Day-Ahead Market Enhancements

Straw Proposal

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Day Ahead Market Enhancements: Straw Proposal

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1. Executive Summary

The objective of this initiative is to enhance the California ISO's (CAISO's) day-ahead market to efficiently schedule resources to:

- Meet the load forecast and accommodate the uncertainty of real-time net load[1] and its rate of variability.
- Appropriately compensate resources that provide flexible capacity to meet this net load uncertainty and variability.
- Optimally clear and price energy and other market products in the day-ahead market, including incorporating actions into the market that system operators currently take outside of the market.
- Respect transmission constraints so that resource schedules are deliverable.

This paper describes the CAISO's proposed design enhancements under which the day-ahead market will co-optimize energy and ancillary services as it currently does, while also including new market products to reserve resources' real-time dispatch capability within the same optimization.

The first of these new market products, termed "reliability energy" (and the associated "reliability capacity up/down") replaces the existing residual unit commitment process. The residual unit commitment process is a separate process and is used to ensure sufficient resources are committed to meet the load forecast. The CAISO runs the existing residual unit commitment process after the day-ahead market co-optimizes energy and ancillary services. Including reliability energy in the day-ahead co-optimization will more efficiently schedule resources to meet both bid-in demand and the load forecast. Similar to the existing residual unit commitment process, the optimization will consider transmission constraints in scheduling reliability energy. Unlike the existing residual unit commitment process, reliability energy will also allow the day-ahead market schedule resources to provide downward dispatch capability and/or avoid committing resources if the load forecast is less than demand that clears the day-ahead market.

Adding reliability energy to the day-ahead market will create two types of day-ahead market energy schedules: (1) A day-ahead energy schedule that is based on cleared bid-in demand. Supply and demand, including virtual supply and demand will have energy schedules. (2) A reliability energy schedule that is based on the load forecast and may be different than a resource's energy schedule. Only physical internal supply, imports and exports will have reliability energy schedules.

The difference between a resource's energy schedule and its reliability energy schedule, will be designated as "reliability capacity up" or "reliability capacity down." This award will result in an obligation to provide economic energy bids to the real-time market so that the resource's dispatch capability is available to the real-time market.

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1 Net load is load minus variable energy resource output, which is the load that must be met by dispatchable resources.

The day-ahead market will settle supply resources' energy schedules (i.e. those based on cleared bid-in demand) at energy locational marginal prices (LMPs) and will settle their reliability energy and reliability capacity up/down schedules at reliability energy LMPs. The market will settle load's energy schedules (i.e. those based on cleared bid-in demand) at the energy LMPs. The market will recover the costs of reliability energy and reliability capacity up/down through a cost allocation.

The second of the new day-ahead market products, termed "imbalance reserves," will ensure the day-ahead market schedules sufficient real-time dispatch capability to meet net load imbalances that materialize between the day-ahead and fifteen-minute markets. These imbalances are due to net load uncertainty and ramping differences between hourly day-ahead market and fifteen-minute real-time market schedules. These imbalances have grown over recent years due to increasing amounts of variable energy resources. Additionally, because of the increased net load uncertainty, system operators have needed to take increased amounts of out-of-market actions to maintain reliability.

Similar to reliability energy, an imbalance reserve up and/or down award will result in an obligation to provide economic energy bids to the real-time market. Only resources dispatchable by the fifteen-minute market will be able to provide imbalance reserves. As with both energy and reliability energy, the proposed design considers transmission constraints to ensure imbalance reserves are deliverable. Resources will receive an imbalance reserve settlement at a LMP and the market will recover the costs through a cost allocation.

The new day-ahead market design will also be used as the foundation for extending the day-ahead market to Energy Imbalance Market (EIM) participants outside of the CAISO balancing authority area, which is just starting the stakeholder initiative process. Imbalance reserves allow the sharing of the diversity benefit from optimizing and pooling loads and resource variability over a larger market footprint and will be an important element of the extended day-ahead market's (EDAM's) resource sufficiency evaluation.

2. Background and Stakeholder Comments

The CAISO conducted stakeholder working group meetings in June and August 2019 that discussed two potential options for a new day-ahead market formulation. Both options change the existing construct of the sequential integrated forward market and the residual unit commitment process and instead include all day-ahead market products in a single optimization.

Option 1 proposed to use only bid-in demand to clear supply in the day-ahead market, which is the same approach used for the existing integrated forward market. This approach would differ from the existing day-ahead market by adding imbalance reserves, which the day-ahead market would co-optimize along with energy and ancillary services. Imbalance reserves would schedule additional dispatch capability to be available in the real-time market. Under Option 1, imbalance reserves would account for both (1) real-time market energy imbalances that materialize because of net load uncertainty and ramping needs due to differences in hourly and fifteen-minute ramp modeling, and (2) differences between cleared demand and the load forecast. The imbalance reserve requirement would be based on historical differences between cleared demand and actual real-time demand adjusted by the variable energy resource forecast for each day. In the event imbalance reserves did not account for the difference between cleared demand and the load forecast on a particular day, system operators may dispatch additional resources out of the market.

Option 2 is the approach proposed in this paper, which differs from Option 1 by also including reliability energy, which is designed to meet differences between cleared demand and the load forecast from physical resources. The day-ahead market will optimize reliability energy with the other day-ahead markets using each day's load forecast. Because the day-ahead market will schedule reliability energy using each day's load forecast, it has the advantage over Option 1 that the schedules produced by the market will always meet the load forecast and all costs will be incorporated into the market solution. It also has the advantage that it can meet this difference with hourly dispatchable resources, as well as fifteen-minute dispatchable resources. Option 1 would meet this difference with imbalance reserves, which will only be able to be provided by fifteen-minute dispatchable resources. Using hourly dispatchable resources to meet the forecast demand as well as fifteen-minute dispatchable resources to meet the level of variability and uncertainty should result in a lower overall cost.

The CAISO received a number of stakeholder comments in response to the stakeholder working group meetings. A number of stakeholders support Option 2, particularly Energy Imbalance Market participants outside of the CAISO balancing authority. They generally believe that Option 2 has the advantage of always incorporating all costs to meet the load forecast and net load uncertainty needs in the market solution. Other stakeholders prefer Option 1 because they maintain that Option 2 is overly complex. They also maintain load would have less transparent and predictable pricing because the market would clear reliability energy based on the load forecast and not demand bids. Some stakeholders asked for a more detailed explanation of the design proposal and additional material to support the need for day-ahead market enhancements. A number of stakeholders also requested additional analysis to support the proposal. The CAISO reviewed all stakeholder data requests. The CAISO has included feasible and appropriate data requests throughout the paper and in Appendix A: Additional Data Analysis.

An earlier phase of the day-ahead market enhancements proposed to schedule the day-ahead market in fifteen-minute intervals rather than one-hour intervals. Fifteen-minute scheduling would have resolved imbalances caused by granularity differences across the hour. However, this part of the proposal was deferred because the CAISO's simulation of a fifteen-minute day-ahead market was unable to run in a reasonable amount of time. Stakeholders were concerned that implementation costs of the fifteen-minute day-ahead market and resulting settlement changes would outweigh financial gains of the fifteen-minute scheduling. Additionally, the CAISO was concerned even with a successful and feasible simulation, that the computational capacity required for this design would limit future market enhancements.

3. Proposed Day-Ahead Market Enhancements

This section provides a detailed description of the proposed day-ahead market enhancements. The CAISO proposes a design that co-optimizes energy and ancillary services as it does today, while also including, in the same optimization, new market products to reserve real-time dispatch capability. This proposal is similar to the Option 2 design that was discussed at previous stakeholders meetings, but differs because it now includes nodally priced and deliverable imbalance reserves.

The CAISO is proposing the Option 2 design because the schedules produced by the market will always meet the load forecast and all costs will be incorporated into the market solution. Also, this design proposal will allow the market to meet the difference between cleared demand and the load forecast with hourly dispatchable resources, which will provide a deeper pool of resources than the pool of fifteen-minute dispatchable resources Option 1 would use.

The CAISO believes the proposed day-ahead market design will result in more efficient and economic unit commitment by:

- Allowing commitment costs for the differences between bid in demand and the load forecast to be included in the market optimization.
- Allowing commitment costs of out of market actions to address upward and downward uncertainty and ramping needs to be included in the market optimization.
- Recognizing the capacity value of physical resources relative to virtual resources.

This section includes the following sub-sections:

- Section 3.1 provides an overview of the proposed day-ahead market products.
- Section 3.2 describes energy and reliability energy pricing.
- Section 3.3 describes the nodal deliverability of reliability energy and imbalance reserves.
- Section 3.4 describes the concept of including energy cost in the procurement of reliability capacity and imbalance reserves.
- Section 3.5 describes real-time bidding obligations for resources that day-ahead awards.
- Section 3.6 describes resource adequacy day-ahead must offer obligations.
- Section 3.7 describes the bidding and scheduling of variable energy resources.
- Section 3.8 describes day-ahead market eligibility and bidding rules.
- Section 3.9 describes various settlement rules.
- Section 3.10 describes modifications to congestion revenue rights under the day-ahead market enhancements.
- Section 3.11 describes modifications to market power mitigation from the day-ahead market enhancements.
- Section 3.12 describes the methodology to determine the imbalance reserves procurement quantity.

3.1. New Market Products

The CAISO proposes new day-ahead market products to reserve real-time dispatch capability. The first of these products is reliability energy (and the associated reliability capacity up/down), which replaces the existing residual unit commitment process to schedule sufficient dispatch capability to meet the load forecast. The second of these products is imbalance reserves, which will ensure the day-ahead market schedules sufficient real-time dispatch capability to meet net load imbalances that materialize between the day-ahead and real-time markets.

Table 1 summarizes the new day-ahead market products. It also includes the existing day-ahead market products for completeness.

Table 1: Proposed and existing day-ahead market products

Title	Acronym	Purpose	Eligibility*	Status
Energy	EN	Energy schedules cleared to meet bid-in demand	All resources	Existing
Reliability Energy	REN	Physical resources cleared to meet the load forecast	60-minute dispatchable physical resources, award based on 60-minute ramp capability	Proposed
Reliability Capacity, Up	RCU	Incremental capacity procured to meet the positive difference between the load forecast and cleared demand	As above	Proposed
Reliability Capacity, Down	RCD	Decremental capacity procured to meet the negative difference between load forecast and cleared demand	As above	Proposed
Imbalance Reserves, Up	IRU	Incremental capacity procured relative to the load forecast to meet the upward uncertainty requirement	15-minute dispatchable physical resources, award based on 15-minute ramp capability	Proposed
Imbalance Reserves, Down	IRD	Decremental capacity procured relative to the load forecast to meet the downward uncertainty requirement	As above	Proposed
Ancillary Services	AS	Incremental capacity procured and reserved to meet real-time regulation and contingency reserve requirements	Resources certified to provide the respective service	Existing

Title	Acronym	Purpose	Eligibility*	Status
Corrective Capacity, Up	CCU	Incremental capacity procured and reserved for corrective action after specific corrective transmission contingencies	All 5-minute dispatchable resources, award based on 20-minute ramp capability	Planned[2]
Corrective Capacity, Down	CCD	Decremental capacity procured and reserved for corrective action after specific corrective transmission contingencies	As above	Planned

**Additional eligibility requirements are described in Section 3.8.*

This document provides an overview of the proposed market products. Additional details describing the market optimization formulation are presented in the Day-Ahead Market Enhancements Draft Technical Description.

Energy (EN)

The energy (EN) schedule will be essentially the same day-ahead market schedule that results from the current integrated forward market. The market determines energy schedules by clearing physical and virtual supply against bid-in demand. Energy will continue to be priced at each node resulting in a LMP for energy. Resources with day-ahead energy will be able to re-bid (self schedule or economically bid) the energy into the real-time market.

Reliability Energy (REN) and Reliability Capacity (RCU/RCD)

The reliability energy product (and the associated reliability capacity up/down) will replace the existing residual unit commitment process. The residual unit commitment process is currently a separate market process that is run after the integrated forward market and is used to ensure sufficient resources are committed to meet the load forecast. By including reliability energy in a single market optimization, the day-ahead market will more efficiently co-optimize products and schedule resources to meet both bid-in demand and the load forecast.

For example, a resource may need to be committed to meet forecast load that is not needed to meet cleared bid-in demand. If that resource is committed, it may be more economic to also use that resource to meet cleared bid-in demand. The existing sequential integrated forward market and residual unit commitment process cannot do this because the integrated forward market and residual

[2] Corrective capacity was developed in the CAISO's Contingency Modeling Enhancements (CME) initiative, which the CAISO has not yet filed with FERC and plans to implement concurrently with the market changes resulting from this day-ahead market initiative. This paper includes discussion of corrective capacity because this product, when implemented, will be co-optimized with the other day-ahead market enhancements. Additional information related to corrective capacity and CME can be found in the draft final proposal: http://www.caiso.com/StakeholderProcesses/Contingency-modeling-enhancements

unit commitment processes run separately. Because reliability energy and energy will be co-optimized in a single market run, the market will be able to schedule the optimal set of resources to meet both cleared bid-in demand and the load forecast.

Similar to the existing residual unit commitment process, the optimization will consider transmission constraints in scheduling reliability energy. Unlike the existing residual unit commitment process, reliability energy will also allow the day-ahead market schedule resources to provide downward dispatch capability and/or de-commit resources if the load forecast is less than demand that clears the day-ahead market. A difference between the energy schedule and the reliability energy schedule will result in an obligation to provide economic energy bids to the real-time market.

Adding reliability energy to the day-ahead market will create two types of day-ahead market energy schedules and LMPs: (1) A day-ahead energy schedule and price that is based on cleared bid-in demand. Supply and demand, including virtual supply and demand will have day-ahead energy schedules. (2) A reliability energy schedule and that is based on the load forecast and may be different than a resource's energy schedule. Only physical supply (internal generation, participating load models, imports, and exports) will have reliability energy schedules.

The day-ahead market will financially settle supply resources' energy schedules (i.e. those based on cleared bid-in demand) at energy LMPs and will settle their reliability energy and reliability capacity up/down schedules at reliability energy LMPs. The market will settle load's energy schedules (i.e. those based on cleared bid-in demand) at the energy LMPs. The market will recover the costs of reliability energy and reliability capacity up/down through a cost allocation.

The reliability energy schedule will be the outcome of additional objectives included in the new day-ahead market formulation that will clear additional physical supply to meet the hourly load forecast above or below the cleared bid-in demand. This is somewhat analogous to the existing market's residual unit commitment schedules, which are schedules for resource dispatch capability to be available in the real-time market above any day-ahead market energy schedule.

A reliability capacity schedule (reliability capacity up (RCU) or reliability capacity down (RCD)) will be defined by a resource's reliability energy (REN) schedule in relation to its energy (EN) schedule. It represents resource capacity scheduled to provide dispatch capability to account for differences between cleared demand and the load forecast. A resource will not receive both a RCU schedule and a RCD schedule.

A resource's reliability energy (REN) schedule will be equal to its day-ahead energy schedule (EN) plus its reliability capacity up (RCU) schedule, or minus its reliability capacity down (RCD) schedule:

$$REN = EN + RCU - RCD$$

Thus, a resource can have the following types of schedules:

- REN that corresponds to its EN schedule
- RCU, which is unloaded REN above a resource's EN schedule
- RCD, which is loaded REN below a resource's EN schedule

These schedules are illustrated in Figure 1 and Figure 2 below.

A reliability capacity award will result in an obligation to economically bid the capacity range of the reliability capacity schedule into the real-time market. Similar to energy, reliability energy will be based on a resource's sixty-minute ramp capability. Only physical resources will be able to provide reliability energy (and the associated reliability capacity up/down) as it represents physical energy and capacity to meet the load forecast).

At the balancing authority area level, reliability capacity will net in either the upward or the downward direction. However, reliability capacity at a resource level may be scheduled in the upward or downward direction despite the direction it nets at the balancing authority area level. This may occur because of transmission congestion.

Imbalance Reserves (IRU/IRD)

Imbalance reserves will ensure the day-ahead market schedules sufficient real-time dispatch capability to meet load imbalances between the day-ahead and real-time markets. These imbalances are due to net load uncertainty and ramping differences between hourly day-ahead market and fifteen-minute real-time market schedules. Imbalance reserves will be comprised of imbalance reserves up (IRU) that will provide upward dispatch capability and imbalance reserves down (IRD) that will provide downward dispatch capability. Unlike reliability energy, the market may schedule a resource to provide both IRU and IRD. Similar to reliability energy, an imbalance reserve schedule will result in an obligation to provide economic energy bids to the real-time market.

Under the proposed enhancements, the day-ahead market will co-optimize and procure imbalance reserves to meet the imbalance reserve requirement relative to the system operator forecast.[3] As with both energy and reliability energy, the market optimization will consider transmission constraints to ensure imbalance reserves are deliverable. This is described in more detail in Section 3.3 As with energy and reliability energy, the market will price imbalance reserves at each node.

Imbalance reserves will enable the market to more appropriately compensate resources that provide flexible capacity to meet net load uncertainty, and will result in more accurate price formation by taking out-of-market actions that system operators currently use and incorporating them into the market. Today, system operators may take out-of-market actions to secure additional supply to increase the ramp capability available to the real-time market and to address uncertainty between the day-ahead

[3] The proposal for setting the imbalance reserve requirement is discussed in Section 3.12.

and real-time markets. These out-of-market actions include increasing the load forecast used by the residual unit commitment process and/or the real-time market and manually dispatching resources. System operators have increasingly taken such actions because of the increased variability resulting from increasing amounts of variable energy resources.

An imbalance reserve award will result in an obligation to economically bid the capacity range of the award as energy into the real-time market. This will ensure the fifteen-minute market has sufficient economic bids to meet energy imbalances that may materialize between the day-ahead and real-time markets.

The day-ahead market will only award imbalance reserves to resources that are dispatchable in the fifteen-minute market. Although the day-ahead market will schedule imbalance reserves hourly, it will procure them based on a resource's fifteen-minute ramp capability. Only physical resources will be able to provide imbalance reserves as they represent physical resource capacity to meet the load imbalances in the real-time market.

Figure 1 and Figure 2 are representations of the relationship between energy, reliability energy, and imbalance reserves. Figure 1 illustrates this relationship when the forecast is greater than cleared bid-in demand. Figure 2 illustrates this relationship when the forecast is less than cleared bid-in demand.

Figure 1: Day-ahead market products when forecast is greater than cleared bid-in demand

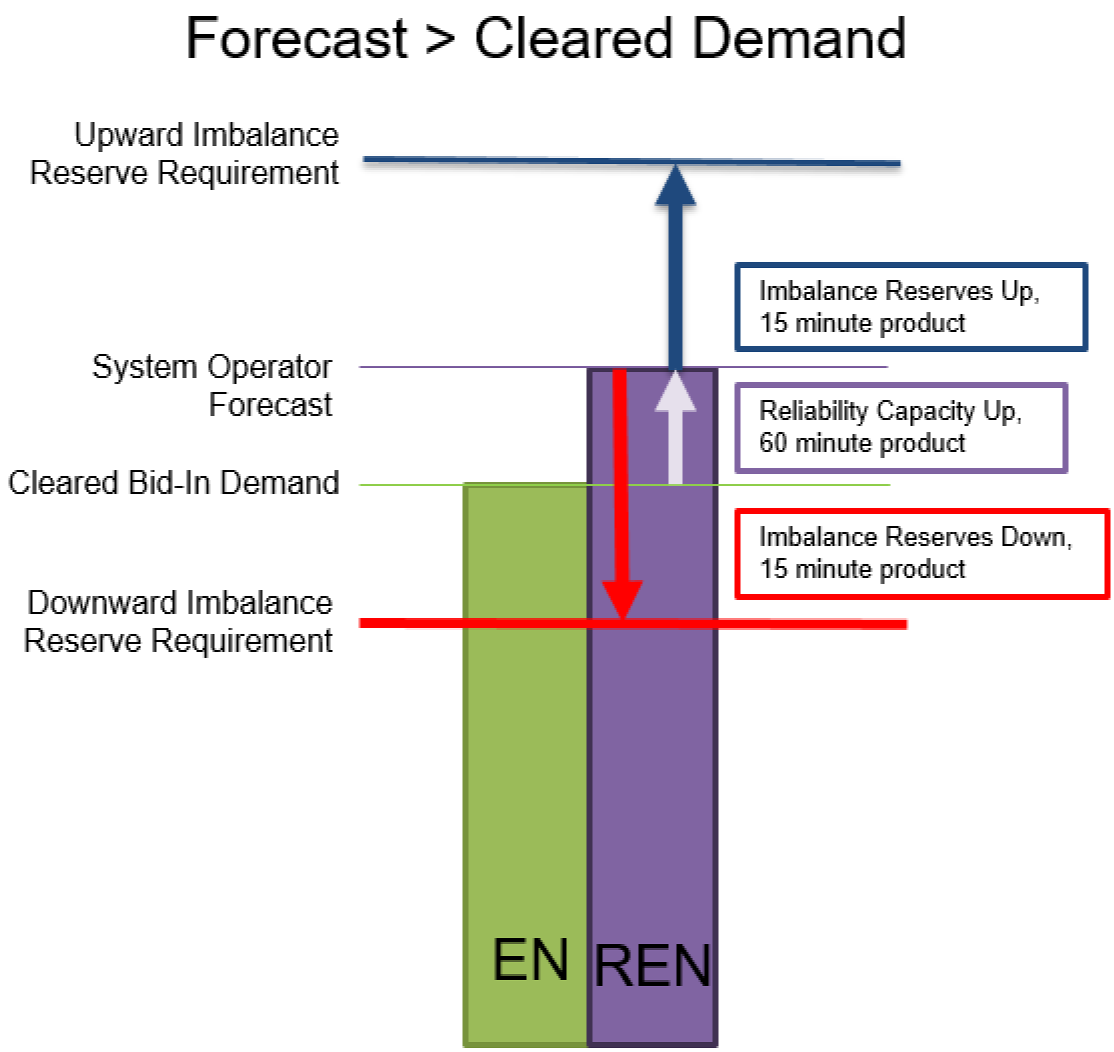
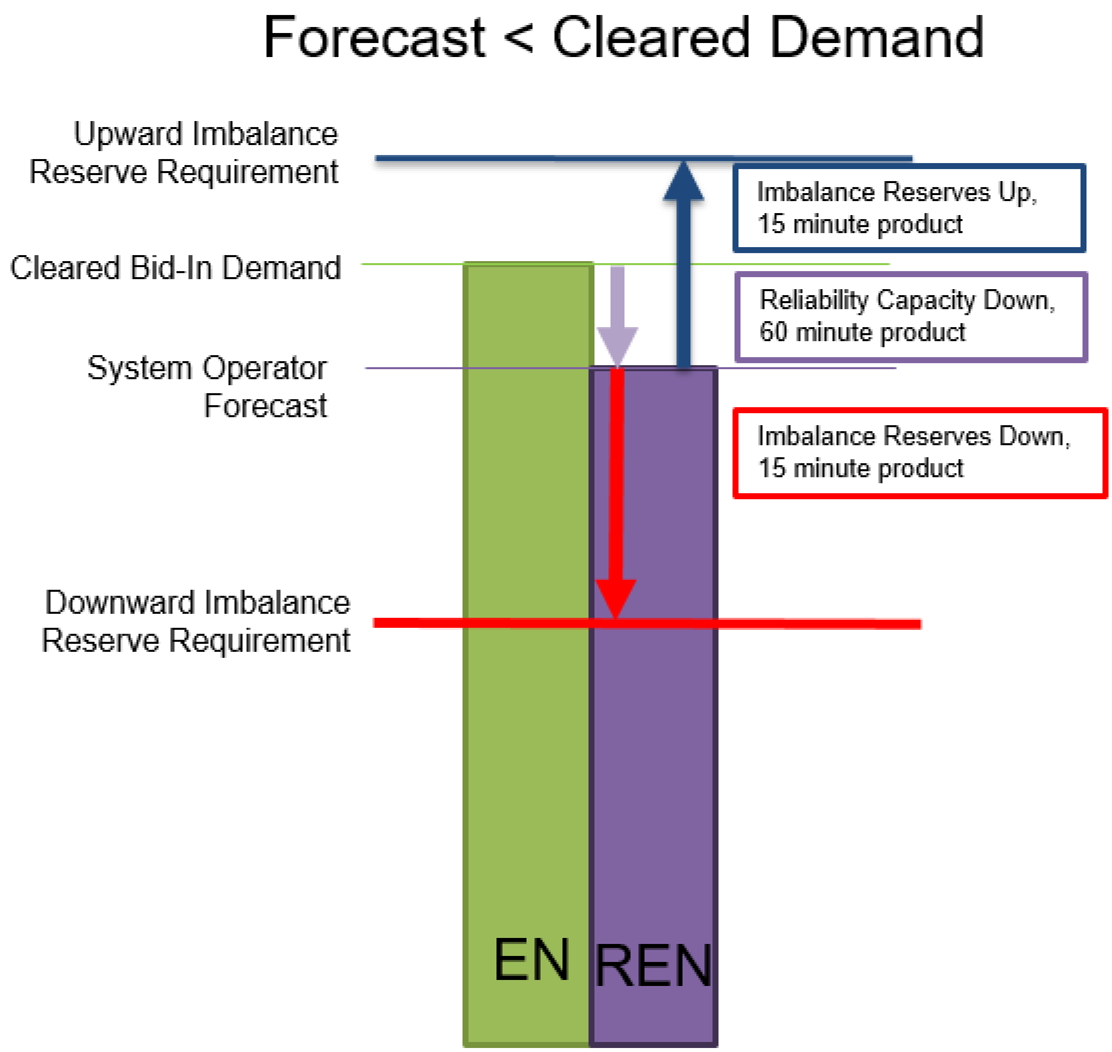


Figure 2: Day-ahead market products when forecast is less than cleared bid-in demand



Ancillary Services

The day-ahead market also procures 100 percent of the expected requirement for four ancillary services:

- Regulation up is procured from certified resources that can respond to the 4 second automated generation control signal to address increases in the net load that occur within a five minute dispatch interval.
- Regulation down is procured from certified resources that can respond to the 4 second automated generation control signal to address decrease in the net load that occur within a five minute dispatch interval.
- Spinning reserves are procured from certified resources that are synchronized to the grid and can be called upon if a contingency event occurs.
- Non-spinning reserves are procured from certified resources that are not synchronized to the grid and can be called upon if a contingency event occurs.

The CAISO is not proposing any changes to ancillary service procurement. They will continue to be procured on a regional basis and not nodally.

Corrective Capacity

With the implementation of contingency modeling enhancements, the day-ahead market will also procure corrective capacity to ensure electrical flows will not exceed emergency transmission system limits immediately after a transmission constraint. Corrective capacity products will compensate generation that is not scheduled for energy because it is positioned so that it can be used to return electrical flows to within normal transmission limits within the required timeframes in the event of a contingency.

3.2. Energy and Reliability Energy Pricing

There will be two LMPs calculated at each location under the proposed day-ahead market design:

- LMPs for day-ahead energy based on physical/virtual supply and physical/virtual demand that reflect the marginal cost of balancing supply and demand bids. Resources with an energy schedule will have an imbalance energy settlement for differences between the day-ahead and real-time energy schedules.
- LMPs for reliability energy (which will also apply to the associated reliability capacity up/down) from physical supply that reflect the marginal capacity cost of the additional incremental/decremental capacity required to meet the system operator's forecast. There will be no imbalance energy settlement for reliability energy because it does not exist in the real-time market. Reliability capacity up and reliability capacity down will result in an obligation to submit economic bids into the real-time market or be subject to no-pay provisions.

In the existing day-ahead market, the calculated energy LMPs reflect the marginal cost of energy from physical/virtual supply and bid-in/virtual demand alike. The energy LMP is greater than or equal to the cleared physical/virtual energy supply bids and less than or equal to the cleared physical/virtual energy demand bids applicable to each location. This means the energy LMPs are consistent with both cleared energy supply and demand bids.[4]

Under the proposed day-ahead market enhancements, each physical supply resource will receive a payment for both its energy schedule and its reliability energy schedule, which will overlap. The sum of the energy LMP and the reliability energy LMP will be greater than or equal to a resource's cleared energy bid.[5] Unlike for energy, load bids will not clear against reliability energy supply bids. The day-ahead market will clear reliability energy supply against the load forecast. Consequently, the energy LMP will be less than or equal to cleared energy demand bids.

Load will pay the costs of reliability energy through a cost allocation. The allocation will decompose reliability energy into its parts because each part has a different cost allocation. The portion of reliability energy not corresponding to reliability capacity up/down will be allocated to scheduled demand and cleared virtual demand. The reliability capacity up and down will be allocated through the tier allocation similar to the residual unit commitment cost allocation in the existing market.[6] Additional details of the proposed settlement rules are in Section 3.9.

Figure 3, Figure 4, and Figure 5 represent a physical generator with an energy bid of $30/MWh. The generator's schedule is consistent with the energy bid for the portion of the reliability energy schedule that overlaps with the energy schedule. The difference between the reliability energy schedule and the energy schedule is compensated for at the clearing price for reliability capacity up or down.

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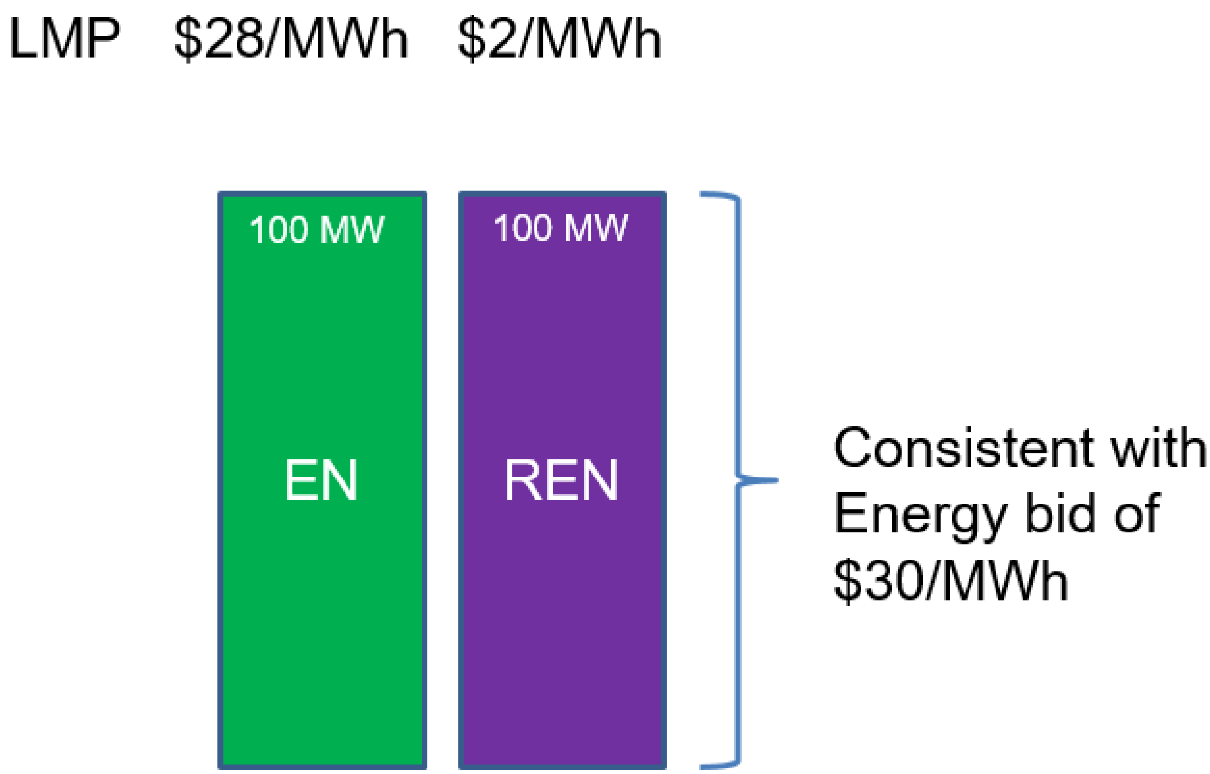
4 Note that LMPs may not be consistent with energy bids due to resource inter-temporal constraints. In this case, resources may receive bid cost recovery payments.

5 ibid.

6 Elsewhere in the paper, the portion of the REN schedule not corresponding to RCU or RCD is paraphrased as "REN: EN", whereas the portion of the REN schedule that does correspond to RCU or RCD is paraphrased as "REN: RCU" or "REN: RCD".

In Figure 3, a physical generator submits a $30/MWh energy bid, a $2/MWh reliability capacity up bid, and a $2/MWh reliability capacity down bid into the day-ahead market. For this resource, the energy schedule and reliability energy schedule clear at the same value of 100 MW. The LMP for energy is $28/MWh. The LMP for reliability energy is $2/MWh. The 100 MW of energy and reliability energy together are paid consistently with the resource's $30/MWh energy bid ($28/MWh + $2/MWh). Because energy and reliability energy are the same, reliability capacity is not needed or cleared for this resource.

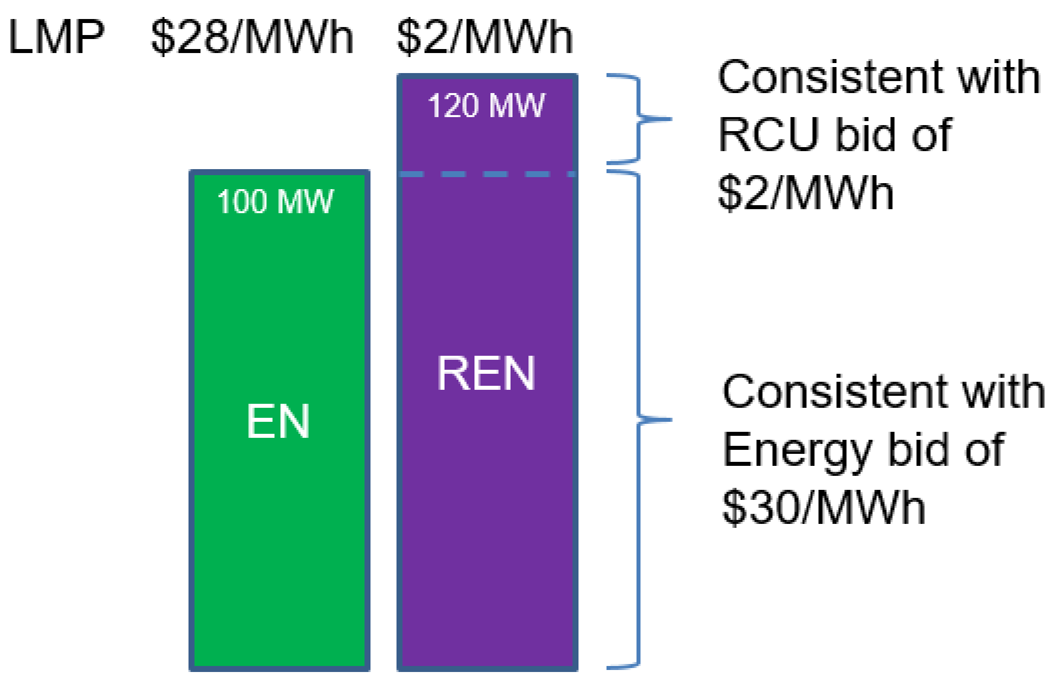
Figure 3: A physical generator with a $30/MWh energy bid when the energy and reliability energy schedules are equal



Schedule Type	Schedule Quantity	LMP	Payment
EN	100 MW	$28/MWh	$2800
REN: EN	100 MW	$2/MWh	$200
REN: RCU/RCD	0 MW	$2/MWh	$0
		Total	$3000

In Figure 4, a physical generator submits a $30/MWh energy bid, a $2/MWh reliability capacity up bid, and a $2/MWh reliability capacity down bid into the day-ahead market. For this resource, the energy schedule clears at 100 MW and reliability energy schedule clears at 120 MW. The LMP for energy is $28/MWh. The LMP for reliability energy is $2/MWh. The 100 MW of energy schedule and the overlapping 100 MW of reliability energy together are paid consistently with the resource's $30/MWh energy bid ($28/MWh + $2/MWh). The 20 MW of reliability energy in excess of the energy schedule is paid consistently with the reliability capacity up bid of $2/MWh.

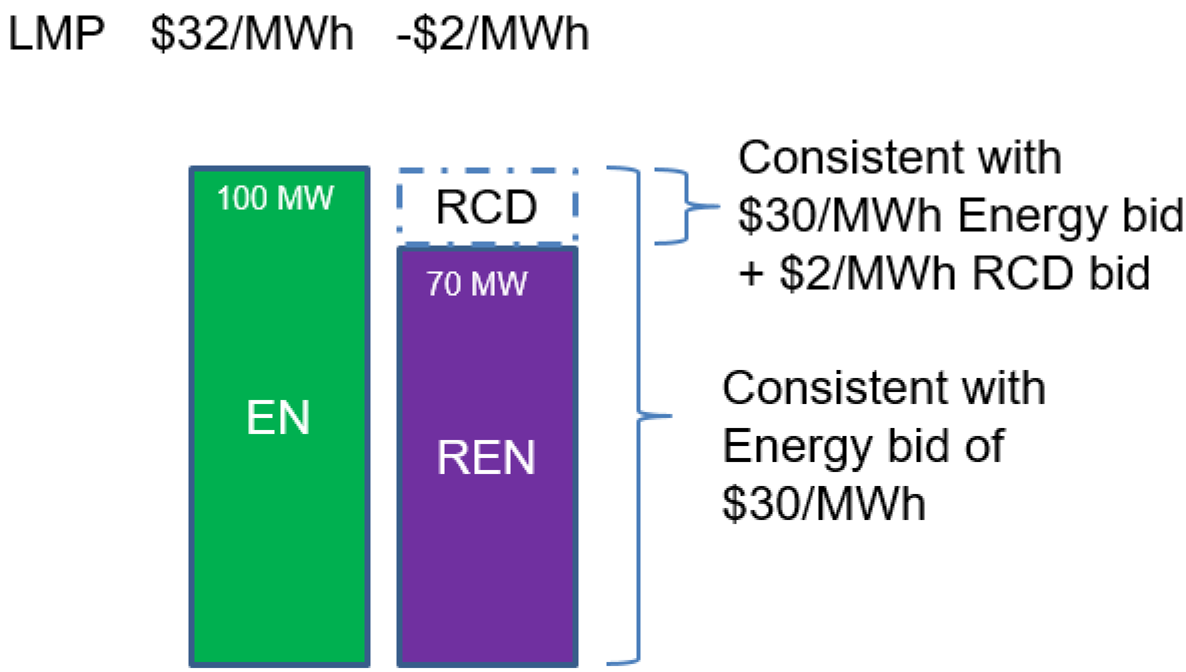
Figure 4: A physical generator with a $30/MWh energy bid when energy is less than reliability energy



Schedule Type	Schedule Quantity	LMP	Payment
EN	100 MW	$28	$2800
REN: EN	100 MW	$2	$200
REN: RCU	20 MW	$2	$40
		Total	$3040

In Figure 5, a physical generator submits a $30/MWh energy bid, a $2/MWh reliability capacity up bid, and a $2/MWh reliability capacity down bid into the day-ahead market. For this resource, the energy schedule clears at 100 MW and reliability energy schedule clears at 70 MW. The LMP for energy is $32/MWh. The LMP for reliability energy is -$2/MWh. The resource's overall settlement, considering its 100 MW energy schedule and its 100 MW of REN:EN, is consistent with its $30/MWh energy bid. This is because it is paid $32/MWh for energy and charged $2/MWh for REN:EN for 100 MW. In addition, the resource is paid $2/MWh for the 30 MW RCD award, which is consistent with its $2/MWh RCD bid.

Figure 5: A physical generator with a $30/MWh energy bid when energy is greater than reliability energy



Schedule Type	Schedule Quantity	LMP	Payment
EN	100 MW	$32	$3200
REN: EN	100 MW	-$2	-$200
REN: RCD	30 MW	$2	$60
		Total	$3060

Previous stakeholder comments expressed concern that settling virtual supply and demand at different prices than physical supply could lead to a gaming opportunities. For example, a market participant could bid virtual demand and physical supply at the same location and receive a reliability energy payment for a reliability energy schedule without the resource actually being available in real-time. In the day-ahead market, the physical supply would be paid for energy and reliability energy. The market participant would then submit an expensive energy bid in the real-time market so the resource does not operate, and the virtual demand settlement will hedge the resource's imbalance energy costs. The market participant would receive a reliability energy payment despite the resource not operating to meet real-time load.

To address this concern, the proposed day-ahead market enhancements will include virtual demand in the cost allocation of the portion of reliability energy not corresponding to reliability capacity up/down. Thus, the reliability energy payment will be offset by the cost allocation to virtual demand.

3.3. Reliability Energy and Imbalance Reserves Deliverability

Under the proposed day-ahead market enhancements, the market will consider transmission constraints while optimizing reliability energy and imbalance reserves to ensure they are deliverable.[7] This will address an existing issue identified with the real-time market's flexible ramping product, which is somewhat similar to imbalance reserves. The CAISO summarized these issues in the CAISO Energy Markets Price Performance Report published on September 23, 2019.[8]

This issue arises because the market does not consider locational constraints when procuring the flexible ramping product. Procurement of the flexible ramping product is based on opportunity costs, which arise from the trade-offs between the need for energy and the need for ramping capability. This results in under-utilization or under-deployment of the flexible ramping product.

The complication relates to congestion from internal constraints within a balancing authority area. The market enforces transmission constraints within each balancing authority area, 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. Since the flexible ramping product is not locational-based, this part of congestion management does not explicitly account for the flexible ramping product procurement. As a result, the market can procure upward flexible ramping capacity from resources that are dispatched down for congestion management, which cannot be deployed if uncertainty materializes in the next market run because of the need to manage the congestion. This interplay between congestion and flexible ramping product procurement can be further complicated because the market may find it optimal to allocate upward flexible ramping product capacity precisely to resources dispatched down for congestion management. A similar dynamic exists

7 The term "deliverable" is not in reference to interconnection requirements or the annual resource adequacy deliverability assessment.

8 The report is available at http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf

for downward flexible ramping capacity and resources dispatched higher for energy to provide counter flow to mitigate congestion.

Consequently, under the proposed enhancements reliability energy (and the associated reliability capacity up/down) as well as imbalance reserves will be deliverable:

- Reliability energy will be deliverable at the nodal level
- Similar to the residual unit commitment process of today, the transmission constrained power flow for reliability energy will result in deliverable reliability capacity
- Imbalance reserves up and down will be deliverable at the nodal level
- The day-ahead market optimization will include deployment scenario constraints (described below) that will ensure imbalance reserves up are not awarded behind binding constraints
- The day-ahead market optimization will include deployment scenario constraints that will ensure imbalance reserves down are not awarded to resources providing counter flow on binding constraints

A deployment scenario is a capacity deployment simulation with power balance and transmission constraints that ensure that capacity awards are procured in optimal locations for meeting the deployment objective without violating transmission constraints. It models the power flow at the level of demand of the respective imbalance reserve up and imbalance reserve down procurement targets. Additional details about the formulation of the deployment scenarios are described in Day-Ahead Market Enhancements Draft Technical Description.

The CAISO is developing a similar approach in a separate initiative to improve deliverability of the real-time market's flexible ramping product.

The CAISO acknowledges the use of deployment scenarios requires complex computational solutions. The CAISO will work diligently to ensure that the use of the deployment scenarios will not compromise the performance of the day-ahead market in producing a solution within the applicable timeline. However, if the deployment scenarios lead to unacceptable solution times, the CAISO will evaluate different levels for nodal deliverability. For example, the current approach is N-1 deliverable whereas base case deliverability may be adequate. The intentions of the deployment scenarios are not to prevent all stranded capacity because system conditions have changed. The purpose is to ensure that, given information at the time of the market optimization, imbalance reserves are not awarded to resources that are known not to be deliverable if system conditions did not change.

Lastly, if the nodal deliverability approach turns out to not be feasible because of impact to the computational performance of the day-ahead market, it may be necessary to fall back on using zonal procurement of imbalance reserves. This approach would use the same zones as the ancillary service zones to procure imbalance reserves. A minimum requirement would be set for each zone and imbalance reserves would be procured within the zone (including imports/exports) to meet the procurement target.

3.4. Considering Energy Costs and Imbalance Procurement

Ideally imbalance reserves and reliability capacity should be awarded to resources with the lowest underlying combined energy and capacity costs. This is necessary because imbalance reserves and reliability capacity have a relatively high likelihood of being dispatched for energy in the real-time market.[9] This concern of considering underlying combined energy and capacity costs is not as much of an issue for contingency reserves because they are not dispatched as often.

Considering energy and capacity costs when awarding capacity is an existing shortfall of the residual unit commitment process. If two resources have the same residual unit commitment availability bid, but different energy bid cost, the residual unit commitment optimization does not distinguish between the resources and is indifferent as to which resource to choose. However, the optimal solution would be to schedule the resource with the lower combined energy and capacity cost.

A related issue exists for the existing flexible ramping product in the real-time market. In the CAISO Energy Markets Price Performance Report, the CAISO identified that the upward flexible ramping product was being awarded to proxy demand response resources with energy bids at or near the energy bid cap of $1,000/MWh. This occurs because the real-time market optimization clears the flexible ramping product based on the lowest opportunity cost of a resource not being dispatched for energy. Since the energy bids from these resources are so high, it is not economic to schedule them for energy, which results in no opportunity costs and the optimization awards the resource upward flexible ramping product. It would be more efficient to award the upward flexible ramping product to the lowest cost resource not scheduled for energy because that is the next resource in the bid stack that will be dispatched if uncertainty materializes.

The CAISO continues to examine mechanisms to consider combined energy and capacity costs in the day-ahead market's imbalance reserve and reliability capacity procurement. The CAISO is considering mechanisms to reflect these underlying costs in resource's imbalance reserve and reliability capacity offers and anticipates providing a proposal in the next iteration of the policy design.

3.5. Real-Time Bidding Obligations based on Day-Ahead Awards

Resources that receive reliability capacity or imbalance reserve awards in the day-ahead market will have real-time market bidding obligations. Resources must economically bid the full range of their RCU/RCD or IRU/IRD awards into the real-time market. Real-time must offer obligations apply in the hourly intervals that a resource has a RCU/RCD or IRU/IRD schedule.

The purpose of the real-time must offer obligation is to provide economic bids to the real-time market. Economic bids enable the real-time market to re-dispatch resources to meet real-time system conditions and imbalances. Real-time self-schedules do not provide the real-time market with the ability to re-

[9] Conversely, for downward capacity, imbalance reserves and reliability capacity should be awarded to resources with higher underlying energy costs.

dispatch the resource unless a power balance constraint is relaxed or congestion requires the un-economic curtailment of self-schedules. These rules are further summarized and illustrated in Figure 6**.**

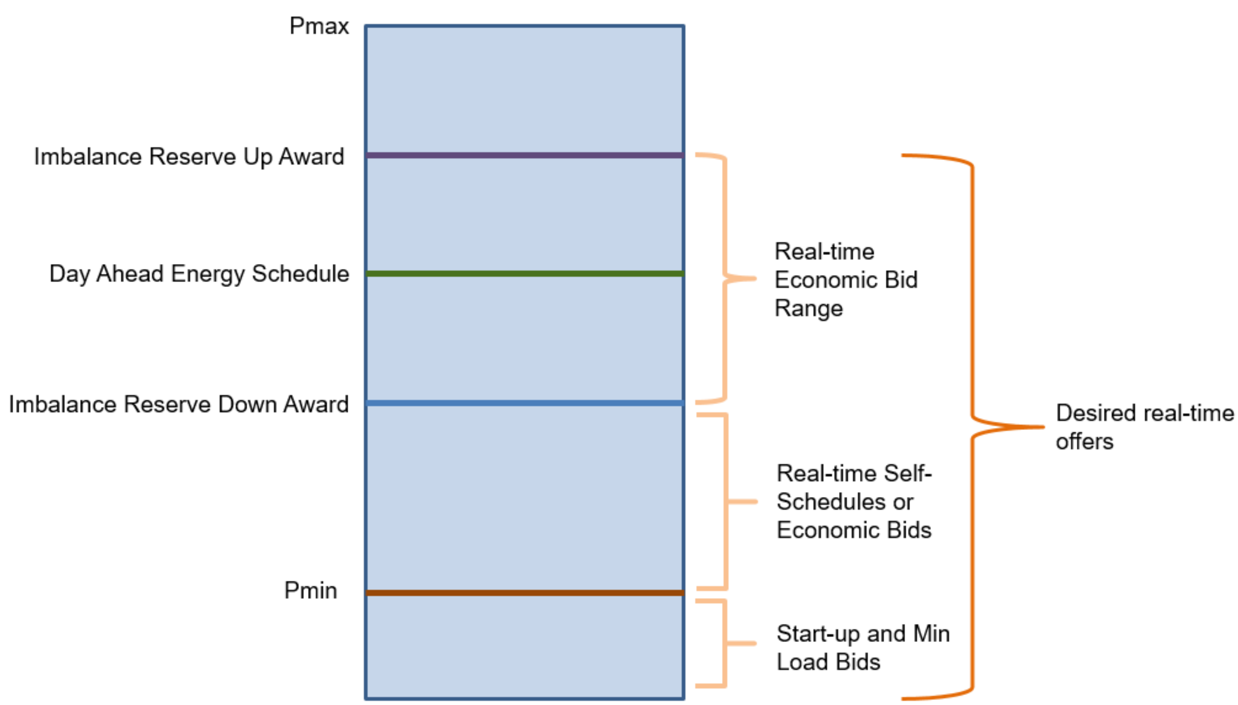
In the example below, since there are no reliability capacity awards, the resource's energy and reliability energy schedules are equal. The real-time must offer obligation rules are the same for imbalance reserves as they are for reliability capacity.

A resource that can be committed in the real-time market can submit start up and minimum load bids to enable the market to re-optimize the unit commitment decision. This is not a requirement because the resource can elect to self-schedule a portion of its output.

A resource cannot submit a self-schedule that exceeds its reliability energy schedule less its imbalance reserve down and reliability capacity down awards. This ensures that there are sufficient economic offers to allow the real-time market to dispatch the resource below its day-ahead energy schedule.

A resource must submit economic bids above its reliability schedule by the amount of imbalance reserves awarded. The resource is not required to submit additional bids up to PMax, but may elect to do so. This ensures that there are sufficient economic offers to allow the real-time market to dispatch the resource above its day-ahead energy schedule.

Figure 6: Real-rime bidding obligations



The CAISO has contemplated various settlement rules to encourage and/or enforce appropriate bidding behavior. These alternatives are discussed in Section 3.9.

3.6. Resource Adequacy Day-Ahead Must Offer Obligations

The following summarizes the resource adequacy must offer obligations for the day-ahead market. Additional detailed rules are being developed in the Resource Adequacy Enhancements[10] initiative.

Resource adequacy resources will continue to be required to bid their resource adequacy capacity into the day-ahead market. Resources providing system and local resource adequacy will be required to bid or self-schedule for energy and bid or self provide ancillary services. Additionally, resources providing system and local resource adequacy will be required to economically bid for reliability capacity and corrective capacity. Resources providing flexible resource adequacy will be required to economically bid (not self schedule) for the previous products and imbalance reserves.

With the exception of flexible resource adequacy, if a resource self-schedules its entire resource adequacy obligation into the day-ahead market for energy or ancillary services, economic bids will not be required for any of the other products.

If a resource economically bids its entire resource adequacy obligation for energy and ancillary services, the resource must economically bid for reliability capacity and corrective capacity. It will be optional for resources providing system and local resource adequacy to bid for imbalance reserves.

If a portion of the resource is self-scheduled for energy or ancillary services, the resource will be required to economically bid the rest of the resource's obligation for energy, ancillary services, reliability capacity and corrective capacity.

Resource adequacy resources will have the same real-time must offer obligation as any other resource based upon day-ahead awards.

3.7. Variable Energy Resources

In the real-time market, variable energy resources are scheduled and dispatched based upon the forecasted output of the resource. The forecast is updated every five minutes whereas bids are submitted hourly and used in both the fifteen-minute market and five-minute real-time dispatch. The forecast is used as the upper economic limit of the resource's bid curve. This allows the bid curve to be updated within the operating hour to ensure the resource receives a feasible dispatch. There is also an alternative option for resources to submit their own five-minute forecast. This forecast is used for settlement purposes but the market optimization still uses the system operator's forecast to clear the market.

Currently in the day-ahead market, variable energy resources can schedule or bid any quantity in each operating hour regardless of the system operator's forecast of the resource's output. However, in the residual unit commitment process, the CAISO adjusts the system operator's forecast that is used to set

10 Additional information on the Resource Adequacy Enhancements initiative is available at http://www.caiso.com/StakeholderProcesses/Resource-Adequacy-Enhancements

the residual unit commitment procurement target based on the difference between the variable energy resources day-ahead schedules and the system operator's forecast output of the resources. This allows the CAISO to account for the *expected* output of variable energy resources, regardless of the bid quantity. Integrating the residual unit commitment process into the new day-ahead market design will require both the system operator's load forecast and variable energy resources' forecast to be included in the optimization. The reliability energy schedule for variable energy resources will be based upon the system operator's day-ahead forecast of the resource.

The CAISO proposes to limit the upper economic limit of variable energy resources to the system operator day-ahead forecast. This will ensure the resource's energy schedule does not exceed the system operator's forecast. Unlike the real-time market, resources will not be allowed to submit their own forecast to be used for settlement purposes. If resources have concerns regarding the system operator's forecast and want to take a different position in the day-ahead market, they will be able to account for differences between their forecast and the system operator forecast through the use of virtual bids. The system operator's forecast for variable energy resources will be known to the market participant prior to the bid submission deadline for the day-ahead market.

If a resource's own forecast is higher than the system operator forecast of their resource, the market participant will be able to submit virtual supply offers for the difference. The virtual supply has the effect of extending the resource's energy bid curve to the resource's forecast. If a resource's forecast is lower than the system operator forecast, the market participant could submit virtual demand offers. The virtual demand has the effect of shortening the resource's bid curve to the resource's forecast (or desired day-ahead market position). The use of virtual bids will enable the market participant to have its preferred day-ahead position energy settled at the day-ahead price. The CAISO has posted an Excel worksheet that illustrates the use of virtual bids to address differences in the forecasted energy.

By using the system operator's forecast to establish the reliability energy schedule, a variable energy resource that does not bid or only self-schedules into the day-ahead market could receive a reliability capacity up or down award, which creates a real-time must offer obligation. The following summarizes how variable energy resources' day-ahead energy and reliability energy will be related based upon their level of participation.

No bid: cleared EN = 0 MW, REN = system operator forecast, but is not settled (described below)

Self-schedule Only: cleared EN = REN = system operator forecast

Economic bid: cleared EN + RCU – RCD = REN <= system operator forecast

If a variable energy resource does not submit a bid, the market optimization will use the system operator forecast to schedule reliability energy. Because the energy schedule and the reliability schedule are not equal, this would otherwise result in a reliability capacity up award equal to the system operator forecast. The award would be paid the reliability energy price, but would also be subject to the reliability capacity up real-time must offer obligation. The CAISO does not believe it would be appropriate to subject a resource that did not want to participate in the day-ahead market to a real-time must offer obligation. Therefore, the CAISO proposes to not pay a resource that does not bid into the day-ahead market for its reliability capacity up award so it is not forced to participate in the real-time market. Since the resource will not be paid for reliability capacity up, the cost allocation to load will likewise be reduced.

Variable energy resources that only provide self-schedules in the day-ahead market will not be subject to the real-time must offer obligation. This is because under this scenario cleared energy and reliability energy are equal, so there is no reliability capacity awarded to the variable energy resource. Essentially, it will not be possible for a resource to self-schedule a quantity that differs from the CAISO forecast. When market participants want an energy schedule for the variable energy resources at a value different than the forecast, they will be able to use virtual bids. For example, if the market participant's forecast is 110 MW and the system operator's forecast is 100 MW, the market participant will need to submit a 10 MW virtual supply bid in order to receive a day-ahead energy schedule consistent with the market participant's forecast. If the market participant's forecast (or desired day-ahead energy position) is lower than the system operator's forecast, the market participant will be able to submit a virtual demand bid for the difference.

Only variable energy resources that submit economic bids will be scheduled to provide reliability capacity or imbalance reserves. If a variable energy resource is awarded reliability capacity or imbalance reserves, the resource will have the same real-time bidding obligations as other resources. Since the bid curve will be limited by the system operator's forecast, if the market participant's forecast is higher than the system operator's forecast, virtual supply bids will need to be submitted to receive a higher energy schedule than the system operator's forecast. The difference between the forecasts will not be paid for reliability energy because the system operator does not believe this supply is physical because the system operator forecast is lower.

3.8. Day-Ahead Market Eligibility and Bidding Rules

The CAISO proposes the following day-ahead market eligibility rules:

- All physical supply, imports, and exports that can be scheduled in the fifteen-minute market can provide imbalance reserves. Imbalance reserves are procured for an entire hour but the amount of the award cannot exceed the fifteen-minute ramp capability of the resource.
- All physical supply, imports, and exports can provide reliability capacity.
- All physical supply that can be ramped in 20 minutes are eligible for corrective capacity.
- All resources (except RA resources that have specific bidding obligations) can opt out of bidding for reliability capacity, imbalance reserves, and corrective capacity.
- A detailed description of resource eligibility, including participating load, variable energy resources, proxy demand resources, and demand response can be found in Appendix B: Eligibility Table.

The CAISO proposes the following day-ahead market bidding rules:

- Market participants will submit separate bids for energy, ancillary services, RCU, RCD, IRU, IRD, CCU, and CCD.
- As is done today, bids will continue to be submitted by 10:00 AM and can have hourly price curves, but with a single segment for capacity products.
- The capacity bid MW quantity must be greater than zero and will be capped by the associated certification quantities that would consider the resource ramp rate over the product horizon (for example, imbalance reserves are fifteen minutes, spinning reserves are ten minutes).

3.9. Settlement Rules

The following section explains the proposed settlement rules for the new day-ahead market design. The settlement rules are also summarized in Appendix C: Settlement Table.

Day-Ahead Payments and Charges

The CAISO proposes the following day-ahead charges and payments for load, virtual supply, virtual demand, physical supply, imports, and exports. These resources will be settled for differences between the day-ahead energy schedule and real-time market energy schedule. There is not an imbalance settlement for reliability energy.

- Bid-in load will be charged the LMP of its load aggregation point for energy.
- Virtual supply and virtual demand will be paid/charged the LMP for energy.
- Internal generation, participating load models, imports, and exports will be paid/charged the LMP for energy plus reliability energy.

The CAISO proposes the following day-ahead payments for eligible resources that are awarded imbalance reserve or reliability capacity awards. These awards expire in the real-time market, and therefore will not be settled for real-time deviations.

- Resources that receive an imbalance reserve award will be paid the LMP for imbalance reserves in the upward or downward direction.
- Resources that receive a reliability capacity award will be paid the LMP for reliability energy.

Reliability Energy Cost Allocation

Reliability energy will have a direct settlement to generation, imports, and exports. The reliability energy cost allocation will be separated into its components (EN, RCU, and RCD) because each component has a different cost allocation billing determinant. The uplift cost for REN will be allocated as follows:

- EN capacity cost at the reliability energy marginal cost is allocated to cleared virtual supply/demand and bid-in load.
- RCU Tier 1 cost at the reliability energy marginal cost is allocated to net virtual supply and under-scheduled load.
- RCU Tier 2 cost will be allocated to metered demand.
- RCD Tier 1 cost at the reliability energy marginal cost is allocated to net virtual demand and over-scheduled load.
- RCD Tier 2 cost will be allocated to metered demand.

Imbalance Reserve Cost Allocation

With the introduction of imbalance reserves, uplift costs will occur to cover the procurement cost for imbalance reserves up and imbalance reserves down. The uplift cost for imbalance reserves up and down will be allocated as follows:

- IRU Tier 1 cost will be allocated to net negative demand deviation and net virtual supply.
- IRU Tier 2 cost will be allocated to metered demand.
- IRD Tier 1 cost will be allocated to net positive demand deviation between day ahead and real time, and net virtual demand.
- IRD Tier 2 cost will be allocated to metered demand.

Bid Cost Recovery

The revenue and bid costs from imbalance reserve awards will be included in the calculation of day-ahead bid cost recovery. Reliability energy schedules will be included as revenue in day-ahead bid cost recovery, but only the bid costs for reliability capacity up and reliability capacity down will be included as a cost. This is because the cost associated with the energy schedule in the reliability schedule uses the bid cost of the energy offer.

Currently, bid cost recovery is calculated separately for the day-ahead and real-time market. This will not change. However, bid cost recovery for resources committed in the residual unit commitment process are able to receive real-time bid cost recovery. This proposal eliminates the residual unit commitment as a stand-alone process, therefore the residual unit commitment bid cost recovery can be removed from real-time bid cost recovery. Resources committed in the day-ahead market, including resources that are scheduled for imbalance reserves and/or reliability capacity, will receive day-ahead bid cost recovery.

Resources committed after the close of the day-ahead market through a real-time market schedule or an exceptional dispatch will continue to receive real-time bid cost recovery.

Application of Grid Management Charge

The market services charge of the grid management charge covers the cost of bidding and clearing the market. Currently, the market services charge is applied to ancillary services awards in the day-ahead market and real-time market. Suppliers include this cost in the bid price for ancillary services. The market services charge is not applied to the flexible ramping product and corrective capacity because suppliers are not allowed to submit bids for those products. Since bids can be submitted for reliability capacity, imbalance reserves, and day-ahead corrective capacity, the market services charged will be applied for awards of these products. Suppliers will include this cost in their bids.

3.10. Congestion Revenue Rights

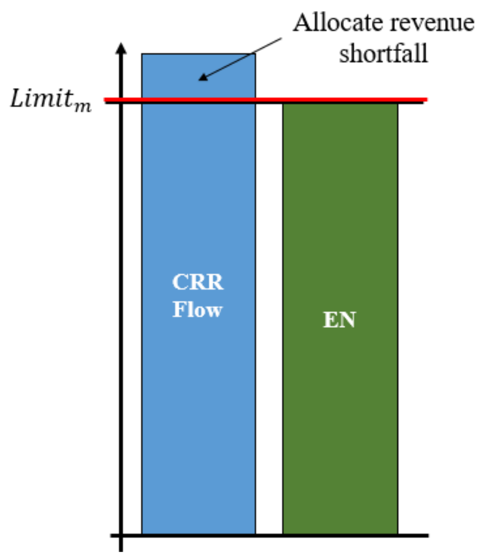
Congestion revenue rights are CAISO forward market products that hedge day-ahead market congestion costs. The CAISO proposes to modify congestion revenue rights settlement under the proposed day-ahead market changes to accommodate the addition of the reliability energy and imbalance reserve products. Reliability energy and imbalance reserves will contribute to transmission congestion, in addition to energy. Market participants will presumably find it desirable to also hedge this contribution to congestion costs. Under the CAISO's proposed changes, congestion revenue rights would also account for reliability energy and imbalance reserve congestion costs, in addition to the energy congestion costs that are the basis of their settlement today.

Today, congestion revenue rights receive congestion revenues collected in the day-ahead market on each binding transmission constraint between the congestion revenue right source and the sink. If there are two binding constraints between locations A and B and a market participant owns a congestion revenue right from A to B, the market operator pays the congestion revenue right the quantity of its right on those two constraints multiplied by the shadow price of each constraint. For example, if constraint 1 has a shadow price of $10 and constraint 2 has a shadow price of $5, a 100 MW congestion revenue right would be paid $1,500, which covers the congestion exposure between location A and B.

The CAISO, since implementing CRR Track 1B enhancements in Month, 2018, also assesses each constraint in the day-ahead market to ensure that each congestion revenue right is only paid the amount of revenues actually collected on each constraint in the day-ahead market. It does this by comparing the day-ahead energy schedules on each constraint to the total implied congestion revenue right flow on each constraint in the day-ahead market. When energy schedules are less than the implied congestion revenue right flows on a constraint, the day-ahead market does not collect enough congestion revenue to pay the full value of congestion revenue rights on that constraint. For example, if a constraint has 120 MW of implied congestion revenue right flow on it but only 100 MW of energy schedules, the CAISO pro-rata allocates the revenue shortfall due to the 20 MW day-ahead congestion collection shortfall to those congestion revenue rights with implied flow on the constraint. If the constraint had a shadow price of $10, a 120 MW congestion revenue right would be paid $1,000 (120 MW multiplied by $10 minus 20 MW multiplied by $10). This value is less than the total notional value of the congestion revenue right by $200, but this is because the day-ahead market did not collect enough congestion revenue to fully pay the congestion revenue right.

Figure 7 shows the portion of congestion revenue rights flowing on a constraint (m) that is pro-rata allocated back to the congestion revenue rights holders. The blue bar represents the total implied congestion revenue right flow on constraint (m). The green bar represents the energy schedules on constraint (m). The portion of congestion revenue rights above the red line is the revenue shortfall the CAISO pro-rata allocates to the congestion revenue rights holders.[11]

Figure 7: Congestion revenue rights shortfall allocation



The CAISO proposes to additionally settle reliability energy and imbalance reserve deployment scenarios congestion revenues to congestion revenue rights. The day-ahead market enhancements proposal introduces nine new categories of constraints that can be binding in the day-ahead market. When any of these new constraints bind in the day-ahead market, the market will collect congestion revenues on the energy portion of the reliability energy schedule and imbalance reserve deployment scenarios, which will include a cost contribution from imbalance reserves and reliability capacity products.

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11 Like today, the CAISO plans to apply this same shortfall allocation to each constraint described in the technical appendix as: $Constraint_{m,t}$, $Constraint_{m,t}^{(k)}$, and $Constraint_{m,t}^{(g)}$.

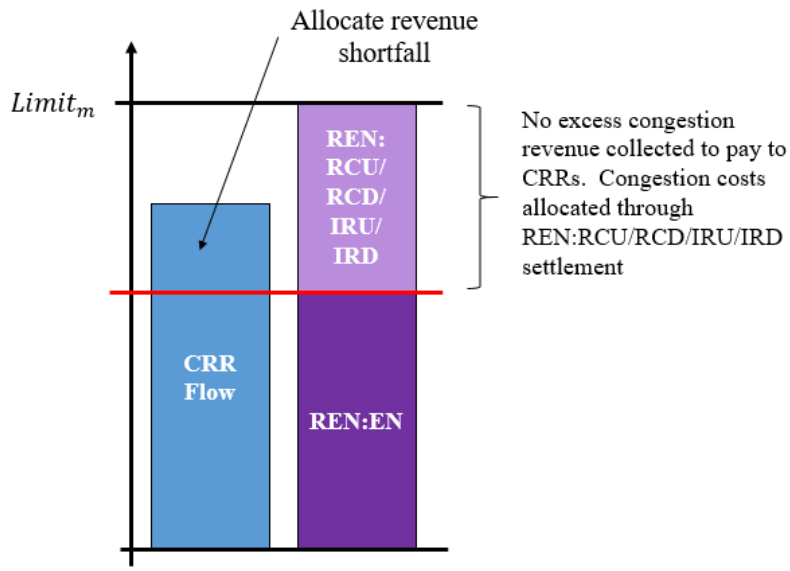
When the energy portion of the reliability energy schedule or imbalance reserve deployment scenarios causes a constraint to bind, the market will collect congestion revenues. For example, if a constraint binds at 100 MW of REN: EN with a shadow price of $10, the day-ahead market will collect $1,000 (100 MW multiplied by $10). A 100 MW congestion revenue right on this constraint would be paid the $1,000 congestion revenues.

The CAISO will also assess each reliability energy and imbalance reserves deployment scenario constraint in the day-ahead market to ensure that each congestion revenue right is only paid the amount of revenues actually collected on each constraint in the day-ahead market. It proposes to do this by comparing the energy portion of the reliability energy schedules and imbalance reserve deployment scenario on each constraint to the total implied congestion revenue right flow on each constraint in the day-ahead market. When the energy portion of the reliability energy and/or imbalance reserve deployment scenario schedules are less than the implied congestion revenue right flows on a constraint, the day-ahead market does not collect enough congestion revenue to pay the full value of congestion revenue rights on that constraint. For example, if a constraint has 75 MW of implied congestion revenue right flow on it but only 50 MW of REN:EN schedules, the CAISO proposes to pro-rata allocate the revenue shortfall due to the 25 MW day-ahead congestion collection shortfall to those congestion revenue rights with implied flow on the constraint. If the constraint had a shadow price of $10, a 75 MW congestion revenue right would be paid $500 (75 MW multiplied by $10 minus 25 MW multiplied by $10). This value is less than the total notional value of the congestion revenue right by $250, but this is because the day-ahead market does not collect enough congestion revenue to fully pay the congestion revenue right.

Figure 8 shows the portion of congestion revenue rights flowing on $Constraint_{m,t}^{(r)}$ that is pro-rata allocated back to the congestion revenue rights holders. The blue bar represents the total implied congestion revenue right flow on $Constraint_{m,t}^{(r)}$. The dark purple bar represents the energy portion of the reliability energy (REN:EN) and the imbalance reserves deployment scenarios schedules on $Constraint_{m,t}^{(r)}$. The light purple bar represents the various capacity products awards that potentially could become energy schedules (REN:RCU/RCD/IRU/IRD) on $Constraint_{m,t}^{(r)}$ in the real-time market. The portion of congestion revenue rights above the red line is the revenue shortfall that the CAISO proposes to pro-rata allocate to the congestion revenue rights holders.[12]

[12] The CAISO plans to apply this shortfall allocation to each constraint described in the technical appendix as $Constraint_{m,t}^{(r)}$, $Constraint_{m,t}^{(r,k)}$, $Constraint_{m,t}^{(r,g)}$, $Constraint_{m,t}^{(u)}$, $Constraint_{m,t}^{(u,k)}$, $Constraint_{m,t}^{(u,g)}$, $Constraint_{m,t}^{(d)}$, $Constraint_{m,t}^{(d,k)}$, and $Constraint_{m,t}^{(d,g)}$.

Figure 8: Congestion revenue rights shortfall allocation with REN settlement



The market does not collect congestion revenue associated with the capacity products because these costs are allocated through the capacity product cost allocation described in the Section 3.9 of this proposal. Therefore, there is no congestion revenue available to pay to congestion revenue rights holders. The market will only settle congestion revenue rights to the extent that it receives congestion revenues on associated binding constraints in the day-ahead market.

In summary, congestion revenue rights will pay the holder the congestion revenue between the source and sink associated with:

- Financial energy flows, including physical supply, scheduled load, and virtual supply/demand;
- Physical energy flows from physical supply meeting the CAISO demand forecast;
- Physical flows from physical supply and deployed IRU for meeting the CAISO demand forecast plus the upward uncertainty requirement; and
- Physical flows from physical supply and deployed IRD for meeting the CAISO demand forecast minus the downward uncertainty requirement.

Congestion revenue rights will not provide a congestion hedge for day-ahead market locational capacity awards.

3.11. Market Power Mitigation for Reliability Capacity and Imbalance Reserves

In the proposed market design, suppliers will offer to sell energy, reliability capacity, and imbalance reserves in the day-ahead market. Energy schedules, reliability energy schedules, and imbalance reserve deployment scenarios will cause transmission constraints to bind indicating a constrained area in the system. Suppliers could exercise market power through their energy offers when constraints bind due to energy congestion or they could exercise market power through their reliability capacity or imbalance reserve offers when constraints bind due to congestion. The CAISO proposes to evaluate constraints for uncompetitive conditions and mitigate resource offers that are effective on those constraints. It also proposes to develop a default *capacity* bid to use when mitigating reliability capacity and imbalance reserve offers.

The CAISO markets employ a dynamic local market power mitigation process that identifies local areas, identifies when the local area is not competitive, and mitigates local suppliers' offers to the greater of a pre-established estimate of marginal costs or the broader system competitive energy price.

The dynamic local market power mitigation process tests transmission constraints for competitiveness by comparing the demand for counter-flow to a constraint to the available supply of counter-flow. The test employs a "residual supply index," which is the ratio of the supply of counter-flow to the demand for counter-flow. The test assumes some portion of the supply for counter-flow from potentially pivotal suppliers is withheld. A transmission constraint is deemed competitive if the ratio of non-pivotal supply to demand is greater than or equal to one and uncompetitive if less than one. Currently, the test treats the three highest ranked suppliers, in terms of capacity that can be withheld, as potentially pivotal.

Generally, the CAISO mitigates supply offers to the greater of what it calls "default energy bids" or the competitive LMP. Default energy bids are the CAISO's estimate of resource marginal costs. The competitive LMP is the energy price outside of the constrained area.

The CAISO proposes to mitigate energy offers on constraints binding due to energy schedules when the constraint is found uncompetitive from an energy perspective and mitigate reliability energy offers on constraints binding due to reliability energy schedules when the constraint is found uncompetitive from a reliability energy perspective. The CAISO proposes to develop default *capacity* bids to use when mitigating reliability capacity or imbalance reserves offers.

3.12. Imbalance Reserve Requirement

This section describes how the CAISO plans to set the imbalance reserve requirement in the day-ahead timeframe.[13] Table 2 below provides definitions that will be used in the remainder of the section.[14]

Table 2: Imbalance reserve requirement definitions

Term	Definition
Load Imbalance Up	Hourly RTD Load Max – Day Ahead Load Forecast
Wind Imbalance Down	Hourly RTD Wind Min – Day Ahead Wind Forecast
Solar Imbalance Down	Hourly RTD Solar Min – Day Ahead Solar Forecast
Load Imbalance Down	Hourly RTD Load Min – Day Ahead Load Forecast
Wind Imbalance Up	Hourly RTD Wind Max – Day Ahead Wind Forecast
Solar Imbalance Up	Hourly RTD Solar Max – Day Ahead Solar Forecast
Net Load	Load – Wind – Solar
Net Load Imbalance Up	Hourly RTD Net Load Max – Day Ahead Net Load Forecast
Net Load Imbalance Down	Hourly RTD Net Load Min – Day Ahead Net Load Forecast

Histogram Approach to Imbalance Reserve Requirement

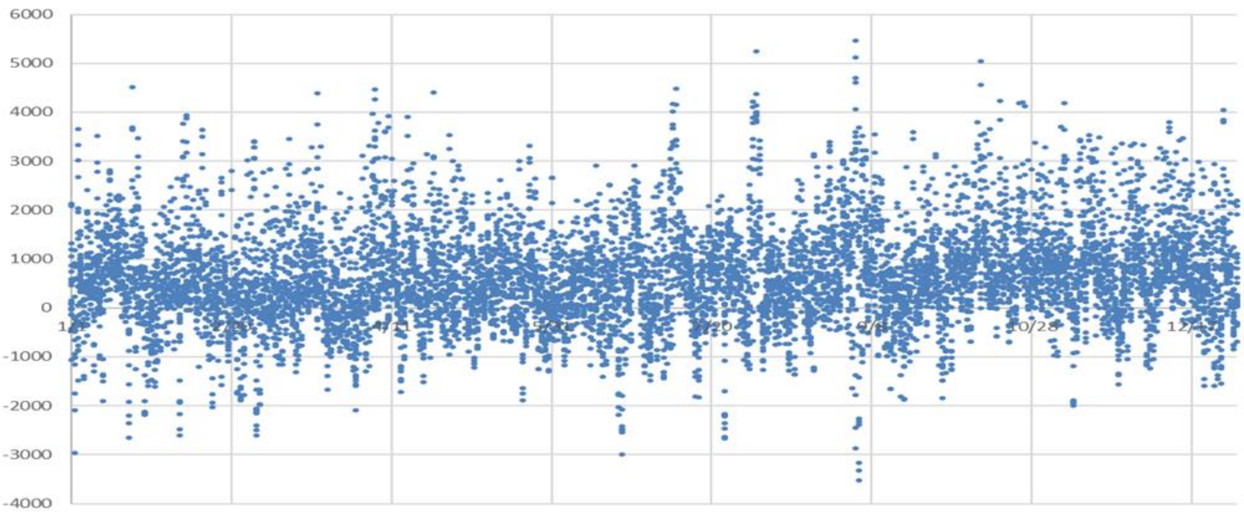
The first approach uses a histogram method to setting the imbalance reserve requirement. Historical data is used to find the maximum and minimum net load values in RTD over each hour. Then, these maximum and minimum RTD values are compared to the day-ahead net load forecast to determine the imbalance values that are used in setting the requirement. For example, the upward requirement would be set using values measuring the difference between the hourly RTD net load maximum and the day ahead net load forecast (net load imbalance up).

13 This section only describes the method to determine the imbalance reserve requirements and does not portend to establish the actual requirement amounts.

14 The figures in this section are from analysis the CAISO presented at the DAME workshop in June 2018. That analysis used RTD as the reference to set the imbalance reserve requirement. To be clear, the proposal is to use historical differences between *the system operator's day-ahead net load forecast* and the *fifteen-minute market net load* to set the imbalance reserve requirement. The methodology, however, is the same.

Figure 9 shows the distribution of net load imbalance up values using data from 2017. Many of the observations are positive but negative values can occur when the day ahead net load forecast exceeds all RTD values observed within the hour interval.

Figure 9: Net load imbalance up

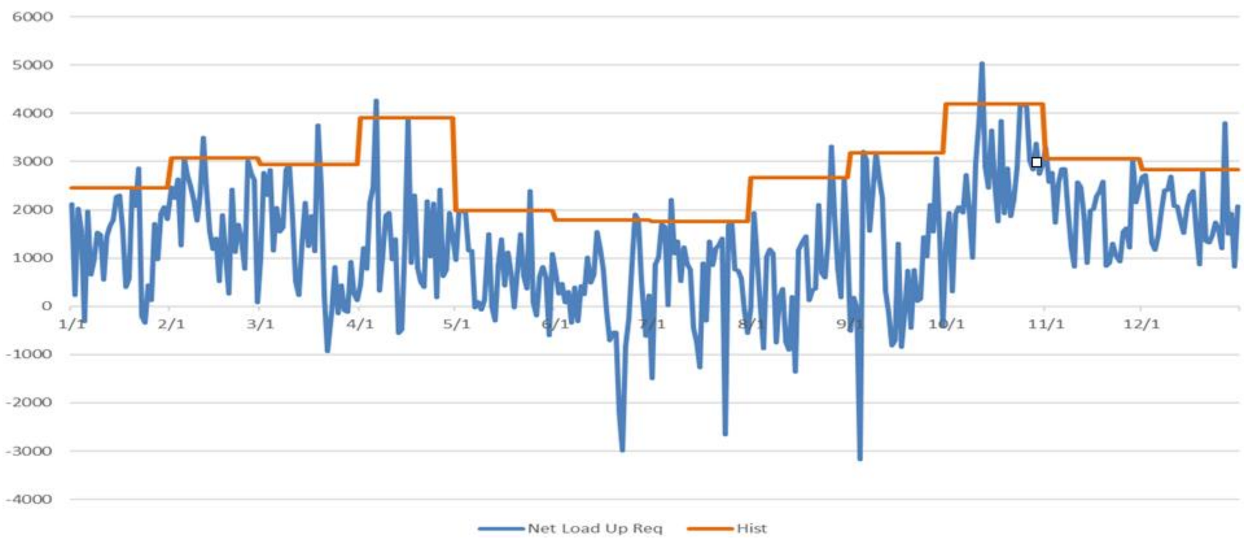


Source: CAISO Analysis

The values in the scatter plot above can further be subcategorized by hour. Figure 10 shows the net load imbalance up values for HE17 in the year 2017. Each point reflects the difference between the maximum RTD net load value observed and the day-ahead net load forecast in HE17 for each day of the year. The histogram approach then involves setting a requirement that captures 95 percent of observations within the month (the orange line in Figure 10).

Each month has a different requirement that varies depending on the imbalance historically observed in that month. For example, the imbalance reserve up requirement would be higher in April and October because the historically observed amount of net load imbalance up is higher in those months. This method would be applied to each hour of the day to determine an imbalance reserve up requirement that varies by hour and month. The method would also be used to develop the imbalance reserve down requirement using net load imbalance down values instead.

Figure 10: Imbalance reserve up requirement: histogram approach (HE17)



Source: CAISO Analysis

The histogram approach yields imbalance reserve up and down requirements that vary seasonally and by time of day. They have the benefit of being relatively simple to calculate. However, Figure 8 illustrates the main drawback of this approach – the imbalance reserve requirement would be excessively high (or low) for a majority of hour intervals using the histogram approach. Because of this, the ISO proposes to use a different approach (regression approach).

Regression Approach to Imbalance Reserve Requirement

It can be observed through a statistical regression model that the forecasted amount of load, wind, and solar day-ahead are statistically significant predictors of the next day's net load imbalance. Thus, they can be used as independent variables in a regression model to refine the imbalance reserve requirement. Statistical regression has the added benefit of providing more refined and generally less excessive requirements compared to a histogram approach.

The type of regression model the CAISO proposes to use to determine the imbalance reserve requirement is a quantile regression. A quantile regression estimates quantiles of a dependent variable conditional on the values of a set of independent variables. A quantile regression is preferred to standard linear regression in this case because the imbalance reserve requirement is based on relatively extreme high and low (i.e., 2.5 and 97.5 percentile) observations of net load imbalances, as opposed to the *average* net load imbalance. The regressors (independent variables) include forecasted load, solar, and wind values, as well as the operating hour and month.[15]

[15] The specific formulation of the regression model used to set the imbalance reserve requirement, including a full list of regressors, will be described in a future straw proposal.

The one drawback of the regression approach is that, rather than using net load as a dependent variable, separate regressions need to be run using load, solar, and wind as dependent variables and then the estimated parameters combined using the identity Net Load = Load – Wind – Solar. This is because using net load as a dependent variable with forecasted load, solar, and wind as independent variables would imply a relationship of, say, real-time wind and solar to day-ahead load, which is meaningless.

Calculating an imbalance reserve up requirement would then involve the following steps:

1. Use quantile regression to estimate parameters of load forecast, month, and hour on the 97.5 percentile of load imbalance
2. Use quantile regression to estimate parameters of wind forecast, month, and hour on the 2.5 percentile of wind imbalance
3. Use quantile regression to estimate parameters of solar forecast, month, and hour on the 2.5 percentile of solar imbalance
4. Combine estimated parameters from steps 1-3 using the identity Net Load = Load – Wind – Solar

However, the method above systematically over-estimates the 97.5 percentile of net load imbalance. In reality, because of the identity Net Load = Load – Wind – Solar, a 97.5 percentile net load imbalance would not simultaneously have 97.5 percentile load imbalance *and* 2.5 percentile wind imbalance *and* 2.5 percentile solar imbalance at the same time. Therefore, the regression output values need to be scaled using an "adjustment ratio".

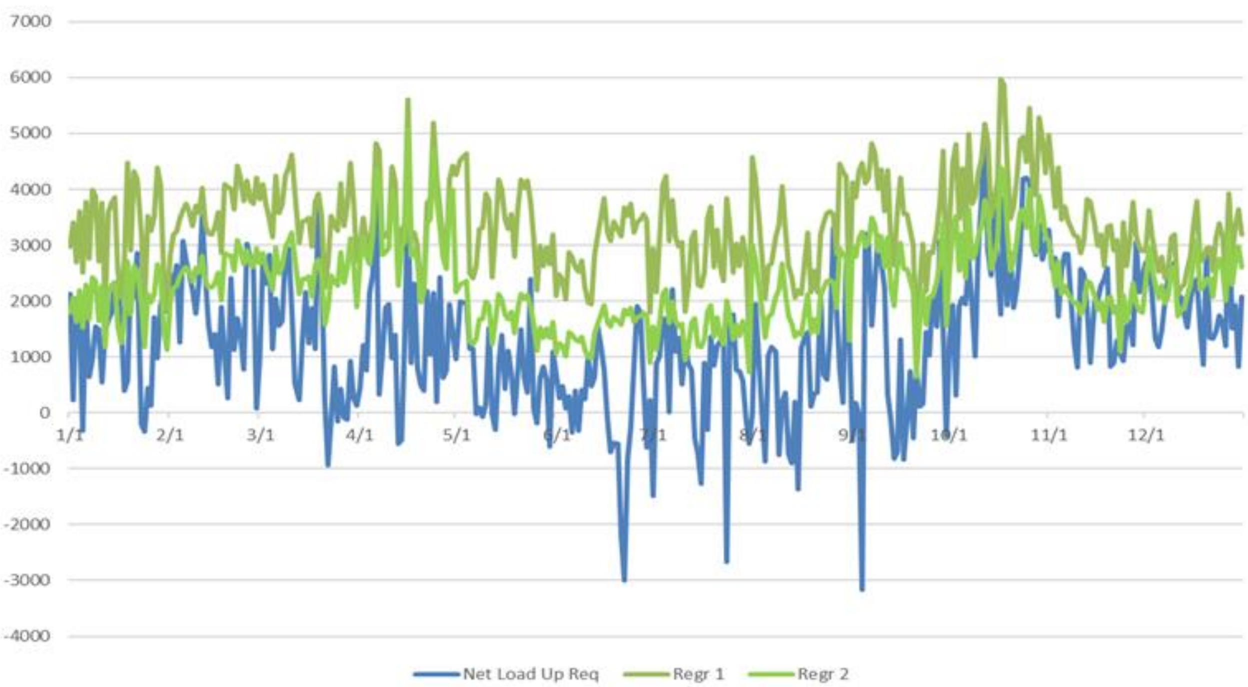
An adjustment ratio for each hour and month can be calculated leveraging the histogram approach. Refer back to the orange line in Figure 10, which shows the histogram approach to setting the imbalance reserve up requirement using net load imbalance up values. The orange line can be re-estimated by using the histogram approach to calculate load, wind, and solar imbalance requirements separately and then combining the values using the identity Net Load = Load – Wind – Solar (similar to steps 1-4 above).

The red line in Figure 11 below illustrates what happens when this calculation is carried out – net load values are overestimated. However, the ratio of the values represented by the orange and red lines in Figure 11 can be used to define the adjustment ratio. Then, output values calculated from the regression approach can be multiplied by this adjustment ratio to scale back the overestimated net load values. Figure 12 illustrates the regression output values scaled by the adjustment ratio. The darker green line represents the original regression output values and the lighter green line represents the values scaled by the adjustment ratio. Notice the light green line more closely "tracks" the blue line.

Figure 11: Scaling the imbalance reserve requirement

Source: CAISO Analysis

Figure 12: Scaling the regression approach to setting the imbalance reserve requirement

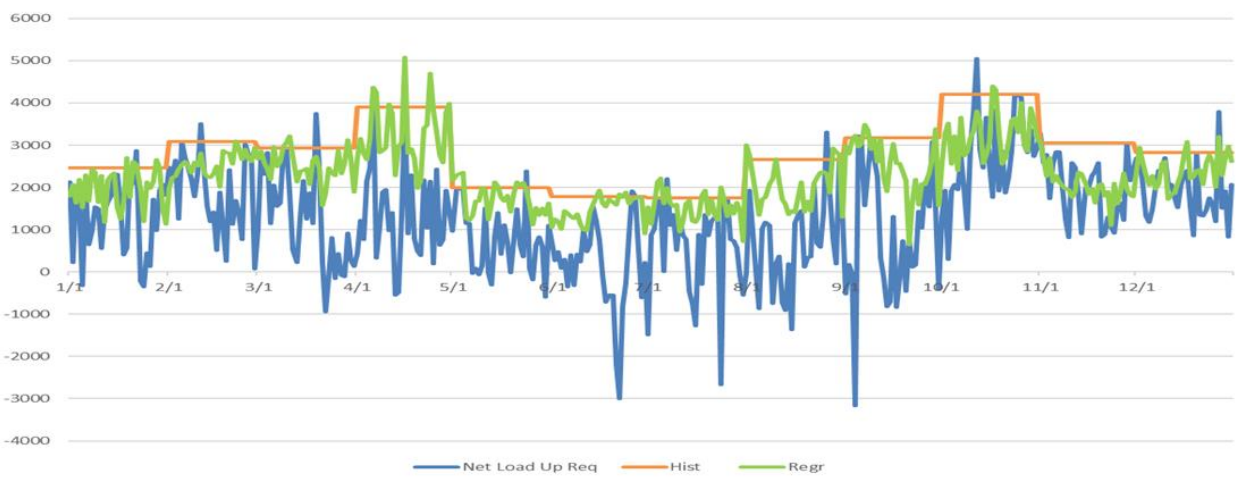


Source: CAISO Analysis

Benefits of Regression Approach for Setting the Imbalance Reserve Requirement

Figure 13 compares the histogram approach (orange line) and regression approach (green line). It is clear that the regression approach better tracks the imbalance values represented by the blue line. In most intervals, the regression approach requires a smaller level of imbalance reserves to be procured while still covering a 95 percent uncertainty band, which implies the regression approach is more efficient.

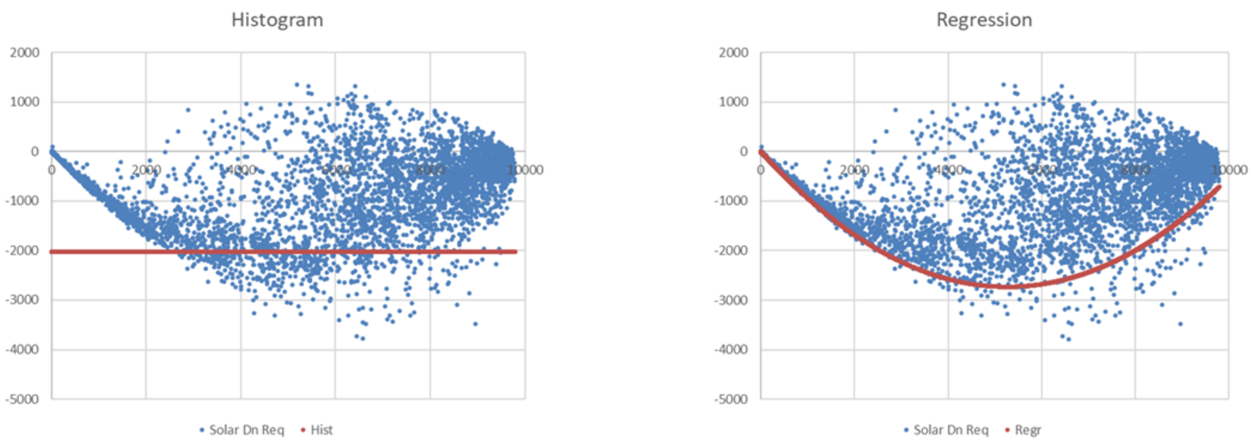
Figure 13: Regression approach vs. histogram approach



Source: CAISO Analysis

Figure 14 illustrates another benefit of using the regression approach. The blue dots in represent solar imbalance down values (y-axis) plotted against the day-ahead solar forecast (x-axis). The shape and spread of the cluster of blue dots show clearly that the variance of solar imbalance down values is unequal across a range of solar forecast values. For example, there is less variance in imbalance down values when the day-ahead forecast predicts very small or very large amount of solar production, but significantly more uncertainty when the forecast is somewhere in the middle. The red lines on both sides of Figure 14 capture 95 percent of the values; however, the regression approach can be shaped to better capture the variation of imbalance to forecast values, and thus producing imbalance reserve requirements that are more refined and accurate.

Figure 14: Regression approach vs histogram approach II



Source: CAISO Analysis

Imbalance Reserve Up Adjustable Procurement

One caveat the CAISO proposes for the regression approach is to build in a reliability safety net for the imbalance reserve up product. The CAISO proposes to set the imbalance reserve up requirement as follows:

$$IRUR = \max(X, Regression)$$

In this equation, *X* is a positive, adjustable parameter. The CAISO envisions that *X* will be fully adjustable by system operators. Instead of resorting to out-of-market actions to resolve anticipated shortfalls in capacity or ramping needs, operators can procure more imbalance reserves *through the market* by adjusting the imbalance reserve up requirement.

4. Need for Day-Ahead Market Enhancements

This section explains why a re-design of the day-ahead market is necessary. Historically, the CAISO balancing authority area consisted of a predictable generation fleet. Resources were scheduled hourly in the day-ahead market, and changes or "imbalances" were addressed in the real-time market. Over the last 10 years, variable energy resources (wind and solar) have become more prevalent. While these resources are critical in meeting Renewable Portfolio Standard (RPS) and carbon emission goals, they also introduce large amounts of operational uncertainty onto the grid and can create challenging conditions for system operators to manage.

Energy imbalances occur because of (1) differences between hourly day-ahead market schedules and fifteen-minute real-time market schedules, termed "granularity differences," and (2) net load uncertainty that materializes between day-ahead and real-time market runs.[16] As stated above, the real-time market must manage energy imbalances that occur between the day-ahead and real-time markets. The real-time market will continue to serve this under the redesigned day-ahead market. The CAISO proposes a new day-ahead market structure to better accommodate net load imbalances. Instead of the existing integrated forward market (IFM) and sequential residual unit commitment (RUC) process, the CAISO proposes a single day-ahead market co-optimization. The new day-ahead market will co-optimize energy, reliability energy, ancillary services, and imbalance reserves. Imbalance reserves will allow the day-ahead market to schedule resources to provide flexible capacity for use in the real-time market to meet net load imbalances.

Improve Market Efficiency

Changes between the day-ahead market and real-time market are inevitable. As the market approaches real time, the load forecast is updated and output from renewable resources may change. Imbalances occur for many reasons including weather changes, outages, and forecasting inaccuracies. Ultimately, the CAISO is responsible for responding to imbalances across markets to ensure load is reliably served at all times.

Large imbalances between the day-ahead and real-time market can result in challenging operating conditions for system operators. When there is potential for large imbalances that are not or cannot be addressed through the real-time market, system operators must rely on out-of-market actions to provide unloaded capacity. These actions may include increasing the load forecast in the market and/or exceptional dispatches. Although these actions are necessary for grid reliability, they also undermine

[16] An earlier phase of DAME proposed to schedule the day-ahead market in fifteen-minute intervals rather than 1-hour intervals. Fifteen-minute scheduling would have resolved imbalances caused by (1). This part of the proposal was deferred because the simulation was unable to run in a reasonable amount of time and stakeholders were concerned that implementation costs and settlement changes would outweigh financial gains of the fifteen-minute scheduling. This proposal sets the imbalance reserve requirement based on both granularity differences and uncertainty.

market price formation and the resultant economic signals provided by market prices. The proposed imbalance reserve product will greatly eliminate the need for out-of-market actions and incorporate these costs into day-ahead market clearing prices. This will compensate resources more appropriately for providing this capacity. Ultimately, the CAISO market should achieve grid reliability through efficient and effective market solutions. The day-ahead market enhancements initiative moves the market closer to that goal by integrating products into the market to capture what would otherwise be effectuated through out-of-market actions. These out-of-market actions can now be accurately priced through the market clearing process.

Additionally, market efficiency can be impacted due to the difference between cleared bid-in demand and the system operator's load forecast. The cleared bid-in demand and load forecast are two different values and are currently met independently. The CAISO believes the market will be more efficient if it recognizes both of these targets, and can schedule resources to meet both targets *and* the difference between these targets, in a single market run.

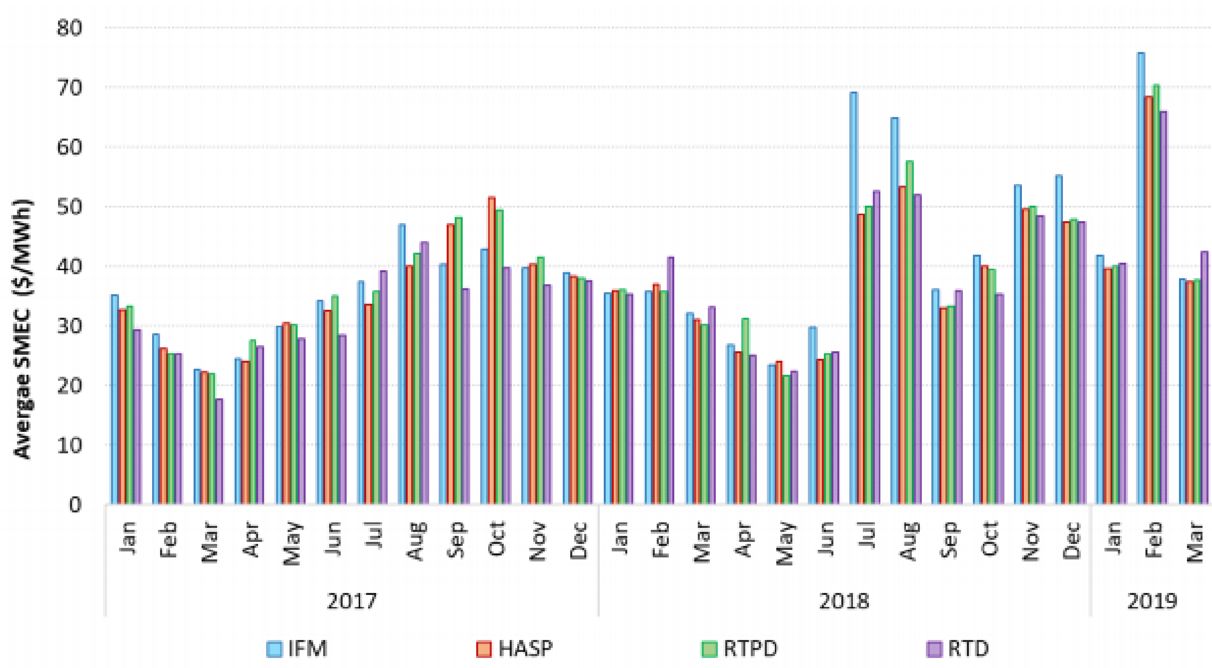
Price Performance Analysis Report

The CAISO recently completed a comprehensive report titled "Price Performance Analysis" that summarized and analyzed price formation in the CAISO markets. The report identified factors that contribute to price divergence between the day-ahead and real-time markets and proposed solutions to mitigate potential inefficiencies.

As a part of this effort, the report quantitatively analyzed imbalances across markets. The majority of imbalances occur between the day-ahead and fifteen-minute market (as opposed to between the fifteen-minute market and the five-minute market). These imbalances can be as much as 6,000 MW in a single hour. The Price Performance Analysis report confirms the large amount of imbalance between the day-ahead and real-time market occur due to load forecast error, and is compounded by variable energy resource output changes. As shown in Figure 15, the "IFM prices are persistently higher than real-time prices starting in 2018 and continue in 2019."[17] We believe this occurs because operators are reliant on out of market actions to procure additional capacity to meet potentially large imbalances. The out of market actions may then lead to price suppression in the real-time market.

[17] **Price Performance Analysis** *Executive Summary* page 12 and *Market Structure and Price Performance* page 21.

Figure 15*:* Pricing differences across day-ahead and real-time markets from 2017 – Q1 2019



Sustained price divergence is a signal that the market is not functioning optimally. The actions the CAISO must take outside of the market to ensure grid reliability contributes to price divergence. While the CAISO must ensure it operates the system reliably and consistently with NERC reliability requirements, the CAISO also recognizes that sustained operator action outside of the market signals that there may be gaps in the current market design that lead to the need for such action. Ultimately, it is the CAISO's goal to produce a market solution that accurately reflect costs and system conditions, and is consistent with reliable operations.

The Price Performance Analysis report identifies the day-ahead market enhancements as an opportunity to address the large imbalances between markets and reduce operator out-of-market actions. One of the goals of this initiative is to identify and implement enhancements to the day-ahead market design that will enhance price convergence between markets.

The Price Performance Analysis report is located here: http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf

4.1. Historical Imbalances between Day-Ahead and Real-Time Markets

This section describes the magnitude of load imbalances that occur between the day-ahead market and the real-time market's fifteen-minute market using data from January 2017 to March 2019. This section also further describes the problems that excessive load imbalances create, notably ramping problems.

Net Load Imbalances between Day-Ahead and Real-Time Markets are Large

Net load imbalance is defined herein as the difference in net load that materializes between the day-ahead and fifteen-minute markets. In the context of day-ahead imbalance reserves, it is useful to compare the fifteen-minute market net load (fifteen-minute market demand forecast minus fifteen-minute market variable energy resource forecast) to three reference points in the day-ahead market:

1) The net load that clears the integrated forward market (cleared demand minus cleared variable energy resources), and
2) The day-ahead net load forecast (day-ahead load forecast minus day-ahead variable energy resource forecast), not including operator forecast adjustments (i.e., residual unit commitment net short adjustment process).
3) The day-ahead net load forecast, including operator forecast adjustments.

Thus, net load imbalance values can be calculated in each fifteen-minute interval for each of the three reference points. Positive net load imbalance values indicate the real-time net load was higher than day-ahead. Negative net load imbalance values indicate the real-time net load was lower than day-ahead.

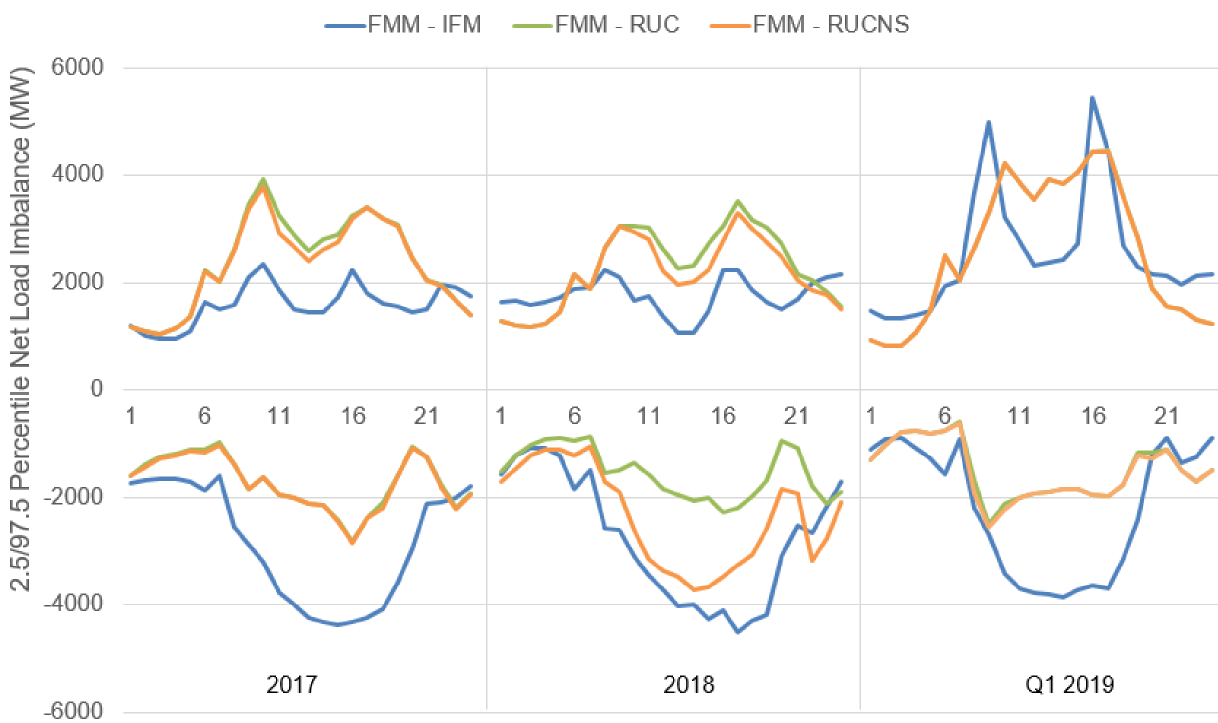
The ISO's Price Performance Analysis documents the factors that drive load imbalances between day ahead and real time. First, there is an increasing amount of variable energy resources on the system. Variable energy resources output are dependent on weather conditions that can be difficult to predict and can change rapidly. Second, large load imbalances can occur when there are significant errors in weather prediction, especially for extreme temperatures during peaking conditions.

Figure 16 shows historical net load imbalances by hour and year at the 2.5 and 97.5 percentiles.[18] This means that 95 percent of the observed historical differences lie between these values. These percentiles are useful as a reference to all but the most extreme imbalance values so that upward and downward imbalance reserve needs can be evaluated.

[18] 2.5% and 97.5% are used because the CAISO proposes to scale the imbalance reserve requirement. See Section 3.12.

Figure 16 illustrates some important observations. First, both upward and downward net load imbalance values vary significantly across hours for each of the three reference points. Second, net load imbalances do not materialize symmetrically in each direction. For example, there is a greater magnitude of downward net load imbalance compared to upward net load imbalance between IFM and fifteen-minute market (blue line) during the mid-day and early evening. A final notable observation is the difference in downward net load imbalance between RUC (green line) and RUCNS (orange line) during 2018 – a year with a high amount of operator forecast adjustments.

Figure 16: Historical net load imbalance



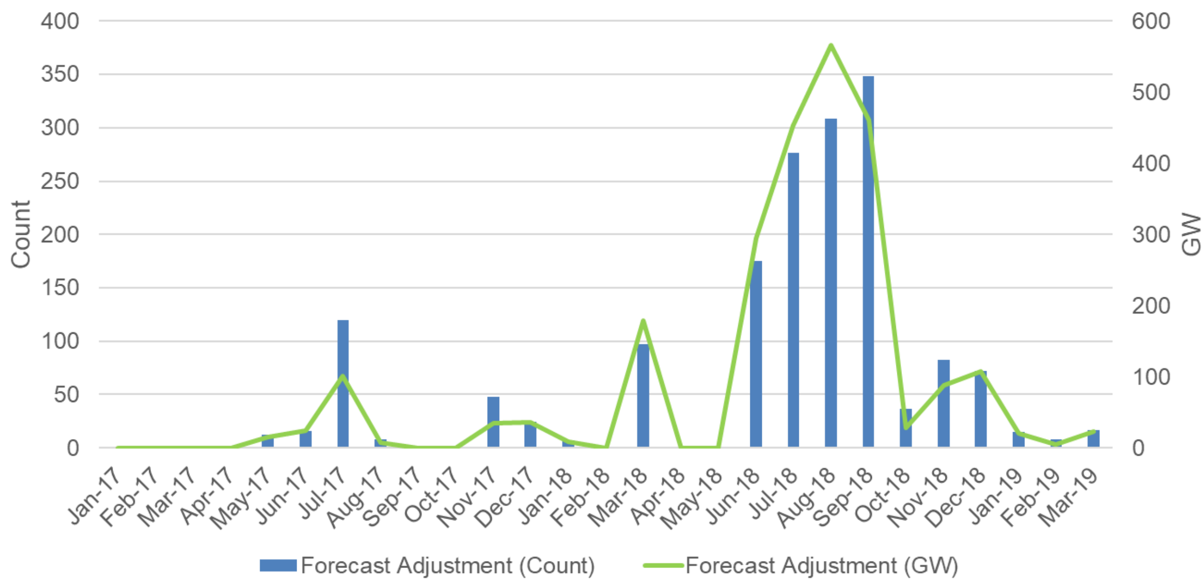
Source: CAISO Analysis

Net Load Imbalances between Day-Ahead and Real-Time Cause Problems

It is important to address net load imbalances between day ahead and real time because excessive load imbalances between markets can cause problems both in the market itself and in system operation. From a system reliability perspective, large net load imbalances make it more challenging to position resources in the day-ahead timeframe to meet real-time needs. The RUC process is intended to enhance grid reliability by securing sufficient capacity to meet the ISO's forecast of load in real time. Based on market performance data from January 2017 to March 2019, operators are increasing the RUC requirements by adjusting the demand forecast in 9.1 percent of intervals. This implies that large net load imbalances diminish system operators' trust that the RUC forecast will provide sufficient capacity or ramp capability to meet real-time conditions.

Figure 17 shows the number of hourly, day-ahead forecast adjustments (blue bar) with the cumulative magnitude of these forecasts adjustments (green line) by month. Operators tended to use forecast adjustments more frequently in the summer months. There was also a large increase in the number and magnitude of operator adjustments between 2017 and 2018, indicating that operators are becoming more reliant on this tool.

Figure 17: Operator forecast adjustments



Source: CAISO Analysis

Ramping Infeasibility

Another major system operation challenge caused by load imbalance is ramp infeasibility. The integrated forward market is designed to secure enough ramp capability such that it is feasible to ramp up or down from one hour interval to the next. The ramp capability needed is determined by measuring the slope (MW/min) between the midpoints of each hour interval. For example, if HE1 cleared IFM at 10,000MW and HE2 cleared IFM at 10,600MW, the optimization would ensure that the resources committed in HE1 had sufficient ramp capability to ramp upward 600 MW over the hour (10 MW/min). This is referred to as "scheduled ramp".

However, real-time system ramps can change quickly and do not follow the smooth, linear shape of the scheduled ramp. Ramping issues can arise when the scheduled ramp in IFM is not steep enough to meet the ramp that materializes in real-time. Similarly, a ramping issue can arise when IFM is scheduled to ramp in opposite directions as real-time. Operators that anticipate lacking sufficient ramp capability may be motivated to perform out-of-market actions such as RUC load adjustments or exceptional dispatches.

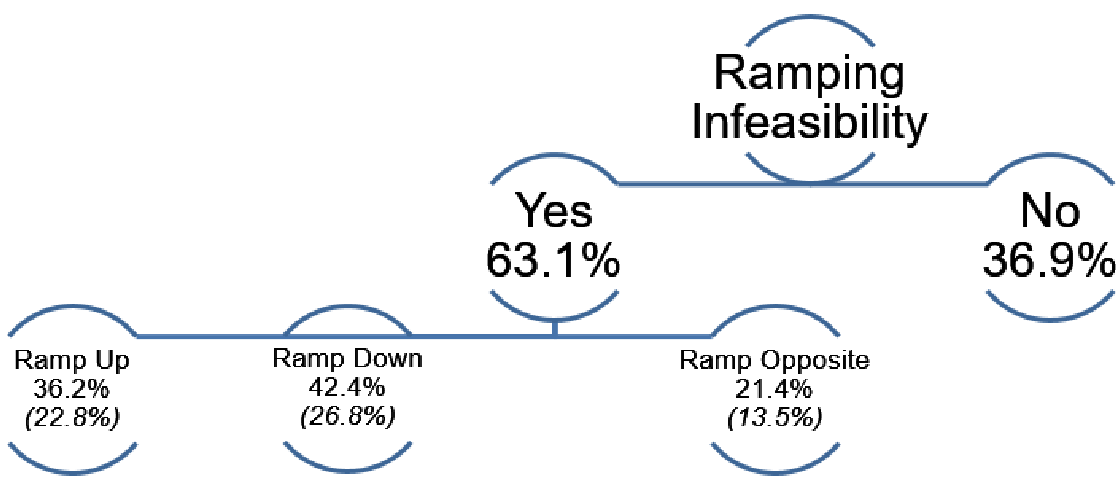
Market performance data can be used to evaluate the frequency of ramping infeasibility. Definitions for this analysis are given in Table 3. Note that ramp rates are measured in MWs per minute and the scheduled (hourly) ramp is measured from inter-hour midpoint to inter-hour midpoint.

Table 3: Definitions for ramp rates and ramp differentials

Term	Definition
IFM Ramp	$(IFM\ Net\ Load_{h+1,i3} - IFM\ Net\ Load_{h,i3})/60$
Fifteen-Minute Market Ramp	$(FMM\ Net\ Load_{i+1} - FMM\ Net\ Load_{i})/15$
Ramp Up Infeasibility	$= TRUE\ if\ FMM\ Ramp > IFM\ Ramp\ and\ FMM\ Ramp > 0\ and\ IFM\ Ramp > 0$
Ramp Down Infeasibility	$= TRUE\ if\ FMM\ Ramp < IFM\ Ramp\ and\ FMM\ Ramp < 0\ and\ IFM\ Ramp < 0$
Ramp Opposite Infeasibility	$= TRUE\ if\ (FMM\ Ramp > 0\ and\ IFM\ Ramp < 0)\ or\ (FMM\ Ramp < 0\ and\ IFM\ Ramp > 0)$
Ramp Differential	$FMM\ Ramp - IFM\ Ramp$

Figure 18 shows the frequency of ramping infeasibility across the data set. 63.1 percent of corresponding fifteen-minute market intervals had ramp rates that were steeper or in opposite directions as the scheduled ramp in IFM. The most common of these ramping infeasibilities is the lack of scheduled ramp in the downward direction, which occurs in over a quarter of all fifteen-minute intervals.

Figure 18: Ramping infeasibility between day-ahead and real-time



Source: CAISO Analysis

Table 4 charts the distribution of ramp differentials for each type of ramping infeasibility. For example, the values in the Ramp Up column are the ramp differentials conditional on a Ramp Up Infeasibility. Positive values indicate either the fifteen-minute market is ramping up faster than the scheduled ramp in IFM or the fifteen-minute market is ramping up while IFM is ramping down. The converse is true for negative values. The results show that the fifteen-minute market ramping needs can be as much as +/-60 MW per minute steeper than the scheduled ramp in IFM.

Table 4: Percentile Distribution of Ramp Differentials

Percentile	Ramp Up (MW/min)	Ramp Down (MW/min)	Ramp Opposite (MW/min)
99%	59.9	-60.3	54.6
95%	40.7	-39.6	34.0
90%	32.2	-30.6	25.4
75%	20.3	-18.7	14.2
50%	10.6	-9.5	2.8
25%	4.6	-4.0	-15.1
10%	1.8	-1.5	-28.9
5%	0.9	-0.7	-38.3
1%	0.2	-0.2	-57.2

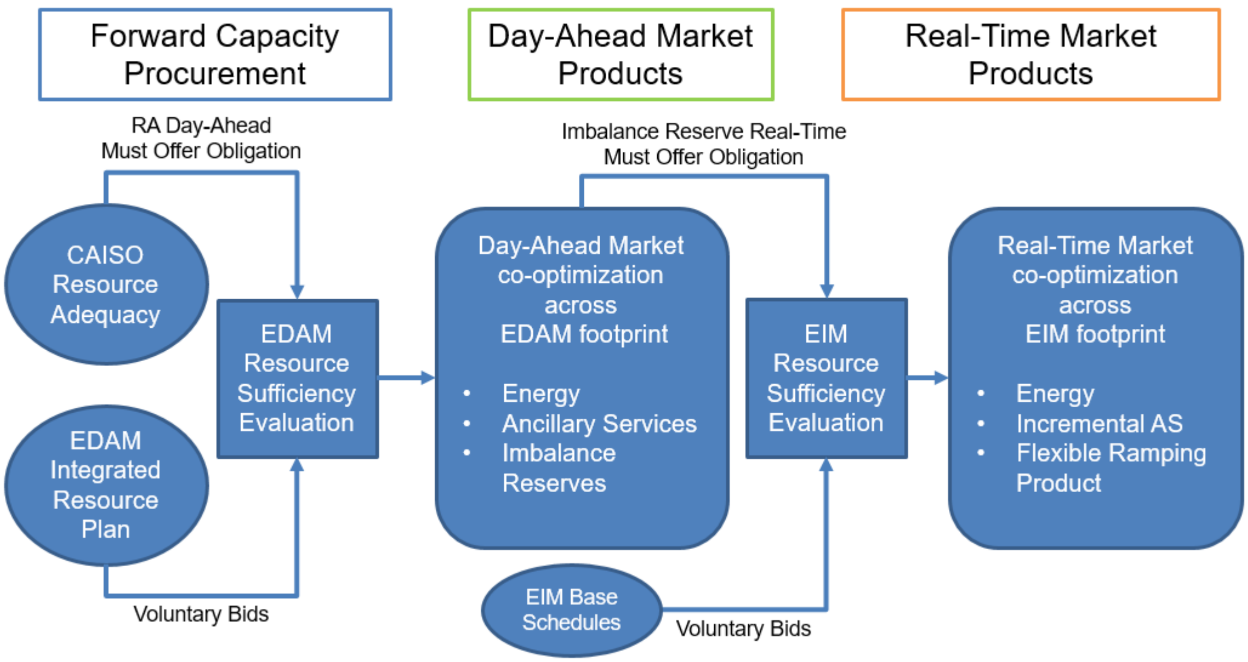
Source: CAISO Analysis

5. Alignment between RA Enhancements, DAME & EDAM

The CAISO is coordinating the stakeholder initiatives for the *Resource Adequacy Enhancements, Day-Ahead Market Enhancements*, and *Extended Day-Ahead Market* to ensure alignment and consistency in determining forward capacity procurement requirements, bidding obligations, and ultimately market solutions. The goal of our effort is to ensure an efficient and robust design that bridges the various election/bidding and program/market timelines.

Figure 19 is a flowchart depicting the correlation between RA Enhancements, DAME, and EDAM

Figure 19*: Correlation between DAME, EDAM and RA Enhancements*



The flowchart can be summarized as follows:

1. The CAISO Resource Adequacy program or an EIM entity's integrated resource plan ensure the balancing authority area has access to adequate supply capacity to meet anticipated system needs. These programs enable energy imbalance market (EIM) participants to enter the EDAM with sufficient resources to meet their own load requirements. The EDAM Resource Sufficiency Evaluation, as proposed in the Extended Day-Ahead Market initiative, is intended to ensure each EIM entity and the CAISO have sufficient bid range from participating resources to individually meet bid-in demand, ancillary services requirements, reliability energy, and their share of imbalance reserves. Assuming the EIM entity passes the EDAM Resource Sufficiency Evaluation, it will be eligible to participate in the day-ahead market and can benefit from EDAM transfers.

2. The purpose of the CAISO's day-ahead market today is to co-optimize energy and ancillary services to meet daily load and reliability requirements. Once the day-ahead market

enhancements have been implemented, this co-optimization will also include the new day-ahead market product called imbalance reserves. The day-ahead market will result in must-offer obligations and bids into the real-time market. In order to participate in the real-time, a balancing authority areas must pass the EIM real-time resource sufficiency test.

3. The real-time market will co-optimize energy, incremental ancillary serves, and real-time flexible ramping product across the entire EIM footprint.[19]

The CAISO acknowledges this new design differs from existing functionality. Currently, resource adequacy provisions create a must offer obligation in both the day-ahead and real-time market, depending on the characteristics of the resource. Under the redesign, the CAISO resource adequacy provisions will still impose a day-ahead must-offer obligation. The nature of the real-time must-offer obligation, however, will change. The real-time obligation currently is based on a resource's start-up time and its status as a resource adequacy resource. Going forward, the real-time obligation for all resources, including resource adequacy resources, will be based on imbalance reserve and reliability capacity schedules. Real-time bidding obligations are described in Section 3.5.

Day-Ahead Market Enhancements (DAME) & Extended Day-Ahead Market (EDAM)

Stakeholders have requested that both the DAME and EDAM initiatives take place within the same stakeholder forum. While the CAISO is committed to aligning the objectives and functionalities of these initiatives, they will continue as distinct stakeholder processes. The day-ahead market enhancements will lay the foundation for EDAM, but will be implemented for the CAISO balancing authority area regardless of the outcome of EDAM. Stated explicitly, the CAISO will pursue DAME even if, for whatever reason, EDAM does not move forward. For this reason, it is critical to keep the initiatives, board decisions, FERC filings, and implementations separate.

That said, it is critical to explain the DAME elements that are foundational for EDAM. The benefit of EDAM is to utilize the diverse resources in multiple EIM balancing authority areas to more efficiently meet load and operational needs across the EIM footprint. Imbalance reserves resulting from the DAME initiative are necessary to facilitate the EDAM because they:

- Establish inputs for the day-ahead resource sufficiency evaluation
- Enable efficient scheduling of energy, AS, and reserves across the EIM footprint
- Identify resources that are responsible for the real-time must offer obligation

Imbalance reserves will allow resources in one balancing authority area to be compensated when providing flexibility to another balancing authority area. This may eliminate the need for an EIM entity to commit a generator with high costs to be ready for potential real-time imbalances, and instead allow the EIM entity to purchase (at lower cost) imbalance reserves from another entity. This will be the primary cost benefit of EDAM.

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[19] The EIM does not procure incremental AS outside of the CAISO BAA.

6. EIM Governing Body Role

ISO management believes the EIM Governing Body should have an advisory role in the approval of all of proposed market enhancements resulting from this initiative.

Under the decisional classification rules in the Guidance Document and Charter for EIM Governance, the EIM Governing Body would have no decisional role concerning the market rule changes proposed in this initiative. Because those changes involve the rules of the day-ahead market only, they fall outside the ISO Board of Governors' delegation of authority to the EIM Governing Body.

However, the proposed changes to day-ahead market rules, which would change the structure of the day-ahead market and introduce a day-ahead imbalance reserve product, are intended to lay the foundation for a future initiative that would give EIM Entities the option of participating in the day ahead market. Given the unique foundational nature of the initiative, Management believes it would be appropriate for the EIM Governing Body to have an advisory role on all aspects of this initiative. This would be consistent with the intentions of the EIM Transitional Committee, which expected that EIM Governance would have a role in "decisions … that would … [a]llow options to expand the functionality of the market to provide additional services …." Final Proposal, August 19, 2015, p.14.[20]

This proposed decisional classification may need to be modified later as work on this policy initiative evolves. For example, if this initiative evolves to include changes to EIM-specific rules of the real-time market, the ISO's recommendation on the decisional classification would be revised to reflect such changes.

Stakeholders are encouraged to submit a response to the EIM categorization in their written comments following the conference call for the Issue Paper/Straw Proposal, particularly if they have concerns or questions.

[20] https://www.westerneim.com/Documents/Decision_EIM_Governance_Proposal-Proposal-Aug2015.pdf

7. Stakeholder Engagement, Implementation Plan & Next Steps

The CAISO is committed to stakeholder engagement and has developed the following plan to ensure stakeholders are involved in the development of this proposal.

Additionally, the CAISO is piloting a new process to develop technology requirements and draft tariff language. Historically the development of these items occurred *after* the CAISO achieved board approval of the proposed policy. This process has proven to be problematic if an implementation detail resulted in needing to change the already-board-approved policy. With the day-ahead market enhancements initiative, the CAISO proposes to develop technology requirements and draft language *before* taking the final proposal to the Board of Governors and EIM Governing Body. This process change is reflected in Table 5 below.

Table 5: Stakeholder engagement and implementation development plan

Date	Milestone
Straw Proposal	
Paper Posted	February 3, 2020
Stakeholder Meeting	February 10, 2020
Comments Due	March 2, 2020
Revised Straw Proposal	
Paper Posted - *tentative*	March 25, 2020
Stakeholder Meeting - *tentative*	April 1, 2020
Comments Due - *tentative*	April 22, 2020
Draft Final Proposal	
Paper Posted - *tentative*	June 10, 2020
Stakeholder Meeting - *tentative*	June 23, 2020
Comments Due - *tentative*	July 14, 2020
Start Tariff Stakeholder Process	August 2020
Start Business Requirement Specification (BRS) Development	August 2020
Policy Final Proposal	Q4 2020
Paper Posted	TBD
Stakeholder Meeting	TBD
Comments Due	TBD
EIM Governing Body & CAISO Board of Governors	Q1 2021
Implementation	Fall 2021

The CAISO will discuss this straw proposal with stakeholders during a stakeholder meeting on February 10, 2020. Stakeholders are asked to submit written comments by March 2, 2020 to initiativecomments@caiso.com. A comment template will be posted on the CAISO's initiative webpage, located here: http://www.caiso.com/informed/Pages/StakeholderProcesses/Day-AheadMarketEnhancements.aspx.

8. Appendices

Appendix A: Additional Data Analysis

Imbalances can be decomposed into two separate components: granularity and uncertainty. The best that the day-ahead market can do to position itself in preparation for real time is to clear at exactly the next day's hourly-average fifteen-minute market load. Even with perfect information about the next-day load, there will still be imbalances since the fifteen-minute market clears every fifteen-minutes while the integrated forward market clears every hour. These imbalances are attributed to granularity differences between the day-ahead and fifteen-minute markets. On the other hand, uncertainty represents the amount the day-ahead market "misses" the real-time load. In this analysis, uncertainty can be thought of as the remaining imbalance after removing granularity.

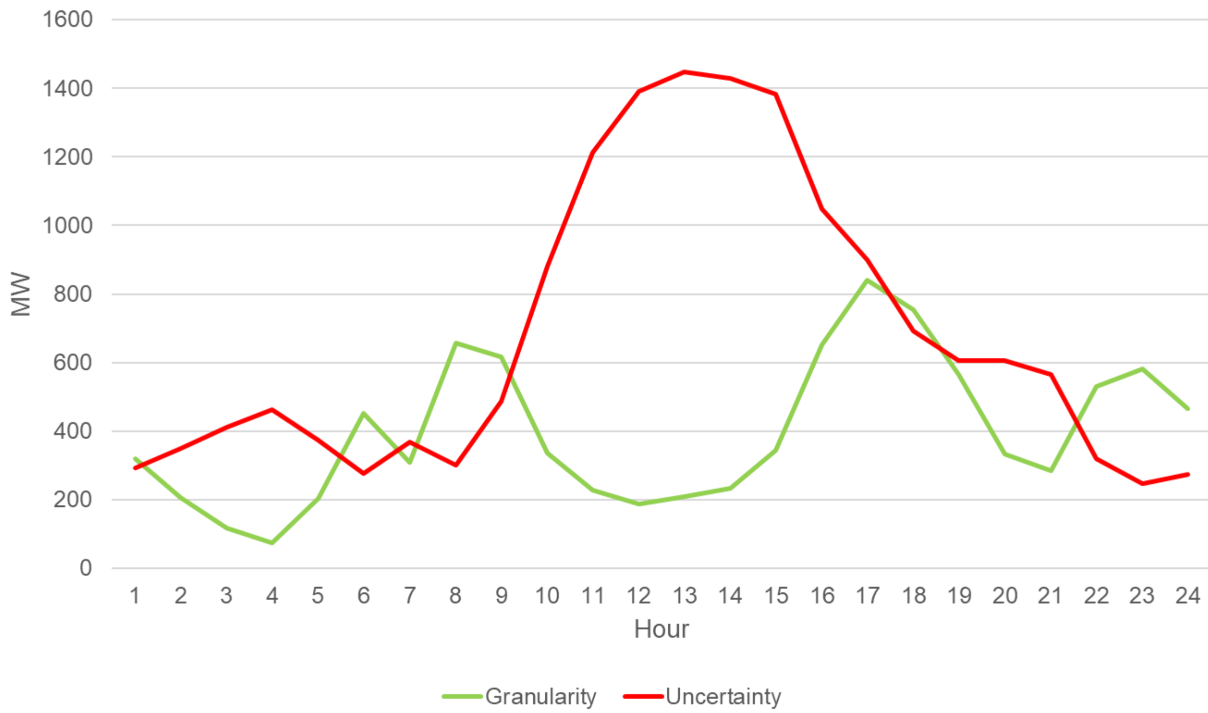
Table 6 shows how imbalances, granularity, and uncertainty are mathematically defined for purposes of this analysis. The value for granularity represents the amount of imbalance that would occur even if the day-ahead market predicted the exact hourly average. The imbalances that are observed in excess of those caused by granularity are attributed to uncertainty. Absolute values are used so imbalance can be exactly proportioned between the two sub-categories. Consequently, the values are non-directional.

Table 6: Definitions of Imbalance, Granularity, and Uncertainty

Term	Unit	Formulation
Imbalance	MW	$\lvert FMM_{i,h} - IFM_h \rvert$
Granularity	MW	$\lvert FMM_{i,h} - FMM_{avg,h} \rvert$
Uncertainty	MW	$\lvert FMM_{i,h} - IFM_h \rvert - \lvert FMM_{i,h} - FMM_{avg,h} \rvert$
Where *i* is the i^{th} 15-min interval and *h* is the h^{th} hour interval		

Figure 20 charts the average magnitude of granularity and uncertainty by hour over the data set. To reiterate, the values for granularity indicate the amount of imbalance that would still occur even if the IFM perfectly predicted the average fifteen-minute market load the following day, given the hourly scheduling constraint. Granularity values tend to be higher during peaking periods where load is ramping up or down quickly. In contrast, uncertainty values are highest during the midday when solar generation is online.

Figure 20: Average Granularity and Uncertainty by Hour



Source: CAISO Analysis

Appendix B: Eligibility Table

	EN	REN	RCU	RCD	EN needed for RCU/D award	IRU	IRD	EN needed for IRU award	EN needed for IRD award
Non-Participating Load	Yes	No	Not Eligible	Not Eligible	N/A	Not Eligible	Not Eligible	N/A	N/A
Virtual Supply	Yes	No	Not Eligible	Not Eligible	N/A	Not Eligible	Not Eligible	N/A	N/A
Virtual Demand	Yes	No	Not Eligible	Not Eligible	N/A	Not Eligible	Not Eligible	N/A	N/A
Hourly Block Import	Yes	Yes	Eligible	Eligible	None	Not Eligible	Not Eligible	N/A	N/A
Hourly Block Export	Yes	Yes	Eligible	Eligible	None	Not Eligible	Not Eligible	N/A	N/A
15-Min Import	Yes	Yes	Eligible	Eligible	None	Eligible	Eligible	None	EN >= IRD
15-Min Export	Yes	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= IRU	None
Dynamic Import	Yes	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= Pmin EN <= Pmax - IRU	EN <= Pmax EN >= Pmin + IRD
Long-Start Generator	Yes	Yes	Eligible	Eligible	EN >= Pmin	Eligible	Eligible	EN >= Pmin EN <= Pmax - IRU	EN <= Pmax EN >= Pmin + IRD
Short-Start Generator	Yes	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= Pmin EN <= Pmax - IRU	EN <= Pmax EN >= Pmin + IRD
Participating Load w/ 15-Min dispatch capability	Yes	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= Pmin EN <= Pmax - IRU	EN <= Pmax EN >= Pmin + IRD

	EN	REN	RCU	RCD	EN needed for RCU/D award	IRU	IRD	EN needed for IRU award	EN needed for IRD award
Participating Load w/ Hourly dispatch capability	Yes	Yes	Eligible	Eligible	None	Not Eligible	Not Eligible	N/A	N/A
Eligible Intermittent Resources (Wind/Solar)	Yes Upper economic limit set at ISO forecast	Yes ISO forecast only. Difference between resource's forecast and ISO forecast addressed using virtual bids that are not settled for REN	Eligible	Eligible	None	Eligible	Eligible	EN >= Pmin EN <= ISO Forecast – IRU	EN <= ISO Forecast EN >= Pmin + IRD
Non-Generator Resources (Storage) Discharging[21]	Yes	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Non-Generator Resources (Storage) Charging	Yes	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

[21] The rules for non-generator resources, and eligibility for the day-ahead market capacity products, will be dependent on the state-of-charge constraints. These rules are being developed in the CAISO's ESDER4 policy initiative. http://www.caiso.com/StakeholderProcesses/Energy-storage-and-distributed-energy-resources

	EN	REN	RCU	RCD	EN needed for RCU/D award	IRU	IRD	EN needed for IRU award	EN needed for IRD award
60-Minute Proxy Demand Resource	Yes	Yes	Eligible	Eligible	None	Not Eligible	Not Eligible	N/A	N/A
15-Minute Proxy Demand Resource	Yes	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= Pmin EN <= Pmax – IRU	EN <= Pmax EN >= Pmin + IRD
5-Minute Proxy Demand Resource	Yes	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= Pmin EN <= Pmax – IRU	EN <= Pmax EN >= Pmin + IRD
Reliability Demand Response Resource	Yes	Yes	Eligible	Eligible	None	Not Eligible	Not Eligible	N/A	N/A

Appendix C: Settlement Table

	Pays	Gets Paid	Uplift
EN LMP	Physical Load Virtual Demand Exports	Conventional Physical Generation VERs* Virtual Supply Imports Participating Load	Day-ahead marginal loss surplus allocated to metered demand. Day-ahead congestion revenue allocated via congestion revenue rights.
REN = EN + (RCU – RCD)	Exports	Conventional Physical Generation VERs* Imports Participating Load	See breakdown in three rows below.
REN (EN)	None	See above.	Pro rata to scheduled physical load and net virtual demand.
REN (RCU)	None	See above.	RCU costs are allocated first to net negative demand deviation and net virtual supply. Any remaining costs are allocated to metered demand.
REN (RCD)	None	See above.	RCD costs are allocated first to net positive demand deviation and net virtual demand. Any remaining costs are allocated to metered demand.
IRU	None	Conventional Physical Generation VERs (15-min and dynamic) Imports (15-min) Participating Load (15- and 5-min) PDRs	IRU costs are allocated first to net negative demand deviation and net virtual supply. Any remaining costs are allocated to metered demand.
IRD	None	Conventional Physical Generation VERs (15-min and dynamic) Imports (15-min) Participating Load (15- and 5-min) PDRs	IRD costs are allocated first to net positive demand deviation and net virtual demand. Any remaining costs are allocated to metered demand.
CC	Physical Load Virtual Demand Exports	Conventional Physical Generation VERs Imports Participating Load	None.
***Upper economic limit is set to REN, which is equal to the CAISO's forecast. VERs can use convergence bids for forecast differences.**			