California ISO

Day-Ahead Market Enhancements

Revised Final Proposal

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Day-Ahead Market Enhancements: Revised Final Proposal

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Executive Summary

This proposal is the product of extensive stakeholder engagement and addresses design elements and concerns raised by stakeholders and industry experts in the development of an imbalance reserve product to enhance the day-ahead market. The purpose is to develop a day-ahead market feature that economically and reliably addresses net load variability and uncertainty observed in the ISO and Western markets. After extensive stakeholder deliberations, the proposal is to:

- Introduce an imbalance reserve product in the integrated forward market that procures flexible reserves to cover uncertainty in the net load forecast between day-ahead and real-time markets, as well as real-time ramping needs not covered by hourly day-ahead market schedules.
- Enhance the residual unit commitment process to enable resources to economically bid compatible with an extended day-ahead market structure and enable the procurement of downward dispatch capability.

The need for the imbalance reserve product stems from the increased demand and supply uncertainty and variability, in part due to the growing penetration of variable energy resources (VERs). The inherent uncertainty in VER forecasting necessitates flexible reserves that can respond quickly to changing system conditions. Although the proposed imbalance reserve product is unique among similar products adopted in other ISO and RTOs, it is designed specifically to address the issues and opportunities seen in Western markets with the accelerated penetration, magnitude and diversity of variable energy resources, not yet seen in other markets. In addition, experience with the existing flexible ramping product currently in place in the real-time market, including the Western Imbalance Energy Market, has highlighted the need to ensure that such ramping products evaluate a resource's ability to provide the product based on resource characteristics and limitations on the transmission system. The Western grid has also experienced significant weather related uncertainty that, although challenging, highlights the benefits of optimizing diversity of system needs and conditions across the larger footprint. This proposal reflects these learnings and includes additional requirements necessary to address the unique challenges posed by the increasing presence of storage resources that also play an important role in the ISO's ability to maintain system reliability. Some have noted that prior versions of the proposal were overly and unnecessarily complex. The most recent extended stakeholder process confirmed that the complexity of issues faced in Western energy markets necessitates an evolution from the limited designs of similar products adopted elsewhere.

The imbalance reserve product defined in this proposal is also essential to an extended day-ahead market (EDAM) as it best ensures EDAM entities, including the ISO, can benefit from the footprint-wide diversity in the day-ahead market's optimization. This proposal addresses the unique requirements of an extended day-ahead market design that seeks to ensure transfers determined in that market are both economic and reliable, which is also a unique feature as compared to similar products previously adopted elsewhere.

Throughout the development of this proposal, we have conducted numerous meetings, outreach efforts, and consultations, involving stakeholders from various backgrounds. One important outcome and evolution coming out of this effort is that the design includes a number of configurable parameters and features that can evolve over time. This configurability was explicitly developed in response to stakeholder feedback that given the unique and innovative nature of this proposal, it is necessary to have off-ramps and an ability to pivot quickly should we face unintended adverse consequences. Although the configurable nature of the proposed design has garnered support from a number of stakeholders, it has also raised concerns regarding transparency on how the parameters will be set at the start, how they will evolve or change, and what discretion the ISO will have in making those changes. This proposal includes a commitment and explanation of the detailed information, workshops and stakeholder engagement that the CAISO will conduct to tune the configurable elements of the design, both during testing, implementation and after go live. The proposal also indicates a commitment to work with the Department of Market Monitoring to independently report on the performance of alternative parameters and settings before and after implementation.

The extensive stakeholder input and participation in this initiative evolved the revised final proposal to provide an overall design that will produce a more efficient, economic and effective market outcome. The additional stakeholder process produced a number of changes and clarifications included in the revised final proposal. These include:

- Implement flexibility to define which transmission constraints to enforce in the deployment scenarios to evaluate the deliverability of a resource awarded the product. This will allow the CAISO flexibility to adjust the transmission constraints enforced in the deployment scenarios in response to optimization performance, market performance, or operational experience. This will also enable the CAISO to work with EDAM balancing authority area operators to define the critical constraints to be enforced in the deployment scenarios in their balancing authority area. This modification addresses stakeholder concerns about the computational performance and market impact of the nodal approach to procurement of imbalance reserves.
- Implement a tunable parameter to control the proportion of imbalance reserve awards deployed with resulting flows in the deployment scenarios. These deployment scenarios test imbalance reserves against transmission constraints by assuming that 100% of imbalance reserve awards are converted to energy. This parameter enables adjustments to the percentage of imbalance reserve deployment, addressing concerns about potential excessive congestion, virtual arbitrage, and associated costs.
- Expand the imbalance reserve product to include the 30-minute ramp-capable portion of the resource. This is less restrictive than the previous 15-minute ramping restriction and is less costly because it requires fewer resources to provide imbalance reserves.
- Include a mechanism to collect congestion revenue rent on imbalance reserve flows and redistribute it to entities entitled to the congestion revenue. This mechanism will involve calculating displaced congestion revenue from imbalance reserve flows and redistributing it according to existing processes.
- Include a demand curve for the product that limits the price for the product to $55/MW, which is comparable to the reserves replacement costs based on the 80th percentile of historical

operating reserves bids submitted to the CAISO, comparable to the methodological approach of the Mid-Continent ISO with a similar product.

- Commitment to evaluating the need to add a layer of regional uncertainty to the nodal uncertainty approach. This evaluation will address stakeholder concerns that the approach to distributing uncertainty in the deployment scenarios is flawed because it does not account for differences in uncertainty across locations.
- Inclusion of an "opt-in" transitional resource adequacy true-up mechanism. This mechanism will allow entities to choose to have specific imbalance reserve and reliability capacity payments that overlap with resource adequacy capacity settled by the ISO.

Summary of Proposed Design

Changes to the Integrated Forward Market to include Imbalance Reserve Product

Under these enhancements, the day-ahead market's integrated forward market would continue to co-optimize energy and ancillary services, but would also include imbalance reserves within the same co-optimization to reserve resources' flexible ramping capability for real-time dispatch and commit resources needed to provide this ramping capability. Imbalance reserves would ensure the day-ahead market schedules sufficient flexible reserves to meet net load imbalances and ramping needs that materialize between the day-ahead and real-time markets.

The day-ahead market currently lacks a product that procures flexible reserves to address day-ahead to real-time uncertainty. Without a day-ahead flexible reserve product, uncertainty around imbalances that may materialize in real-time poses operational risks. To address such risk, market operators have historically taken manual actions outside of the market framework to procure additional capacity in the day-ahead timeframe. Specifically, grid operators increase the demand forecast used in the day-ahead market's residual unit commitment process. Although this results in the residual unit commitment process committing additional units to address uncertainty between the day-ahead and real-time markets, persistent and systematic out-of-market actions taken by CAISO operators signal a gap in the CAISO's market design. The absence of the ability to co-optimize the procurement of imbalance reserves with energy and ancillary services results in less optimal and less economic energy and ancillary services schedules. In addition, there is currently no price to signal the value of the uncertainty covered by manual grid operators' adjustments to the demand forecast used in the residual unit commitment process. The introduction of imbalance reserves in the integrated forward market will greatly decrease the need for grid operator adjustments to the demand forecast used in the residual unit commitment process, creating a more efficient and effective market outcome.

Imbalance reserves would be procured in the upward direction (imbalance reserves up) and downward direction (imbalance reserves down). The quantity of imbalance reserves the market would procure would be based on the historical uncertainty in the day-ahead load, solar, and wind forecasts. Only resources that can be dispatched in the fifteen-minute market would be eligible to provide imbalance reserves. Imbalance reserve awards would be capped at the resource's 30-minute ramping capability. Suppliers would provide price and quantity bids separately for imbalance reserves up and imbalance reserves down that the market would use to determine optimal imbalance reserve awards. The market would consider certain transmission constraints to ensure imbalance reserves are deliverable in the day-ahead timeframe to locations where uncertainty historically materializes. An imbalance reserve demand curve will decrease the procurement of imbalance reserves at higher costs by assessing the trade-off between the incremental cost and operational value of the reserves.

Settlement of the Imbalance Reserve Product

Resources awarded imbalance reserves would receive a day-ahead payment at the product's locational marginal price. Ramping capability provided by imbalance reserve awards in the day-ahead market would be settled against the flexible ramping product in the real-time market. The market would recover the costs of imbalance reserves, including congestion costs, through cost allocations that collect payments from entities based on their contribution to the need for procuring the product.

Changes to the Residual Unit Commitment Process

As supply and demand variability increased, operators increasingly adjusted requirements in the residual unit commitment process to ensure sufficient additional resource capacity is committed to meet net demand uncertainty between day-ahead and real-time markets, without considering resources' flexible ramping or dispatch capabilities. Like other ISO/RTO markets, the original purpose of the residual unit commitment process is to procure capacity for two reasons: (1) to address the difference between market-cleared load schedules and demand forecasts, and (2) to replace cleared virtual supply with physical resources. The residual unit commitment process remains an essential part of the day-ahead market and continues to procure capacity for these reasons. With the integrated forward market procuring flexible ramping capabilities needed to address load and resource uncertainty, operators will no longer need to bias the residual unit commitment procurement target for uncertainty.

This proposal also considers enhancements to the current residual unit commitment process. CAISO would continue to run the process after the integrated forward market co-optimizes energy, ancillary services, and imbalance reserves. Reserves awarded in this process would be called *reliability capacity*. In addition to procuring upward capacity, this process would also procure downward capacity if the procurement target is less than the demand cleared in the integrated forward market.

All resources currently eligible for the residual unit commitment process would be eligible to provide reliability capacity, including storage. Reliability capacity awards would be capped at the resource's 60-minute ramping capability. Suppliers would provide separate price and quantity bids for reliability capacity up and down, which the market would use to determine optimal awards. Like today, the process would continue to consider transmission constraints to ensure reliability capacity is deliverable in the day-ahead timeframe. Resources awarded reliability capacity would receive a day-ahead payment at the product's locational marginal price.

In addition to procuring downward dispatch capability, this proposal enhances the residual unit commitment process by establishing the binding configuration for multi-stage generating resources.

Currently, resource adequacy resources are required to bid at \$0/MW prices and are not compensated for scheduled capacity determined in the residual commitment process. The proposal allows resource adequacy resources to bid non-zero prices into the process, better optimizing reliability capacity in the context of an extended day-ahead market. As all resources, including resource adequacy capacity resources, can bid to offer reliability capacity and localized scarcity could occur due to congestion constraints, the proposal includes local market power mitigation measures for reliability capacity offers through an additional market pass.

Resources receiving an imbalance reserve or reliability capacity award would be obligated to provide economic energy bids in the real-time market for the quantity of their awards.

Integration of the Imbalance Reserve Product and Reliability Capacity in the EDAM

Imbalance reserves would optimize the scheduling of flexible reserves across the EDAM footprint to meet each EDAM participants' net load uncertainty and real-time ramping needs while maximizing the diversity benefit of a large market footprint. The EDAM contemplates that participants must meet both their load and uncertainty requirements as part of the residual imbalance energy. The proposed imbalance reserves provide the EDAM resource sufficiency evaluation a consistent method for evaluating and addressing uncertainty needs in each EDAM balancing area. By including the product in the integrated forward market, the EDAM can minimize the costs across the larger footprint and maximize the ability to optimize the diversity of load, transmission limitations and resources characteristics and availability. Additionally, reliability capacity up and down would be procured in the EDAM to ensure each EDAM participant has sufficient physical supply scheduled in the day-ahead timeframe to meet their balancing area's load forecast.

1. Changes from Final Proposal and Responses to Stakeholder Feedback

The CAISO published the Day-Ahead Market Enhancements (DAME) final proposal on January 11, 2023, intending to bring it to the CAISO Board of Governors and WEIM Governing Body for a decision in February. However, in response to concerns raised by stakeholders, ISO management decided to extend the DAME stakeholder process for a limited period to address lingering stakeholder concerns with the proposal. The main concerns were over design details regarding how the imbalance reserves are procured. Specifically, stakeholders raised concern with the BAA level at which the imbalance reserve products were to be procured and the degree to which transmission constraints would be modeled to ensure deliverability. Some continued to question which of the day-ahead market processes should procure imbalance reserves (i.e., IFM or RUC). The extended stakeholder process was intended to facilitate more discussion on key design elements and allow the ISO and stakeholders additional time to consider all stakeholder input. This would enable them to make informed judgments on the final design. Management limited the time for extending the process because the inclusion of the imbalance reserve product in the day-ahead market is a critical element of the EDAM market design and further delays in solidifying the DAME design would be problematic for the EDAM efforts.

The CAISO solicited stakeholder presentations and held its first public meeting in this extended stakeholder process on February 27, 2023. The Western Power Trading Forum, Vistra, and CAISO staff presented their views on the proposed imbalance reserve product. At the second public meeting on March 7, 2023, CAISO staff, Vistra, and Southern California Edison presented their views on alternative designs. At the third public meeting on March 8, 2023, CAISO staff and WPTF presented their views on alternatives and the proposed design. Finally, the Market Surveillance Committee considered DAME at its March 10, 2023 meeting, with presentations by CAISO staff and MSC members Scott Harvey and Jim Bushnell. In all, the CAISO dedicated approximately 20 hours of public meetings to this extended stakeholder process, with robust participation from a wide array of market participants.[1]

On March 20, 2023, the CAISO published a comparison matrix to highlight the differences and tradeoffs between the various design options considered in the workshops.[2] Although there are many possible variations of each approach, the basic descriptions of these options are as follows:

- **Nodal approach** - procuring imbalance reserves within the IFM (co-optimized with energy and ancillary services) and using deployment scenarios to ensure the awards are transmission feasible if deployed as energy.
- **Zonal approach** - procuring imbalance reserves within the IFM (co-optimized with energy and ancillary services) using zonal procurement similar to ancillary services.

[1] Presentations and recordings from these meetings can be found at: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements

2 http://www.caiso.com/InitiativeDocuments/ComparisonMatrix-Day-AheadMarketEnhancements.pdf. Please note that WPTF provided a redlined version of the matrix from their perspective in their stakeholder comments.

- **SCE approach** - procuring imbalance reserves within the RUC (co-optimized with reliability capacity) using nodal procurement to respect transmission constraints, with a fallback option of keeping imbalance reserves in the IFM but modeling less than full deployment of the imbalance reserves in the deployment scenarios.

On March 30, 2023, stakeholders submitted written comments to provide feedback on what modifications the CAISO should consider for DAME based on the workshop discussions. This stakeholder feedback informed the creation of a draft revised final proposal, published by the CAISO on April 6, 2023. A stakeholder meeting was held on April 7, 2023, to discuss the draft revised final proposal. An additional stakeholder workshop was held on April 17, 2023, for the discussion of DAME policy related to energy storage resources, in which both CAISO staff and the California Energy Storage Alliance (CESA) made presentations.

On April 18, 2023, the CAISO published an addendum to the draft revised final proposal reflecting updates to the imbalance reserve demand curve and related changes based on stakeholder feedback. The material described within that addendum is incorporated in this proposal. On April 24, 2023, stakeholders provided written comments on the draft revised final proposal. These comments were considered in the creation of this revised final proposal. The changes made to this revised final proposal are as follows:

- **Replaces the hybrid demand curve approach with a capped imbalance reserve demand curve for all EDAM BAAs.** The Draft Revised Final Proposal included a hybrid design for the CAISO BAA imbalance reserve requirement. However, the ISO no longer recommends this approach after further evaluation revealed potential issues. Instead, the ISO will implement an imbalance reserve demand curve for all EDAM BAAs, including CAISO BAA, capping the imbalance reserve up and down demand curve values at $55/MWh. The calculation of the imbalance reserve demand curve will resemble that of the flexible ramping product demand curve but will use $247/MWh as the basis for calculating the various segments of the demand curve. Demand curves will be calculated each hour and determined separately for each EDAM entity. The demand curve represents the relationship between the price of imbalance reserves and the quantity the market is willing to procure, allowing the market to determine whether to meet all or some of the upward and downward uncertainty requirements. By capping the demand curve values, market participants can gradually adapt to the new market design, allowing for a smoother transition. The ISO will closely monitor the market to ensure the demand curve cap does not unintentionally affect market efficiency or suppress essential price signals. As the market matures, it will be crucial to review and adjust the demand curves periodically.
- **Revises local market power mitigation and the imbalance reserve bid cap in connection with the change above.** The newly proposed demand curve negates the effect of local market power mitigation for imbalance reserves, as the mitigated bid has the same value as the cap of the demand curve. However, the ISO still intends to implement local market power mitigation procedures in its market software, should the need arise where the parameters for the demand curve or the mitigated bids change in a way that makes the mitigation binding. The newly

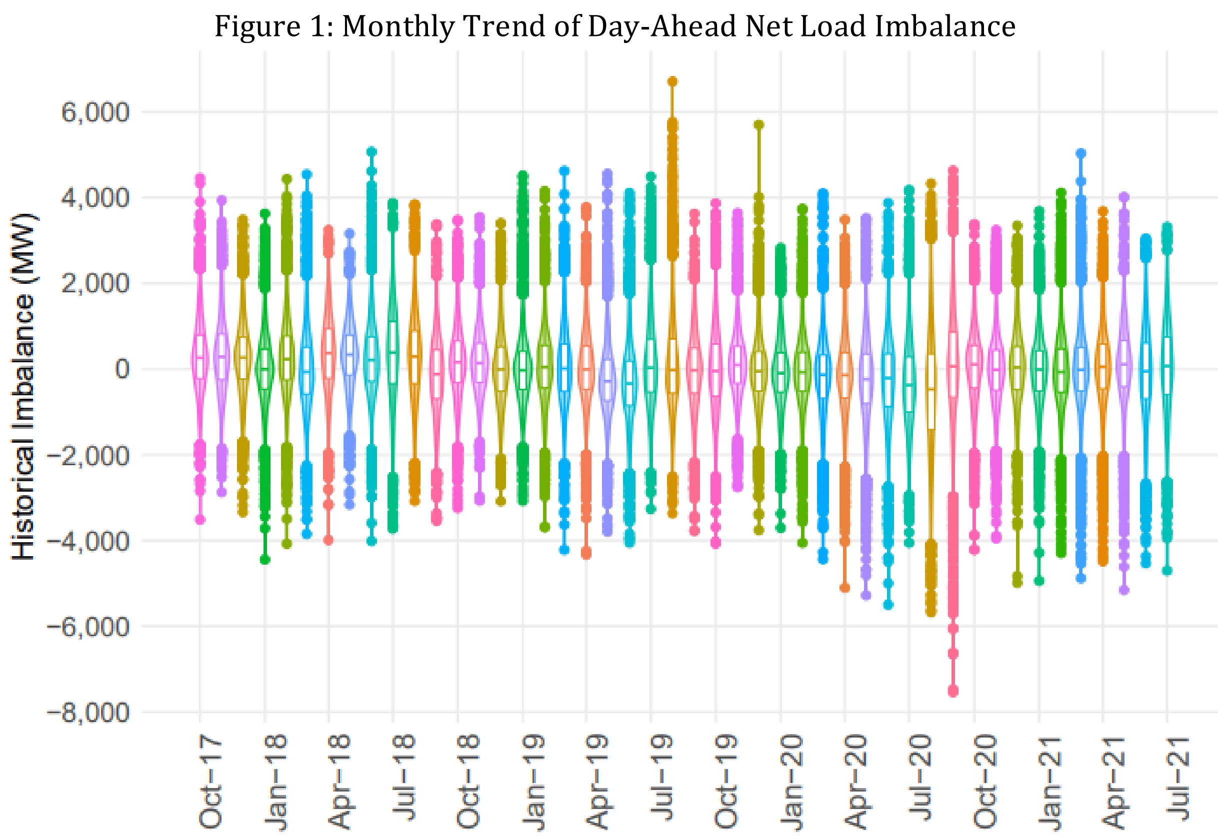
proposed demand curve also initiates a reduction in the imbalance reserve offer cap from $247/MWh to $55/MWh.

- **Confirms new requirements for storage resources' state of charge to support imbalance reserve awards in the day-ahead market, updates the multipliers used in the "envelope constraints" from 0.2 to 0.85, and commits to an ongoing evaluation and discussion of these topics.** Further analysis revealed that a higher multiplier was necessary to strike a balance between the participation of storage resources in imbalance reserves and the operational need to maintain state of charge to support imbalance reserve awards throughout the day. Stakeholders requested more time to evaluate the new envelope equations, their impact on existing constraints, and the best methodologies for setting multipliers. The policy commits to ongoing evaluation and discussions of these topics prior to implementation and inclusion in the ISO business practice manuals. This proposal also clarifies that RUC participation for non-RA resources is optional.
- **Clarifies an exception to the joint authority classification of this initiative.** Section 3.1 proposes a bidding obligation for California RA resources, specifically a day-ahead must-offer obligation for RA capacity eligible to provide imbalance reserves. These resources must offer imbalance reserves for the portion of their energy bid that is not self-scheduled. This element will remain under the sole authority of the Board, with no role for the WEIM Governing Body.

2. Need for Day-Ahead Market Enhancements

Historically, the CAISO balancing authority area consisted of a predictable generation fleet and a predictable load. Resources were scheduled hourly in the day-ahead market with relatively predictable real-time load and ramping needs. Over the last 10 years, variable energy resources (i.e., wind and solar resources) have become more prevalent. While these resources are critical in meeting renewable energy and greenhouse gas emission goals, they also introduce supply uncertainty and can create challenging conditions for system operators. Rather than the relatively predictable load conditions, system operators must manage the more unpredictable and variable net load differences.

Changes between day-ahead market schedules and real-time market schedules are commonly referred to as energy imbalances. Energy imbalances can occur for two reasons. First, the day-ahead market schedules energy in hourly time increments compared to 15- and 5-minute energy schedules in the real-time market. These granularity differences cause imbalances because the real-time market schedules fluctuate within the hour while the day-ahead market schedules are fixed for the hour. In other words, the real-time market can require faster, more granular intra-hour ramping capability when compared to the ramp rate needed to simply transition from one hourly schedule to the next. Second, there is uncertainty in the day-ahead net load forecast. The day-ahead net load forecast cannot perfectly predict the actual net load during the operating day. Any differences between the day-ahead forecast and what actually occurred results in imbalances. Figure 1 illustrates a monthly trend in day-ahead imbalances, calculated as the difference between the net load forecasted in the day-ahead market and the net load forecasted in the fifteen-minute market.



Source: Day-Ahead Market Enhancements Analysis, page 7

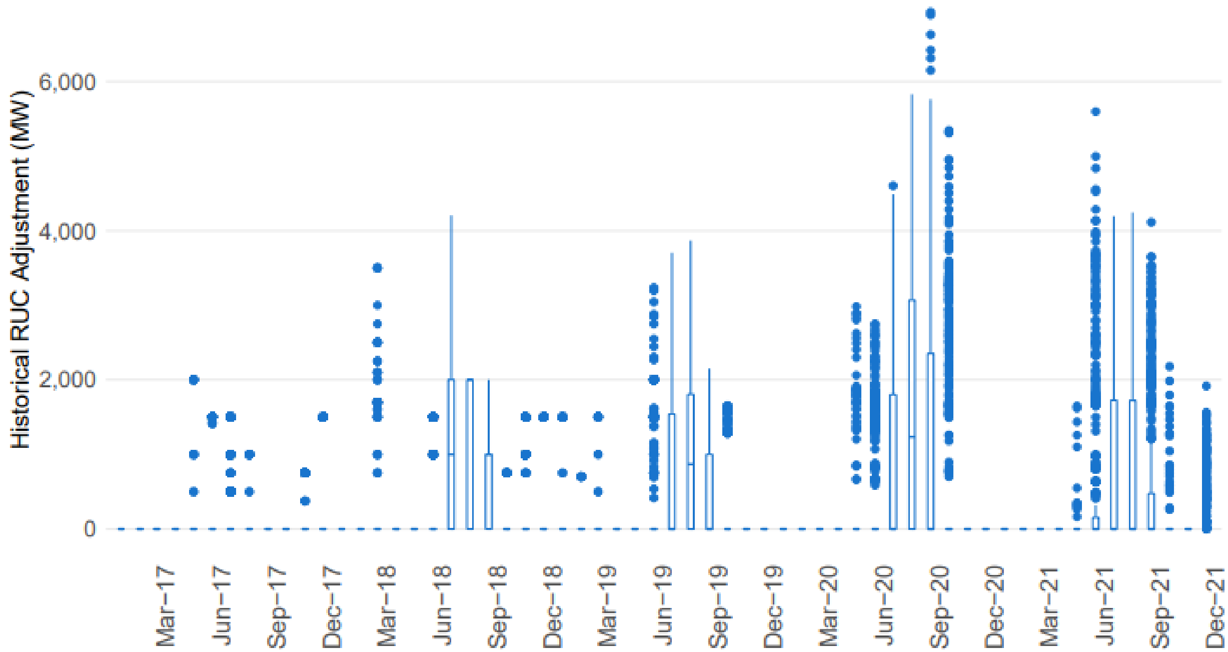
The real-time market must manage energy imbalances that occur between the day-ahead and real-time markets. The real-time market will continue to serve this purpose under the redesigned day-ahead market. This proposal introduces a new day-ahead market product called “imbalance reserves” to better accommodate net load imbalances. The new day-ahead market will co-optimize energy, ancillary services, and imbalance reserves, and will preserve the sequential integrated forward market and residual unit commitment structure.

2.1. Improve Market Efficiency

Changes between the day-ahead market and real-time market are inevitable. Energy imbalances occur for many reasons including weather changes, outages, and forecasting uncertainty. Ultimately, the system operator is responsible for responding to energy imbalances between the day-ahead and real-time to ensure load is served reliably at all times.

Large imbalances between the day-ahead and real-time market can result in challenging conditions for system operators. When there is a risk that imbalances are too large to address through the real-time market, system operators must rely on out-of-market actions to cover these imbalances. CAISO operators have had to make upward adjustments to the forecast used in the RUC process for the last several years to ensure system reliability (see Figure 2). These operator adjustments to the RUC forecast have increased in frequency and magnitude over the last several years. CAISO system operators manually increase the RUC forecast because they need to procure capacity in addition to the supply scheduled in the IFM to address the high net load uncertainty.

Figure 2: Monthly Distribution of Operator Adjustments to RUC Forecast



Source: Day-Ahead Market Enhancements Analysis, page 12

CAISO system operators have to rely on systematic out-of-market actions because the IFM lacks a product that is optimized with energy and ancillary services that procures flexible reserves to cover net load uncertainty. Procuring flexible reserves to meet net load uncertainty through imbalance reserves, as opposed to through out-of-market actions such as operator adjustments to the RUC forecast, will provide substantial benefits:

- **Imbalance reserves will be co-optimized with energy and ancillary services in the IFM, as opposed to procured separately in RUC.** Co-optimization of imbalance reserve procurement with energy and ancillary services will help maximize the value of these reserves by resulting in more optimal unit commitment decisions and more optimal allocation of system ramping capability. In addition, marginal prices will consider the opportunity costs of not providing the other products. For example, if a resource is economic for energy but is held back to provide imbalance reserves instead, the marginal prices will ensure that resource earns sufficient revenue from providing imbalance reserves to cover the opportunity cost of not selling energy. In this way, the resource is indifferent to receiving an incremental energy schedule or imbalance reserve award.
- **Flexible reserves will be procured based on costs represented by imbalance reserves bids.** Today, resource adequacy resources that are required to participate in RUC must do so with a bid price of $0 for all resource adequacy capacity. Furthermore, resource adequacy resources do not receive compensation when the marginal clearing price of RUC supply is non-zero.

However, there are costs to make resources available in the real-time market. These costs can include gas-scheduling costs, costs to set up a hydro system, opportunity costs from other market opportunities, and transmission costs for imports. Resource adequacy resources do not recover these costs through market payments; they must recover these costs through resource adequacy contract payments. It is more efficient, for both the overall system and individual resources, to procure flexible reserves using bids and compensate resources for those flexible reserves through direct market payments. Load serving entities can factor in these expected revenues for resources they procure for meeting their resource adequacy obligation in the contract negotiations. Using bids allows the market optimization to consider costs when scheduling and committing units, leading to better economic outcomes. Marginal prices are a more appropriate mechanism to compensate resources for their availability than fixed contract payments because it results in compensation that reflects when and where the reserves are most valued.

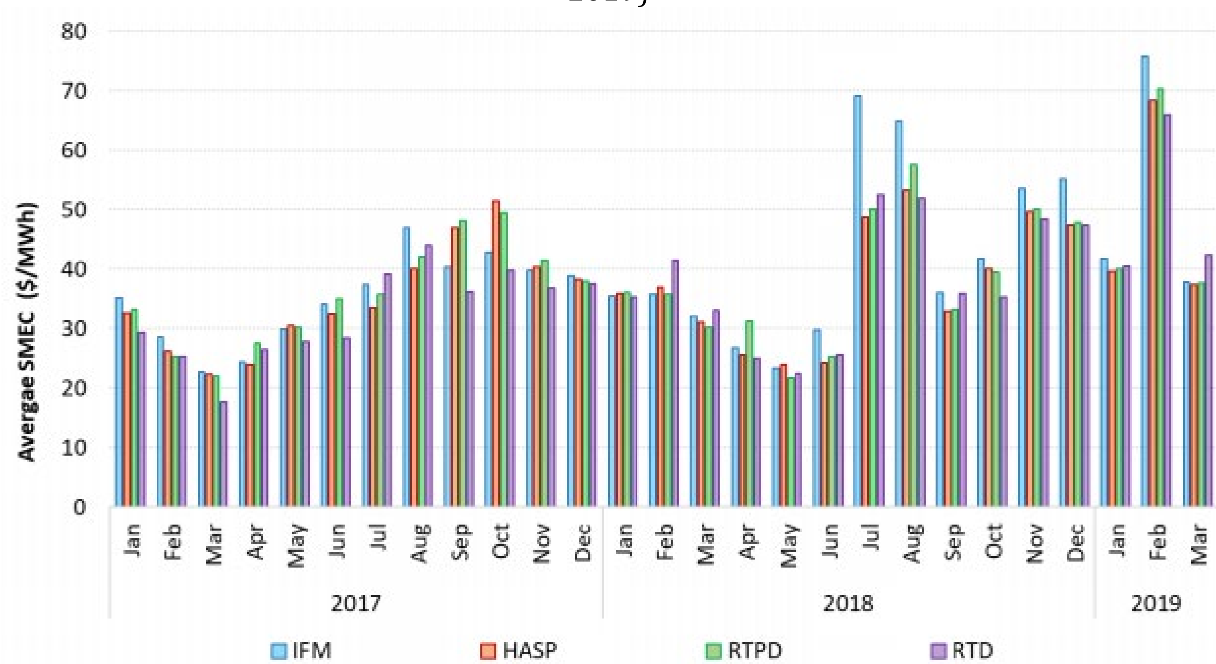
- **Imbalance reserves ensure the system has sufficient ramping capability.** By being co-optimized with energy, imbalance reserves allow the market optimization to consider the full ramping needs of the system (for energy and uncertainty). In addition, because imbalance reserves are 15-minute dispatchable, they are designed to be more flexible than RUC supply, because they are procured to meet the ramping needs that materialize in real-time. There is no assurance the supply committed or scheduled in RUC is sufficient to meet faster ramping needs.
- **Deliverability of capacity through imbalance reserves is more sophisticated than the deliverability of capacity procured through RUC adjustments.** Unlike like RUC adjustments, imbalance reserve deployment scenarios ensure that flexible reserves are deliverable to locations on the system where uncertainty needs are anticipated.
- **Procuring flexible reserves in the IFM better ensures that IFM export schedules are feasible.** Relying on RUC adjustments to procure supply pushes the RUC procurement target farther away from the IFM solution. This can lead to export schedules that were cleared in IFM no longer being feasible in RUC. Because imbalance reserves are expected to significantly reduce the use of RUC adjustments, export schedules cleared in the IFM have a lower chance of being curtailed in RUC.
- **Imbalance reserves will encourage more 15-minute non-EDAM import schedules.** The opportunity to sell imbalance reserves into the CAISO market should encourage non-EDAM importers to set up their system resources as 15-minute dispatchable. This would give the CAISO real-time market additional flexibility.
- **Imbalance reserves align CAISO resource adequacy resources with other EDAM participants.** Imbalance reserves are the mechanism by which the EDAM establishes each participating BAAs uncertainty requirements. It would not be desirable in EDAM for the CAISO BAA to continue to procure additional supply to meet uncertainty through RUC adjustments.

2.2. Price Performance Analysis Report

The CAISO completed a comprehensive report titled *Price Performance Analysis* that summarized and analyzed price formation in the CAISO markets.[3] The report identified factors that contribute to price differences between the day-ahead and real-time markets and proposed solutions to mitigate potential inefficiencies.

As a part of this effort, the report analyzed imbalances across market runs. The greatest magnitude of imbalance occurs 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 large as 6,000 MW in a single hour. The *Price Performance Analysis* report indicated that large imbalances between the day-ahead and real-time market occur because of load forecast error and variable energy resource output changes. As shown in Figure 3, the "IFM prices are persistently higher than real-time prices starting in 2018 and continue in 2019."[4] CAISO believes this occurs because operators use out-of-market actions to procure additional capacity to meet potentially large imbalances. These out-of-market actions may then lead to less efficient and accurate pricing in the real-time market relative to the day-ahead market.

Figure 3: Pricing Differences across Day-Ahead and Real-Time Markets (Jan 2017 - Mar 2019)



Source: Price Performance Report, Page 22

Sustained price differences are a signal that the market is not functioning optimally. The actions the CAISO must take outside of the market to ensure grid reliability contribute to price differences. While

[3] CAISO Energy Markets Price Performance Report. September 23, 2019.
http://www.caiso.com/Documents/FinalReport-PricePerformanceAnalysis.pdf
[4] Ibid., page 22

the CAISO must operate the system reliably, the CAISO also recognizes that consistent out-of-market actions signal there may be gaps in the current market design. Ultimately, the CAISO's goal is 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 initiative 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.

2.3. Deliverability Challenges of Flexible Ramping Product

For the last several years, FRP deliverability has been a concern. The *2019 Price Performance Analysis* discussed the deliverability challenges with CAISO's flexible ramping product.[5] This report documented how FRP capacity could be stranded due to congestion management of internal constraints within an EIM area. This documentation included examples of cases when flexible ramp capacity was stranded because resources were held back to mitigate congestion on internal constraints.

The *2021 Annual Report on Market Issues and Performance*[6] issued by the Department of Market Monitoring also highlighted deliverability challenges with FRP.[7] The report noted that implementing nodal procurement for flexible ramping product could help address the issue of low FRP prices due to procurement of stranded flexible ramp. The report explained that stranded flexible ramp could occur because of WEIM transfer constraints or internal congestion. For example, the report noted that the Northwest region of the WEIM has limited transfer capability out of the region, which can lead to stranded flexible ramping capacity. This issue is highlighted through example intervals and figures, which show the potential for upward flexible ramping capacity to be procured in the region beyond what is actually accessible for the surrounding system.

These findings motivated CAISO to develop its nodal procurement approach for the flexible ramping product as a way to avoid procuring undeliverable reserves. Moreover, this experience now informs the ISO's perspective that any viable approach to procure imbalance reserves must consider deliverability.

2.4. Imbalance Reserves Role in EDAM

The benefit of EDAM is to utilize diverse resources across balancing authority areas to meet load and operational needs across the west more efficiently.[8] Imbalance reserves will be an important component of the EDAM in doing this and increasing its benefits for the following reasons:

- **Reduces each EDAM BAAs individual net load uncertainty requirements and capacity procurement through the EDAM diversity benefit.** By pooling the uncertainty risk over a wider

[5] Ibid, pp. 78-80 and 121.
[6] http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf
[7] Ibid, pp. 121-125.
[8] More information about the EDAM stakeholder process can be found at: http://www.caiso.com/StakeholderProcesses/Extended-day-ahead-market

geographic footprint, the EDAM reduces the flexible reserves needed to meet each individual BAA's uncertainty because uncertainty is not expected to materialize coincidently across the larger and more geographically diverse EDAM market footprint.

- **Builds confidence in energy transfers between BAAs scheduled in the day-ahead market through a common market product to address forecast net load uncertainty in the day-ahead timeframe.** EDAM participants can be assured they can rely on other BAAs in the EDAM to support their transfer obligations because of a common day-ahead market imbalance reserve product.
- **Imbalance reserves will more efficiently reserve resource capacity by allowing balancing authority areas access to resources across the EDAM.** In addition to reducing the overall amount of reserves needed to address net load forecast uncertainty in the day-ahead timeframe, imbalance reserves will more efficiently select the resources to provide these reserves. It will provide EDAM BAAs access to resources that can potentially provide these reserves at lower cost than their own resources. In addition, it will provide additional revenue opportunities to balancing authority areas with these more efficient and flexible resources. Imbalance reserve transfers will be firm, ensuring a BAA can access any imbalance reserves to meet its net load uncertainty that come from another BAA.
- **Imbalance reserves establish a consistent treatment of uncertainty in the EDAM resource sufficiency evaluation.** This ensures that each BAA's uncertainty needs are evaluated equitably.

As with the existing day-ahead market, reliability capacity is needed in the EDAM to ensure physical supply is committed to cover differences in cleared physical supply and each BAA's net load forecast. The integrated forward market is a financial market where bid-in load clears against bid-in supply while also meeting the ancillary services and imbalance reserve requirements. On the other hand, the residual unit commitment is a physical market that clears physical supply to meet the BAA's load forecast. The EDAM will facilitate reliability capacity transfers between BAAs to minimize the cost of ensuring there is enough physical supply in the EDAM footprint to meet each BAA's load forecast.

2.5. Imbalance Reserve Net Benefits

The CAISO commissioned a study to estimate EDAM benefits. As part of that study, in response to stakeholder requests, CAISO requested a sensitivity study to elaborate on the role of imbalance reserves in the EDAM benefit. The CAISO published this study on November 15, 2022 and held a public webinar to discuss the study results on November 18, 2022.[9]

The study results showed the imbalance reserve is an important component in realizing the inter-regional dispatch efficiency. The study found that without the imbalance reserve component, the EDAM

[9] The study presentation materials can be found at http://www.caiso.com/Documents/Presentation-CAISO-Extended-Day-Ahead-Market-Benefits-Study.pdf and the webinar can be accessed at https://www.westernenergyboard.org/webinar-energy-strategies-findings-of-edam-benefits-study-sponsored-by-caiso/.

benefit would be about 60% lower. In addition, removing the imbalance product from the EDAM market was estimated to reduce the benefit to California by $120 million annually.

Figure 1: Annualized EDAM Operational Savings with and without Imbalance Reserves

Study Summary: Annualized Operational Savings
($M/year)

Scenario	California	Other Western States	TOTAL
West-wide EDAM	$214	$329	**$543**
No Imbalance Product	$86	$120	**$206**

Source: CAISO EDAM Benefits Study, page 22

3. Proposed Day-Ahead Market Enhancements

Section 3 describes the proposed day-ahead market enhancements. This section is organized as follows:

- Section 3.1 provides an overview of the proposed changes and the various bidding obligations, including obligations specific to resource adequacy resources.
- Section 3.2 describes the proposed changes to the market power mitigation pass for the integrated forward market.
- Section 3.3 describes the proposed changes to the integrated forward market.
- Section 3.4 introduces and describes an additional market pass to perform local market power mitigation for the residual unit commitment process.
- Section 3.5 describes the proposed changes to the residual unit commitment process.

3.1 Overview

The day-ahead market would consist of four sequential market passes:

1. IFM market power mitigation (MPM) pass
2. Integrated forward market (IFM) pass
3. RUC market power mitigation pass
4. Residual unit commitment (RUC) pass

Today, the IFM market power mitigation pass identifies and mitigates potentially uncompetitive energy bids to ensure market prices remain competitive. Nothing is scheduled or committed in the IFM market power mitigation pass. Any bids that are mitigated in the IFM MPM pass are used in the integrated forward market. This proposal would include mitigation of imbalance reserve offers in the IFM market power mitigation pass.

Today, the integrated forward market uses supply and demand bids to determine the amount of energy the day-ahead market will clear. Convergence bids, also known as virtual supply and virtual demand bids, can participate in this financial market. The integrated forward market also procures ancillary services and commits resources to meet the CAISO BAA's ancillary service requirements. The integrated forward market co-optimizes energy and ancillary services to produce financially binding day-ahead schedules and ancillary services awards. This proposal introduces an imbalance reserves up and down product to the integrated forward market. Imbalance reserves would be procured based on historical net load imbalance between the day-ahead and real-time markets.

This proposal also includes a new market power mitigation pass before the residual unit commitment to assess the competitiveness of reliability capacity offers. In the event the RUC market power mitigation pass detects the potential for market power, reliability capacity bids would be mitigated. Any mitigated bids would be used as inputs to the residual unit commitment process.

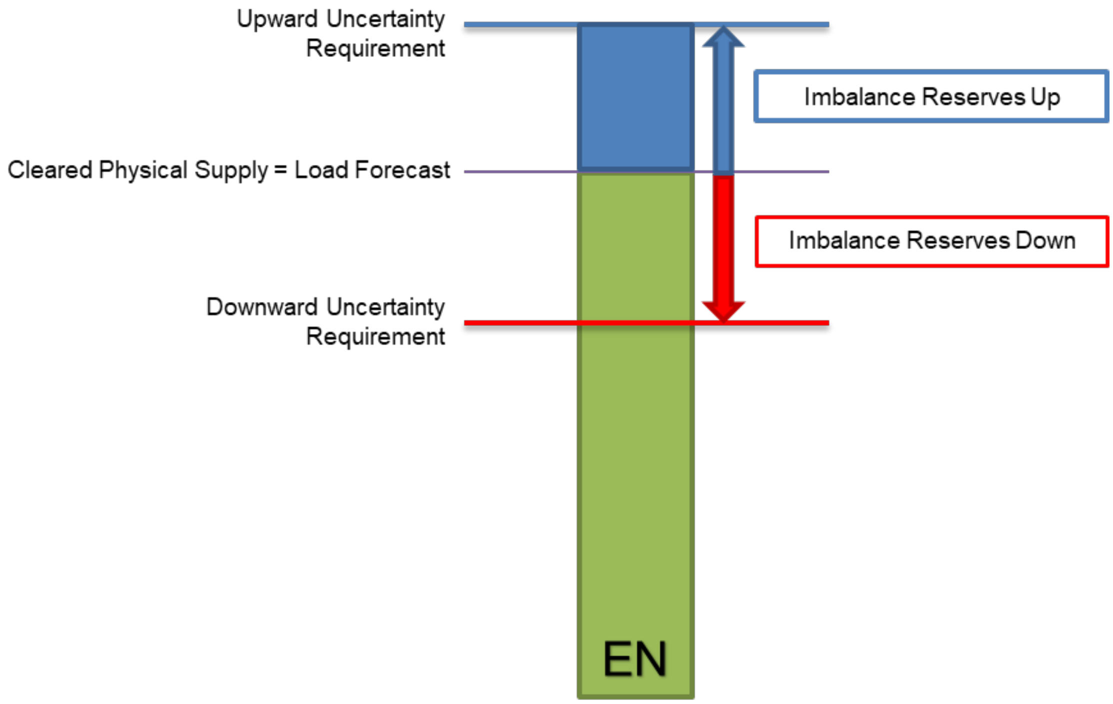
Today, the residual unit commitment process bridges the gap between the CAISO's load forecast and the physical energy cleared in the integrated forward market by procuring incremental supply that was not scheduled or committed in the integrated forward market. This additional supply ensures there is sufficient physical supply available to meet the day-ahead load forecast. In addition, this proposal enhances the residual unit commitment process to procure downward dispatch capability when the physical supply cleared in the integrated forward market exceeds the load forecast.

New Day-Ahead Market Products

This proposal introduces imbalance reserves as a new market product to address net load uncertainty and granularity differences between the day-ahead and real-time markets. Imbalance reserves would minimize the need for out-of-market actions and appropriately value a resource's flexible reserves. This proposal also enhances the residual unit commitment process by adding a downward reliability capacity product.

Figures 3, 4 and 5 illustrate the proposed relationship between energy and imbalance reserves (procured in the integrated forward market) and reliability capacity (procured in the residual unit commitment process). Figure 3 illustrates a scenario where the integrated forward market clears physical supply equal to the BAA's load forecast. The market would procure imbalance reserves to cover upward and downward uncertainty requirements. The day-ahead market would not need to procure reliability capacity in the residual unit commitment process.

Figure 3: Day-ahead market products when physical supply equals load forecast



However, rarely does physical supply clear equal to the BAA's load forecast. Several factors would contribute to the need for the residual unit commitment to procure reliability capacity. The drivers for reliability capacity up would be:

- Bid-in load clears the integrated forward market less than the CAISO load forecast
- Virtual supply clears the integrated forward market in excess of virtual demand

The drivers for reliability capacity down would be:

- Bid-in load clears the integrated forward market greater than the CAISO load forecast
- Virtual demand clears the integrated forward market in excess of virtual supply

These drivers could also offset each other. For example, virtual demand may clear to address under-scheduled load and virtual supply may clear to address under-scheduled variable energy resources.

Figure 5 illustrates the proposed relationship between energy, imbalance reserves, and reliability capacity when the cleared physical supply is greater than the BAA's load forecast. When this occurs, the residual unit commitment would procure reliability capacity up to provide upward dispatch capability, relative to the energy schedules, to meet the load forecast. The integrated forward market would still procure the full imbalance reserve requirements to meet the upward and downward uncertainty.

Figure 5: Day-ahead market products when physical supply is less than load forecast

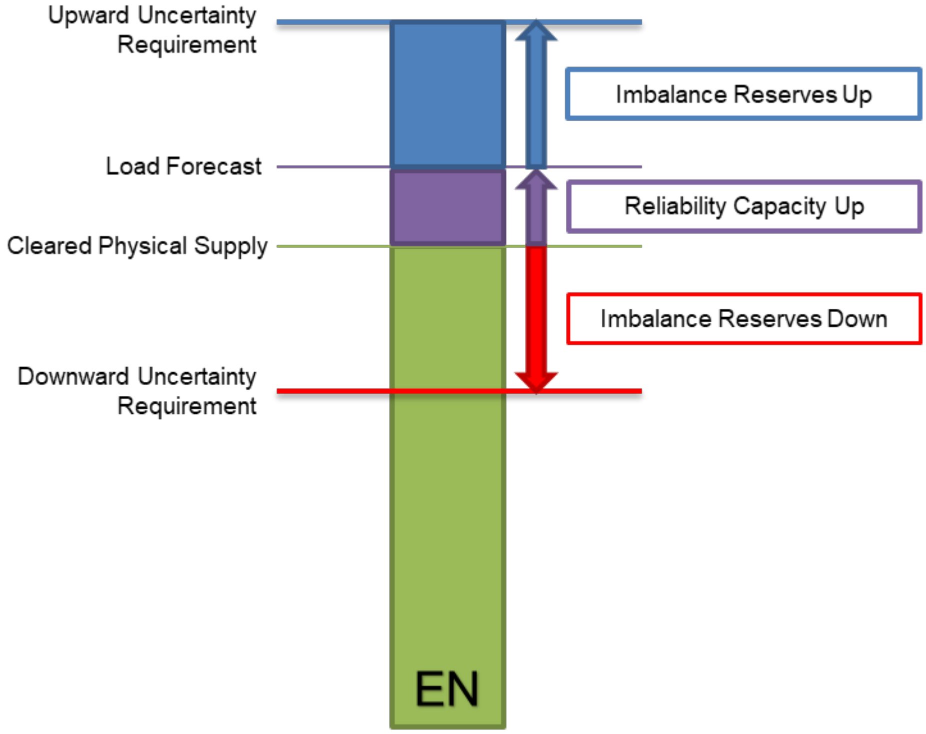
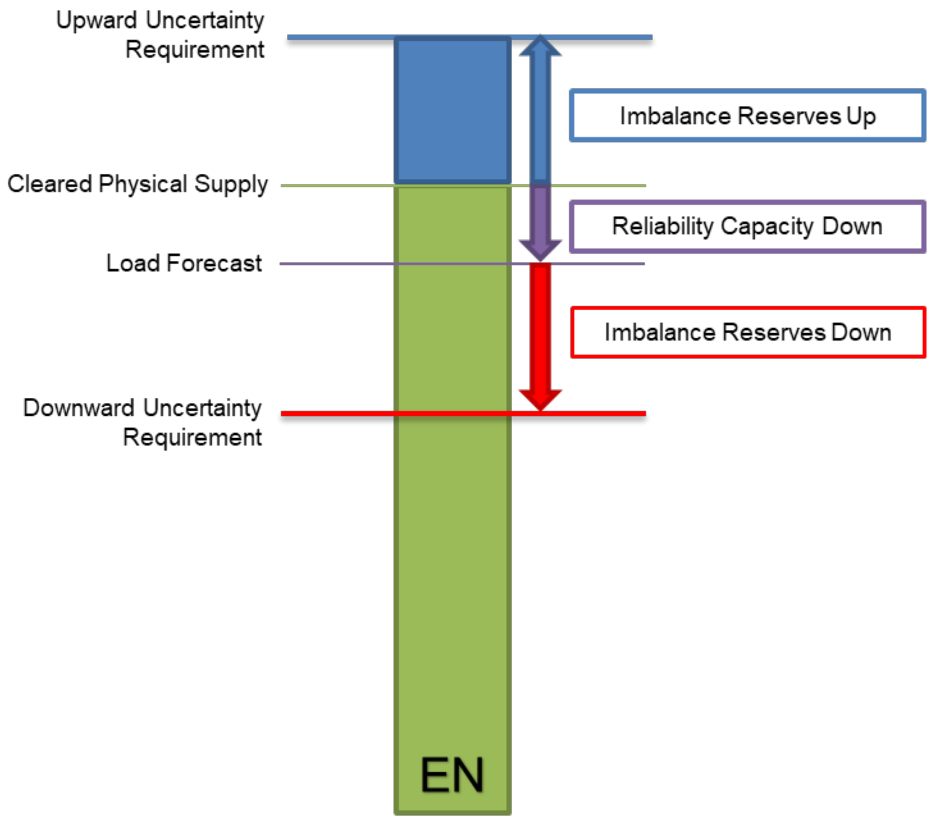


Figure 6 illustrates this relationship when the cleared physical supply is less than the BAA's load forecast. When this occurs, the residual unit commitment would procure reliability capacity down to provide downward dispatch capability, relative to the energy schedules, to meet the load forecast. The integrated forward market would still procure the full imbalance reserve requirements to meet the upward and downward uncertainty.

Figure 6: Day-ahead market products when physical supply is greater than load forecast



The load forecast and the amount of uncertainty determines the amount of physical energy and dispatch capability from physical resources needed to ensure reliability.

Table 1 summarizes the proposed 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*	Procured In	Status
Energy	EN	Energy schedules cleared to meet bid-in demand	All resources	IFM	Existing
Reliability Capacity Up	RCU	Incremental supply procured to meet the positive difference between the load forecast and cleared physical supply	Physical resources based on 60-minute ramp capability	RUC	Replaces RUC awards
Reliability Capacity Down	RCD	Decremental supply procured to meet the negative difference between the load	Physical resources based on 60-minute ramp capability	RUC	Proposed

Title	Acronym	Purpose	Eligibility*	Procured In	Status
		forecast and cleared physical supply			
Imbalance Reserves Up	IRU	Incremental reserves procured to meet the upward uncertainty requirement	15-minute dispatchable physical resources, award based on 30-minute ramp capability	IFM	Proposed
Imbalance Reserves Down	IRD	Decremental reserves procured to meet the downward uncertainty requirement	15-minute dispatchable physical resources, award based on 30-minute ramp capability	IFM	Proposed
Ancillary Services	AS	Incremental reserves procured and reserved to meet real-time regulation and contingency reserve requirements	Resources certified to provide the respective service	IFM	Existing

Differences between Imbalance Reserve and Reliability Capacity

Some stakeholders have questioned why the day-ahead market needs both imbalance reserves and reliability capacity. While both these market products procure reserves in the day-ahead market, they serve different purposes and procure reserves based on different resource characteristics and system needs.

There could be perfect certainty between day-ahead and real-time markets and the market would still need reliability capacity. That is because the integrated forward market is a financial market (as opposed to a physical market) that clears based on demand bids instead of a demand forecast. Therefore, the integrated forward market can clear supply at a different quantity than the BAA demand forecast. Reliability capacity is procured in RUC to meet that difference. In addition, the integrated forward market allows for virtual bids, which are not backed by physical resources. If virtual bids clear the market, reliability capacity is procured in RUC to ensure there are sufficient physical resources to meet the BAA demand forecast.

The day-ahead market would procure reliability capacity based only on the load forecast. Assuming no operator load biasing, the reliability capacity procurement requirement does not address net load forecast uncertainty between the day-ahead timeframe and real-time. In contrast, the day-ahead market would procure imbalance reserve to cover this net load uncertainty. Imbalance reserves also provide additional ramping capability for real-time five-minute ramping needs that can be greater than the ramp capability procured in the day-ahead market.

If the integrated forward market clears physical resource supply up the day-ahead load forecast, then RUC would not schedule reliability capacity because there would already be enough scheduled supply (assuming that supply could meet the load forecast based on RUC's 60-minute ramp modeling.) However, the actual real-time net load and associated ramping needs could be much greater if net load comes in above or below the day-ahead forecast. These ramping needs can also be highly variable and can be greater than that scheduled by RUC's modeling of ramping for 60-minute granularity net load changes.

Imbalance reserves addresses this by procuring upward and downward resource ramping capability to meet differences in net load in each real-time market 15-minute interval that are different than that scheduled to be met in 60-minute granularity RUC schedules.

Procuring only imbalance reserves and not procuring reliability capacity is not an option because imbalance reserves should be procured relative to the day-ahead forecast, not the IFM market cleared load. If reliability capacity did not exist, then imbalance reserves would be procured to the wrong reference. In the initial DAME straw proposal, the ISO considered whether to eliminate reliability capacity and have imbalance reserves procured relative to the IFM market cleared load. It was decided this method could not guarantee there was sufficient physical supply to meet the forecasted demand, and that the relative quantity of imbalance reserves would have been unnecessarily high, and so abandoned this approach.

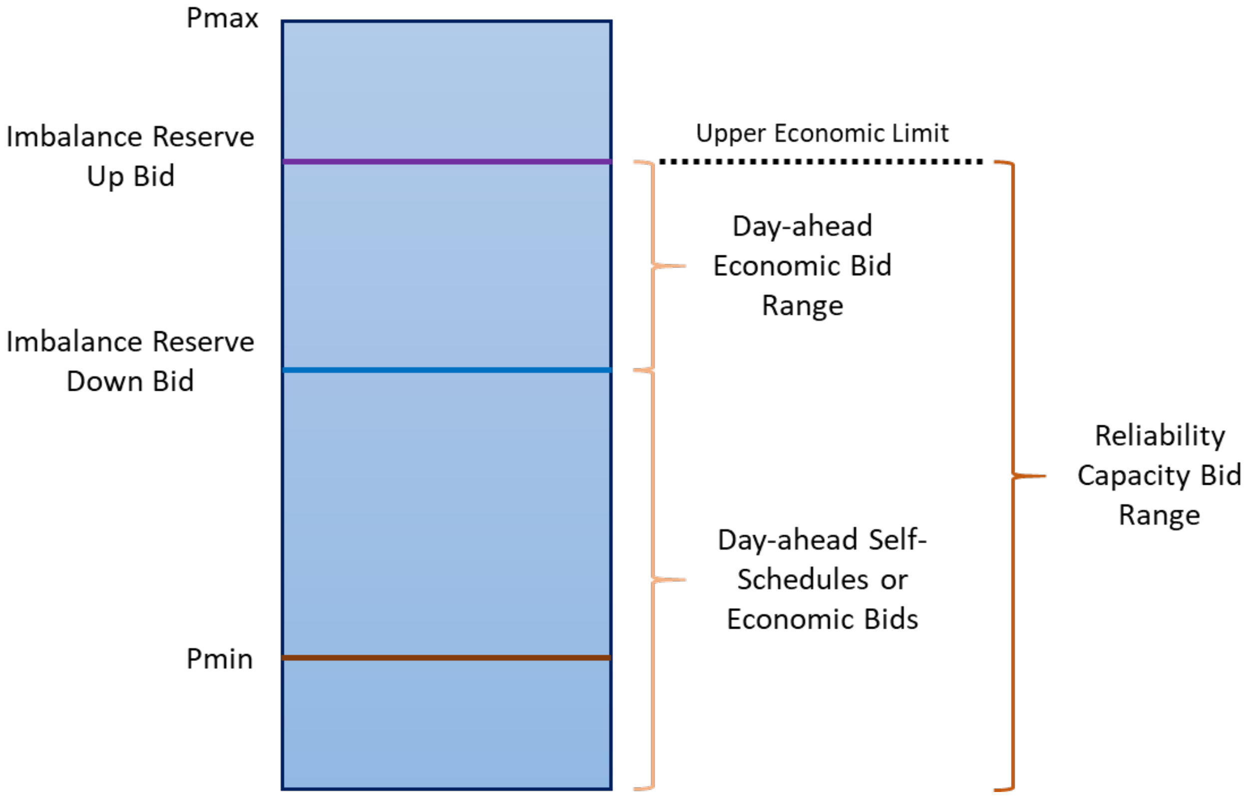
Day-Ahead Bidding Rules for Imbalance Reserves and Reliability Capacity

Eligible resources would submit bids for imbalance reserves (see Appendix A for eligibility by resource type). In order to bid for imbalance reserves, resources must provide an energy bid in the day-ahead market and must economically bid the portion of the energy bid that overlaps with the imbalance reserve bid. Figure 7 provides an illustration of this bidding requirement.

Eligible resources would also submit bids for reliability capacity (see Appendix A for eligibility by resource type). Resources need to provide an energy bid in the day-ahead market to bid for reliability capacity but do not need to overlap with the economically bid portion of the energy bid. As part of EDAM, all resources offering energy bids in the IFM (and thus included in the EDAM resource sufficiency evaluation) must submit bids for reliability capacity up at the same quantity as their energy bid plus ancillary service self-provision. This ensures all resources shown in the EDAM RSE are fully available for use in RUC, including excess supply that participants offered above their RSE requirements.

The total quantity of energy, imbalance reserves, and reliability capacity scheduled on a resource would be capped based on the resource's upper economic limit. The upper economic limit is the highest operating level submitted in the resource's energy bid.

Figure 7: Day-Ahead Bidding Rules for Imbalance Reserves and Reliability Capacity



Real-Time Bidding Obligations based on Day-Ahead Awards

Resources that receive an energy schedule, ancillary service awards, reliability capacity awards, or imbalance reserve awards in the day-ahead market will have real-time market bidding obligations. Resources must provide economic energy bids for the full range of their reliability capacity and imbalance reserve awards in the real-time market. Real-time must-offer obligations apply in the hours that a resource has a reliability capacity or imbalance reserve award.

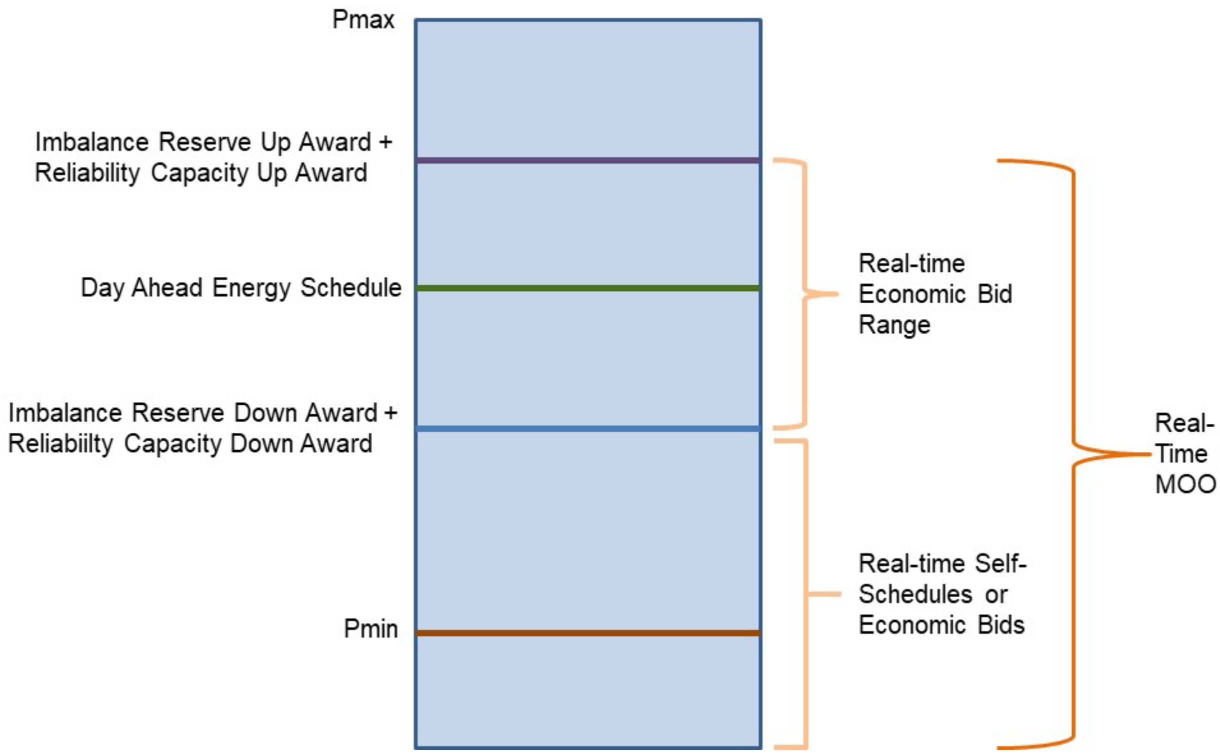
The purpose of the real-time must-offer obligation is to provide economic bids to the real-time market. Economic bids enable the real-time market to re-dispatch resources to meet real-time system conditions and imbalances. Real-time self-schedules do not provide the real-time market with the ability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

The minimum real-time bidding obligations are illustrated in Figure 8. A resource must submit economic bids above its day-ahead energy schedule by the amount of imbalance reserves up and reliability capacity up awarded. The resource is not required to submit additional bids up to its Pmax but may elect to do so. This ensures there are sufficient economic offers to allow the real-time market to dispatch the resource above or below its day-ahead energy schedule.

Any portion of this resource’s day-ahead energy schedule below the imbalance reserves down and reliability capacity down awards can be either self-scheduled or economically bid. A resource cannot submit a self-schedule that exceeds its energy schedule less its imbalance reserves 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 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.

Figure 8: Real-time Bidding Obligations



Day-Ahead Must-Offer Obligations for Resource Adequacy Resources

The following summarizes the resource adequacy must-offer obligations for the day-ahead market.

CAISO BAA resource adequacy resources will continue to be required to economically bid or self-schedule their resource adequacy capacity into the integrated forward market. This applies all hours of the month the resource is physically available. Resources providing system and local resource adequacy will continue to be required to economically bid or self-provide ancillary services.

Resources providing resource adequacy capacity that are currently required to submit RUC availability bids will be required to bid their resource adequacy capacity into the residual unit commitment for reliability capacity up. Bids for reliability capacity down will be optional. The CAISO will not require that resource adequacy resources offer resource adequacy capacity into RUC with $0 availability bids.

Instead, resource adequacy capacity can be bid into RUC at any price between the bid floor and bid cap.[10]

Resource adequacy capacity would be leveraged to facilitate a day-ahead must-offer obligation for imbalance reserves. This proposal would require that all RA capacity eligible to provide imbalance reserves (i.e., 15 minute dispatchable) have a must-offer obligation for imbalance reserves for the portion of their energy bid that is not self-scheduled (i.e., economically bid). Thus, this must-offer obligation would apply to all flex RA capacity since flex RA capacity is 15-minute dispatchable and already required to economically bid in the day-ahead market. System RA capacity that is eligible for imbalance reserves would maintain its ability to self-schedule or economically bid for energy, but any portion of the energy bid that is economic must be accompanied by an imbalance reserve offer. System RA capacity that is not eligible for imbalance reserve would have no change to their existing must-offer requirements from this rule. These must-offer requirements would maximize participation of RA capacity in imbalance reserve to increase competitiveness of the product, improve congestion management, reduce concerns about physical withholding, and help the CAISO BAA pass the EDAM resource sufficiency evaluation. At the same time, these must-offer requirements do not prevent any RA capacity from self-scheduling – an option that stakeholders expressed was extremely important. Imbalance reserve must-offer obligations would not be subject to RAAIM (Resource Adequacy Availability Incentive Mechanism) penalties.

Real-Time Must-Offer Obligations for Resource Adequacy Resources

This proposal maintains the CAISO BAA resource adequacy real-time must-offer obligation. Today, certain resource adequacy resources have an obligation to bid or self-schedule in the real-time market even if they do not receive an IFM schedule or binding RUC commitment. The CAISO enforces these obligations through its tariff and through mechanisms like bid insertion, which enables the market to generate real-time bids for eligible resource adequacy capacity that did not submit bids and is not on outage.

This proposal would initially implement DAME with the resource adequacy real-time must-offer obligation in place. After some future operational experience with EDAM, the CAISO could engage stakeholders to re-discuss whether an ISO-enforced resource adequacy real-time must-offer obligation continues to be needed.

Mechanism to Protect RA Capacity in EDAM

Some stakeholders from the CAISO BAA have expressed concerns about asymmetrical participation between CAISO and other BAAs in EDAM that center around the CAISO resource adequacy program's day-ahead and real-time must-offer obligations. Whereas non-CAISO BAAs are only obligated to offer into the EDAM market sufficient supply to pass their resource sufficiency evaluation, the CAISO resource adequacy program obligates all resource adequacy capacity to offer into the day-ahead market. The CAISO load serving entities would have no mechanism to "hold back" or "protect" a certain portion of

[10] RCU/RCD payments that overlap with RA capacity would be subject to reverse settlement as described in Section 3.5.

their resource adequacy capacity from supporting firm EDAM transfers. The EDAM proposal considers a net export transfer constraint to address this concern.

3.2 Market Power Mitigation Pass for IFM Changes

In the market power mitigation pass for IFM, the market would use unmitigated bids to clear bid-in load, bid-in supply, imports, exports, ancillary services requirements, and the imbalance reserve requirements. Binding transmission constraints in the base scenario (cleared bid-in load), the imbalance reserve up deployment scenario, and the imbalance reserve down deployment scenario would be evaluated for competitiveness. This proposal would continue use of the dynamic competitive path assessment (DCPA) to determine whether a transmission constraint is competitive.

Today, resources that can provide counter-flow to an uncompetitive constraint in the base scenario have their energy bids subject to mitigation. That would not change in this proposal. However, with the introduction of upward and downward deployment scenarios in the integrated forward market, this proposal would mitigate energy bids from resources that can provide counter-flow to an uncompetitive constraint in these deployment scenarios as well. This is because energy marginal prices have congestion contributions from binding constraints in the deployment scenarios.[11]

Resources that can provide counter-flow to an uncompetitive constraint in the upward deployment scenario would also have their imbalance reserve up bid mitigated. Imbalance reserve up marginal prices have congestion contributions only from binding constraints in the upward deployment scenario.[12] This proposal would not mitigate imbalance reserve down bids. This proposal would also not mitigate the imbalance reserve up bids of non-EDAM intertie resources certified to provide imbalance reserves, consistent with current policy for energy bid mitigation.

Local market power mitigation of energy and imbalance reserve up would be based on the same optimization, bids, set of binding constraints, and set of shift factors. The supply of counter flow for a binding transmission constraint in the upward deployment scenario would be the product of the negative shift factor and the energy schedule plus the imbalance reserve up award.[13]

CAISO provided detailed examples of local market power mitigation applied to energy and imbalance reserve offers.[14] The examples show that while energy mitigation alone does help mitigate market power exercised through imbalance reserve bids, it does not fully prevent it. Because energy and imbalance reserve up are fungible, the market will attempt to reorient energy and imbalance reserve schedules to avoid awarding resources with high priced imbalance reserve bids in favor of awarding

[11] See the DAME technical description. The terms $\sum SF_{i,m,t}\,\mu^{(\mathrm{u})}{}_{m,\mathrm{t}}$ and $\sum SF_{i,m,t}\,\mu^{(\mathrm{d})}{}_{m,\mathrm{t}}$ represent how transmission constraints in the upward and downward deployment scenarios contribute to the LMP.

[12] Id. The term $\sum SF_{i,,}\,\mu^{(\mathrm{u})}{}_{m,\mathrm{t}}$ represents how transmission constraints in the upward deployment scenario contribute to the IRU marginal price.

[13] Detailed description of the RSI calculation is provided in the DAME technical description.

[14] http://www.caiso.com/InitiativeDocuments/Appendix-C-Third-Revised-Straw-Proposal-Day-Ahead-Market-Enhancements.pdf

them energy schedules. However, this forces the market to schedule energy on a resource with higher bid costs, which drives up the total production cost. In this way, suppliers could utilize their position on the grid to exercise local market power, driving up costs to the system and increasing their market payments above competitive levels.

Today, the CAISO mitigates energy offers to the greater of what it calls *default energy bids* or the *competitive locational marginal price*.[15] Default energy bids are the CAISO's estimate of a resource's marginal cost. The competitive locational marginal price is the marginal price of energy minus the non-competitive congestion components at the location of the mitigated resource. The competitive locational marginal price represents the going rate for competitive energy at the relevant location and ensures resources are mitigated only to the extent needed to resolve market power for higher-priced bids.

This proposal maintains this method of determining mitigated bid prices for energy offers and extends this method to imbalance reserve up offers. This proposal would mitigate imbalance reserve up offers to the higher of a *default availability bid* or the competitive locational marginal price for imbalance reserve up. The latter would be derived as the marginal price of imbalance reserve minus the non-competitive congestion components from binding constraints in the imbalance reserve up deployment scenario at the location of the mitigated resource. This proposal would also include a Negotiated Rate Option, under which the CAISO would use information provided by the Scheduling Coordinator to determine the negotiated default availability bid. The Negotiated Rate Option would be available to Scheduling Coordinators once the CAISO has sufficient operational knowledge of, and experience with, imbalance reserve bids. The CAISO expects it will need approximately one year of operational experience with the new products before it will be able to support the Negotiated Rate Option. Further details on the Negotiated Rate Option would be communicated in the CAISO's Business Practice Manuals.

Default availability bids would be distinct from default energy bids. Default energy bids (DEBs) are specific to each resource and are generally designed to approximate a resource's variable costs of providing energy, using any of the five methodology options the CAISO offers.[16] The variable costs of providing energy can be approximated based on generally understood criteria such as generator performance data, fuel costs, and opportunity costs. However, costs related to a resource's ability to provide reserves are more nebulous. Estimating the variable costs of each resource to provide reserves is subject to significant uncertainty.

Therefore, this proposal considers a static system-wide default availability bid for imbalance reserve mitigation when DAME is first implemented. This default availability bid would be the same price for all

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[15] If the resource's unmitigated energy bid were less than the default energy bid or the competitive locational marginal price, there would be no modification to the resource's bid.

[16] LMP option, negotiated rate option, variable cost option, hydro DEB option, storage DEB option. See attachment D of the Business Practice Manual for Market Instruments - https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments.

resources and across all market intervals. It would provide a mitigation "floor" that balances the need to protect consumers against market power but also protect producers against excessive mitigation by forcing offers below their costs. The imbalance reserve up default availability bid would be set conservatively using a high percentile value of historical spinning reserve bids. After the CAISO and market participants gain operational experience with imbalance reserves, and more information is available on the costs of offering imbalance reserves under competitive conditions, the CAISO could re-engage with stakeholders to develop a more rigorous default availability bid methodology.

The CAISO proposes the default availability bid for imbalance reserves be set to $55/MWh. This represents greater than the 80th percentile of spinning reserve bids using historical data (see Table 2). Spinning reserve bids is a reasonable approximation of a resource's cost to provide reserves. CAISO will investigate whether spinning reserve bid prices are related to prevailing gas prices to potentially make the default bid scalable by gas prices.

Table 2: Spinning Reserve Bid Prices (Jan - Jun 2022)

Type	Spinning Reserve Bid Price ($/MWh)
50 Percentile	$1.90
60 Percentile	$5.00
70 Percentile	$21.70
80 Percentile	$50.00
90 Percentile	$100.00

Note that changes made to the imbalance reserve demand curve negate the effect of local market power mitigation for imbalance reserves, as the default availability bid has the same value as the cap of the demand curve. However, the ISO still intends to implement local market power mitigation procedures in its market software, should the need arise where the parameters for the demand curve or the mitigated bids change in a way that makes the mitigation binding.

3.3 Integrated Forward Market Changes

Today, the integrated forward market obtains a full market solution using mitigated bids from the market power mitigation pass. The integrated forward market solves the optimal unit commitment to clear bid-in load, bid-in supply, imports, exports, and ancillary services requirements. This proposal enhances the day-ahead market by introducing an imbalance reserves product that is co-optimized and procured in the integrated forward market.

Energy (EN)

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

Ancillary Services

The day-ahead market currently 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.[17]
- 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 either are or are not synchronized to the grid and can be called upon if a contingency event occurs.

This proposal considers no changes to ancillary service procurement. Ancillary services would continue to be procured on a system and regional basis as opposed to a nodal basis and subject to the existing cascading procurement rules where regulation up can substitute for spinning and non-spinning reserves, and spinning reserve can substitute for non-spinning reserve.[18]

Imbalance Reserves (IRU/IRD)

Imbalance reserves would ensure the integrated forward market schedules sufficient dispatch capability to meet net load imbalances between the day-ahead and real-time markets. These imbalances are caused by uncertainty in the day-ahead net load forecast and granularity differences between hourly day-ahead market and fifteen-minute real-time market schedules. Imbalance reserves would be comprised of imbalance reserves up (IRU) that provide upward dispatch capability and imbalance reserves down (IRD) that provide downward dispatch capability. An imbalance reserve schedule would

[17] In addition, there is a mileage requirement for regulation up and regulation down, representing the expected amount of system-wide resource operating point travel needed to provide the service.
[18] The CAISO may consider an initiative in 2023 to explore collapsing the current spin and non-spin requirement into a single contingency reserve requirement. This initiative would also examine removing the current cascading rule between upward ancillary service products.

result in an obligation to provide economic energy bids to the real-time market. The market may schedule a resource to provide both IRU and IRD.

The integrated forward market would co-optimize and procure imbalance reserves to meet an hourly imbalance reserve requirement. The market would use imbalance reserve deployment scenarios to ensure imbalance reserves are transmission-feasible to the locations the uncertainty is expected to materialize if they are fully deployed. The market would price imbalance reserves at each node, resulting in locational marginal prices that reflect transmission constraints.

Imbalance reserves would enable the day-ahead market to compensate resources that provide flexible reserves to meet net load uncertainty and ramping needs. Today, system operators frequently take out-of-market actions, including increasing the load forecast used in RUC, to secure additional supply to increase the ramp capability available to the real-time market and to address uncertainty between the day-ahead and real-time markets. System operators are taking such actions because of the increased net load variability and uncertainty resulting from increasing amounts of weather-dependent supply and demand. Imbalance reserves would reduce the need for these out-of-market actions and would create a market price signal for day-ahead flexible reserves.

The day-ahead market would only award imbalance reserves to resources that are dispatchable in the fifteen-minute market. Although the day-ahead market will schedule imbalance reserves hourly, the maximum award would be based on a resource's 30-minute ramp capability. Offline resources could be awarded imbalance reserves if the resource has a start-up time of 15 minutes or less. This proposal would make these parameters adjustable in response to stakeholder feedback that these requirements may be overly restrictive. The CAISO would monitor the performance of the imbalance reserve product once implemented to assess whether allowing for longer start-up times or longer ramp horizons is necessary or desirable.

Imbalance Reserve Requirement

This section provides a high-level overview of the method used to calculate the imbalance reserve requirements in the day-ahead market. This method intends to align with the approach proposed for the real-time market flexible ramping product requirements.[19]

Historical data would be used to identify the load, wind, and solar forecast error between the day-ahead market and fifteen-minute markets. These historical forecast errors would then be used to determine the imbalance reserves up and down requirement based on the prevailing load, wind, and solar forecasts for each hour of each day using statistical regression. This proposal considers use of quantile regression to determine the imbalance reserve requirements. 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 requirements are based on relatively extreme high and low (i.e., 97.5 and 2.5 percentile) observations of

[19] CAISO Flexible Ramping Product Refinements initiative. Appendix C – Quantile Regression Approach. http://www.caiso.com/InitiativeDocuments/AppendixC-QuantileRegressionApproach-FlexibleRampingProductRequirements.pdf

forecast error, as opposed to the average forecast error. Furthermore, the quantile regression produces a polynomial function of the forecast that can be evaluated at the forecast for the relevant hour of the trading day, thus yielding an imbalance reserve requirement that does not only depend on historical forecast error, but also on the VER forecast used in the IFM and the demand forecast used in RUC.

Separate regressions need to be run using load, solar, and wind as dependent variables and then the estimated parameters are combined using the identity Net Load = Load – Wind – Solar. 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 because a 97.5 percentile net load imbalance (using the identity Net Load = Load – Wind – Solar) 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 output values from the three quantile regressions are synthesized using a formula for the Net Load and they go through an additional quantile regression to produce the final imbalance reserve up requirement polynomial (see link in Footnote 14 for more detail). A similar process is undertaken to calculate the imbalance reserve down requirement. This results in an independent imbalance reserve up and imbalance reserve down requirement for each hour in the day-ahead market.

The CAISO would implement the quantile regression such that the percentiles used (2.5 and 97.5) are configurable so the CAISO could make adjustments after gaining operational experience.

In the EDAM, the CAISO intends to calculate the imbalance reserve requirement for each EDAM BAA separately using historical data specific to the BAA. The CAISO would develop a process for collecting load, wind, and solar forecast data from EDAM entities during the EDAM onboarding process so the CAISO can calculate an accurate imbalance reserve requirement when the EDAM entity goes live in the market.

Imbalance Reserve Demand Curve

Introduction

The market uses penalty prices to establish the priority of different schedules and constraints and to set market prices when schedules or constraints need to be relaxed when there is insufficient supply to satisfy requirements. Previous DAME proposals have suggested various penalty price structures, ranging from demand curves to graduated penalty prices that relax the imbalance reserve requirement as the cost increases, to strict penalty prices that protect the full imbalance reserve requirement at higher costs.

The Draft Revised Final Proposal published on April 6, 2023 proposed for the CAISO BAA a hybrid design for the imbalance reserve requirement, dividing it equally between a demand curve and high penalty prices. This addressed concerns of prioritizing LPT exports over imbalance reserves for the CAISO BAA's net load uncertainty, ensuring more predictable export volumes. The demand curve followed the flexible ramping product's design. The hybrid model was exclusive to the CAISO BAA, as other EDAM BAAs would be subject solely to the imbalance reserve demand curve due to the absence of intertie bidding.

New Proposal

The ISO no longer recommends the hybrid approach for the CAISO BAA. Further evaluation of this approach revealed that it could lead to high prices that exceed the operational benefit of the product. Given the updated RUC proposal that allows the market to signal that exports may not be feasible in real-time, the CAISO BAA’s exposure to unpredictable export volumes is reduced. One continued concern is that the cost of curtailing these exports in real-time might be high. CAISO will monitor the situation and make adjustments if necessary after implementation.

In response to stakeholder feedback, the ISO will replace the previous proposal and instead implement an imbalance reserve demand curve for all EDAM BAAs, including the CAISO BAA, and cap the imbalance reserve up and down demand curve values at $55.[20] The calculation of the imbalance reserve demand curve will resemble that of the flexible ramping product demand curve. The principle is that CAISO would calculate demand curves by determining the amount of the imbalance reserve requirement that should be relaxed at different price levels to ensure the cost of imbalance reserve awards does not exceed the expected cost of foregoing them. However, instead of the $1,000/MWh cost used in the flexible ramping product calculation, the avoidance cost of imbalance reserves will be set to $247/MWh, which is the lowest penalty price for violating contingency reserve requirements. Although $247/MWh is the basis for calculating the various segments of the demand curve, no steps of the demand curve will exceed the administrative ceiling of $55/MWh for the imbalance reserve product. Demand curves will be calculated each hour and determined separately for each EDAM entity.

Demand Curve

A demand curve represents the relationship between the price of imbalance reserves and the quantity that the market is willing to procure. It shows how the market's willingness to procure imbalance reserves changes with the price, helping to establish an appropriate price level while considering the expected cost of not procuring them.

[20] $55/MWh represents a high-percentile replacement cost of spinning reserves, which can be deployed in real-time in response to net load forecast error. This is similar to the approach of Midcontinent Independent System Operator, in which their Ramp Capability Up product demand curve uses a “cost of violation” equivalent to the first step of their spinning reserve demand curve.

The imbalance reserve demand curve establishes the price of not fulfilling the imbalance reserve requirement for a given hourly interval. This allows the market to determine whether to meet all or some of the upward and downward uncertainty requirements. The market makes this determination by assessing the trade-off between the cost and the value of an incremental unit of imbalance reserves.

If the imbalance reserve price is lower than the expected cost of not meeting the uncertainty requirement, the market will continue to procure imbalance reserves. Conversely, if the imbalance reserve price is higher than the expected cost of not meeting the uncertainty requirement, no additional imbalance reserves will be procured to cover it.

Implementation and Monitoring

By capping the demand curve values at the default bid price for imbalance reserve mitigation, market participants can gradually gain experience and adapt to the new market design. This approach allows for a smoother transition, reducing the likelihood of unforeseen issues or price spikes that could arise from a more aggressive initial implementation. However, the ISO emphasizes the importance of closely monitoring the DAME/EDAM market to ensure that the demand curve cap does not unintentionally stifle market efficiency or suppress price signals that are essential for maintaining system reliability. As the market matures and more operational experience is gained, it will be crucial to periodically review and adjust the demand curves to better reflect the true value of imbalance reserves and the associated scarcity conditions. This process should involve ongoing collaboration between the ISO, market participants, and other stakeholders to identify potential improvements and to make informed adjustments to market rules and design based on empirical evidence.

Other Considerations

This revised demand curve approach also simplifies the DAME design by decreasing the necessity for local market power mitigation of upward imbalance reserves. Since the $55/MWh administrative cap on imbalance reserves is equivalent to the proposed upward imbalance reserve mitigation price, there is no need to apply local market power mitigation to imbalance reserve bids. However, the ISO plans to develop the local market power mitigation functionality to apply to upward imbalance reserve bids in the DAME implementation, even if the functionality is not immediately employed. This will provide the flexibility for local market power mitigation to be deployed if the future need arises to adjust the imbalance reserve demand curve calculation. This revised approach also means the imbalance reserve offer cap would be reduced from $247/MWh to $55/MWh.

Some additional considerations are listed below:

- The uncertainty requirement used in the demand curve would include the EDAM diversity benefit.
- There would be separate demand curves for imbalance reserve up and down for each hour and for each BAA in the EDAM footprint.
- The EDAM resource sufficiency evaluation (RSE) would not use the imbalance reserve demand curve that will be used in the IFM. Instead, the RSE will penalize any imbalance reserve requirement relaxation at a high penalty price to ensure that all economic imbalance reserve

bids are fully used before incurring an imbalance reserve shortfall, which would result in failing the RSE in that direction.

Imbalance Reserve Deliverability

Under this proposal, the market would consider transmission constraints when awarding imbalance reserves in the integrated forward market to ensure they are deliverable if deployed in real-time. The proposed approach is similar to the upward and downward deployment scenarios developed in the flexible ramping product refinements initiative. The integrated forward market would solve the base scenario and deployment scenarios simultaneously to ensure all scenarios are transmission feasible. The deployment scenarios would result in nodal imbalance reserves that ensure scheduled day-ahead physical supply can meet the uncertainty requirements if deployed without violating transmission constraints.

The upward deployment scenario would ensure supply and imbalance reserves up awards are deliverable to where upward net load uncertainty may materialize. The downward deployment scenario would ensure supply less imbalance reserves down awards are deliverable to where the downward net load uncertainty may materialize. The net load uncertainty that materializes occurs at load nodes and variable energy resource nodes. The CAISO will use allocation factors derived by historical data to distribute the IRU/IRD requirements among load and VER nodes.

Some stakeholders have urged this proposal adopt a zonal approach to imbalance reserves procurement, similar to ancillary services. Stakeholders argue a zonal approach would simplify the market design and would reduce the need for additional elements like local market power mitigation. The ISO published a comparative matrix to highlight some of the tradeoffs between these approaches.[21]

This proposal continues to put forth nodal procurement of imbalance reserves, with some modifications. First, the CAISO will implement functionality that allows for the flexible activation/deactivation of individual transmission constraints in deployment scenarios. This modification addresses stakeholder concerns that if market simulation or operational experience reveals the need to enforce fewer constraints in deployment scenarios because of lower computational performance or market performance, the ISO can do so. Additionally, this will enable CAISO to collaborate with EDAM BAAs that may have lower frequency and quantity of binding constraints than the CAISO BAA to identify the most critical constraints to enforce, so as not to reduce computational performance with negligible market impact.

This proposal also would implement a tunable parameter to define the proportion of imbalance reserve awards that are "deployed" with resulting flows in the deployment scenarios. For example, if the parameter is set to 0.5, the market will still procure the full imbalance reserve requirement, but only half of each imbalance reserve award supply injection and demand withdrawal will be modeled against transmission constraints in the deployment scenarios at each location. This modification should help mitigate stakeholder concerns about excessive congestion costs resulting from the deployment

[21] Ibid footnote 2.

scenarios. The ISO plans to set the parameter initially to "1," resulting in the full deployment of imbalance reserves. This is because there are opposing concerns that modeling only a subset of imbalance reserve flows will reduce the robustness of EDAM transfers because transfer capacity could be overly consumed by energy. Nonetheless, if market simulation or operational experience supports lower deployment of imbalance reserve flows, the ISO will have a parameter to control that.

Imbalance Reserves from Intertie Resources

Hourly intertie resources would not eligible for IRU/IRD awards because they are not 15-minute dispatchable. However, 15-minute or dynamic intertie resources could offer imbalance reserves if they are certified to do so. To be certified to provide imbalance reserves, intertie resources would have to be registered with a resource ID defined in the CAISO Master File. This is so the market can certify the resource's ramp capability and capacity constraints to ensure the market awards are accurate. The market would not allow intertie resources to bid for imbalance reserves with only a transaction ID. The corresponding intertie schedule must be tagged after RUC with a transmission profile equal to the sum of the day-ahead energy schedule, plus the imbalance reserve award, if any.

Bidding Rules

The CAISO proposes the following bidding rules for products procured in the integrated forward market:

- Market participants would submit separate bids for energy, ancillary services (regulation up, regulation down, regulation up/down mileage, spinning reserves, and non-spinning reserves), imbalance reserves up, and imbalance reserves down.
- The bidding deadline would continue to be 10:00AM, at which point the day-ahead market closes.
- The current bid structure for energy and ancillary services would not change.
- Imbalance reserve bids could have different hourly price/quantity pairs but only a single price/quantity pair in each hour.
- The imbalance reserve bid quantity (MW) must be greater than zero and will be limited to the resource's maximum 30-minute ramp capability.[22]
- The imbalance reserve up and down bid prices will be capped at $55/MWh.
- All resources with imbalance reserve awards would be subject to bid insertion in the real-time market. This means that resources that do not submit the real-time energy bids that are required based on their imbalance reserve award will have economic energy bids[23] inserted for them at their Default Energy Bid in the real-time market.

IFM Payments and Charges

This proposal would not change day-ahead charges and payments for load, ancillary services, virtual supply, virtual demand, physical supply, imports, and exports. These would continue to be settled for

[22] The market will enforce dynamic ramp capability constraints for resources with dynamic ramp rates.
[23] The CAISO Tariff refers to these as Generated Bids.

differences between the day-ahead energy schedule and real-time market energy schedule at the relevant market prices.

This proposal considers the following day-ahead payments for resources that are awarded imbalance reserve awards:

- Resources that receive an imbalance reserve up award will be paid the locational marginal price for imbalance reserves up.
- Resources that receive an imbalance reserve down award will be paid the locational marginal price for imbalance reserves down.

The CAISO does not propose a direct settlement for imbalance reserve charges but instead will distribute the costs based on a cost allocation as described in the section below.

Imbalance Reserve Cost Allocation

Imbalance reserves are deployed when system conditions change between day-ahead and real-time, which requires the re-dispatch of available resources in real time. For example, if a generator or an import is unable to meet its day-ahead energy schedule, another resource must be scheduled in FMM to replace the lost supply. If a variable energy resource submits a self-schedule and its real-time forecast exceeds its day-ahead schedule, all else being equal, a dispatchable resource will need to be re-dispatched in real-time below its day-ahead schedule.

Imbalance reserves up/down costs will be allocated as follows:

Imbalance Reserves Up

- Tier 1
  - Generation: MAX(0, Day-ahead energy schedule – FMM upper economic limit as affected by de-rates and reduction in VER forecast (if applicable))[24]
  - Load: Negative uninstructed imbalance energy
  - Imports: MAX(0, Day-ahead energy schedule – FMM upper economic limit as affected by e-Tag transmission profile)
  - Exports: MAX(0, FMM self-schedule – Day-ahead energy schedule)
- Tier 2
  - Metered demand

The price used for the imbalance reserve up tier 1 cost allocation is the minimum of the imbalance reserve up price and the imbalance reserve up derived price. The imbalance reserve up derived price is the imbalance reserve up cost divided by the imbalance reserve up tier 1 allocation quantity.

[24] The determinant is the portion of the day-ahead schedule that is rendered undeliverable because of a de-rate or reduction in VER forecast. The priority order of the capacity services are (from highest to lowest priority): regulation, spin, non-spin, IRU, RCU.

Imbalance Reserves Down

- Tier 1
  - Generation: MAX(0, FMM lower economic limit as affected by rerates or self-schedules – Day-ahead energy schedule)
  - Load: Positive uninstructed imbalance energy
  - Imports: MAX(0, FMM self-schedule – Day-ahead energy schedule)
  - Exports: MAX(0, Day-ahead energy schedule – e-Tag transmission profile)
- Tier 2
  - Metered demand

The price used for the imbalance reserve down tier 1 cost allocation is the minimum of the imbalance reserve down price and the imbalance reserve down derived price. The imbalance reserve down derived price is the imbalance reserve down cost divided by the imbalance reserve down tier 1 allocation quantity.

Energy storage resources (using either the Non-Generator Resource model or the proposed Energy Storage Resource mode) would be considered under the "Generation" component of the cost allocations above.

This proposal considers a cost allocation instead of a direct settlement for a few reasons. First, the cost allocation aligns with flexible ramping product such that the cost allocation is based on the drivers of uncertainty. Second, there would be challenges in determining which loads and resources to charge at each nodal location and in what proportion since demand does not bid to buy imbalance reserves and imbalance reserve requirements are determined on a system level. The CAISO acknowledges the implications this has on congestion revenue rights and discusses this further in Section 4.2.

Imbalance Reserve Unavailability No Pay

Capacity that is not available in real time reduces the available supply of real-time energy and flexible ramping product and drives up their price. A stronger incentive than a no-pay mechanism is needed to ensure resources follow through on their must-offer obligations. Resources should be penalized commensurate with the harm they cause to the system by not being available. The CAISO proposes to implement the following unavailability penalties for imbalance reserves:

Imbalance reserves up: Resources with an upper economic limit in FMM that does not support their day-ahead energy + IRU award less the 5-minute ramp-capable portion[25] will be charged the higher of the RTPD FRU price or the IRU price.

[25] This term is included so that a resource is not charged no pay and a deviation settlement for ramp when the resource is unavailable. In Section 4.1 discusses the proposed settlement of ramp deviation.

Imbalance reserves down: Resources with a lower economic limit in FMM that does not support their day-ahead energy - IRD award plus the 5-minute ramp-capable portion will be charged the higher of the RTPD FRD price or the IRD price.

These unavailability penalties provide a strong incentive to deliver imbalance reserves and reflect the full cost of unavailability. That is because suppliers can be charged the cost of real-time flexible ramping product, whose price may spike because of a shortage of flexible capacity, for the portion of their award that was not provided. Resources that receive both a reliability capacity and imbalance reserve award and are not available, or only bid a portion of their combined award, will have the unavailability charge applied first to reliability capacity and then to imbalance reserves.

Bid Cost Recovery

Currently, bid cost recovery is calculated separately for the day-ahead and real-time market. This would not change in this proposal. However, the revenue and bid costs from imbalance reserve awards would be included in the calculation of day-ahead bid cost recovery. Resources committed in the integrated forward market, including resources that are scheduled for imbalance reserves, would be eligible to receive day-ahead bid cost recovery.

Application of Grid Management Charge to Imbalance Reserves

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 because suppliers do not submit bids for that product. Since bids can be submitted for imbalance reserves, the market services charge would be applied for imbalance reserve awards. Suppliers would include this cost in their bids.

Exports and Imbalance Reserves

Export Protection

One of the benefits of imbalance reserves is they should reduce the quantity of export schedules curtailed in the RUC process. That is because implementing imbalance reserves should greatly reduce the use of manual operator adjustments to the RUC forecast. Operator RUC adjustments push the RUC procurement further away from the IFM results, which increases the risk that an export scheduled in IFM would be reduced in RUC.

High-Priority (PT) Self-Scheduled Export Rules

High-priority (PT) self-scheduled exports are supported by a resource with non-RA capacity bid into the day-ahead market. It is feasible that a resource with non-RA capacity could both support a PT export and receive an imbalance reserve award in the day-ahead market. That is because there is no direct link between the supporting resource's output and the export quantity.

For example, assume an exporting scheduling coordinator bids a 100MW PT export that is supported by a non-RA resource with a 100MW energy bid and 20MW imbalance reserve up bid. The PT export would pass the day-ahead market validation because its supporting resource has sufficient energy bids to cover the export quantity. Assume the IFM results in the non-RA resource receiving an 80MW energy schedule and a 20MW imbalance reserve up award. In the real-time market, the non-RA resource submits a 100MW economic energy bid. This real-time energy bid is consistent with the resource's real-time bidding obligations based on its day-ahead schedule (80MW energy + 20MW imbalance reserve up). Assuming the PT export rebid in the real-time market, this real-time time energy bid also enable the PT export to pass the real-time market validation.

Again, this outcome is enabled by the fact there is no direct link between the supporting resource's output and the export quantity. The supporting resource just needs to submit sufficient bids in the day-ahead and real-time market. In the example above, presumably the market deemed it optimal to award the supporting resource 20MW of imbalance reserves and instead "support" the remaining 20MW of the export with energy with a different resource in the bid stack.

In the Market Enhancements for Summer 2021 Readiness stakeholder initiative[26], the CAISO implemented a rule that non-RA resources designated to support a PT export must bid into RUC up to the export self-scheduled quantity. Under this initiative, non-RA resources designated to support a PT export would be required to bid for reliability capacity up to the export self-scheduled quantity.

3.4 Market Power Mitigation Pass for RUC

Reliability capacity up and down awards would be priced in RUC at locational marginal prices that have marginal congestion contributions from binding constraints. All resources (including RA resources) would have the ability to offer non-zero prices for reliability capacity up and down in RUC. Therefore, it would be appropriate to perform local market power mitigation for reliability capacity up bids in RUC.[27] This would be achieved by adding a new market power mitigation pass after IFM and before RUC.

The market power mitigation pass for RUC would use unmitigated reliability capacity bids to procure reliability capacity to meet the CAISO demand forecast. The demand forecast would be distributed to load nodes in the market footprint using load distribution factors. Transmission constraints would be enforced using the same shift factors from IFM. Reliability capacity awards would be modeled as energy flows and the market would evaluate whether binding transmission constraints are uncompetitive using a dynamic competitive path assessment (DCPA). Resources that could provide counter-flow to uncompetitive constraints would have their reliability capacity up bids mitigated. Reliability capacity down bids would not be mitigated. The market would also not mitigate the reliability capacity up bids of non-EDAM intertie resources certified to provide reliability capacity, consistent with procedures for energy bid mitigation.

This proposal would mitigate reliability capacity offers to the higher of a default availability bid or the competitive locational marginal price for reliability capacity up. The latter would be derived as the

[26] California ISO. Market Enhancements for 2021 Summer Readiness stakeholder initiative. https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-enhancements-for-summer-2021-readiness.

[27] RUC availability is nodally procured today, but market power is not a concern because RA capacity must participate in RUC at $0 price, so there is no ability for RA resources to physically or economically withhold.

marginal price of reliability capacity up minus the non-competitive congestion components from binding constraints in RUC at the location of the mitigated resource. This proposal would also include a Negotiated Rate Option, under which the CAISO would use information provided by the Scheduling Coordinator to determine the negotiated default availability bid. The Negotiated Rate Option would be available to Scheduling Coordinators once the CAISO has sufficient operational knowledge of and experience with reliability capacity bids, ideally after one year of operational experience. Further details on the Negotiated Rate Option would be communicated in the CAISO's Business Practice Manuals.

The RUC default availability bid would be a static system-wide default availability bid for reliability capacity mitigation when DAME is first implemented. This default availability bid would be the same price for all resources and across all market intervals. It would provide a mitigation "floor" to balance the need to protect consumers against market power but also protect producers against excessive mitigation by forcing offers above a resource's costs. The reliability capacity up default availability bid would be set conservatively using a high percentile value of historical non-RA RUC availability offers. After the CAISO and market participants gain operational experience with biddable reliability capacity, and more information is available on the costs of offering reliability capacity under competitive conditions, the CAISO could re-engage with stakeholders to develop a more rigorous default availability bid methodology.

Similar to imbalance reserves, this proposal considers a default bid for reliability capacity mitigation of $55/MWh.

The competitive locational marginal price for reliability capacity is the marginal price of reliability capacity minus the non-competitive congestion components at the location of the mitigated resource.

Market Performance and Solve Time

The RUC market power mitigation pass should have a minimal impact on market performance and solve time because RUC is much less computationally complex than IFM. For example:

- **There is no co-optimization in RUC.** RUC only clears reliability capacity up and reliability capacity down.
- **There are no upward and down deployment scenarios in RUC.** There is only a base scenario in RUC.
- **IFM schedule, ancillary services, and imbalance reserve awards are fixed in RUC.** RUC is only procuring incremental or decremental supply to meet the BAA's demand forecast using the residual supply that is left over from IFM.
- **RUC has fewer binary variables.** Most of the resources are already committed in IFM.
- **RUC has fewer bids to consider.** For example, there are no load bids, no virtual bids; bids can only have a single capacity segment, etc.

Furthermore, to aid in the performance and solution time of the overall day-ahead market, the CAISO proposes to limit the RUC market power mitigation pass to a 24-hour horizon, rather than RUC's optimization horizon that may extend past the trading day.

3.5 Residual Unit Commitment Changes

Today, the residual unit commitment process runs after the integrated forward market produces energy schedules and ancillary service awards. The residual unit commitment process procures incremental capacity based on CAISO's demand forecast. The need for incremental capacity is based on the difference between the amount of physical supply that clears the integrated forward market and the amount of physical supply needed to meet the demand forecast. Resources participate in the residual unit commitment process by providing RUC availability bids.

This proposal considers several enhancements to the residual unit commitment process. First, physical capacity would be procured in the residual unit commitment process through a new day-ahead market product called reliability capacity. Reliability capacity could be procured in the upward or downward direction. Second, the residual unit commitment would be able to transition multi-stage generating resources in the downward direction (but not turn them off completely) and would establish their binding configuration. These enhancements are described in detail in the following sections.

Reliability Capacity (RCU/RCD)

The proposed reliability capacity product would improve the existing residual unit commitment process as the mechanism to ensure the day-ahead market schedules sufficient supply to meet a BAA's demand forecast. Unlike the existing residual unit commitment process, reliability capacity would provide both upward and downward dispatch capability. If a BAA's demand forecast is greater than the physical supply that clears the integrated forward market, the residual unit commitment process would procure reliability capacity up to provide upward dispatch capability and/or commit additional units. If the BAA's demand forecast is less than the physical supply that clears the integrated forward market, the residual unit commitment process would procure reliability capacity down to provide downward dispatch capability (but would not de-commit units).

Similar to the existing residual unit commitment process, the RUC optimization would consider transmission constraints when scheduling reliability capacity. Energy schedules, imbalance reserve awards, and ancillary services awards would be held fixed in RUC at their integrated forward market schedules.

A reliability capacity award would result in an obligation to provide economic energy bids to the real-time market. Resources awarded reliability capacity would have their reliability capacity schedule settled at a reliability capacity locational marginal price. The market would recover the costs of reliability capacity through a cost allocation (described in more detail in a later section).

Reliability capacity awards would be limited to a resource's 60-minute ramp capability. A resource can receive reliability capacity awards only in one direction (i.e., either reliability capacity up or reliability capacity down, not both).

Multi-Stage Generating Resource Configuration in the Residual Unit Commitment

Currently, multi-stage generating resource configurations are committed in the integrated forward market. These commitments are passed to the residual unit commitment as an input. The residual unit commitment is able to commit multi-stage generating resources or transition them to a higher configuration. System operators report seeing congestion or oversupply in the residual unit commitment where multi-stage generating resources should be allowed to transition downward but the current residual unit commitment does not have that functionality. This causes system operators to exceptionally dispatch the units down manually.

This proposal would enhance the residual unit commitment to transition multi-stage generating resources in the downward direction but not turn them off completely (i.e., transition down to their lowest configuration range but not shut down). This would help manage congestion in the residual unit commitment and avoid out-of-market actions by system operators.

This new functionality interacts with the process to validate high-priority (PT) exports. For example, assume an MSG resource is designated as a non-RA supporting resource for a PT export. Assume the exporter bids 80MW as a PT export. Assume the designated MSG resource bids 80MW into IFM, receives an 80MW IFM schedule, and is transitioned down to 60MW in RUC. The day-ahead market would validate support for an 80MW PT export schedule because the designated resource bid at least 80MW of energy into the day-ahead market. The day-ahead market does not require that a supporting resource actually clear IFM or RUC to support a PT export. Note that scenarios where RUC would de-commit an MSG to a lower configuration would tend to occur when CAISO is in an over-generation situation or otherwise low price conditions, which are not associated with tight system conditions.

Market Operator Adjustments to RUC Demand Forecast

One of the driving factors of this initiative is the increased frequency and magnitude of market operator adjustments to the RUC demand forecast. The cause and effect of these RUC adjustments are described in Section 2. As described in the Day-Ahead Market Enhancement Analysis Report[28], market operators reference an "upper confidence" demand forecast that assesses the maximum demand expected under current weather conditions. When the day-ahead forecasted load exceeds a certain level, market operators consider this upper confidence forecast to determine the size of the RUC adjustments.

The implementation of imbalance reserves into the day-ahead market should greatly reduce the amount of RUC adjustments going forward. However, market operators would still have the authority to use RUC adjustments as needed. Although net load uncertainty is the main reason market operators use RUC adjustments, RUC adjustments can be used to cover other operational risks as well, such as wildfire

[28] California ISO. Day-Ahead Market Enhancements Analysis. Alderete, Guillermo Bautista and Zhao, Kun. January 24, 2022. http://www.caiso.com/InitiativeDocuments/Day-AheadMarketEnhancementsAnalysisReport-Jan24-2022.pdf.

risks. Therefore, market participants should not expect the use of operator RUC adjustments to completely disappear.

The CAISO publishes the RUC load adjustment (MW) and RUC load adjustment reason in OASIS to provide transparency. The CAISO would continue to do so after DAME is implemented.[29]

Reliability Capacity and Intertie Resources

Hourly intertie resources are eligible to provide reliability capacity up and down if they are certified to do so. To be certified to provide reliability capacity, intertie resources would have to be registered with a resource ID defined in the Master File. This is so the market can certify the resource's ramp capability and capacity constraints to ensure the market awards are accurate. The market would not allow intertie resources to bid for reliability capacity with only a transaction ID.

The corresponding intertie schedule must be tagged after RUC with a transmission profile equal to the sum of the day-ahead energy schedule, plus the reliability capacity award, if any. Hourly exports to non-EDAM BAAs can also provide reliability capacity up at ISO interties, with the obligation to provide a decremental energy bid to dispatch down the export schedule in the FMM if needed.

Updates to the RUC market formulation in DAME require changes to the process for indicating exports at risk of curtailment in real-time. To indicate that economic exports and lower priority (LPT) exports that clear the IFM are at risk of curtailment in the RTM, if these exports do not explicitly bid for RCU, they will be considered in the RUC scheduling run with RCU bids at penalty prices that maintain the merit order of their energy bids in the IFM. Consequently, if there is no available physical supply capacity in the RUC above energy schedules to meet both the demand forecast and the economic and LPT exports that cleared the IFM, the latter will receive a curtailment indication for the RTM in the form of RCU awards. Note that these are only proxy RCU awards and, as such, they will not be paid at the relevant marginal RCU price. The scheduling coordinator for these exports will be obligated to submit energy bids for the RCU capacity, similar to the must-offer obligation for RCU awards. If an economic export submits an RCU bid (LPT exports may not submit RCU bids since an energy bid is required for them) and is awarded RCU, that RCU award will be paid at the relevant marginal RCU price.

Reliability Capacity Bidding Rules

The CAISO proposes the following bidding rules for products procured in the residual unit commitment process:

- Market participants would submit separate bids for RCU and RCD.
- Reliability capacity bids could have different hourly price/quantity pairs but only a single price/quantity pair in each hour.
- Reliability capacity up and down bid MW quantity must be greater than zero and would be capped by the associated resource's 60-minute ramp rate over the product horizon.
- Reliability capacity up and down bid prices will be capped at $250/MWh.

[29] California ISO OASIS. See System Demand > Load Adjustments. http://oasis.caiso.com/mrioasis/logon.do.

- Reliability capacity up bid MW quantity must be greater than or equal to the sum of the resource's energy bid quantity.
- CAISO resource adequacy resources would be able to bid non-zero prices for reliability capacity.
- CAISO resource adequacy resources with a day-ahead must-offer obligation in RUC will be subject to bid insertion for reliability capacity up. If the required amount of resource adequacy capacity is not offered as reliability capacity into the day-ahead market, the CAISO will
  - Extend the bid quantity to the required amount using the submitted bid price if the resource provided a partial reliability capacity up bid
  - Insert reliability capacity bids at $0 bid price for the required amount if the resource did not submit a reliability capacity up bid
- All resources with reliability capacity awards would be subject to energy bid insertion in the real-time market. This means that resources that do not submit the energy bids that are required based on their reliability capacity award would have energy bids inserted for them at their Default Energy Bid price in the real-time market.

Reliability Capacity Payments

The CAISO proposes the following day-ahead payments for resources that are awarded reliability capacity awards:

- All resources (including CAISO resource adequacy resources) that receive a reliability capacity up or down award will be paid the locational marginal price for reliability capacity in the upward or downward direction, respectively.

Reliability Capacity Cost Allocation

It is appropriate to design a cost allocation for reliability capacity payments that builds off the existing cost allocation for the residual unit commitment and accounts for the drivers of reliability capacity needs (load bids, virtual bids). The uplift cost for reliability capacity would be allocated as follows:

Reliability Capacity Up

- RCU Tier 1 cost would be allocated to net virtual supply and under-scheduled load.
  - The net virtual supply allocation quantity would be a maximum of (a) zero or (b) scheduling coordinator net virtual supply awards. Thus, net virtual demand would not net against the load allocation base for RCU. This assumes a balancing authority area procures net virtual supply.
  - Under-scheduled load would be defined using net negative metered demand. The net negative metered demand would exclude net negative demand associated with balanced ETC/TOR rights, negative deviation for Participating Load resulting from a market dispatch, and metered sub-systems that have elected not to participate in reliability capacity.
- RCU Tier 2 cost would be allocated to metered demand.

RCU Tier 1 costs would be limited by the minimum of the RCU capacity price and the RCU Tier 1 price.[30] In other words, if the RCU obligation were higher than the RCU awards, all of the cost would be allocated to RCU Tier 1. If RCU awards were greater than the RCU obligation, then costs would be split between Tier 1 and Tier 2.

Reliability Capacity Down

- RCD Tier 1 cost would allocated to net virtual demand and over-scheduled load.
    - The net virtual demand allocation quantity would be a maximum of (a) zero or (b) scheduling coordinator net virtual demand awards. Thus, net virtual demand would not net against the other allocation bases for RCD. This assumes a balancing authority area procures net virtual demand.
    - Over-scheduled load would be defined using net positive metered demand. The net positive metered demand would exclude net positive demand associated with balanced ETC/TOR rights, positive deviation for Participating Load resulting from a market dispatch, and metered sub-systems that have elected not to participate in reliability capacity.
- RCD Tier 2 cost would be allocated to metered demand.

RCD Tier 1 costs would be limited by the minimum of the RCD capacity price and the RCD Tier 1 price. In other words, if the RCD obligation were higher than the RCD awards, all of the cost would be allocated to RCD Tier 1. If RCD awards were greater than the RCD obligation, then costs would be split between Tier 1 and Tier 2.

Reliability Capacity Unavailability No Pay

This proposal considers the following unavailability penalties for reliability capacity:

Reliability capacity up: Resources with an upper economic limit that does not support their day-ahead energy + RCU award would be charged the RCU price.

Reliability capacity down: Resources with a lower economic limit that does not support their day-ahead energy - RCD award would be charged the RCD price.

Resources that receive both a reliability capacity and imbalance reserve award and are not available or only bid a portion of their combined award will have the unavailability charge applied first to reliability capacity and then to imbalance reserves.

Bid Cost Recovery

Currently, bid cost recovery is calculated separately for the day-ahead and real-time market. This would not change under this proposal. However, all resources committed in the residual unit commitment

[30] RCU Tier 1 price is the minimum of the RCU allocation price and the RCU capacity price. The RCU allocation price is the RCU cost divided by the total RCU Tier 1 allocation quantity. RCD Tier 1 price is calculated similarly.

process are eligible to receive real-time bid cost recovery.[31] The revenue and bid costs from reliability capacity awards would be included in the calculation of real-time bid cost recovery.[32] Resources committed after the close of the day-ahead market through a real-time market schedule or an exceptional dispatch would also continue to be eligible for real-time bid cost recovery.

Any surplus revenues from the residual unit commitment process would continue to be netted against revenue shortfalls in the real-time market. A revenue surplus would occur in the residual unit commitment when the marginal price of reliability capacity exceeds a resource's reliability capacity bid cost. Conversely, any surplus revenues from the real-time market would be netted against revenue shortfalls in the residual unit commitment process. Bid cost recovery payments from the integrated forward market and the residual unit commitment/real-time market would continue to be kept separate because they have different cost allocations. RUC bid cost recovery costs would be allocated to net virtual supply and under-scheduled load in alignment with reliability capacity up cost allocation.

Application of Grid Management Charge to Reliability Capacity

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, the market services charge would be applied for reliability capacity awards. Suppliers would include this cost in their bids.

4. Additional Day-Ahead Market Enhancement Design Considerations

4.1 Measures to Accommodate Long-Term Contracts

No matter how the day-ahead market settles the payments for the new day-ahead market products, RA contracts ultimately dictate how the revenue generated from the new market products is settled between counterparties. CAISO is concerned about getting into the middle of procurement contracts; however, it recognizes that entities may need additional information to settle revenues from the new market products in accordance with their contractual provisions.

During the implementation of DAME, CAISO will work with parties to understand and provide to the greatest extent possible the information needed to facilitate contractual settlement provisions and develop a process for providing this information to the relevant parties in a regularly issued settlement

[31] Units committed in RUC are included in the real-time market BCR (as opposed to day-ahead market BCR) because 1) many commitments made in RUC are non-binding so the real-time market makes the binding commitment decision and 2) long-start and extra-long-start resources that do receive binding commitments in RUC are only committed to their PMin so they can participate in the real-time market.

[32] Reliability capacity payments and bids would not be considered in the RUC/RT BCR calculation for RA resources.

report. In particular, the CAISO will provide a breakdown of the imbalance reserve marginal price by capacity versus opportunity cost, which several stakeholders have indicated is important.

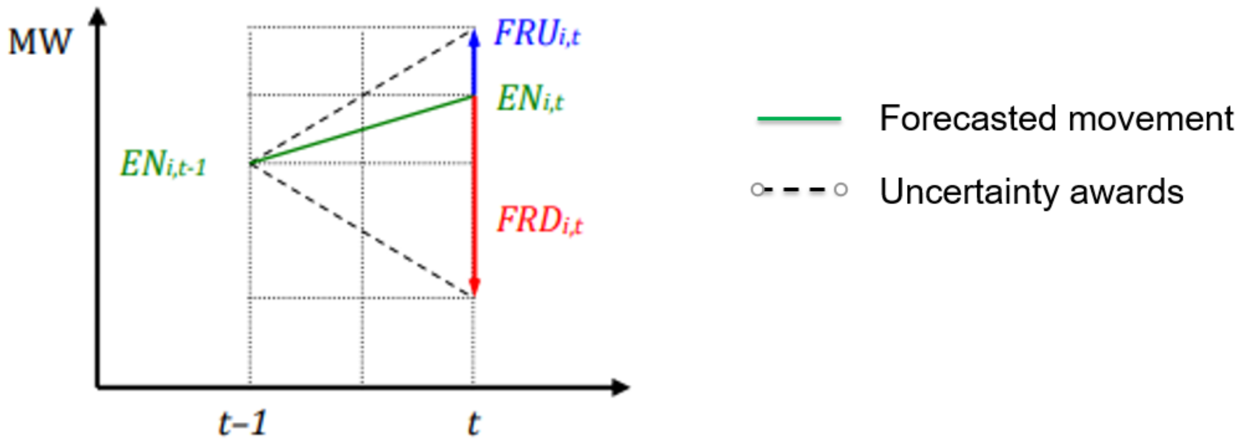
The CAISO also proposes to introduce a three-year "opt-in" transitional resource adequacy true-up mechanism whereby entities can choose to have the CAISO settlement system true-up specific imbalance reserve and reliability capacity payments that overlap with RA capacity. The transitional RA true-up mechanism allows load serving entities (LSEs) in agreement with the RA supply resource to have RA capacity shown on the LSE monthly RA plan and procured through the day-ahead market for imbalance reserve and/or reliability capacity to settle with both the LSE and the generator.

First, the CAISO will calculate an RA resources' overlapping RA capacity by comparing the resource's shown RA capacity against the resource's stacked awards for energy, ancillary service, imbalance reserve, and reliability capacity. Any portion of RA capacity that overlaps with either the imbalance reserve awards or reliability capacity awards will considered overlapping RA capacity potentially subject to the RA true-up mechanism. If a resource has multiple RA contracts that are shown on multiple LSE's monthly RA plans, the CAISO will determine the portion of overlapping RA capacity associated with LSE that "opt-in" to the RA true-up mechanism versus the LSEs that 'opt-out" of the RA true-up mechanism by distributing the overlapping RA capacity to the contracted LSE in proration to the LSE's RA showing as compared to the resource's total RA showings. In all cases, the CAISO will compensate the LSE for "opt-in" RA capacity at the respective imbalance reserve capacity price and/or reliability capacity price while also compensating the RA resource for the same overlapping RA capacity at the respective imbalance reserve opportunity cost. Furthermore, the CAISO will compensate the RA resource for any overlapping RA capacity that has not elected to "opt-in" to the RA true-up mechanism, as well as non-RA capacity procured for imbalance reserve or reliability capacity at the respective marginal imbalance reserve price or marginal reliability capacity price

4.2 Real-Time Market Ramp Deviation Settlement

The deviation settlement of ramp would involve two components: (1) forecasted movement and (2) uncertainty awards (see Figure 9). Forecasted movement is the change in energy schedules between market intervals. Uncertainty awards reserve additional ramping capability that is needed to meet net load forecast uncertainty in the next market run. The marginal value of providing ramp capability is the same for both forecasted movement and uncertainty awards.

Figure 9: Forecasted movement and uncertainty awards



Imbalance reserves in the day-ahead market and flexible ramping product in the real-time market both provide additional capacity for ramping. Market payments for the provision of ramping services should net in each market. However, there are differences in the configuration, eligibility, and pricing of these products that would make a direct deviation settlement infeasible. Table 3 describes these differences.

Table 3: Differences between Imbalance Reserves and Flexible Ramping Product

Imbalance Reserves	Flexible Ramping Product
Single settlement (uncertainty awards)	Dual settlement (uncertainty awards and forecasted movement)
Awards based on resource's 30-min ramp capability	Awards based on resource's 5-min ramp capability
Marginal clearing price based on bids and opportunity cost	Marginal clearing price based only on opportunity cost

This proposal considers a deviation settlement for ramp services. This approach is necessary to avoid the following issues:

- **Double payment of opportunity costs.** Resources that receive an imbalance reserve award in the day-ahead market are paid the locational marginal price of imbalance reserves for the corresponding interval. The locational marginal price of imbalance reserves is based on two factors: imbalance reserve bids and any opportunity costs. Opportunity costs for imbalance reserves occur when a resource is held out of merit for energy or ancillary services to preserve its ramp capability to provide upward capacity to meet the uncertainty requirements in a given interval. Similarly, opportunity costs for energy can occur when a resource is held out of merit for energy in order to preserve its downward capability to provide sufficient ramping to meet the load in a subsequent interval. However, the marginal clearing price of flexible ramping product is based only on opportunity costs; there are no bids associated with this product. A resource awarded both imbalance reserves and flexible ramping product could thus be paid opportunity costs from both products, even if its energy and ancillary service schedules did not change. This represents a double payment. However, the resource should retain its imbalance reserve bid costs, which reflect the resource's marginal cost of being available for dispatch in the real-time market.

- **Double payment of forecasted movement.** In the day-ahead market, all hourly schedules are financially binding across the 24-hour horizon. That is, there are no unsettled advisory intervals in the day-ahead market. As a result, there is no need to settle forecasted movement in the day-ahead market because the energy prices already reflect the opportunity cost of resources scheduled out-of-merit in previous hourly intervals. However, in the real-time market, only one market interval is financially binding over the optimization horizon. The market produces unsettled "advisory" prices for the remaining market intervals. If a resource is dispatched for energy in the binding interval to provide ramp capability to meet the energy dispatch of an advisory interval, the resource can incur an opportunity cost if the binding interval price is less than its energy bid. If in this market run the resource incurs an opportunity cost, the advisory interval energy price will increase to reflect this tradeoff. However, the advisory interval energy price is not settled, and when it becomes binding in the next market run, the out-of-merit dispatch is unknown and the opportunity cost is not embedded in the binding energy price. In order to compensate the resource, it receives a separate payment for forecasted movement at the marginal price of ramp capability.[33] This incentivizes the resource to follow its energy dispatch because the resource is indifferent to receiving an incremental energy schedule or a forecasted movement payment because it earns the same profit under both scenarios. However, a resource may receive compensation for forecasted movement both in the day-ahead market (embedded in the energy prices) and in the real-time market (as a side payment). This represents a double payment.
- **Unavailable ramp drives up real-time prices.** Capacity that is not available in real-time reduces the available supply of ramp and drives up its price. Therefore, resources that do not provide the ramp they are obligated to should settle those deviations at prices reflecting real-time conditions.

The proposed settlement for imbalance reserves has several components:

- **The 5-minute ramp-capable portion of an imbalance reserve award will be subject to a deviation settlement with a flexible ramping product award in FMM.** Imbalance reserve is 30-minute ramp capability reserved for use in FMM to address the granularity difference between IFM and FMM, and uncertainty that may materialize between IFM and FMM. The uncertainty that may materialize between FMM and RTD is addressed by the flexible ramping product, which is 5-minute ramp capability reserved in FMM and RTD. Therefore, the 5-minute ramp-capable portion of imbalance reserve can be procured as flexible ramping product in FMM.
- **The portion of an imbalance reserve award in excess of the 5-minute ramp-capable portion will not be subject to a deviation settlement but will be subject to no pay provisions.** This portion of the imbalance reserve award can be scheduled as energy in FMM to address the uncertainty that may materialize in FMM or the granularity difference between IFM and FMM.

[33] See Section 7.1.3.1.4 of the Market Operations BPM for numerical examples.

This portion of the imbalance reserve award would not be subject to a deviation settlement. However, if any of this portion were unavailable due to outages, it would be subject to no pay provisions at the higher of the IFM marginal price for imbalance reserves, the FMM marginal price for flexible ramping product, or the RTD marginal price for flexible ramping product (see Section 3.3).

- **Forecasted movement in the FMM will be subject to a deviation settlement with forecasted movement in the IFM.** Forecasted movement in the FMM is paid the flexible ramp up price and charged the flexible ramp down price. Therefore, an upward deviation in forecasted movement is paid the flexible ramp up price and charged the flexible ramp down price, and a downward deviation in forecasted movement is paid the flexible ramp down price and charged the flexible ramp up price. This aligns with the deviation settlement between FMM forecasted movement and RTD forecasted movement.

The ramp capability of a resource may manifest as forecasted movement between energy schedules or it may be awarded as uncertainty awards, or any combination in between. That is why it is important the overall settlement of these complementary products have the following property:

> If the 5-minute ramp capability that is awarded in IFM (as either energy movement or an imbalance reserve award) is available and awarded in FMM (as either forecasted movement or a flexible ramping product award), there should be no net deviation settlement in FMM. Furthermore, if the 5-minute ramp capability that is awarded in FMM is available and awarded in RTD (as either forecasted movement or a flexible ramping product award), there should be no net deviation settlement in RTD.

The CAISO has published an Excel spreadsheet model[34] that illustrates that if the 5-minute ramp capability of a resource is awarded between forecasted movement and uncertainty awards the same across markets, from IFM to FMM to RTD, there are no net payments or charges due to deviations in the real-time market. The only exceptions are when a resource reaches their PMin or PMax at a different time than in the preceding market, there is a ramp rate de-rate, or the resource's ramp capability is not fully used.

Impacts to WEIM from Ramp Settlement

The Western Energy Imbalance Market also procures flexible ramping product to commit and position resources to meet future load and supply variability and uncertainty. Therefore, WEIM participants would also be subject to a forecasted movement deviation settlement in FMM. The baseline forecasted movement for each resource would be based on WEIM base schedules. For WEIM participants, forecasted movement from base schedules is equivalent to forecasted movement in the integrated forward market. If resources are already scheduled to ramp in WEIM base schedules, then paying an additional forecasted movement payment in FMM for the same ramp constitutes a double payment.

[34] FMM and RTD Settlement Example - Day-Ahead Market Enhancements. http://www.caiso.com/InitiativeDocuments/FMM-RTDSettlementExample-Day-AheadMarketEnhancements.xlsx

Impact to Convergence Bidding from Ramp Settlement

Convergence bids, also known as virtual bids, are settled at the day-ahead price and liquidated in the FMM. Virtual supply is paid the IFM price and charged the FMM price. Virtual demand is charged the IFM price and paid the FMM price. Since the IFM energy price includes the settlement of forecasted movement, virtual supply and demand would have a forecasted movement deviation settlement at the FMM FRP prices.

4.3 Congestion Revenue from Deployment Scenarios

Participants in EDAM will have different mechanisms for collecting and allocating congestion revenues.

The CAISO BAA uses Congestion Revenue Rights (CRRs) as forward market products to hedge integrated forward market congestion costs. Today, CRR holders receive congestion revenues collected in the integrated forward market due to each binding transmission constraint between the CRR source and sink. The CRR settles at the difference between the marginal congestion components of the energy LMP at the sink and source of the CRR.

For EDAM BAAs, the process of collecting and allocating congestion revenue is determined through the Open Access Transmission Tariff (OATT) and may vary by entity.

This proposal would settle the cost of imbalance reserves through a cost allocation rather than a direct settlement with load and VERs using the locational marginal price of imbalance reserves. In this way, the CAISO would not collect congestion revenues to cover the marginal cost of congestion in the imbalance reserve deployment scenarios. Whenever a constraint is binding in the deployment scenarios, there could be a shortfall of congestion revenue collected on that constraint, since the CAISO would not otherwise collect congestion revenue on the imbalance reserve flow. In other words, the imbalance reserve deployment scenario flow can “displace” energy flows over constrained transmission paths.

The trade-off between using transmission for energy or imbalance reserve flows depends on the relative difference between the marginal energy and imbalance reserve offers inside and outside the constrained area. The CAISO expects that the differences between imbalance reserve bid prices for the constrained vs. unconstrained areas generally will be much lower than the differences in energy bid prices for the constrained vs. unconstrained areas. This expectation is based on the lower cost of providing imbalance reserves compared to providing energy. As a result, CAISO expects the constrained transmission to be mostly used for energy. Thus, CAISO does not expect this to be a major issue.

However, stakeholders pointed out that without a mechanism to collect congestion rent on imbalance reserve flows, the CAISO would be shifting costs away from entities who are entitled to congestion revenues and not considering the full cost of using the transmission system. The CAISO agrees with this notion and proposes the following mechanism to address the problem.

The CAISO would determine the “displaced” congestion revenue from imbalance reserve up flows by calculating and summing (Imbalance Reserve Up Flow) * (Shift Factor) * (Shadow Price of Transmission

Constraint) for all binding constraints in the upward deployment scenario. Similarly, the CAISO would determine the "displaced" congestion revenue from imbalance reserve down flows by calculating and summing (Imbalance Reserve Down Flow) * (Shift Factor) * (Shadow Price of Transmission Constraint) for all binding constraints in the downward deployment scenario.

The CAISO would collect this revenue through the existing imbalance reserve cost allocation. Congestion contributions to transmission constraints in an EDAM BAA from resources in other EDAM BAAs contribute to the congestion offset of the EDAM BAA where the congestion occurs. For the CAISO BAA, the congestion offset distribution is through the CRR Balancing Account.

For the CAISO BAA, the CAISO would redefine the notional value of CRRs to incorporate marginal cost of congestion differences between source and sink for imbalance reserve deployment scenarios. The CAISO would also redefine the congestion revenue collection to fund the CRR notional value to include imbalance reserve deployment scenarios.[35]

For non-CAISO BAAs, the CAISO would return the revenues to the BAA for distribution to its participants according to their OATT processes.

4.4 Variable Energy Resources Eligibility to Provide New Products

This proposal maintains that variable energy resources (VERs) would be eligible to provide imbalance reserves and reliability capacity in both directions. This proposal no longer considers distinguishing VER resources in the Master File to determine their eligibility to provide imbalance reserve up. All VERs would be eligible for imbalance reserve up awards. However, the ISO continues to be concerned about awarding upward reserves on VERs above their day-ahead forecast. To prevent this, the IFM would apply a capacity constraint to VERs such that their energy, upward ancillary services, and imbalance reserve up awards could not exceed their VER forecast.

A similar capacity constraint would apply in RUC where the sum of IFM awards and reliability capacity up awards could not exceed the VER forecast. This proposal would also require VERs to bid reliability capacity up quantity equal to their VER forecasted output. This is consistent with an EDAM proposal where all resource capacity shown in the EDAM resource sufficiency evaluation must be bid into RUC as reliability capacity up. Since VERs would be considered in the EDAM resource sufficiency evaluation at their forecast, they must bid reliability capacity up into RUC at their forecast MW. Independent of EDAM, this rule would be necessary to ensure that RUC can consider all physical supply, including the supply forecasted for VERs that is not bid into the IFM. If VERs do not bid reliability capacity up to their VER forecast, the ISO will generate bids at a bid price of $0. As part of these changes, this proposal would no longer consider VERs in the RCU/RCD cost allocation, because they no longer contribute to the reliability capacity requirement (see Section 3.4). In addition, this proposal updates the RCU no pay rule such that resources would only have to pay back the RCU price, instead of the higher of the RCU price or

35 This proposal would not change the existing CRR nomination and auction processes to account for imbalance reserves. Transmission capacity would not be withheld in the CRR model for the CRR nomination and auction processes.

RTPD FRU price, if the resource capacity is unavailable. This is so VERs that are awarded reliability capacity up but cannot produce to their day-ahead forecast in real-time only have their RCU awards rescinded and do not face any further financial penalty. This is also consistent with the current no pay RUC settlement (charge code 6824). Finally, VERs would be exempt from a current rule enforced in SIBR that capacity bid in RUC must first bid in IFM, which would force VERs to bid energy up to their forecast.

4.5 Changes to Storage Resources

This proposal includes a requirement that storage resources participate in the residual unit commitment process. Today, all schedules for storage resources from the integrated forward market are directly copied into the residual unit commitment. This policy includes a proposal to require that all storage resources shown for resource adequacy participate in the residual unit commitment process, but allows resources to bid freely in the process. This proposal also allows the ability for all storage resources that are not shown for resource adequacy to also participate in the residual unit commitment process, should they choose to do so.

This policy includes changes to the ancillary service state of charge equations to include imbalance reserves and reliability capacity. These equations ensure that storage resources have state of charge when awarded ancillary services.

Finally, the policy proposes new requirements that govern the amount of state of charge that a storage resource must hold to support imbalance reserve awards in the day-ahead market via anticipating upper and lower values (or an envelope) for state of charge. This change will help ensure that storage resources will be able to deliver imbalance reserve awards if called upon in the real-time market. This is extremely important because if the storage resources are not able to deliver, it could result in negative reliability implications. These equations provide additional guardrails than those developed in the energy storage enhancements policy for modeling expected impacts to state of charge from regulation awards. These guardrails may not be necessary for ancillary service awards because these awards may be smaller in magnitude and more granular than hourly energy awards. This proposal does not include updates to the state of charge equation to include expected impacts from imbalance reserve awards. Imbalance reserve awards could potentially introduce inconsistencies in modeled state of charge compared to state of charge that materializes in real-time. As more experience is gained with this issue, this equation may be revisited in future enhancements.

Many stakeholders requested that more time be spent thinking about the introduction of the new envelope equations and continuing to think about how these equations interact with existing constraints that are already imposed on storage resources. This policy commits to continuing this evaluation of the efficacy of the envelope equations, their impact on existing constraints, best methodologies to set multipliers, and what these initial multipliers will be set to. This policy understands that new constraints imply new complexities in operating storage resources, and that these new constraints could be challenging for storage resources operating in the day-ahead markets. This commitment will include discussions of these topics prior to policy implementation and formal inclusion of these values in the ISO business practice manuals.

These changes are summarized as follows:

- RA storage resources will be required to participate in the residual unit commitment process
    - All storage will be allowed to specify capacity bids in this process
    - Resources adequacy storage that do not provide bids will have bids inserted at $0/MW
- The ancillary service state of charge constraint will be extended to include imbalance reserves
- The day-ahead market will generate an upper and lower bound, or envelope, for state of charge
    - The envelope could constrain operation for storage resources
    - The initial upper and lower bounds will be set to the initial day-ahead state of charge
    - The initial multiplier attached to the imbalance reserves in the envelope equation will continue to be discussed, but may be set initially to .85

Residual Unit Commitment

Today storage resources do not formally participate in the residual unit commitment process. The market software uses results from the integrated forward market pass of the day-ahead market and includes those schedules directly in the residual unit commitment pass. Because storage resources are inherently use limited, schedules from the day-ahead market tend to reflect optimal schedules for the resources. These schedules include charging when prices are lowest and discharging when prices are highest and fully utilizing the storage resources.

However, there can be scenarios when storage resources are not fully utilized in the integrated forward market pass of the day-ahead market. This could occur because of economics, specifically if the bid spread for the resource does not materialize for the full duration of the resource. For example, if a 1-hour duration storage resource is bidding to charge when prices are less than $10/MWh, and to discharge if prices are greater, in other words submitting a $50/MWh price spread. But, if the difference between the highest priced hour and the lowest priced hour in the integrated forward market does not exceed $40/MWh, the storage resource will not be scheduled in the market.

If the discharge energy from storage resources could prevent commitment of other resources, this example can result in inefficiencies in the residual unit commitment process. Specifically, inefficiencies occur if the shortfall between the actual price spread and bid spread is less than the commitment costs for the resource. These inefficiencies are relieved if storage resources participate in the residual unit commitment process. Participation would allow the market optimization to make the economic tradeoff between committing the storage resource for an energy schedule or committing the other resource.

This proposal includes a requirement that storage resources shown for resource adequacy be required to participate in the residual unit commitment pass in the day-ahead market. This proposal will also allow storage resources that are not shown for resource adequacy to participate in the residual unit commitment process. Storage resources will be allowed to bid charging and discharging capability into the residual unit commitment process at any price. If bids are not provided, bids of $0/MWh will be inserted for storage resources shown for resource adequacy for the entire bid curve.

Ancillary Service State of Charge

Today the day-ahead market ensures that ancillary services awarded to storage resources will have sufficient state of charge to deliver those awards. The market accomplishes this by enforcing the ancillary service state of charge constraint, shown in Equation Set 1. These equations state that a storage resource must have sufficient state of charge to ensure that they provide awarded capacity for ancillary services for at least one hour. For example, if a storage resource receives an award for 10 MW of regulation up in the day-ahead market, it is required to have a state of charge of 10 MWh (10 MW multiplied by 1 hour) above the minimum state of charge. This ensures the resource's ability to deliver regulation for the entire 60-minute period of the award. Similarly, these constraints ensure sufficient state of charge headroom for resources providing regulation down.

$$\begin{gathered} SOC_{i,t-1} - RU_{i,t} - SR_{i,t} - NR_{i,t} \geq \underline{SOC}_{i,t} \\ SOC_{i,t-1} + \eta_i \, RD_{i,t} \leq \overline{SOC}_{i,t} \end{gathered} \tag{1}$$

Where:

- $RU_{i,t}$ *Regulation up award for resource i at time t*
- $SR_{i,t}$ *Spinning reserve award for resource i at time t*
- $NR_{i,t}$ *Non-spinning reserve award for resource i at time t*
- $\underline{SOC}_{i,t}$ *Minimum state of charge for resource i at time t*
- $RD_{i,t}$ *Regulation down award for resource i at time t*
- $\overline{SOC}_{i,t}$ *Maximum state of charge for resource i at time t*

This policy proposes enhancements to the day-ahead state of charge requirements for storage resources providing imbalance reserves. The current requirements ensure that storage resources have sufficient state of charge to provide all four ancillary services including regulation up, regulation down, spinning reserve and non-spinning reserve. This policy proposes expanding these requirements to require sufficient state of charge to provide imbalance reserve up and imbalance reserve down in addition to the other ancillary services. These proposed changes are outlined in Equation Set 2. These changes help ensure that storage resources have sufficient state of charge to provide awarded products.

$$\begin{gathered} SOC_{i,t-1} - RU_{i,t} - SR_{i,t} - NR_{i,t} - IRU_{i,t} \geq \underline{SOC}_{i,t} \\ SOC_{i,t-1} + \eta_i \left(RD_{i,t} + IRD_{i,t} \right) \leq \overline{SOC}_{i,t} \end{gathered} \tag{2}$$

Where:

- $IRU_{i,t}$ *Imbalance reserve up award for resource i at time t*
- $IRD_{i,t}$ *Imbalance reserve down award for resource i at time t*

Furthermore, these constraints would be expanded into the residual unit commitment process to require sufficient state of charge to provide reliability capacity up and reliability capacity down in addition to the other terms included in the constraint enforced in the day-ahead market. This change is included in Equation Set 3.

$$\begin{gathered} SOC_{i,t} - RU_{i,t} - SR_{i,t} - NR_{i,t} - IRU_{i,t} - RCU_{i,t} \geq \underline{SOC}_{i,t} \\ SOC_{i,t} + \eta_i \left(RD_{i,t} + IRD_{i,t} + RCD_{i,t} \right) \leq \overline{SOC}_{i,t} \end{gathered} \tag{3}$$

Where:

$RCU_{i,t}$ *Reliability capacity up award for resource i at time t*

$RCD_{i,t}$ *Reliability capacity down award for resource i at time t*

Accounting for State of Charge

The final proposal for the day-ahead market enhancements policy included an update to the equation that governs state of charge for storage resources. One concern about this approach continues to be the nature of how imbalance reserves will be deployed – and thus impact state of charge – for storage resources in the real-time market. Many times imbalance reserves may not be a critical part of real-time market operations, but during some periods, imbalance reserves may be critical for reliable grid operation. During these periods, it is critical that storage resources have sufficient state of charge to provide these services. Also, there may be occasions when all, or nearly all, of the imbalance reserves awarded in one direction are converted to energy in the real-time market – even if imbalance reserves were procured in both directions. It is important to ensure that these kinds of scenarios do not lead to situations where storage resources have no state of charge to provide these services in future hours.

To ensure that storage resources have sufficient state of charge to provide imbalance reserves, this proposal introduces new constraints outlined in Equation Set 4. These equations include an estimate of a hypothetical upper bound for storage resources and a hypothetical lower bound for storage resources, and tracks these values over time. These values create an envelope, or boundary, for state of charge. Once the hypothetical state of charge reaches the lower/upper limit of the resource, then the market will schedule the resource to charge prior to scheduling any additional imbalance reserves that could potentially cause the hypothetical value to exceed the limit.[36]

$$\begin{gathered} SOC_{i,t}^{(u)} = SOC_{i,t-1}^{(u)} - EN_{i,t}^{(+)} - \eta_i \, EN_{i,t}^{(-)} + \eta_i \, AIRD_t \, IRD_{i,t} \leq \overline{SOC}_{i,t} \\ SOC_{i,t}^{(l)} = SOC_{i,t-1}^{(l)} - EN_{i,t}^{(+)} - \eta_i \, EN_{i,t}^{(-)} - AIRU_t \, IRU_{i,t} \geq \underline{SOC}_{i,t} \end{gathered} \tag{4}$$

Where:

$SOC_{i,t}^{(u)}$ *Upper envelope for state of charge for resource i at time t*

$AIRD_t$ *Adjustable multiplier applied to downward imbalance reserves to calculate the upper envelope for state of charge at time t*

$SOC_{i,t}^{(l)}$ *Lower envelope for state of charge for resource i at time t*

36 The initial values for both the upper and lower state of charge would be the actual initial state of charge in the day-ahead market.

$AIRU_t$ *Adjustable multiplier applied to upward imbalance reserves to calculate the lower envelope for state of charge at time t*

The envelope equations ensure that the upper envelope is always at or above the modeled state of charge and that the lower envelope is always at or below the modeled state of charge. This implies that if the state of charge is at a resource's maximum, then the upper envelope will also be at the maximum. The same is true for the lower limit and the minimum. When the values for the upper and lower envelopes are both at limits, this effectively implies that the state of charge of the resource is uncertain and will prevent further use of the resource.

This policy also notes that no explicit changes are being proposed to the state of charge formulation.

Example 1

Suppose a storage resource has a +/- 100 MW operating range and can hold a state of charge between 0 MWh and 400 MWh. Also, suppose that the model assumes that the resource will have 200 MWh of energy going into hour ending 1, and that the resource has no losses between charging and discharging. Further, assume the multipliers for both imbalance reserve up and down are set to 1. In this scenario, all of the following outcomes are feasible in the day-ahead market for hour ending 1:

- *0 MW of energy and 100 MW of imbalance reserve up*

This award does not impact the state of charge, which remains at 200 MWh. It does reduce the lower envelope to 100 MWh, but leaves the upper envelope and the state of charge at 200 MWh. The resource has sufficient state of charge to meet the ancillary service state of charge constraints.

Hour	En	IRU	IRD	SOC_U	SOC	SOC_L
0				200	200	200
1	0	100	0	200	200	100

- *100 MW of charging energy and 100 MW of imbalance reserve up*

The award increases the state of charge to 300 MWh. It also increases the upper envelope to 300 MWh, but the lower envelope remains unchanged at 200 MWh. The resource has sufficient state of charge to meet the ancillary service state of charge constraints.

Hour	En	IRU	IRD	SOC_U	SOC	SOC_L
0				200	200	200
1	-100	100	0	300	300	200

- *100 MW of discharging energy and 100 MW of imbalance reserve down*

The award decreases the state of charge to 100 MWh. It does not change the upper envelope from 200 MWh, but decreases the lower envelope to 100 MWh. The resource has sufficient state of charge to meet the ancillary service state of charge constraints.

Hour	En	IRU	IRD	SOC_U	SOC	SOC_L
0				200	200	200
1	100	0	100	200	100	100

- *100 MW of imbalance reserve up and 100 MW of imbalance reserve down*

The award does not impact state of charge, which remains at 200 MWh. It increases the upper envelope to 300 MWh, and decreases the lower envelope to 100 MWh. The resource has sufficient state of charge to meet the ancillary service state of charge constraints.

Hour	En	IRU	IRD	SOC_U	SOC	SOC_L
0				200	200	200
1	0	100	100	300	200	100

Example 1, Continued

Now suppose the same resource receives an award for 100 MW of imbalance reserve up and 100 MW of imbalance reserve down during hour ending 1. The following are feasible awards for hour ending 2:

- *0 MW of energy and 100 MW of imbalance reserve up*

This award does not impact the state of charge, which remains at 200 MWh. It does reduce the lower envelope to 0 MWh, but leaves the upper envelope and the state of charge at 300 MWh. The resource has sufficient state of charge to meet the ancillary service state of charge constraints.

Hour	En	IRU	IRD	SOC_U	SOC	SOC_L
0				200	200	200
1	0	100	100	300	200	100
2	0	100	0	300	200	0

- *100 MW of charging energy and 100 MW of imbalance reserve up*

The award increases the state of charge to 300 MWh. It also increases the upper envelope to 400 MWh, but the lower envelope remains unchanged at 100 MWh. The resource has sufficient state of charge to meet the ancillary service state of charge constraints.

Hour	En	IRU	IRD	SOC_U	SOC	SOC_L
0				200	200	200

1	0	100	100	300	200	100
2	-100	100	0	400	300	100

- *100 MW of discharging energy and 100 MW of imbalance reserve down*

The award decreases the state of charge to 100 MWh. It does not change the upper envelope from 300 MWh, but decreases the lower envelope to 0 MWh. The resource has sufficient state of charge to meet the ancillary service state of charge constraints.

Hour	En	IRU	IRD	SOC_U	SOC	SOC_L
0				200	200	200
1	0	100	100	300	200	100
2	100	0	100	300	100	0

- *100 MW of imbalance reserve up and 100 MW of imbalance reserve down*

The award does not impact state of charge, which remains at 200 MWh. It increases the upper envelope to 400 MWh, and decreases the lower envelope to 0 MWh. The resource has sufficient state of charge to meet the ancillary service state of charge constraints.

Hour	En	IRU	IRD	SOC_U	SOC	SOC_L
0				200	200	200
1	0	100	100	300	200	100
2	0	100	100	400	200	0

Example 1, Continued

Now suppose the same resource receives an award for 100 MW of imbalance reserve up and 100 MW during hour ending 1 and 100 MW of imbalance reserve up and 100 MW of imbalance reserve down during hour ending 2. The following are examples of infeasible for hour ending 3:

- *0 MW of energy and 100 MW of imbalance reserve up*

This award would not impact the state of charge, which would remain at 200 MWh. It reduces the lower envelope to -100 MWh, which is infeasible. The resource would have sufficient state of charge to meet the ancillary service state of charge constraints.

Hour	En	IRU	IRD	SOC_U	SOC	SOC_L
0				200	200	200
1	0	100	100	300	200	100
2	0	100	100	400	200	0
3	0	100	0	400	200	-100

- *100 MW of discharging energy and 100 MW of imbalance reserve down*

This award would decrease the state of charge to 100 MWh. It would not change the upper envelope from 400 MWh, but it would decrease the lower envelope to -100 MWh, which is infeasible. The resource would have a sufficient state of charge to meet the ancillary service state of charge constraints.

Hour	En	IRU	IRD	SOC_U	SOC	SOC_L
0				200	200	200
1	0	100	100	300	200	100
2	0	100	100	400	200	0
3	100	0	100	400	100	-100

Example 2

Suppose a storage resource has a +/- 100 MW operating range and can hold a state of charge between 0 MWh and 400 MWh. Also, suppose that the model assumes that the resource will have 100 MWh of energy going into hour ending 1, and that the resource has no losses between charging and discharging. Further, assume the multipliers for both imbalance reserve up and down are set to 0.2. This shows a potential scenario for multiple hours of awards, and includes comments on the awards.

Hour	En	IRU	IRD	SOC_U	SOC	SOC_L
0				100	100	100
1	20	50	0	80	80	70
2	0	80	100	100	80	54
3	-100	0	100	220	180	154
4	0	100	100	240	180	134
5	0	100	100	260	180	114

- *The resource starts the begins the day (is anticipated to end the previous day) at close to zero state of charge*
- *During hour ending 1 the resource has a discharge award, that moves the state of charge closer to 0 MWh*
- *Imbalance reserve up awards in hour ending 2 are limited to 80 MW because of the low state of charge*
- *The market schedules the resource to charge in hour ending 3, accompanied by awards for regulation up and regulation down*

These constraints will also be included in the residual unit commitment market run. The equations governing this relationship are outlined in Equation Set 5.

$$\begin{aligned} SOC_{i,t}^{(u)} &= SOC_{i,t-1}^{(u)} - EN_{i,t}^{(+)} - \eta_i\, EN_{i,t}^{(-)} + \eta_i\, AIRD_t\, IRD_{i,t} + \eta_i\, ARCD_t\, RCD_{i,t} \le \overline{SOC}_{i,t} \\ SOC_{i,t}^{(l)} &= SOC_{i,t-1}^{(l)} - EN_{i,t}^{(+)} - \eta_i\, EN_{i,t}^{(-)} - AIRU_t\, IRU_{i,t} - ARCU_t\, RCU_{i,t} \ge \underline{SOC}_{i,t} \end{aligned} \quad (5)$$

Where:

$ARCD_t$ *Adjustable multiplier applied to downward reliability capacity at time t*

$ARCU_t$ *Adjustable multiplier applied to upward reliability capacity at time t*

Setting the Multipliers

Because storage operation and market outcomes are dependent on how the parameters for these constraints are set, care will need to be taken when setting up a methodology to set the multipliers applicable for these constraints. Setting the multipliers too high could result in restricted outcomes for storage resources and setting the multipliers too low could result in ineffective constraints that do not ensure resource availability. Further, because these products are new, there is no actual operational experience for how awards for these products typically impact storage resources or how storage may be relied on during stressed system conditions to provide these products.

This policy proposes that the multipliers for all hours begin by being set to 0.85. This value will continue to be discussed with stakeholders prior to implementation of this constraint.

The constraints, the current hourly values for the multipliers, and the methodology for developing those multipliers will be described in the business practice manuals.

4.6 Treatment of Metered Subsystems, Existing Transmission Contracts, and Transmission Ownerships Rights

Metered Subsystems

Currently, metered subsystem operators must make an election on four issues that govern the manner in which the metered subsystem participates in the markets. The metered subsystem operator must choose either:

i. Net settlements or gross settlements.
ii. To load follow or not to load follow with its generating resources.
iii. To have its load participate in residual unit commitment procurement or not have its load participate in residual unit commitment procurement.
iv. To charge or not to charge the CAISO for their emissions costs.

With the day-ahead market enhancements, metered subsystem operators must make an election on three issues that will govern the manner in which the metered subsystem participates in the markets. The metered subsystem operator must choose either:

i. Net settlements or gross settlements.
ii. To load follow or not load follow with its designated generating resources.

iii. To charge or not to charge the CAISO for their emissions costs.

A metered subsystem operator may:

i. Bid to supply energy to or purchase energy from the markets.
ii. Bid to provide available capacity for imbalance reserves up/down to meet uncertainty requirements.
iii. Bid to provide available capacity for reliability capacity up/down to meet net load forecast
iv. Bid or self-provide an ancillary service from a system unit or from individual generating units, participating loads or proxy demand response resources within the metered subsystem. A metered subsystem operator also may purchase ancillary services from CAISO or third parties to meet its ancillary service obligations under the CAISO tariff.

The CAISO proposes to maintain the current settlement of metered subsystem operator day-ahead energy schedules who have elected gross settlement or net settlement. The CAISO proposes to settle metered subsystem resources that have received imbalance reserves or reliability capacity awards in a similar manner as non-metered subsystem resources, regardless of the metered subsystem operator's selection of net or gross settlement. Imbalance reserve up/down awards will settle at the relevant locational marginal price for imbalance reserves. Reliability capacity up/down awards will settle at the relevant locational marginal price for reliability capacity. For both reliability capacity tier 1 and reliability capacity tier 2 cost allocations, metered subsystem operators will settle in a similar manner as non-metered subsystem resources, regardless of their net versus gross selection. A metered subsystem operator that has elected to load follow to manage its own load variability shall not receive a reliability capacity tier 1 or a reliability capacity tier 2 cost allocation. For both imbalance reserve tier 1 and imbalance reserve tier 2 cost allocations, metered subsystem operators will settle in a similar manner as non-metered subsystem resources, regardless of their net versus gross selection. A metered subsystem operator that has elected to load follow to manage its own load variability shall receive imbalance reserve tier 1 and imbalance reserve tier 2 cost allocations based on the metered subsystem operator's net portfolio uninstructed deviations.

Existing Transmission Contracts and Transmission Ownership Rights

The CAISO proposes to maintain the current energy settlement for existing transmission contract rights (ETCs) and transmission ownership rights (TORs). Day-ahead energy schedules associated with an ETC or TOR self-schedule will settle at the relevant integrated forward market locational marginal price. In addition, the CAISO proposes to maintain the settlement of integrated forward market congestion credit for the valid and balanced portion of ETC or TOR self-schedules and relative eligible point of receipt of delivery.

Reliability capacity will ensure sufficient physical resources are committed to meet the net load forecast with adjustments for known differences between what cleared the integrated forward market including under-scheduled variable energy resources. As long as the ETC/TOR self-schedules supply to meet their demand, the market does not need to procure reliability capacity to meet the valid and balanced portion of ETC or TOR self-schedule. As such, the CAISO proposes to exclude the ETC and TOR self-schedules from reliability capacity tier 1 and reliability capacity tier 2 allocations up to the valid and balanced portion of ETC and TOR self-schedules. In contrast, the ETC and TOR self-schedules are subject to reliability capacity tier 1 and reliability capacity tier 2 allocations for quantities above the valid and balanced portion of the ETC or TOR self-schedules.

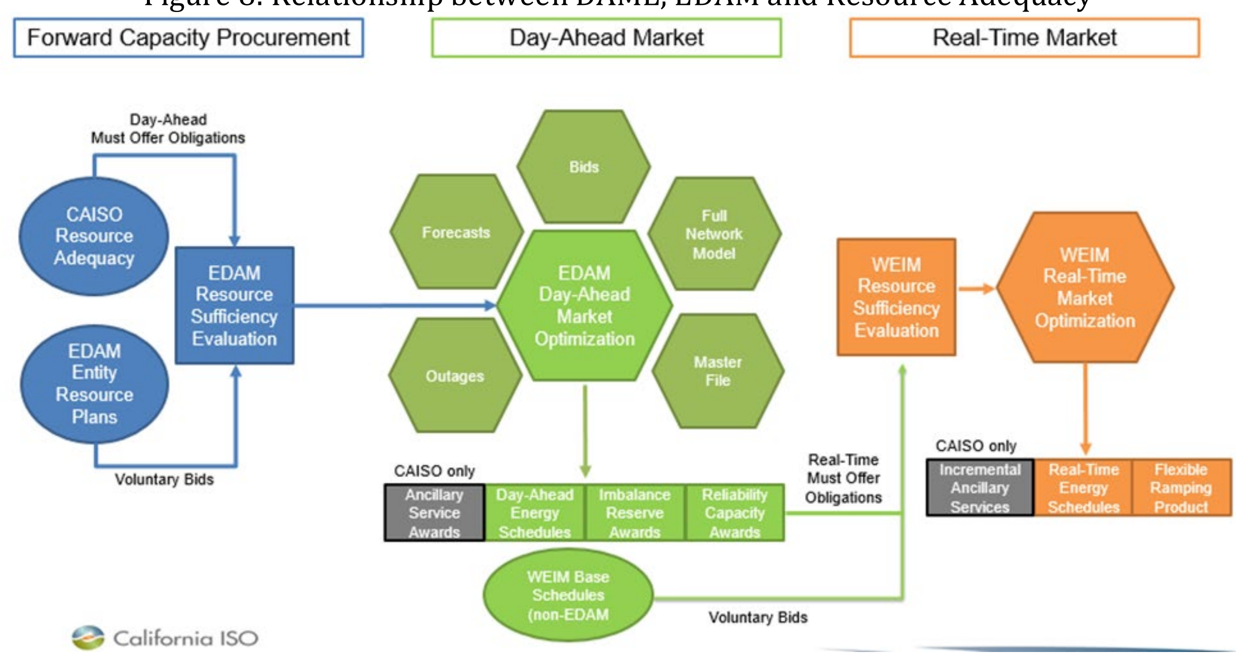
Imbalance reserves will ensure the day-ahead market schedules sufficient real-time dispatch capability to meet net load imbalances between the day-ahead and real-time markets. As long as the ETC and TOR self-schedules supply to meet their demand, the CAISO does not need to procure additional imbalance reserves. As such, the CAISO is proposing to exclude the ETC and TOR self-schedules from imbalance reserve tier 1 and imbalance reserve tier 2 allocations up to the valid and balanced portion of ETC and TOR self-schedules. In contrast, the ETC and TOR self-schedules are subject to imbalance reserve tier 1 and imbalance reserve tier 2 allocations for quantities above the valid and balanced portion of the ETC or TOR self-schedules.

5. Alignment between Resource Adequacy, DAME, and 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 market solutions. The goal of this effort is to ensure an efficient and robust market design that bridges the various election/bidding and program/market timelines.

Figure 8 is a flowchart depicting the correlation between resource adequacy, DAME, and EDAM.

Figure 8: Relationship between DAME, EDAM and Resource Adequacy



The flowchart can be summarized as follows:

1. The CAISO resource adequacy program and non-CAISO EDAM participants' integrated resource plan are the forward procurement processes that ensure the balancing authority areas have forwarded-contracted with adequate supply to meet their anticipated system needs. To participate in the day-ahead market and benefit from EDAM transfers, each EDAM participant must pass the EDAM resource sufficiency evaluation. The EDAM resource sufficiency evaluation ensures all EDAM participants have sufficient bids from participating resources to individually meet their demand forecast, ancillary service requirements, and uncertainty requirements for each hour of the operating day. This prevents EDAM participants from leaning on the capacity of others in the day-ahead timeframe. For the CAISO, the resource adequacy program requires resource adequacy capacity to bid in the day-ahead market through must-offer obligation rules. Non-CAISO EDAM participants provide voluntary bids to the day-ahead market that must be sufficient for the participant to meet its day-ahead resource sufficiency requirements.

2. EDAM participants will have their energy and imbalance reserves co-optimized to meet daily load and uncertainty requirements.[37] In addition, the residual unit commitment will procure reliability capacity in each EDAM balancing authority area across the EDAM footprint to meet difference in cleared physical supply and the BAA's demand forecast. The day-ahead market will result in must-offer obligations and bids into the real-time market. For EDAM participants, these real-time market bids are inputs into the WEIM resource sufficiency evaluation. EDAM participants will benefit in the WEIM RSE with assurance their day-ahead schedules are balanced. Entities participating in the WEIM but not in the EDAM will continue to provide WEIM base schedules. In order to benefit from transfers in the real-time market, WEIM participants must pass the WEIM real-time resource sufficiency evaluation.

3. The real-time market will co-optimize energy and real-time flexible ramping product across the entire WEIM footprint, and incremental ancillary services for the CAISO BAA.[38]

6. WEIM Governing Body Role

Under Currently Applicable Rules

Under the currently effective *Charter for EIM Governance*, this initiative would fall mostly outside the authority of the WEIM Governing Body because it focuses on the day-ahead market. As explained below, three elements do include proposed changes to real-time market rules, which would give the Governing Body a limited decisional role, as follows:

1. Financial settlement of flexible ramping product, to remove the double payment of forecasted movement (§ 4.2) – Joint authority

[37] The EDAM proposal would not co-optimize ancillary services at the onset of EDAM.
[38] The Western Energy Imbalance Market currently does not procure incremental ancillary services outside of the CAISO balancing authority area.

2. Other changes to the financial settlement of flexible ramping product (§4.2) – Advisory role

3. Bidding obligations for resources that have day-ahead schedules for imbalance reserve or reliability capacity (§ 3.1) – Advisory role.

The Governing Body would not have any role with respect to the remainder of this initiative.

More specifically, the changes to the settlement of flexible ramping product to remove the double payment of forecasted movement (proposal 1) would be "applicable to EIM Entity balancing authority areas, EIM Entities, or other market participants within EIM Entity balancing authority areas, in their capacity as participants in EIM,"[39] and therefore would fall within the scope of joint authority under the currently effective rules.

On the other hand, proposals 2 and 3, to the extent they change rules of the real-time market, would not be applicable to WEIM Entities in their capacity as participants in WEIM. To be clear, they may apply to some market participants within a WEIM Entity balancing authority area, but only as importers into or exporters from the ISO balancing authority, which are transactions that occur outside of the WEIM. Accordingly, these proposed tariff changes fall outside the scope of joint authority. They do, however, fall within the scope of the WEIM Governing Body's advisory role, because the WEIM Governing Body "may provide advisory input over proposals to change or establish tariff rules that would apply to the real-time market but are not within the scope of joint authority." Id.

Proposed Adjustment

CAISO management has stated that, notwithstanding this classification based on the current rules, it would be appropriate to consider an adjustment of this classification, subject to Board approval. Stakeholder comments on earlier papers indicated broad support for requiring joint approval of both the Board and the WEIM Governing Body for all aspects of this initiative. Such a classification could be appropriate given the unique nature of this initiative in the sense that it is foundational for EDAM because the imbalance reserve product developed in this initiative drives a significant portion of the potential benefits of EDAM.

The Chair of the Board of Governors during the December 14, 2022 joint meeting agreed that joint authority would be appropriate over all aspects of the proposal that are not specific to the CAISO's balancing authority area or operation of the CAISO controlled grid, such as California resource adequacy provisions. Therefore, in alignment with the Board's direction, management proposes that the entire proposal fall under the joint authority of the WEIM Governing Body and the ISO Board of Governors,

[39] The Board and the WEIM Governing Body have joint authority over any

> proposal to change or establish any CAISO tariff rule(s) applicable to the EIM Entity balancing authority areas, EIM Entities, or other market participants within the EIM Entity balancing authority areas, in their capacity as participants in EIM. This scope excludes from joint authority, without limitation, any proposals to change or establish tariff rule(s) applicable only to the CAISO balancing authority area or to the CAISO-controlled grid. Charter for EIM Governance § 2.2.1.

While it has been decided that this scope will be expanded after EDAM has been approved to include day-ahead market rules, this has not yet occurred.

subject to one exception. One of the obligations proposed in Section 3.1 is a bidding obligation for California RA resources – specifically, must-offer obligation in the day-ahead market for RA capacity that is eligible to provide imbalance reserves (i.e., 15 minute dispatchable). Those resources must offer imbalance reserves for the portion of their energy bid that is not self-scheduled (i.e., economically bid). Under the Board's direction, there would be no adjustment to the classification of this element, which thus would fall within the authority of the Board only, with no role for the WEIM Governing Body, because it proposes a rule of the day-ahead market as opposed to the real-time market.

There have been no objections to joint authority applying generally to this initiative overall except for the April 5, 2023 comments of the California Public Utilities Commission on the February and March workshops. They stated:

> ED staff is concerned about this recommendation because this initiative will affect penalty parameters, which affect reliability for California customers (e.g., what penalty parameter does IR get compared to low priority exports). Further, if EDAM does not materialize, these provisions will apply only to CAISO customers.

CAISO staff notes that a premise of this position is incorrect; if EDAM does not move forward, CAISO would not move forward with this version of DAME. In that case, a different version of DAME would be developed based on participation by CAISO only, and there would be an opportunity to revisit these proposed rules. Accordingly, CAISO staff maintains its recommendation that this matter should be adjusted to joint authority generally, as explained above, because this version of the proposal is foundational to EDAM.

7. Stakeholder Engagement, Implementation Plan & Next Steps

Table 4 outlines the proposed schedule for completing the policy and implementation of the Day-Ahead Market Enhancements (DAME) initiative. CAISO has shifted the implementation of DAME to fall 2024 to coincide with the EDAM. Some stakeholders have requested that both the DAME and EDAM initiatives occur within the same stakeholder forum. Although the day-ahead market enhancements lay the foundation for EDAM, and CAISO is committed to aligning the objectives and functionalities of these initiatives, they were conducted as separate but parallel stakeholder processes. For this reason, it is crucial to keep the initiatives, board decisions, FERC filings, and implementation efforts aligned with EDAM. If there is a change in the EDAM schedule and CAISO were to consider implementing the day-ahead market changes without EDAM, it would reinstate a stakeholder process to ensure the design is appropriate for the CAISO balancing authority area alone.

Table 3: Stakeholder engagement and implementation development plan

Date	Milestone
Revised Final Proposal	May 1, 2023
Stakeholder Workshop	May 2, 2023
Joint ISO Board of Governors and WEIM Governing Body meeting (decision)	May 17, 2023

Draft Tariff Publication and Stakeholder Process	May 2023 – June 2023
Business Requirement Specification (BRS) Development	May 2023 – June 2023
Implementation	Fall 2024

Appendices

Appendix A: Eligibility Table

	EN	RCU	RCD	IRU	IRD
Non-Participating Load	Yes	Not Eligible	Not Eligible	Not Eligible	Not Eligible
Virtual Supply	Yes	Not Eligible	Not Eligible	Not Eligible	Not Eligible
Virtual Demand	Yes	Not Eligible	Not Eligible	Not Eligible	Not Eligible
Hourly Block Import	Yes	Eligible	Eligible	Not Eligible	Not Eligible
Hourly Block Export	Yes	Eligible	Eligible	Not Eligible	Not Eligible
15-Min Import	Yes	Eligible	Eligible	Eligible	Eligible
15-Min Export	Yes	Eligible	Eligible	Eligible	Eligible
Dynamic Import	Yes	Eligible	Eligible	Eligible	Eligible
Long-Start Generator	Yes	Eligible	Eligible	Eligible	Eligible
Short-Start Generator	Yes	Eligible	Eligible	Eligible	Eligible
Participating Load w/ 15-Min dispatch capability	Yes	Eligible	Eligible	Eligible	Eligible
Participating Load w/ Hourly dispatch capability	Yes	Eligible	Eligible	Not Eligible	Not Eligible
Variable Energy Resources (Wind/Solar)	Yes	Eligible	Eligible	Eligible	Eligible
Non-Generator Resources (Storage)	Yes	Eligible	Eligible	Eligible	Eligible
Hybrid Resource	Yes	Eligible	Eligible	Eligible	Eligible
Energy Storage Resource	Yes	Eligible	Eligible	Eligible	Eligible
60-Minute Proxy Demand Resource	Yes	Eligible	Eligible	Not Eligible	Not Eligible
15-Minute Proxy Demand Resource	Yes	Eligible	Eligible	Eligible	Eligible
5-Minute Proxy Demand Resource	Yes	Eligible	Eligible	Eligible	Eligible
Reliability Demand Response Resource	Yes	Not Eligible	Not Eligible	Not Eligible	Not Eligible