly added to the data of intertie deviation like additional intertie deviation records. Such erroneous data issue may have led the MSC to construct some hypothesis and conclusions provided in the MSC's opinion about the interplay between intertie deviations and pricing in the real-time markets.

as a result of the high loads thus offsetting interties were declined. However, the majority of the deviation on the intertie happened to be for an export decline of 500 MW. This decline represents additional supply from the HASP to RTD market and actually provided more supply to the real-time market.

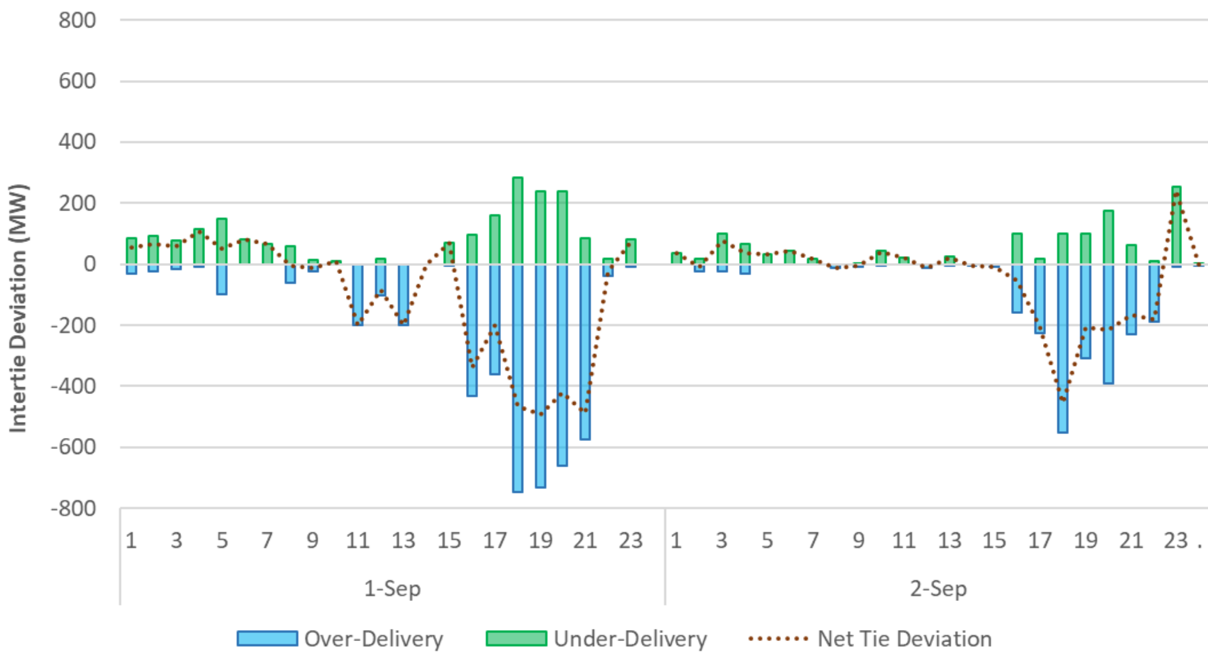
On that peak load day, congestion was significant and systematic. In the HASP run, the clearing prices at a southern California ties were negative due to compounded congestion from different constraints in that area. This price led to an export resource clearing based on the offered price that was greater than zero. However, this schedule was declined by the scheduling coordinator. One possible reason for the decline could be the uncertainty on whether the scheduled export would be economical based on the subsequent FMM prices. In actuality, the decline actually occurred due to lack of transmission capacity to support the export schedule. The FMM price for this scheduled export also happened to be above the offer price for the export (not in merit), so an economic incentive may not have existed to take on the export award.

However, when looking at the pricing differences between HASP, FMM and RTD, the dynamics of the interties (characterized by manual dispatches and declines) were not the main driver for the price divergences. The FMM had 1100 MW higher conformance than RTD market, 280 MW additional load due to forecast, and 200 MW additional renewable energy. Thus, in relative terms, the magnitude of intertie deviations played a secondary role in pricing in comparison to the magnitude and effect of other drives such as load conformance, renewable deviation and congestion.

In another comment of the MSC's opinion, there is a reference to many non-deliveries observed on the MEAD intertie on Sep 1 and 2, 2017 and to concerns about pricing observed across the markets during the intervals when such non-deliveries occurred. However, based on the intertie-deviation data, there were negligible intertie deviations with under-deliveries on Mead intertie. On these days, the intertie deviations were in fact made in the opposite direction. These over-deliveries resulted from several resources on this tie being manually dispatched. For instance, on Sep 2, 2017 HE 19, manual intertie dispatches were over 800 MW. These manual intertie dispatches lead FMM and RTD to procure more energy than the level at which the HASP cleared. This in turn led to more supply in FMM and RTD rather than less. Thus, the expectation is that, on a system-wide basis, more supply will only lower prices further in these markets. This is indeed what actually happened in the market: for HE 19, the system prices in HASP, FMM and RTD were $464/MWh, $359/MWh and $309/MWh, respectively.

Figure 113 below shows the hourly profile of all intertie deviations. Positive values stand for under-delivery, meaning the tagged value was less than the HASP clearing value.

Figure 113: Intertie deviation on September 1 and 2, 2017



In regards to price divergence on the specific tie price across the markets, consider the case of Sep 2, HE 18 during which the price divergence was driven mainly by congestion. The constraint 24086_LUGO _500_26105_VICTORVL_500_BR_1 _1 was binding in the real-time market and required decremental energy on the MEAD intertie. Prior to running the HASP for that hour, there was a forced outage of a transmission line and this led to an overload on the Lugo-VictorVille constraints in the HASP. This is a significant constraint with many resources being effective for mitigation. When this constrained led to decremental dispatches, supply became more limited and thus the system marginal price increased. By the time HASP had completed, operational actions had been taken to better manage the congestion in the area, which in turn led to better congestion management in the market that reflected in lower congestion and, in some cases, the constraint no longer bound in FMM and RTD. From a supply perspective, FMM also solved for a higher demand given a load conformance of 1100 MW compounded with lower load forecast in RTD.

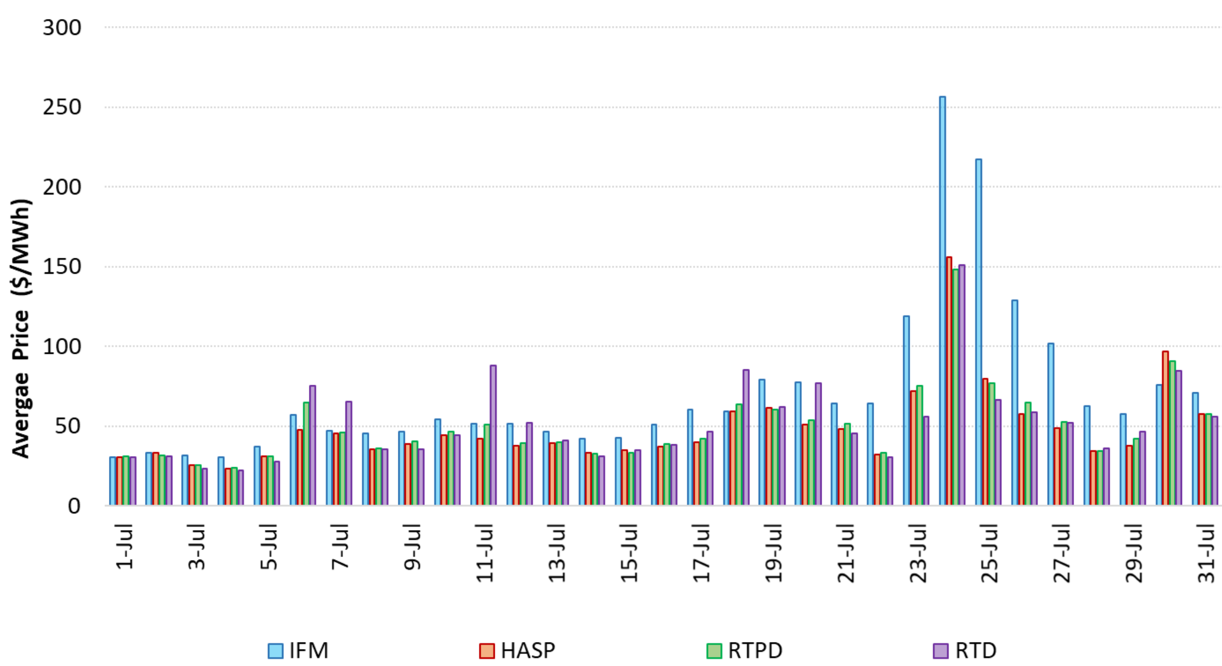
Detailed Analysis of Price Performance

While overall trends aid pattern observation, analyzing specific market outcomes can help complement and unravel dynamics in the price construct. For this type of analysis, the CAISO took some of the instances identified in previous sections with the largest price divergence between markets. Below is a sample of deeper analysis undertaken to understand specific cases of price performance.

Price divergence in July 2018

As discussed in the analysis and trends in previous sections, July 2018 is a month in which the CAISO observed large and system-wide price divergence. This makes it an ideal month on which to perform more detailed analysis to understand the underlying drivers of observed price performance. Figure 114 and Figure 115 show a more granular trend of prices for the month of July 2018, on a daily and hourly basis.

Figure 114: Daily system-weighted price across the CAISO markets



IFM prices were higher than the real-time prices on average for 29 days in July 2018, indicating a persistent trend. When this pattern is organized by trading hour, the largest divergence is observed during the peak hours. In particular, July 24 and 25 saw the largest price divergence between IFM and the real-time markets as shown in the box-whisker plot in Figure 116. The divergence of average prices between the various real-time markets, as illustrated through price spreads, are in general less frequent and are characterized by a smaller range of spreads. Naturally, the real-time market may observe more volatile prices that may lead to outliers in the spread, as shown in Figure 117 and Figure 118.

Figure 115: Hourly system-weighted price across the CAISO markets. July 2018

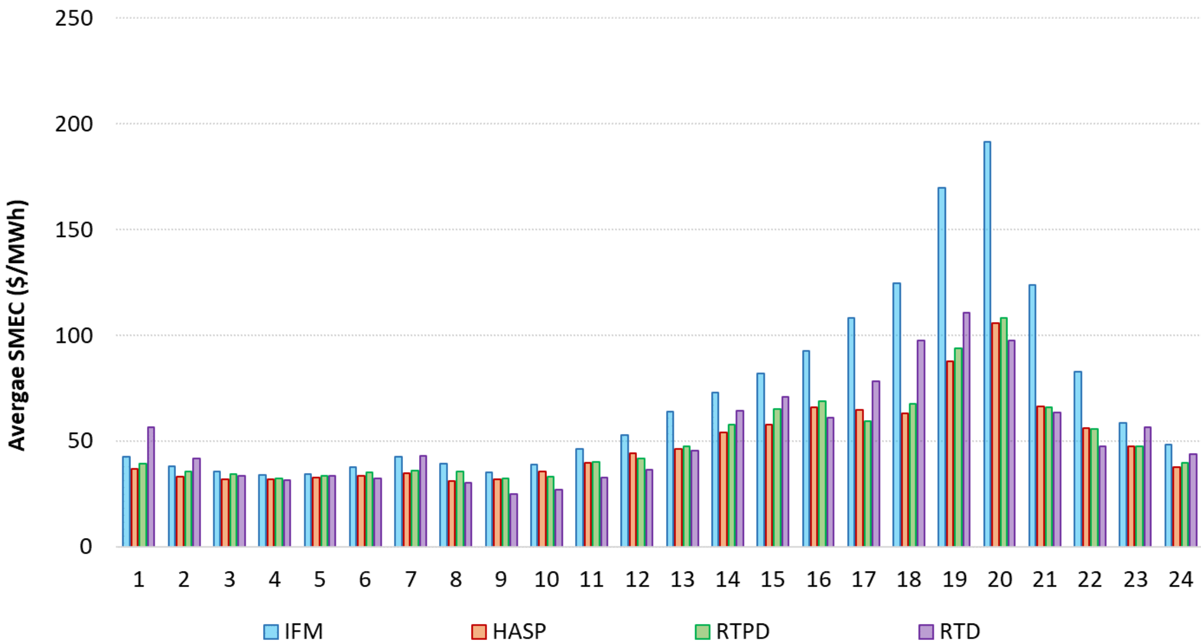


Figure 116: Price spreads between IFM and HASP. July 2018

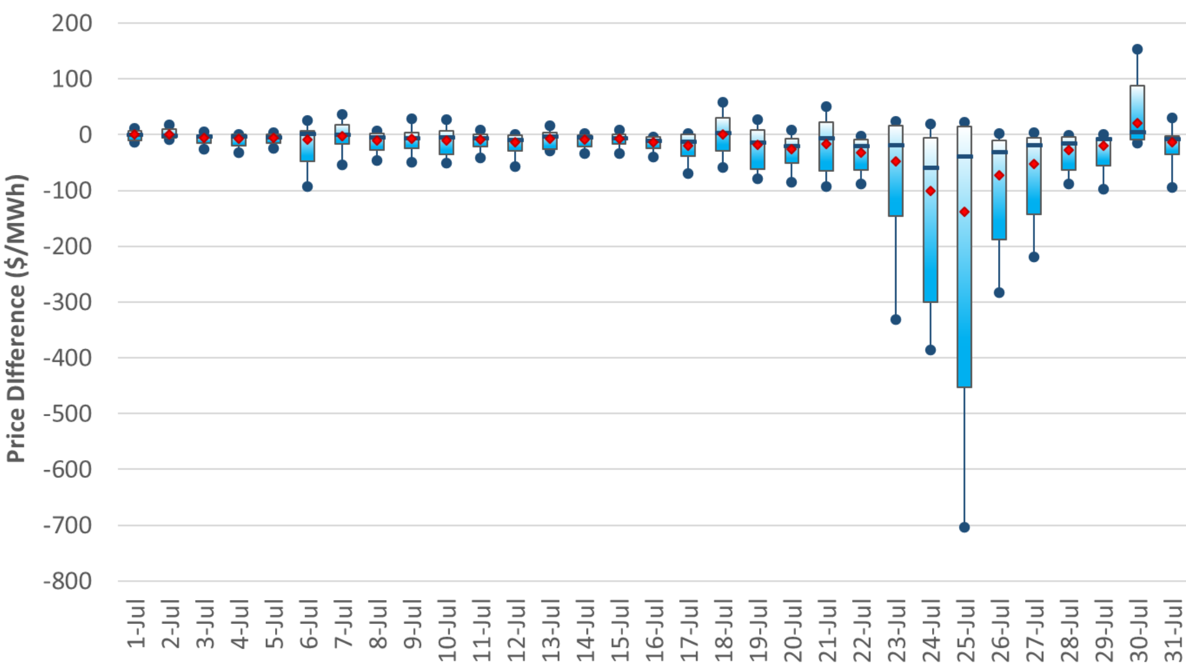


Figure 117: Price spreads between HASP and FMM. July 2018

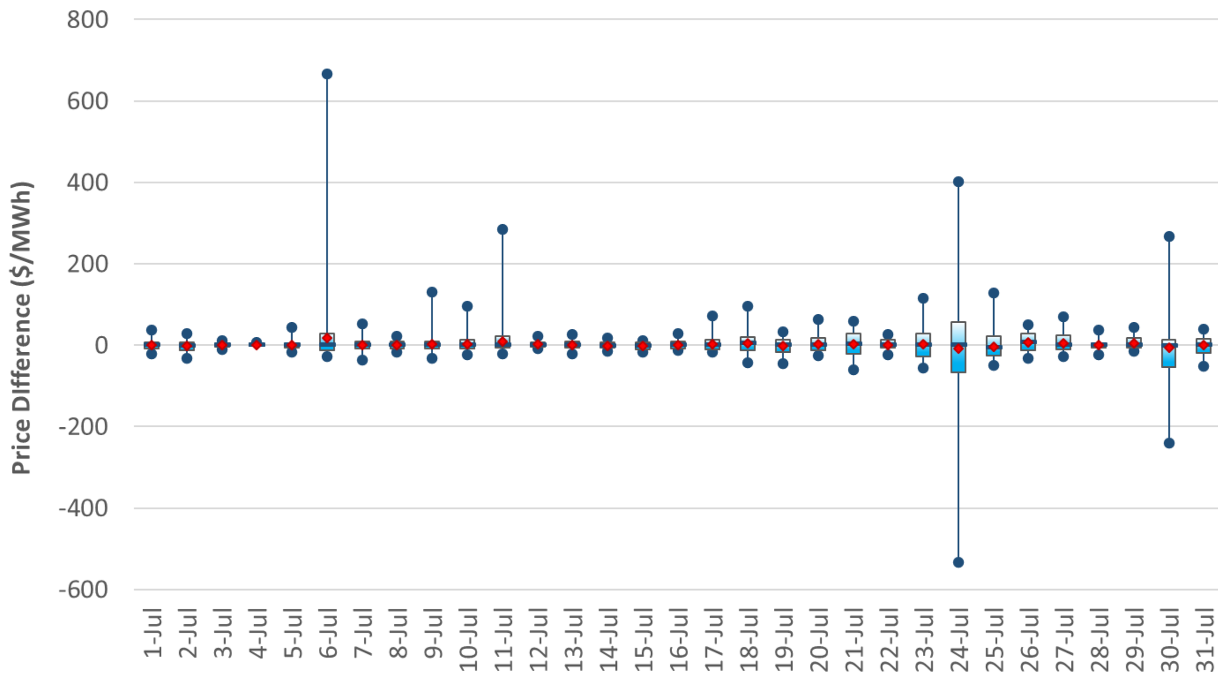
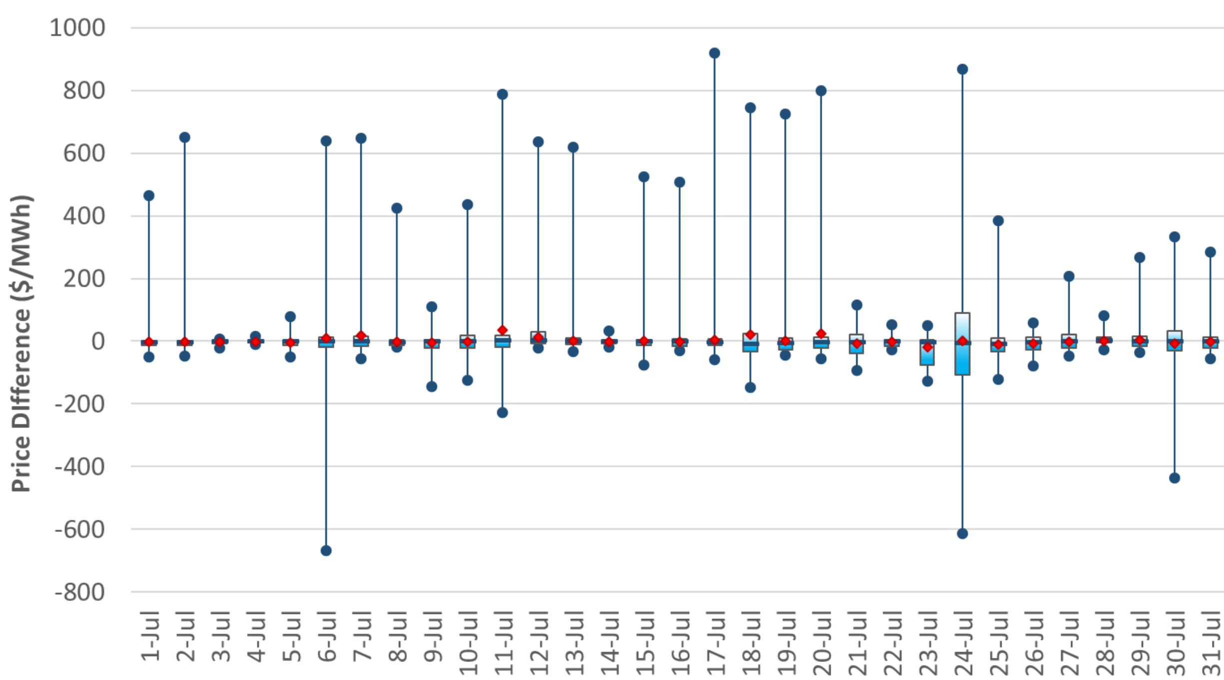
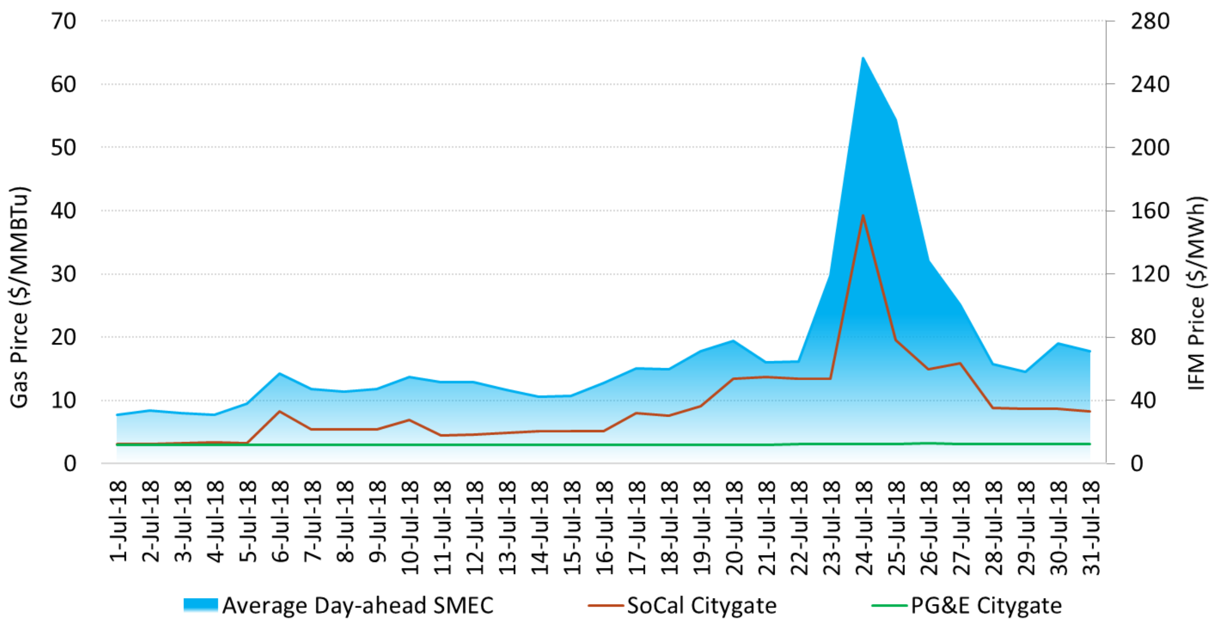


Figure 118: Price spreads between FMM and RTD markets. July 2018



The month of July 2018 was operationally challenging; gas prices in Southern California were volatile and particularly high on July 24 and 25, reaching about $39/MMBTu. Figure 119 shows a more granular trend of the correlation between electric and gas prices. Given the meaningful contribution of gas resources to the electric system and their tendency to be marginal, such high gas prices consequently led to high electric prices. While the high gas prices can explain the high electric prices observed in IFM, they may not fully justify a large price divergence between IFM and the real-time markets.

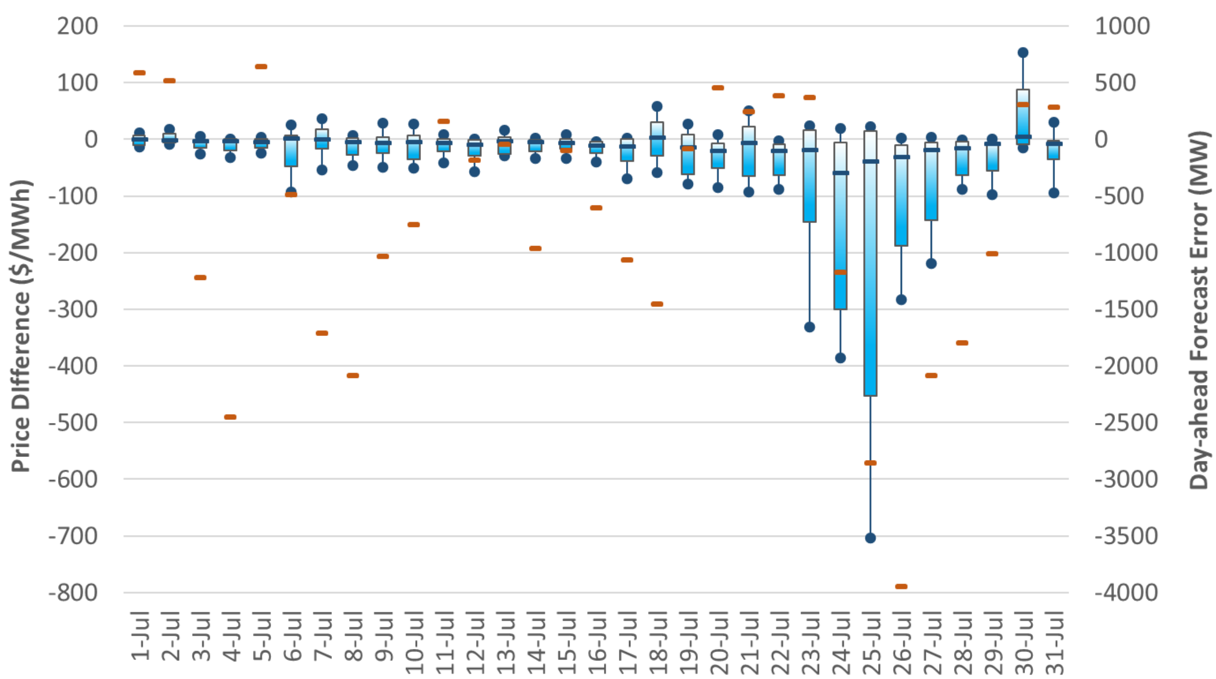
Figure 119: Electric and gas prices in the CAISO IFM



High temperatures that led to peak load conditions was a key factor during the month of July. CAISO experienced the peak demand of the summer on Wednesday, July 25. This day was the third week day of heat buildup experienced throughout the state of California. During this week, all regions experienced above-normal maximum temperatures, minimum temperatures, and average temperatures throughout the day exceeding these values by 2 to 12 degrees. This summer season was characterized by record-breaking heat in coastal cities with San Diego reported its warmest August since records began in 1939 averaging 78.1 degrees Fahrenheit, 6.5 degrees above normal. In addition, Los Angeles reported its 3rd warmest July since records began in 1877 at 78.8 degrees Fahrenheit, 5.5 degrees above normal. Inland areas also saw records with Fresno setting a record all-time hottest calendar month at 88.2 degrees Fahrenheit, 5.2 degrees above normal. One specific factor observed this summer is the record warm minimum temperatures, which can have a big impact overall on the mean temperatures throughout July and August, leading to potential higher loads in the electric system. With such challenging conditions, the CAISO system observed significant forecast errors in the day-ahead timeframe.

Figure 120 shows a comparison between the price spreads (HASP-IFM) against the maximum day-ahead load forecast error. The largest errors, some in excess of 2,500 MW, were observed on July 25 (the peak day of the year) and July 26[24]. Although the load forecast is not used directly in IFM, the challenging conditions may affect the IFM because bids into this market may rely on forecasted conditions for the trading date. If the CAISO forecast observed such an error based on the temperature errors, other forecasts used by SCs for bidding purposes may also suffer similar challenges. On these two days, the day-ahead market was overscheduling the load. With such increased load requirements, the RUC market may have committed excess resources to meet the lower actual load realized in the real-time markets. July 25 and subsequent days had the largest over-forecasting error and coincide with the period with the largest price divergence between DAM and RTM.

Figure 120: Price spreads compared with day-ahead load forecast error in July 2018



July 25th was also the day with the largest price spreads, making it a good day to further explore the conditions leading to such divergence. Figure 121 shows comparison across the various CAISO markets of what each market cleared against supply. The market requirement determines that enough supply is available to meet demand including any system losses and operator adjustments to the load forecast (*i.e.* the RUC adjustment in RUC, and load conformances in HASP, FMM and RTD). For IFM, this is the total demand cleared in the market, including losses. Accordingly, this measure compares the load requirements across the markets on the same basis. There are two lines to represent IFM, one is for physical demand only which can be a good reference against RUC requirements, and a second one that includes the displacement introduced with net virtual demand. In this specific day, the net virtual was net supply for all hours and effectively converged the IFM requirements closer towards the real-time requirements. This brought IFM closer to the real-time conditions since IFM physical and RUC were

[24] The load forecast errors have a sign convention to reflect overscheduling with a negative value.

clearing above the actual conditions for that day. RUC used an over-forecast for this day and, given the uncertainties, operators had an additional RUC adjustment of 2,000MW.

Figure 121: Demand needs across the CAISO markets on July 25, 2018.

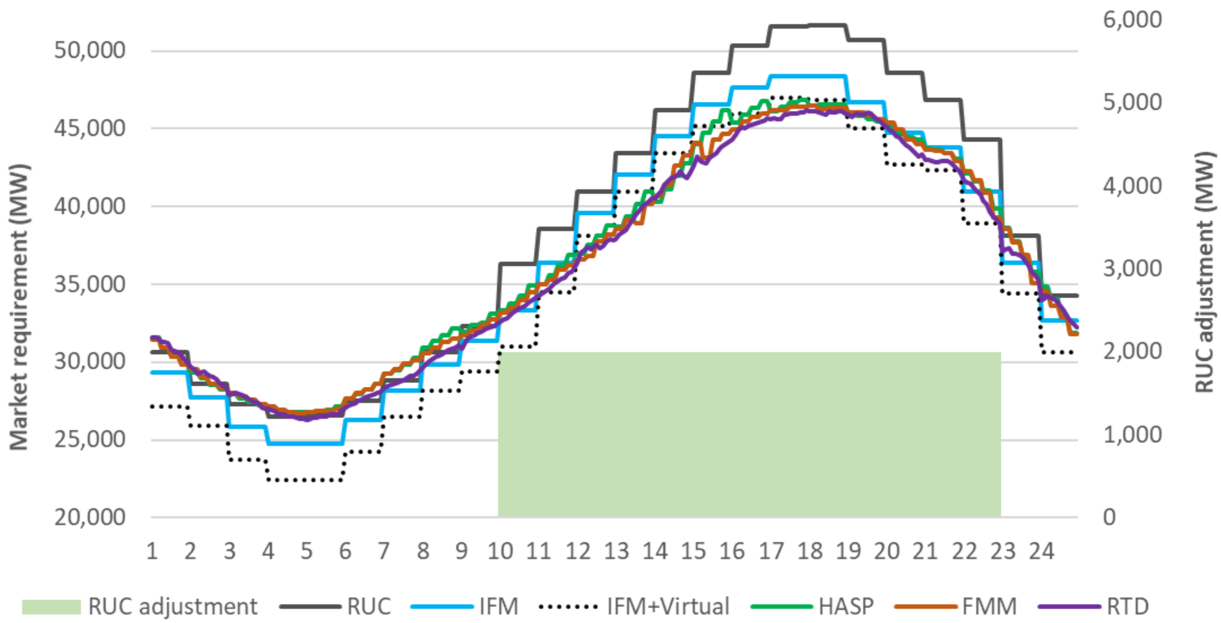
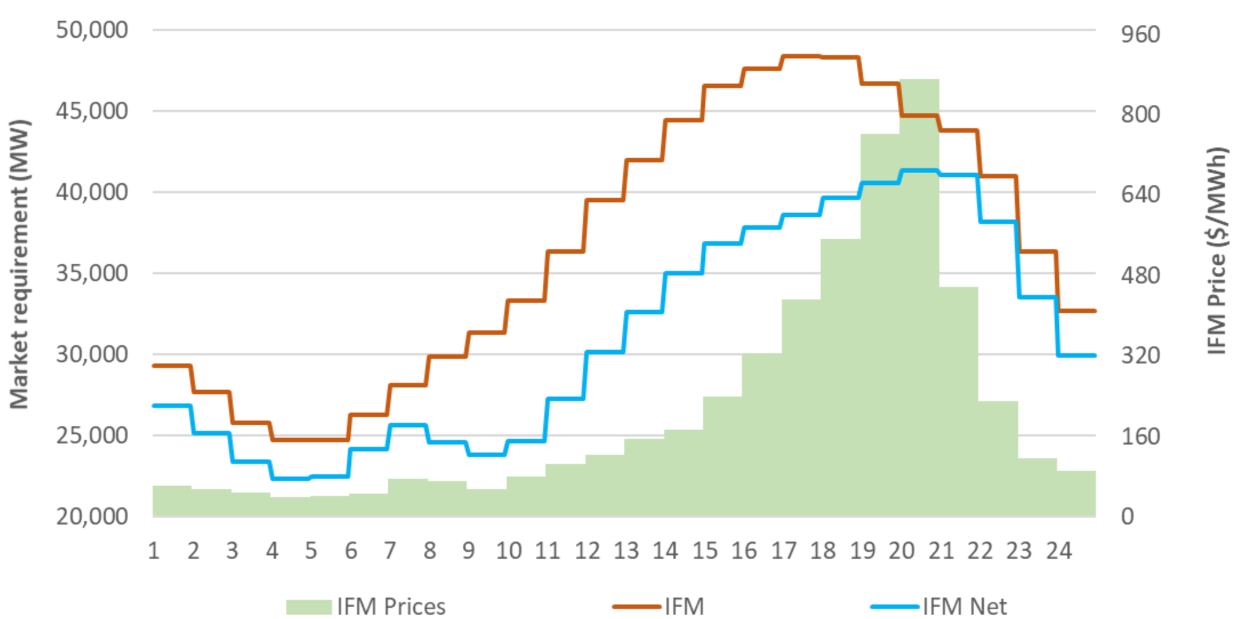


Figure 122: Gross and net demand requirements in IFM for July 25, 2018.

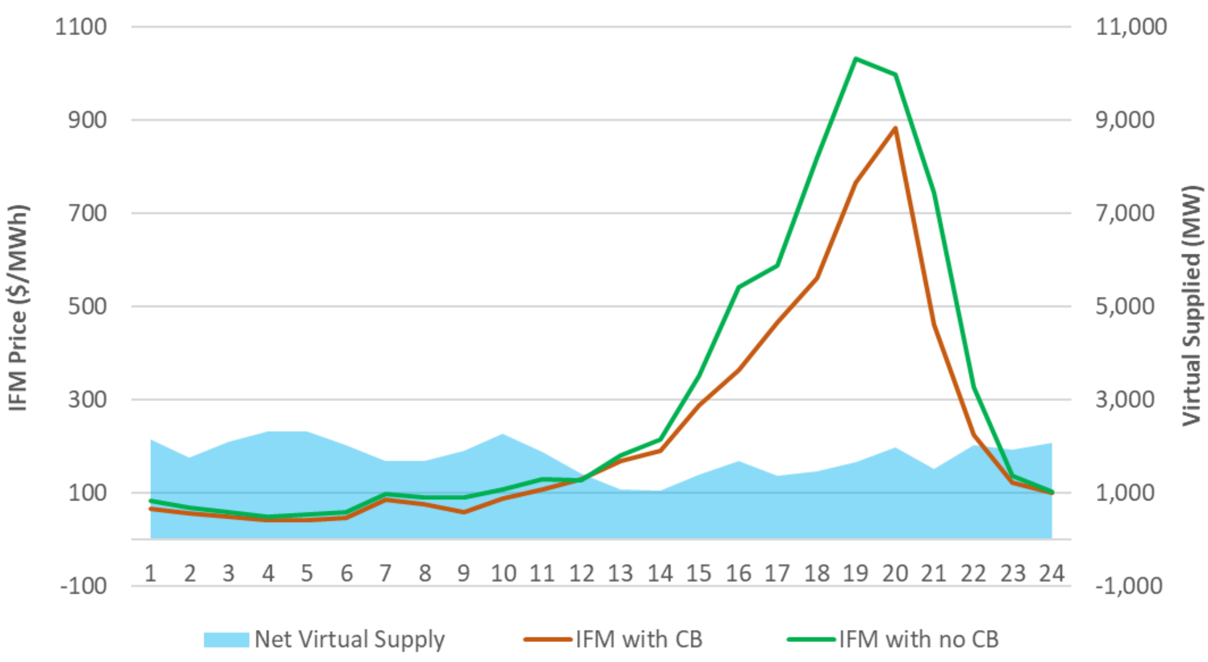


This meant that the capacity schedule in IFM based on physical resources was already in excess to meet actual system conditions, and naturally cleared higher in the bid supply stack at a correspondingly higher price. RUC dispatched even more capacity above IFM. Then, with the extra capacity scheduled in RUC, and real-time conditions coming lower than forecast, the real-time market may effectively have plenty of supply.

Figure 122 compares the IFM prices with the gross and net demand requirements. The net requirements are estimated by taking the gross requirement and subtracting the VER awards in IFM. As discussed in previous forums[25], the highest prices observed in the DAM typically occurs at the peak of the net load, which is when the more stringent ramping needs are observed in the system as the solar production diminishes with sunset. During these forums, the CAISO also discussed what type of resources can actually set prices above $200/MWh. Marginality that defines prices can be beyond standard heat rates from conventional units. In addition to conventional fuel generation, imports, proxy demand resources, batteries or convergence bids can become marginal and set prices.

In the specific case of July 25, convergence bids were setting the price during peak hours. The CAISO performed a counterfactual analysis in order to see convergence bids' effect on prices. The CAISO took the original solution of the DAM for July 25 and reran the market with and without consideration of convergence bids. Figure 123 shows the comparison of prices between these two reruns.

Figure 123: Comparison of IFM solution when virtual bids are not considered



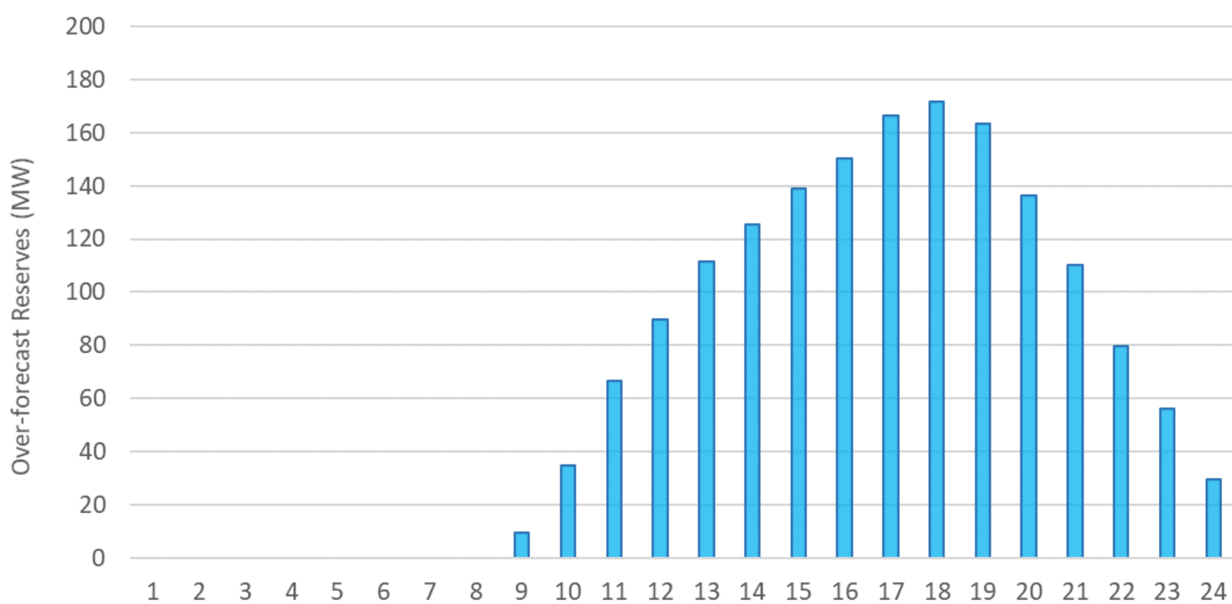
In this simulation, IFM prices increased up to $1,000/MWh in the net load peak hours when convergence bids were not included in the market. In the solution with convergence bids included, convergence bids were the marginal bids during peak hours. In the rerun simulation (*i.e.* in the absence of the convergence

[25] For a reference on this discussion please refer to http://www.caiso.com/Documents/Presentation-MarketPerformance-PlanningForum-Dec11_2018.pdf

bids), proxy-demand resources were marginal at about $1,000/MWh. The use of the highest-price bids in the market simply reflects the fact that, for this day, there was a tight supply condition in DAM leading the market to clear in the upper-end of the supply stack[26].

The over-forecasting of the load partly explains this outcome. Although the load forecast is not explicitly used in the IFM market, bid-in demand most likely relied on over-forecasts. A secondary effect on the IFM is the determination of the operating reserves. Generally, the full amount of operating reserves are expected to be procured from IFM while any incremental procurement is done through the real-time market. One of the components that may determine the level of operating reserves is the six percent of the load forecast[27]. Thus, if the load is over-forecasted, the operating reserves may also be over-forecasted. For July 25, the IFM was experiencing an over-forecast and the potential for over-forecasting the requirements for operating reserves was under 200MW. The hourly profile of this over-forecast of requirements is illustrated in Figure 124.

Figure 124: Comparison of IFM solution when virtual bids are not considered



This additional requirement for operating reserves will put upward pressure in the supply stack available and naturally will have the market clearing higher in the bid stack.

To compare the supply available in both the IFM and RTM, consider hour ending 20 for a reference. Figure 125 shows a comparison of supply bid stacks between IFM and HASP. The bids below -$150/MW

[26] This aspect of the margin on supply was part of the discussion on system market power; material is available at http://www.caiso.com/Documents/Presentation-SystemMarketPowerAnalysisJune7_2019.pdf

[27] Effective January 1, 2018 as per new standard BAL-002 the operating reserves requirements also account for the PDCI schedules as part of largest single contingency. So either this component or the 6% of load requirement will set the level of operating reserves: when loads are not that high, the PDCI schedules will typically set the requirements; when loads exceed certain level, the 6% of load will set the requirements. On July 25, 2018 with loads exceeding 45, 000MW, the 6% requirements set the level of operating reserves.

are self-scheduled, which prices are associated with penalty prices. It can been seen that the total bid-in capacity (MW) of the two markets is very close. The bids are tracking closely in the range of $150/MWh to $850/MWh. There is a shift of bids in the range between self-schedules and $150/MWh. Figure 126 and Figure 127 show the differences of bid-in supply between the IFM and HASP. The net between these two sets is relatively small.

Figure 125: Bid stack for IFM and HASP. July 25

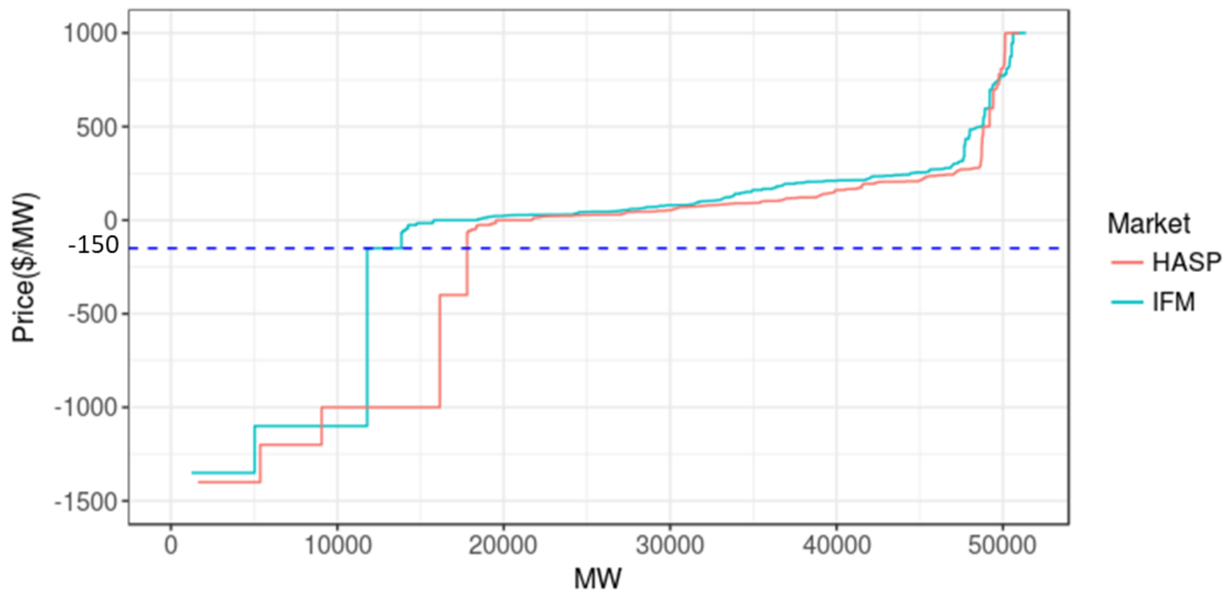


Figure 126: Bid supply in IFM that is not in HASP

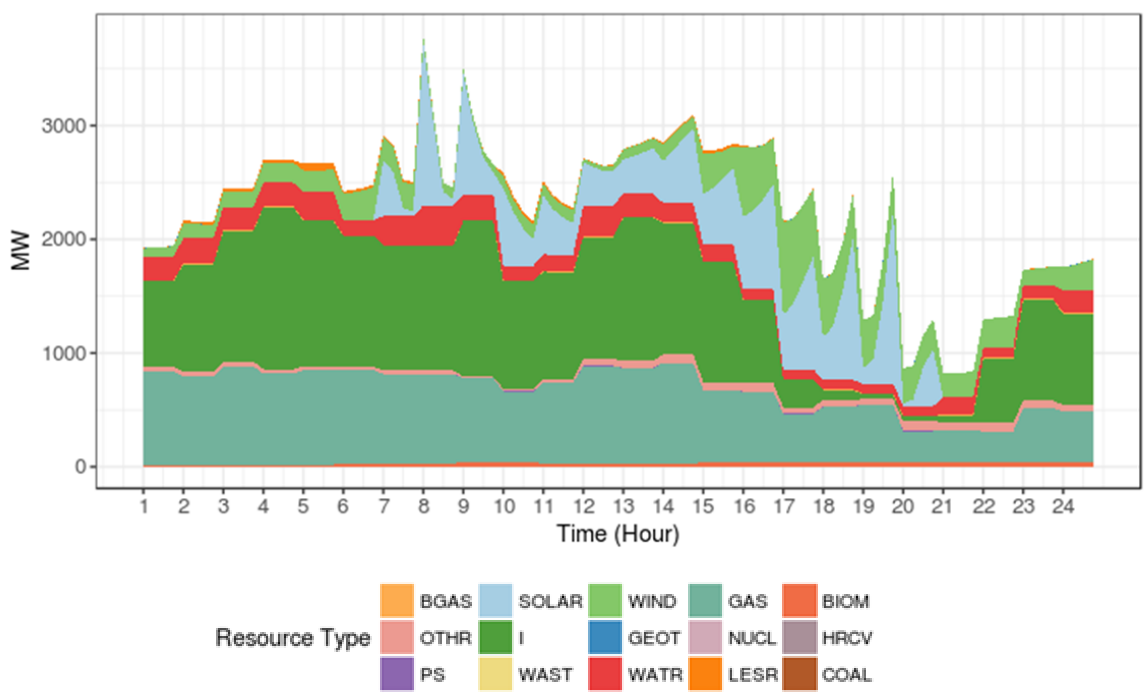
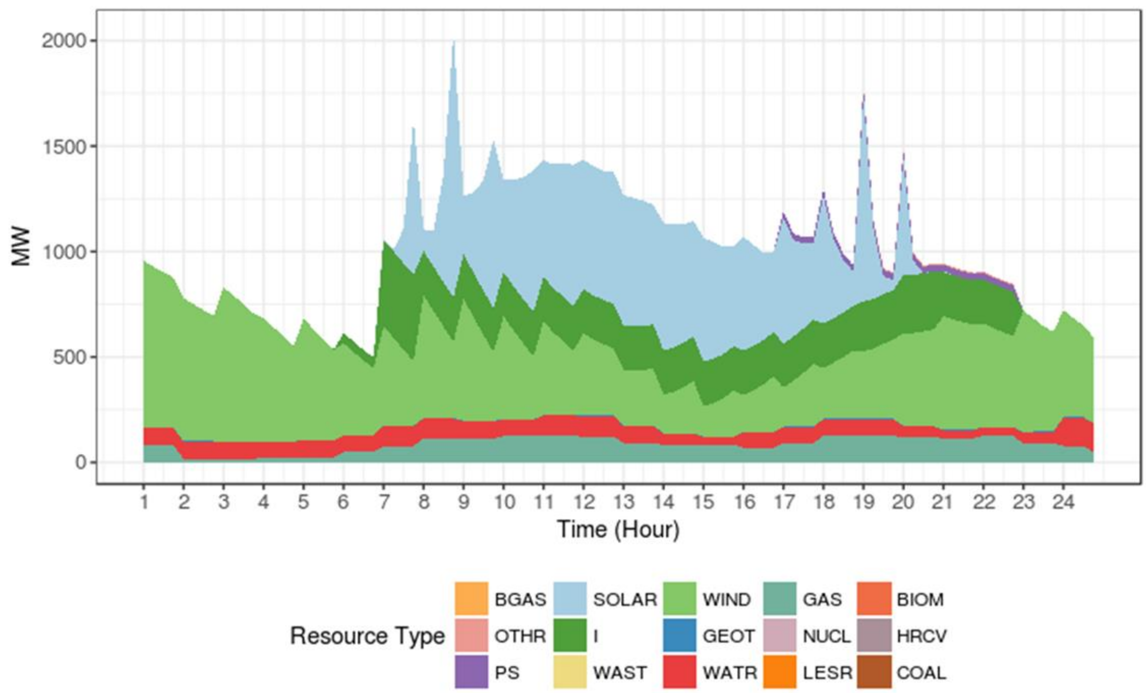


Figure 127: Bid supply in HASP is not in IFM



For a more targeted comparison, each resource's bid is compared between markets. Even though the capacities of bids can be the same, the bids may be priced differently between markets. Therefore, the price distributions of bids could contribute to price divergence between DAM and RTM.

Figure 128 and Figure 129 show the price distribution of bids in both IFM and HASP, organized by the type of resource. The statistics in the figures take a bin range of $50/MWh. For example, bids priced anywhere between $100/MWh and $150/MWh are counted in the bin of $100/MWh. If there are bids from both markets in a given bin, one bar per market will be depicted. If there are bids only in one market, then only one bar will show.

Two sets of resources have major shifts of the bid prices. The first set concentrates at a lower price range (less than zero), which can be explained by the fact that economical bids in IFM come now as real-time self-schedules. These resources are primarily wind, solar, geothermal, and biomass, hydro, pump storage and import. However, if some resources were infra-marginal in IFM in the economical range to the point of influencing the market clearing price, by the time they become self-schedule in the real-time market they no longer influence the clearing price in terms of price, but only in terms of the capacity they displace in the bid stack.

Figure 128: Bid price distribution

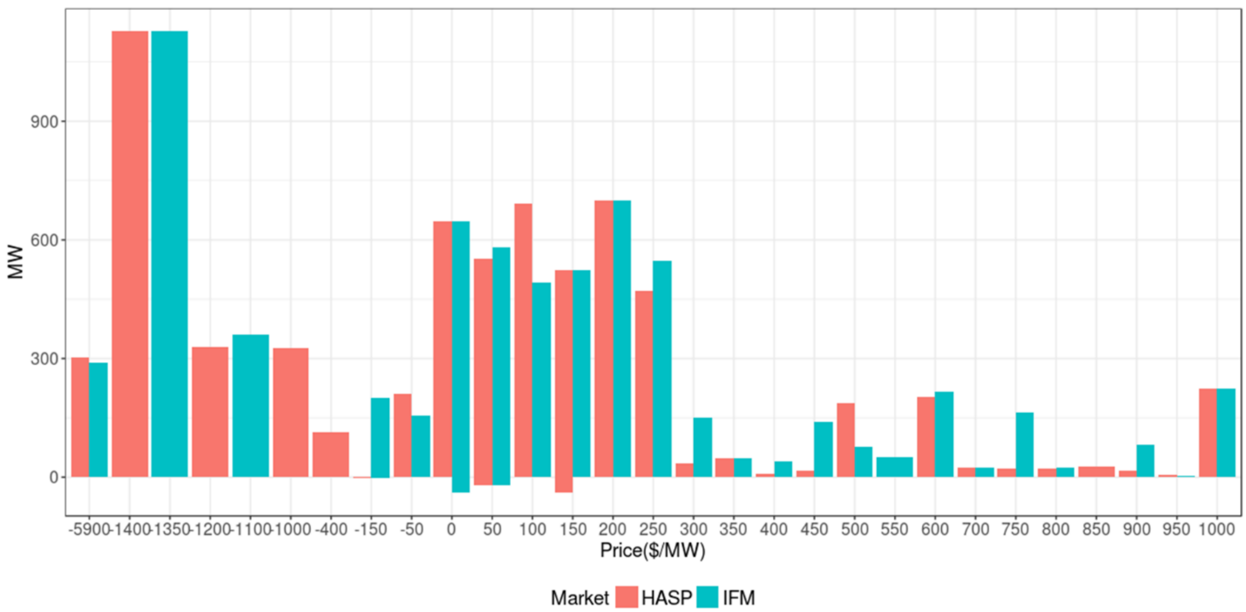
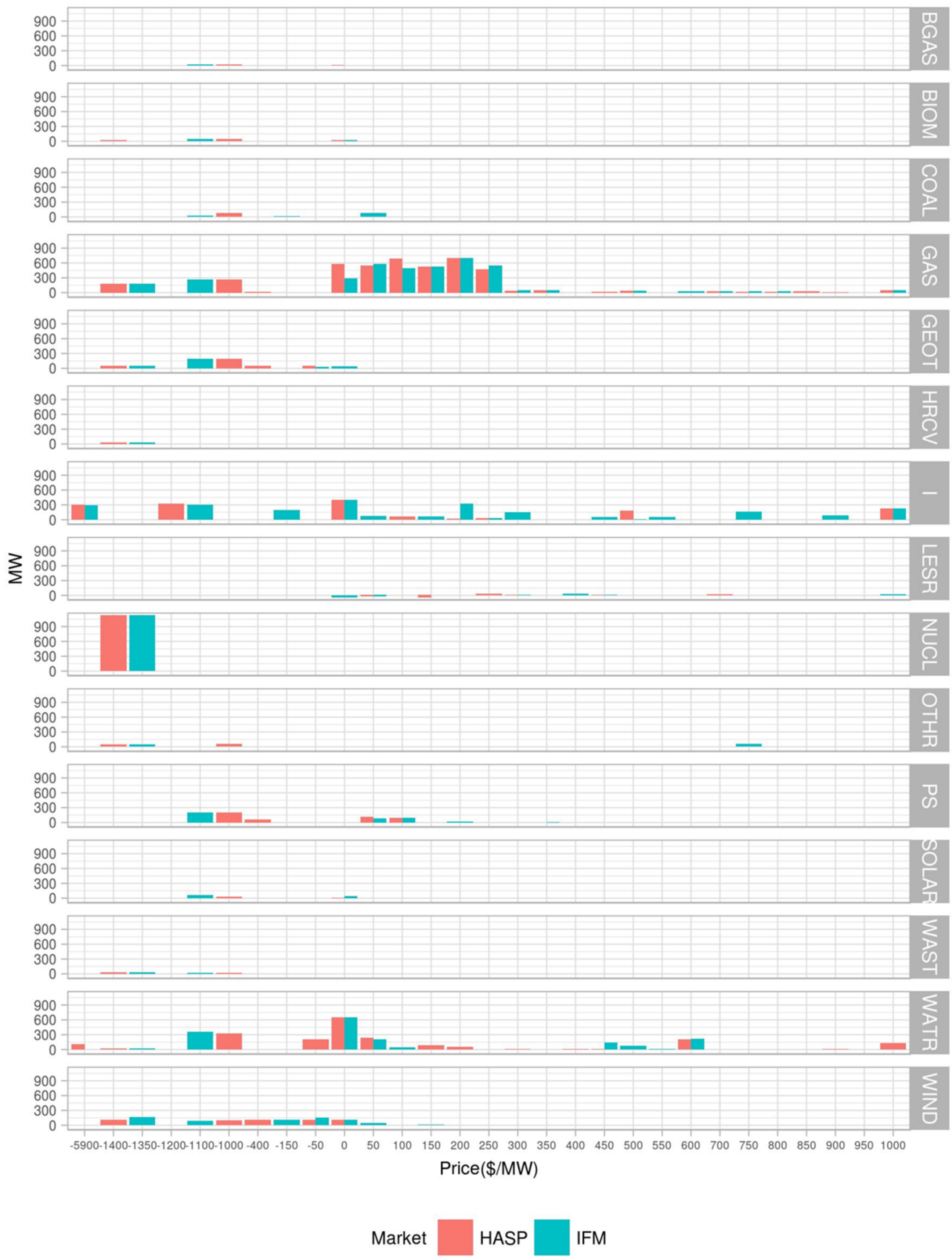


Figure 129: Bid price distribution by resource price

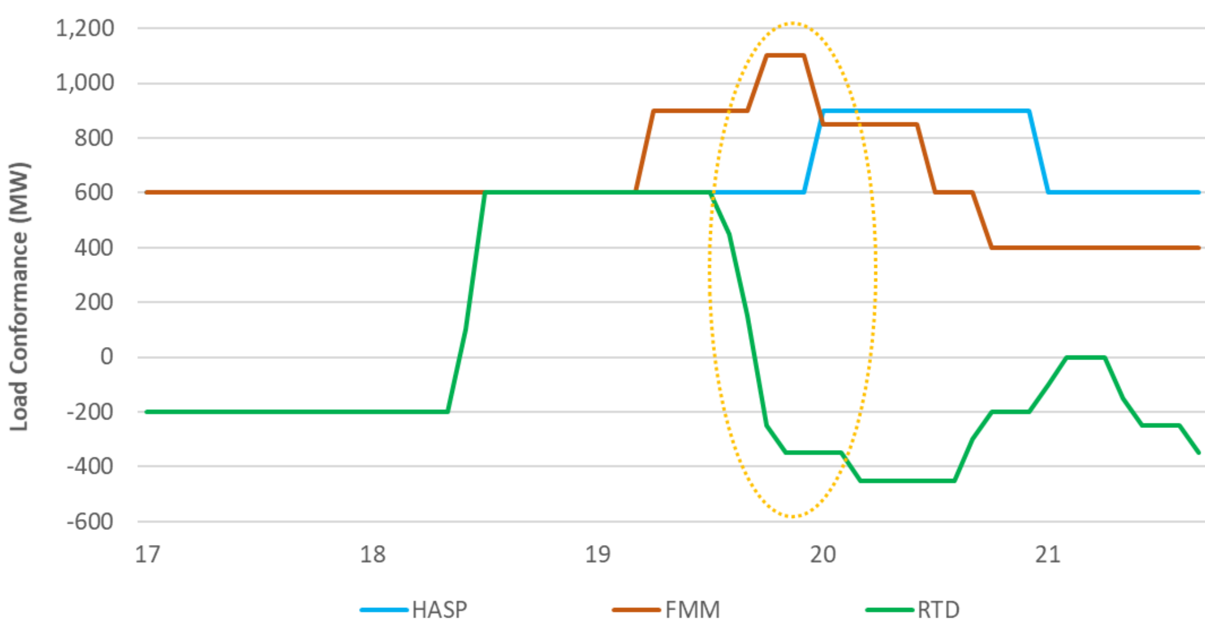


Price divergence on March 1, 2018

On March 1, 2018, in HE 19, the HASP price was about $48/MWh, the FMM interval 4 price spiked to $1,000/MWh, and the RTD interval 12 price was about $36/MWh. These price differences were driven by differences in load conformance across the real-time markets.

Four elements caused FMM to clear an additional 1,300 MW more than HASP: 1) load conformance was 500 MW higher in the HASP in comparison to the conformance used in FMM; 2) the load forecast came in 500 MW higher in the FMM timeframe; 3) an increase of over 100 MW in a particular export; and 4) renewable resources came in about 200 MW lower in FMM than originally shown in the HASP. Clearing this higher load level naturally set the market in a higher range of the supply stack where higher prices can be expected. Figure 130 shows the load conformance profile across the various real-time markets for the period under analysis. The interval circled in yellow illustrates the large delta of conformances. Then, when the RTD market ran, the price dropped to $36/MWh as a primary result of having a load conformance of -35 0MW, which was a reduction of load of 1,450 MW with respect to FMM.

Figure 130: Load conformance across the real-time markets



The flexible ramp capacity that was procured for the system was in the range of 900 MW for the entire EIM area footprint. About 620 MW out of that was procured within the PAC West area. However, this was undeliverable to the CAISO due to transfer (ETSR) limitations into the CAISO creating a situation where flexible ramp capacity is procured and then gets stranded due to transfer limitations. These types of situations were addressed later in 2018 with a software enhancement that took into consideration the transfer capability when awarding flexible ramp. The remaining of the flexible ramp capacity was procured within CAISO area, with about 50 MW not being deliverable due to gas limitations imposed in the market. The rest of flexible capacity (about 133 MW from conventional generation and about 96 from proxy demand resources) was dispatched in FMM but was not sufficient to absorb the changes observed in FMM.

The export that increased by 100 MW was not an actual intertie resource but rather a record introduced in the real-time market reflecting the consideration of losses between the CAISO BAA and an adjacent area. This specific instance of in-kind losses is only in the FMM and RTD timeframe; neither the HASP nor the IFM consider this additional requirement, and may create a modest, but relatively persistent, misalignment between the IFM and HASP versus FMM and RTD

Price divergence on September 5, 2017

On September 5, 2017, in hour ending 18, the IFM price was $74/MWh, the HASP price was $76/MWh, RTD interval 7 price was $80/MWh, while the FMM price spiked to near $1,000/MWh.

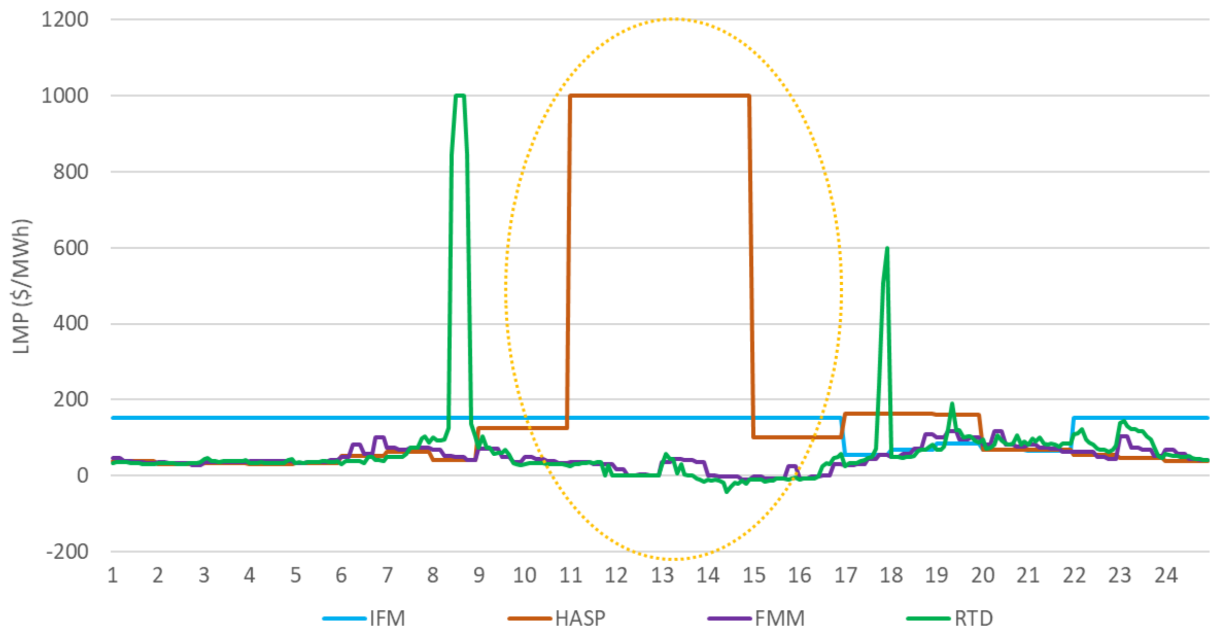
Forecasting differences and outages drove these price divergences. On September 5, California system and parts of the West were experiencing the end of a heat wave. The CAISO load levels during this hour where over 43,000MW. For HE18, the real-time forecast came in about 1,000MW higher than forecasted in the DAM timeframe. There were also losses of over 700MW due to generation outages when going from day-ahead to real-time. HASP had run with the forecasted loads, renewable levels, tie capacities, and resource schedules that had been determined at the start of the run. However, by the time FMM ran for this hour, there had been over 250 WM of tie cuts at SYLMAR due to a derating of a line and about 70MW of additional exports to address losses with another BAA. The load forecast increased 846 MW, renewable forecast decreased 117 MW, and two resources were lagging or didn't start, resulting in a loss of over 450 MWs in comparison to HASP. Additionally, in the RTD market, the VER forecast increased by 430 MWs and the load conformance was 1,100 MW lower than it had been in FMM also leading to price divergences. EIM transfers helped address this loss by contributing 500 MW but weren't enough to cover the lost supply and demand increases.

Price divergence in March 1, 2019

On March 1, 2019, in hour ending 14, FMM interval 4, the prices at the scheduling point for the NOB intertie diverged across markets: IFM saw a price of about $151/MWh (with $113/MWh of marginal congestion), HASP had a price of $999/MWh , FMM had a price -$9.85/MWh (with -$67/MWh of marginal congestion) while RTD saw a price of -$20.5/MWh (-$113.78/MWh of marginal congestion). The daily price trend for NOB intertie is shown in Figure 131.

The main concern in this case is the large divergence of the HASP with respect to IFM, FMM and RTD markets which can be attributed to weather conditions, gas market dynamics, and transfer issues. An intense late-season polar cold blast led to large natural gas spot price increases on March 1, including a record-setting spike in the Pacific Northwest[28]. The high natural gas prices drove high energy prices for cities like Portland, OR and Seattle, WA. In the IFM, the NOB inter-tie had a zero MW limit in the export direction and 1,622 MW in the import direction. The constraint was binding in the export direction based on economical bids for both imports and exports at a shadow price of $151.68. For the HASP, the IFM awards are self-scheduled, implying a net zero MW flow

Figure 131: LMPs at the NOB scheduling point for March 1, 2019



. Additionally, there were self-schedule export bids for volumes greater than the economical bids in the import direction. Because the self-schedule could not be fully offset with the economical import bids, the export bids were curtailed. This leads to $1,000/MWh price based on a penalty price for constraint relaxation. In the HASP, the NOB intertie was binding at the shadow price of about $952/MWh which was set by the export bid. In this case, the HASP resolves the overscheduling and achieves feasibility for the tie limit. Once FMM and RTD ran and the cleared schedules from HASP were shown as tagged values, no congestion management was needed on NOB and the tie was no longer binding. Additionally, there was congestion from other constraints, such as the 30060_MIDWAY_500_24156 and VINCENT _500_BR_2 _3 lines, contributing to the marginal congestion component at NOB scheduling point.

[28] Source: https://www.naturalgasintel.com/articles/117595-sumas-hits-200-mark-as-natural-gas-spot-markets-soar-on-cold-blast-futures-tepid

Price divergence in June 19, 2017

On June 19, 2017, in hour ending 19, FMM interval 2, prices were about $116/MWh, $498/MWh, $1,984/MWh and $49/MWh in IFM, HASP, FMM and RTD, respectively.

Two main items explain the large divergence of the FMM prices. First, an additional requirement of 700 MW through load conformance compounded with an increase in load forecast with respect to the HASP while solar ramping down contributed to a tighter supply condition. Second, a solution for this particular market could not be improved further within the time the market had to run producing what seemed to be a suboptimal solution. This same market was rerun with more recent software version and the solution looks more optimal and prices reduced by about half of the original prices.

Price divergence in March 3, 2019

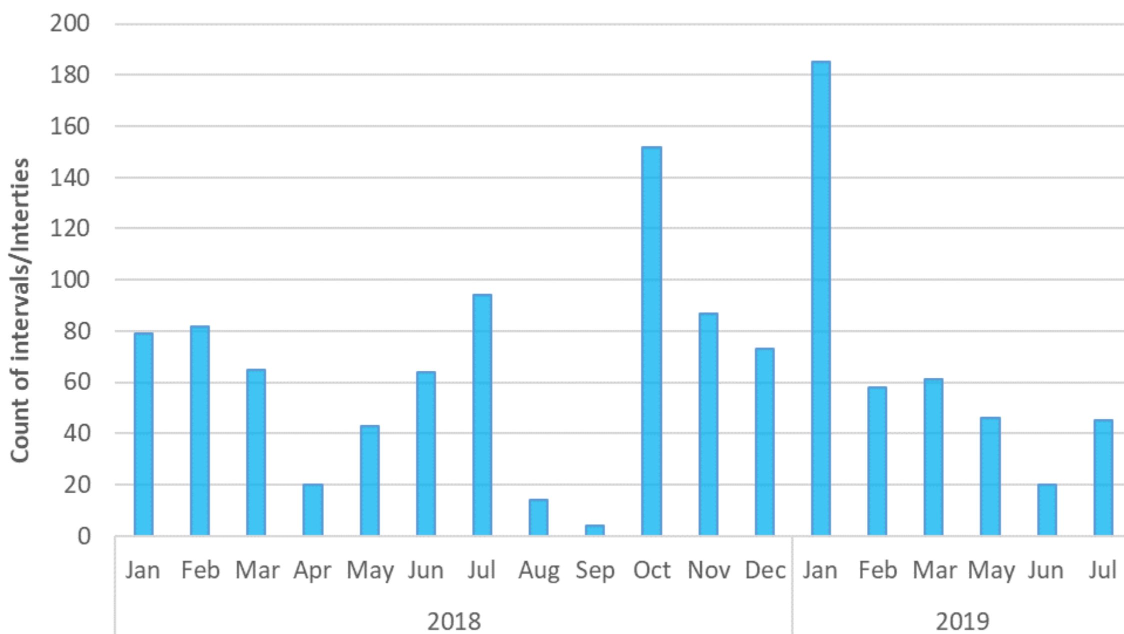
On March 3, 2019, in hour ending 17, FMM interval 1, the price at the Malin scheduling point (MALIN_ISL) diverged significantly in the HASP. In this interval, prices were $52/MWh, $1000/MWh, $10/MWh, and $14/MWh in the IFM, HASP, FMM and RTD markets, respectively.

When the DAM ran, two outages on MALIN_ISL limited the export capacity. These were the OMS 6081202-Roung Mountain Table mountain line outage and OMS 6081202-VACA Tesla series compensator outage, the latter of which limited the export direction on the tie to 1465 MW. When the DAM ran, these outages were expected to be completed by 9AM (or hour ending 10) and then the capacity would go up to 2450 MW. However, the outages did not return by that scheduled time. So in HASP for hour ending 17, the export operating transfer capacity (OTC) limit was 1463 MWs. In the CAISO markets, there is functionality to protect for Existing Transmission Contracts (ETCs) and Transmission Operating Reservations (TORs) contracts. These contracts are most often 75-minute contracts meaning that they can be used up till 75 minute before the hour. If the contracts are not used prior to that time, the capacity must be reserved. Effectively that capacity is not available to the markets to be optimized. This results in an Available Transfer Capacity calculation for un-used ETCs or TORs prior to the contract expiration. T-75 contracts are still considered in the HASP. Because of this, the ATC in the HASP run was much less than OTC capacity to reserve the capacity un-used ETCs and TORs. Because of this ATC being much lower than the DA ATC, DA export schedules had to be cut in the HASP resulting in the high price in HASP. Due to the cuts in HASP making flows feasible but also with the release of the ETC and TOR contracts capacity into FMM, this constraint was no longer binding and FMM prices were within reasonable economical range.

Congestion divergence between HASP and FMM

Analyzing more broadly the instances when the price signal for congestion between HASP and FMM diverges at the different interties of the CAISO system, there were over 1000 instances for FMM intervals across the different CAISO interties that may exhibit the divergence for congestion pricing at intertie; the monthly count is depicted in Figure 132. This metric illustrate potential cases when congestion is managed in HASP such that when FMM comes in there is no more congestion to manage; this the congestion price signal in FMM no longer exist.

Figure 132: Frequency of congestion divergence at interties between HASP and FMM

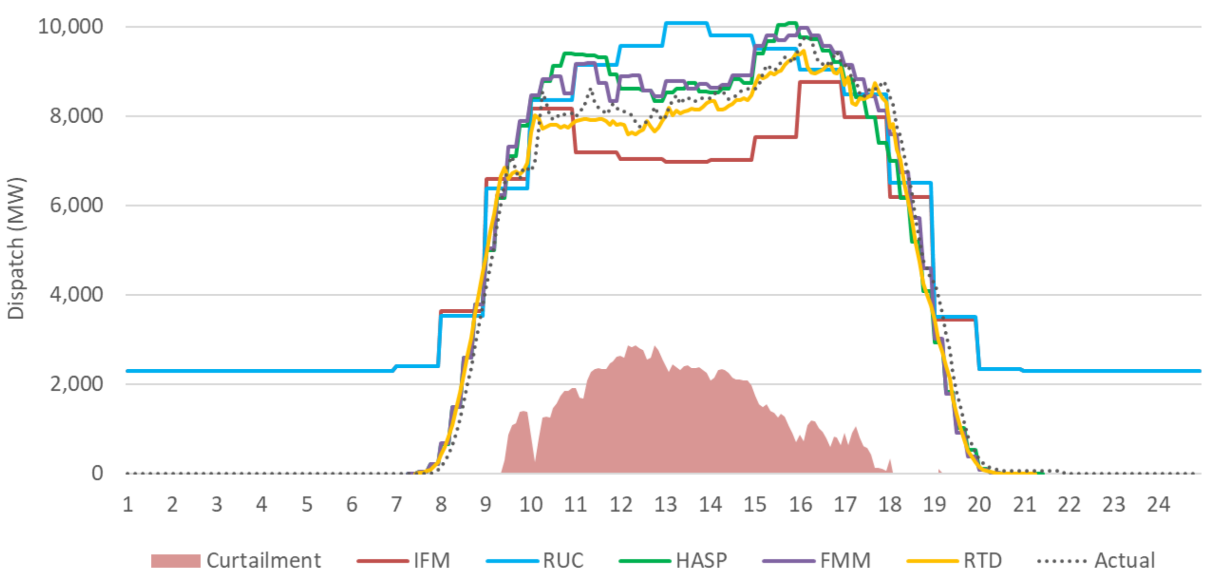


Scheduling of VER resources in IFM

Currently, VER resources can participate in IFM with same flexibility as conventional resources. They may use a self-schedule or an economical bid. When it comes to the real-time market, their bids are capped by the CAISO forecast even if they have economical bids. RUC uses similar logic. However, in IFM VER resources are not limited in their bids by the CAISO forecast since this is a financial market. Historically, because VER resources have under-scheduled in IFM, the CAISO developed a logic to true up VER bids up to the forecast level in the RUC process so that RUC can better determine the supply needs for the real-time market. If this true up is not implemented, RUC will fail to consider additional VER capacity that is forecasted to be available in the real-time and may over-schedule resources in RUC.

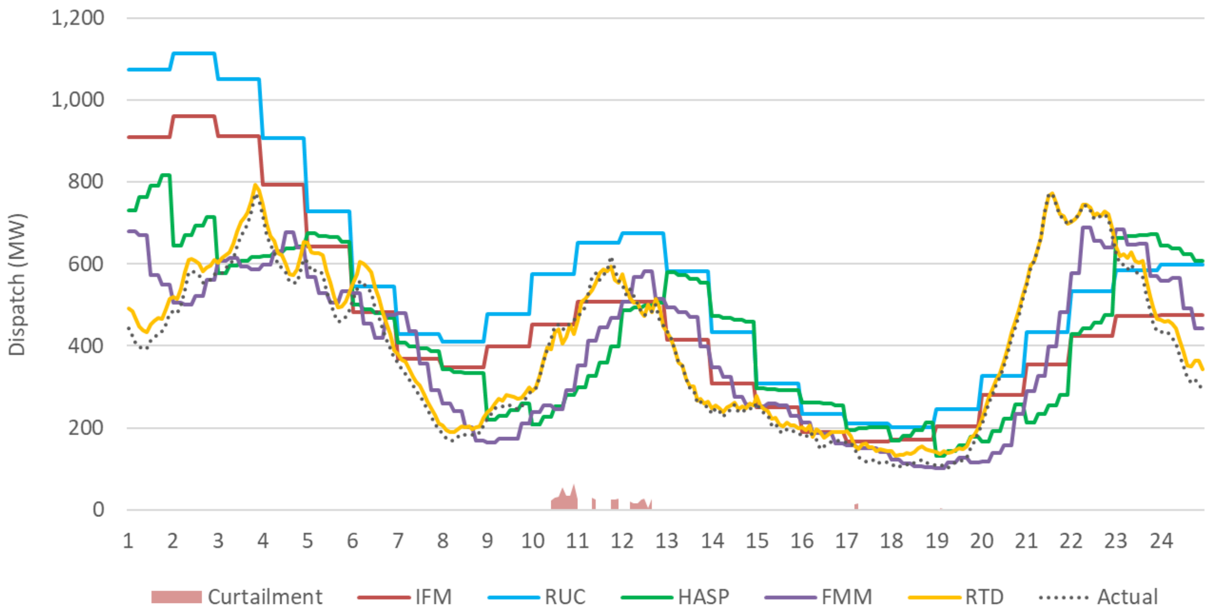
The CAISO expects that under-scheduling of VER resources in IFM can be offset with virtual bids. Through this analysis effort, the CAISO found that some VER resources are actually over-scheduling in IFM. This is more visible for solar resources bidding up to their maximum capacity in hours with no sunlight, such as in the first six hours of the day and the last four hours of the day, clear times when conventional solar resources cannot produce.

Figure 133: Solar production profile for March 31, 2019



For instance, consider the VER bidding and dispatches for March 31, 2019 represented in Figure 133 and Figure 134. The solar profile has a flat line of about 2300 MW for the first six hours of the day and the last four hours of the day. This is driven by about three dozen resources bidding up to their maximum capacity. Since these resources will not be able to produce at this level in the real-time market, this volume will be liquidated in RTM at real-time prices. Effectively, these VER bids are acting like virtual bids without being virtual bids and without the settlements implications for virtual bids. For reporting purposes, this bidding also blurs the tracking of VER scheduling as it does not reflect forecasting or actual production conditions.

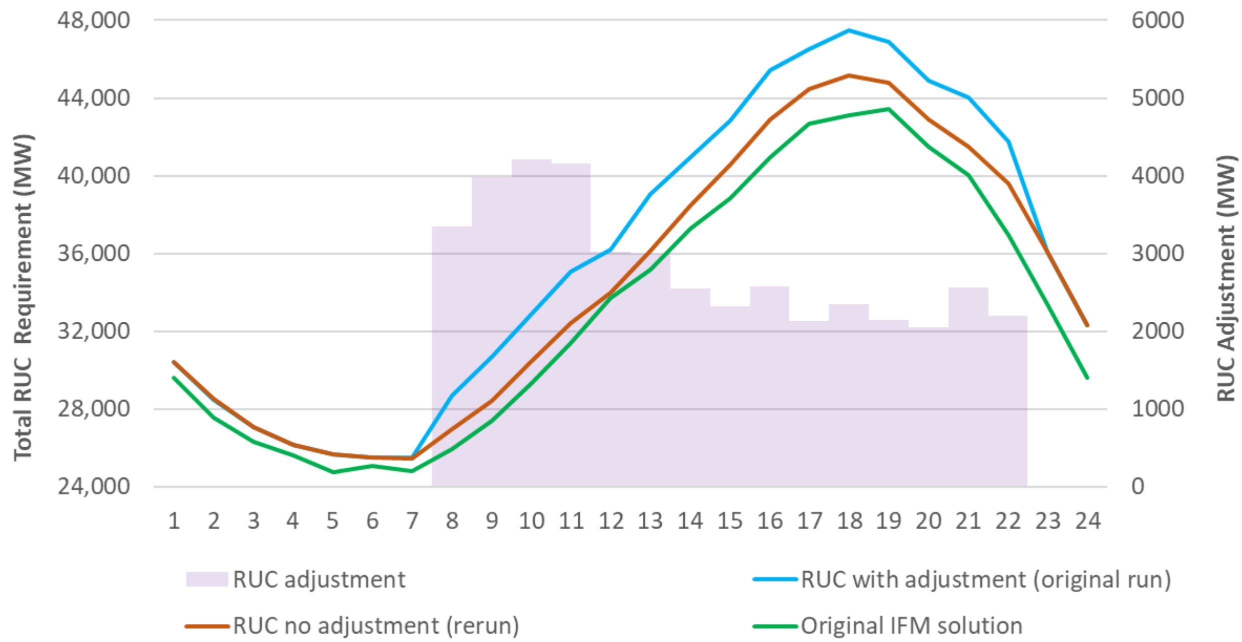
Figure 134: Wind production profile for March 31, 2019



RUC adjustment for DAM of July 8, 2018.

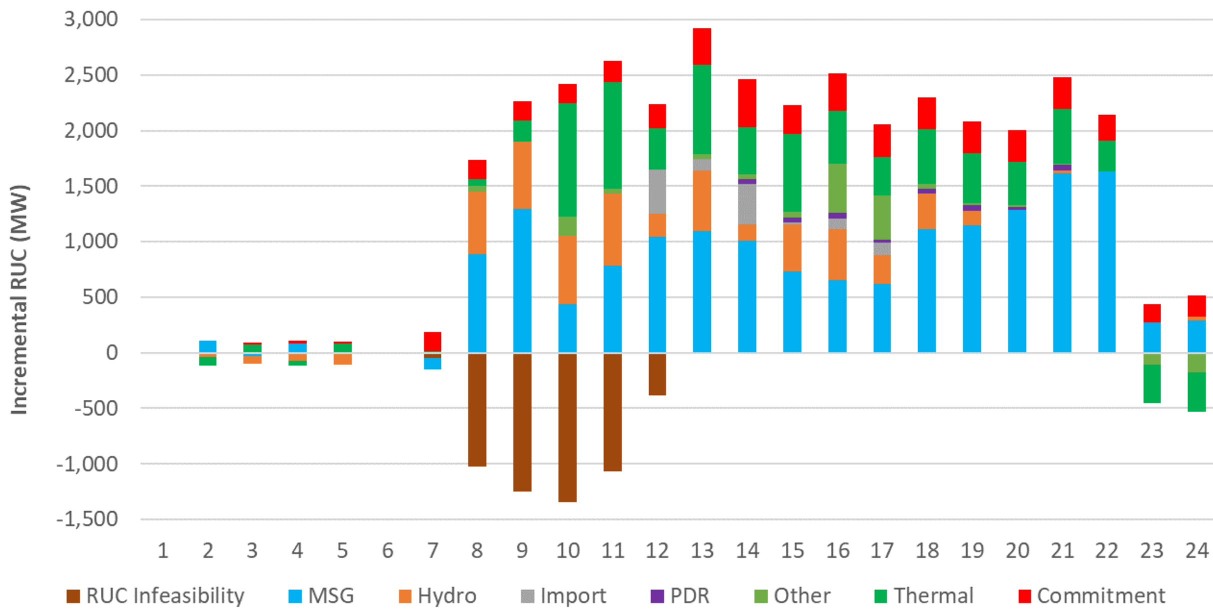
As described in previous sections, based on projected conditions operators may adjust the RUC forecast to ensure the proper capacity is positioned for RTM. During the month of July 2018, RUC adjustment were significant. However, these adjustments to the load forecast do not necessary have a straightforward impact on what resources will be committed for the real-time market. If 1,000 MW of additional adjustment is imposed on RUC, it does not mean the market will commit an additional 1,000 MW of generation relative to the IFM solution. For a more detailed analysis, July 8, 2018 was chosen because this was the day in which the largest adjustment to the RUC forecast was applied (in the order of 4,250 MW in hour ending 8). These adjustments effectively increased the overall RUC requirement that the market takes as the reference to clear against supply. Figure 135 shows the profile of the RUC adjustment and the RUC requirement with and without the adjustments, and compares it with the reference of what IFM cleared. The original case that included the RUC adjustment was modified to take out such an adjustment and then this modified DAM was rerun in order to compare the original solution with the adjustment versus the solution obtained after removing the RUC adjustment. This comparison can help quantify the impact of the RUC adjustment on the original market solution.

Figure 135: Demand requirements in the DAM of July 8, 2018



The additional requirement imposed by the adjustment increases the need for additional capacity to be cleared in RUC. Figure 136 shows the additional capacity cleared by having the additional RUC requirement.

Figure 136: Incremental RUC capacity due to operator adjustment

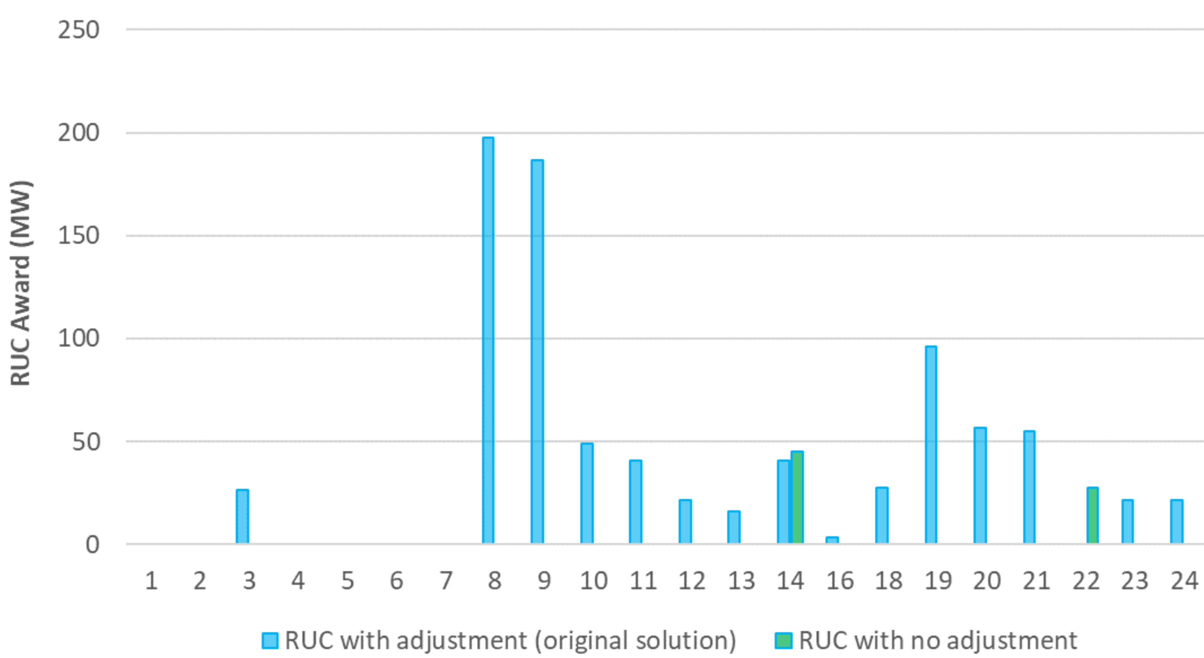


This capacity is organized by the type of dispatch and the type of resource procuring for the additional requirement. First, in the early hours of the day when the additional requirements reached 4,250 MW, the market run was actually infeasible to meet such capacity. The bars in brown show the amount of capacity from the RUC adjustment that could not be procured in RUC, which reached about -1,400 MW.

This capacity was not procured because the power balance constraint was relaxed instead. From the capacity that was actually procured to meet the RUC adjustment, over 80 percent was achieved by incrementally dispatching resources already committed. Such capacity has no direct impact on the pool of resources that are made available to RTM since it does not involve additional commitment instructions. The majority of such incremental capacity was procured by dispatching up MSG units and other non-MSG thermal resources, as well as some imports and proxy demand resources.

For the resources that were committed due to the extra RUC requirement, only two resources, amounting to less than 200 MW, had a RUC binding commitment. This status refers to the condition in which the resource commitment is defined in the DAM since the RTM cannot re-optimize its commitment. Thus the start-up instruction from RUC is binding and will lead to the resource to be online for the real-time market. Finally, for resources dispatched incrementally due to the additional RUC adjustment, a certain level of that dispatch will be naturally covered by resource adequacy capacity and will have no associated costs in the RUC market. The capacity above the RA level is identified as *RUC awards* and will be have associated payments based on RUC prices. Figure 137 compares the RUC awards between the rerun market with no adjustments and the original RUC awards due to the additional RUC adjustments; relatively speaking these were modest RUC awards given the level of the adjustments. For instance, in hour ending 8 when the net requirements adjustments were over 2,500MW, the RUC awards were less than 200MW.

Figure 137: Comparison of RUC awards for July 8, 2018



Exceptional dispatches on July 22, 2018.

Trade Date July 22, 2018 was selected for this simulation because the largest volume of Exceptional Dispatches (EDs) were observed in the real-time market for the period of analysis. There were about eight units that were required to be online, which had not been committed originally in the day-ahead market. Out of these, about 5 units were online for the time interval selected for this simulation. These EDs made up approximately 1,200MW of additional generation than the market originally had.

The purpose of the simulation is to estimate, in a counterfactual mode, the market solution if these EDs were not in the market. This would effectively deprive the market from the supply provided by these units and would require the economics of the market to compensate for that missing supply, with the corresponding market price reflecting the new tighter supply condition[29].

The original system marginal energy price for hour ending 19, FMM interval 1 was $38.97/MWh. This price reflected the contribution of the units that had been exceptionally dispatched. In the simulation, these units are not available to the market with the assumption that if these units were not exceptionally dispatched, the real-time market could not have economically committed them[30]. When the market simulation is run without these units, there is effectively 1,400 MW (1200MW of ED plus 200MW of incremental energy above ED levels) of generation that is lost in that FMM interval, which represents supply that now has to be made up by other supply resources through market economics. In this simulated

[29] Re-running original markets to produce counter-factual outcomes need to be taken with certain cautions. For simulations of the DAM, rerunning the original market under certain changes, like disregarding RUC adjustments, may provide a very accurate representation of a counterfactual outcome. This is because the DAM is self-contained and optimized in a discrete and isolated fashion. The solution of one DAM run does not depend strongly on the solution of the previous day. However, this is not the same for the real-time market. The real-time market is inherently sequential, in which a current market interval depends strongly on the market solution of previous interval. For instance, for the market to determine the optimal dispatch of resources in the current interval, it needs to rely on the most recent dispatch operating point as derived from telemetry. In turn, that operating point from telemetry was derived by the unit following a market dispatch in previous intervals. So, each market interval cannot be analyzed in total isolation. If a market solution leads to a certain dispatch of units, the dispatch trajectory of these units will be built upon previous dispatches. If one single interval is analyzed in isolation and a counter-factual dispatch is produced in a simulation, it will fail to capture this dynamics of these sequential dispatches. Currently, the CAISO has no means to produce a counter-factual dispatch that can fully simulate the alternate dispatch over time when certain inputs or conditions are adjusted. It can only rerun a counter-factual market simulation for one interval at a time. Therefore, simulations of real-time markets need to be considered with certain level of caution as these results will not fully reflect the dynamics of the real-time market.

[30] This is the most stringent assumption for the simulation which considers the units are not commit-able for this interval. Since an ED committed these units online, it is reasonable to expect that, with other conditions fixed, the units would have not been committed through economics in earlier hours in the RTM. For some units with long startup times, the horizon of RTM would not allow for the optimal commitment of these units even if they were economical to start; only the DAM would be able to commit them.

case, the SMEC in this FMM interval increases to $57.63/MWh. Furthermore, when comparing this simulation that neglects EDs against the day-ahead solution, FMM had about 1,400MW of EIM transfers making up the supply to meet the demand. Additionally, FMM had about 700 MW of additional VER contributions.

Exceptional dispatches on August 6, 2018.

The second study case examining EDs looks at August 6, 2018, a day with the second largest volume of EDs. The original system marginal energy price at hour ending 8, FMM interval 4 was $24.62/MWh. There were about five exceptionally dispatched units that amounted to about 400 MW of ED energy. In the simulated case where the exceptionally dispatched units are made unavailable in FMM, about 250 MW of supply is lost; this represents capacity that the market now has to procure through market economics using existing available supply. The loss of supply is essentially supplemented by incrementally dispatching several units that were already online. In this case, the system marginal energy component increases modestly to $28.62/MWh. In both cases, original and rerun, EIM transfers provided additional supply to the CAISO of about 460 MW. In this scenario, the IFM price for this hour was $45.79/MWh.

Exceptional dispatches on September 2, 2017.

The third study case regarding EDs again examines August 6, 2018, which was one of the days with the highest load observed in the year. This case study inspects hour ending 18, interval 10 for the RTD market. The SMEC in the original production case is $210.87/MWh, and climbs modestly to $223.81/MWh upon rerun, which is still a relatively reasonable reference for this study. In a second rerun, the resources that were exceptionally dispatched for system ramping (load pull) conditions are discarded; the capacity lost by ignoring these EDs is over 890 MW. The second rerun produce a system price of $999.22/MWh with a power balance constraint infeasibility of more than 400 MW. These results indicate that there was not sufficient supply in this market run to meet the forecasted load.

System challenges on June 10-12, 2019

Monday, June 10, 2019 posed several challenges for CAISO grid operators. It was the first day of the heat wave that California experienced in June 2019. Figure 138 shows the CAISO demand trend for June 10, 2019 and preceding days. The load peak exceeded 40,000 MW on June 10, representing an increase of about 6,000 MW from previous day’s load peak.

Figure 138: Load profile for sample days of June 2019

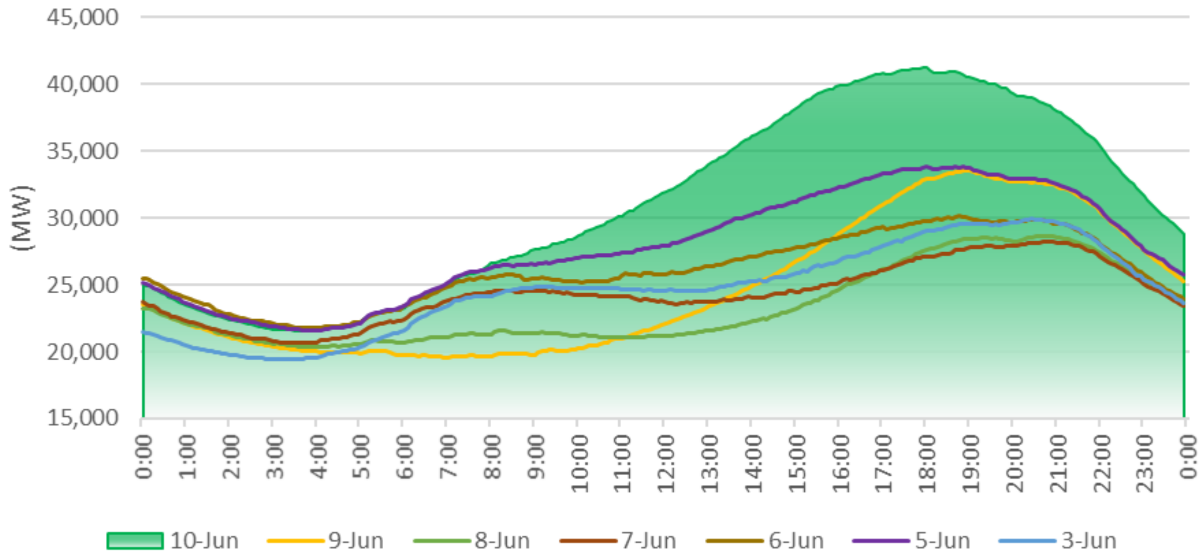
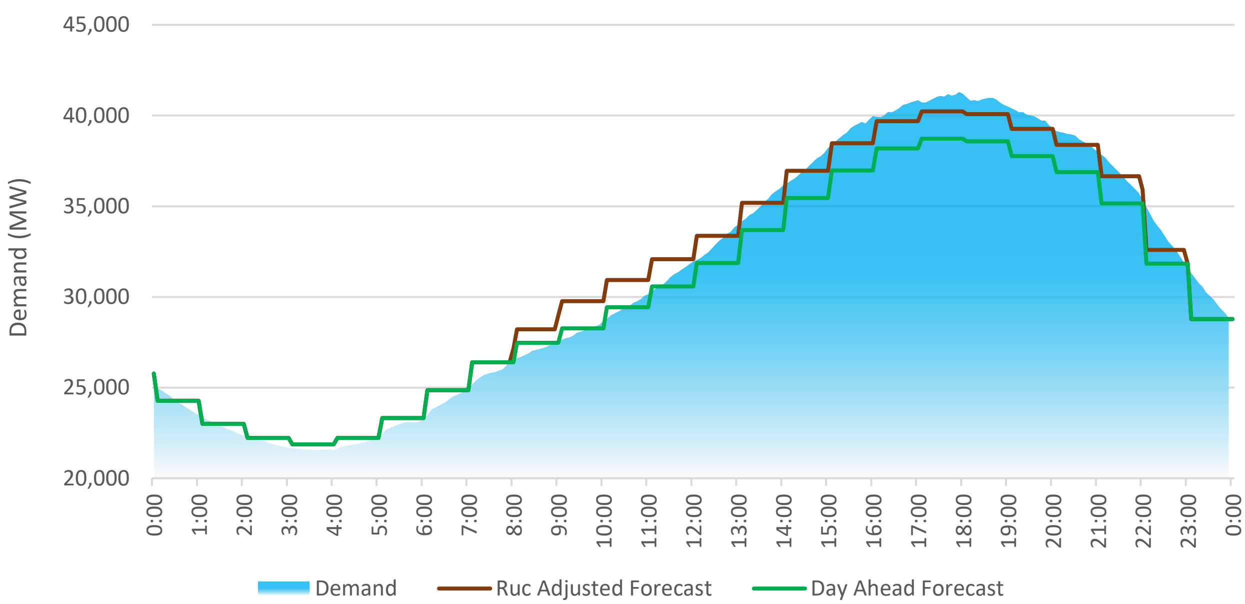


Figure 139 compares the five-minute demand with the original day-ahead forecast and the adjusted day-ahead forecast for June 10.

Figure 139: Load forecast for June 10, 2019



One challenge to grid operators was that the real-time load came in about 2,500 MW above the day-ahead load forecast[31]. There was a RUC adjustment made to increase the demand that RUC used to clear during its run, but it was still below the real-time demand. This instance represents the challenge that

[31] The load forecast error experienced on June 10th, 2019 was due to a temperature error in both Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) coastal areas.

additional capacity needed to be dispatched in the real-time market to meet the increasing levels of demand. Figure 140 shows the System Marginal Energy Component for the fifteen-minute market and the real-time market with specific emphasis on price excursion that occurred at 5:15 PM on June 10, 2019. At this time, VER generation sharply declined, as shown in Figure 141.

Figure 140: System Marginal Energy Component for June 10, 2019

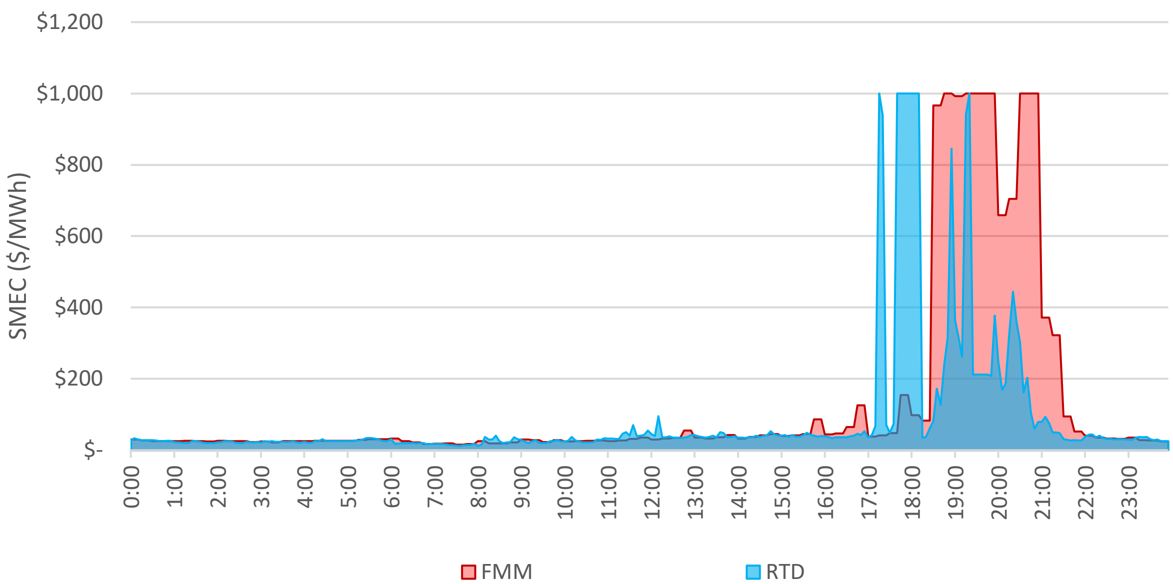
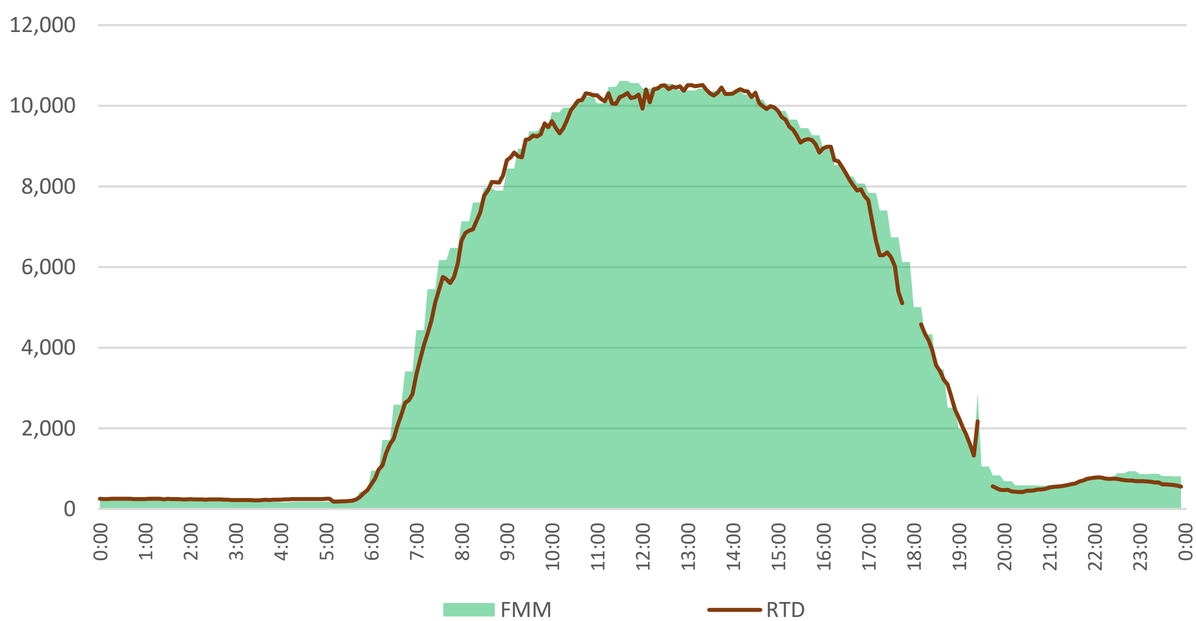


Figure 141: VER schedules and dispatches for June 10, 2019

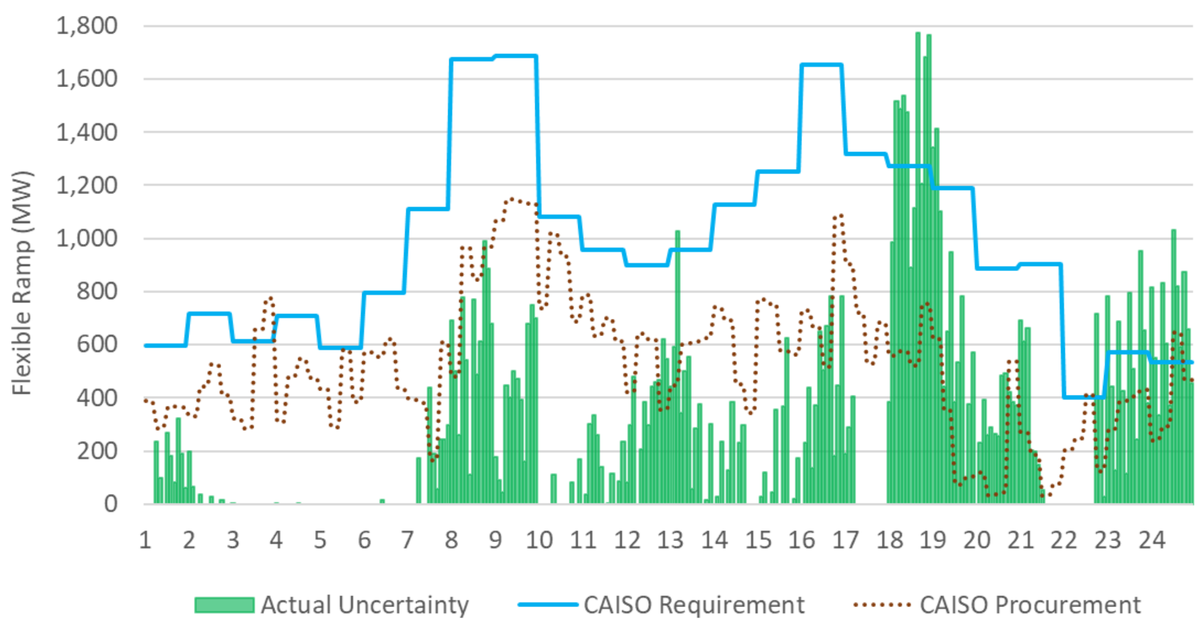


There was a sharp decline in VER generation around 5:00 PM: VER output dropped from 7,657 MW at 5:00 PM to 6,295 MW at 5:15 PM, resulting in a loss of 1,362 MW within fifteen minutes. The total RTD VER output was 1,106 MW below the FMM awards.

In order to meet the uncertainty resulting from the sharp decline in VER output, 1,283 MW of upward Flexible ramp capacity was procured in FMM. Since all EIM entities had passed the flex ramp test, the total procurement in this period was based on the EIM area requirement, which is met based on the optimal decision to procure FRP across all the BAAs. About 430 MW of the Flexible ramp capacity that was procured from Northwest entities could not be delivered because of EIM transfer congestion. The real-time spikes driven by the change in load and VER output could not be absorbed by the flexible ramp capacity that was procured because of two factors: first, the level of flexible ramp requirement was lower than the actual flexible capacity needed by the system and second, the flexible capacity that was procured could not be delivered.

Figure 142 shows a comparison between the FRP requirements for June 10 in FMM and the actual uncertainty that realized for FMM, and compares these against the flexible ramp capacity that was procured and utilized. For the hours of the net load peak, the actual uncertainty exceeded the FRP requirements[32], which could lead to having insufficient flexible ramp capacity even if the ramp capacity could have been fully utilized.

Figure 142: FRP needs and requirements observed on June 10, 2019



[32] The FRP requirements are estimated based on a sample of historical uncertainty for FMM, which is derived as the difference of net loads between the advisory FMM intervals and the binding RTD interval. Using historical data to calculate FRP requirements is subject to some limitations. First, the requirements are based on a given FRP percentile which, unless it is the 100th percentile, may not cover all instances of historical uncertainties. Currently, the calculation relies on a 97.5th percentile for upward requirements. Second, in order to have a more robust data sample, the calculation uses the last 40 days of historical data. Due to the length of this historical period, there is a risk that the profile of uncertainties may change significantly during the horizon and thus, the requirement for a given day may not be closely representative of requirements from the last 40 days. This could have the effect of lagging the requirements when the uncertainty realizes in a given day. The CAISO is currently exploring alternatives to estimate FRP requirements that could account for the more dynamic nature of the load and VER production.

Figure 143 shows the evolution of the load forecast thought the day on June 10, 2019. The load forecast is generated for every FMM and RTD market run and is updated continuously. A load forecast generated at 7:30 AM will additionally have a projection of the load forecast for future hours. In the real-time market, the load forecast is used to clear the markets for a forward horizon of up to 4.5 hours. This horizon allows the market to position resources as needed based on the projected conditions, including load forecast. When FMM observes the projected load, it can determine unit commitments to properly make resources available for the required intervals. A higher forecast will potentially lead to unnecessary commitments whereas a lower load forecast may deprive the market of the opportunity to commit more resources. This load forecast also has implications for the procurement of intertie resources. The profile of load forecast for June 10 shows that, as the day progressed and weather conditions became less uncertain, the load forecast for a target time of 5:00 PM gradually increased. Figure 144 shows the specific changes in the load forecast for the target time of 5:00 PM. Early in the morning on June 10, the load forecast for 5:00 PM was about 37,000 MW. That forecast remained relatively stable for several hours in the morning, but then by 1:00 PM the load forecast began to quickly increase due to temperatures climbing higher than forecasted. By the time the load forecast was generated for the binding interval covering 5:00 PM, the forecast was about 2,500 MW higher than it was in the early morning.

Figure 143: Evolution of load forecast towards the daily peak

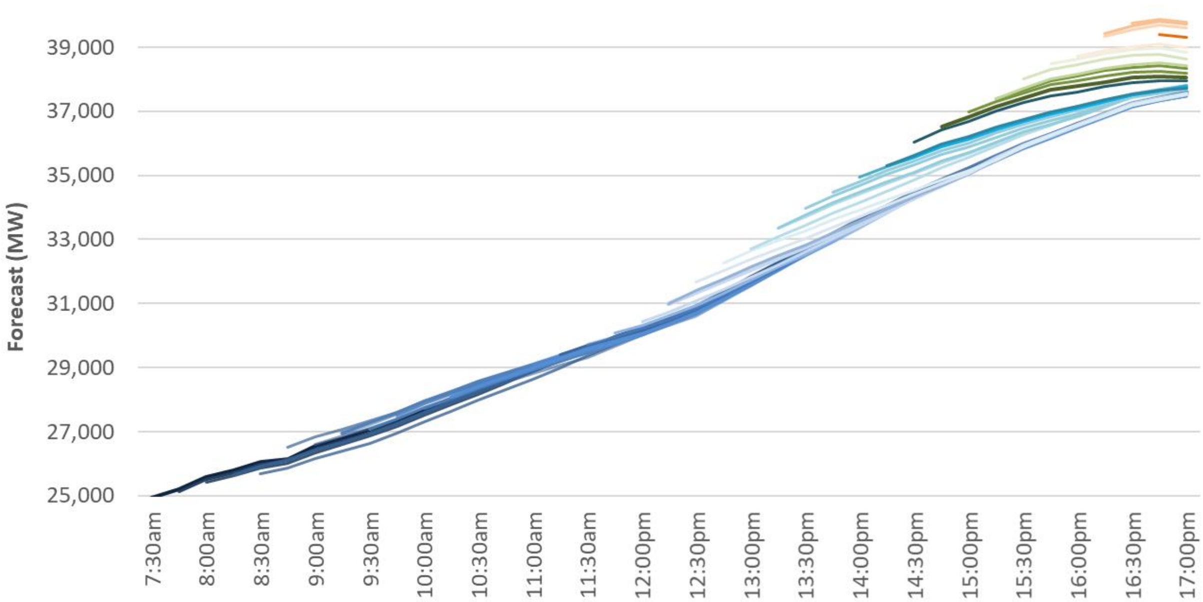


Figure 144: Evolution of load forecast at 5:00 PM on June 10

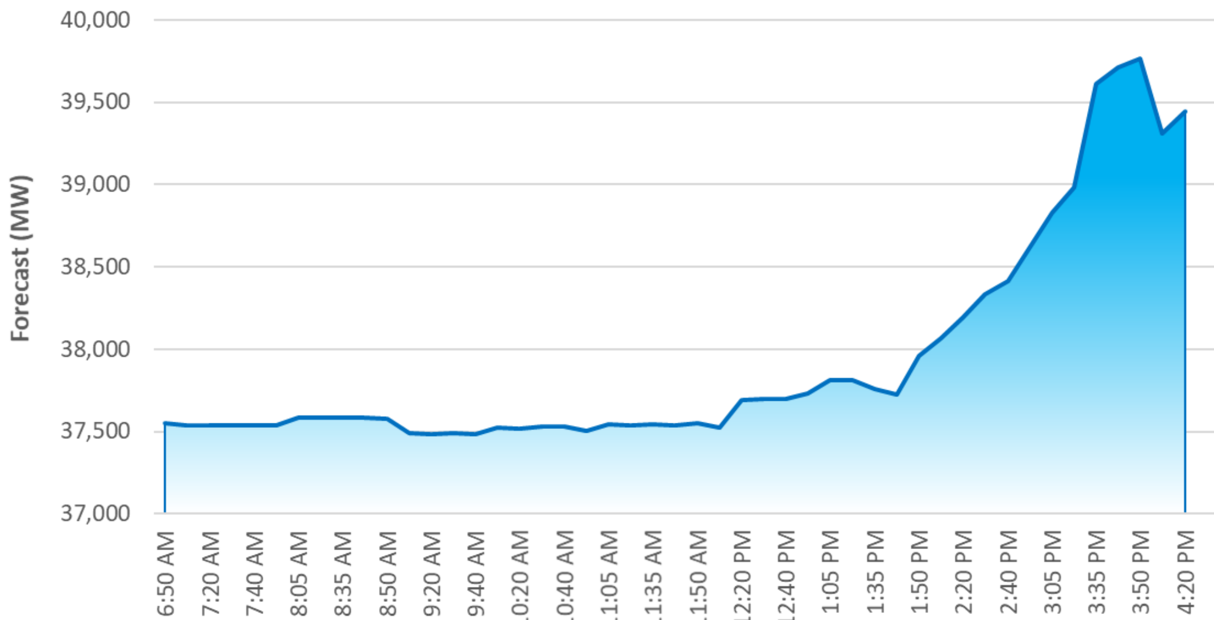
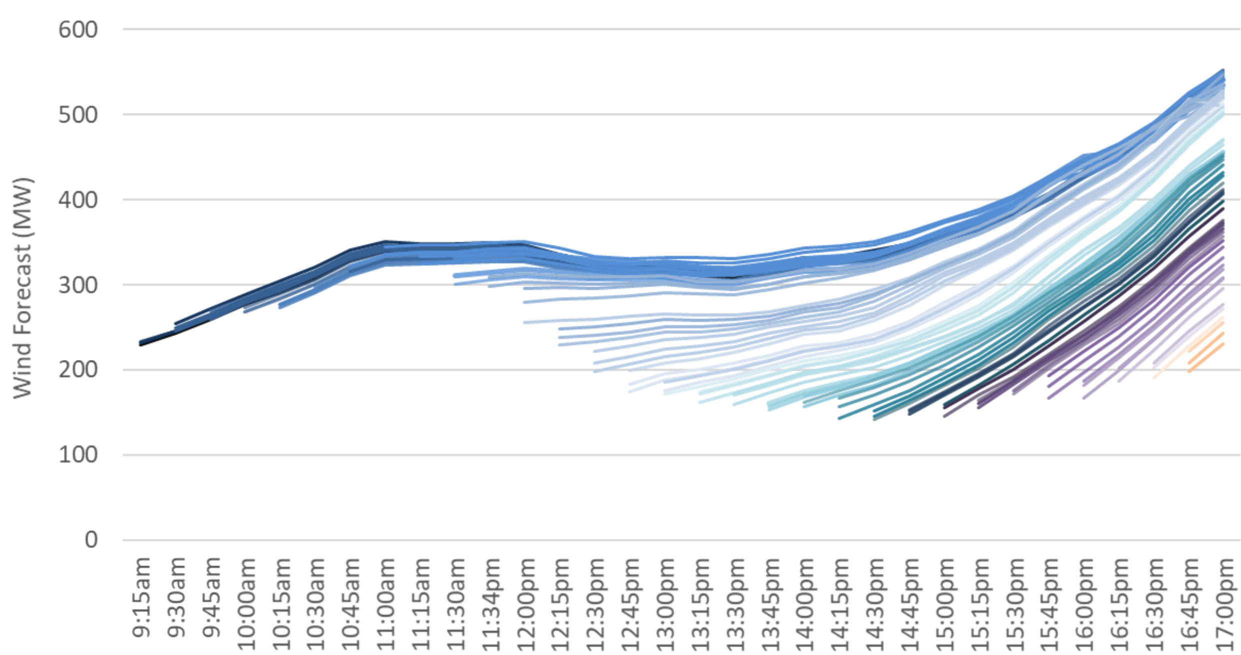


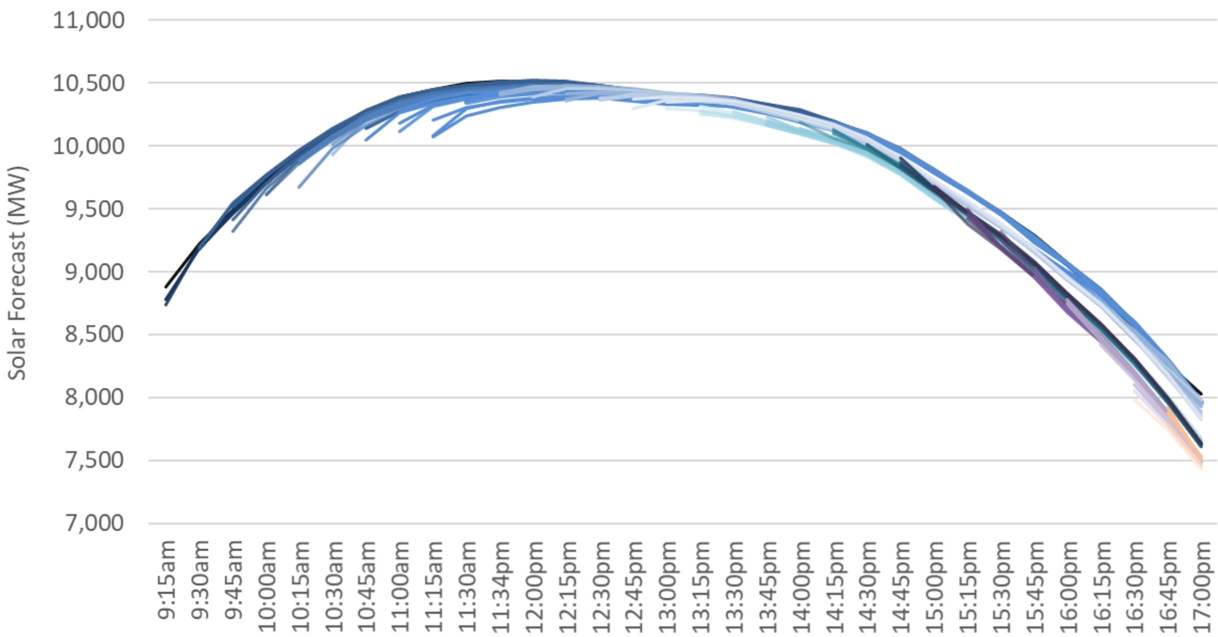
Figure 146 and Figure 145 show similar profiles of the forecast for solar and wind resources. Both show similar evolution, however as the day progressed, the ultimate forecast came in lower.

Figure 145: Evolution of wind forecast towards the daily load peak



When the increasing load forecast is compounded with the lower VER forecast, the system is faced with a much higher net load that it must meet with conventional resources, naturally putting upward pressure on the bid stack and resulting in higher real-time prices.

Figure 146: Evolution of solar forecast towards the daily load peak

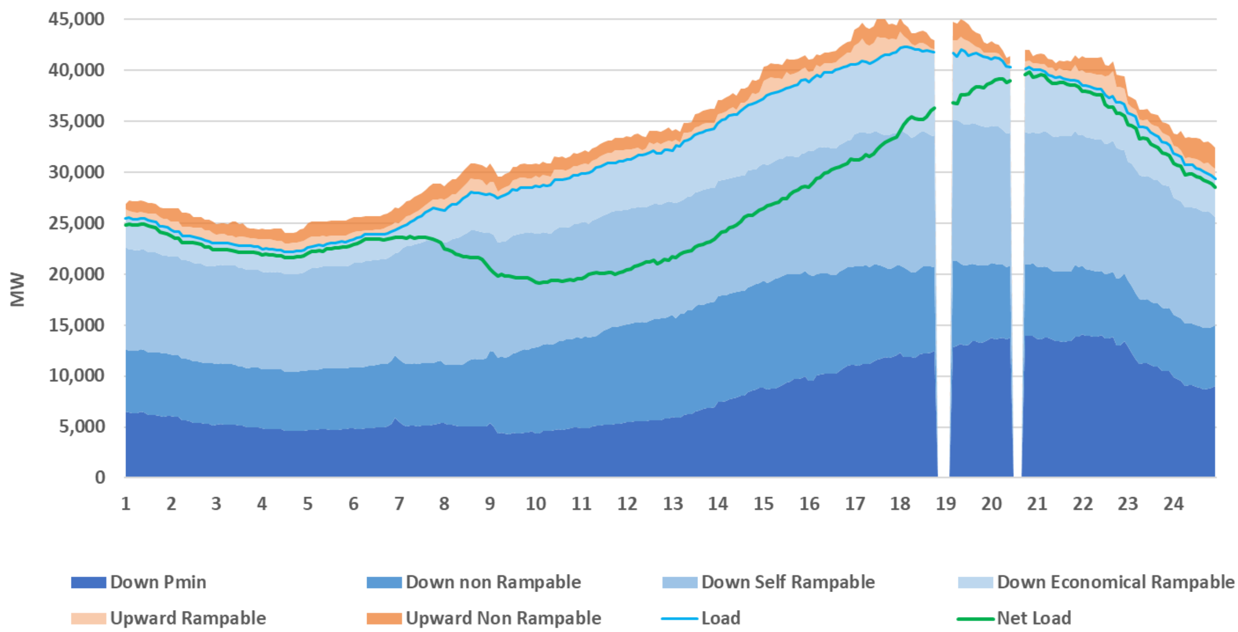


If these variations continue to occur over time, the market may not be able to adequately position resources to account for the dual increase of load and reduction of VER production.

Figure 147 shows a rough approximation of the ramp capability that the RTD market had for June 10[33]. The areas in blue represent flexible ramp downward capacity while the areas in orange represent upward ramp capability. The ramp capabilities are organized by capacity that is readily ramp-able within five minutes and that RTD can use to meet imbalances; the other group is for upward capacity that is available but cannot be accessed within five minutes simply because, in each RTD market, only the ramp capacity that can be deployed in 5 minutes is considered readily available. For downward ramp capacity, the figure also shows ramp groups that can be accessed if either the market curtails self-schedules or if resources are shutdown (Down Self Ramp-able and Down PMin). For June 10, the ramp-able upward capacity around both the gross load peak and the net load peak times was basically exhausted; when this happens, the market will relax the power balance constraint which will result in under-supply infeasibilities with penalty prices of $1,000/MWh. Prices near $1,000/MWh can also result from the market clearing the most expensive bids in the system without reaching the power balance infeasibilities.

[33] Given some data nuances, this metric may properly consider all upward or downward ramp capacity, but the breakdowns between whether the capacity is accessible or not within five minutes may tend to assign potentially more capacity to the ramp-able group.

Figure 147: Ramp capability in the RTD market for June 10, 2019



The missing data around the peak times in the figure above are due to contingencies run in the market.

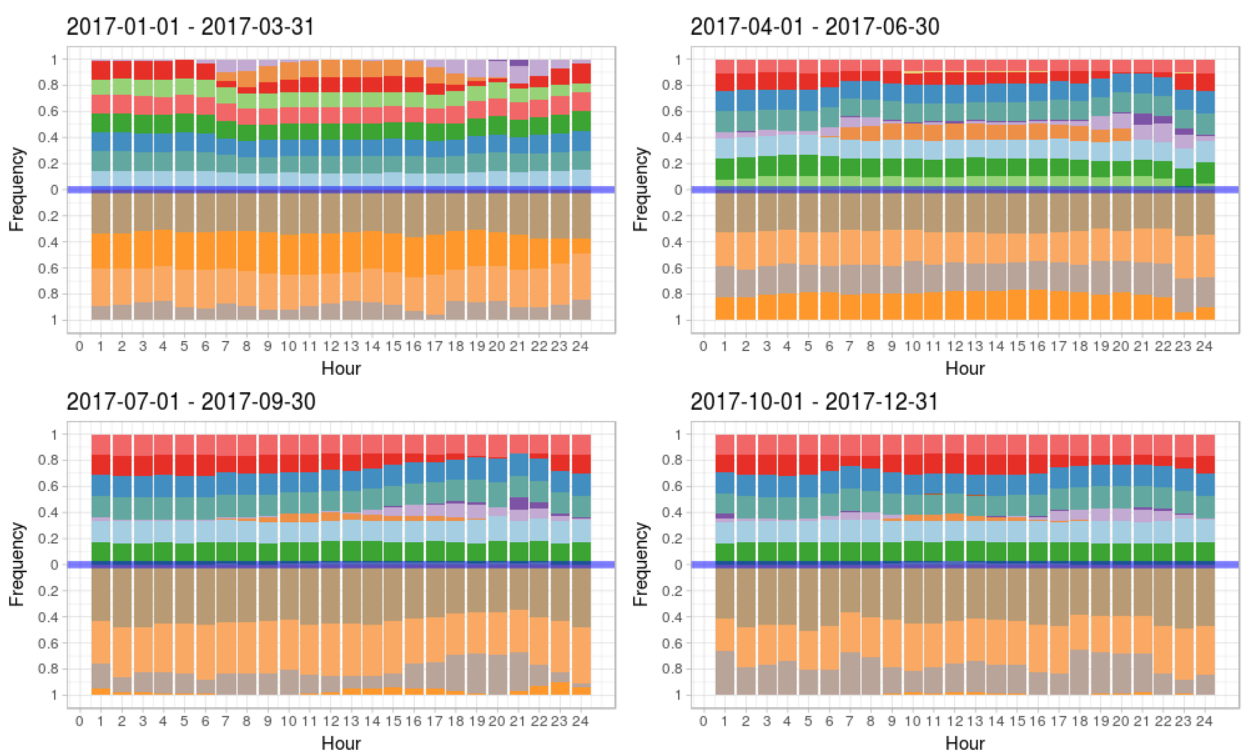
Impact of load conformance

Following the analysis from the previous section, consider the case of June 10, 2019 hour ending 19 FMM interval 4. The FMM price reached $1000/MWh. The load conformance was 2000MW and the FMM was power balance infeasible by 895 MW. In this study case, the FMM market is rerun without the load conformance. This effectively reduces the load requirements in this interval by the amount of conformance and set the market to clear based on the expected load forecast. The rerun results show that the system prices drops to $119/MWh, while the market no longer experience any undersupply infeasibility. With 2000MW of less load required to meet, the market reduces schedules from internal resources by about 882 MW while EIM transfers are reduced by 51 MW. In terms of generation changes, about 167MW are no longer dispatch from PDR and 680 MW are reduced from thermal resources. SO of the resources are the ones with the highest energy bids.

Marginal Units

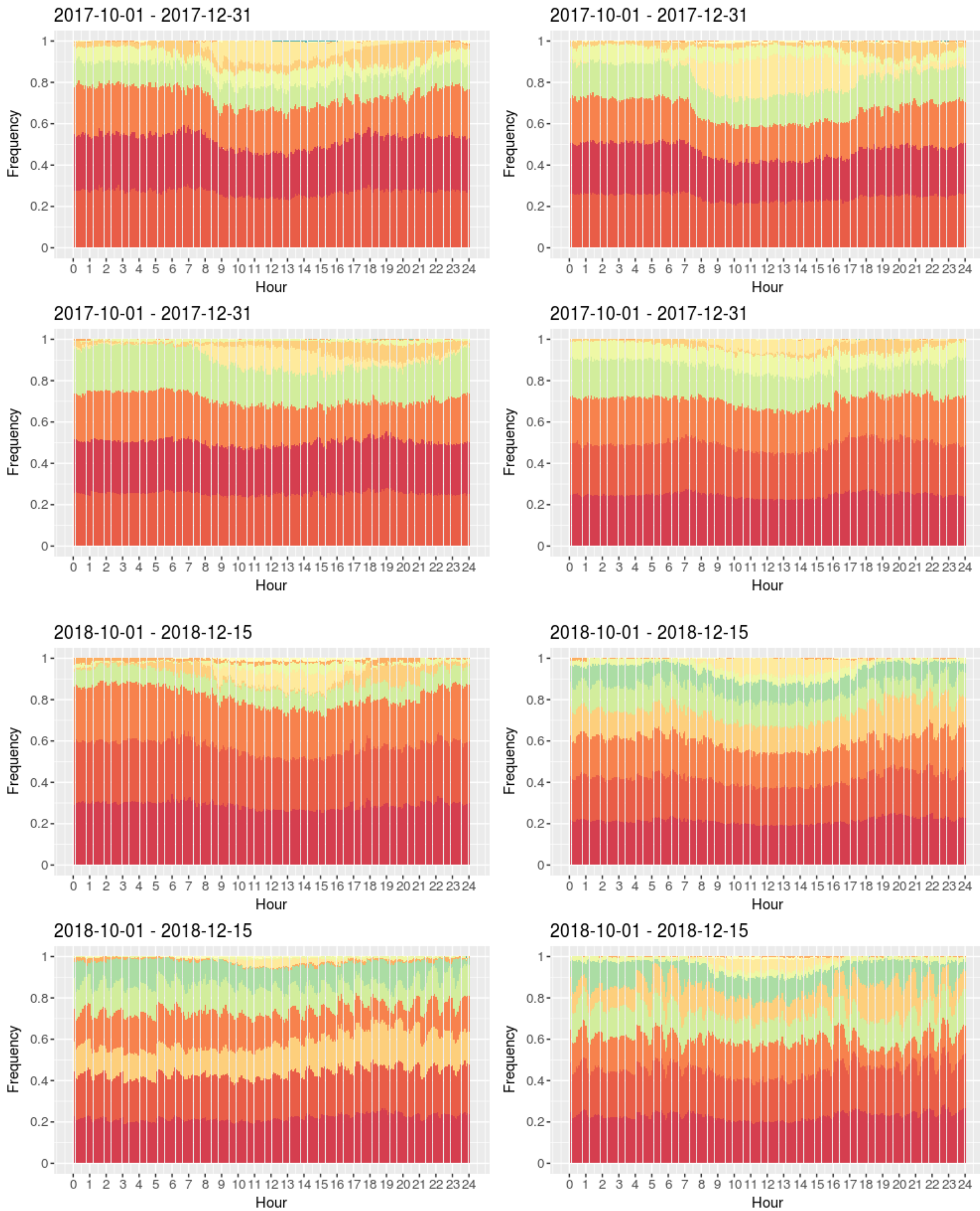
As part of the analysis of price performance, a typical concern is about marginality; *i.e.*, what resources are setting the price. In a given market interval, it is common to have more than one resource being marginal due to all the constraints that may be binding in the market and also by the way bids are constructed in step-wise format in the CAISO markets. Generally, resources will be cleared at the breaking point between two segments and thus the standard concept of marginality where the bid equals the clearing price may not capture all conditions of marginality. All type of resources in the CAISO markets can set the prices. In particular, in the IFM, both supply and demand will be marginal, since demand can participate with bids. In the RTMs, only supply will define marginal resources, since demand is inelastic and defined by the load forecast. In IFM and HASP, however, exports which are equivalent to demand may set the prices as well. Figure 148 and Figure 149 below shows the frequency of marginal resources organized by the type of resources for DAM and RTM. This is presented in an hourly profile for each quarter from January 2017 through March 2019. Each plot has both sides of the power balance, showing the type of resources being marginal in the supply and also on the demand sides.

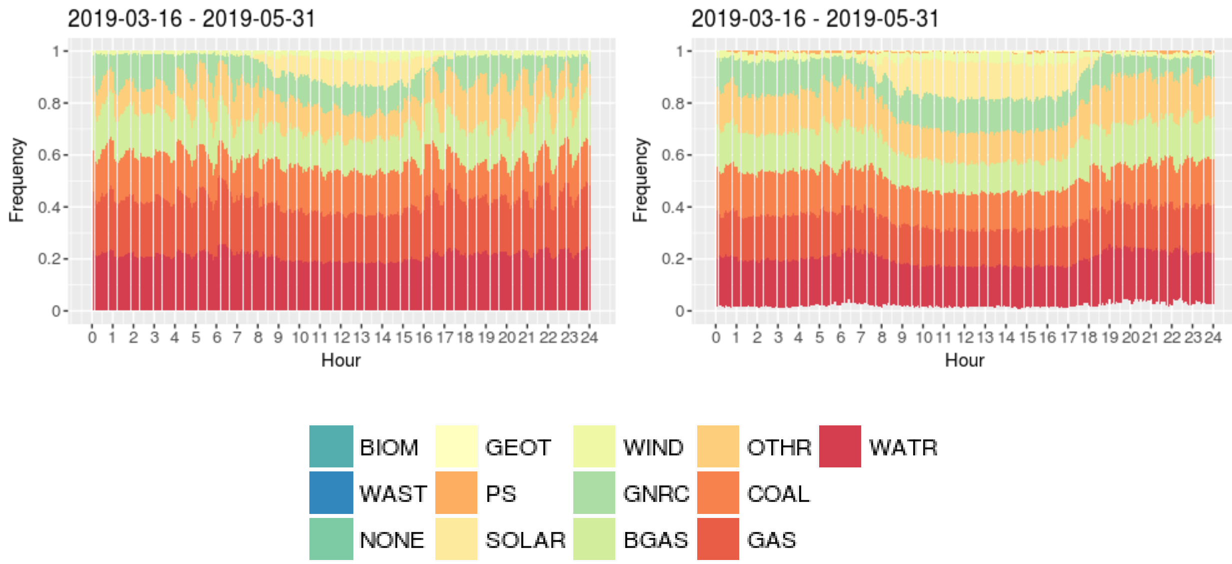
Figure 148: Marginal resources in the DAM by type of technology




2018-01-01 - 2018-03-31
2018-04-01 - 2018-06-30
2018-07-01 - 2018-09-30
2018-10-01 - 2018-12-31
2019-01-01 - 2019-03-31
2019-04-01 - 2019-05-31
Frequency
Hour
LESR
GEOT
COAL
WATR
E
BIOM
BGAS
I
NL
OTHR
WIND
GAS
VL
PS
SOLAR
VG

Figure 149: Marginal resources in the real-time market by type of technology




2019-03-16 - 2019-05-31
Frequency
Hour
2019-03-16 - 2019-05-31
Frequency
Hour
BIOM
WAST
NONE
GEOT
PS
SOLAR
WIND
GNRC
BGAS
OTHR
COAL
GAS
WATR

Appendix A: Additional Metrics

This section provides additional metrics to complement the analysis and discussion presented in previous sections.

Figure 150: Monthly comparison of average SMEC prices across the CAISO markets

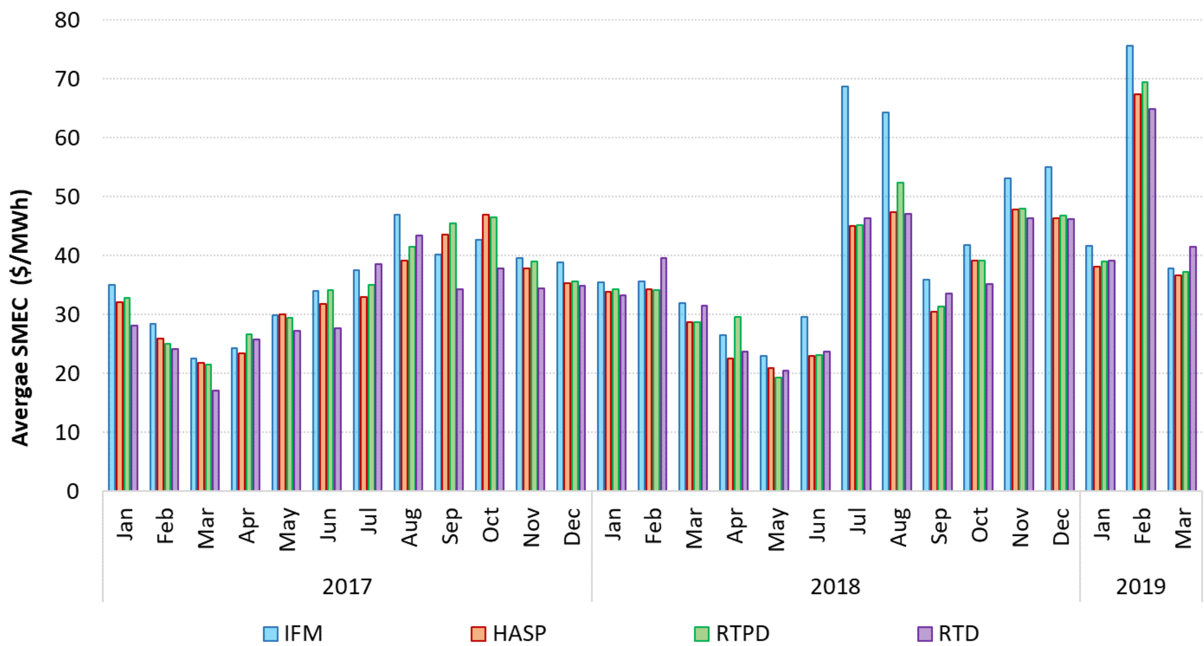


Figure 151: 2017 Hourly comparison of average SMEC prices across the CAISO markets

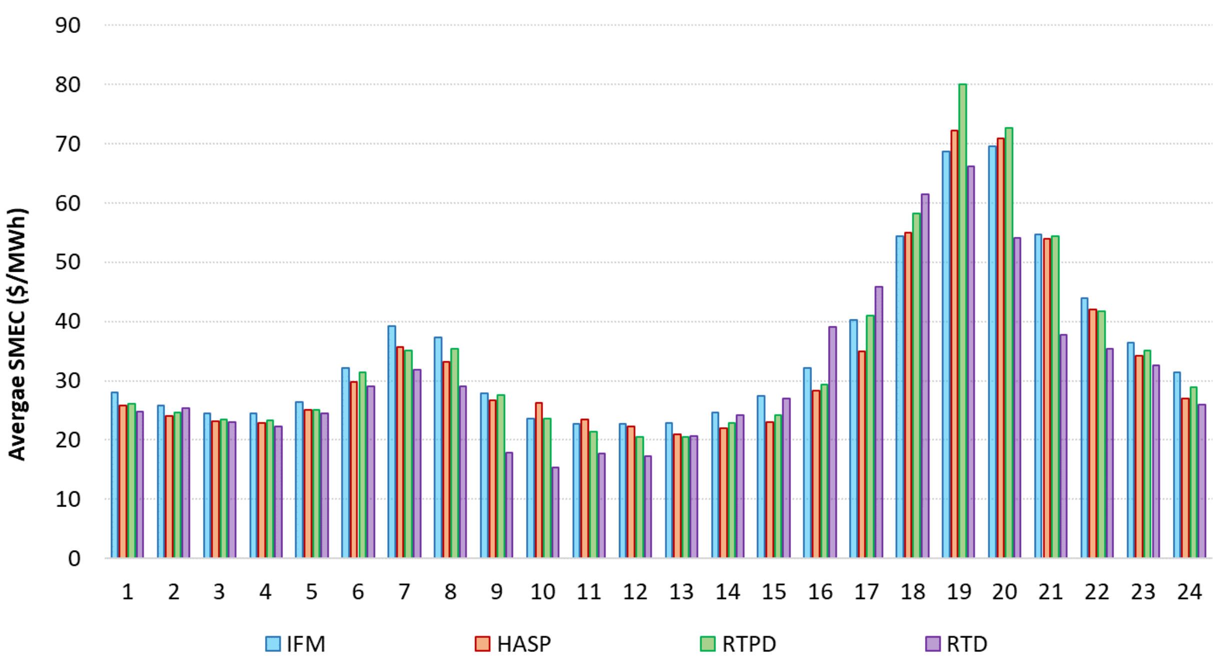


Figure 152: 2018 Hourly comparison of average SMEC prices across the CAISO markets

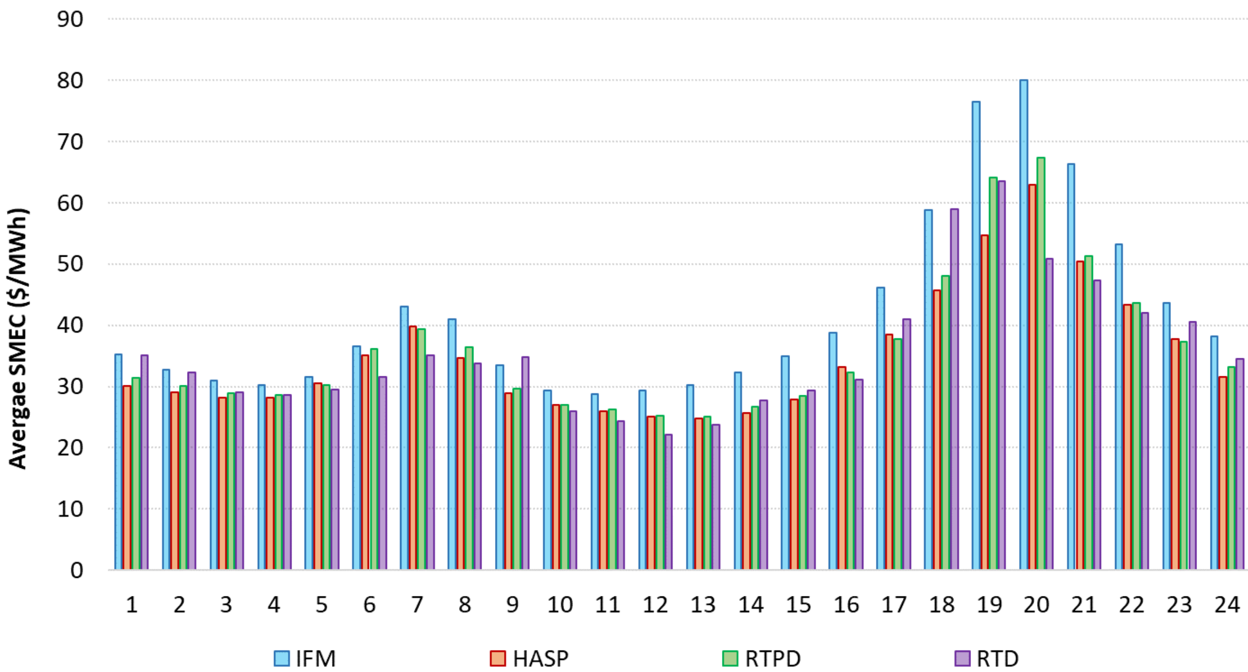


Figure 153: 2019 Hourly comparison of average SMEC prices across the CAISO markets

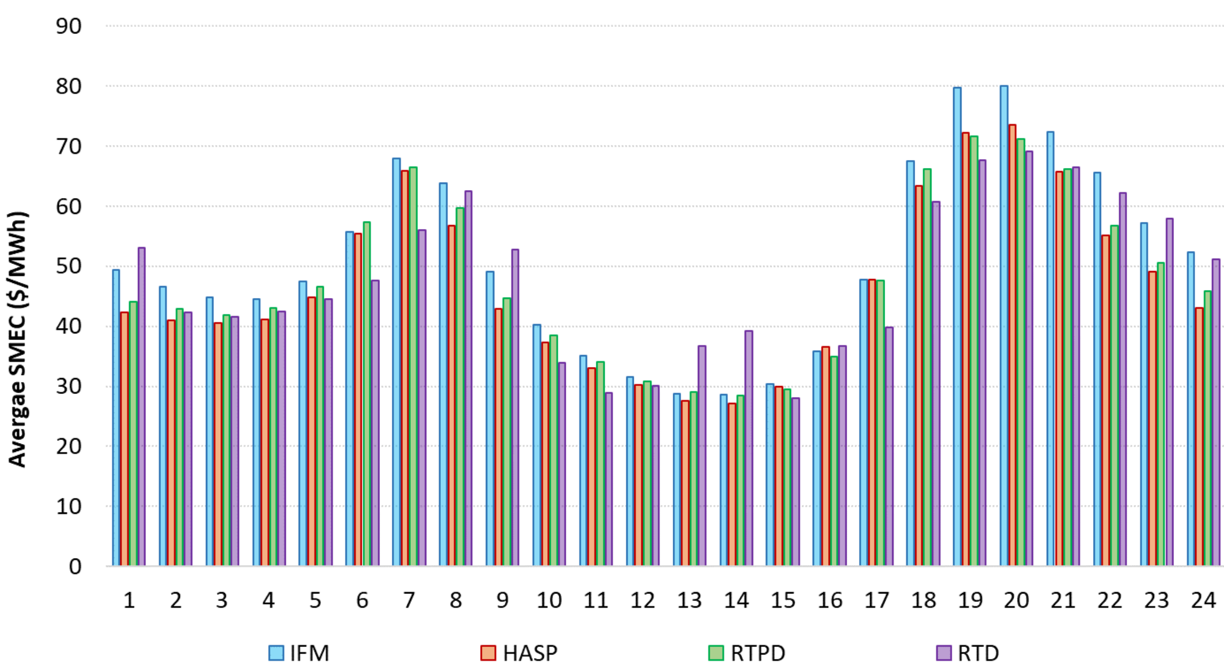


Figure 154: Monthly system-weighted price in IFM –Full price range

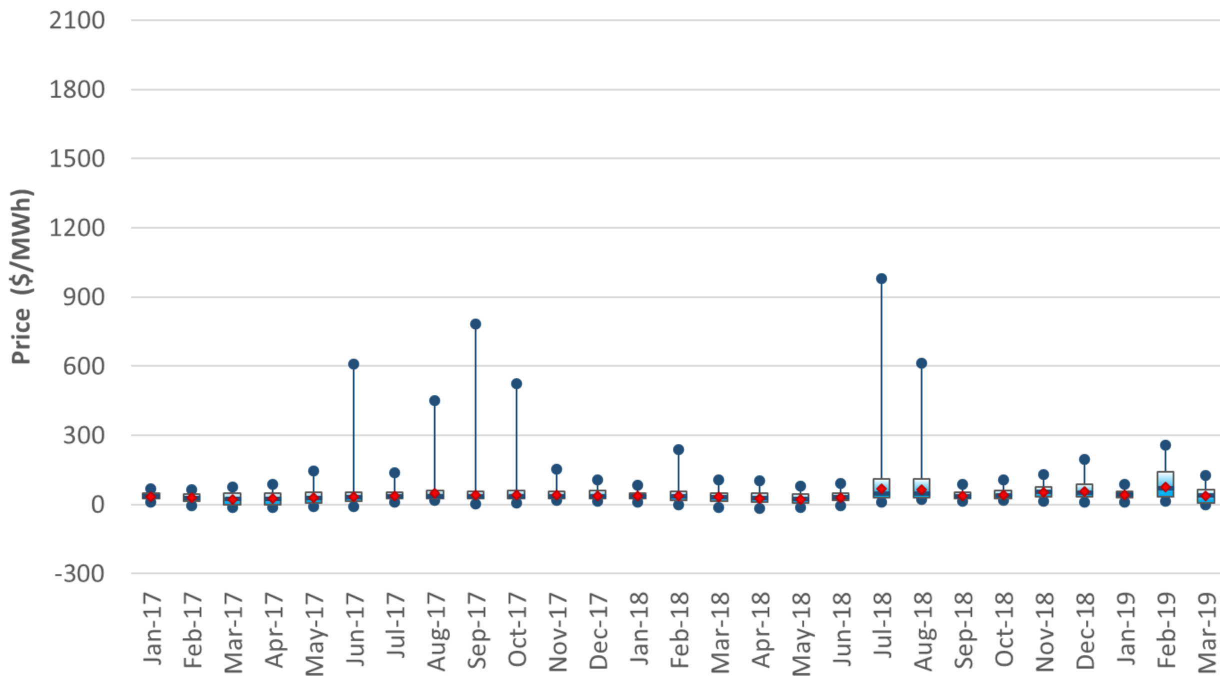


Figure 155: Monthly system-weighted price in HASP –Full price range

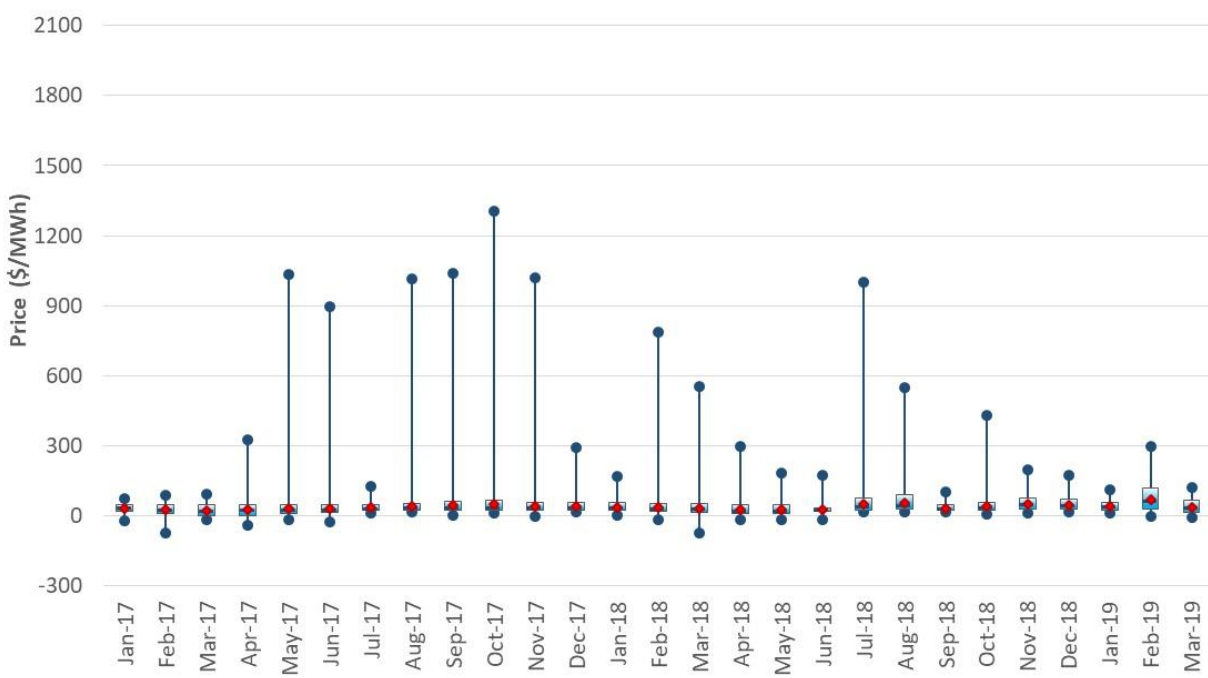


Figure 156: Monthly system-weighted price in FMM –Full price range

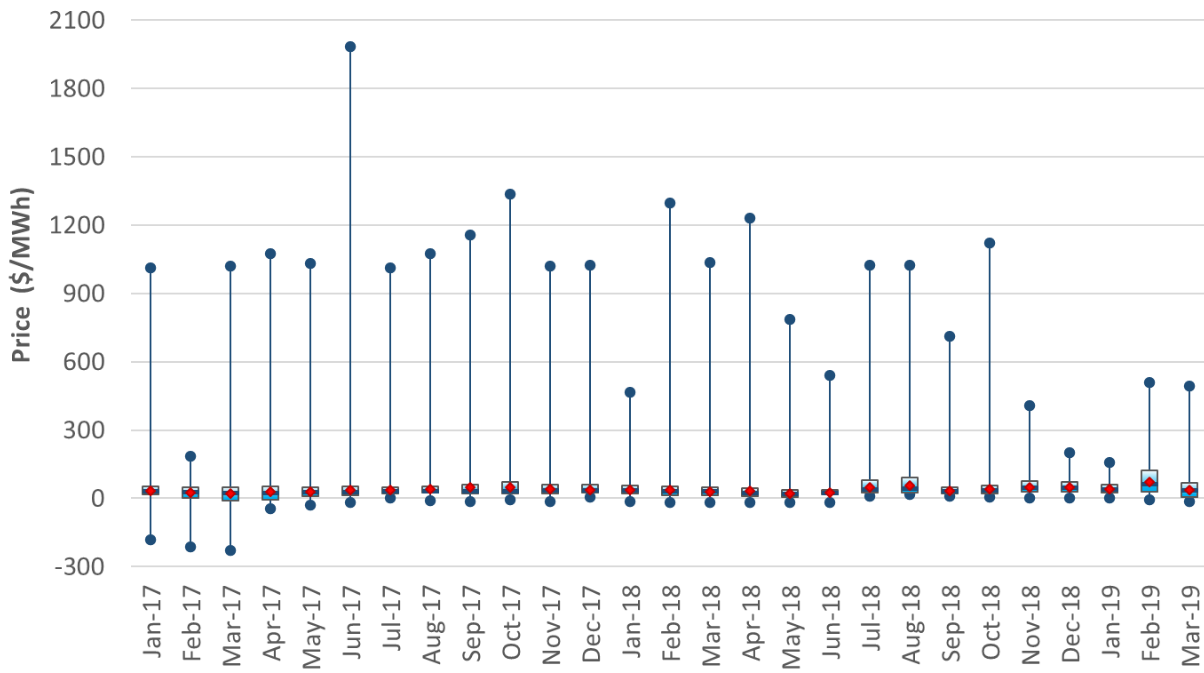


Figure 157: Monthly system-weighted price in RTD –Full price range

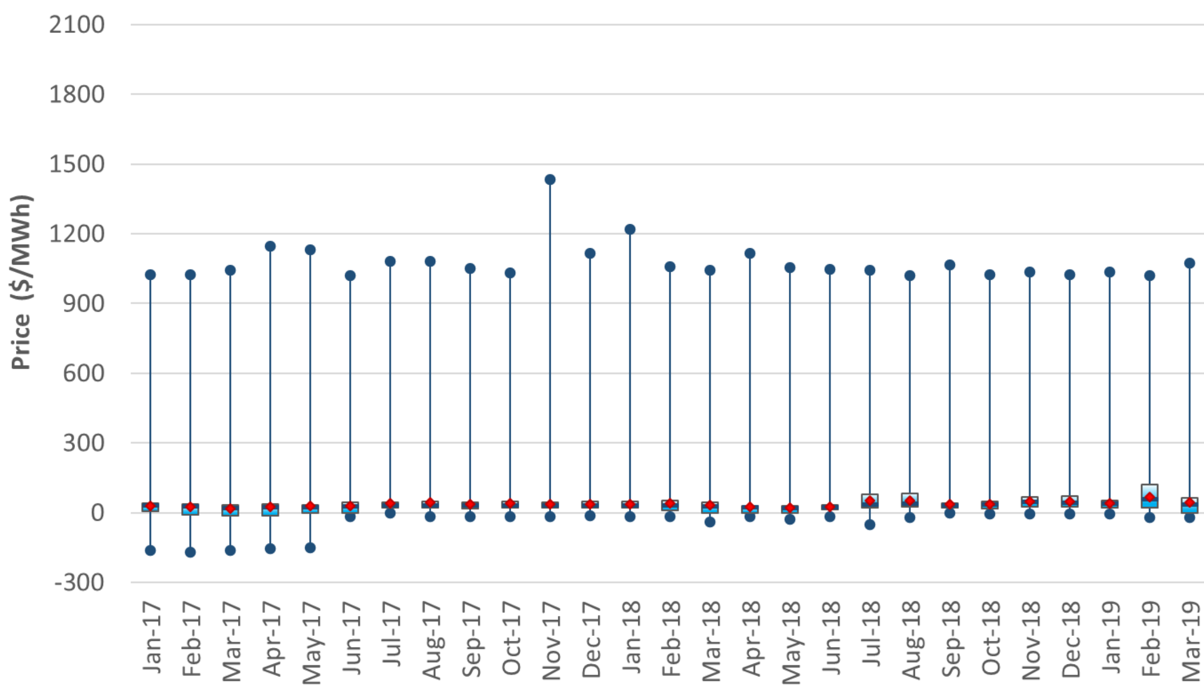


Figure 158: Price spreads between IFM and HASP –Full price range

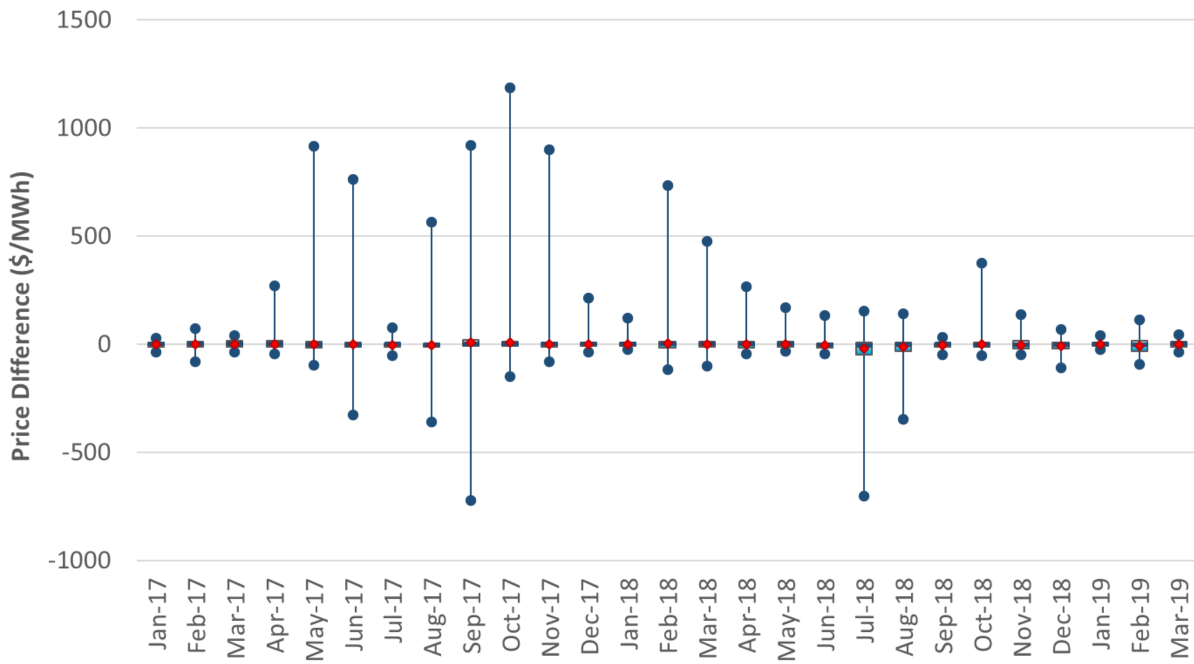


Figure 159: Price spreads between HASP and FMM –Full price range

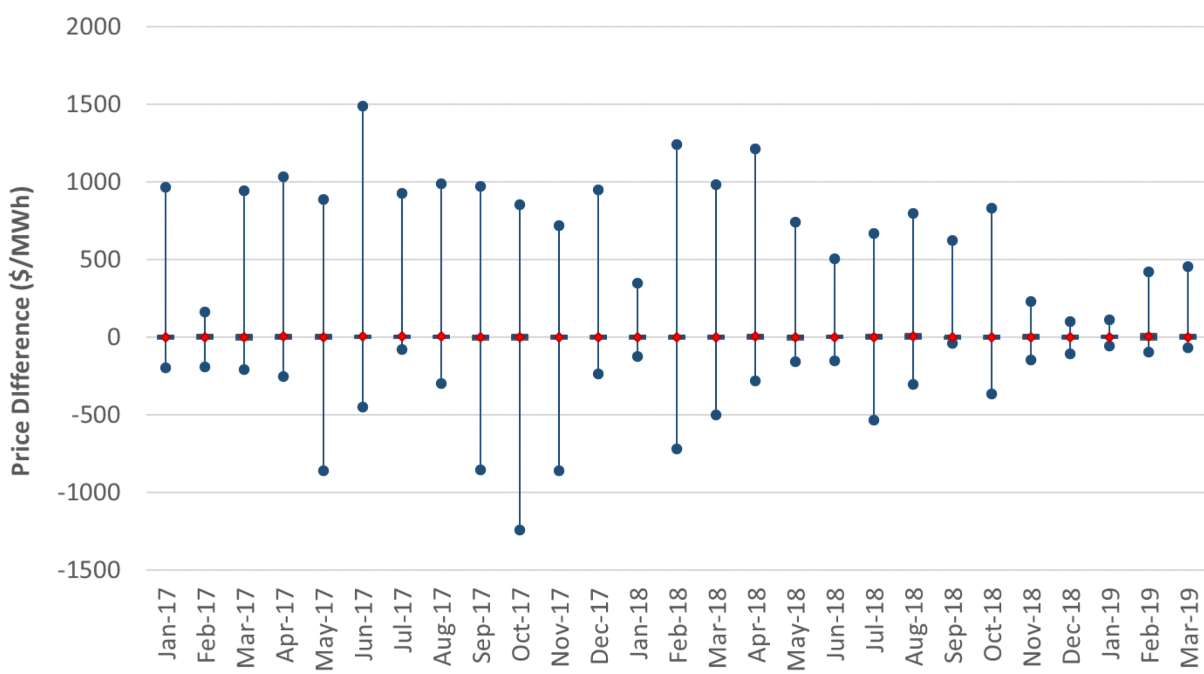


Figure 160: Price spreads between FMM and RTD –Full price range

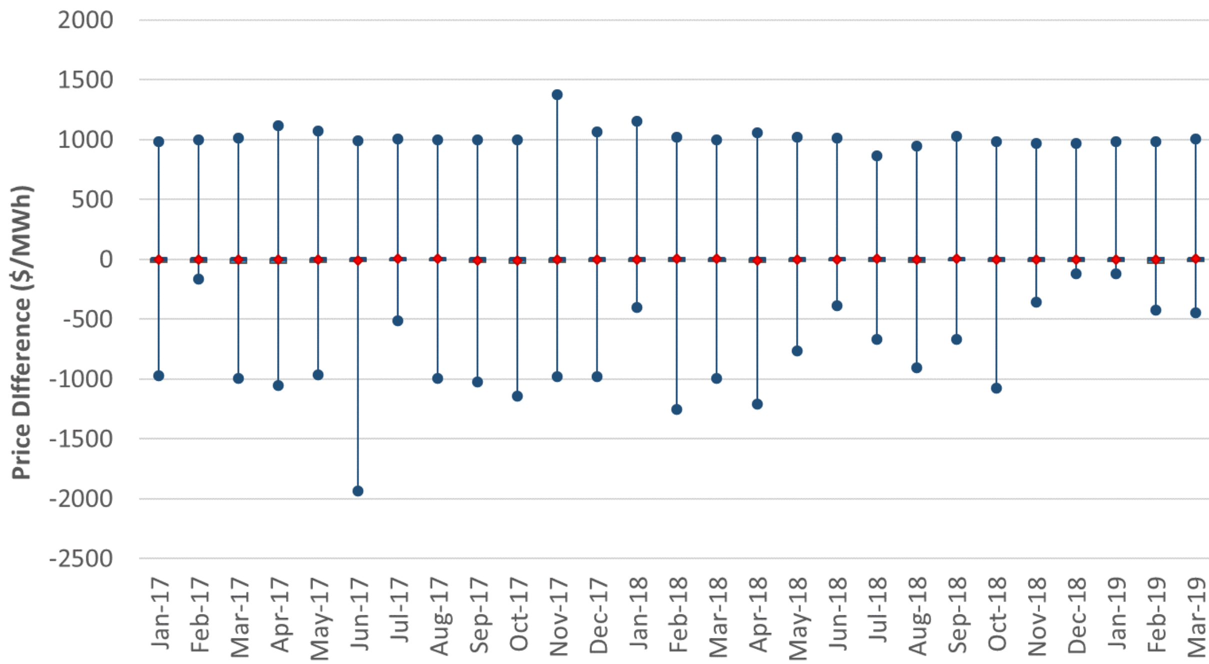


Figure 161: Correlation between HASP and FMM load conformance

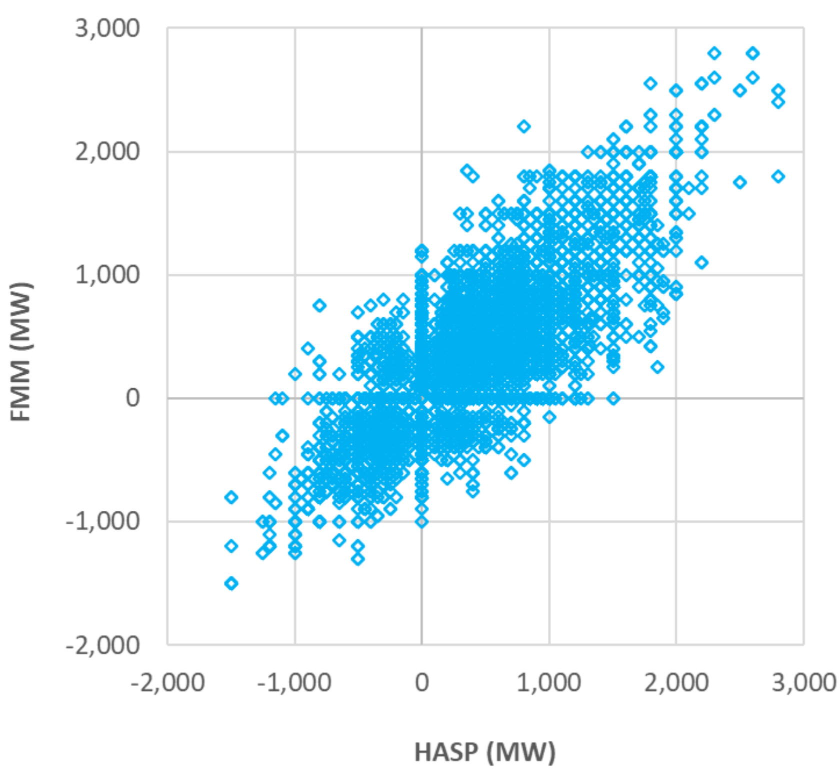


Figure 162: Correlation between FMM and RTD conformance

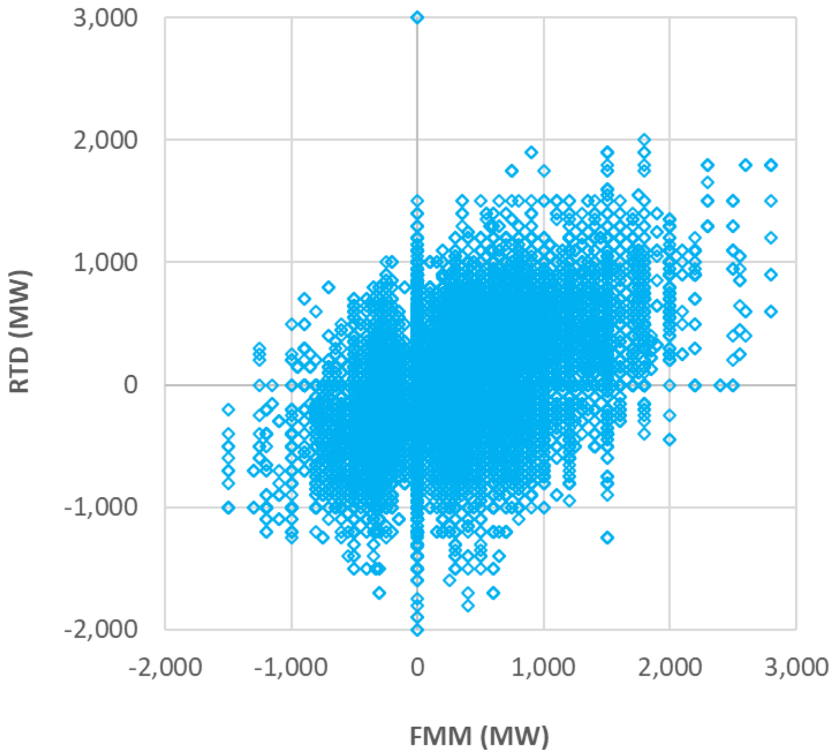


Figure 163: Correlation between day-ahead prices and forecast error

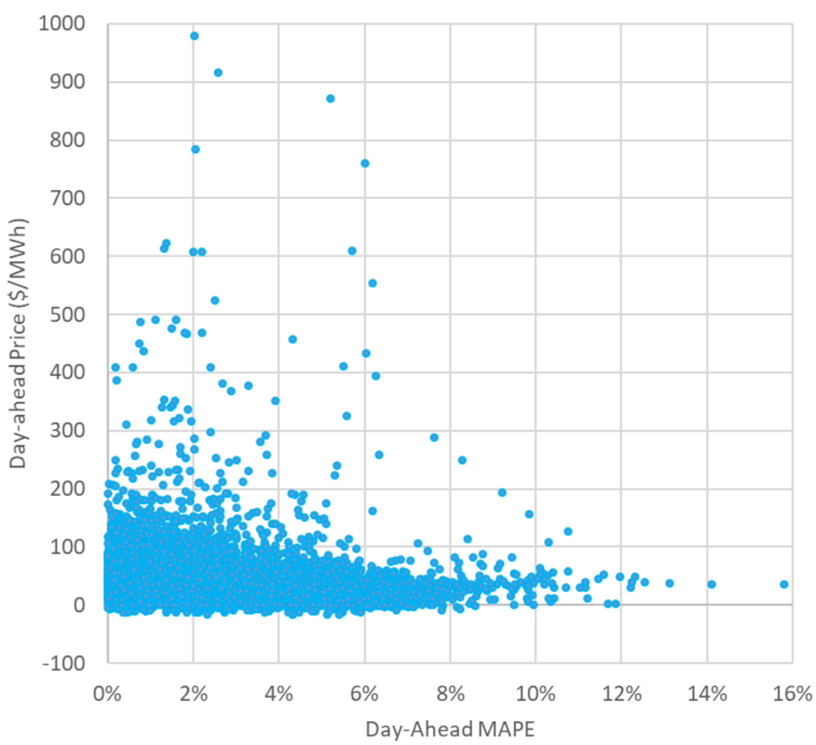


Figure 164: 2017 Hourly profile of VER convergence

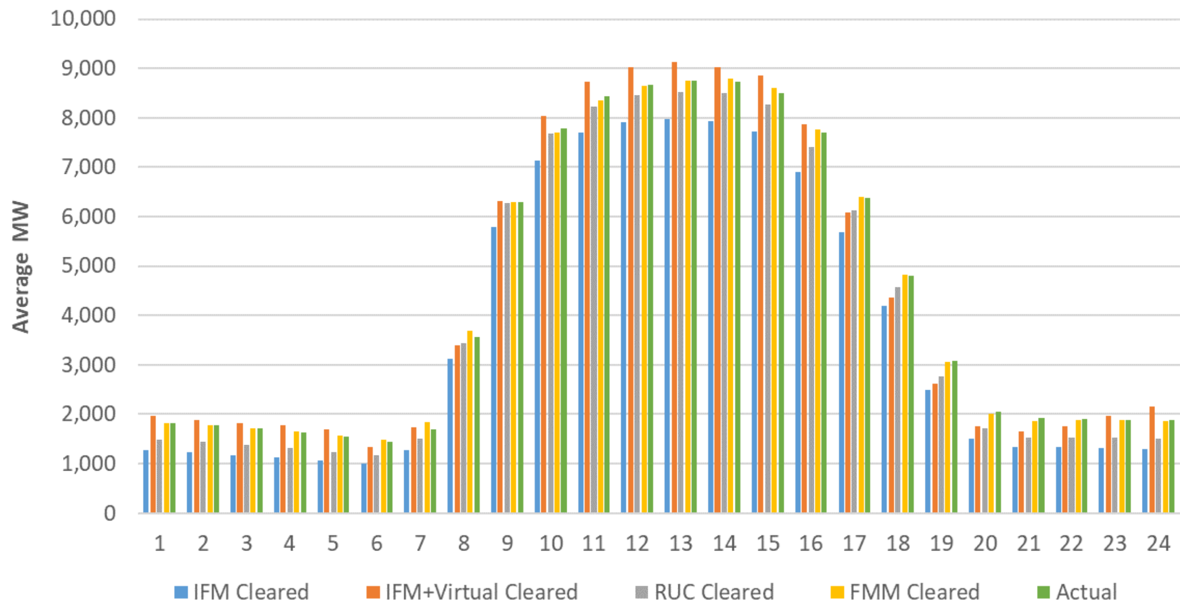


Figure 165: 2018 Hourly profile of VER convergence

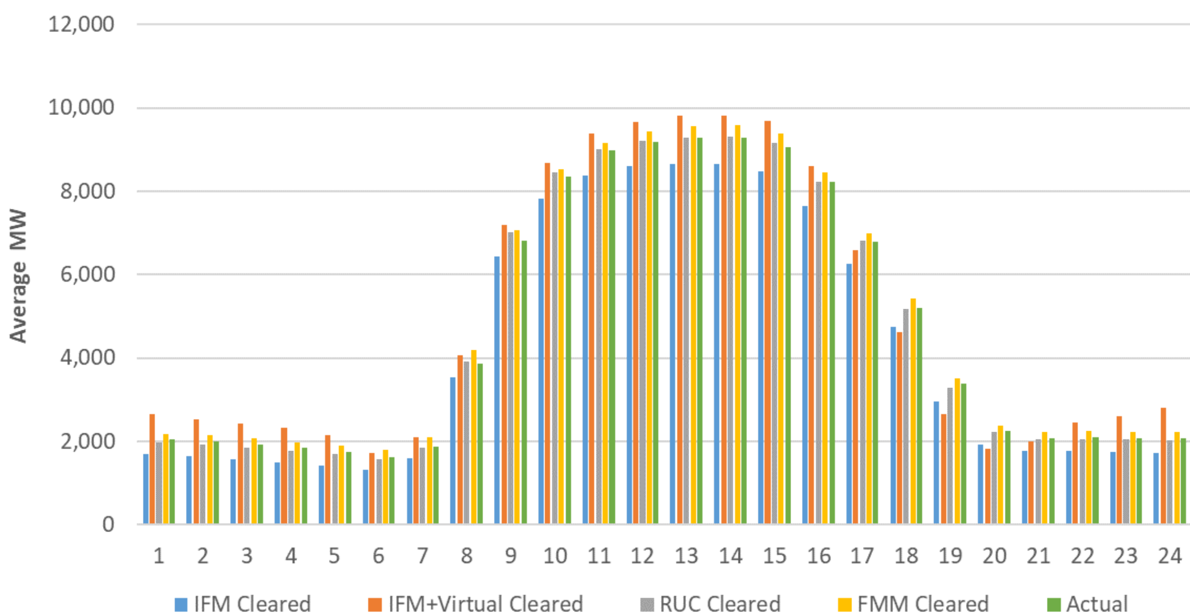
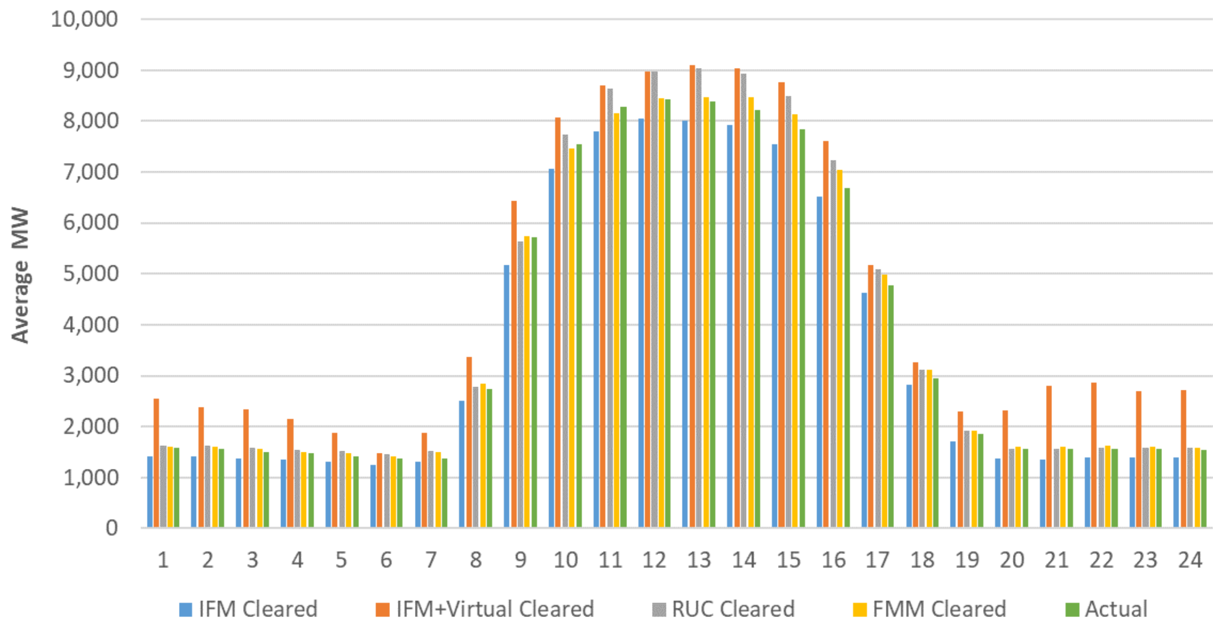


Figure 166: 2019 Hourly profile of VER convergence



Appendix B: Flexible Ramp Utilization from FMM to RTD

Consider two number series described below:

Series 1.

$$\mathrm{T}_0 = x_0 \tag{A1}$$

$$\mathrm{T}_{k+1} = \max\left(x_{k+1} - max\binom{x_k}{s_k}, 0\right) \tag{A2}$$

where $s_k = \{x_0, \dots, x_k\}$ and $s_0 = x_0$ is a set of x_k

Series 2.

$$U_0 = \mathrm{T}_0 \tag{A3}$$

$$U_{k+1} = \min(\sum_k \mathrm{T}_i\,, M) \tag{A4}$$

where M is a constant and T_k is defined in (A3) and (A4).

For a given K,

$$U_K = \min(M, \max s_K - x_0). \tag{A5}$$

Proof.

$\because \max(x - y, 0) \Leftrightarrow \max\binom{x}{y} - y$

- ➔ (A2) $\Leftrightarrow \mathrm{T}_{k+1} = \max s_{k+1} - \max s_k$
- ➔ (A4) $\Leftrightarrow U_{k+1} = \min(\sum_k \max s_{i+1} - \max s_i\,, M)$

$$= \min(\max s_{k+1} - \max s_k + \max s_{k+1} - \max s_k + \dots + s_0, M)$$

$$= \min(\max s_{k+1} - x_0, M).$$

- ➔ $U_K = \min(M, \max s_K - x_0)$.

Q.E.D

Appendix C: Proposed Schedule

In order to provide opportunities for engagement and to shape the direction of this analysis, as well as to discuss the analysis findings, the CAISO carried out this analysis effort through a more formal stakeholder engagement. The timeline below highlights the main milestones.

Task	Schedule
Draft proposal for analysis	Monday April 3, 2019
Discussion at MSC meeting	Friday April 5, 2019
Stakeholder call	Wednesday April 10, 2019
Stakeholder comments	Wednesday April 17, 2019
Posting of first report	Monday June 17, 2019
Stakeholder call	Friday June 21, 2019
Stakeholder comments	Wednesday, July 3, 2019
Final report	September 23 2019
Stakeholder call	September 27, 2019

Appendix D: Responses to Stakeholders Comments

When the CAISO committed to launch this analysis effort, stakeholders expressed interest in actively participating and helping set the direction of the analysis to address specific concerns regarding price performance. In order to accommodate this interest, the CAISO organized this analysis effort in such a manner to allow engagement and feedback from participants as the CAISO progresses on this analysis.

The CAISO appreciates stakeholder comments in response to the proposal for analysis of price performance. The CAISO posted a white paper on April 3, 2019 and held a conference call on April 10, 2019 to discuss the scope and schedule of this analysis effort. Previously, the CAISO discussed this analysis effort in the Market Surveillance Committee (MSC) session of April 5, 2019.

First round of stakeholders' comments

The CAISO received 12 sets of comments[34].

Calpine suggested complementing the analysis with an evaluation of bid cost recovery as a vehicle to identify potential drivers of price performance. The CAISO will consider this item for potential analysis. Calpine seconded the questions raised by the MSC in their opinion about the Intertie Decline effort to analyze flexible ramp product performance and the manual intertie dispatches. These two areas are within the scope of this analysis. Calpine similarly requested the CAISO to select specific days with problematic price performance and rerun the market under a perfect dispatch construct in which all actual conditions are used. In this regard, this concept of perfect dispatch may naturally apply to an *ex-post* market that relies on actual conditions to come with prices. In contrast, the CAISO uses an *ex-ante* construct in which the market clears and the prices are set based on projected conditions. This makes a rerun of a counterfactual dispatch using actual conditions more problematic. In the RTM, where the current solution heavily depends on the previous solution, changing one condition in a given interval will change not only the market outcome of that interval but the setup and market solution for any subsequent market, effectively creating a parallel world of market solutions. For the scope of this specific analysis effort, the current CAISO technology is not setup to be able to create a counterfactual market that can accurately internalize the actual conditions. The CAISO still sees merit with the overall concept of having specific cases rerun with some changes included to realize the effect of that change, such as the inclusion of operator actions.

The California Large Energy Consumers Association (CLECA) suggested adding the impact of Reliability Demand Response Resources (RDRR) to the price performance scope. Based on historical outcomes, RDRR are only dispatched in the real-time market once the CAISO system is in or is eminently getting into a system emergency. These instances are infrequent and isolated and, thus, RDRR performance is not a

[34] The straw proposal and as well as the stakeholder comments are available at http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=6C9CDFDA-E9A0-4F65-9FC6-4CB01C1ADAA5

primary driver of the more recurrent price performance concerns. The CAISO will consider this suggestion as a potential item in the analysis.

Pacific Corporation (PAC) seeks clarification regarding the intended actions to be taken from the outcome of this effort. This CAISO notes that this is an analysis effort and not a policy effort. The CAISO envisions that this analysis effort can shed light into the drivers of price performance issues; these drivers, in turn, may point to different levels of next actions. There could be actions as simple as correcting identified defects or gaps in the implementation of certain market functionality, identifying areas for potential enhancements in the existing market functionality, or creating inputs for further policy evaluation regarding market design. PAC supported the scope of the analysis, including operator actions as a whole, and highlighted the role that integration of renewable resources may play in price performance. Lastly, PAC put in context a broader discussion of the design of extended DAM and the ongoing day-ahead market enhancements. This analysis effort is not a substitute to any policy initiative but may instead actually provide inputs and information to better guide these policy discussions.

Powerex indicated that the price formation issues discussed in the proposal have their origin in the design of having an energy-only market, which creates a misalignment between the CAISO market and the actual needs of the grid, and urged the CAISO to consider this from a more underlying market design angle. Powerex elaborated on their guiding principles by advocating for a more efficient market. They provided a white paper on efficient markets (dated March 2019) which is perhaps more in the context of recent discussions of the CAISO DAM enhancements. The white paper notes that rapid changes in the resource mix may be exposing the CAISO's limitations of the energy-only market. The CAISO notes that the expected scope of this effort is more on the evaluation of the existing and current market design, and not about exploration of alternative market design. There are other efforts in the policy spectrum that may be better place to discuss policy design. This analysis effort naturally might provide inputs to policy discussions such as the ongoing DAME policy.

PG&E suggested focusing the analysis on how each contributing factors impacts price performance and to what extent. It also suggested rerunning counterfactual cases to compare the effect of operator actions. As part of this analysis, the CAISO expects to cover these suggestions. NRG suggested making all data available, while PG&E suggested releasing load conformance and ED data. The CAISO will consider these suggestions. Changes to existing applications to publish data, either publicly or through participants portal, require system changes.

NRG and SCE suggested expanding the analysis period beyond the originally proposed period of 2018. The CAISO has considered this suggestion, and will expand the analysis period to cover 2017 through the first quarter of 2019. This will allow for a longer period of analysis while still being recent enough to ensure drivers are still relevant. Additionally, this period will cover the peak days of September 1, 2017, July 25 2018 and March 31, 2019 which are useful as peak days tend to demonstrate unusual conditions that "stress test" the markets. NRG also suggested that this effort go one level deeper in analyzing the impact of market operator actions on price performance. The CAISO expects to be able to analyze the impact of the various operator actions on the price performance. NRG also suggested that the CAISO use case studies to provide detailed analysis of price performance issues. This type of analysis is within the scope of this effort and, in this partial update, the CAISO is providing some cases studies already analyzed in response to this suggestion.

SCE suggested analyzing the potential impact of load forecast accuracy, virtual bids, and gas-related drivers since these factors can have an impact on price performance. For instance, load forecast errors can influence the procurement of ancillary services. These items are all within the scope of this analysis effort. SCE suggested allowing stakeholders to submit comments after the release of the first report. The CAISO has adjusted the schedule to include a time window during which participants can review the report and submit comments. Depending on the extent of these comments and their potential to trigger changes in the scope of the analysis, this may impact the suggested analysis completion date.

Seattle City Light (SCL) generally supported the CAISO's suggested scope and suggested using counterfactual cases (reruns) to analyze the effect of certain market aspects such as the inclusion of virtual bids. The ongoing analysis effort is doing this type of analysis. Furthermore, SCL suggested expanding the analysis to explore implications of having an energy-only market and this situation's interplay with firm energy. The CAISO notes that expected scope of this effort is more on the evaluation of the existing and current market design; there are other efforts in the policy spectrum that may be better place to discuss policy design. This analysis effort may provide inputs to policy discussion such as the ongoing DAME policy. SCL also suggests that this effort should become a regular and recurrent effort and evaluation. Based on the outcome of this effort, the CAISO may evaluate if there is any need beyond this scheduled deliverable.

Shell suggested including analysis on price formation at the interties as well as analysis based on counterfactual market outcomes and very specific market cases. The CAISO notes that this ongoing effort is explicitly looking at the performance of interties and also uses case studies based on counterfactual solutions. Some of these results are provided in this partial report.

The cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California ("Six Cities") suggested comparing the frequency and magnitude of price divergence with other CAISOs' markets. The CAISO will search for such metrics to see if they are readily available for comparison but, given the tight schedule for this analysis, the CAISO may not commit to do any direct comparisons with other CAISOs' markets.

WPTF generally supported the proposed scope and encouraged the CAISO to connect this effort with other policy discussions such as the enhancements for the DAM. It also encouraged the CAISO to re-visit the schedule if needed to produce a comprehensive study, and to consider the importance of transparency for a well-functioning market. It suggested also analyzing the transmission differences. The CAISO notes that this area has not been envisioned within the original scope of analysis, although is a critical component in the proper functioning of the LMP-based markets. The CAISO proposes to continue working on the original scope and consider a potential second effort to target transmission- and congestion-related items.

Second round of stakeholders' comments

The CAISO received eight sets of comments about the preliminary analysis[35].

NCPA suggested to expand the study horizon to include Q2 of 2019 to cover a period under which the Commitment Costs Enhancements initiative (CCE3) was already activated. As requested, the ISO has included further analysis covering instances of price performance observed in June 2019, but it does not expand all metrics to cover Q2 of 2019. Although CCE3 was implemented in April 2019, there is no expectation that such feature can have a direct impact on price performance. The CCE3 initiative directly impacts commitment costs for resources with opportunity costs, which may influence commitment. However, since participants cannot bid differently between the HASP, FMM and RTD markets, such an initiative will not lead to price divergence among these real-time submarkets. Furthermore, the opportunity costs adders will be unique for the resource and do not change by market; hence, there is very little possibility that CCE3 would impact price performance across markets.

NRG pointed out several areas of interest in the price performance analysis. First, it refers to the fact that the forecast error tends to be in the over-forecast direction. As illustrated in the various metrics within this analysis, there is a balanced distribution of forecast errors in both directions. In any given hours, the forecast error can range from +3,000 MW to -3,000 MW, showing either over- or under-forecast conditions. The average error tends to be incrementally positive, indicating over-forecast. Over-forecast tends to be observed in the afternoon hours due to the influence of behind-the-meter generation. Currently, the effect of behind-the-meter generation is internalized in the load forecast through some mechanisms, however the ISO is currently evaluating alternatives to improve the behind-the-meter forecast. NRG suggested that the ISO provides more descriptive labels to the exceptional dispatches reported in the system. The ISO has currently undertaken an effort to better align the classification of EDs used in the market and future metrics will rely on these classifications. NRG also discussed the concerns of RUC adjustments impacting real-time prices. The ISO has provided metrics about the specific adjustments made in the RUC process, including operator adjustments and VER adjustments; there is also additional analysis provided regarding the impact of virtual bids on the convergence of the markets. NRG also encouraged the ISO to commit to using the best available gas price information. In this regard, the ISO has been working through policy initiatives including the Commitment Costs and Default Energy Bid Enhancements initiative to ensure the most updated gas price information is used in the CAISO markets. NGR also suggested to provide specific findings of the analysis in the final report; the ISO is providing additional analysis, a summary of the findings, and possible solutions to the analyzed issues. Although this report is a specific deliverable, the ISO is committed to continue evaluating the efficacy of price performance in the markets.

Powerex suggested several avenues of additional analysis and classification, as well as a discussion of system conditions and grid operators concerns explaining their actions and adjustments in the market. Unfortunately, this type of information is not recorded in a fashion that could be robustly data-mined and

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[35] Comments are available at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=4657EBD0-2E71-4740-A61D-3D837EC4EC67.

programmatically analyzed. The only level of such information that is currently available is already provided within the metrics of this report, which includes classifications of EDs. The only metric that exists to describe grid operators needs for performing load conformances is related to the main classification that has been already provided in the policy effort surrounding the Load Conformance Limiter. Regarding the suggestion by Powerex to evaluate the uncertainty faced by operators in the real-time market in comparison to what the day-ahead market is currently providing, the ISO has expanded the analysis of uncertainty from the DAM to the RTM. This analysis shows that the largest uncertainty observed in the CAISO markets is indeed from DAM to RTM. Currently, there is no market mechanism to deal with this level of uncertainty and grid operators need the ability adjust as needed to ensure the system is properly positioned to manage the uncertainties materializing in the real-time timeframe.

SCE and WPTF suggested the CAISO should include analysis of price divergence between IFM and FMM since the preliminary analysis only included IFM and HASP. This additional comparison has been included in this final report.

Shell Energy provide several suggestion for specific analysis, including the effect of EDs on real-time prices, frequency of real-time prices being lower than HASP prices, and inclusion of counterfactual scenarios by rerunning the markets without operator ED actions. These recommendations were included in the subsequent analysis and the findings are provided in this report. The suggestion of analyzing cases when southern CAISO prices were lower than external BAAs prices was not explicitly considered since this seems to indicate a case of congestion which may depress prices in a specific area of the real-time market while increasing prices elsewhere, which is an expected outcome of congestion.

Six Cities expressed concerns about the price divergence between HASP and FMM analyzed in the preliminary report. The ISO has further analyzed this divergence and is also providing some potential solutions to the issues identified. Six Cities also expressed concerns about the finding in the preliminary report regarding VERs bidding beyond their natural production; the ISO will take appropriate actions to ensure such behavior does not continue.

WPTF shows interest in analysis that can identify the frequency and magnitude of price divergence due to load conformance. This type of analysis is not feasible without running the original markets in parallel. Another complication is that load conformance may be one of several drivers of price performance and it is not feasible to analyze this scenario in a vacuum to only study the impact of load conformance. Instead, the ISO took a different approach of counterfactual analysis by targeting specific instances of operator adjustments. This counter-factual approach aligns with subsequent comments from WPTF regarding case studies. WPTF continues to request the analysis is expanded to cover price difference in congestion. As indicated in the first round of comments, the ISO is keeping the original scope of the analysis in order to have a feasible scope. The ISO recognizes the importance of this area in the market and commits to further analyze price performance related to congestion. WPTF suggest the ISO provides a focused summary of findings from this analysis effort; in this final report, the ISO has summarized the main findings and potential solutions.