Day-Ahead Market Enhancements

Revised Straw Proposal

June 8, 2020

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Day-Ahead Market Enhancements: Revised Straw Proposal

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1. Executive Summary

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

- Introducing a reliability capacity product to meet the net load forecast[1] with non-VER physical supply[2].
- Introducing an imbalance reserve product to provide flexible capacity to accommodate the increasing uncertainty and variability of real-time net load.
- Co-optimizing these new products with energy and ancillary services to schedule resources more efficiently.

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

The first of these new market products, termed "reliability capacity up/down" replaces the existing residual unit commitment awards. The existing residual unit commitment process ensures sufficient physical resources are effectively 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. The CAISO runs the existing residual unit commitment process after the day-ahead market integrated forward market co-optimizes energy and ancillary services. The proposed design will co-optimize and schedule resources to meet both bid-in demand and the net load forecast.

Similar to the existing residual unit commitment process, the optimization will consider transmission constraints in scheduling reliability capacity. However, unlike the existing residual unit commitment process, reliability capacity can also provide downward dispatch capability and/or avoid committing resources if the net load forecast is less than the net load that clears the integrated forward market. A reliability capacity award will result in an obligation to provide economic energy bids to the real-time market so that the resource's dispatch capability is available to the real-time market.

The second of the new day-ahead market products, termed "imbalance reserves," will ensure the day-ahead market schedules sufficient real-time dispatch capability to meet net load imbalances that materialize between the day-ahead and fifteen-minute markets. These imbalances are due to net load uncertainty and ramping differences between hourly day-ahead market and fifteen-minute real-time market schedules. These imbalances are growing because of increasing amounts of variable energy resources. This increasing net load uncertainty has caused system operators to utilize more out-of-market actions to maintain reliability such as exceptional dispatch, load conformance in the residual unit commitment process and real-time load conformance.

Similar to reliability capacity, an imbalance reserve award will result in an obligation to provide economic energy bids to the real-time market. Only resources that can be dispatched in the fifteen-

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[1] The net load forecast is the CAISO's load forecast less CAISO's forecast of variable energy resources.
[2] Non-VER physical supply is defined as non-VER internal generation plus imports less exports.

minute market will be able to provide imbalance reserves. As with both energy and reliability capacity, the proposed design considers transmission constraints to ensure imbalance reserves are deliverable.

Resources will provide price and quantity bids for capacity availability in both the upward and downward direction. Resources awarded reliability capacity or imbalance reserves will receive a day-ahead payment at the locational marginal price for the relevant product and the market will recover the costs through a cost allocation.

The new day-ahead market design is the foundation for extending the day-ahead market to Energy Imbalance Market (EIM) participants outside of the CAISO's balancing authority area. The stakeholder process for this initiative is concurrently underway.[3] As a result, it is important that balancing authorities have confidence that the day-ahead solution schedules sufficient physical supply to meet reliability and the resources capability to address uncertainty can be dispatched in real-time because it is physically deliverable.

2. Stakeholder Comments and Changes from Straw Proposal

The CAISO published the Day-Ahead Market Enhancements (DAME) straw proposal on February 3, 2020 and held an in-person meeting to discuss the straw proposal on February 10, 2020. The CAISO also held a web meeting on March 5, 2020 to discuss the congestion revenue and market power mitigation aspects of the proposal and to clarify how the energy and reliability energy LMPs interact by providing additional examples.

The straw proposal included a new day-ahead market formulation to change the integrated forward market (IFM) and residual unit commitment (RUC) from a sequential process to a co-optimized process. This approach introduced "reliability energy (REN)" which was defined as the energy schedule plus reliability capacity up less reliability capacity down. The energy schedule met both the financial energy schedules and reliability energy of the overlapping supply. The reliability capacity is meets the difference between cleared demand and the net load forecast from non-VER physical supply resources. The day-ahead market would co-optimize reliability energy with the other day-ahead market products using the CAISO's hourly net load forecast.

The other major day-ahead market design change introduced in the straw proposal was the introduction of an imbalance reserve product, which the day-ahead market would co-optimize along with energy and ancillary services. Imbalance reserves would schedule additional dispatch capability to be available in the real-time market. The imbalance reserve requirement will be based on historical differences between the hourly day-ahead forecasted net load and the real-time 15-minute net load forecast. The day-ahead market would co-optimize energy, reliability energy, imbalance reserves, and ancillary services in a single market pass.

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[3] CAISO Extended Day-Ahead Market Initiative. http://www.caiso.com/StakeholderProcesses/Extended-day-ahead-market

The CAISO received stakeholder comments in response to the straw proposal and stakeholder meetings. There was broad stakeholder support for the development of an imbalance reserve product to meet uncertainty and ramping needs between the day-ahead and real-time markets. Stakeholders also supported including reliability capacity up and down to address differences between cleared net load and the CAISO net load forecast. There was broad support for nodal deliverability of day-ahead capacity products.

However, stakeholder opinions diverged when it came to the introduction of reliability energy (REN). The REN requirement ensured the energy (EN) plus reliability capacity up (RCU) less reliability capacity down (RCD) was greater than or equal to the net load forecast. The result is that the physical supply price included a component reflecting the shadow price of the REN constraint while virtual supply/demand and bid-in load prices did not reflect the shadow price of the REN constraint. Some stakeholders voiced support for REN. They believe that since REN is co-optimized with energy (as opposed to RUC, which is incremental), it results in more efficient unit commitment and equitable compensation of resources, and ensures physical capacity and flexibility are available in real-time. Several EIM entities remarked that the day-ahead market design presented in the straw proposal would unlock benefits for EDAM. Imbalance reserves would provide the diversity benefit while REN would ensure that resources committed to serve load are physical and non-speculative so balancing authority can have confidence that day-ahead schedules involving energy from other balancing authority areas would be delivered.

Other stakeholders were opposed to the overlapping portion of the EN and REN schedules. Stakeholders were concerned that adding the CAISO forecast as a constraint abandons the purpose of the day-ahead market as a financial interaction between supply and bid-in load. They believe that co-optimization efficiencies depend on the accuracy of the forecast under the proposed approach and that REN could prevent load-serving entities from achieving their desired day-ahead market position. Others viewed the interaction between EN and REN as distorting price signals. Finally, some expressed concern that the compensation of REN for resources that were under Resource Adequacy obligations to California LSEs could conflict with compensation already incorporated into such Resource Adequacy contracts.

Several stakeholders who voiced opposition to REN were open to the portion of REN (RCU/RCD) needed to address differences between the cleared net load and the CAISO net load forecast. Others believe that imbalance reserves could be designed to make RCU/RCD unnecessary or included within the imbalance reserve requirement. The CAISO's Department of Market Monitoring suggests that stronger incentives are needed to ensure that resources with imbalance reserve obligations perform in real-time and that the proposed design incentivizes market participants to engage in implicit virtual bidding.

Some stakeholders expressed confusion and opposition to how VERs would be treated in the day-ahead market. Other stakeholders felt that forcing VERs into a day-ahead market position reduces uncertainty and contributes to market liquidity.

Several stakeholders requested more detail and information, especially around the topics of metered subsystems, developing a DEB for capacity bids, and market power mitigation.

The revised straw proposal seeks to address stakeholder concerns of various energy schedules settling at different prices due to the reliability energy constraints. The market formulation changes also seek to ensure that sufficient physical supply is committed in the day-ahead market that is deliverable in real-time to meet the net load forecast and cover uncertainty in net load. Both objectives are met by decoupling energy and reliability capacity in the market formulation by using multiple passes to determine a fixed requirement for reliability capacity and imbalance reserves.

The following table summarizes topics from the straw proposal that are no longer relevant given the design changes presented in this revised straw proposal.

Topic	Comments
Congestion Revenue Rights	The elimination of REN removes the need to modify the existing congestion revenue rights settlement. In addition, the upward and downward deployment scenarios used in the last market pass do not result in a marginal congestion cost to energy schedules. Congestion revenue rights will settle using the same marginal congestion calculation as the current day-ahead market.
Energy and Reliability Energy Pricing	The elimination of REN removes the co-dependent energy and reliability energy LMPs and associated settlement and cost allocation of the overlapping portion of energy and reliability energy schedules. The proposed market formulation eliminates the price dependency of energy and reliability capacity by decoupling energy and capacity products through two market passes.
Variable Energy Resources	Variable energy resources will participate in the day-ahead in the same manner as they do today. However, as explained more fully in section 4.6, variable energy resources will not be eligible for reliability capacity up or imbalance reserve up awards. Variable energy resource will be eligible for reliability capacity down, imbalance reserve down, and ancillary services awards.

3. Need for Day-Ahead Market Enhancements

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

Energy imbalances occur because of (1) differences between hourly day-ahead market schedules and fifteen-minute real-time market schedules, termed "granularity differences," and (2) net load uncertainty that materializes between day-ahead and real-time market runs. As stated above, the real-time market must manage energy imbalances that occur between the day-ahead and real-time markets.

The real-time market will continue to serve this under the redesigned day-ahead market. The CAISO proposes a new day-ahead market structure to better accommodate net load imbalances. Instead of the existing integrated forward market (IFM) and sequential residual unit commitment (RUC) process, the CAISO proposes a two-pass day-ahead market co-optimization. The new day-ahead market will co-optimize energy, ancillary services, reliability capacity, and imbalance reserves.

3.1. Improve Market Efficiency

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

Large imbalances between the day-ahead and real-time market can result in challenging operating conditions for system operators. When there is potential for large imbalances that are not or cannot be addressed through the real-time market, system operators must rely on out-of-market actions to provide unloaded capacity. These actions may include increasing the load forecast in the market and/or exceptional dispatches. Although these actions are necessary for grid reliability, they also undermine market price formation and the resultant economic signals provided by market prices. For example, assume additional supply is committed after the day-ahead market to cover uncertainty with a PMin burden 1000MW. If the uncertainty materializes less than the PMin burden there will be price divergence between the day-ahead market and real-time market because resources with day-ahead energy schedules will need to be dispatched lower leading to lower real-time prices relative to day-ahead prices. The proposed imbalance reserve product will greatly eliminate the need for out-of-market actions and incorporate these costs into day-ahead market clearing prices. This will compensate resources more appropriately for providing this capacity and improve price convergence between the day-ahead market and real-time market.

Ultimately, the CAISO market should achieve grid reliability through efficient and effective market solutions. The day-ahead market enhancements initiative moves the market closer to that goal by integrating products into the market to capture what would otherwise be obtained through out-of-market actions. These out-of-market actions can now be accurately priced through the market clearing process.

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

3.2. Price Performance Analysis Report

The CAISO recently completed a comprehensive report titled "Price Performance Analysis" that summarized and analyzed price formation in the CAISO markets.[4] The report identified factors that contribute to price divergence between the day-ahead and real-time markets and proposed solutions to mitigate potential inefficiencies.

As a part of this effort, the report analyzed imbalances across markets. The majority of imbalances occur between the day-ahead and fifteen-minute market (as opposed to between the fifteen-minute market and the five-minute market). These imbalances can be as much as 6,000 MW in a single hour. The Price Performance Analysis report confirms the large amount of imbalance between the day-ahead and real-time market occur due to load forecast error and is compounded by variable energy resource output changes. As shown in Figure 1, the "IFM prices are persistently higher than real-time prices starting in 2018 and continue in 2019." We believe this occurs because operators are reliant on out of market actions to procure additional capacity to meet potentially large imbalances. The out of market actions may then lead to price suppression in the real-time market.

Figure 1**:** Pricing differences across day-ahead and real-time markets from 2017 – Q1 2019
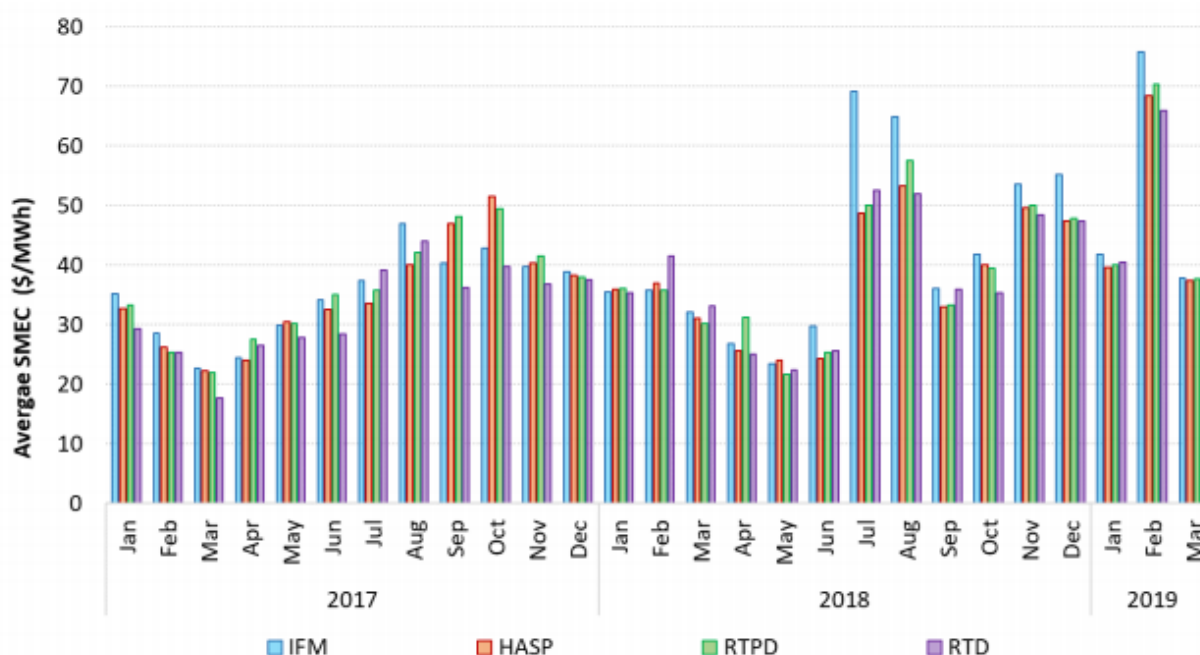
Sustained price divergence is a signal that the market is not functioning optimally. The actions the CAISO must take outside of the market to ensure grid reliability contributes to price divergence. While the CAISO must ensure it operates the system reliably and consistently with NERC requirements, the

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

CAISO also recognizes that sustained operator action outside of the market signals that there may be gaps in the current market design that lead to the need for such action. Ultimately, 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 Enhancement 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.

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

This section describes the magnitude of net load imbalances that occur between the day-ahead market and the real-time market's fifteen-minute market using data from January 2017 to March 2019. Net load imbalance values were calculated in each fifteen-minute interval for each of the following reference points:

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

Figure 2 shows historical net load imbalances by hour and year at the 2.5 and 97.5 percentiles. This means that 95 percent of the observed historical differences lie between these values. These percentiles are useful as a reference to the upward and downward imbalance reserve requirement.

Figure 2: Historical net load imbalance
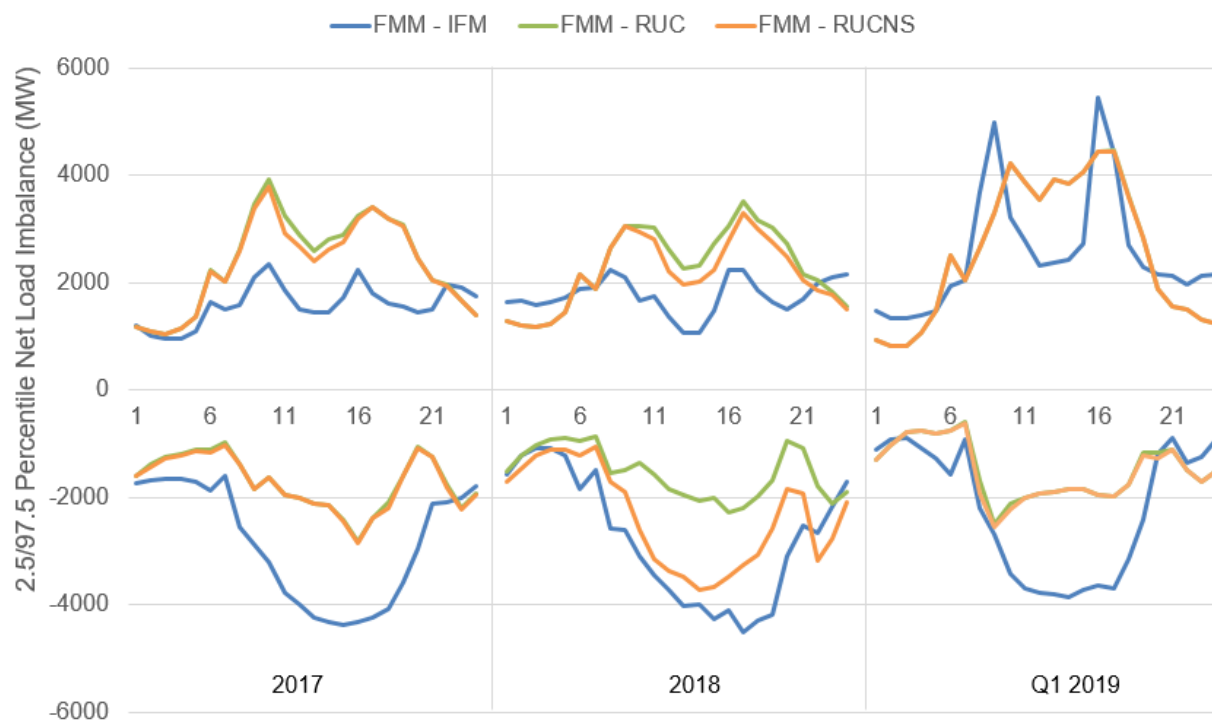
4. Proposed Day-Ahead Market Enhancements

In this revised straw proposal, the CAISO proposes a revised day-ahead market formulation that addresses stakeholder concerns about the co-dependency between energy and reliability energy as presented in the straw proposal. This revised design continues to propose a new reliability capacity product to meet the net load forecast with non-VER physical supply resources and continues to propose imbalance reserves to address the net load uncertainty between the day-ahead and real-time markets. The day-ahead market schedules ensure sufficient physical supply clears as energy, reliability capacity or imbalance reserves to meet the net load forecast and the uncertainty that may materialize between the day-ahead market and real-time market. This minimizes the need for out of market actions and appropriately values the services provided by market participants.

This section includes the following sub-sections:[5]

- Section 4.1 provides an overview of the updated market formulation.
- Section 4.2 describes the nodal deliverability of reliability capacity and imbalance reserves.
- Section 4.3 describes the proposed method to account for energy costs when procuring upward capacity products.

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[5] The following sections from the straw proposal were removed because they are no longer relevant to the proposal: Energy and Reliability Energy Pricing and Congestion Revenue Rights.

- Section 4.4 describes real-time bidding obligations for resources with day-ahead awards.
- Section 4.5 describes resource adequacy day-ahead must offer obligations.
- Section 4.6 describes the bidding and scheduling of variable energy resources.
- Section 4.7 describes day-ahead market eligibility and bidding rules.
- Section 4.8 describes various settlement rules.
- Section 4.9 describes the proposed application of market power mitigation to capacity bids.
- Section 4.10 provides an overview of the methodology to determine the imbalance reserves procurement quantity.
- Section 4.11 describes how the day-ahead market enhancements applies to metered sub-systems, ETCs, and TORs.

4.1. Updated Market Formulation

The day-ahead market enhancements objective is to develop a day-ahead market design that efficiently determines and prices day-ahead market energy schedules based on economic bids, while also efficiently scheduling sufficient physical capacity to provide dispatch capability. This dispatch capability is needed to meet the net load forecast and any net load uncertainty that materializes between the day-ahead and real-time markets and needs to provide energy that is deliverable to load.

The system operators' forecast of net load and the amount of potential net load uncertainty determines the amount of physical energy and dispatch capability from physical resources needed to ensure reliability. In contrast, clearing economic supply and demand bids, which may also include non-physical virtual supply and demand, may produce energy schedules that are different from the amount of physical energy and capacity needed for reliability.

Currently, the day-ahead market procures an incremental amount of capacity to meet reliability needs in the residual unit commitment process, which the system operators run after the integrated forward market produces energy schedules. The system operators run the residual unit commitment process using a fixed requirement based on the incremental need for capacity. This incremental need is based on the difference between the amount the integrated forward market cleared based on economics and the amount needed for reliability based on the net demand forecast and potential uncertainty.

The disadvantage of this sequential RUC process is that the capacity it procures is not co-optimized with the resource commitment and energy schedules produced by integrated forward market. Co-optimizing energy cleared based on economic bids with capacity needed for system reliability will improve market efficiency in a number of ways:

- Allowing commitment costs for resources needed to account for the differences between cleared net demand and the net load forecast to be included in the day-ahead market optimization, including those costs of resources currently committed through out of market actions

- Create more appropriate energy prices by co-optimizing with cleared energy the resource capacity reserved to meet the differences between cleared net demand and the net load forecast
- Allow resources the ability in the day-ahead market to reflect the costs of potentially being available for real-time dispatch and provide a price-signal for this cost and for the value of flexible capacity

As outlined in the previous section, the CAISO proposed in the previous straw proposal to co-optimize energy schedules based on economic supply and demand bids and energy and capacity needed for reliability through the introduction of reliability energy. The proposed optimization dynamically determined the amount of reliability energy to procure by considering the system operators' net load forecast as well as the quantity of physical energy versus virtual energy cleared. However, having the net load forecast be an input into the day-ahead market introduced potentially undesirable effects into the scheduling and pricing of day-ahead market energy schedules that result in market participants' day-ahead market financial positions.

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

In this paper, the CAISO has revised its proposed day-ahead market formulation to avoid these potentially undesirable effects. As described further below, this revised approach includes an initial market run that uses the net load forecast as an input and produces the amount of additional capacity needed for reliability needs. Under this approach, this amount of additional capacity needed for reliability is used as an accurate fixed requirement input into a subsequent market run. This run schedules and prices energy based on supply and demand economic bids, schedules and prices the reliability capacity needed for reliability based on economic bids, and schedules and prices based on economic bids the imbalance reserve products needed to address uncertainty.

Figure 3, Figure 4, and Figure 5 are representations of the relationship between energy, reliability capacity, and imbalance reserves.

Figure 3 illustrates where the market would clear if there were no bid-in demand, virtual supply or demand and variable energy resources scheduled at the CAISO forecast. This is similar to how the real-time market would clear. Since net load forecast is equal to the cleared non-VER physical supply the day-ahead market would not need to procure reliability capacity. The market will procure imbalance reserves to cover upward (P97.5) and downward (P2.5) uncertainty requirements. The meets the operational need to meet the day-ahead net load forecast and uncertainty that may materialize in real-time.

Figure 3: Day-ahead market products when forecast is equal to non-VER physical supply
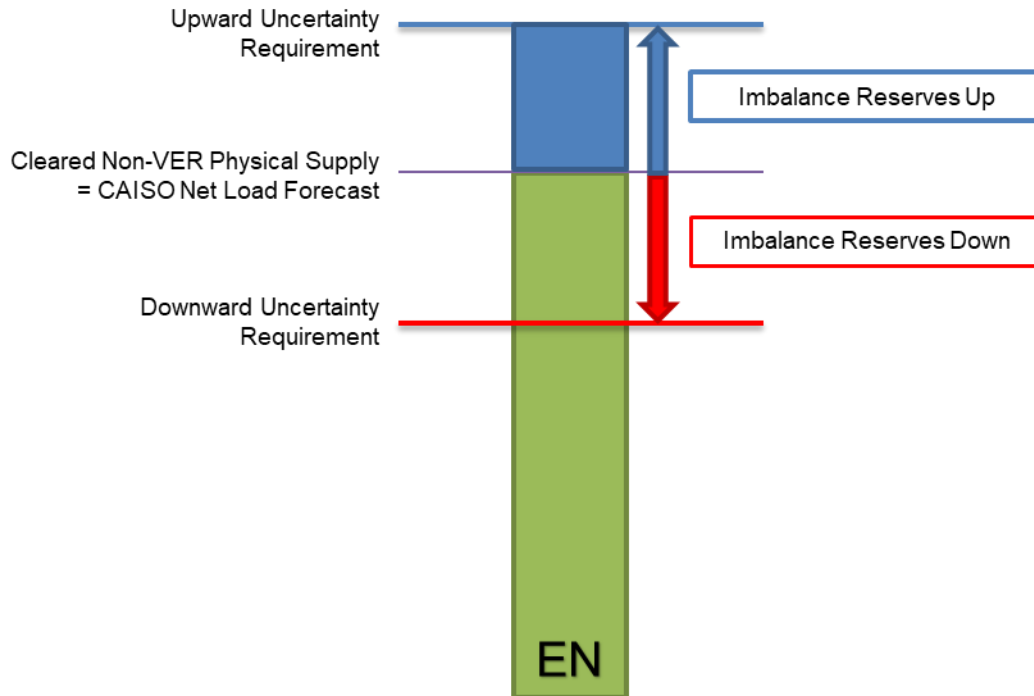
There are several reasons why non-VER physical supply will not clear equal to the net load forecast[6]. If bid-in load clears below (above) the CAISO load forecast this creates the need for reliability capacity up (down). If net virtual supply (demand) clears the market this creates the need for reliability capacity up (down). If variable energy resources schedule above the CAISO forecast this creates the need for reliability capacity up (down). These drivers can also offset the need for reliability capacity in a given directions. For example, virtual demand may clear addressing under scheduled load and virtual supply may clear addressing under scheduled variable energy resources.

Figure 4 illustrates this relationship when the CAISO's net load forecast is greater than the cleared non-VER physical supply. When this occurs, the day-ahead market procures upward dispatch capability to meet the net load forecast by awarding reliability capacity up to non-VER physical supply. It also procures the full imbalance reserves requirement up to meet the upward uncertainty but procures fewer imbalance reserves down because less downward capacity is needed to reach the downward uncertainty requirement from where the non-VER physical supply cleared relative to the net load forecast.

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[6] The CAISO has developed an Excel spreadsheet illustrating how cleared energy schedules determine the reliability capacity imbalance reserve need. The spreadsheet is posted on the CAISO website with this revised straw proposal.

Figure 4**:** Day-ahead market products when forecast is greater than non-VER physical supply
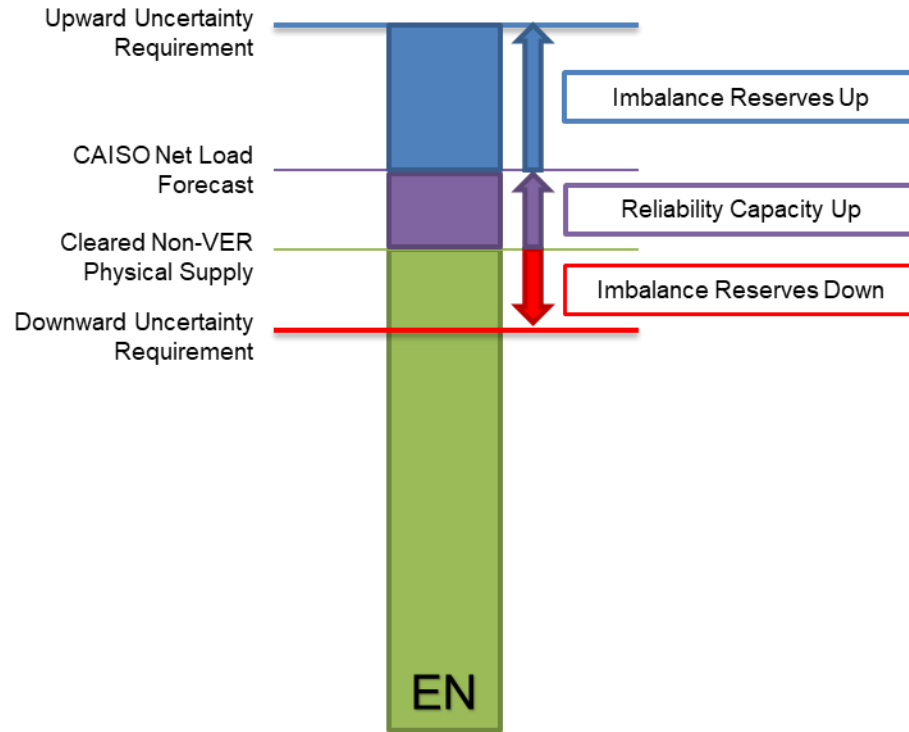
Figure 5 illustrates this relationship when the CAISO's net load forecast is less than the cleared non-VER physical supply. When this occurs, the day-ahead market procures reliability capacity down to provide downward dispatch capability relative to the energy schedules to meet the net load forecast. It also procures the full imbalance reserves down to meet the downward uncertainty requirement but procures fewer imbalance reserves up because less upward capacity is needed to reach the upward uncertainty requirement from where the physical supply cleared the market.

Figure 5: Day-ahead market products when forecast is less than non-VER physical supply
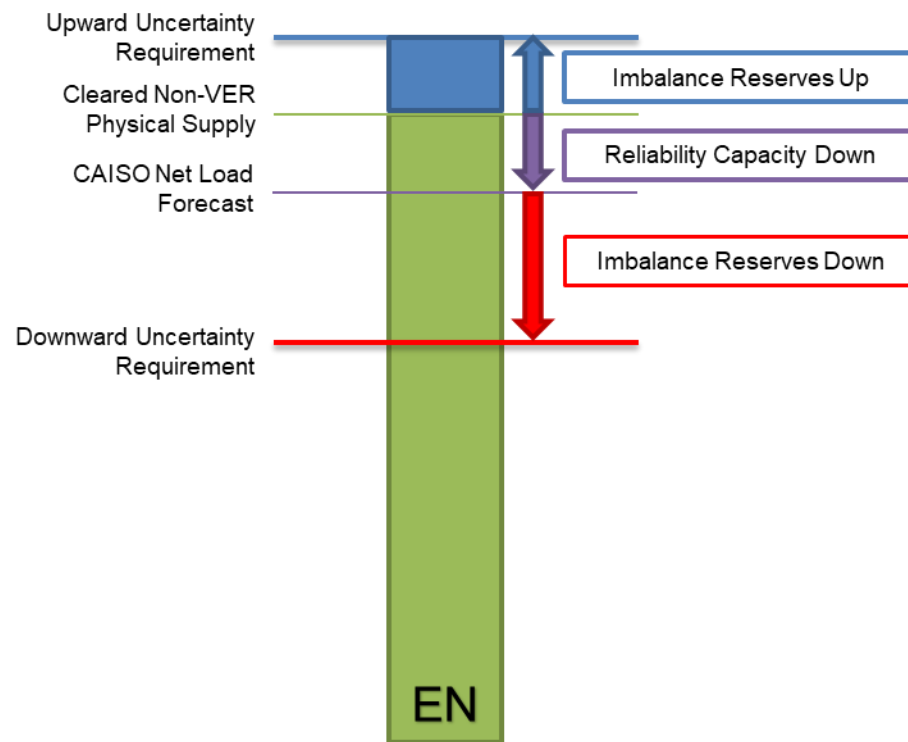
As described above, in this paper the CAISO proposes an updated day-ahead market formulation to meet the net load forecast with non-VER physical supply resources without the overlapping reliability energy. The day-ahead market enhancement continues to replace the existing residual unit commitment process, but the approach removes the price interaction between energy and reliability energy by introducing an additional market pass to determine the quantity of reliability capacity up or down and imbalance reserve up and down needed.[7] Therefore, the proposed day-ahead market solution uses three passes:

1. Market power mitigation (MPM) pass
2. First market pass
3. Last market pass

In the market power mitigation pass, the market uses unmitigated bids to clear bid-in load, bid-in supply, imports, exports, ancillary services requirements, the net load forecast, and the imbalance reserve requirement. The base scenario (cleared bid in load), the upward net load forecast scenario, and the downward net load forecast scenario are evaluated to determine if any binding transmission constraints are uncompetitive. Resources with a positive congestion contribution to an uncompetitive constraint will have their energy and/or capacity bids mitigated.

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[7] Detailed information on the proposed day-ahead market formulation are in the Appendix B: Updated DAME Formulation.

The first market pass will then obtain a solution using mitigated bids. The first market pass determines the optimal unit commitment to clear bid-in load, bid-in supply, imports, exports, ancillary services requirements, the net load forecast, and the imbalance reserve requirement. The first market pass determines the amount of reliability capacity up or reliability capacity down needed to cover the difference between non-VER physical supply and the net load forecast. This then allows the reliability capacity up or reliability capacity down to be a fixed requirement in the last market pass to decouple reliability capacity from the energy schedule. In addition, the imbalance reserve down requirement is reduced by the reliability capacity up and the imbalance reserve up requirement is reduced by the reliability capacity down determined through the first market pass. If no mitigation, then the results of the market power mitigation run will be used as the input to the last market pass.

The last market pass then has the same mathematical formulation as the first market pass, but with the following simplifications:

1. Fix the resource unit commitment at the first market solution.
2. Fix the requirement quantity of RCU or RCD at requirement obtained in the first market pass. This replaces the need to include the net load forecast in the optimization.
3. Fix the requirement of IRU and IRD at the adjusted quantity given the RCU or RCD requirement quantity.
4. In the upward and downward deployment scenarios, fix the non-VER physical supply at the first market pass result and variable energy resources at their forecast.

The last market pass then clears bid in load, bid in supply, imports, exports, ancillary services, reliability capacity up or down, and imbalance reserves up/down. Since the net load forecast is not considered, the energy and reliability capacity products are decoupled eliminating the pricing interactions in the previously proposed market formulation.

Since, the energy schedules in the deployment scenarios are fixed and equal to the first market pass schedules, the last market pass energy schedules will not have a marginal congestion impact created by including the deployment scenarios. As a result, the existing congestion revenue rights market design can remain unchanged because the day-ahead market will not have congestion components the CRR allocation and auction would not consider.

In addition, virtual supply and demand clear at the same price as physical supply and load at the same node even though not considered in the deployment scenarios. However, similar to the residual unit commitment cost allocation virtual supply and demand are allocated reliability capacity costs if the schedules drive the need for procurement of reliability capacity.

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

Table 1: Proposed and existing day-ahead market products

Title	Acronym	Purpose	Eligibility*	Status
Energy	EN	Energy schedules cleared to meet bid-in demand	All resources	Existing
Reliability Capacity, Up	RCU	Incremental capacity procured to meet the positive difference between the net load forecast and cleared non-VER physical supply	Physical Resources except variable energy resources based on 60-minute ramp capability	Proposed
Reliability Capacity, Down	RCD	Decremental capacity procured to meet the negative difference between net load forecast and cleared non-VER physical supply	Physical Resources based on 60-minute ramp capability	Proposed
Imbalance Reserves, Up	IRU	Incremental capacity procured relative to the net load forecast to meet the upward uncertainty requirement	15-minute dispatchable physical resources, award based on 15-minute ramp capability except variable energy resources	Proposed
Imbalance Reserves, Down	IRD	Decremental capacity procured relative to the net load forecast to meet the downward uncertainty requirement	15-minute dispatchable physical resources, award based on 15-minute ramp capability	Proposed
Ancillary Services	AS	Incremental capacity procured and reserved to meet real-time regulation and contingency reserve requirements	Resources certified to provide the respective service	Existing
Corrective Capacity, Up	CCU	Incremental capacity procured and reserved for corrective action after specific corrective transmission contingencies	All 5-minute dispatchable resources, award based on 20-minute ramp capability	Planned[8]
Corrective Capacity, Down	CCD	Decremental capacity procured and reserved for corrective action after specific corrective transmission contingencies	As above	Planned

Additional details describing the market optimization formulation are presented in the Day-Ahead Market Enhancements Formulation.

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

Energy (EN)

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

Reliability Capacity (RCU/RCD)

The proposed reliability capacity product will replace and improve the existing residual unit commitment process as the mechanism to ensure the day-ahead market schedules sufficient capacity to meet the net load forecast.[9] By co-optimizing capacity to meet both bid-in demand (which is currently scheduled in the integrated forward market) and to meet the net load forecast (which is currently scheduled in residual unit commitment process), the proposed day-ahead market design will more efficiently schedule resources to meet both needs.

For example, a resource may need to be committed to meet the net load forecast but not to meet cleared bid-in demand. If that resource is committed, it may also be more efficient to use that resource to meet cleared bid-in demand. The existing integrated forward market and residual unit commitment process cannot do this because they run successively. With a co-optimized formulation, the market will be able to commit and schedule the optimal set of resources to meet both cleared bid-in demand and the net load forecast.

Similar to the existing residual unit commitment process, the market optimization will consider transmission constraints in scheduling reliability capacity. Unlike the existing residual unit commitment process, reliability capacity can also provide downward dispatch capability and/or avoid committing resources if the net load forecast is less than the non-VER physical supply that clear the first market pass A reliability capacity award results in an obligation to provide economic energy bids to the real-time market.

Procuring reliability capacity through the day-ahead market passes, as introduced in this paper, avoids the coupling of energy and capacity products that existed under the approach the CAISO previously proposed and no longer creates two types of day-ahead market energy prices. This ensures that energy prices alone are consistent with bids and offers whereas the settlement of two different products ensured consistency with bids and offers. Resources awarded reliability capacity will have their reliability capacity schedule settled at a reliability capacity locational marginal price. The market will recover the costs of reliability capacity through a cost allocation including allocation to virtual supply and demand.

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[9] As described above, the existing residual unit commitment process currently runs after the current integrated forward market that produces energy schedules.

When the non-VER physical supply clears the first market pass less than the net load forecast, the requirement is for reliability capacity up. When the non-VER physical supply clears the first market pass greater than the net load forecast, the requirement is for reliability capacity down

A resource's sixty-minute ramp capability limits the amount of its reliability capacity awards. In addition, a resource will receive reliability capacity awards only in one direction (i.e. either reliability capacity up or reliability capacity down). Non-VER physical supply will be able to provide reliability capacity up or down, as it represents physical energy and capacity to meet the net load forecast. Variable energy resources will only be able to provide reliability capacity down so that the resource is not required to submit bids consistent with the CAISO's forecast as discussed further in Section 4.6.

Imbalance Reserves (IRU/IRD)

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

Under the proposed enhancements, the day-ahead market will co-optimize and procure imbalance reserves to meet the imbalance reserve requirement relative to the net load forecast.[10] As with both energy and reliability capacity, the market optimization will consider transmission constraints to ensure imbalance reserves are deliverable as described in more detail in Section 4.2. As with energy and reliability capacity, the market will price imbalance reserves at each node reflecting any deliverability constraints.

The day-ahead market will procure imbalance reserves based on a demand curve. The day-ahead market will relax the procurement quantity, i.e. the "requirement," using a demand price curve that reflects the expected cost of foregoing imbalance reserve procurement. The expected cost is the probability that the power balance constraint will be relaxed which results in prices at the bid cap/floor. This results in the market procuring a quantity of imbalance reserves less than the total requirement if imbalance reserves are more expensive than the benefit they would provide. The market would not procure the quantity of imbalance reserves corresponding to a given segment of the demand price curve if the cost of imbalance reserve price for that quantity exceeds the price of the segment of the demand curve.[11]

Imbalance reserves will enable the day-ahead market to compensate resources that provide flexible capacity to meet net load uncertainty and will result in more accurate price signals by taking the out-of-

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[10] The proposal for setting the imbalance reserve requirement is discussed in Section 4.10.

[11] To implement the demand curve, the market will use an imbalance reserve surplus variable to add "supply" that it does not actually procure that it uses to meet its imbalance reserve procurement quantity constraint.

market actions that system operators currently use and incorporating them into the market. Today, system operators may take out-of-market actions, including conforming load and exceptional dispatch 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. These out-of-market actions include increasing the forecast used by the residual unit commitment process and/or the real-time market and manually dispatching resources. System operators have increasingly taken such actions because of the increased variability resulting from increasing amounts of variable energy resources.

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

The day-ahead market will only award imbalance reserves to resources that are dispatchable in the fifteen-minute market. Although the day-ahead market will schedule imbalance reserves hourly, it will procure them based on a resource's fifteen-minute ramp capability. Only non-VER physical resources will be able to provide imbalance reserves up and down, as they represent physical resource capacity to meet the net load imbalances in the real-time market. Variable energy resources will only be able to provide imbalance reserve down so that the resource is not required to submit bids consistent with the CAISO's forecast as discussed further in Section 4.6

Ancillary Services

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

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

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

Corrective Capacity

With the implementation of contingency modeling enhancements, the day-ahead market will also procure corrective capacity to ensure electrical flows will not exceed emergency transmission system

limits immediately after a transmission constraint. Corrective capacity products will compensate generation that is not scheduled for energy because it is positioned so that it can be used to return electrical flows to within normal transmission limits within the required timeframes in the event of a contingency.

4.2. Reliability Capacity and Imbalance Reserves Deliverability

Under the proposed day-ahead market enhancements, the market will consider transmission constraints when awarding reliability capacity and imbalance reserves to ensure they are deliverable if deployed in real-time. The approach is similar to the upward and downward deployment scenarios developed in the flexible ramping product refinements initiative. These deployment scenarios will result in nodal reliability capacity and imbalance reserves to ensure that scheduled day-ahead physical supply can meet the net load forecast and uncertainty up and down, if deployed.

The nodal approach more accurately prices individual resource's reliability capacity and imbalance reserve awards. The awards will result in a locational value of the capacity product similar to energy.

The upward deployment scenario ensures non-VER physical supply + the VER forecast + RCU awards + IRU awards are deliverable to where net load uncertainty can materialize. The downward deployment scenario ensures non-VER physical supply + the VER forecast – RCD awards – IRD awards are deliverable to where the net load uncertainty can materialize. The net load uncertainty that materializes occurs at load nodes and variable energy resource nodes. The VER forecast is used in the deployment scenarios because that is the physical supply the CAISO expects to be available in the real-time market whereas the VER energy schedule is the financial position the scheduling coordinator wished to take in the day-ahead market.

The surplus variable needed to implement the demand curve for imbalance reserves will also be included in the deployment scenarios similar to the flexible ramping product in real-time. The surplus variables will be independent decision variables to relax the imbalance reserve requirements separately for each major load aggregation point (LAP). This may limit the shortfall to an individual LAP while allowing the requirement in other LAPs to be fully met. The surplus variable in the deployment scenarios will account for supply moving from the LAPs to individual load and variable energy resources nodes.

4.3. Accounting for Energy Offer Cost in Upward Capacity Procurement

Suppliers offering upward capacity in the day-ahead market would presumably bid their cost of making the resource available in real-time when bidding to provide upward capacity in the day-ahead market. However, if two resources have the same real-time availability bid, but different energy costs, the optimization cannot differentiate between the two resources. In this situation, the optimal solution would be to award the resource with the lowest underlying energy cost because it would be most cost-effective if needed in real-time.

Currently the day-ahead market does not attempt to distinguish the energy cost of resources when awarding existing reserve products such as spinning reserves. This is not as much of a concern for

contingency reserves because the real-time market only dispatches contingency reserves during relatively infrequent contingency events. The price of energy from a resource is a much greater concern for reliability capacity and imbalance reserves because there is a relatively high likelihood of being dispatched for energy in the real-time market. Thus, this proposal proposes to implement rules that distinguish resources with high energy costs when awarding for upward reliability capacity and imbalance reserves.

The proposal is to have a real-time energy offer cap for resources awarded upward reliability capacity and imbalance reserves.[12] The real-time energy offer cap would be set on an hourly basis before the day-ahead market closes to give scheduling coordinators sufficient time to adjust capacity bids. The upward imbalance reserve requirement is set to meet the CAISO's P97.5 net load forecast. Ideally, the real-time energy offer cap would be set at the marginal price of meeting the P97.5 net load forecast using all available day-ahead energy bids. This would be the least cost solution to meet the same net load level in the real-time market if those resources not scheduled for energy in the day-ahead market received reliability capacity up or imbalance reserve up awards. By setting the real-time offer energy cap at this level, resources with higher energy costs will be less likely to clear for reliability capacity up or imbalance reserve up. However, the offer cap needs to be determined before the day-ahead market closes to allow enough time to adjust and submit capacity bids. One complication is, since the offer cap needs to be set before the day-ahead market closes, the offer cap calculation cannot consider all of the energy bids the day-ahead market will use. Lastly, an additional market pass is not feasible within existing market timelines. The CAISO is determining how to forecast the P97.5 net load price and evaluating the implementation feasibility of this approach to determine the cap.

In addition, if market conditions change materially between the day-ahead timeframe and the real-time market, the CAISO may adjust the real-time energy offer cap. The CAISO would leverage processes developed in the commitment cost and default energy bid enhancement initiative to determine if an adjustment is needed.

Resources with underlying energy costs below the real-time offer cap are not impacted by the real-time offer cap and therefore are not expected to change their capacity or energy bidding behavior. However, resources with underlying energy costs above the real-time energy offer cap will need to increase their upward capacity bids in order to be sufficiently compensated for being required to bid below cost in real-time. Thus, the real-time energy offer cap provides an incentive for high-cost resources to increase their day-ahead capacity offers, which decreases the chances those resources will clear before lower energy cost resources to provide upward capacity. To summarize:

- If the marginal energy cost of a resource is below the cap, they will bid their real-time availability cost.
- If the marginal energy cost of a resource is above the cap, they will bid their real-time availability cost plus compensation for bidding energy below cost in real-time.

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[12] There is no plan at this time to design a similar requirement for downward reliability capacity or imbalance reserves.

- If marginal energy cost of a resource is above the cap and the availability cost plus the compensation for bidding energy below cost in real-time exceeds the $247 capacity offer cap, then the resource will not bid for the upward capacity products.

For example, assume a real-time energy offer cap of $150/MWh and assume resources with the following marginal energy costs: resource A $25/MWh, resource B $100/MWh, resource C $240/MWh, and resource D $950/MWh. Ignoring costs of being available for real-time dispatch, each resource would seek to increase their upward capacity bid price as follows: resource A $0/MWh, resource B $0/MWh, resource C $90/MWh, and resource D $800/MWh. The resources with marginal energy costs above the $150/MWh bid cap would only be willing to bid energy below their marginal cost in real-time if they were sufficiently compensated through their reliability capacity up or imbalance reserve up award. Since resource D is above the capacity offer cap it would not provide an upward capacity bid. This achieves the objective of differentiating the capacity offers given the underlying energy cost of the resource. The real-time energy offer cap does not change the incentive for resources A or B to bid their marginal cost in the real-time market because they would still earn profits when they were dispatched and the price is above their marginal costs, even if real-time prices did not reach the real-time energy offer cap. In addition, all resources are still subject to market power mitigation rules even if bidding below the real-time offer cap.

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

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

The purpose of the real-time must offer obligation is to provide economic bids to the real-time market. Economic bids enable the real-time market to re-dispatch resources to meet real-time system conditions and imbalances. Real-time self-schedules do not provide the real-time market with the ability to re-dispatch the resource unless a power balance constraint is relaxed or congestion requires the un-economic curtailment of self-schedules.

The minimum real-time bidding obligations are illustrated in Figure 6. 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 that there are sufficient economic offers to allow the real-time market to dispatch the resource above its day-ahead energy schedule.

Any portion of this resource's day-ahead energy schedule below the imbalance reserve 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 reserve down and reliability capacity down awards. This ensures that there are sufficient economic offers to allow the real-time market to dispatch the resource below its day-ahead energy schedule.

A resource 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 6: Real-time bidding obligations
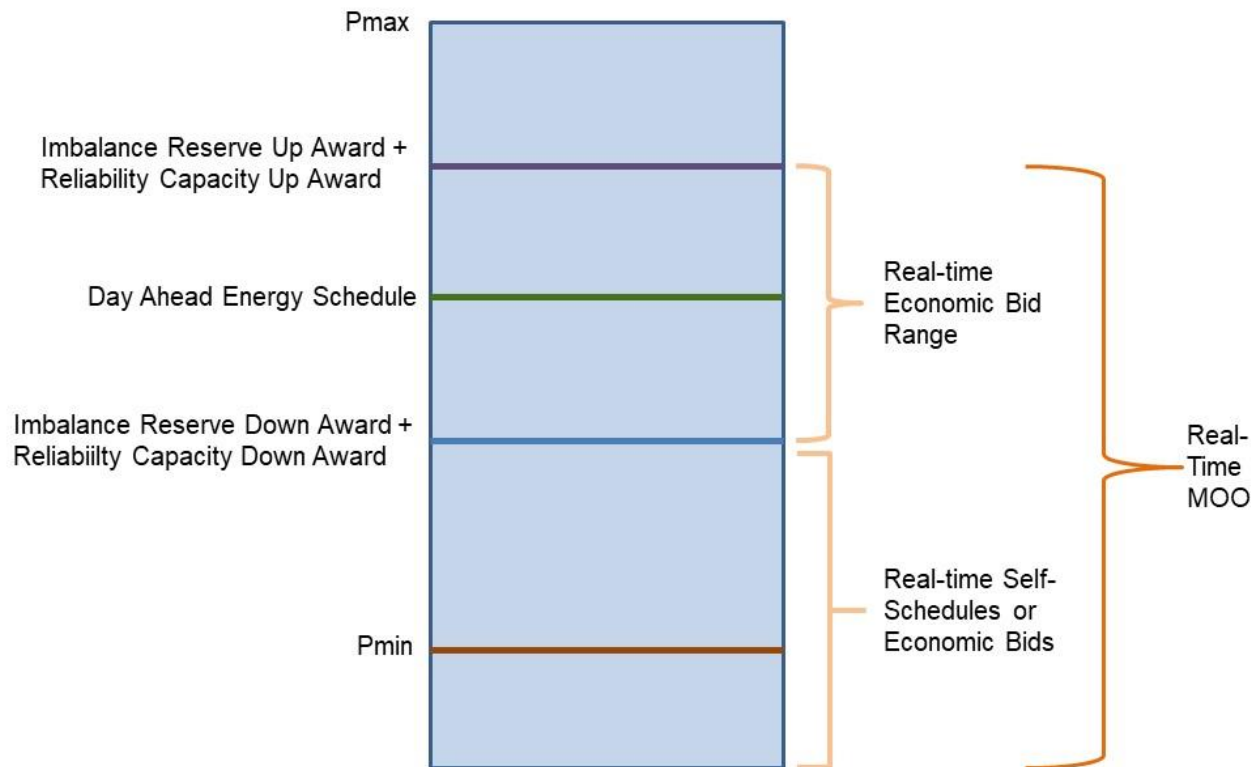
4.5. Resource Adequacy Day-Ahead Must Offer Obligations

The following summarizes the resource adequacy must offer obligations for the day-ahead market. Additional detailed rules are being developed in the Resource Adequacy Enhancements initiative.[13]

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

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

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[13] CAISO Resource Adequacy Enhancements initiative. http://www.caiso.com/StakeholderProcesses/Resource-adequacy-enhancements

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

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

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

4.6. Variable Energy Resources

The CAISO previously proposed that all variable energy resources must submit day-ahead energy offers with the upper economic limit determined by the CAISO forecast for the resource. In the event the resource desired to schedule day-ahead energy inconsistent with the CAISO forecast, the resource could utilize virtual supply and virtual demand bids at their location. In comments, LSA questioned the need for such complexity.

The CAISO proposes to make no changes to how variable energy resources can bid into the day-ahead market. However, variable energy resources would be ineligible to provide reliability capacity up and imbalance reserve up. Variable energy resource would still be eligible to bid and be awarded for reliability capacity down and imbalance reserves down. In addition, variable energy resources will be eligible to provide all ancillary services they are certified to provide.

The restriction on awarding the upward capacity products addresses the concern by the CAISO of awarding energy and the upward capacity products above the CAISO forecast. This would undermine, from the CAISO operations perspective, the reliability of the market and could create the need for out of market actions we are seeking to minimize. For example, assume the CAISO forecast is 100 MW and the energy offer from the resource allows a schedule at 110 MW energy, 10 MW imbalance reserve up, and 10 MW reliability capacity down. The market would be counting the resource as physically capable of providing 130 MW of energy and capacity, but from a reliability perspective, the CAISO can only rely on the resource for 100 MW and would need to take out of market actions to procure 30 MW of capacity from another physical resource. The restriction from awarding the upward capacity products does not change the ability of the resource to be cleared at a higher level in the real-time market based upon the real-time forecast.

A similar concern does not exist for the downward capacity products because the downward capacity awards must be less than or equal to the energy schedule. A reduction from the day-ahead energy schedules is providing downward capability and its downward capability cannot exceed the full energy schedule. Since variable energy resource's real-time energy offer curves do use the CAISO forecast as the upper economic limit, having variable energy resources establish a maximum energy level in the real-time market that could be self-scheduled provides a valuable service to manage over supply in the real-time market. For example, assume a resource had an energy schedule of 50 MW and an imbalance

reserve down awards of 30 MW, the resource could not submit a self-schedule exceeding 30 MW. If the real-time forecast were 65 MW, there would be 35 MW dispatch range. If the real-time forecast were 40 MW, there would be a 10 MW dispatch range.

If in the future it was determined that variable energy resources are needed to provide the upward capacity products, the variable energy resources would be required to provide day-ahead energy bid curves with the upper economic limit established by the CAISO forecast. In addition, the calculation of reliability capacity in the market passes would need to be modified to use the energy schedule rather than the CAISO forecast and the deployment scenarios would likewise need to be modified for variable energy resources to provide the upward capacity product.

4.7. Day-Ahead Market Eligibility and Bidding Rules

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

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

4.8. Settlement Rules

The following section explains the proposed settlement rules for the new day-ahead market design. As the market formulation is finalized the CAISO will evaluate if additional changes can improve the cost allocation of reliability capacity and imbalance reserves discussed below.

Day-Ahead Payments and Charges

The CAISO proposes the following day-ahead charges and payments for load, virtual supply, virtual demand, physical supply, imports, and exports. These resources will be settled for differences between the day-ahead energy schedule and real-time market energy schedule.

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

The CAISO proposes the following day-ahead payments for eligible resources that are awarded imbalance reserve or reliability capacity awards.

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

Reliability Capacity Cost Allocation

Reliability capacity will have a direct settlement to generation, imports, and exports. The uplift cost for reliability capacity will be allocated as follows:

- RCU Tier 1 cost is allocated to net virtual supply, under-scheduled load and over-scheduled variable energy resources.
- RCU Tier 2 cost will be allocated to metered demand.
- RCD Tier 1 cost allocated to net virtual demand, over-scheduled load and under-scheduled variable energy resources
- RCD Tier 2 cost will be allocated to metered demand.

Imbalance Reserve Cost Allocation

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

- IRU Tier 1 cost will be allocated to net negative demand deviation.
- IRU Tier 2 cost will be allocated to metered demand.
- IRD Tier 1 cost will be allocated to net positive demand deviation.
- IRD Tier 2 cost will be allocated to metered demand.

The net demand deviation is calculated for each scheduling coordinator. The calculation compares the meter less the day-ahead energy schedule. In the event, the scheduling coordinator has multiple load resources the difference can net across the load resources. A net negative demand means the scheduling coordinator under scheduled load. A net positive demand means the scheduling coordinator over scheduled load.

Bid Cost Recovery

The revenue and bid costs from imbalance reserve awards and reliability capacity awards will be included in the calculation of day-ahead bid cost recovery.

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

Application of Grid Management Charge

The market services charge of the grid management charge covers the cost of bidding and clearing the market. Currently, the market services charge is applied to ancillary services awards in the day-ahead

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

4.9.   Market Power Mitigation for Reliability Capacity and Imbalance Reserves

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

The CAISO markets employ a dynamic local market power mitigation process that identifies when the local area is not competitive, and mitigates local suppliers' offers to the greater of a pre-established estimate of marginal costs or the broader system competitive energy price. The dynamic local market power mitigation process tests transmission constraints for competitiveness by comparing the demand for counter-flow to a constraint to the available supply of counter-flow. The test employs a "residual supply index," which is the ratio of the supply of counter-flow to the demand for counter-flow. The test assumes some portion of the supply for counter-flow from potentially pivotal suppliers is withheld. A transmission constraint is deemed competitive if the ratio of non-pivotal supply to demand is greater than or equal to one and uncompetitive if less than one. Currently, the test treats the three highest ranked suppliers, in terms of capacity that can be withheld, as potentially pivotal.

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

The CAISO proposes no changes to market power mitigation for energy offers. For reliability capacity and imbalance reserve offers, the CAISO will allow offers up to $247.[14] When uncompetitive conditions arise, the proposal is to mitigate capacity bids to the maximum of either $30 or $30 plus the resource's default energy bid minus the real-time energy offer cap. $30 is greater than the 90th percentile historical spinning reserve price, which is assumed a competitive capacity price that reflects the cost of being available in the real-time market (see Figure 7 and Figure 8). However, as explained in Section 4.3, resources bidding for reliability capacity up and imbalance reserve up that have energy costs higher than the hourly real-time energy offer cap are expected to incorporate that difference into their capacity bid. If all capacity bids were mitigated to $30, that may not be enough to cover resources who need to increase their capacity bids to compensate for the real-time energy offer cap requirement. For those

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[14] If there is a power balance constrain violation, CAISO will relax the flexible ramping up product before relaxing corrective capacity and upward ancillary services at this price.

resources, their bids would be mitigated to $30 plus the resource's default energy bid minus the real-time energy offer cap. The idea is that the default energy bid minus the real-time energy offer cap reflects the competitive mark-up on the capacity bid. For resources with energy costs (represented through default energy bids) below the cap, there is no mark-up needed because the resource's energy only its real-time availability costs need to be mitigated to the competitive availability cost. The real-time energy offer cap is not applicable to imbalance reserve down and reliability capacity down. In the event of mitigation of the downward capacity products, only the competitive capacity price of $30 will apply.

Figure 7 and Figure 8show the distribution of spinning reserve prices by month and by hour respectively. These data are based on day-ahead market prices from Jan 1, 2018 through March 31, 2020. The end of the lines represent the maximum and minimum prices, and the boundaries of the boxes represent the 10th and 90th percentiles.

Figure 7: Distribution of spinning reserve prices by month
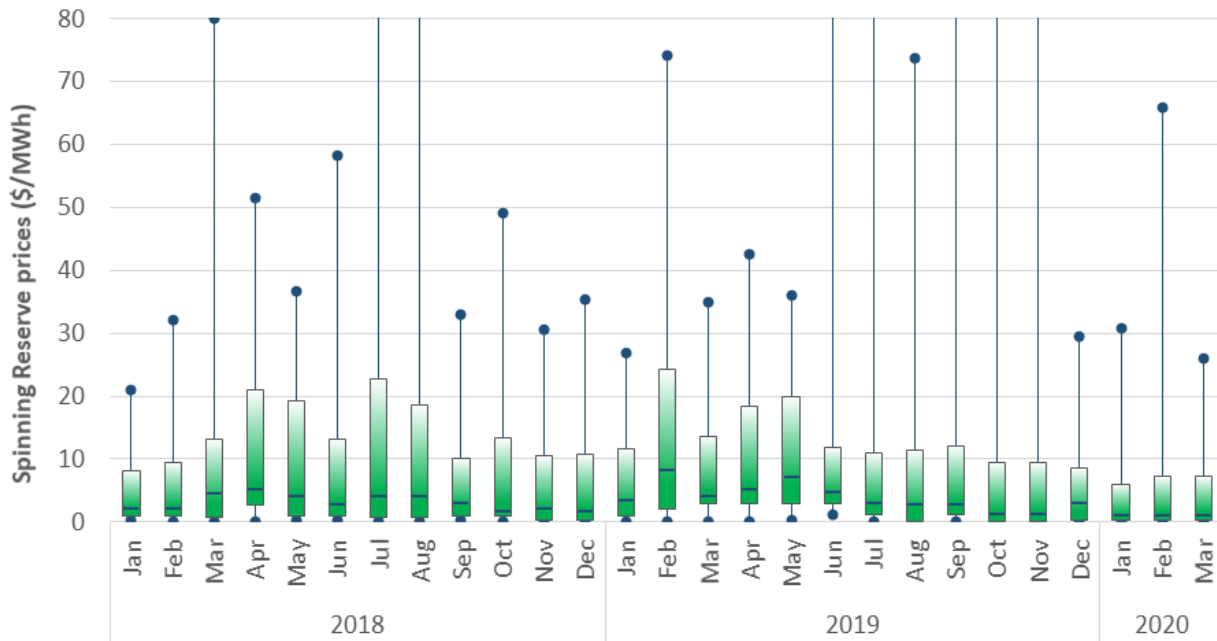
Source: CAISO Analysis

Figure 8: Distribution of spinning reserve prices by hour
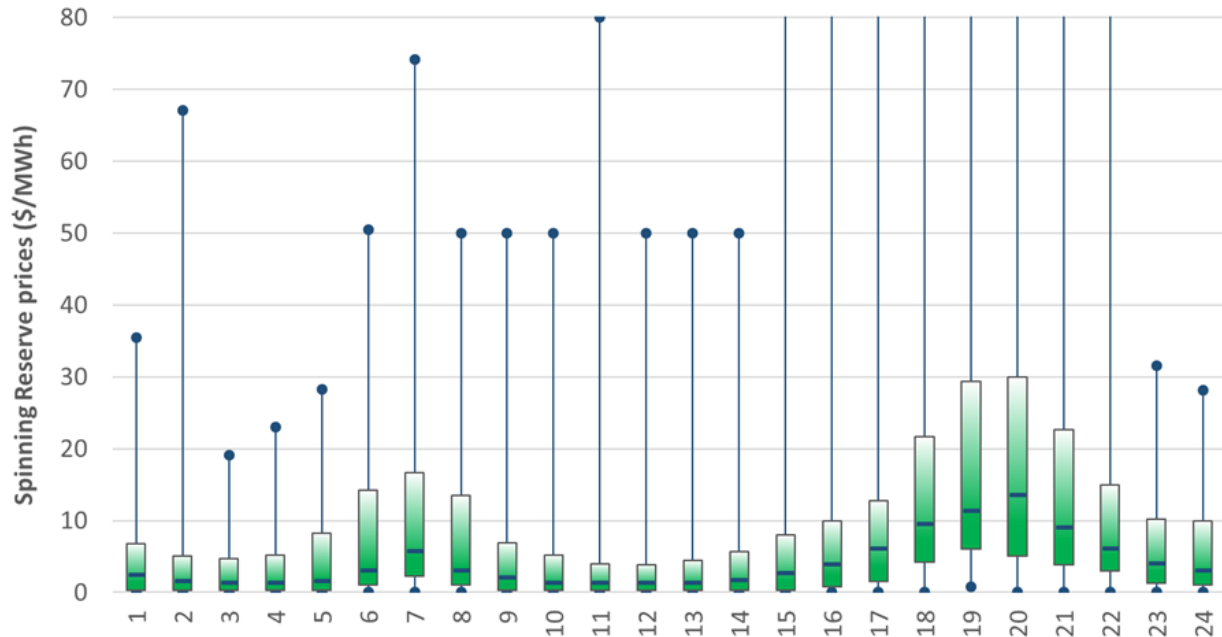
Source: CAISO Analysis

4.10.   Imbalance Reserve Requirement

This section provides a high-level overview of the method to set the imbalance reserve requirement in the day-ahead market. This method intends to align with the approach proposed for the flexible ramping product requirement.[15]

Historical data will be used to identify the net load forecast error between the day-ahead market and the fifteen-minute market. These historical net load forecast errors will then be used to determine the imbalance reserve up and down requirement for each hour of each day using statistical regression

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

The type of regression model the CAISO proposes to use to determine the imbalance reserve requirement is a quantile regression. A quantile regression estimates quantiles of a dependent variable conditional on the values of a set of independent variables. A quantile regression is preferred to standard linear regression in this case because the imbalance reserve requirement is based on relatively

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

extreme high and low (i.e., 2.5 and 97.5 percentile) observations of net load imbalances, as opposed to the average net load imbalance. The regressors (independent variables) includes the day-ahead load, solar, and wind forecasts, as well as the operating hour and month.

Rather than regress these independent variables on net load forecast error directly, the CAISO proposes a blend of estimators to create a new input variable that accomplishes the following:

1. Better captures the variance in forecast error for each individual component of net load (load, wind, solar) when setting the requirement.
2. Adjusts the estimate of the quantile regression to account for the fact that estimating the 97.5/2.5 percentile of load, wind, and solar forecast error individually and combining them will not correspond to the 97.5/2.5 percentile of net load.

4.11.   Treatment of MSSs, ETCs, and TORs

Metered Subsystems

Currently, the meter subsystems (MSS) operators must make an election or choice on four (4) issues that govern the manner in which the MSS participates in the markets. The MSS operator must choose either: (i) net settlements or gross settlements, (ii) to load follow or not load follow with its generating resources, (iii) to have its load participate in the RUC procurement process or not have its load participate in the RUC procurement process; and (iv) whether or not to charge the CAISO for their emissions costs.

With the day-ahead market enhancement to co-optimize a resource capacity with its commitment and energy schedules, MSS operators must make an election or choice on three issues that will govern the manner in which the MSS participates in the markets. The MSS operator must choose either: (i) net settlements or gross settlements; (ii) to load follow or not load follow with its' designated generating resources; and (iii) whether or not to charge the CAISO for their emissions costs.

MSS operator may: (i) bid to supply energy to, or purchase energy from the markets, (ii) bid to provide available capacity for imbalance reserve up/down to meet uncertainty requirements, (iii) bid to provide available capacity for reliability capacity up/down to meet net load forecast, and (iv) bid or make a submission to self-provide an ancillary service from a system unit or from individual generating units, participating loads or proxy demand response resources within the MSS. An MSS operator also may purchase ancillary services from CAISO or third parties to meet its ancillary service obligations under the CAISO tariff.

The day-ahead market enhancement initiative is proposing to maintain the current settlement treatment of MSS operator day-ahead energy schedules who have elected gross settlement or net settlement. The day-ahead market enhancement initiative is proposing to settle MSS resources that have received imbalance reserve or reliability capacity awards in a similar manner as non-MSS resources, regardless of MSS operator's selection of net or gross settlement. Imbalance reserve award up/down will settle at the relevant LMP for imbalance reserve. Reliability capacity awards will settle at the relevant LMP for reliability capacity. For both reliability capacity tier 1 and reliability capacity tier 2

cost allocations, MSS Operators will settle in a similar manner as non-MSS resources, regardless of their net versus gross selection. For both imbalance reserve tier 1 and imbalance reserve tier 2 cost allocations, MSS Operators will settle in a similar manner as non-MSS resources, regardless of their net versus gross selection.

Existing Transmission Contracts and Transmission Ownership Rights

The day-ahead market enhancement is proposing to maintain the current energy settlement for existing transmission contract rights (ETC) and transmission ownership rights (TOR). Day-ahead energy schedules associated with the ETC-self-schedule or TOR self-schedule will settle at the relevant IFM LMP. In additions, the day-ahead market enhancement is proposing to maintain the settlement of IFM congestion credit for the valid and balanced portion of ETC or TOR self-schedule and relative eligible point of receipt of delivery.

Reliability capacity will ensure sufficient physical resources are committed to effectively meet the net load forecast with adjustments for known differences between what cleared the IFM 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 day-ahead market enhancement initiative is proposing to exclude the ETC and TOR self-schedules from reliability capacity tier-1 and imbalance reserve tier-2 allocations up to the valid and balance portion of ETC and TORs self-schedules. In contrast, the ETC and TOR self-schedules is subject to reliability capacity tier-1 and imbalance reserve tier-2 allocations for that quantity above the valid and balanced portion of the ETC or TORs 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/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 balance portion of ETC and TORs self-schedules. In contrast, the ETC and TOR self-schedules is subject to imbalance reserve tier-1 and imbalance reserve tier-2 allocations for that quantity above the valid and balanced portion of the ETC or TORs self-schedules.

5. Alignment between RA Enhancements, 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 ultimately market solutions. The goal of our effort is to ensure an efficient and robust design that bridges the various election/bidding and program/market timelines.

Error! Reference source not found. Figure 9 is a flowchart depicting the correlation between RA Enhancements, DAME, and EDAM.

Figure 9: Correlation between DAME, EDAM and RA Enhancements
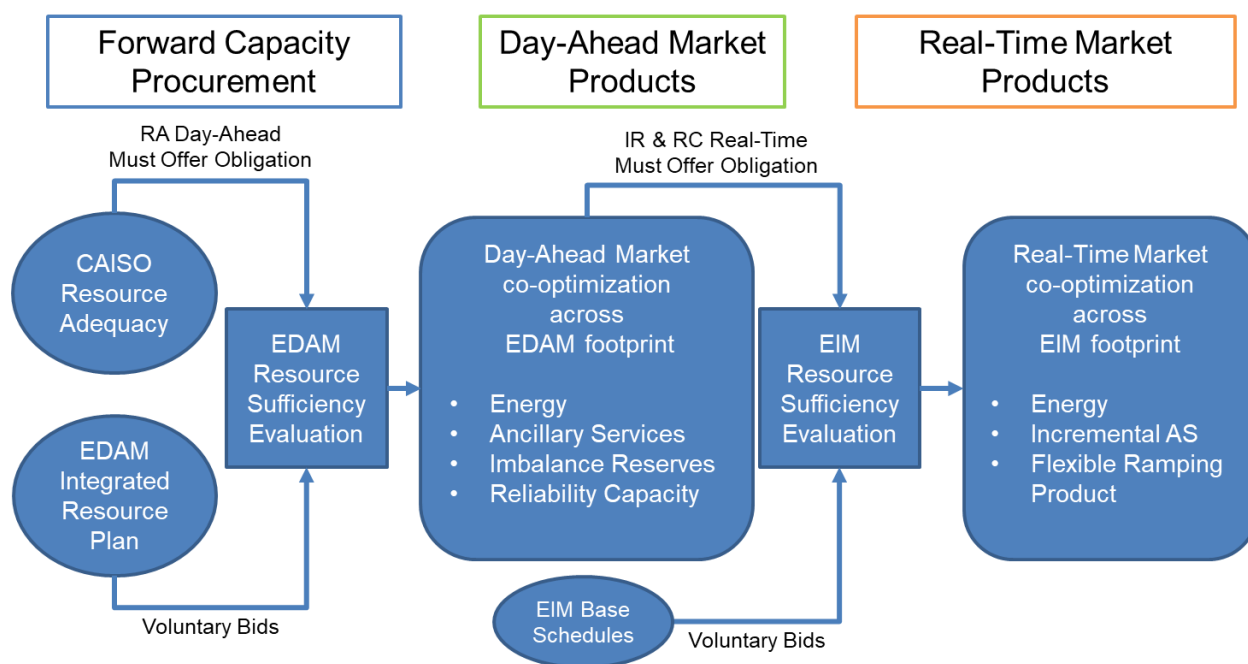
The flowchart can be summarized as follows:

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

2. The purpose of the CAISO's day-ahead market today is to co-optimize energy and ancillary services to meet daily load and reliability requirements. Once the day-ahead market enhancements have been implemented, this co-optimization will also include the new day-ahead market products called reliability capacity and imbalance reserves. The day-ahead market will result in must-offer obligations and bids into the real-time market. In order to participate in the real-time, a balancing authority area must pass the EIM real-time resource sufficiency test.

3. The real-time market will co-optimize energy, incremental ancillary serves, and real-time flexible ramping product across the entire EIM footprint.[16]

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

The CAISO acknowledges this new design differs from existing functionality. Currently, resource adequacy provisions create a must offer obligation in both the day-ahead and real-time market, depending on the characteristics of the resource. Under the redesign, the CAISO resource adequacy provisions will still impose a day-ahead must-offer obligation. The nature of the real-time must-offer obligation, however, will change. The real-time obligation currently is based on a resource's start-up time and its status as a resource adequacy resource. Going forward, the real-time obligation for all resources, including resource adequacy resources, will be based on imbalance reserve and reliability capacity schedules. Real-time bidding obligations are described in Section 4.4.

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

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

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

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

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

6. EIM Governing Body Role

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

Under the decisional classification rules in the Guidance Document and Charter for EIM Governance, the EIM Governing Body would have no decisional role concerning the market rule changes proposed in this

initiative. Because those changes involve the rules of the day-ahead market only, they fall outside the ISO Board of Governors' delegation of authority to the EIM Governing Body.

However, the proposed changes to day-ahead market rules, which would change the structure of the day-ahead market and introduce a day-ahead imbalance reserve product, are intended to lay the foundation for a future initiative that would give EIM Entities the option of participating in the day-ahead market. Given the unique foundational nature of the initiative, Management believes it would be appropriate for the EIM Governing Body to have an advisory role on all aspects of this initiative. This would be consistent with the intentions of the EIM Transitional Committee, which expected that EIM Governance would have a role in "decisions … that would … [a]llow options to expand the functionality of the market to provide additional services …." Final Proposal, August 19, 2015, p.14.[17]

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

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

7. Stakeholder Engagement, Implementation Plan & Next Steps

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

Additionally, the CAISO's new process to develop technology requirements and draft tariff language. Historically the development of these items occurred *after* the CAISO achieved board approval of the proposed policy. This process has proven to be problematic if an implementation detail resulted in needing to change the already-board-approved policy. With the day-ahead market enhancements initiative, the CAISO proposes to develop technology requirements and draft language *before* taking the final proposal to the Board of Governors and EIM Governing Body. This process change is reflected in **Table *2*** below.

Also, note that the day-ahead market enhancements are planned for implementation in Fall 2022. Previously, the implementation schedule was planned for Fall 2021. The flexible ramping product refinements, which introduces nodal deliverability in the real-time market for the flexible ramping product, will be implemented in Fall 2021. This will allow for one year of operations experience with nodal deliverability of capacity products before implementing nodal deliverability of reliability capacity and imbalance reserves in the day-ahead market.

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

Table 2: Stakeholder engagement and implementation development plan

Date	Milestone
Revised Straw Proposal	
Paper Posted	June 8, 2020
Stakeholder Meeting	June 15 and 17, 2020
Comments Due	July 6, 2020
Second Revised Straw Proposal	
Paper Posted - *tentative*	August 10, 2020
Stakeholder Meeting - *tentative*	August 17 and 18, 2020
Comments Due - *tentative*	Aug 31, 2020
Draft Final Proposal	
Paper Posted - tentative	Oct 27, 2020
Stakeholder Meeting - *tentative*	Nov 3, 2020
Comments Due - *tentative*	Nov 17, 2020
Start Tariff Stakeholder Process	Early Q1 2021
Start Business Requirement Specification (BRS) Development	Early Q1 2021
Policy Final Proposal	Late Q1 2021
EIM Governing Body & CAISO Board of Governors	Early Q2 2021
Implementation	Fall 2022

The CAISO will discuss this straw proposal with stakeholders during a stakeholder calls on June 15 and 17. Stakeholders are asked to submit written comments by July 6, 2020 to initiativecomments@caiso.com. A comment template will be posted on the CAISO's initiative webpage, located here: http://www.caiso.com/StakeholderProcesses/Day-ahead-market-enhancements.

Appendices

Appendix A: Eligibility Table

	EN	RCU	RCD	EN needed for RCU/D award	IRU	IRD	EN needed for IRU award	EN needed for IRD award
Non-Participating Load	Yes	Not Eligible	Not Eligible	N/A	Not Eligible	Not Eligible	N/A	N/A
Virtual Supply	Yes	Not Eligible	Not Eligible	N/A	Not Eligible	Not Eligible	N/A	N/A
Virtual Demand	Yes	Not Eligible	Not Eligible	N/A	Not Eligible	Not Eligible	N/A	N/A
Hourly Block Import	Yes	Eligible	Eligible	None	Not Eligible	Not Eligible	N/A	N/A
Hourly Block Export	Yes	Eligible	Eligible	None	Not Eligible	Not Eligible	N/A	N/A
15-Min Import	Yes	Eligible	Eligible	None	Eligible	Eligible	None	EN >= IRD
15-Min Export	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= IRU	None
Dynamic Import	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= Pmin EN <= Pmax - IRU	EN <= Pmax EN >= Pmin + IRD
Long-Start Generator	Yes	Eligible	Eligible	EN >= Pmin	Eligible	Eligible	EN >= Pmin EN <= Pmax - IRU	EN <= Pmax EN >= Pmin + IRD
Short-Start Generator	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= Pmin EN <= Pmax - IRU	EN <= Pmax EN >= Pmin + IRD
Participating Load w/ 15-Min dispatch capability	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= Pmin EN <= Pmax - IRU	EN <= Pmax EN >= Pmin + IRD
Participating Load w/ Hourly dispatch capability	Yes	Eligible	Eligible	None	Not Eligible	Not Eligible	N/A	N/A
Eligible Intermittent	Yes	Not Eligible	Eligible	None	Eligible	Not Eligible	EN >= Pmin	EN <= ISO Forecast

	EN	RCU	RCD	EN needed for RCU/D award	IRU	IRD	EN needed for IRU award	EN needed for IRD award
Resources (Wind/Solar)	Upper economic limit set at ISO forecast						EN <= ISO Forecast – IRU	EN >= Pmin + IRD
Non-Generator Resources (Storage) Discharging[18]	Yes	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Non-Generator Resources (Storage) Charging	Yes	TBD	TBD	TBD	TBD	TBD	TBD	TBD
60-Minute Proxy Demand Resource	Yes	Eligible	Eligible	None	Not Eligible	Not Eligible	N/A	N/A
15-Minute Proxy Demand Resource	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= Pmin EN <= Pmax – IRU	EN <= Pmax EN >= Pmin + IRD
5-Minute Proxy Demand Resource	Yes	Eligible	Eligible	None	Eligible	Eligible	EN >= Pmin EN <= Pmax – IRU	EN <= Pmax EN >= Pmin + IRD
Reliability Demand Response Resource	Yes	Eligible	Eligible	None	Not Eligible	Not Eligible	N/A	N/A

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

Appendix B: Updated DAME Formulation

This short technical discusion summarizes the mathematical formulation for the Day-Ahead Market Enhancements (DAME) initiative. Black symbols are constants, green symbols are energy variables, blue symbols are upward uncertainty capacity variables, red symbols are downward uncertainty capacity variables, and purple symbols are upward/downward reliability capacity variables.

The proposed solution for DAME is obtained with three passes:

1) Market Power Mitigation (MPM) pass.

2) First Market pass.

3) Last Market pass.

The first two passes have the same mathematical formulation, whereas the last pass employs a simplification to remove some pricing interactions between energy and capacity products resulting in simpler price formation and settlement.

In the updated DAME formulation, flexible ramping up (FRU) is synonymous with imbalance reserve up (IRU) and flexible ramping down (FRD) is synonymous with imbalance reserve down (IRD).

Notation

The following notation is used in this short technical paper:

i	Resource/node index.
m	Network constraint index.
r	Load Aggregation Point (LAP) index.
t	Time period index (0 for initial condition).
(u)	Superscript denoting Flexible Ramp Up deployment scenario values.
(d)	Superscript denoting Flexible Ramp Down deployment scenario values.
T	The number of time periods in the Trading Day (23-25), considering the short and long days due to daylight savings changes.
$\in$	Member of...
$\notin$	Not member of...
Δ	Denotes incremental values from the previous iteration.
$\sim$	Accent denoting initial values from an AC power flow solution.
$\frown$	Accent denoting values from the solution of the previous pass.
$\forall$	For all...
$\wedge$	Logical and...
VER	Set of Variable Energy Resources (VER).
$EN_{i,t}$	Day-Ahead Energy schedule of Resource i in time period t; positive for supply (generation and imports) and negative for demand (demand response and exports).
$VS_{i,t}$	Day-Ahead Energy schedule of Virtual Supply Resource i in time period t.

$VD_{i,t}$ Day-Ahead Energy schedule of Virtual Demand Resource i in time period t.

$L_{i,t}$ Day-Ahead Energy schedule of Non-Participating Load Resource i in time period t.

D_t Demand forecast in time period t.

ND_t Net demand forecast in time period t.

$RCU_{i,t}$ Reliability Capacity Up award of Resource i in time period t.

$RCD_{i,t}$ Reliability Capacity Down award of Resource i in time period t.

$FRU_{i,t}$ Flexible Ramp Up award of Resource i for potential delivery in time period t.

$FRD_{i,t}$ Flexible Ramp Down award of Resource i for potential delivery in time period t.

$FRUS_{r,t}$ Flexible Ramp Up surplus (elastic demand) in LAP r in time period t.

$FRDS_{r,t}$ Flexible Ramp Down surplus (elastic demand) in LAP r in time period t.

$LPF_{i,t}$ Loss penalty factor for node i in time period t.

$SF_{i,m,t}$ Shift factor for the energy injection schedule of Resource i on network constraint m in time period t.

$SF_{r,m,t}$ Aggregate shift factor for energy injection at LAP r on network constraint m in time period t.

$F_{m,t}$ Active power flow or scheduled flow due to energy schedules on network constraint m in time period t.

$LFL_{m,t}$ Lower active power flow or scheduling limit (non-positive) on network constraint m in time period t.

$UFL_{m,t}$ Upper active power flow or scheduling limit on network constraint m in time period t.

MPM and First Market Pass

The power balance constraint (PBC) is as follows:

$$\sum_i \left(EN_{i,t} + VS_{i,t} - VD_{i,t} - L_{i,t} \right) - Loss_t = 0, t = 1,2,\dots,T$$

The transmission losses are linearized at an AC power flow (ACPF) solution between iterations. The linearized PBC is as follows:

$$\sum_i \frac{\Delta EN_{i,t} + \Delta VS_{i,t} - \Delta VD_{i,t} - \Delta L_{i,t}}{LPF_{i,t}} = 0, t = 1,2,\dots,T$$

The RCU/RCD procurement constraint is as follows:

$$\sum_i EN_{i,t} + \sum_i RCU_{i,t} - \sum_i RCD_{i,t} = D_t \Longrightarrow \sum_{i \notin VER} EN_{i,t} + \sum_{i \notin VER} RCU_{i,t} - \sum_i RCD_{i,t} = ND_t, t = 1,2,\dots,T$$

The Net Demand (*ND*) is the demand forecast minus the VER forecast. VER are considered fixed at their VER forecast in the RCU/RCD procurement constraint. Therefore, VER are not eligible for RCU awards, but they are eligible for RCD awards.

The FRU/FRD procurement constraints are as follows:

$$\left.\begin{array}{l} \sum_i RCD_{i,t} + \sum_{i \notin VER} FRU_{i,t} + \sum_r FRUS_{r,t} \geq FRUR_t \\ \sum_{i \notin VER} RCU_{i,t} + \sum_i FRD_{i,t} + \sum_r FRDS_{r,t} \geq FRDR_t \end{array}\right\}, t = 1,2,\dots,T$$

The FRU/FRD requirements (*FRUR/FRDR*) for a given hour are calculated as the extreme historical difference between the highest/lowest net demand forecast over the four 15min intervals of that hour in the FMM and the hourly net demand forecast in the DAME, within a specified confidence interval (95%). VER are considered fixed at their VER forecast in the FRU/FRD procurement constraints. Therefore, VER are not eligible for FRU awards, but they are eligible for FRD awards. RCU and RCD are 60min capacity products constrained along with energy schedules and ancillary services awards by 60min ramp capability constraints. FRU and FRD are 15min capacity products constrained along with energy schedules by 15min ramp capability constraints. The FRU/FRD procurement constraints reflect the fact that keeping RCD reserved (not deploying it) can meet FRU requirements, whereas keeping RCU reserved can meet FRD requirements. The FRU/FRD surplus (*FRUS/FRDS*) is the demand elasticity at the relevant expected cost of not procuring FRU/FRD. Multiple independent surplus controls are used for non-overlapping regions (*r*) such as load aggregation points (LAPs).

The transmission constraints for the base scenario of balancing supply with bid-in demand and for the FRU/FRD deployment scenarios are linearized at an ACPF solution between iterations as follows:

$$\left.\begin{array}{l} \widetilde{LFL}_{m,t} \leq \tilde{F}_{m,t} + \sum_i \left(\Delta EN_{i,t} + \Delta VS_{i,t} - \Delta VD_{i,t} - \Delta L_{i,t}\right) SF_{i,m,t} \leq \widetilde{UFL}_{m,t} \\[2mm] \widetilde{LFL}^{(u)}_{m,t} \leq \tilde{F}^{(u)}_{m,t} + \sum_{i \notin VER} \left(\Delta EN_{i,t} + \Delta RCU_{i,t} + \Delta FRU_{i,t}\right) SF_{i,m,t} + \sum_r \Delta FRUS_{r,t}\, SF_{r,m,t} \leq \widetilde{UFL}^{(u)}_{m,t} \\[2mm] \widetilde{LFL}^{(d)}_{m,t} \leq \tilde{F}^{(d)}_{m,t} + \sum_{i \notin VER} \Delta EN_{i,t}\, SF_{i,m,t} - \sum_i \left(\Delta RCD_{i,t} + \Delta FRD_{i,t}\right) SF_{i,m,t} - \sum_r \Delta FRDS_{r,t}\, SF_{r,m,t} \leq \widetilde{UFL}^{(d)}_{m,t} \end{array}\right\}, \forall m$$

$\wedge\ t = 1,2,\dots,T$

Three AC power flows per hour are needed: one for the base scenario and one for each of the FRU/FRD deployment scenarios. $\tilde{F}$, $\tilde{F}^{(u)}$, and $\tilde{F}^{(d)}$ are the active power flows from the previous ACPF solutions obtained with the control variables at the previous iteration. Δ indicates incremental change from the previous iteration. The transmission constraint upper/lower active power flow limits ($\widetilde{UFL}$ and $\widetilde{LFL}$) are adjusted in each iteration to convert the respective MVA limits to MW limits accounting for reactive power flows at the previous ACPF solution. The linear lossless shift factors (*SF*) are calculated with reference the distributed load in the market footprint.

In the FRU deployment scenarios, the VER are considered fixed at their VER forecast and the RCU and FRU awards are fully deployed while the RCD and FRD awards are kept in reserve and the demand forecast is increased by the FRU requirements. Similarly, in the FRD deployment scenarios, the VER are considered fixed at their VER forecast and the RCD and FRD awards are fully deployed while the RCU and FRU awards are kept in reserve and the demand forecast is decreased by the FRD requirements. The distribution of the FRU/FRD requirements in the ACPF solution is divided among load, solar, and wind resources using allocation factors derived from historical data that reflect the relative contributions of these resource classes to the net demand forecast uncertainty. More specifically, the FRU requirement component for load is distributed in the FRU deployment scenario as positive demand, whereas the FRD requirement component for load is distributed in the FRD deployment scenario as negative demand. This requirement component is distributed to load nodes with the same distribution factors as the distribution of the demand forecast. The FRU requirement components for solar and wind are distributed in the FRU deployment scenario as negative demand, whereas the FRD requirement components for solar and wind are distributed in the FRD deployment scenario as positive demand. These requirement components are distributed to solar and wind VER pro rata on the available VER maximum capacity. The effect of the VER forecast and the FRU/FRD requirement ($FRUR/FRDR$) distribution on transmission power flows is captured in the ACPF solutions for the FRU/FRD deployment scenarios ($\tilde{F}^{(u)}$, and $\tilde{F}^{(d)}$).

The regional FRU/FRD surplus (*FRUS*/*FRDS*) is distributed to the load nodes in the respective region (LAP) with the same distribution factors as the demand forecast, but normalized for the region. The effect of the FRU/FRD surplus (*FRUS*/*FRDS*) distribution on transmission power flows from the previous iteration is captured in the ACPF solutions for the FRU/FRD deployment scenarios ($\tilde{F}^{(u)}$, and $\tilde{F}^{(d)}$), whereas incremental power flow changes are added using aggregate shift factors (*SF*).

After the MPM solution is obtained, each binding transmission constraint will be evaluated by the Dynamic Competitiveness Path Assessment (DCPA) methodology to determine if it is competitive or not. Resources with net positive marginal congestion price contribution from uncompetitive binding constraints will have their bids above the respective Competitive LMP mitigated to the lower of their submitted bid or their Default Energy Bid (DEB). The Competitive LMP excludes contributions from uncompetitive binding constraints.

After the MPM pass, the First Market pass will obtain a solution using the mitigated bids. This pass will be skipped if there is no bid mitigation.

Last Market Pass

The mathematical formulation of the Last Market pass is the same as the one used for the First Market pass, with the following simplifications:

a) The resource unit commitment will be fixed at the solution of the previous pass.

b) The physical supply in the RCU/RCD procurement constraint is fixed at the solution of the previous pass ($\widehat{EN}$) to decouple the marginal pricing of energy schedules and RCU/RCD awards.

c) The marginal impact of physical supply is removed from the linearized transmission constraints in the FRU/FRD deployment scenarios to decouple the marginal pricing of energy schedules from congestion contributions from these constraints.

Consequently, the power balance and capacity procurement constraints in the Second Market pass are as follows:

$$\left.\begin{array}{l} \displaystyle\sum_i \frac{\Delta EN_{i,t} + \Delta VS_{i,t} - \Delta VD_{i,t} - \Delta L_{i,t}}{LPF_{i,t}} = 0 \\[2ex] \displaystyle\sum_{i\notin VER} RCU_{i,t} - \sum_i RCD_{i,t} = ND_t - \sum_{i\notin VER} \widehat{EN}_{i,t} \\[2ex] \displaystyle\sum_i RCD_{i,t} + \sum_{i\notin VER} FRU_{i,t} + \sum_r FRUS_{r,t} \geq FRUR_t \\[2ex] \displaystyle\sum_{i\notin VER} RCU_{i,t} + \sum_i FRD_{i,t} + \sum_r FRDS_{r,t} \geq FRDR_t \end{array}\right\}, t = 1,2,\dots,T$$

The linearized transmission constraints are as follows:

$$\left.\begin{array}{l} \displaystyle\widetilde{LFL}_{m,t} \leq \tilde{F}_{m,t} + \sum_i \left(\Delta EN_{i,t} + \Delta VS_{i,t} - \Delta VD_{i,t} - \Delta L_{i,t}\right) SF_{i,m,t} \leq \widetilde{UFL}_{m,t} \\[2ex] \displaystyle\widetilde{LFL}_{m,t}^{(u)} \leq \tilde{F}_{m,t}^{(u)} + \sum_{i\notin VER} \left(\Delta RCU_{i,t} + \Delta FRU_{i,t}\right) SF_{i,m,t} + \sum_r \Delta FRUS_{r,t}\, SF_{r,m,t} \leq \widetilde{UFL}_{m,t}^{(u)} \\[2ex] \displaystyle\widetilde{LFL}_{m,t}^{(d)} \leq \tilde{F}_{m,t}^{(d)} - \sum_i \left(\Delta RCD_{i,t} + \Delta FRD_{i,t}\right) SF_{i,m,t} - \sum_r \Delta FRDS_{r,t}\, SF_{r,m,t} \leq \widetilde{UFL}_{m,t}^{(d)} \\[2ex] \qquad = 1,2,\dots,T \end{array}\right\}, \forall m \wedge t$$

By fixing the physical supply in the RCU/RCD procurement constraint and removing the marginal impact of physical supply from the linearized transmission constraints in the FRU/FRD deployment scenarios a uniform marginal energy price results for all resources: physical supply and virtual supply