BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
RESOURCE ADEQUACY PROPOSALS

Roger E. Collanton
General Counsel
Anthony Ivancovich
Deputy General Counsel
Anna A. McKenna
Assistant General Counsel
Jordan Pinjuv
Senior Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom California 95630
Tel.: (916) 351-4429
jpinjuv@caiso.com

Date: February 16, 2018

Table of Contents

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	Rulemaking 17-09-020 (Filed September 28, 2017)

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION RESOURCE ADEQUACY PROPOSALS

I. Introduction

The Commission issued its Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge (Scoping Memo) on January 18, 2018. The Scoping Memo provides an opportunity for parties to submit proposed modifications to the resource adequacy program. The California Independent System Operator Corporation (CAISO) hereby submits four proposals addressing the following issues: (1) aligning the Commission's resource adequacy assessment hours with the CAISO's Availability Assessment Hours; (2) the flexible resource adequacy capacity framework; (3) system load and resource adequacy requirements during shoulder months; and (4) counting use-limited resources to meet local capacity requirements. The CAISO believes there is sufficient information for the Commission to align its resource adequacy assessment hours with the CAISO's Availability Assessment Hours in Track 1 of this proceeding. The other three proposals may require further development in Track 2 of this proceeding to ensure the Commission has sufficient information to make appropriate modifications to the resource adequacy program.

II. Discussion

A. Aligning the Commission Resource Adequacy Assessment Hours and CAISO Availability Assessment Hours

The Commission's current resource adequacy assessment hours do not correspond to the hours of peak system need and have not been updated since 2010. In addition, the resource adequacy assessment hours are inconsistent with the CAISO's Availability Assessment Hours, which causes confusion and competing regulatory incentives for generating resources. To remedy this misalignment, the Commission should prospectively adopt resource adequacy assessment hours that align with the CAISO's Availability Assessment Hours. This will ensure that resources are properly valued and provide energy services to the grid in the hours of greatest need.

1. Purpose of the Availability Assessment Hours and the Resource Adequacy Assessment Hours

The CAISO's Resource Adequacy Availability Incentive Mechanism (RAAIM) is designed to incentivize system and local resource adequacy resources to comply with their must-offer obligations during a daily five-consecutive hour period defined as the Availability Assessment Hours. System/local resources that fail to provide bids or self-schedules into the CAISO's day-ahead and real-time markets during the Availability Assessment Hours are subject to non-availability charges, while resources that meet certain minimum bidding requirements are eligible to receive availability assessment payments.[1] The CAISO is required to establish its Availability Assessment Hours annually, and the five consecutive hour period must "correspond to the operating periods when high demand conditions typically occur" and "vary by season as necessary so that the coincident peak load hour typically falls within the five-hour range each day during the month, based on historical actual load data."[2] The CAISO sets separate Availability Assessment Hours for the summer (currently April through October) and winter (currently November through March) time periods.[3]

The Commission's resource adequacy assessment hours are used to establish Qualifying Capacity values for demand response and certain cogeneration resources.[4] The Commission adopted the currently applicable resource adequacy assessment hours in Decision 10-06-036. The Commission has not modified its resource adequacy

[1] CAISO Tariff Section 40.9.6.
[2] CAISO Tariff Section 40.9.3.1.
[3] The seasonal periods may shift over time.
[4] See the Commission's 2018 Qualifying Capacity Methodology Manual, p. 13-18. Accessible at the Commission's website under the "Guides and Resources" tab: http://www.cpuc.ca.gov/General.aspx?id=6311.

assessment hours since 2010, even though system loads and resources have changed significantly since then.

2. *Need for Alignment between the Availability Assessment Hours and Resource Adequacy Assessment Hours*

In 2017, the CAISO undertook a stakeholder process to update its Availability Assessment Hours to ensure that the hours aligned with the hours of greatest system need. Prior to this stakeholder process, the CAISO's Availability Assessment Hours and the Commission's resource adequacy assessment hours were aligned as indicated in Table 1 below.

Table 1

CAISO/Commission Availability/Resource Adequacy Assessment Hours (Before 2017)	
Winter Assessment Hours	4:00 p.m. – 9:00 p.m.
Summer Assessment Hours	1:00 p.m. – 6:00 p.m.

The CAISO's analysis indicated that its summer Availability Assessment Hours should be adjusted to 4:00 p.m. – 9:00 p.m. to better meet critical system needs and the CAISO coincident system peak. The CAISO did not find a need to modify the winter assessment hours.

Consistent with its tariff, the CAISO sought to implement its updated Availability Assessment Hours by modifying its business practice manual.[5] Stakeholders, including the Commission Energy Division staff, requested that the CAISO refrain from modifying its Availability Assessment Hours for the 2018 resource adequacy compliance year because the proposed changes "would negatively impact resource delivery by causing uncertainty and confusion," specifically for resources participating in the Commission's Demand Response Auction Mechanism (DRAM).[6]

---

[5] CAISO Tariff Section 40.9.3.1(a)(1).
[6] Commission Staff Comments on CAISO business practice manual, proposed revision request no. 986, available on the CAISO's website at https://bpmcm.caiso.com/Lists/PRR%20Comments/Attachments/1418/CPUC%20Staff%20Comments%20on%20PRR%20986_.docx.

To accommodate these concerns, the CAISO sought a waiver of its tariff requirement to annually establish Availability Assessment Hours that align with the coincident peak load hour.[7] The Federal Energy Regulatory Commission (FERC) denied the CAISO's waiver request because it was not appropriately limited in scope and there was insufficient evidence that no undesirable consequences would occur as a result of the waiver.[8] Thus, the CAISO updated the Availability Assessment Hours to 4:00 p.m. – 9:00 p.m. for the summer period. In addition, on February 9, 2018, the CAISO filed a more limited tariff waiver petition of the summer Availability Assessment Hours for affected DRAM resources with FERC, and it is currently pending FERC approval.[9]

The existing discrepancy between the CAISO's Availability Assessment Hours and the Commission's resource adequacy assessment hours is undesirable because it causes uncertainty and confusion for resource owners-operators, and it potentially reduces the availability of resources during times of high demand conditions when they are most critically needed to maintain system reliability. Accordingly, the Commission and CAISO assessment hours should be aligned. The CAISO specifically recommends that the Commission adopt the CAISO's Availability Assessment Hours by reference, rather than adopting a specific five-hour time block. This will reduce the possibility of any future disconnect between the CAISO and Commission assessment hours.

3. *The CAISO's Annual Review of Availability Assessment Hours*

The CAISO has formalized an annual review process for establishing its Availability Assessment Hours. To establish the Availability Assessment Hours, the CAISO collects load forecast data from the California Energy Commission (CEC) and behind-the-meter renewable build-out data from the CEC and load-serving entities. The CAISO uses this data to determine historical and future hourly average load by month. The CAISO then calculates the top five percent of load hours within each month using an

[7] *See* Petition of the California Independent System Operator Corporation for Limited Tariff Waiver, ER17-2263, http://www.caiso.com/Documents/Aug8_2017_Petition_LimitedTariffWaiver-AvailabilityAssessment_Hours2018_ER17-2263.pdf.
[8] Order Denying Request for Waiver, ER17-2263, 161 FERC ¶ 61,088 at PP. 30-31.
[9] *See* Petition of the California Independent System Operator Corporation for Limited Tariff Waiver, ER18-838, http://www.caiso.com/Documents/Feb9_2018_Petition_LimitedTariffWaiver-DemandResponseResourcesAvailabilityAssessmentHours_2018_ER18-838.pdf.

hourly load distribution and identifies the five consecutive hour block that corresponds to the operating periods when high demand conditions typically occur and such that the peak load hour typically falls within the range each day during the applicable months. The CAISO will conduct this review on an annual basis going forward, though the actual Availability Assessment Hours may not change annually.

Included as Attachment A to this proposal is the CAISO's 2018 Annual Review of Availability Assessment Hours. This review indicates that for the summer period (April through October), the hours from 4:00 p.m. to 9:00 p.m. most closely correspond with high demand conditions in 2019. The review also provides forward looking data that indicates that system coincident peak load conditions are trending later in the day as the penetration of behind-the-meter solar increases. Figures 1 and 2 below provide the CAISO's analysis for the months of August (a peak summer month) and October (a shoulder summer month). These figures indicate that the 4:00 p.m. to 9:00 p.m. block adequately captures the majority of peak hours in both months.

Figure 1

August Average Daily Loads

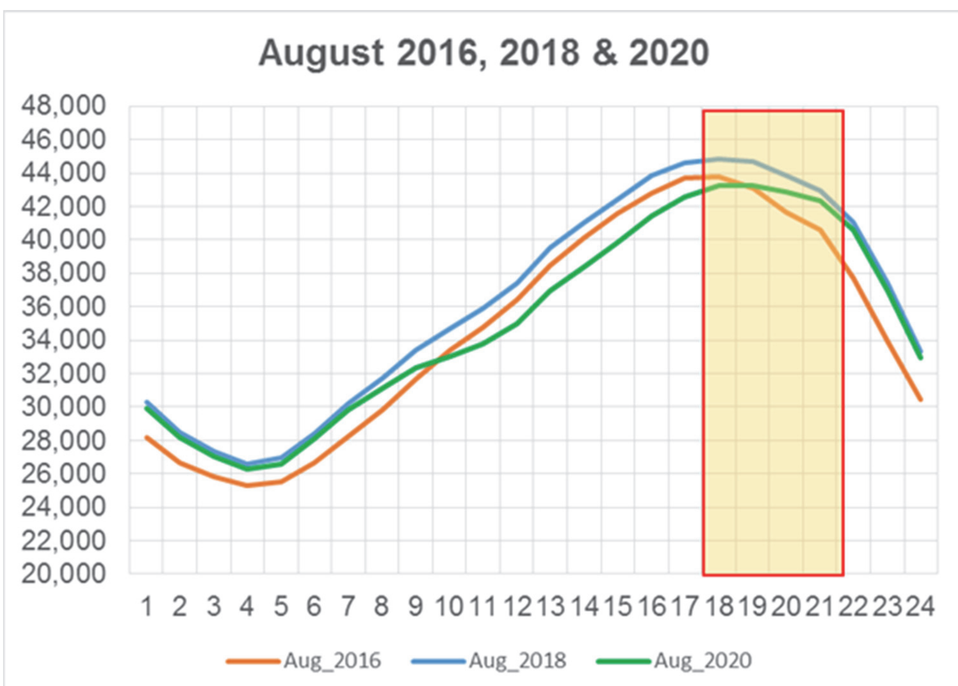
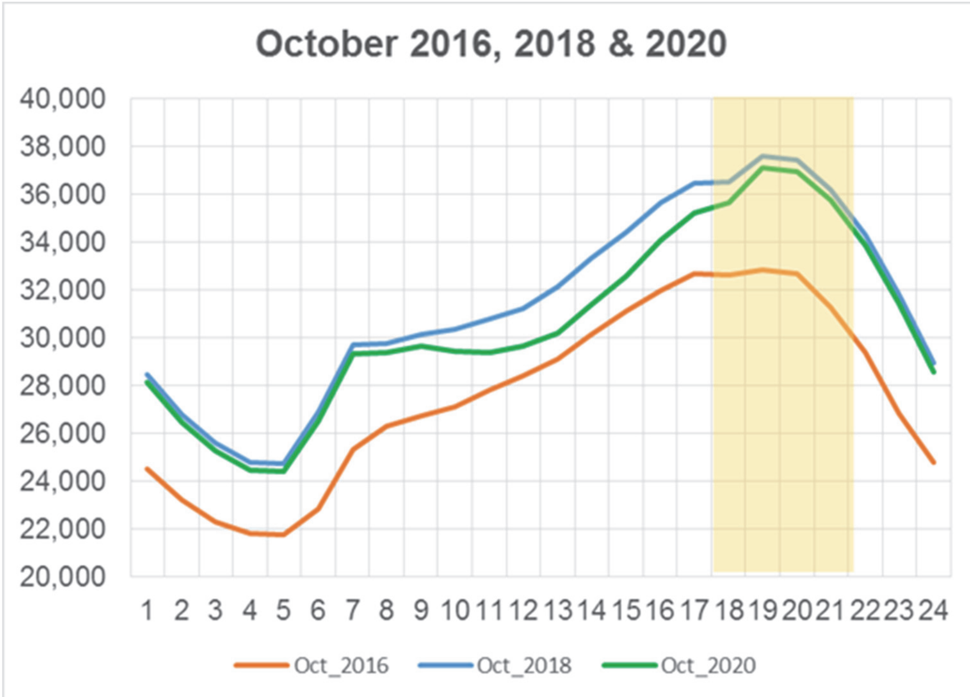


Figure 2

October Average Daily Loads



4. *Summary of CAISO Proposal*

The CAISO recommends that the Commission adopt the CAISO's Availability Assessment Hours by reference, thereby reducing the possibility of any future disconnect between the CAISO and Commission assessment hours. Adopting the CAISO's updated Availability Assessment Hours will also provide regulatory certainty for resource adequacy capacity and ensure that resources are available at times of critical system needs.

B. Revised Flexible Capacity Framework

The CAISO recently issued a revised flexible capacity framework in its Flexible Resource Adequacy Capacity and Must-Offer Obligation (FRACMOO) 2 initiative. Concurrently with this proceeding, the CAISO will continue to develop and refine this revised framework. The CAISO is not requesting the Commission adopt this framework in Track 1 of this proceeding because additional time will be required to finalize the framework. Therefore, in an effort to fully develop the necessary record, the CAISO submits its current proposed framework in Track 1 as an initial step towards adopting a final framework as part of Track 2 of this proceeding.

The current flexible resource adequacy framework produces fundamental gaps between the CAISO's markets and operational needs. To close these gaps, the CAISO is developing a new flexible capacity framework that better captures both the CAISO's forecasted operational needs and the predictability (or unpredictability) of ramping needs. Changes to the flexible capacity product and flexible capacity needs determination should align forward procurement with the CAISO's actual operational needs and how the CAISO commits and dispatches resources through the various market runs (*i.e.,* the Integrated Forward Market, fifteen-minute market, and five-minute market runs).

To successfully align procurement with operational needs, the flexible resource adequacy program must enable the CAISO to meet anticipated ramping uncertainty within the time scales of the real-time market. The most efficient way to address this anticipated uncertainty is to develop flexible capacity rules and products that are tied directly to two types of ramping needs: (1) predictable ramping needs, *i.e.*, those that are known or reasonably forecastable; and (2) unpredictable ramping needs, *i.e.*, those caused by load following and forecast error. To meet these needs, a revised flexible capacity product both should ensure that sufficient capacity is economically bid into the CAISO's day-ahead market to establish a market solution (as opposed to solutions that rely on penalty parameters) and ensure that sufficient fast ramping and responsive resources are procured and available in real-time to address uncertainty.

The CAISO proposes to develop three products as part of the new flexible capacity framework: (1) a five-minute flexible resource; (2) a fifteen-minute flexible resource; and (3) a day-ahead shaping resource. Flexible capacity needs should first plan for the uncertainty that occurs between the fifteen-minute market and the real-time dispatch, then extending that planning to longer notice intervals, for example from the Integrated Forward Market to the fifteen-minute market. Resources capable of addressing the fifteen-minute market to the real-time dispatch needs can also address the uncertainty between the Integrated Forward Market and the fifteen-minute market, but additional capacity needs to be procured to address the larger uncertainty that occurs between those market runs. As such, these flexible capacity requirements will be structured such that procuring higher quality resources will meet other identified needs.

The CAISO proposes to establish the overall flexible capacity requirement in a manner similar to the current practice, *i.e.*, based on the largest three-hour net load ramp plus contingency reserves. However, the proposed framework includes two notable differences. First, the CAISO will update the required contingency reserves to align with the new North American Electric Reliability Corporation (NERC) reliability standard BAL-002 requirements. Second, the CAISO will reconstitute the curtailed wind and solar resources into the three-hour net load ramp value. This will allow the new framework to include improved opportunities for imports, renewable resources and inverter-based technologies to provide flexible resource adequacy capacity.

Given the stability of the distributions of the uncertainty, it is reasonable to expect flexibility needs at the highest end of the distribution almost monthly. The CAISO proposes to set flexible capacity requirements to encompass the widest range of uncertainty for all real-time flexible capacity products. Additionally, as load and resource variability continue to increase, this requirement will include an additional growth factor that will be based on the relative changes to each of the contributing factors (*i.e.*, increasing in wind or solar or changes to load due to behind-the-meter-solar penetration). Finally, the CAISO proposes that load-serving entities procure 100% of the monthly needs in the year-ahead timeframe and reflect such procurement in their year-ahead resource adequacy showings.

Proper allocation of the revised flexible capacity requirements must be based on reasonable causation principles. The methodology currently employed by the CAISO to allocate flexible capacity requirements is based on load-serving entity procurement practices. The CAISO proposes to maintain its current practice of allocating flexible capacity requirements to local regulatory authorities based on the respective contributions to the requirement associated with their jurisdictional load-serving entity.

The CAISO proposes to allocate flexible capacity requirements based on the three primary contributing factors to each product. Similar to current practice, these three factors will be based on the contributions from load, wind, and solar. However, unlike current flexible resource adequacy allocation practice in which the CAISO applies a single allocation factor to all three flexible products, the CAISO proposes to apply an allocation methodology to each flexible product that accounts for load, wind, and solar contribution to each need.

Attachment B to this proposal contains the CAISO's proposed revised flexible capacity framework. As noted above, the CAISO is not seeking the Commission's approval of the flexible capacity framework at this time. Instead, the CAISO requests that the Commission establish additional workshops in Track 1 to discuss new developments to the proposal and to further develop the record on this matter so the Commission can issue a final decision adopting the CAISO's completed framework as part of its Track 2 decision and implemented for the 2020 Resource Adequacy compliance year.

C. System Load and Resource Adequacy Requirements

The Scoping Memo notes that the Commission expects the current system requirement, based on the CEC's 1-in-2 monthly load forecast, plus a 15 percent planning reserve margin, to continue for the 2019 RA program year absent any alternative proposals.[10] Based on actual events that occurred during 2017, the CAISO proposes that the Commission consider adopting more conservative monthly load forecasts during shoulder month for resource adequacy planning purposes.

The CAISO's proposal is based on observations and studies based on actual system events that occurred during May 2017. The primary example is the CAISO's declaration of a Stage 1 Emergency on May 3, 2017. Several factors led to this Stage 1 Emergency including (1) an unseasonably early and extreme heat wave; (2) a significant number of planned generator maintenance outages to prepare for summer operations; and (3) large generator forced outages. Demand remained high during and after sunset, but as solar production declined, thermal resources could not come online at the same rate. As a consequence, the CAISO depleted its operating reserves faster than expected during the solar production ramp down and ultimately declared a Stage 1 Emergency at 7:01 p.m. Operating reserves were ultimately recovered at 7:56 p.m. and the CAISO terminated the Stage 1 Emergency at 9:00 p.m. Although this was an extreme event, it highlighted that

[10] Scoping Memo, p. 6.

months such as May can experience wide temperature ranges that lead to a significant difference in peak demand during different days within the month. Using a 1-in-2 (average) load forecast for all months by definition overlooks the potential and actual occurrence of extreme variability in temperatures that can occur in a single month. The CAISO conducted a preliminary analysis of weather driven historical demand[11] for May, June, and July comparing 1-in-2, 1-in-5, and 1-in-10 demand levels. The results of this analysis are included with this proposal as Attachment C. For May, the 1-in-5 peak demand is eight percent higher than the 1-in-2 peak demand, and the 1-in-10 peak demand is 10 percent higher than the 1-in-2 peak demand. Analysis for June shows a similar pattern. In contrast, the 1-in-5 peak demand in July is only five percent higher than the 1-in-2 peak demand, and the 1-in-10 peak demand is only seven percent higher than the 1-in-2 peak demand level. This preliminary comparative analysis indicates that May and June experienced greater variability in recorded peak demand within the month than July. This variability is largely driven by the increasing temperatures experienced as the season changes from spring to summer, followed by stabilizing at warmer summer temperatures. The larger variability in demand above 1-in-2 peak levels results in a smaller portion of the 15 percent planning reserve margin being available for unplanned resource outages and other operational issues occurring during May and June.

The CAISO is conducting a similar analysis for the remainder of the year to identify other months with high levels of variability. The ultimate goal is to base monthly resource adequacy procurement on a demand forecast plus reserve margin that ensures sufficient resource adequacy resources are procured given the specific characteristics of a month to ensure reliable operation of the grid during that month. Based on the results of the CAISO's subsequent analysis, the Commission consider adopting more conservative monthly load forecasts during shoulder month for resource adequacy planning purposes.

[11] 1995 through 2017 data.

D. Use-Limited Resources and Local Capacity Requirements

On October 4, 2017, the CAISO and Commission staff hosted a joint workshop to discuss how "slow response" resources could count towards meeting local capacity requirements.[12] Slow response resources are energy-limited resources, such as some demand response resources, that cannot be dispatched within 20 minutes following a contingency event. The workshop first focused on the results of transmission planning analyses outlining the reliability needs of specific local areas and how demand response programs could meet those needs if all technical, regulatory, and market barriers were removed. The workshop also addressed potential options to remove market barriers to allow slow response resources to be dispatched prior to the contingency (*i.e.*, pre-contingency dispatch).

The CAISO submits into the record of this proceeding the transmission planning analysis presented at the October 2017 joint workshop and an explanation of how to interpret the data. Based on this analysis, discussion at the workshop, and comments submitted afterwards, the CAISO also submits a proposed methodology to address slow response and use-limited resources at both the Commission and the CAISO.

1. *Transmission planning analysis on characteristics of slow response local capacity resources*

At the October 2017 joint CAISO-Commission workshop, the CAISO presented its transmission planning analysis to assess availability requirements necessary for slow response resources to count for local resource adequacy (October 2017 Presentation). The October 2017 Presentation is included as Attachment D to this proposal. The study assessed the availability requirements for slow response resources to determine (1) annual, monthly and daily event hours; and (2) number of events per month, day and consecutive days.

---

[12] There were two joint workshops on the transmission planning analysis. The first was held on October 3, 2016. Presentation, materials, and stakeholder comments for the workshops are available at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=9457D220-D7EE-4828-94F4-1D9A30B6E812.

The CAISO's transmission planning analysis assumed the following:

1. Slow response resources would be dispatched in anticipation of loading conditions that would be problematic if contingencies occurred;
2. No emergency declaration would be required for the CAISO to dispatch the slow response resources;
3. The slow response resources are called last and therefore have the lightest possible duty;
4. An idealized "perfect" forecast and dispatch capabilities; and
5. Demand response capacity values would be constant throughout every hour of the year.

The analysis did not take into account an operational or implementation issues regarding dispatching slow response resources, but rather was focused on determining the "technical availability requirements" of slow response resources in local areas.[13]

To conduct the analysis, the CAISO collaborated with participating transmission owners (PTOs) to develop a two-step methodology to assess the availability requirements for slow response resources.[14] In Step 1, the PTOs selected local capacity areas and sub-areas to be studied, developed an hourly load forecast for each area and sub-area and provided an assessment of the necessary slow response characteristics based on a simplified methodology that uses forecast hourly load and the amount of slow response resources as the only inputs. They performed the Step 1 analysis for existing amounts of slow response resources as well as differing potential levels of resource penetration as a percentage of peak demand. The CAISO performed the analysis using three forecast hourly load profiles for 2017 which were derived from three years of historical load profiles. Step 1 assumed all resources were equally effective within a study area and did

---

[13] The CAISO's study methodology did not consider other factors that could require upward availability adjustments to the requirements for local reliability resources, and it is expected that these, if necessary, will be addressed directly by the utility/participating transmission owner. Slow response resources would require additional availability to the extent they respond to (1) prices or triggers other than local capacity related reliability events; (2) system events; (3) distribution system issues; or (4) planned outages and unforeseen events.

[14] October 2017 Presentation, pp. 11-12. The CAISO was not provided process book definitions for Sierra, Stockton and Kern and therefore the footprint does not align with local capacity area definitions. In the future, the CAISO would need information for all studied sub-areas to conduct a full analysis.

not consider reactive capability impacts. In Step 2, the CAISO tested selected scenarios based on locational and reactive capability impacts. The Step 2 analysis yielded more accurate results than Step 1, particularly for voltage stability limited areas, but the analysis was much more time and resource intensive. As a result, the CAISO only evaluated a subset of areas and penetration levels using Step 2. The study scenarios studied are reproduced in Table 2 below:[15]

Table 2

Slow Response Study Scenarios

<table>
<tr><th>Study Sponsor</th><th>Areas Studied</th><th>Resource Amounts</th></tr>
<tr><td>SCE</td><td>- All LCAs,
- All sub-areas</td><td rowspan="3">- Existing DR (Slow Response)
- 2% of study area load
- 5% of study area load
- 10% of study area load</td></tr>
<tr><td>PG&E</td><td>- All LCAs,</td></tr>
<tr><td>SDG&E</td><td>- San Diego subarea</td></tr>
<tr><td>CAISO</td><td>- Voltage stability limited areas in southern California</td><td>- Existing DR (Slow Response)
- 5% of study area load</td></tr>
</table>

As shown in Table 2 above, the CAISO analyzed four scenarios (based on existing levels of slow demand response and penetrations of 2%, 5%, and 10%) for each local capacity and sub-area under Step 1, but it only evaluated two of the scenarios (existing and 5% penetration of slow response demand response) using Step 2. Similarly, the CAISO only evaluated a subset of the local capacity and sub-areas using Step 2.

The results of both the Step 1 and Step 2 analyses are included in the October 2017 Presentation.[16] In general, the existing slow response resources were able to meet reliability standards based on *existing* program annual and monthly event hours and event days. However, the analysis showed that existing programs may not have sufficient duration (in hours) to reliably serve load in the local area given the studied contingency.

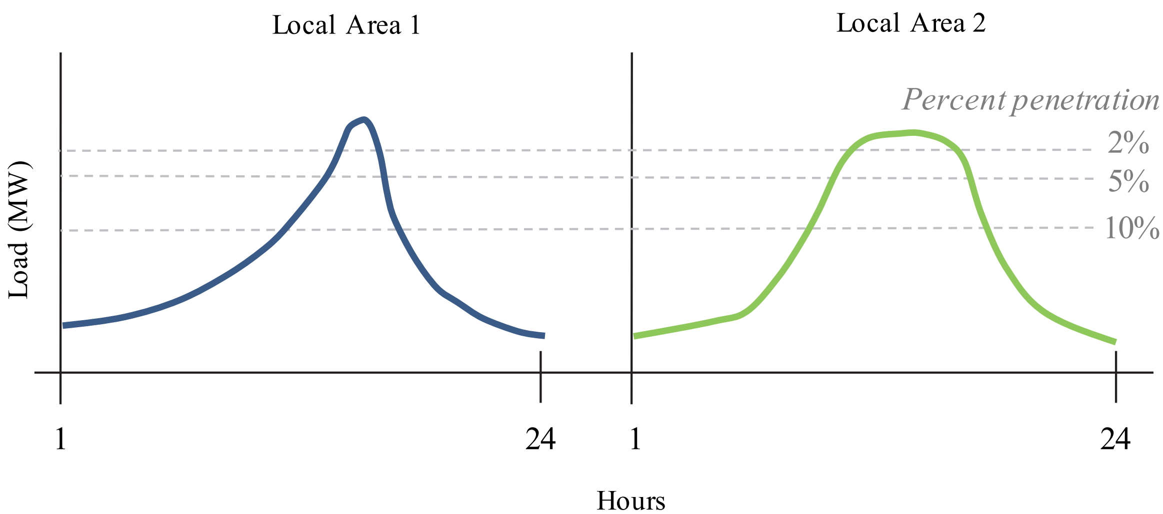
---

[15] October 2017 Presentation, p. 10.
[16] October 2017 Presentation, pp. 13-43.

Figure 3 below illustrates this relationship with two representative daily load shapes. These daily shapes represent a typical peak demand day for two representative areas. Local Area 1 that experiences a high and sharp peak demand for a relatively few hours during the course of the day. Local Area 2 has a flatter daily load profile that includes a sustained, multi-hour period in which the load is within two percent of the peak. Because the CAISO's analysis assumed a "light duty" for slow response resources, they are assumed dispatched last in the supply stack—only when all other resources are exhausted. With the understanding that slow response resources would be the last supply resources called, Figure 3 demonstrates that the same level of slow response resource capacity will require the resources to have different hourly durations due to the differing load profiles in the local areas.

Figure 3

Local Capacity Area Representative Daily Load Graphs



In Local Area 1 the slow response resources would only be called-on for the relatively few hours the load is at or near the peak demand. Local Area 2—with its flatter, sustained peak—would require slow response resources capable of producing a sustained output for a longer duration than Local Area 1 at each of the studied levels of slow response resource penetration. These graphs also illustrate that as the penetration of slow response resources increases, these resources will be relied upon more often, serving load during more hours and for longer durations. In addition, this analysis applies equally to all use-limited resources, which the CAISO discusses in more detail below.

This means that getting the same megawatt hours of service in the local area will require more robust use-limited resources (i.*e.*, resources with longer durations) or more installed capacity of use-limited resources.

As the CAISO conducted the analysis, it recognized that the duration requirements have implications for other use-limited resources such as battery storage, fast responding demand response, and use-limited thermal generators. In the analysis, the CAISO identified the current and procured penetration of all demand response (slow and fast) and energy storage resources in each local capacity and sub-area in Southern California Edison Company's (SCE) territory. In the El Nido sub-area, the combined penetration of these use-limited resources is currently 3.6 percent of the estimated 2017 load, compared to a 2.1 percent penetration for slow response resources.[17] The CAISO transmission planning analysis only considered the penetration of slow response demand response in determining the availability and duration requirements for those resources,[18] but the ability of slow response resources to meet local area needs is significantly affected by the total quantity of use-limited resources in the local capacity area. As more traditional resources are displaced by use-limited resources in a local area, use-limited resources will be dispatched more often and for longer durations to serve load. As a result, to maintain a sufficient amount of energy (megawatt-hours) to serve area load, either additional megawatts of capacity or use-limited resources with longer durations and more hours of availability must be procured to maintain reliability in the local area.

Another important development that departs from the CAISO's study assumptions pertains to the regulatory or market barriers to pre-dispatching slow response resources. In its analysis, the CAISO assumed there were no regulatory or market barriers to pre-dispatching slow response resources, yet the CAISO recognized that Reliability Demand Response Resources (RDRR) can only be dispatched if the CAISO declares a Warning or an Emergency, which the CAISO cannot do in its pre-contingency planning and unit commitment efforts. For this reason, the CAISO cannot use slow responding RDRR to address local contingencies. Thus, only slow responding proxy demand response (PDR)

[17] October 2017 Presentation, p. 22.
[18] October 2017 Presentation, p. 16, p. 22. 34.3 MW of existing slow response demand response compared to 1,659 MW of 2017 load is 2.1 percent penetration.

resources can count toward meeting the local capacity requirement.[19] As a result, slow response RDRR must be removed from the analysis because it cannot be used to address local area contingencies (either before or after). The CAISO has not conducted this specific analysis, but the expectation is that the currently shown "existing" levels of demand response penetration will decrease.

The results of the CAISO's analysis and the subsequent lessons learned about the interaction between slow response resources and other use-limited resources indicates the need for a more holistic review of the role of use-limited resources in meeting local capacity requirements. In the subsequent section, the CAISO presents a proposal to address this need in both the short- and long-term.

2. *Proposal for analyzing characteristics of use-limited local capacity resources*

The CAISO proposes that in Track 1 the Commission adopt the CAISO's methodology to establish maximum levels of resource adequacy use-limited capacity in local areas in 2020. Track 1 approval with a 2020 implementation date will allow the Commission and the CAISO to successfully incorporate any necessary changes to demand response programs, contracts for preferred resources that are use-limited, studies, and implementation requirements. The CAISO also proposes that in subsequent tracks the CAISO and the Commission should work to refine the methodology to provide more flexibility in incorporating use-limited resources to meet local capacity requirements.

i. 2020 Local Capacity Requirements

The CAISO proposes to set 2020 local capacity requirements consistent with the transmission planning analysis discussed above. To establish 2020 local capacity requirements, the CAISO will update its analysis in the 2020 local capacity technical study, which it will perform in 2019. The analysis would identify the maximum level of use-limited capacity in each local capacity area and sub-area[20] based on the Commission's existing four-hour minimum duration requirement for demand response

---

[19] "Fast response" RDRR and PDR currently counts towards the local capacity requirement.

[20] To conserve resources, it may be appropriate to limit this analysis to local capacity areas and sub-areas in that have exceeded a threshold amount of use-limited capacity.

and battery storage. Adopting the CAISO's study methodology and the resulting use-limited capacity maximums for the 2020 resource adequacy compliance year would provide load-serving entities an adequate opportunity to conduct procurement, and it would ensure that the procured resources have the technical and operational characteristics the CAISO needs to ensure that local capacity requirements are met.

The proposed timeline for incorporating the CAISO's methodology into 2020 local capacity requirements is listed in Table 3 as follows:

Table 3

Proposed Timeline

Time	Activity under the CAISO's proposal for establishing maximum use-limited local capacity in local capacity areas
Q2 2018	• Commission adopts CAISO methodology for establishing maximum use-limited capacity in local capacity areas
Q4 2018	• CAISO works with PTOs to set up the analysis and compile necessary data
Q1 2019	• Single forecast set is adopted by the California Energy Commission • Unified Inputs and Assumptions document is transmitted to the CAISO • CAISO performs analysis and conducts stakeholder process
Q2 2019	• CAISO submits analysis into the Commission's resource adequacy proceeding with the Local Capacity Technical Study for the 2020 compliance year

In parallel with the Commission's efforts in this proceeding, the CAISO will discuss in a stakeholder initiative ways to allow pre-dispatch of slow response PDR prior to the contingency. One such methodology was presented at the joint workshop and will continued to be analyzed with stakeholders.[21] The CAISO will seek to implement a pre-dispatch solution by the 2020 resource adequacy compliance year so that both Commission and CAISO-led processes are coordinated.

[21] October 2017 Presentation, pp. 47-63.

ii. Local Capacity Requirements Beyond 2020

Beyond the 2020 resource adequacy compliance year, the CAISO proposes to refine its transmission planning analysis to provide more flexibility in considering whether use-limited resources meet local capacity requirements. The CAISO's analysis demonstrates that each local area has unique needs based on load profiles, the amount of use-limited resources in the area, and the operational characteristics (particularly hourly duration) of existing resources in the area. In Track 2 of this proceeding, the CAISO recommends that the Commission and the CAISO continue to refine the CAISO's analysis to determine how to balance these factors while enabling the continued growth of preferred resources and maintaining local reliability.

The Commission and the CAISO will need to establish a framework that accommodates an increasing amount of use-limited resources being used to meet local capacity requirements. As the penetration of use-limited resources in local areas increases, more onerous operational requirements (such as longer duration times) likely will be needed because these resources will be relied upon for an increasing number of hours each day and across the year. This could potentially raise the minimum requirements for all resources in the local area or require a more complicated resource adequacy framework with different levels of resource performance requirements for similar resources within a local area. The Commission should use Track 2 of this proceeding to consider the policy implications of these potential paths forward.

The CAISO also proposes to conduct additional forward-looking studies based on this approach to inform future load-serving entity procurement. The operational characteristics identified in the studies will allow parties to engage in more effective procurement and program design,[22] and provide an early indication of changing local reliability conditions that may occur as a result of changing load shapes, increases in use-limited resource levels, new technologies or capabilities, or other unanticipated changes.

---

[22] Program design changes may need to be coordinated under other proceedings such as demand response or storage.

III. Conclusion

The CAISO appreciates this opportunity to provide proposals in this resource adequacy proceeding and looks forward to presenting additional details at the Commission's upcoming workshops.

Respectfully submitted,

By: *_/s/ Jordan Pinjuv_*
Roger E. Collanton
General Counsel
Anthony Ivancovich
Deputy General Counsel
Anna A. McKenna
Assistant General Counsel
Jordan Pinjuv
Senior Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom California 95630
Tel.: (916) 351-4429
jpinjuv@caiso.com

Date: February 16, 2018

Attachment A

CAISO's 2018 Annual Review of Availability Assessment Hours

California ISO

2018 Annual Review of Availability Assessment Hours

Amber Motley
Manager, Short Term Forecasting
Clyde Loutan
Principal, Renewable Energy Integration
Karl Meeusen
Senior Advisor, Infrastructure & Regulatory Policy

What’s the purpose of this call?

- To discuss the input assumptions, methodology, and results of the annual CAISO’s Availability Assessment Hours

Agenda/Overview

- High level look at RAAIM and components within RAAIM.
- BPM Changes
- Evolution of Load Shape
- Overview of methodology used for system/local availability assessment hours
- 2018 availability assessment hours
- 2019-2020 draft availability assessment hours

Availability Assessment Hours- Background and Purpose

- Concept originally developed as part of the ISO standard capacity product (SCP)
  - Maintained as part of Reliability Service Initiative – Phase 1 (i.e. RA Availability Incentive Mechanism, or RAAIM)
- Determine the hours of greatest need to maximize the effectiveness of the availability incentive structure
  - Resources are rewarded for availability during hours of greatest need
  - Hours determined annually by ISO and published in the BPM
    - See section 40.9 of the ISO tariff

Availability incentive mechanism assesses availability based on market offers.

- Mechanism penalizes low performance and rewards high performance for system, local, and flexible capacity:
  - Captures flexible resource adequacy economic bidding must-offer obligations.
  - Enhances assessment of availability of use-limited resources.
  - Assesses availability of proxy demand and non-generator resources (storage resources not subject to bid insertion).

Wind, solar, combined heat and power, and grandfathered resources exempt from availability incentive mechanism.

BPM CHANGES

Proposed BPM Changes – Reliability Requirements; Section 7

2018 System and Local Resource Adequacy Availability Assessment Hours
Analysis employed: Top 5% of load hours using average hourly load

Summer – April 1 through October 31
Availability Assessment Hours: 4pm – 9pm (HE17 – HE21)

Winter – November 1 through March 31
Availability Assessment Hours: 4pm – 9pm (HE17 – HE21)

2018 Flexible Resource Adequacy Availability Assessment Hours and must offer obligation hours

Flexible RA Capacity Type	Category Designation	Required Bidding Hours	Required Bidding Days
January – April October – December			
Base Ramping	Category 1	05:00am to 10:00pm (HE6-HE22)	All days
Peak Ramping	Category 2	2:00pm to 7:00pm (HE15-HE19)	All days
Super-Peak Ramping	Category 3	2:00pm to 7:00pm (HE15-HE19)	Non-Holiday Weekdays*
May – September			
Base Ramping	Category 1	05:00am to 10:00pm (HE6-HE22)	All days
Peak Ramping	Category 2	3:00pm to 8:00pm (HE16-HE20)	All days
Super-Peak Ramping	Category 3	3:00pm to 8:00pm (HE16-HE20)	Non-Holiday Weekdays*

*Non-Holiday Weekdays are any day of the week from Monday through Friday that is not a FERC holiday

Proposed Revision Request (PRR) 986 on the Reliability Requirements BPM – Update resource adequacy availability incentive mechanism assessment hours

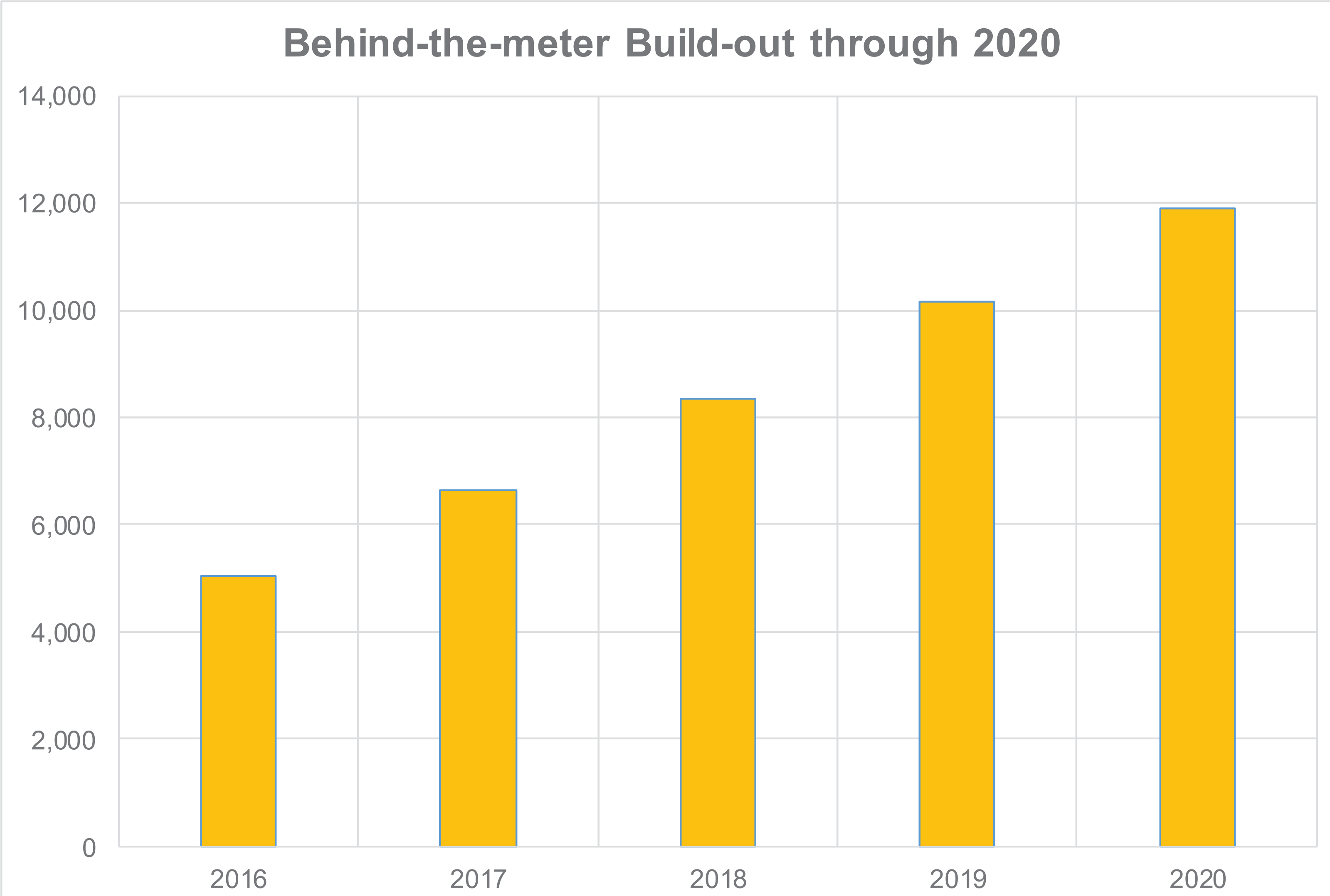
- **Reason for revision:** The change is due to the flex assessment study.
- **Stakeholder comments:**
  - Pacific Gas & Electric Company 4/25/17 and 6/5/17
  - California Large Energy Consumers Association 5/16/17 and 5/31/17
  - San Diego Gas & Electric Company 5/23/17
  - California Public Utilities Commission 6/5/17
  - Joint Demand Response Parties 6/5/17
  - Southern California Edison Company 6/5/17
- **PRR Status:**
  - PRR was submitted by ISO on 4/10/17
  - Initial comment period 4/10/17 through 4/24/17
  - Initial stakeholder meeting 4/25/17
  - ISO Recommendation posted on 5/2/17
  - Recommendation comment period 5/2/17 through 5/16/17
  - Recommendation comment period was reopened 5/22/17 to allow comments on the revised Redlined Reliability Requirements BPM, version 3 which includes the availability assessment hours for generic and flexible RA for 2017 and 2018
- **Next Step: ISO will review all comments and post the Final Decision**

DATA COLLECTED

What data did the ISO collect?

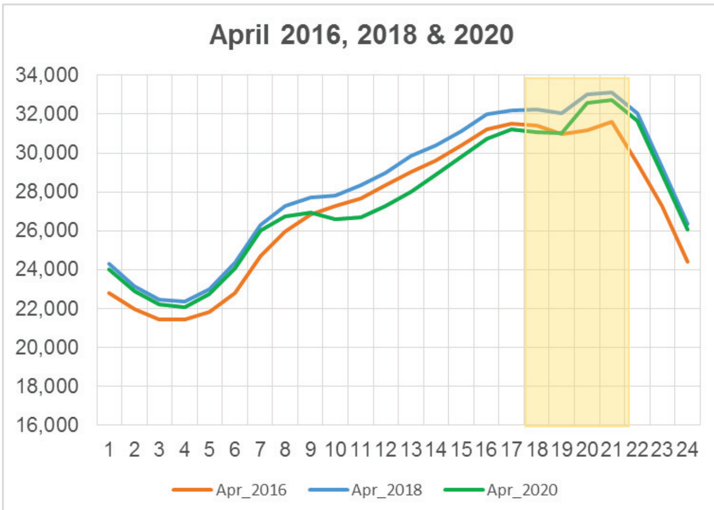
- CEC’s monthly peak demand forecast (e.g. 2017-20 demand forecast)
- LSE SCs updated renewable build-out for 2016 through 2020
- The data included:
  - Installed capacity by technology and expected operating date (e.g. Solar thermal, solar PV tracking, solar PV non-tracking, estimate of behind-the-meter solar PV etc.) for all variable energy resources under contract
  - Operational date or expected on-line date
  - Location of CREZ latitude and longitude coordinates
  - Resources located outside ISO’s BAA indicated if the resources are firmed or non-firmed

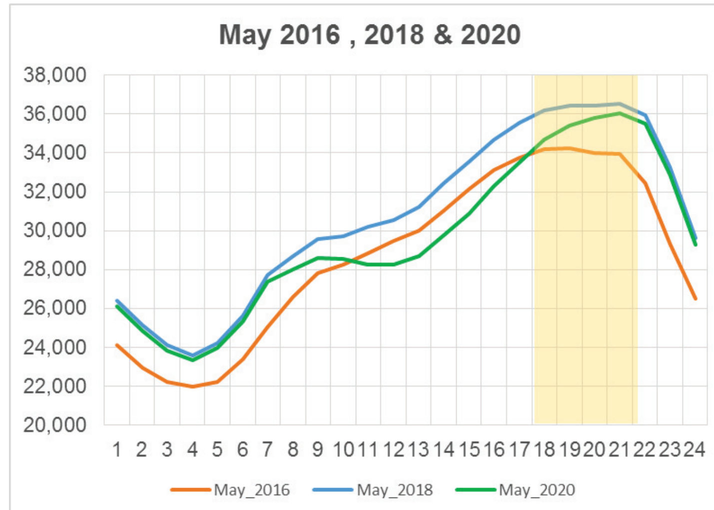
Behind the meter solar PV build-out through 2020

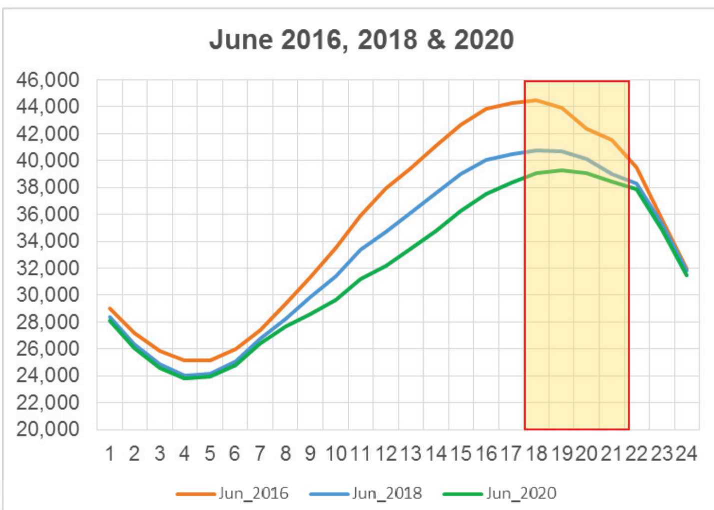


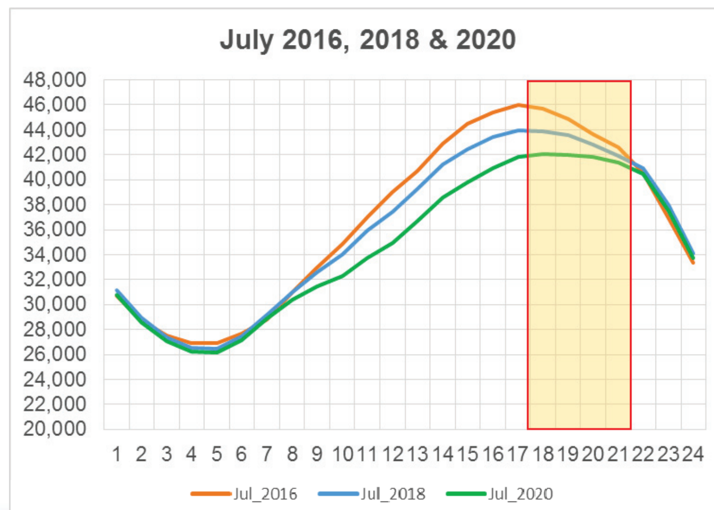
EVOLUTION OF LOAD SHAPE

Expected Load Shape Evolution:
Summer Season: April, May, June, July



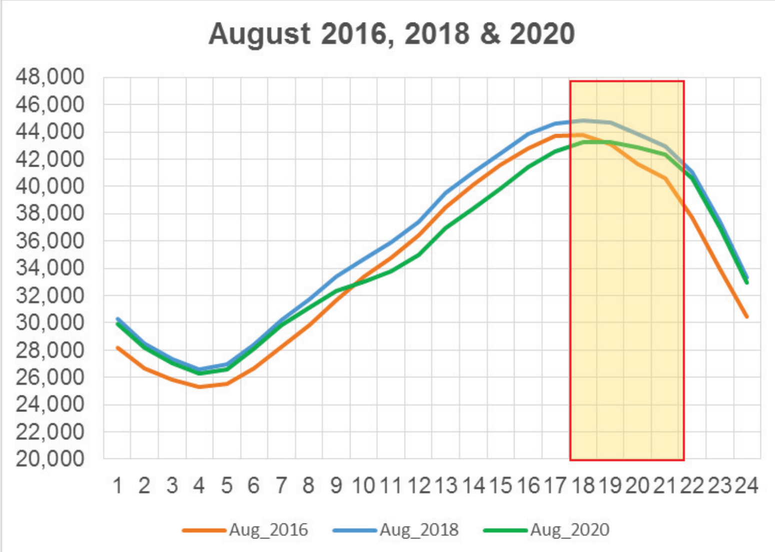


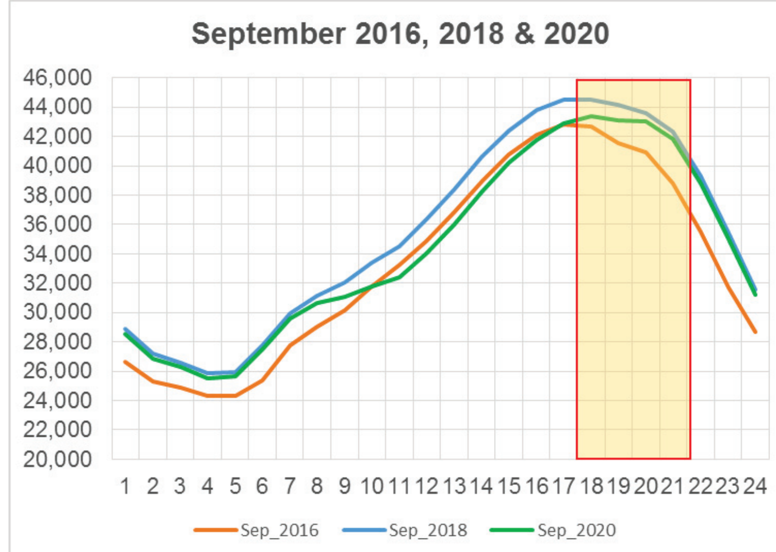


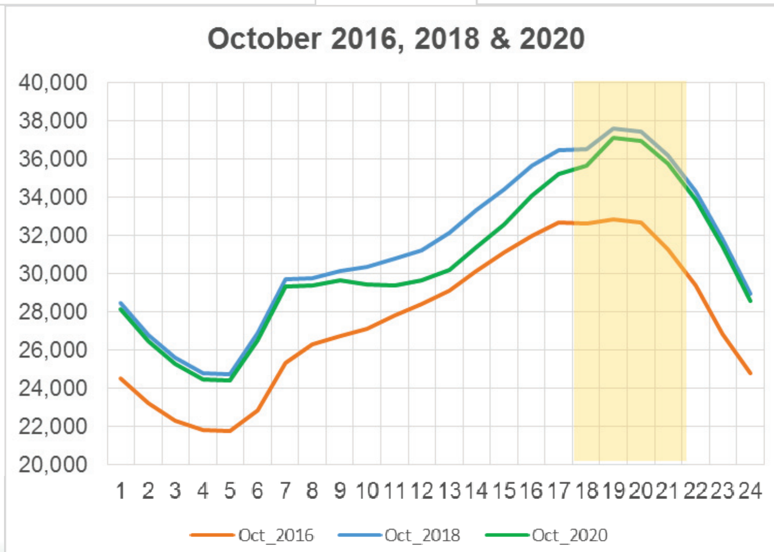


*Note: Graphs developed using max of hour by month

Expected Load Shape Evolution:
Summer Season: August, September, October

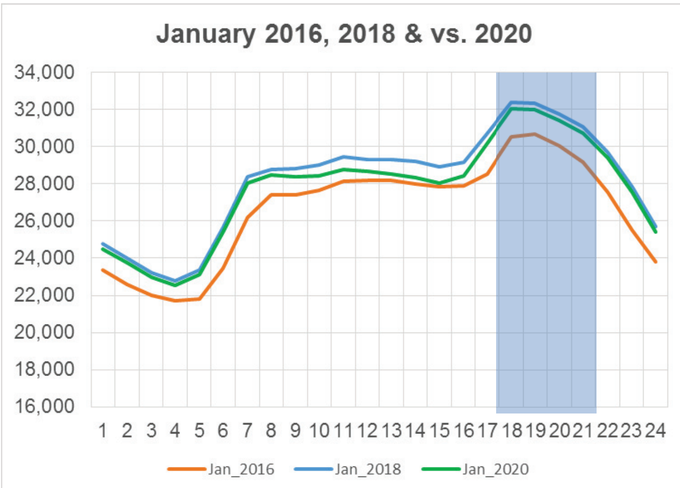


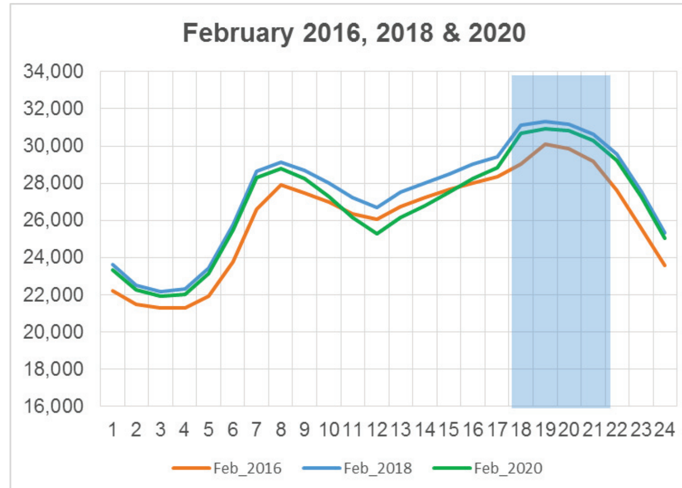


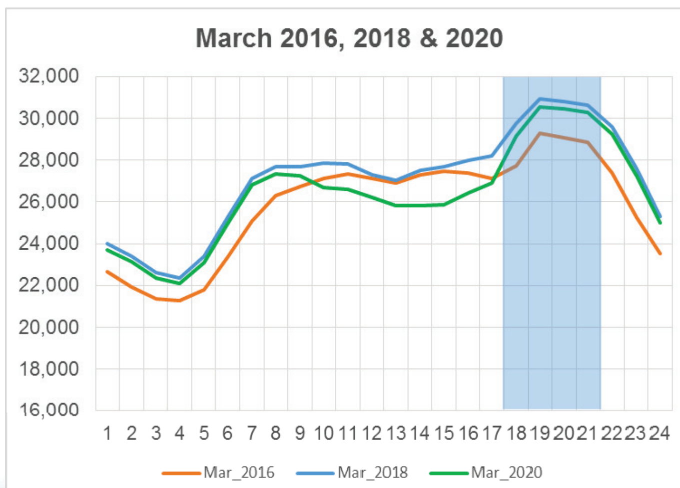


*Note: Graphs developed using max of hour by month

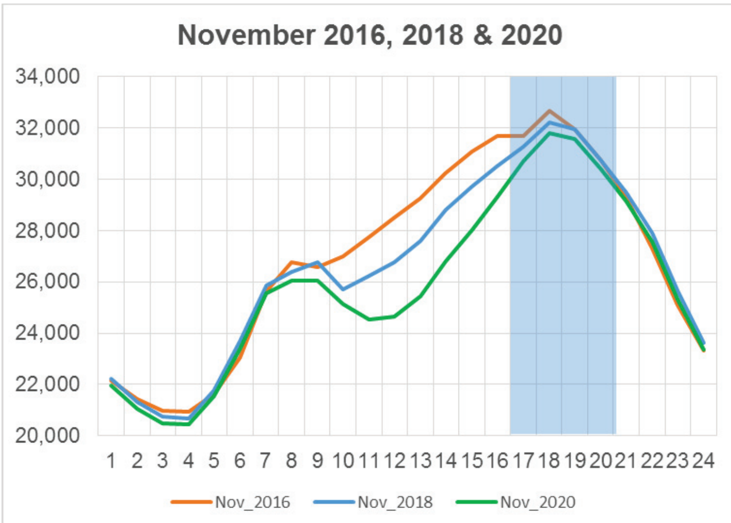
Expected Load Shape Evolution: Winter Season: January, February, March

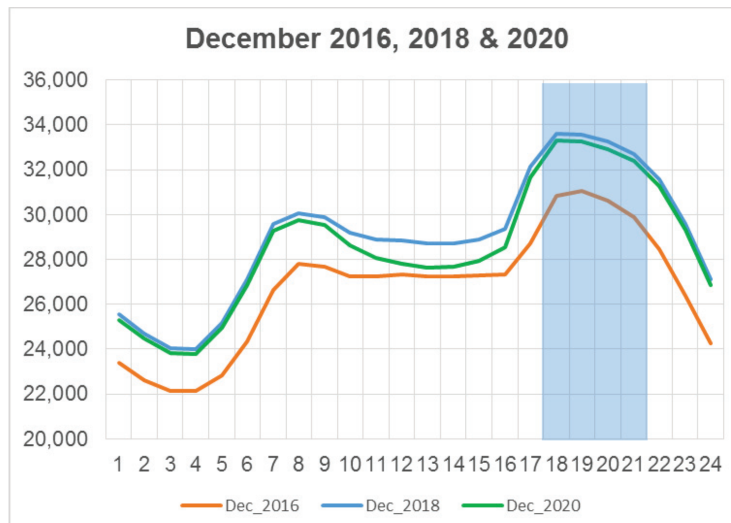






Expected Load Shape Evolution: Winter Season: November, December



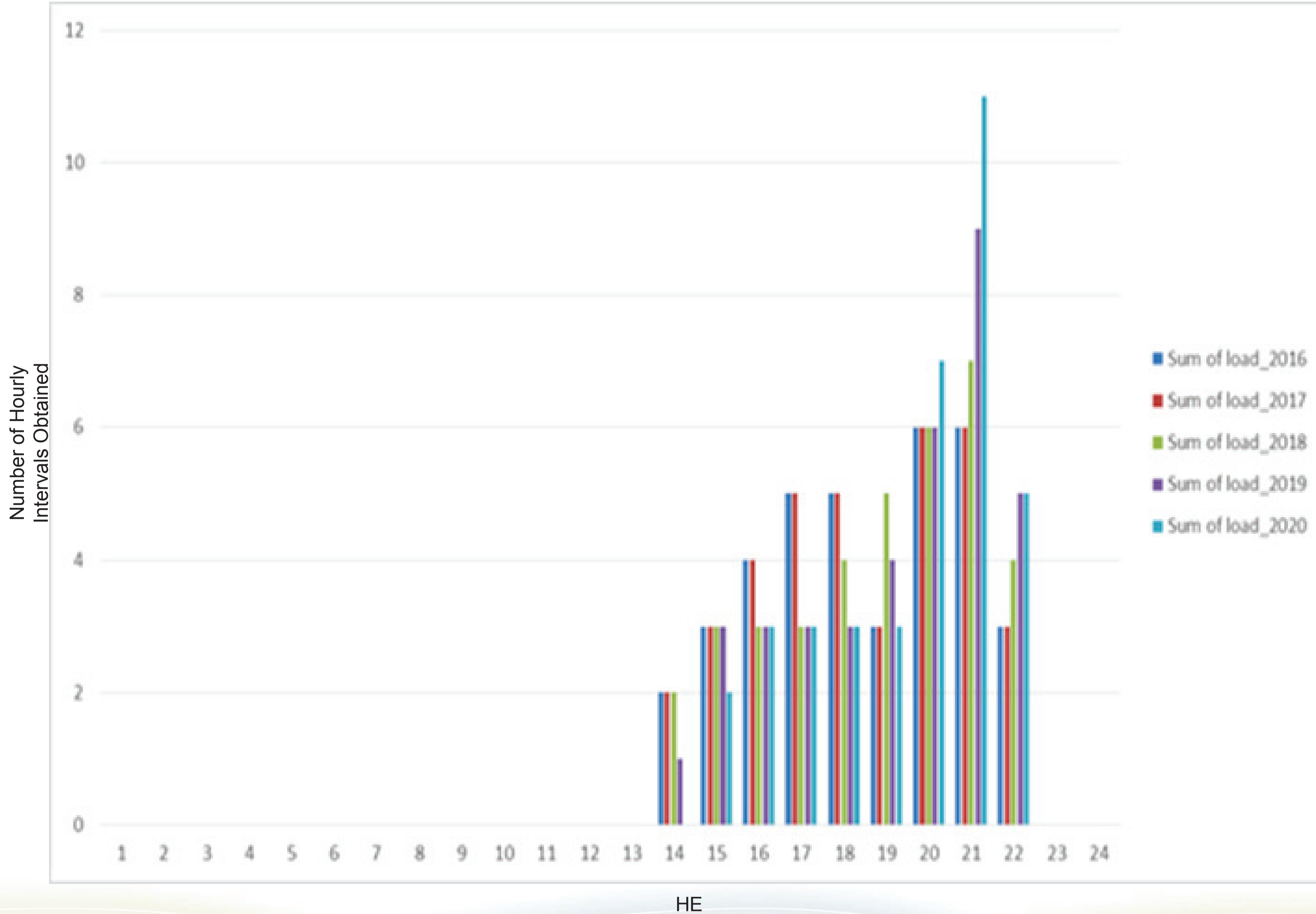


METHODOLOGY OVERVIEW

Methodology Overview of System/Local Availability Assessment Hours

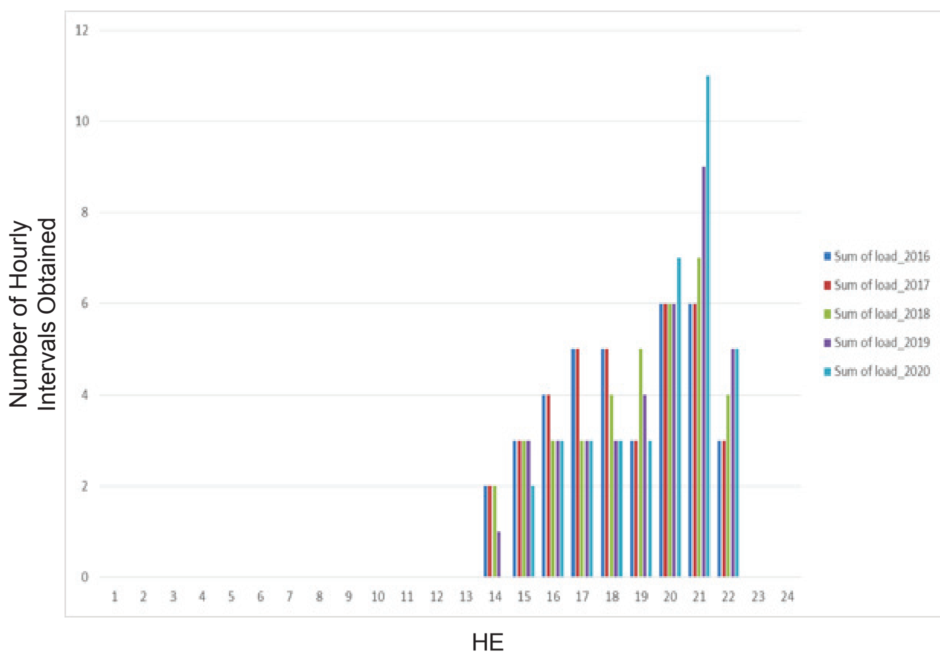
- Used data described in previous slides to obtain:
  - Hourly Average Load
    - By Hour
    - By Month
    - Years 2016-2020
- Calculated:
  - Top 5% of Load Hours within each month using an hourly load distribution
  - Years 2016 through 2020

Observations in the Month of April

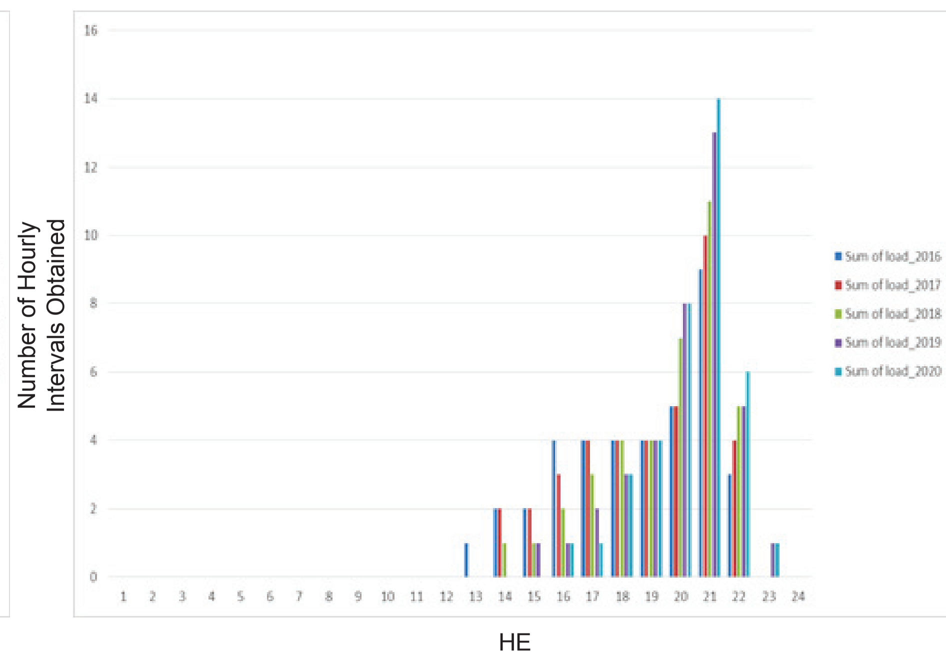


Observations in the Month of: April – May
Summer

April

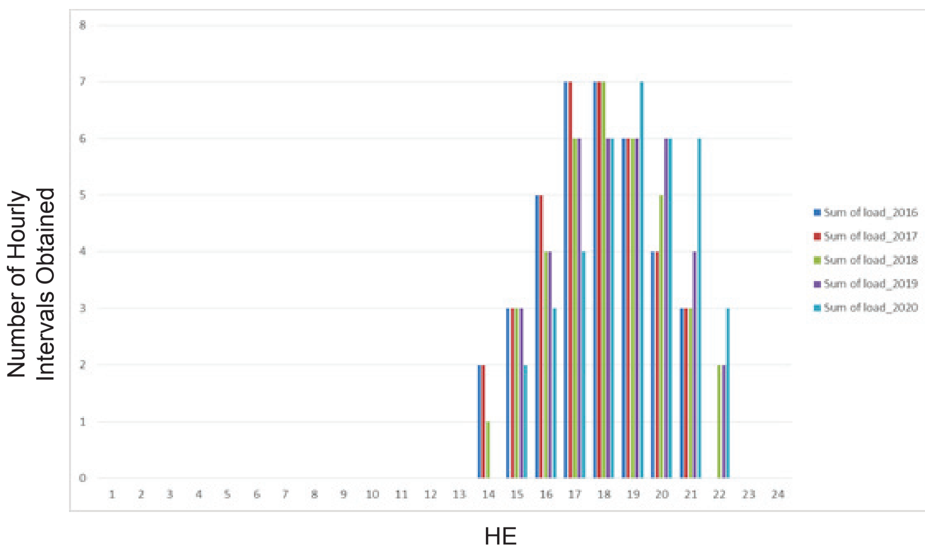


May

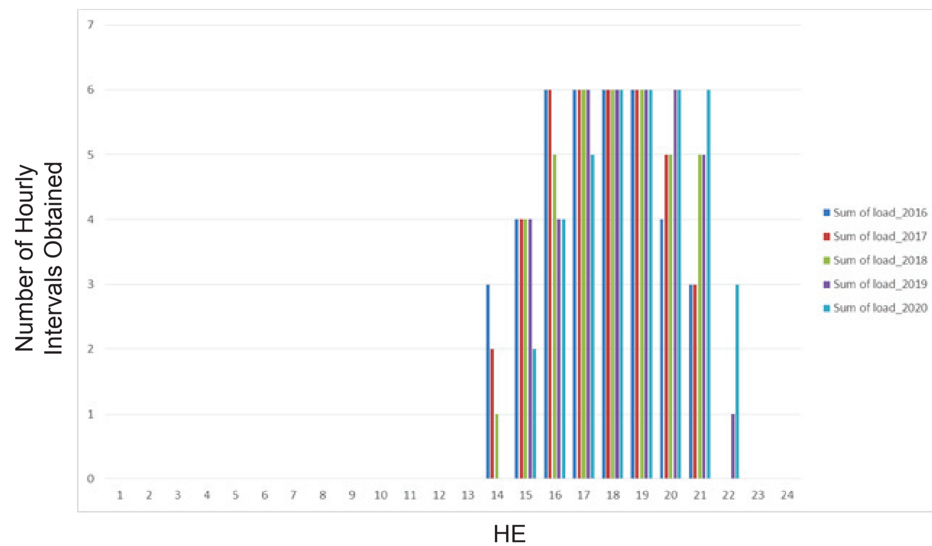


Observations in the Month of: June - July
Summer

June



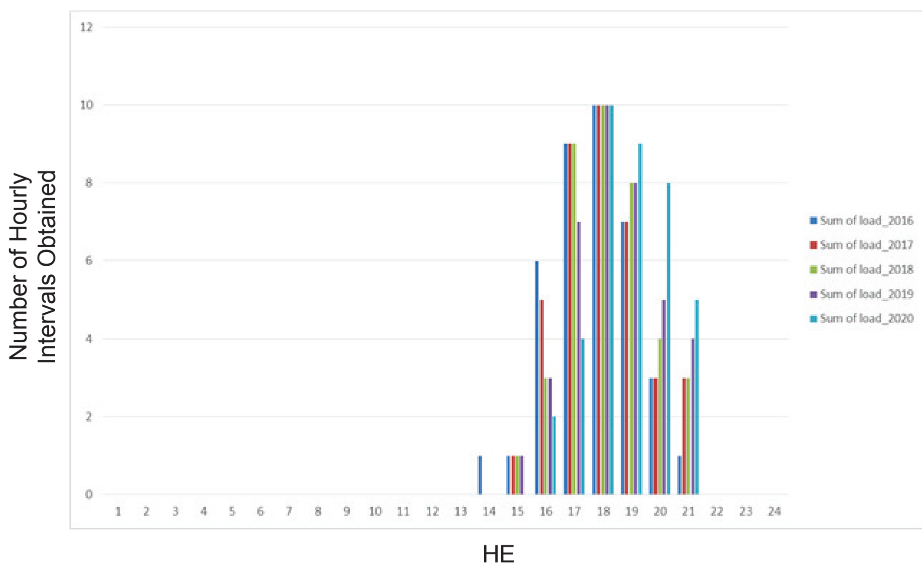
July



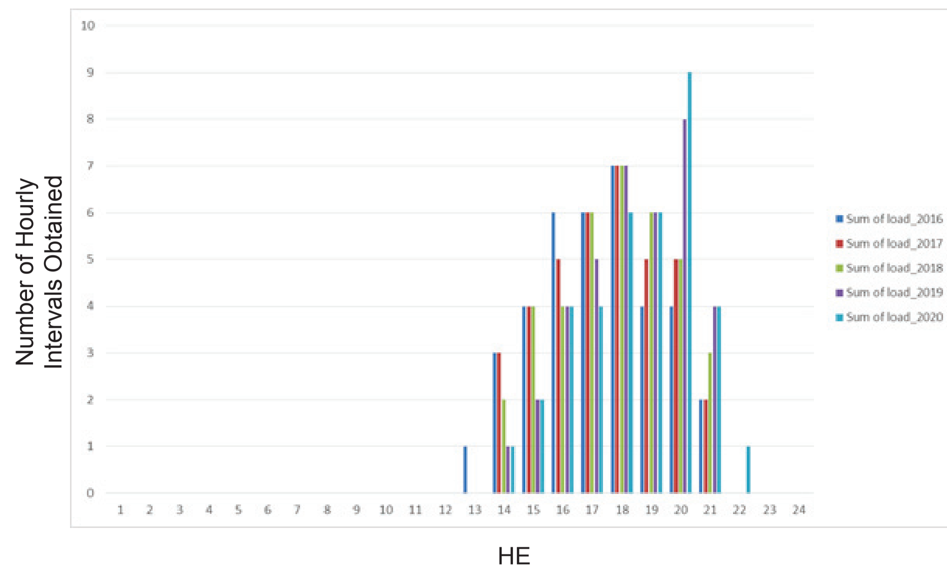
Observations in the Month of: August –Sept.

Summer

August

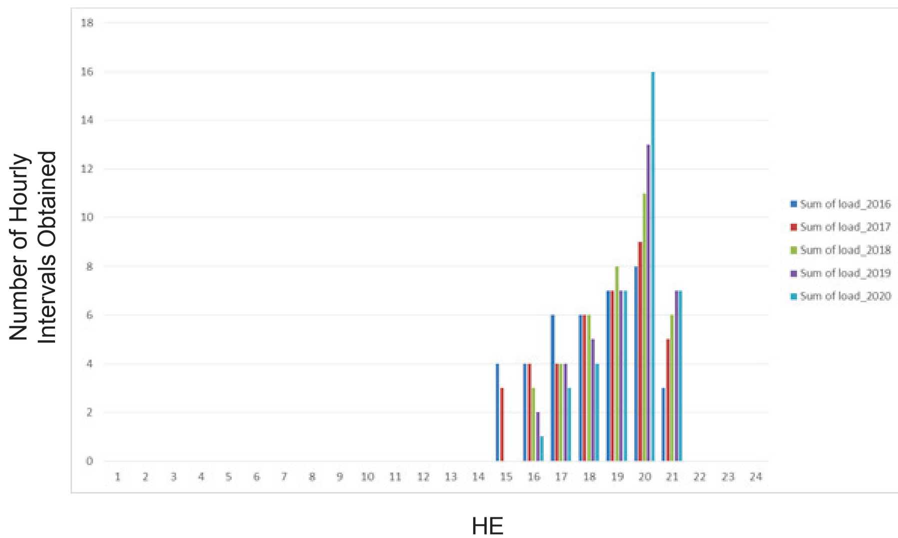


September



Summer Season

October



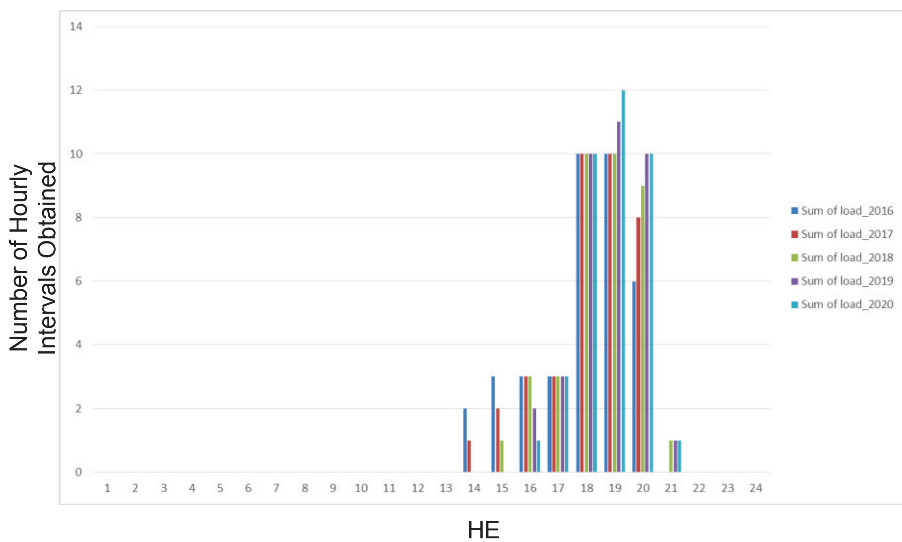
Summer Season Final Recommendation:

Year	Start	End
2016	HE14	HE18
2017	HE14	HE18
2018 (Final)	HE 17	HE 21
2019 (Estimate)	HE 17	HE 21
2020 (Estimate)	HE 17	HE 21

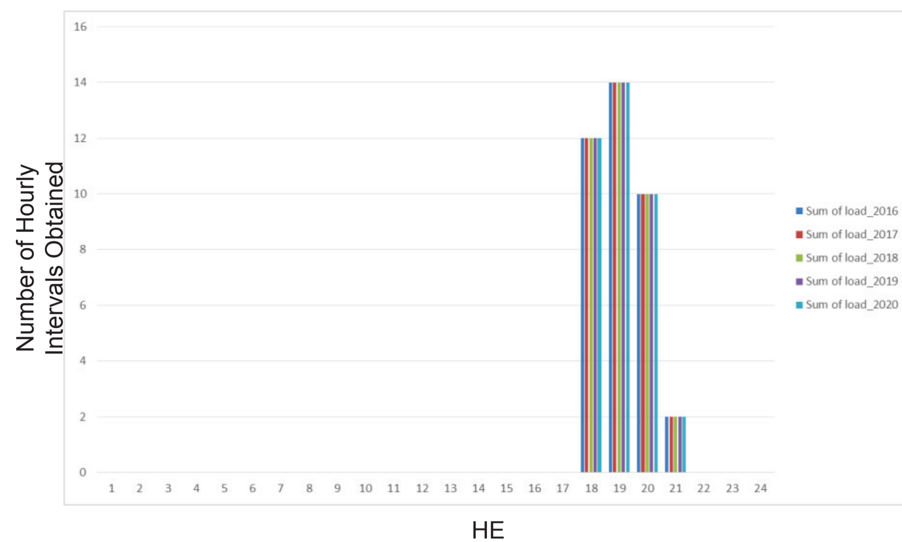
Observations in the Month of: Nov - Dec

Winter

November



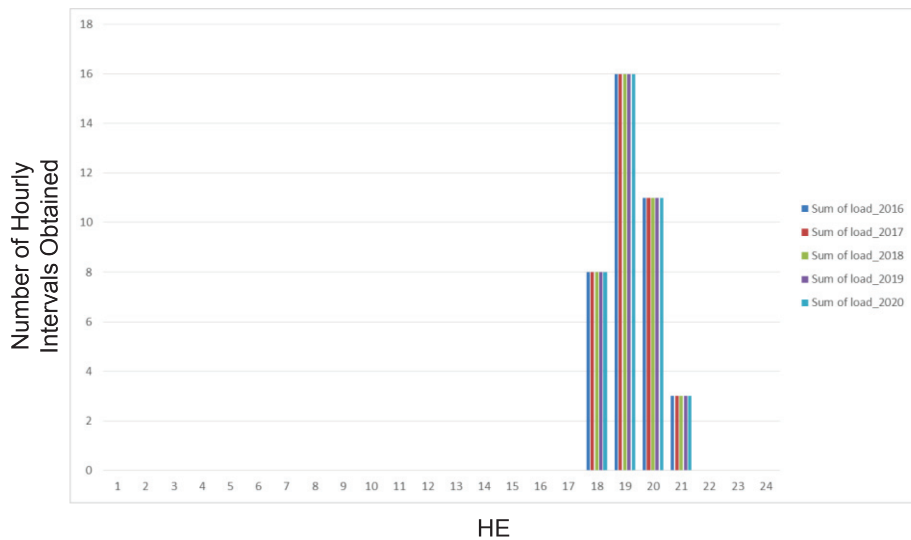
December



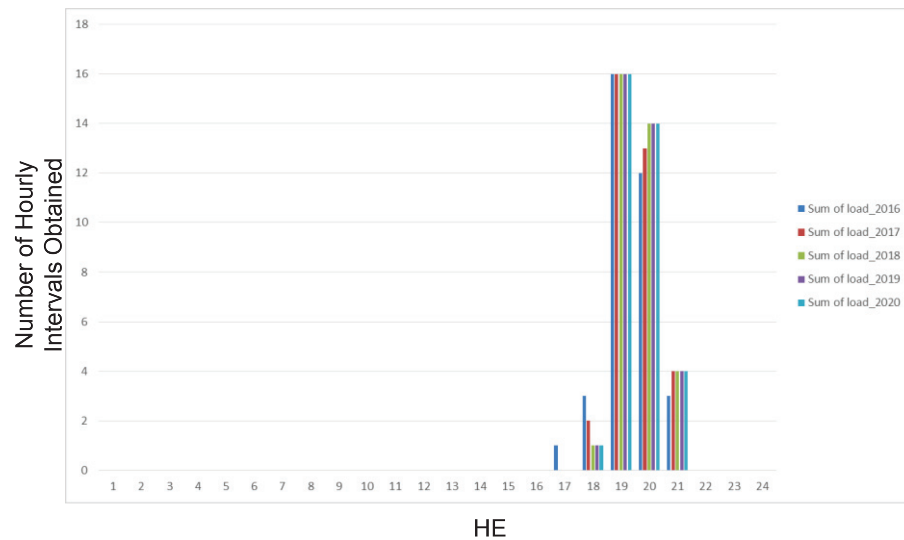
Observations in the Month of: Jan. – Feb.

Winter

January

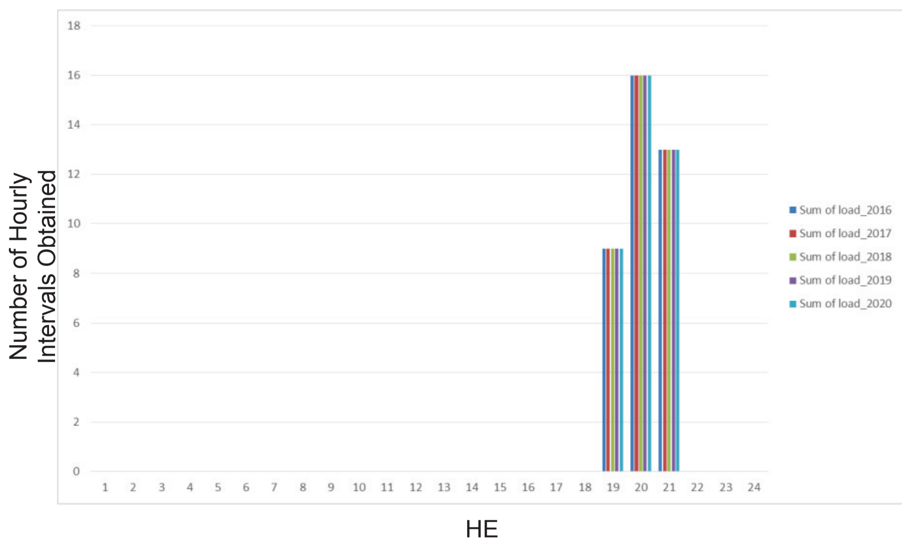


February



Winter Season

March



Winter Season Final Recommendation:

Year	Start	End
2016	HE 17	HE 21
2017	HE 17	HE 21
2018 (Final)	HE 17	HE 21
2019 (Estimate)	HE 17	HE 21
2020 (Estimate)	HE 17	HE 21

QUESTIONS?

- To submit written comments to this revised redlined BPM, version 3, please register on the BPM change management site: https://bpmcm.caiso.com/Pages/default.aspx
  - Click “Login” and then “Register”
  - Must be registered to submit comments (registration is one-time only)
  - Please submit by COB 6/13, as ISO has re-opened the 10-day recommendation comments period following today’s call

- Link to BPM PRR 986: https://bpmcm.caiso.com/Pages/ViewPRR.aspx?PRRID=986&IsDlg=0

APPENDIX

Flexible Resource Adequacy 2018 Data and Spreadsheet Information

- 2018 Flexible RA data and related information can be found on our Flexible Capacity Needs Technical Study Process page:

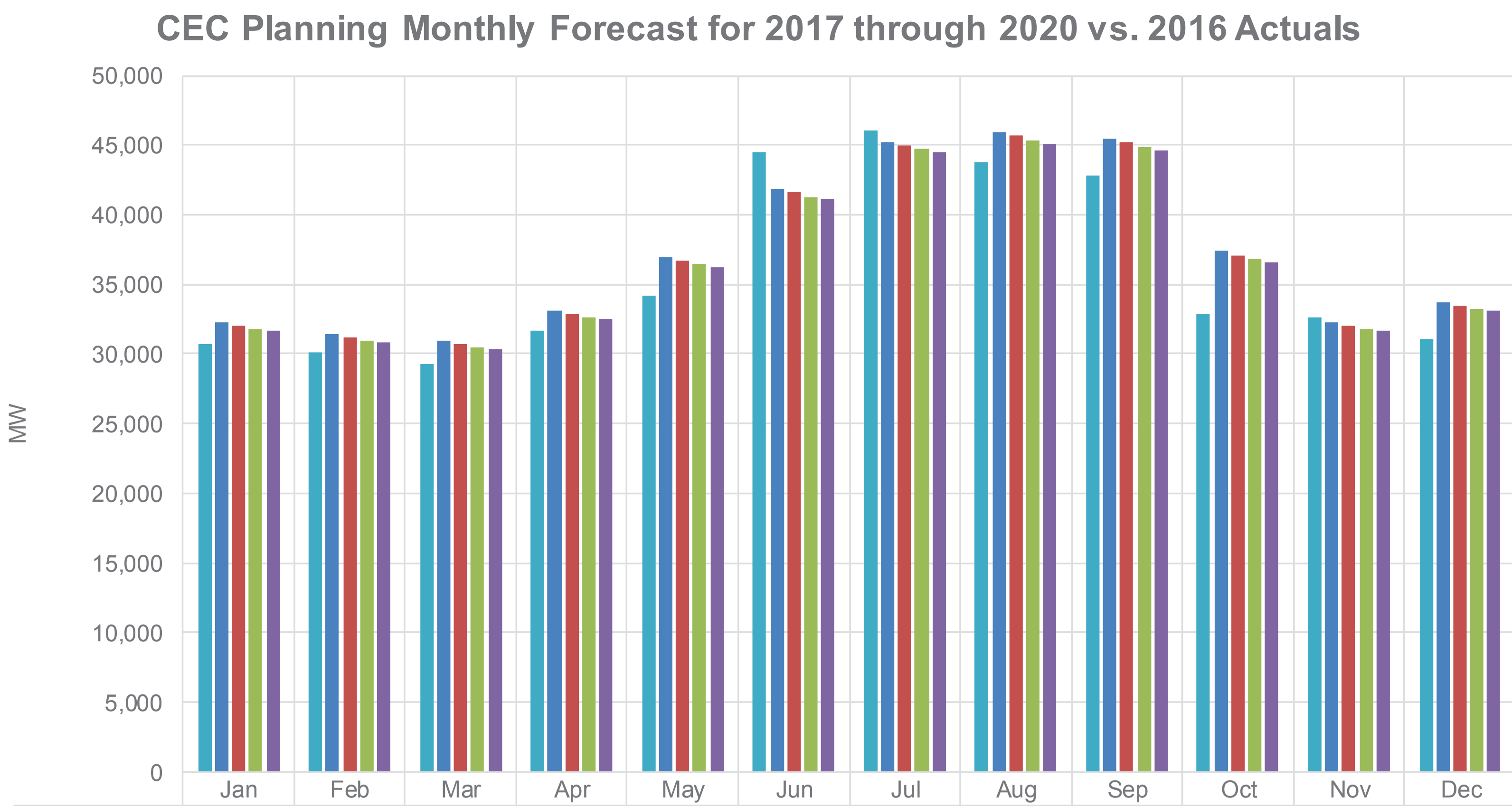
  http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityNeedsTechnicalStudyProcess.aspx

DATA COLLECTED AND USED

The ISO annual hour availability assessment is based on current LSE’s RPS build-out data

- Uses most current data available for renewable build-out obtained from all LSE SCs
- For new renewable installation scale 2016 actual production data based on installed capacity in subsequent years
- For new BTM use NEXANT production data located in close geographic proximity
- Generate gross-load profiles for 2017 through 2020

Projected 1 in 2 CAISO coincident peak, CEC Planning Forecast (Mid Baseline, Mid AAEE)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016 (Actual)	30,669	30,096	29,294	31,619	34,250	44,452	46,008	43,798	42,837	32,823	32,664	31,039
2017	32,299	31,453	30,944	33,113	36,989	41,834	45,259	45,967	45,489	37,384	32,322	33,661
2018	32,052	31,195	30,688	32,843	36,719	41,577	44,978	45,652	45,188	37,074	32,054	33,434
2019	31,845	30,979	30,477	32,613	36,463	41,312	44,685	45,336	44,882	36,799	31,826	33,241
2020	31,709	30,832	30,335	32,455	36,288	41,137	44,487	45,115	44,671	36,606	31,667	33,121

The ISO used the CEC's 1-in-2 monthly peak load forecast to develop the load forecast

- Used 2016 actual 1-minute load data to build 1-minute load profiles for 2017 through 2020
- Scaled the actual 1-minute load value of each month of 2016 using a load growth factor of monthly peak forecast divided by actual 2016 monthly peak

2017 Load Growth Assumptions

- Scale the actual 1-minute load value of each month of 2016 by the fraction ($Monthly_{2017\_Peak\_Load\_Forecast}/Monthly_{2016\_Actual\_Peak\_Load}$)

2018 Load Growth Assumptions

- Scale each 1-minute load data point of 2017 by the fraction ($Monthly_{2018\_Peak\_Load\_Forecast}/Monthly_{2016\_Peak\_Load}$)

2020 Load Growth Assumptions

- Scale each 1-minute load data point of 2018 by the fraction ($Monthly_{2020\_Peak\_Load\_Forecast}/Monthly_{2016\_Peak\_Load}$)

1-minute behind the meter solar PV data was developed using the methodology outlined below

TRACK I DIRECT TESTIMONY OF MARK ROTHLEDER ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION (Rulemaking 10-05-006)

Located at:

https://www.caiso.com/Documents/2011-08-10_ErrataLTPPTestimony_R10-05-006.pdf

Attachment B

CAISO's Proposed Revised Flexible Capacity Framework

California ISO

Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2

Revised Flexible Capacity Framework

January 31, 2018

Table of Contents

1. Executive Summary

The original FRACMOO proposal was an initial step toward ensuring that adequate flexible capacity was available to the ISO to address the needs of a more dynamic and rapidly transforming grid. The FRACMOO proposal represented the first ever flexible capacity obligation in any ISO market, recognizing that a resource adequacy program should include both the size (MW) of resource needs and the flexible attributes needed (e.g., dispatchability and ramp rate). The ISO anticipated making enhancements to the original FRACMOO design and tariff provisions once it had experience operating under a flexible capacity paradigm and better understood the system's flexible capacity needs, especially in light of the ISO's changing operational needs as the system relies more on variable and distributed energy resources. The ISO's assessment of the current flexible capacity product shows that it is overly inclusive, and risks exacerbating the ISO's operational challenges by sustaining largely inflexible resources (long starting, long minimum run times, and high Pmins) at the expense and financial viability of more flexible resources.

The current flexible RA product results in fundamental gaps between the ISO's markets and operational needs. The ISO seeks to close these gaps by developing a new flexible RA framework that more intentionally captures both the ISO's forecasted operational needs and the predictability (or unpredictability) of ramping needs. **Changes to the flexible capacity product and flexible capacity needs determination should align forward procurement with the ISO's actual operational needs and how the ISO commits and dispatches resources through the various market runs (i.e. Integrated Forward Market, fifteen-minute market, five-minute market runs).**

Success of a flexible RA program must include meeting anticipated ramping uncertainty within the time scales of the real-time market. The most efficient way to address this anticipated uncertainty is to develop flexible capacity rules and products that are tied directly to two types of ramping needs:

1) Predictable: known and/or reasonably forecastable ramping needs, and

2) Unpredictable: ramping needs caused by load following and forecast error.

The new flexible RA framework should address both predictable and forecastable ramping needs with the unpredictable and uncertain ramping needs. First, by ensuring there is sufficient capacity economically bid into the ISO day-ahead market to establish a market solution (as opposed to solutions that rely on penalty parameters) that properly shapes resources in the day-ahead to the forecasted load shape, and second by ensuring enough fast ramping and responsive resources are procured and available in real-time to address uncertainty.

The ISO conducted an assessment of the distribution of historical real-time uncertainty. These distributions provide the basis for what kind of granularity of uncertainty must be addressed and how much real-time uncertainty should be addressed in the planning horizon. The results of the ISO assessment show that it must manage a significant quantity of uncertainty between the day-ahead and real-time markets. This uncertainty can be over 4,000 MW in either direction, swinging more than 6,000 MW in any single day, and can occur even during the largest net-load ramps. Therefore, the ISO requires flexible RA products that include eligibility criteria focused on the ramping speed and dispatch capabilities to address these needs.

The ISO has conducted additional analysis regarding the relative ranges of the largest MW needs between day-time and night-time hours. While there was no clear delineation month-by-month, the ISO's general assessment is that roughly 75 percent of the day-time uncertainty presents a reasonable starting point for considering how much flexible capacity needs to be available 24 hours a day. To address these needs, the ISO proposes to develop three flexible RA products:

1) Five-minute Flexible RA
2) Fifteen-minute Flexible RA
3) Day-Ahead Shaping RA

The ISO must be prepared to address the largest uncertainties that occur with the shortest notice. **Therefore, flexible RA needs should first plan for the uncertainty that occurs between FMM and RTD, then extending that planning to longer notice intervals, i.e. IFM to FMM.** Resources capable of addressing FMM to RTD needs are also capable of addressing the uncertainty between IFM and FMM, but additional capacity should be procured to address the larger remaining uncertainty that occurs between IFM and FMM. As such, these flexible capacity requirements will be structured such that procuring higher quality resources will meet other identified needs.

The ISO proposes to establish the overall flexible capacity requirement in a manner similar to the current practices: the largest three-hour net ramp plus contingency reserves. However, there are two notable differences. First, the ISO will update the portion required for contingency reserves to align with the new BAL- 002 requirements. Second, the ISO will reconstitute the curtailed wind and solar resources into the three-hour net load ramp value. This will allow the new framework to include improved opportunities for imports and VERs to provide flexible RA capacity. The ISO's overall flexible capacity need will therefore be defined as:

Maximum Forecasted 3-Hour ramp (including reconstituted renewable curtailments) + ½ Max(MSSC, 6% of the monthly expected peak load) + ε

Given the stability of the distributions of the uncertainty, it is reasonable to expect flexibility needs at the highest end of the distribution almost monthly. **The ISO proposes to set flexible capacity requirements to encompass the widest range of uncertainty for all real-time flexible capacity products.**[1] Additionally, as load and resource variability continue to increase, this requirement will include an additional growth factor that will be based on the relative changes to each of the contributing factors (i.e. increasing in wind or solar or changes to load due to behind-the-meter-solar penetration). Finally, the ISO proposes that 100% of the monthly needs be procured for year ahead showings.

The ISO identifies basic eligibility criteria for the three basic Flexible RA products. Then the ISO details the must offer obligations and counting rules to provide each of these products. This is done separately for internal resources, EIM resources, and purely external resources (i.e. resources external to both the ISO BAA and any EIM). Then the ISO describes its proposed assessment of flexible RA capacity showings and backstop cost allocations

The ISO provides an assessment the most recent flexible RA showings to determine if these showings fulfilled the identified need or modifications to procurement practices would be required and if any market power concerns exist. This assessment shows that there will be adequate capacity available to meet each of the new flexible capacity products and there appear to be no market power concerns. Further, based on flexible RA showings to date, there appears to generally be sufficient five-minute and fifteen-minute flexibility shown system wide.

Proper allocation of flexible capacity requirements must be based on reasonable causation principles. The methodology currently employed by the ISO to allocate flexible capacity requirements is based on LSEs procurement practices. Further, the ISO proposes to maintain its current practice of allocating flexible capacity requirements based on an LRA's jurisdictional LSEs' contribution to the requirement.

The ISO proposes to allocate flexible capacity requirements based on the three primary contributing factors to each product. Specifically, the ISO will allocate based on the contributions from load, wind, and solar. This is similar to current practice. However, unlike current flexible RA allocation practice where the ISO applies a single allocation factor to all three flexible RA products, the ISO will apply this allocation methodology to each flexible RA product.

Given the need to create a more interconnected market, the ISO is also exploring additional market enhancements to enhance reliability, improve system control, and

[1] However, the ISO recognizes that anomalies may be identified that warrant a lower percentage. If anomalies are identified, then those data points will be discarded.

address real-time supply and demand uncertainty. These enhancements include developing a fifteen-minute IFM market, developing a day-ahead load following reserve product, exploring means to better ensure resources follow their Dispatch Operating Target (DOT), and investigating the root cause of recent intertie declines and any potential market changes necessary to mitigate this as a recurring problem.

2. Stakeholder Comments on Draft Flexible Capacity Framework

The ISO received 35 sets of comments to the draft flexible capacity framework. The ISO has summarized stakeholder comments based on central themes identified throughout the comments. Additionally, the ISO also addresses any substantive proposals put forward by stakeholders, including why such proposals were either accepted or rejected. While general responses to stakeholder proposals are provided here, additional details may be provided in subsequent relevant sections of this proposal. The ISO is adopting numerous stakeholder proposed design elements, as was recommended by WPTF.

PG&E, SDG&E, and SCE believe the ISO should pause the development of new flexible RA requirements until the development of the appropriate market enhancements is complete. However, numerous other stakeholders support the ISO's progress. Specifically, comments and frameworks submitted from E3 and WPTF[2] both align with the ISO's draft framework (and further clarified herein). The ISO believes both stakeholder processes are necessary and has identified the interdependencies between them. Given these independencies and the time necessary for policy develop and implementation, the ISO plans to conduct these two processes on parallel tracks.

2.1. Identification of Ramping and Uncertainty Needs

Most stakeholder comments indicate general support of the ISO's identification of predictable ramping needs and uncertainty as the two drivers of flexible capacity needs. Stakeholders are supportive of the ISO's goal to align the flexible capacity product and flexible capacity needs determination with actual operating needs. However, the ISO understands that a number of stakeholders believe the ISO should focus on market based solutions in addition to, or in lieu of, new flexible capacity products.

Stakeholders are generally supportive of the idea that a flexible RA program must include meeting anticipated ramping uncertainty within specified timeframes. However, the ISO received mixed comments on the three proposed products; Five-minute Flexible RA, Fifteen-minute Flexible RA, and Day-Ahead Shaping RA. Many stakeholders

[2] WPTF also cited to questions from their previous comments. There were too many questions to address each individually, but the ISO believes the spirit of these questions have been addressed through the body of this proposal.

generally support the three proposed products. For example, Powerex and PGP strongly support the ISO's proposal to adopt three distinct flexible RA products. E3 suggests that the ISO's products are generally reasonable but suggest an additional fourth product; a monthly RA capacity product with a sufficient planning reserve margin to ensure adequate spinning and non-spinning reserves. Alternatively, some stakeholders disagree with the need for some of the ISO's proposed products. For example, Cogentrix disagrees with the need to implement a five-minute product, and suggests that instead, a properly designed fifteen-minute product is adequate to meet real time uncertainty needs. However, the distinction between the five and fifteen-minute needs, is essential to ensure proper alignment with ISO markets and assures that the most pressing uncertainty needs are addressed.

The ISO has considered these comments and aims to ensure the flexible capacity framework and market design changes are in alignment. Given the ISO's state objective to align the flexible RA products with ISO markets, the ISO believes the three products proposed are necessary and will best meet operational needs. As such, the ISO proposal continues to include the five-minute, fifteen-minute, and day-ahead products.

2.2. Quantification of Flexible Resource Adequacy Needs

In its proposal, the ISO provided data demonstrating levels of uncertainty and net load ramps and requested stakeholder input regarding this data and potential procurement levels. Stakeholders appreciate the additional detail quantifying flexible capacity needs and generally support the proposed methodology as a starting point to meet these needs. Stakeholders offer the following suggestions regarding the quantification of flexibly capacity needs.

Many stakeholders including NRG, the CPUC, CDWR, Calpine, and CEERT and RNW question the need for additional flexible capacity for uncertainty beyond what is estimated for the predictable three-hour net load ramp. After considering stakeholder feedback, the ISO has modified its proposal by removing the additional upward uncertainty requirement based on the reasoning that the uncertainty need is already contained within the maximum three-hour net load ramping need.

Other stakeholders request additional review of regulation in identifying real time flexibility needs. For example, Powerex believes five-minute procurement requirement should include regulation need due to potential overlap between resources capable of providing regulation and those capable of providing five-minute flexible capacity. After considering these comments, the ISO finds Powerex's argument persuasive and proposes to add regulation to the five-minute flexible capacity need, as discussed in detail in section 5.3.2.

In its Draft Flexible Capacity Framework, the ISO provided historical data demonstrating the need for flexible capacity products. LS Power, CESA, PGP, Seattle City Light, and BPA recommend the ISO also use forecast data to determine future flexibility needs and procurement targets. BAMx and CCSF ask the ISO to consider using historical data to determine the amount of forecast error that is attributable to each type of VER and to gross load, then use this information along with projected VER and forecasted load to develop five-minute flexible capacity need. The ISO's proposal is in alignment with BAMx and CCSF's suggestion. The ISO will use this approach for both estimating forecasted needs as well as for allocating requirements. Section 5.3 provides greater detail regarding forecasted flexible capacity requirements, while Section 5.5 provides detail on the ISO's proposed allocation methodology, which allocates requirements based on a Local Regulatory Authority and/or Load Serving Entity's (LSE) contribution to flexible capacity need based on load and VER uncertainty.

Additionally, ORA recommends using the monthly error ranges of the past decade to detect trends of increasing uncertainty or months or seasons with increased uncertainty. The ISO continues to explore the correct time-horizon to include. While ten years is too long given the advancements in forecasting over that time, one year may not be adequate.

2.3. Eligibility Criteria

The ISO requested stakeholder feedback regarding operating parameters and threshold criteria resources must meet to provide the proposed flexible RA products. Stakeholders support the ISO's identification of fast ramping capability as the key eligibility criterion for providing flexible RA. Calpine is unaware of any analytic baseline for limiting eligibility to provide the proposed products beyond ramp rate as this demonstrates the ability to ramp sufficiently quickly within the relevant time frame. However, many other stakeholders, including LS Power, Cogentrix, and Powerex, support a fast start time requirement to provide capacity in time frames that require a fast response. CalWEA suggests strict technical requirements around eligibility for each product, such that any resource that can demonstrate that they can meet these requirements would be able to provide flexible RA. The ISO generally agrees with CalWEA, and believes that its proposal is in alignment with this suggestion with limited exceptions. Additional detail regarding eligibility criteria can be found in section 5.4.1.

NCPA supports the concept of defining attributes for resource eligibility but cautions the ISO to carefully define these attributes to avoid creating an artificial scenario that would strand relatively new and efficient gas generators that are not as fast as a single cycle combustion turbine, regardless of other benefits such as GHG superiority.

Most stakeholders, including Powerex, Energy Innovation, PGP, Six Cities, National Grid and BPA are supportive of the ISO's proposal to allow interties to provide flexible RA. Stakeholders support ensuring intertie resources are connected to physical resources. In their comments, Energy Innovation suggests that regional resources are already providing significant ramping capability and that the ISO should develop a formalized process for these resources to participate in RA and be compensated for the flexibility they provide. Alternatively, MRP expresses concern with allowing interties to provide flexible RA, suggesting resources located outside of California do not provide the same level of reliability and could not be subject to the same requirements as internal resources. While the ISO understands the concerns raised by MRP, Energy Innovation is correct. Imports are providing flexible capacity benefits today, particularly in addressing the three-hour net load ramps. With requirements comparable to those required for providing generic RA, interties can provide comparable dependable flexible capacity. Section 5.4.1 provides detailed discussion of the ISO's proposed eligibility criteria for each product, including specifics on requirements for internal resources, resources within an Energy Imbalance Market (EIM) Balancing Area Authority (BAA), and purely external resources.

Stakeholders are supportive of the ISO proposal to allow VERs to provide flexible RA through economic bidding. In their comments, E3 suggests that VERs can significantly reduce the quantity of flexible capacity services needed from thermal generators or other resources. As such the ISO should ensure procurement guidelines take maximum advantage of VERs' ability to provide economic flexibility.

ECE suggests that while deliverability studies are appropriate for generic RA, they should not be used to determine a resource's eligibility for flexible RA. Instead, all resources should be eligible to provide flexible RA as long as they are willing to assume the economic MOO. The ISO believes it is important to ensure flexible capacity is deliverable. As such, this proposal modifies existing EFC eligibility to include a flexible capacity deliverability study to determine how much flexible capacity is deliverable during the times of greatest flexibility need. Because the ISO will conduct two separate deliverability studies, NQC and EFC can be reasonably and reliably unbundled. Section 5.4.1 describes in detail the ISO's proposal regarding EFC values and deliverability studies.

2.4. Must Offer Obligation

The ISO also requested stakeholder input on the structuring of Must Offer Obligation (MOO) windows for the day-ahead shaping product and real-time products (i.e. five and fifteen-minute products). Currently, resources with flexible RA have MOOs for the day-ahead and real-time for time periods based on the type of flexible RA they are awarded. Because we observe more uncertainty during particular daylight hours, the ISO considered creating an additional day time product with a shorter obligation window. Some stakeholders including CEDMC, First Solar, and Six Cities support a more granular approach to MOO that would take into account times of day with the largest operational need. Others, including Powerex, Seattle City Light, and LS Power, support a structure in which if a resource receives flexible RA, they have a 24 by seven MOO in the day ahead and real time markets. In order to maintain a three-product structure, the ISO is proposing MOOs be consistent across all resources providing a given product. Section 5.4.2 includes detailed descriptions of MOOs for the day-ahead and real-time products, including how they apply to VERs and resources internal and external to the ISO.

2.5. Flexible RA Counting Rules

The ISO's foundational counting rule for meeting flexible RA requirements is that capacity procured to meet a higher quality product will automatically be counted towards meeting the lower quality requirements. Some stakeholders, such as Calpine, support this nesting requirement. Energy Innovation, however, suggests entirely different requirements with different rules would work better than nesting the requirements. Once procured and shown as flexible RA, the ISO's market dispatches will ensure resources are dispatched optimally to meet operational needs. The ISO's proposal is based in meeting needs in shorter time horizons. However, another critical element of this proposal is simplicity and fungibility. The three proposed products have similar rules and obligations to help meet these objectives. Therefore, it is necessary to maintain the ISO's proposed "nested requirements."

For the five and fifteen-minute flexible RA products, PGP and Powerex's beliefs are in alignment with the ISO's proposal to base resource counting on the number of MWs a resource can ramp in a given time interval.

For the day-ahead shaping product, Calpine recommends eliminating the 90 minute start-time requirement for the day ahead product. The ISO declines to remove the start-time as a means to determine if the Pmin is flexible, in order to manage the Pmin burden of long start resources.

For VER Effective Flexible Capacity (EFC) calculations, many stakeholders, including E3, NRG, and PG&E suggested variations of a forward looking EFC calculation that uses a forecast of VER output to determine flexibility. For example, PG&E recommended a simple and complex method. The simple approach uses nameplate capacities to translate the aggregate contribution of wind and solar resources to an individual wind and solar resource's contribution to the maximum monthly three hour net load ramp. The complex approach changes the Flexible RA requirement to use Day-Ahead load and renewable forecasts to calculate each resource's contribution to the monthly maximum three hour net load ramp. The ISO gave both of PG&E's proposed options significant consideration. However, ultimately, the ISO believes there is an intermediate option for determining the monthly EFC for VERs: a variant of the exceedance methodology. This is discussed in greater detail in section 5.4.1.1.

CEDMC, Nextera, and ECE support the decoupling of EFC values from Net Qualifying Capacity (NQC) values to allow resources to provide flexible RA without qualifying as generic RA. They suggest some resources, including storage and demand response, are capable of providing flexible capacity but are unable to do so because of the requirement that they must also meet system RA requirements in addition to flexible RA.

2.6. Equitable Allocation of Flexible Capacity Needs

Many stakeholders, including NRG, BAMx and CCSF, CalWEA, CDWR, and the CPUC, support using a similar approach to the ISO's current allocation methodology in which the ISO allocates the proportion of system flexible capacity needs to each LRA based on its jurisdictional LSEs' contribution to the largest three-hour net load ramp change each month. NRG strongly opposes allocating flexible capacity requirement to flexible generation such as VERs, and instead asserts that the costs associated to procurement should be allocated to load, as is done today. Additionally, VEA voiced concern regarding changes to the Flexible RA allocation that may adversely affect smaller LSEs due to potential cost shifts. CEERT and RNW recommend little effort be spent on developing new cost allocation protocols until at least a few years of actual experience with the newly developed fifteen-minute and five-minute products.

Some stakeholders provided suggested changes to the ISO's allocation methodology. BPA suggests the ISO develop a methodology that identifies sources of uncertainty created by loads and resources, and a means for estimating the level of uncertainty for defined groups, including the net loads of an LSE, the RA resources selected by that LSE, non-RA resources interconnected in the ISO BAA, and imports into the ISO. CLECA proposes an allocation methodology based on the resource portfolios of the various LSEs.

The ISO has considered these comments and will base allocation of requirements on similar causation rules as are used today, but will apply a more granular measurement than simply maintaining the existing approach. The ISO believes its proposal is generally in alignment with CLECA's proposal. Each flexible capacity requirement will be allocated based on a proportion of need caused by load and VER uncertainty and proportion of each LSE or LRA share. Allocation of flexible capacity needs are further addressed in Section 5.5.

2.7. Other

PGP and Powerex believe the Maximum Import Capability (MIC) framework impedes efficient and least-cost procurement of flexible RA by artificially limiting participation of external resources that can satisfy flexible RA requirements. The ISO believes that the MIC allocation process is beyond the scope of this stakeholder process. However, as the ISO extends the ability to provide flexible RA capacity to external resources, it remains critical that this capacity is deliverable. Therefore, the ISO is not proposing any changes to the MIC allocation process but is proposing that LSEs must have a MIC for any imports that provide flexible RA.

The ISO received several comments regarding the calculation of net load and the treatment of self-schedules. CDWR supports the exclusion of self-schedules from the calculation of net load and notes that at times, they are required to self-schedule generation but can do so in a way that minimizes the system need for flexibility. In addition, PG&E supports the proposed Day Ahead flexible RA product structure based on the current three-hour net load ramp for now, but does not support a flexible RA structure that completely ignores the ability of self-schedules to adjust to load changes. PG&E and BAMx and CCSF believe that in the future, a DA shaping flexible capacity requirement should account for the flexibility provided by self-schedules. WPTF and PCWA believe the ISO should explore alternative definitions of net load to better align with operational needs. PCWA suggest a longer eight hour ramp and net load defined as load minus non-dispatchable resources may be a better depiction of operational reality. At this time, the ISO will maintain the previously defined definition of net load as gross load minus wind minus solar, while reconstituting the concept of economic curtailment.

Cogentrix expressed concerns that the current proposal will take unnecessarily long to implement and will not address the goal of sending proper signals for the efficient retention and retirements of existing generation. Cogentrix proposes splitting the FRACMOO2 effort into two tracks in order to facilitate a timelier implementation. Track One would develop a Transitional Needs Based Flexible RA Program with two products: Flexible RA and Fast Flexible RA. This one-time transition proposal would be implemented for the 2019 RA season and have a three-year term. Track Two would develop the long term reformation of Resource Adequacy and include all of the other issues raised in the current Straw Proposal and be implemented by the 2022 RA season. While the ISO understands the concern over an unnecessarily long implementation time, the ISO's proposed timeline and scope (i.e. no interim steps) is consistent with the schedule put forth in the CPUC's scoping memo in R.17-09-020. This will ensure implementation Fall 2019, effective for the 2020 year. Therefore, the ISO declines to adopt this aspect of the Cogentrix proposal.

3. Stakeholder Engagement Plan

The FRACMOO2 flexible capacity framework initiative schedule is shown below. The ISO's intent is to move this framework into the CPUC's resource adequacy proceeding where parties can further discuss how the framework informs needed resource capabilities, and how it should be incorporated into the CPUC's resource adequacy program.

Milestone	Date
Revised straw proposal posted	May 1, 2017
Revised straw proposal stakeholder meeting	May 8, 2017
Stakeholder written comments due	May 22, 2017
Working group meeting	September 26, 2017
Draft Flexible Capacity Framework posted	November 17, 2017
Draft Flexible Capacity Framework stakeholder Meeting	November 29, 2017
Stakeholder Written Comments Due	December 13, 2017
Revised Flexible Capacity Framework posted	January 31, 2018
Revised Flexible Capacity Framework stakeholder Meeting	February 7, 2018
Submit Revised Flexible Capacity Framework into CPUC RA proceeding	February 16, 2018
Stakeholder Written Comments Due	February 21, 2018
Second Revised Flexible Capacity Framework posted	Early April, 2018
Second Revised Flexible Capacity Framework stakeholder Meeting	Mid-April, 2018
Stakeholder Written Comments Due	Early May, 2018
Draft Final Flexible Capacity Framework posted and submitted to the CPUC RA proceeding	June 6, 2018
Draft Final Flexible Capacity Framework stakeholder Meeting	June 13, 2018
Stakeholder Written Comments Due	June 27, 2018
Complete coordination with CPUC's RA proceeding prior to Board Approval of final flexible RA Framework	Q4 2018

4. Background

In 2014, the ISO filed, and FERC subsequently approved, tariff revisions to implement the ISO's FRACMOO proposal. The ISO developed the original FRACMOO proposal and accompanying tariff provisions through an extensive stakeholder process in collaboration with the CPUC, municipal utilities, investor-owned utilities, generators, environmental groups, and other market participants. The FRACMOO proposal was a first step toward ensuring that load serving entities procured and offered resources to the ISO that would ensure the ISO had sufficient flexible capacity to reliably operate a transforming grid that was growing more reliant on distributed and variable energy resources. The tariff provisions resulting from that effort provided the ISO with a flexible capacity framework. Specifically, the FRACMOO tariff provisions established:

- A study methodology for determining flexible capacity needs and allocating those needs to local regulatory authorities;
- Rules for assessing the system-wide adequacy of flexible capacity showings;
- Backstop procurement authority to address system-wide deficiencies of flexible capacity; and
- Must offer obligations to ensure the ISO has the authority to commit and dispatch flexible resources through its markets.

When the ISO filed the tariff revisions to implement the FRACMOO proposal with FERC, the ISO stated:

> This simplified initial approach provides a smooth transition to establishing durable flexible capacity requirements. The ISO has committed to re-evaluating the effectiveness of the flexible capacity requirements in 2016 to consider, among other matters, whether enhancements are needed to meet system flexibility needs or to allow resources that are dispatchable on a fifteen-minute basis to fulfill a portion of the flexible capacity needs.[3]

The original FRACMOO proposal was an initial step toward ensuring that adequate flexible capacity was available to the ISO to address the needs of a more dynamic and rapidly transforming grid. The FRACMOO proposal also represented the first ever flexible capacity obligation in any ISO market, recognizing that a resource adequacy program should include both the size (MW) of resource needs and the attributes of the resources providing them (e.g., dispatchability and ramp rate). The ISO expected to make enhancements to the original FRACMOO tariff provisions once it had experience

[3] Transmittal letter at p. 19.

with a flexible capacity paradigm and better understood the system's flexible capacity needs, especially in light of the ISO's operational needs.

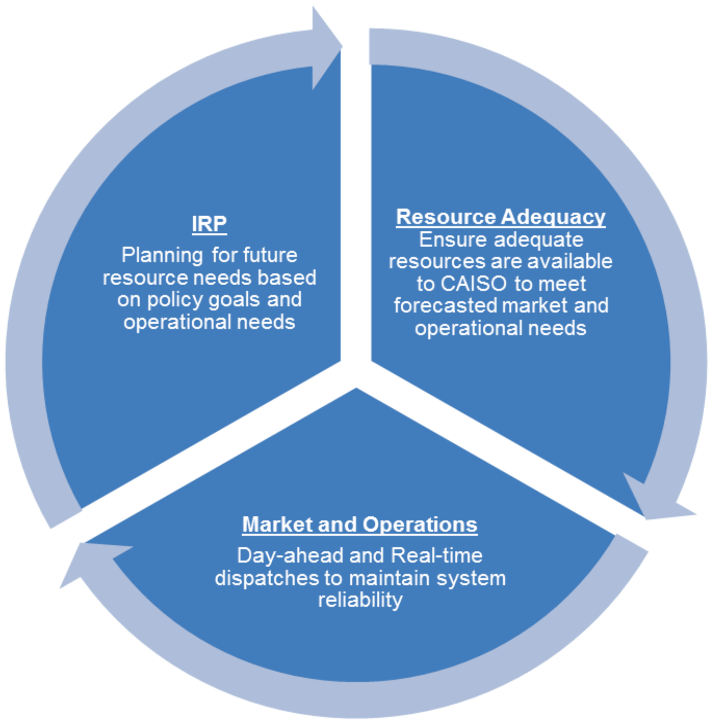
One of the initial FRACMOO goals was simplicity and an opportunity for a variety of resource types to provide flexible capacity. The rules allowed for virtually all technology types to offer flexible capacity, regardless of operational attributes like start-up time and minimum run-time. These rules also did not impose requirements on the dispatch frequency of resources. This highly inclusive set of eligibility criteria gave LSEs broad discretion over how to meet their flexible capacity requirements. It has also allowed the ISO to gain important insights into how well-suited the flexible capacity resources shown would meet future ISO reliability needs, and what signals were being sent to the market for mid-term and long-term flexible resource procurement. The ISO's assessment shows that the current flexible capacity product is overly inclusive, and risks exacerbating the ISO's operational challenges by sustaining largely inflexible resources (long starting, long minimum run times, and high Pmins) at the expense and financial viability of more flexible resources.

Ultimately, ISO grid operations and operational needs are determined by resource planning decisions, including resource additions and retirements. The selection of resources to build, maintain, and retire all impact the ISO's ability to reliably operate the grid with RA resources. Figure 1 shows how resource planning and procurement are critically connected to ISO operations. Any enhancements to the flexible RA program should inform both the Integrated Resource Plan at the CPUC and RA programs across all LRAs. Therefore, the ISO's flexible RA framework should achieve the following overarching goals:

1) Provide signals to help ensure the efficient retention and retirement of existing resources; and
2) Provide the ISO a resource portfolio that meets grid reliability needs through economic market dispatch, including a Flexible RA program that ensures access to the flexibility of the fleet to ensure reliable grid operation all hours of the year.

The current flexible RA product does not ensure either of these goals is met. For example, over 4,000 MW of once-through cooling (OTC) resources have been shown as flexible RA resources. These OTC resources are planned to retire over the next couple years and are infrequently dispatched in day-ahead and, therefore, unavailable to address real-time market needs.

Figure 1: A unified vision guiding planning, procurement, and operations



Given the need to create a more interconnected market, the ISO is also exploring additional market enhancements to enhance reliability, improve system control, and address real-time supply and demand uncertainty. Specifically, the ISO will:

- Develop a fifteen-minute IFM market: This product will make IFM schedules more granular and allow the ISO to better shape dispatches, reducing the amount of load following required between IFM and FMM.
- Develop a day-ahead load following reserve product: This product is similar to the existing real-time flexible ramping product; however, it is designed to ensure there is sufficient load following capabilities (both up and down) reserved between day-ahead and real-time markets.
    - ISO plans to conduct these two processes on parallel tracks.
    - The ISO believes both stakeholder processes are necessary (FRACMOO2 to ensure sufficient flexible capacity is available, the day-ahead load following reserve product to help ensure an efficient use of these resources) and has identified the interdependencies between them, including how much of the day-ahead load following reserve product is needed relative to the availability and offer obligations for flexible capacity.

5. Proposed Flexible Capacity Framework

In November 2016, the ISO published a supplemental issue paper to expand the scope of the FRACMOO2 stakeholder initiative. As part of the supplemental issue paper, the ISO conducted a preliminary assessment of historic flexible RA showings finding "that the flexible capacity product is not sending the correct signal to ensure flexible capacity will be maintained long-term."[4] The ISO identified numerous issues and potential enhancements to mitigate these concerns in the supplemental issue paper, and explored these issues more thoroughly in the Revised Straw Proposal – Short-Term Solutions.[5]

The current flexible RA product fails to address fundamental gaps between the ISO's markets and operational needs. **The ISO seeks to close this gap by developing a new flexible RA framework that more deliberately captures both the ISO's operational needs and the predictability (or unpredictability) of ramping needs.[6]** Changes to the flexible capacity product and flexible capacity needs determination should closely align with the ISO's actual operational needs in alignment with the ISO's various market runs (i.e. Integrated Forward Market (IFM), fifteen-minute market, five-minute market runs).

Success is not simply whether the flexible RA fleet can meet an *ex-ante* known determined ramp, but whether it also can meet anticipated ramping uncertainty within the time scales of the real-time market. Under the current flexible RA paradigm, there is no assurance the flexible RA resources procured are capable of meeting real-time ramping uncertainty. Enhancing the flexible RA product to incorporate ramping speed and real-time availability sends an important longer-term procurement signal to the market to ensure the ISO has the resource's procured and available to satisfy anticipated, yet unpredictable ramping needs. The most efficient way to address this anticipated uncertainty is to develop flexible capacity rules and products that are tied directly to both known and unknown ramping needs. As such, the ISO will work with stakeholders to achieve the following objectives:

[4] http://www.CAISO.com/Documents/AgendaandPresentation-FlexibleResourceAdequacyCriteriaMustOfferObligationPhase2-SupplementalIssuePaper.pdf
[5] http://www.caiso.com/Documents/RevisedStrawProposal-FlexibleResourceAdequacyCriteriaandMustOfferObligationPhase2.pdf
[6] In comments, WTPF indicated that the ISO's policy should aim to influence procurement practices. While the ultimate result of the proposed policy may be changes to procurement practices, this is not a primary objective of this initiative. The goal is to clearly send signals to the market about the operational attributes that are needed to reliably operate the grid. LRAs and LSEs should remain the entities with the primary responsibility for determining what resources should be procured to meet a given requirement.

A. Develop critical linkages between RA and energy markets to ensure the ISO is able to meet grid reliability needs through its markets, accounting for uncertainty (including load forecast error, VER forecast error, and outages and other resource deviations);
B. Provide a framework for intertie, Energy Imbalance Market (EIM) and VER resources to be part of the flexible capacity solution; and
C. Provide LSEs and LRAs flexibility to meet system, local, and flexible capacity needs in ways that best align with their business and policy objectives.

The remainder of this section provides the basis of a new flexible RA framework in five steps.

1) Identify the ramping needs that flexible RA should be procured to address;
2) Define the product to be procured;
3) Quantify the capacity needed to address all identified needs;
4) Establish criteria regarding how resources qualify for meeting these needs including:
    a. Basic eligibility criteria;
    b. Must-offer obligations;
    c. Counting rules; and
    d. Establish rules necessary to determine if sufficient capacity has been procured or if additional procurement is needed. This includes any necessary backstop procurement rules.
5) Allocation of flexible capacity requirements based on a sound causal principles.

The ISO is still assessing the impact of this new framework on the Resource Adequacy Availability Incentive Mechanism (RAAIM). While the ISO understands that changes will be required, these changes will ultimately depend on other fundamental elements of the new flexible RA framework. Therefore, the ISO will not propose modifications to RAAIM as part of this present proposal, but will assess in the next iteration of this stakeholder process when those other elements become clearer.

Once a complete flexible capacity program is established that achieves goals A-C, above, the ISO believes it will then be possible to replace the existing flexible capacity products with this new design construct. This includes eliminating the exiting flexible capacity categories in favor of this proposed framework.

5.1. Identifying Ramping Needs

The ISO reviewed the day-to-day operational system needs pertaining to flexible capacity.[7] The ISO sees flexible capacity needs breaking down into two categories:

1) Predictable: known and/or reasonably forecastable ramping needs, and

2) Unpredictable: ramping needs caused by load following and forecast error.

These two types of flexible capacity needs─ predictable and unpredictable─ drive different forms of flexible capacity procurement needs. Predictable and reasonably forecastable ramping needs require a fairly large set of resources economically bidding into the ISO's day-ahead market to properly shape the day-ahead market to meet forecastable ramps. This allows the ISO to create a feasible market dispatch in the day-ahead market without relying on penalty parameters or exceptional dispatches. However, once the ISO produces a day-ahead dispatch solution the ISO must rely on real-time market dispatches to account for unpredictable ramps caused by uncertainty and load following.

The ISO's flexible capacity framework is based on connecting these two ramping needs into a single larger framework. The remainder of this section describes each type of ramping needs in greater detail.

5.1.1. Predictable and forecastable ramping needs

The current flexible RA product needs determination is based on the largest forecasted three-hour net load plus 3.5 percent expected peak load.[8] The net load ramp is driven largely by the setting of the sun during the non-summer months, when the ramps are greatest. Numerous stakeholders have questioned the need for a specific RA product predicated on ramps that are largely predictable. The ISO agrees that these ramps are largely forecastable on a day-to-day basis; however, this does not mean forward procurement to meet these ramps is not important for continued reliable operations. Setting up a fleet of resources to meet day-ahead net load ramps allows the ISO to better shape day-ahead commitments. Specifically, a deeper pool of resources that can be flexible in the IFM through day-ahead economic bids will improve the efficiency of the ISO dispatch and management of renewable resources.

[7] The ISO issued a revised straw proposal in the initiative on May 1, 2017. Based on stakeholder feedback and continued assessment of system operational needs, the ISO will not pursue further action on that proposal.

[8] The 3.5 percent portion of this equation was originally established to address overlap between flexible RA provisions and contingency reserves. However, the basis for determining the quantity of contingency reserves needed has since been revised.

To date, the ISO manages most resource commitments through the IFM process. The ISO does not expect this to change. However, the ISO expects net load ramps to grow and minimum net load to decrease over time. This will likely lead to ramp constraints within the RA fleet and require additional exceptional dispatches if not addressed through forward planning. As such, the ISO proposes to maintain a product for, and assessment of, flexible capacity that ensures there is sufficient bid range to cover the forecasted maximum three-hour net load ramps.[9] The ISO envisions that this day-ahead shaping product will provide the resources the ISO needs to shape IFM awards and commitments based on market solutions and should mitigate the need for exceptional dispatches and Capacity Procurement Mechanism (CPM) designations. The objective of this product will be to improve ISO market efficiency and send signal to the market about how well procurement profiles are able to facilitate increased VER penetration. Additionally, this tool will provide information about the likelihood and frequency of exceptional dispatch CPM designations.

5.1.2. Unpredictable and uncertain ramping needs

With the continued expansion of VERs and behind-the-meter solar photovoltaic systems, both load and generation output will continue to create greater uncertainty between the day-ahead and real-time markets. The ISO has always faced this uncertainty. The ISO's IFM and residual unit commitment (RUC) process is tasked with sending financially binding awards to generating resources to address forecasted load. Once the day-ahead market and RUC close and awards are made, the opportunity to commit additional long-start resources has passed. All remaining uncertainty, including both load following and forecast error, must be addressed by resources previously committed in the IFM or those faster more flexible resources that are committable during the real-time market runs.

The ISO proposes to develop flexible capacity products to address forecast error and load following needs between IFM and real-time dispatch. While the benefits of having sufficient ramping capabilities to address the three-hour net load ramp were addressed in great detail through the initial FRACMOO process, the challenges with uncertainty from forecast error and load following in the forward planning horizon did not

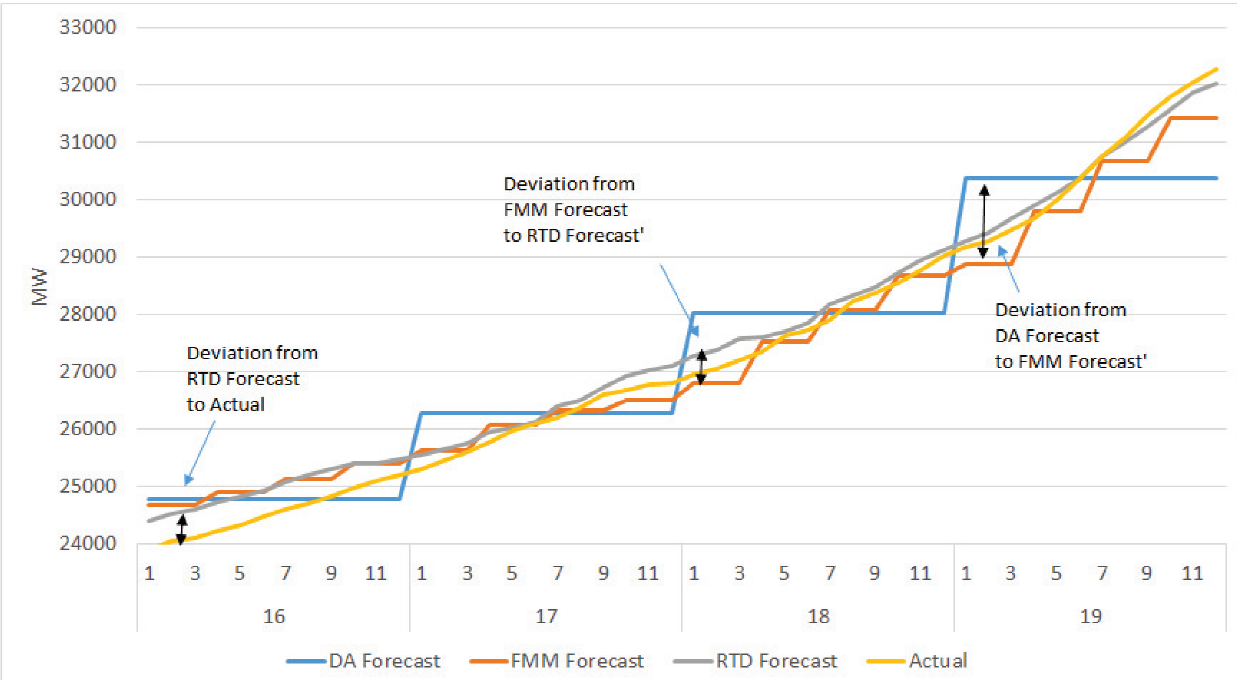
[9] WPTF opposes the ISO's continued use of net load defined as load minus wind and solar. However, it should be noted that this is a NERC accepted definition of net load. To avoid confusion, the ISO will not use the term "net load" differently than NERC. Additionally, the ISO understands that the issue raised by WPTF is not really how net load is defined, but how the ISO identifies the operational needs the ISO seeks to address within the scope of FRACMOO2. The ISO has reviewed numerous ramping time horizons (i.e. 6-8 hours) and has not identified a need longer than the three-hour net load ramp. While summer days have longer ramps with greater magnitudes in terms of MWs, the overall net load ramp rates observed on the days is far less than observed during the non-summer months three-hour net load ramps. As such, the ISO will not explore a flexible RA product spanning a time interval longer than three hours.

receive comparable attention. Therefore, the ISO provides here the additional details and descriptions of the challenges and magnitude of issues that must be addressed.

5.1.3. Description of Real-Time Uncertainty

Uncertainty between day-ahead and real-time can be addressed at three levels of granularity: between the IFM's hourly dispatch to Fifteen-Minute Market (FMM), the FMM to the Real-Time Dispatch (RTD), and the RTD and actual operations. Figure 2 depicts each of these types of error/uncertainty.

Figure 2: Forecast error and load following needs between IFM and actual needs



The yellow line in Figure 2 shows the actual net load the ISO served between hours ending 16 through 19 on a given day. The ISO's first full market run is its IFM. This market is currently run at an hourly granularity using a forecast between 14 to 36 hours ahead of actual operations. This is shown by the blue line. Given the large increments of time and the gap between the market run and operations, there can be significant differences between this commitment and actual operations based on forecast error and the lack of granularity. This is particularly true during the times surrounding sun rise and sun set. The next ISO market iteration is the FMM, shown by the orange line. It runs every fifteen minutes and uses more up-to-date forecasts and covers shorter time intervals. The FMM should improve on IFM commitments and awards and ensure faster ramping resources are committed in instances were forecast error and/or load following requires it. The FMM represents a more temporally proximate and more granular forecast than the IFM.

The RTD is even closer and more granular. The RTD is represented by the grey line and is the final market solution run to serve actual load. The RTD is run every 5 minutes, which occurs 12.5 minutes prior to real-time, with actual dispatches sent 7.5 minutes prior to real-time. The objective of each of these iterations is to refine the resource commitment and dispatches, once through IFM, then FMM and again in the RTD. Once RTD has run, forecast errors are still present. Thus, the ISO now relies on regulation to balance the system post RTD. Regulation is procured in the day-ahead market for upward and downward balancing needs. These needs are shown as the difference between the grey and yellow lines.

The ISO notes that regulation is distinct from the other types of uncertainty in three ways. First regulation is explicitly procured through the day-ahead market. Second, a resource's ability to provide regulation is based on it having Automatic Generation Control (AGC). Finally, there is sufficient regulation capacity available in the system. However, in comments, Powerex notes that the same type of resources needed to address five-minute uncertainty would be procured by the ISO for regulation. Powerex's comment is based on the same rationale the ISO originally used when including contingency reserves in the original FRACMOO proposal. Therefore, the ISO proposes to include regulation as part of the five-minute flexible capacity need. The ISO is currently exploring the options for how much overlap to account for. It is not necessary to cover the maximum range of uncertainty between RTD and actual load. Instead, the ISO is currently focused on options that reflect the quantities of market procurement of regulation. The ISO seeks additional stakeholder comments regarding the level of overlap to include flexible capacity needs.

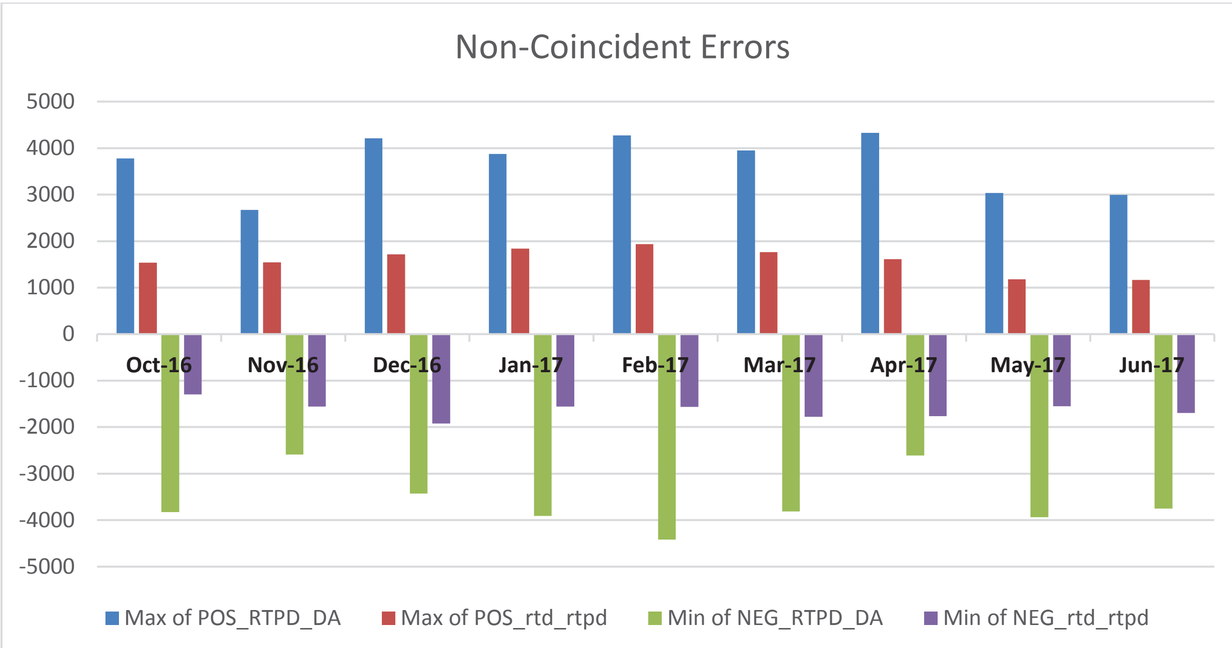
5.2. Defining the Flexible RA Products Needed

The ISO needs flexible capacity products that address both predictable and unpredictable ramping needs. To address these needs the ISO proposes three flexible capacity products.

1) Day-ahead load shaping
2) Fifteen-minute flexible RA capacity
3) Five-minute flexible RA capacity

The day-ahead load shaping product should ensure the ISO is able to meet its three-hour net load ramps. The real-time products – the five and fifteen minute flexible RA capacity – will be designed to address real-time uncertainty, including both forecast error and load following needs that occur between IFM and RTD. The ISO has conducted additional analysis on each of these levels of uncertainty. Figure 3 shows the maximum non-coincident errors for October 2016 through June 2017.[10]

Figure 3: Maximum non-coincident error



As Figure 3 demonstrates, the range of maximum forecast errors (including both upward and downward errors) between FMM and RTD are fairly consistent over all months, ranging between 2,700 MW and 3,600 MW. While the range of maximum forecast errors between the IFM and the FMM shows slightly more deviation, between 5,200 MW and 8,700 MW, these deviations are likely due to weather sensitivity and weather conditions between the IFM and FMM. However, the data shows an overall upward trend over time for both intervals.

Although these uncertainties are non-coincidental and do not occur on the same day, they do provide a basis for determining how much uncertainty might be needed on a given day and the timeframe within which that uncertainty occurs. However, in recognition of the fact that these errors are non-coincident, the ISO is not seeking to address each source of error independently. The ISO has also conducted an analysis of the coincident errors for these same months. This is shown in Figure 4.

[10] The ISO is in the process of updating this data using all of 2016-2017 data. This data, along with updated analysis, will be posted to the ISO webpage as soon as this update is complete.

Figure 4: Maximum Coincident Errors

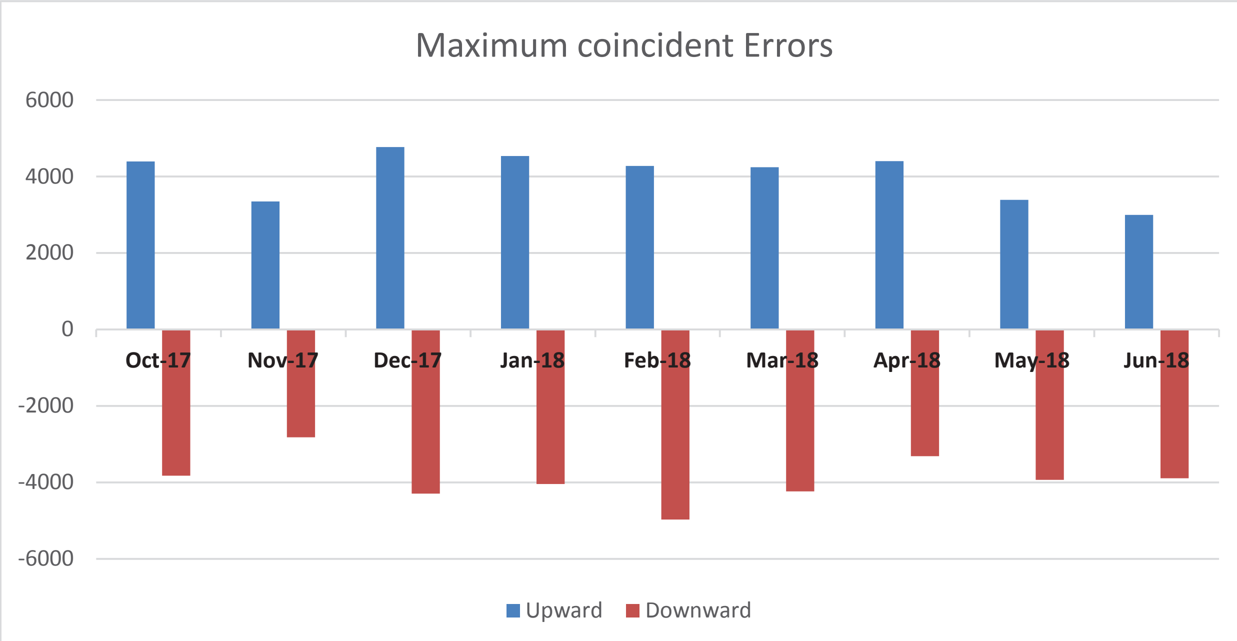


Figure 4 shows the maximum coincident real-time uncertainty by upward and downward ranges. On the days the ISO experienced the greatest coincident uncertainty, almost all the uncertainty was the difference between the IFM and the FMM. While these ranges do not occur on the same days, it is not possible to know which could occur until they are actually realized. Ranges of uncertainty realized on a single day are discussed below.

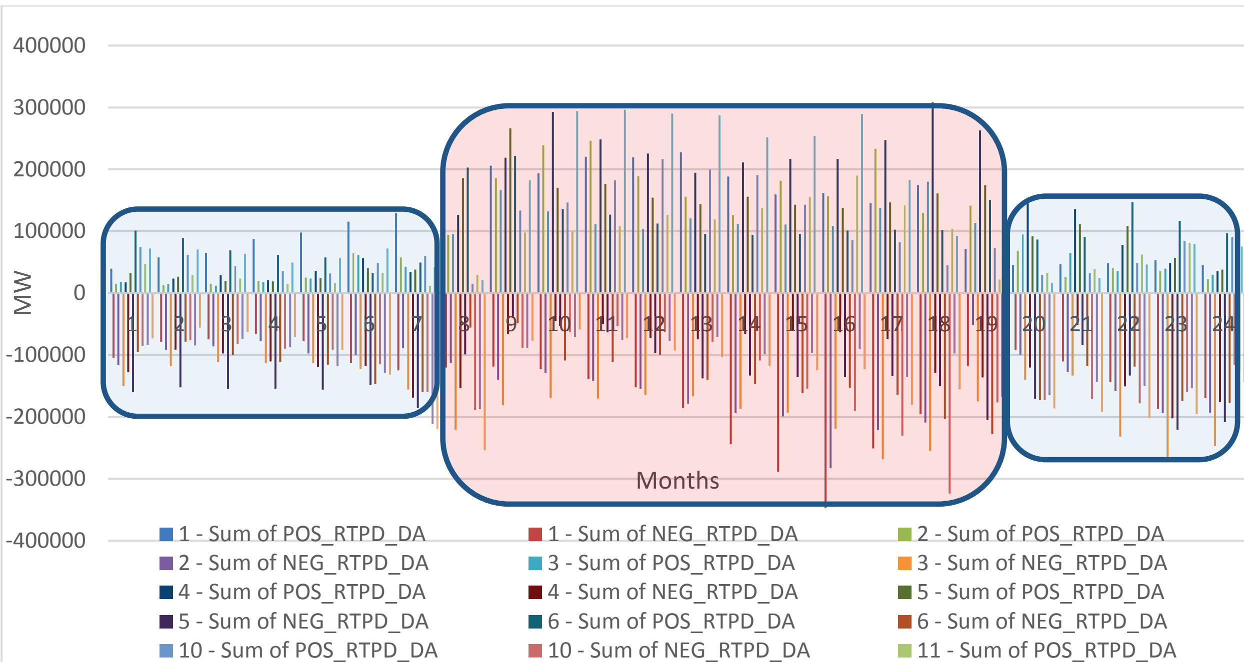
The ISO must be prepared to address the largest uncertainties that occur with the shortest notice. **Therefore, flexible RA needs should first plan for the uncertainty that occurs between FMM and RTD, then extending that planning to longer notice intervals, i.e. IFM to FMM.** Resources capable of addressing FMM to RTD needs are also capable of addressing the uncertainty between IFM and FMM, but additional capacity should be procured to address the larger remaining uncertainty that occurs between IFM and FMM.

Additionally, because the ISO does not know if the uncertainty will be due to under or over-forecast error, flexible RA needs should be procured to cover both upward and downward uncertainty ranges. Therefore, while real-time flexible RA may not need to be greater than the maximum coincidental errors, flexible RA requirements should account for the both the upward and downward uncertainty between the FMM to RTD and IFM to FMM.

5.2.1. Assessing the timing of uncertainty

While this uncertainty can occur at any time, the greatest potential uncertainty occurs during daytime hours while load and solar output have the greatest potential for change, including during the largest three-hour net load ramps. Figure 5 clearly demonstrates that more forecast error occurs during daylight hours. This is simply a function of more load and VER output leading to greater levels of uncertainty occurring between market runs. Additionally, Figure 5 shows that a fair amount of error occurs during net load ramping intervals, including upward ramping needs.

Figure 5: Timing of Observed Uncertainty



The ISO has conducted additional analysis regarding the relative ranges of the largest MW needs between day-time and night-time hours.[11] The proportion of the largest uncertainty range night-time hours to day-time uncertainty was fairly wide ranging, between 50 percent and 80 percent for the IFM to FMM and 50 percent to 95 percent for FMM to RTD. While there was no clear delineation month-by-month, the ISO's general assessment is that roughly 75 percent of the day-time uncertainty presents a reasonable starting point for considering how much flexible capacity needs to be available 24 hours a day. This difference demonstrates that there are opportunities for resources, like solar, that may not have a fuel source during night-time hours to provide flexible RA capacity.

[11] Daytime hours are defined generally as hours ending 7-19. Night-time hours are hours ending 1-7 and 20-24.

5.3. Quantifying Flexible Resource Adequacy Needs

The previous section defined the flexible capacity products needed. This section quantifies how much of each flexible RA capacity is needed to address each type of ramping need.

5.3.1. Determining the overall flexible capacity need

The ISO believes maintaining the existing flexible capacity needs determination using the maximum forecasted three-hour net load ramp plus contingency reserves should continue serving as the preliminary starting point since the interplay between contingency reserves and flexible capacity identified in the original FRACMOO process still exists. However, with the modifications to NERC standard on calculating contingency reserve "WECC Standard BAL-002-WECC-2a "Contingency Reserve", the means for determining the quantity of contingency reserves has changed. Contingency Reserve is determined by the greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

Based on the new requirement, the Operating Reserve – Spinning is approximately 50% of the Contingency Reserve requirement. As such, the ISO will modify the existing 3.5 percent expected peak load portion of the flexible capacity requirement to be consistent with the revised standard. Specifically, the ISO proposes to change the flexible requirement formula to the following:

Maximum Forecasted 3-Hour ramp + ½ Max(MSSC, 6% of the monthly expected peak load[12]) + ε

There are two modifications to this formula from the previous iteration. First, in the previous iteration of this stakeholder initiative, the ISO proposed to add a portion of the upward uncertainty measure to the overall flexible capacity need. However, the ISO is persuaded by stakeholders that such a need is already accounted for within the maximum three-hour net load ramp. As such, the ISO has remove this driver. The second modification is the insertion of the ε term. The ε term was included in the original FRACMOO needs assessment to "more accurately reflect[] the ISO's actual

[12] 6% of the monthly expected peak load is approximately equivalent to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation.

flexible capacity needs." Its omission from the previous iteration was as an oversite and it has been reinserted.

Finally, since the inception of the flexible capacity product there has been an increase in ISO dispatches of VER resources, both through economic bidding and curtailed self-schedules. This makes forecasting the three-hour net load ramp more challenging. As a result, the ISO will enhance its forecasting study to account for these dispatches. Therefore, the ISO will reconstruct overall available wind and solar output and include this quantity into the formulation of the three-hour net load ramp. This eliminates the concerns of double counting VERs – once through the dispatch reduce the three-hour net load ramp and again through counting the resource as flexible – towards meeting flexible capacity needs. The ISO will modify how wind and solar resources are considered in meeting the flexible RA requirements. The ISO's proposed changes to the treatment of wind and solar resources for Effective Flexible Capacity (EFC) are discussed in greater detail below.

Combining all off these elements yields an overall flexible capacity needs determination of:

Maximum Forecasted 3-Hour ramp (including reconstituted renewable curtailments) + ½ Max(MSSC, 6% of the monthly expected peak load) + ε

5.3.2. Determining the need for real-time flexible capacity

The ISO has also conducted an assessment of the distribution of real-time uncertainty. These distributions provide the basis for how much real-time uncertainty should be addressed in the planning horizon.[13]

Table 1 shows the maximum observed MW range of potential upward and downward uncertainty between October 2016 and June 2017.

[13] These results are based on the ISO's day-market market using hourly schedules. However, the ISO is exploring moving day-ahead scheduling to fifteen-minute granularity. This would reduce the uncertainty between the IFM and FMM, reducing these ranges and the requirements for the fifteen minute flexible RA capacity.

Table 1: Observed Uncertainty, Maximum Positive and Negative Ranges

Month	Max Positive error DA-FMM	Max Negative error DA-FMM	Max Error Range DA-FMM	Max Positive error FMM-RTD	Max Negative error FMM-RTD	Max Error Range FMM-RTD
October	3781	-3826	7606	1537	-1297	2834
November	2673	-2591	5264	1542	-1557	3099
December	4210	-3428	7638	1715	-1921	3636
January	3877	-3912	7789	1842	-1559	3401
February	4276	-4421	8697	1933	-1565	3498
March	3950	-3813	7763	1761	-1779	3540
April	4331	-2610	6941	1615	-1765	3380
May	3033	-3938	6971	1178	-1548	2726
June	2996	-3753	6750	1164	-1693	2857

Table 1 shows that maximum of errors within a month for DA to the FMM (shown by the range between the maximum error of 4,276 MW of upward error and 4,421 MW of downward error) just under 8,700 MW, the minimum was 5,264 MW, and the average was 7,269 MW. The range of errors between FMM and RTD shows a maximum range of 3,636 MW of error, a minimum of 2,726 MW, and an average of 3,219 MW.

While these values represent the maximum monthly ranges, the ISO also conducted an assessment of the distribution of these ranges by both non-coincident percentiles (percentile of any given observed error) and by daily coincident ranges (i.e. the maximum swings that occurred on a single day).

Table 2 and Table 3 show the distributions of non-coincident observed uncertainty ranges between October 2016 and June 2017.

Table 2: Percentile Rankings for observed error range: IFM to FMM

DA-FMM	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
100.0%	3781	2673	4210	3877	4276	3950	4331	3033	2996
99.5%	2617	1933	3324	2821	3154	2392	3254	2411	2346
97.5%	1597	1311	2244	2006	2281	1761	2332	1885	1671
95.0%	1200	1041	1798	1590	1575	1260	1865	1479	1426
87.5%	706	634	971	906	863	666	1164	886	901
75.0%	303	299	454	446	356	189	621	419	465
50.0%	-147	-149	-72	-49	-130	-278	-5	-79	-77
25.0%	-579	-541	-555	-636	-632	-780	-493	-591	-597
12.5%	-968	-845	-950	-1098	-1179	-1222	-868	-999	-1006
5.0%	-1367	-1207	-1435	-1728	-1811	-1708	-1254	-1467	-1497
2.5%	-1698	-1449	-1966	-2185	-2198	-1980	-1544	-1820	-2063
0.5%	-2286	-1902	-2765	-3046	-3049	-2587	-1981	-2789	-2958
0.0%	-3826	-2591	-3428	-3912	-4421	-3813	-2610	-3938	-3753

Table 3: Percentile Rankings for observed error range: FMM to RTD

FMM-RTD	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
100.0%	1537	1542	1715	1842	1933	1761	1615	1178	1164
99.5%	1041	1104	1027	974	1255	991	1016	723	780
97.5%	734	718	668	669	760	626	646	516	511
95.0%	566	534	504	536	572	464	497	404	405
87.5%	347	290	280	321	310	263	294	258	246
75.0%	183	145	147	167	160	115	155	129	113
50.0%	10	0	-2	13	-2	-33	-9	-37	-51
25.0%	-133	-137	-161	-134	-183	-217	-220	-223	-232
12.5%	-256	-275	-317	-283	-366	-391	-401	-376	-384
5.0%	-420	-447	-509	-471	-610	-611	-609	-575	-558
2.5%	-565	-583	-650	-632	-760	-770	-783	-704	-699
0.5%	-871	-871	-1019	-996	-1025	-1093	-1096	-1017	-1165
0.0%	-1297	-1557	-1921	-1559	-1565	-1779	-1765	-1548	-1693

5.3.3. Proposed flexibility capacity requirements

Figure 6 and Figure 7, below, show the complete distribution of the uncertainty ranges. As these figures show, currently, the levels and distributions of uncertainty are fairly consistent across months. While there are observations with high quantities of uncertainty, these observations are infrequent, as shown by the steep drop off in each of the tails in the figures below. These distributions also show that average error is approximately zero, meaning the uncertainty is fairly symmetric (i.e. the forecast is equally likely to be either over or under actual load).

Figure 6: Distribution of IFM to FMM Uncertainty Ranges

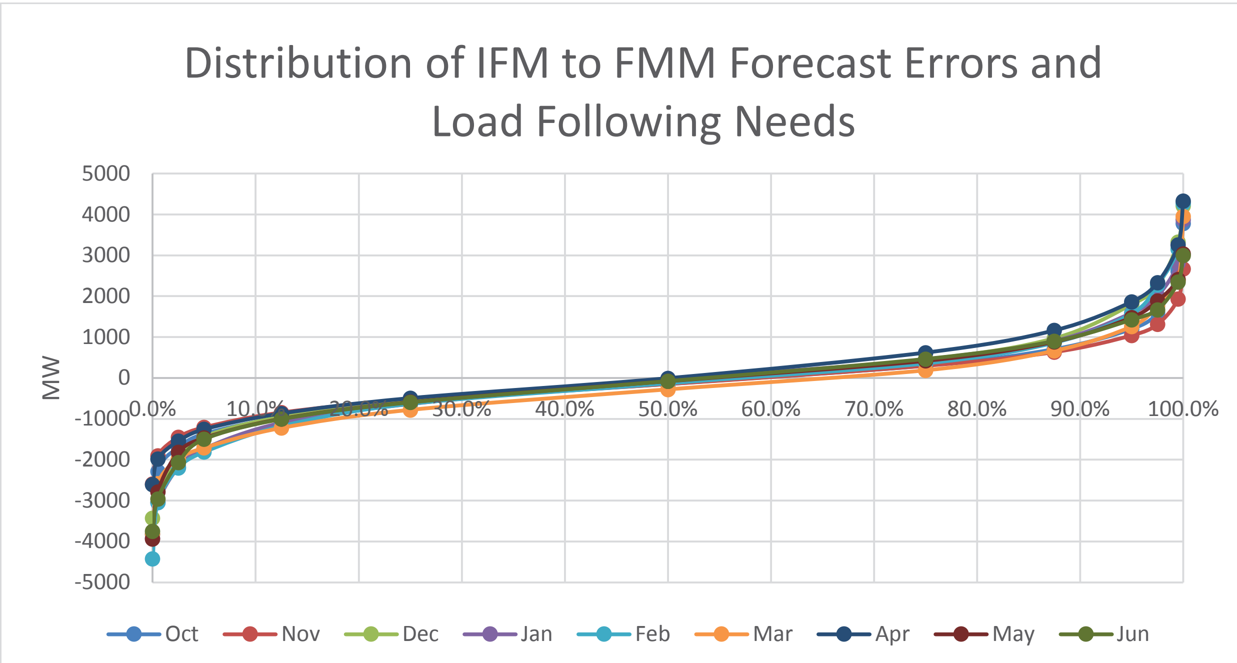
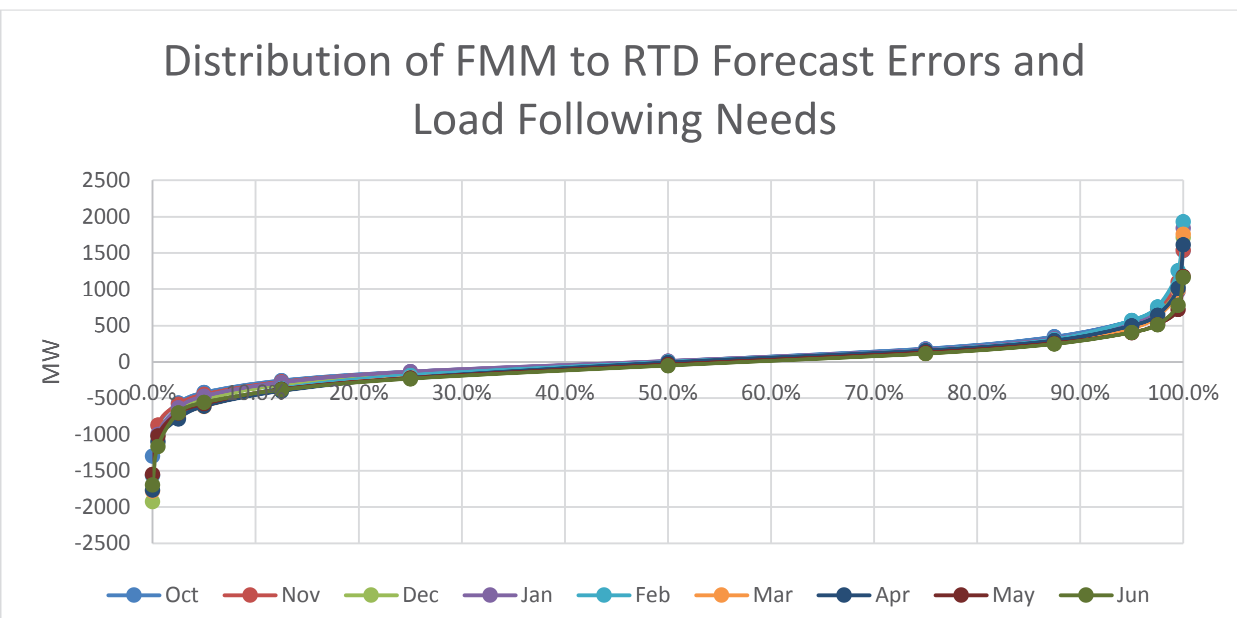
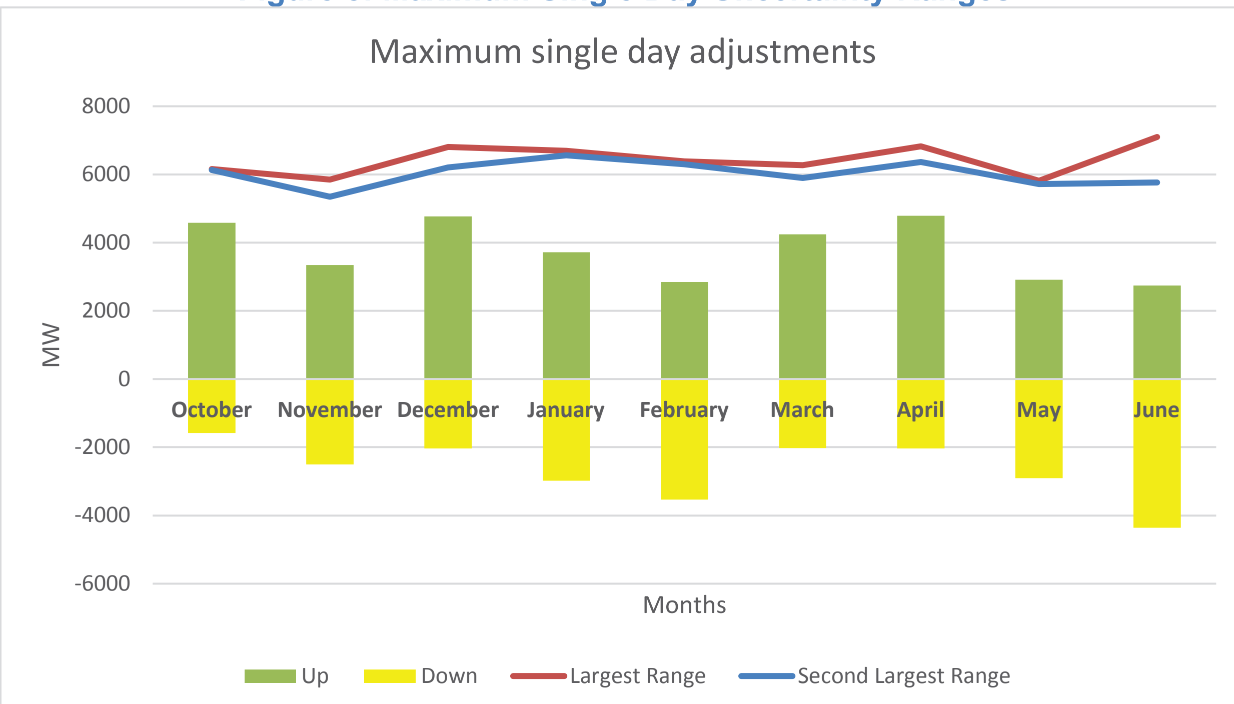


Figure 7: Distribution of FMM to RTD Uncertainty Ranges



Additionally, while monthly ranges are important to assess overall variability, it is critical to understand what this range could look like within a single day. Figure 8 shows the two largest ranges observed on any given day within a month. These are shown as the red and blue lines respectively. Additionally, Figure 8 shows the positive and negative error that was observed on the days that had the widest range of error within each month.

Figure 8: Maximum Single Day Uncertainty Ranges



As Figure 8 shows, the maximum daily uncertainty range between positive and negative uncertainty is fairly stable between 6,000 to 7,000 MW. Additionally, it shows that the second largest daily swing between positive and negative uncertainty falls within a very similar range. Finally, Figure 8 shows that the uncertainty swings fairly unpredictably between positive and negative on these days.

In conclusion, the ISO must manage a significant quantity of uncertainty between the day-ahead and real-time markets. This uncertainty can be over 4,000 MW in either direction, swinging more than 6,000 MW in any single day, and can occur even during the largest net load ramps. Therefore, the ISO requires sufficient flexible RA products that include eligibility criteria focused on the ramping speed and dispatch capabilities to address these needs. However, given the stability of the distributions of the uncertainty (i.e. that is shown in Table 2, above), it is reasonable to expect flexibility needs at the highest end of the distribution almost monthly.

The ISO proposes to set flexible capacity requirements to encompass the widest range of uncertainty for all real-time flexible capacity products.[14] Additionally, as load and resource variability continue to increase, this requirement will include an additional growth factor that will be based on the relative changes to each of the contributing factors (i.e. increasing in wind or solar or changes to load due to behind-the-meter-solar penetration).[15]

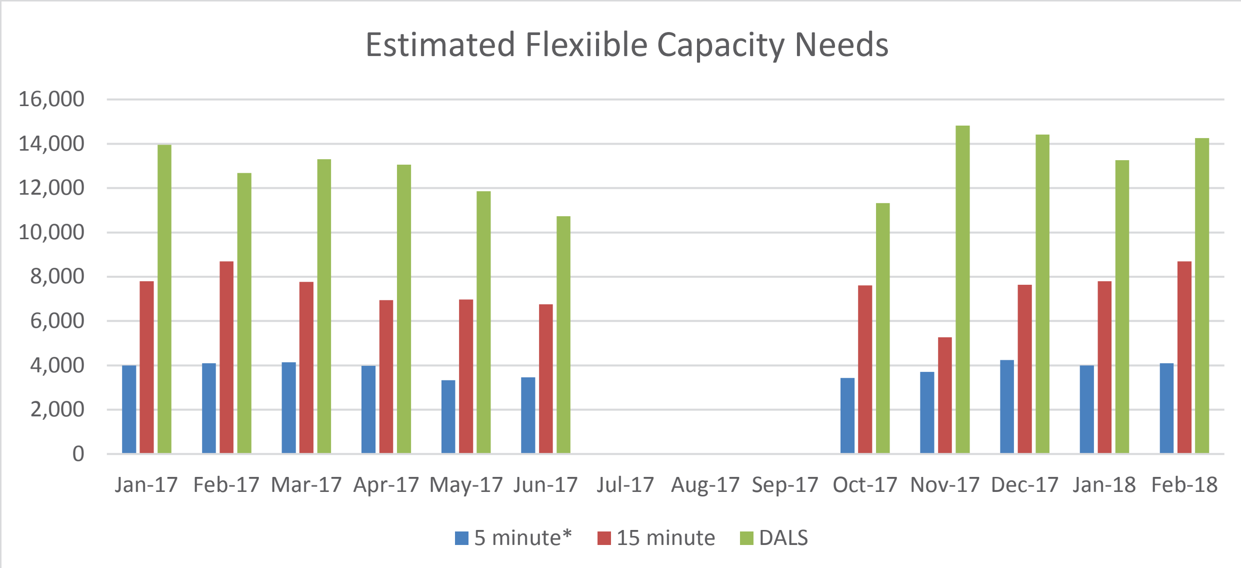
Finally, the ISO proposes that 100% of the monthly needs be procured for year ahead showings. The ISO has done an assessment of the existing capacity available to meet each these requirements and finds that there is current sufficient capacity available, though not necessarily procured as flexible RA capacity. This should provide mitigation to the costs of procuring to the high ends of the distributions.

5.3.4. Example of flexible capacity requirements

Based on the data provided to date, the ISO has estimated the flexible capacity requirements for each of the proposed flexible capacity products. The ISO has not had an opportunity to expand the uncertainty analysis to include the remainder of 2017. As such, the real time flexible capacity product need is not provided for those months at this time. The overall flexible capacity needs (i.e. the maximum three-hour net load ramp plus contingency reserves) are drawn from the 2017 and 2018 flexible capacity needs assessment, but adjusted to account for the new contingency reserve requirement.[16]

[14] However, the ISO recognizes that anomalies may be identified that warrant a lower percentage. If anomalies are identified, then those data points will be discarded.
[15] The ISO is in the processes of compiling data to estimate the historic contributions that would be attributable to each factor.
[16] These estimates are done using the 3 percent expected peak load.

Figure 9: Estimated Flexible Capacity needs[17]



5.4. Criteria for Resources to Meet the Identified Need

Given the short lag between realizing the need for flexible capacity and actual market operations, the ISO addresses the need for real-time flexibility and then the need for day-ahead shaping. Based on stakeholder comments the ISO proposes to keep eligibility criteria simple, based on operational attributes (as opposed to technologies), and reasonably inclusive.

The ISO will start by identifying basic eligibility criteria for the three basic Flexible RA products: The Five-minute Flexible RA product, Fifteen-minute Flexible RA Product, and day-ahead load shaping product. Then the ISO details the must offer obligations and counting rules to provide each of these products. This is done separately for internal resources, EIM resources, and purely external resources (i.e. resources external to both the ISO BAA and any EIM). Then the ISO describes its proposed assessment of flexible RA capacity showings and backstop cost allocations. Finally, the ISO provides an assessment the most recent flexible RA showings to determine if these showings fulfilled the identified need or modifications to procurement practices would be required and if any market power concerns exist.

5.4.1. Eligibility Criteria

Given the eligibility criteria defined below, the ISO envisions that VERs and other use-limited resources will be eligible to provide any of the flexible RA capacity products.

[17] The ISO is in the process of updating these estimates for all of 2016 and 2017. A supplemental report will be issued with these estimates.

However, these resources will be subject to new replacement and availability rules. Specifically, the ISO proposes to require replacement capacity for all use-limited resources providing flexible RA that reach their use-limitation.[18] Additionally, VER availability measurements in the RSI1A policy are based on a percentage of the capacity available relative the forecast. The ISO proposes to reassess this policy and is considering calculating VER availability assessment based on the minimum of the resource's forecast or EFC value shown. However, this element must be considered in the context of other RAAIM modifications in the next iteration of this proposal.

5.4.1.1. Real-time products

Internal Resources

The five-minute and fifteen-minute flexible RA products, the two products designed to address real-time uncertainty, must be available to the ISO real-time markets. Therefore, eligibility criteria should reflect this need. The ISO considered numerous operational attributes to determine resource eligibility to provide this product.[19] However, because the objective of this product is to address real-time uncertainty, the ISO has determined that the only necessary eligibility criteria are the capacity comes from a specific resource[20] and that the resource must have a start-up time of less than 60 minutes to be eligible to provide this product. This allows the ISO to commit resource in the shortest interval of the Real-Time Unit Commitment process, ensuring the resource could be available to address real-time uncertainty.

The ISO understands that resources with longer start times could address real-time uncertainty, but could do so only if committed in the IFM. The ISO explored options to allow more resources to provide this product by removing the start time requirement. However, the ISO is concerned that removing this eligibility criteria may result over inclusion of inflexible capacity, similar to procurement today. This could defeat one of the primary overall objectives of flexible RA capacity: creating a deep pool of economic bids in the real-time market to address uncertainty.

In addition to start-up time, the ISO will still require that all flexible RA resources have an EFC. The EFC for all resources, with the exception of storage, is currently capped at the resource's Net Qualifying Capacity (NQC). The NQC is determined based on a resource's output during peak load hours and tested based on the ISO

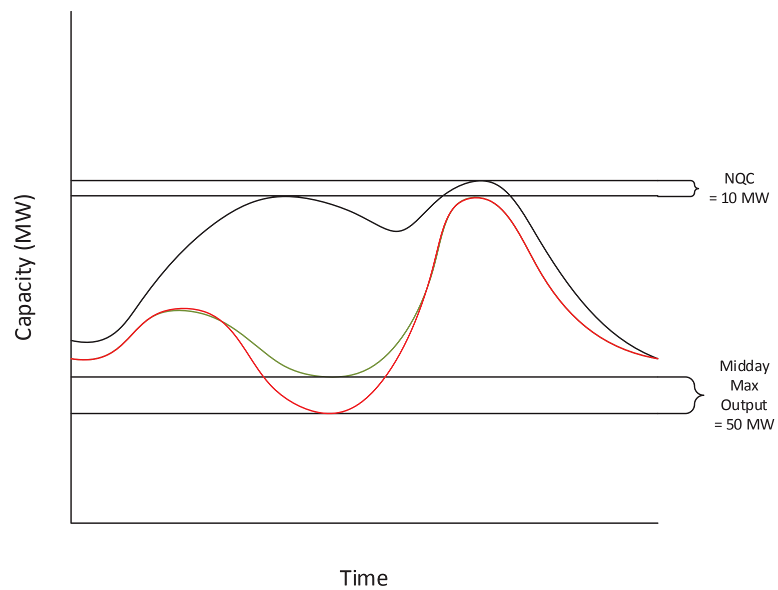
---

[18] The ISO will be filing its Commitment Cost Enhancements – Phase 3 Tariff language soon. This policy is assumed to be in place when this FRACMOO2 policy goes into effect. The ISO is not proposing any changes to the daily start requirements established in Commitment Cost Enhancements – Phase 3.
[19] Operational attributes the ISO considered include minimum and maximum ramp rates, Start-time, cycle time, capacity factor, start frequency, PMin, and Pmin-Pmax ratio.
[20] A specific resource is defined as a single resource ID, not a single physical facility.

deliverability study processes that confirm that the resource's qualified capacity is deliverable to the aggregate of load during stressed system conditions.

In non-summer months, the NQC value for a solar resource is very small relative to the resource's potential output during early afternoon hours when net load is at its lowest and the largest net load ramps are imminent. However, VER resources that are willing to economically bid into the day-ahead market help the ISO to better shape IFM commitments and address the net load ramp at quantities that far exceed the NQC of the resource. This is demonstrated in Figure 10.

Figure 10: Flexible Capacity Available for Solar Resource Midday versus Daily Peak



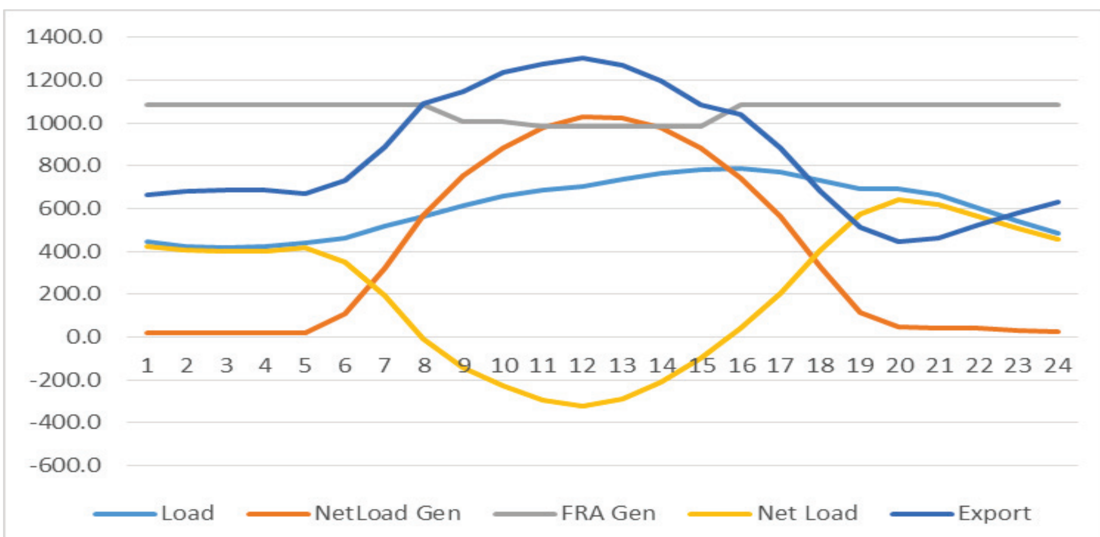
In this example a solar resource may have an NQC of 10 MW in March, but a maximum output during the middle of the day of 50 MW. By economically bidding this 50 MW into the IFM, the ISO can now dispatch the resource to less than full output during these hours, helping the ISO to better manage ramp constraints using market priced RA resources, instead of pro rata curtailments and CPMs of non-RA resources.

Several stakeholders, including ECE, CEDMC, and Nextera argue that flexible RA resources should not require full capacity deliverability status to provide flexible RA. Just as NQC may not fully align with a resource's ability to provide flexible capacity, the ISO's current deliverability assessment may not fully capture a resources ability to deliver capacity during times of greatest flexible capacity need. For example, it is possible that the resource shown in Figure 10, may not be deliverable for 50 MW in the middle of the day. Therefore, the ISO proposes to modify its existing EFC eligibility to include a flexible capacity deliverability study to confirm that the flexible capacity is deliverable during the times of greatest flexibility needs.

Deliverability of the flexible capacity shall mean that the output of a flexible resource could be ramped from Pmin to (Pmin + EFC) simultaneously with other flexible resources in the same generator pocket to match the net load ramping without being constrained by the transmission capability. The specific conditions that will be studied (i.e. the most stressed conditions) must be determined through a separate stakeholder process, and are beyond the scope of the current stakeholder process.

A simple illustration of the flexible RA deliverability condition being more stressed than the peak load deliverability is SCE's North of Lugo area. North of Lugo area is a big gen-pocket from which the export is limited by the Lugo 500/230 kV transformer bank capacity. Figure 11 shows the generator output, net load and net export on a summer day using the 2026 production simulation results. The net export is the highest at the starting point of the ramping curve when flexible resources are dispatched at Pmin, combined output from all solar, wind and energy efficiency is the highest and the load is mild. At the ending point of the ramping curve that falls into the time window for the current deliverability study, the generation export is significantly lower and the transmission system is not as stressed.

Figure 11: North of Lugo Gen-Pocket Summer Day Ramping Pattern



The addition of a separate EFC deliverability study has two main benefits. First, just as the ISO's deliverability studies provide a confirmation that the NQC is deliverable under stressed grid conditions, a flexible capacity deliverability study will provide the same confirmation for EFC. Second, the ISO will no longer have to rely on the use of the "dispatchable" flag in Masterfile as a primary qualifying attribute to provide flexible capacity. Instead, the resources willingness to accept the requirement to economically bid into the market provides a better measure of "dispatchability" and flexibility.

Because the ISO will conduct two separate deliverability studies, NQC and EFC can be reasonably and reliably unbundled.[21] This allows a resource to have:

- An NQC with no EFC;
- An EFC with no NQC;
- Both an NQC and EFC equal to one another; and
- Different NQC and EFC.

The EFC deliverability study will study all flexible resources.

EIM resources

EIM resources are unique in fact that in the IFM they are external resources, but comparable to ISO internal resources in the real-time markets. As a result, real-time dispatch instructions are made to a portfolio of resources on the other side of an intertie in the IFM, but to a specific resource with base schedules in the real-time. However, the ISO does not believe this to be an insurmountable problem. As such, the ISO proposes to allow EIM resources to provide real-time flexible RA capacity.

The EIM resource must be registered as an EIM Participating Resource. The ISO will enhance Masterfile registration to support System Resource association with the EIM Resources. The System Resource will then be associated for auto-mirroring with a Mirror System Resource (ETIE) registered from the relevant EIM Entity at the same ISO Scheduling Point.[22] This will allow the ISO to see the EIM resource's participation in both the day-ahead and real-time markets through a registered import System Resource (ITIE) at an ISO Scheduling Point, associated with the EIM Participating Resource.

Any LSE using an EIM resource for flexible capacity must demonstrate that it has sufficient Maximum Import Capability (MIC) capacity. The MIC capacity is how LSEs demonstrate that the resource's output, and therefore flexibility, is deliverable to the ISO. While the MIC ensures the flexible capacity is deliverable, the ISO will still need to ensure the flexible capacity is credited to the ISO BAA for purposes of the EIM sufficiency tests. Therefore, the ISO will also change all EIM sufficiency tests to credit the ISO with any capacity from resources based in an EIM BAA shown as flexible RA capacity and remove the resources from any EIM entity's sufficiency tests.

---

[21] Many of the benefits of unbundling have been covered by SDG&E in previous RA iterations at the CPUC. SDG&E's presentations detailing these benefits can be found at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6539.

[22] This is currently scheduled as a Winter 2017 EIM Enhancement.

Purely External Resources

External resources may provide the fifteen-minute, but will not be eligible to provide the five-minute flexible RA product. The exception to this limitation is for dynamic and pseudo-tied resources. The reason for this is simply that purely external resources are not dispatchable on a five-minute basis, while for dynamic and pseudo-tied resources are five-minute dispatchable.

Any LSE using an import resource for flexible capacity must demonstrate that it has sufficient Maximum Import Capability (MIC) capacity.[23] The MIC capacity is how LSEs demonstrate that the resource's output, and therefore flexibility, is deliverable to the ISO. Given the already vast scope of this stakeholder, the ISO is not proposing changes to this process, as requested by PGP and Powerex. However, having sufficient MIC is a requirement for any import resources to provide RA capacity. It is equally important that flexible capacity be deliverable into the ISO and therefore appropriate to maintain this standard for flexible capacity.

From a tracking standpoint, purely external resources have the benefit of maintaining a consistent resource ID between the IFM and real-time markets. However, this also means purely external resources cannot be resource specific in the same way that internal and EIM resources can be. However, the ISO will require that the Resource SC provide to the ISO the physical resources used to support the resource ID along with any information necessary to determine if the resources are capable of providing the flexible capacity for which it has been procured. These combinations have to be submitted prior to the ISO issuing the final EFC list in order to be eligible to provide flexible RA capacity.

5.4.1.2. Day-ahead Shaping

Internal Resources

The ISO proposes that, like the real-time flexible RA products, any resource providing the day-ahead flexible shaping product must be studied for EFC deliverability. Further, this product is designed to ensure the day-ahead market has sufficient ramping capabilities all day, not simply a subset of hours. Therefore, the ISO proposes to eliminate the three categories of flexible capacity currently being used for three-hour net load ramps, including the MOO, in favor of a single product. Elimination of the existing flexible capacity categories and various MOOs should help simplify flexible RA procurement and understanding of obligations. Because the ISO can make commitments of long-start resources in the IFM, there is no need to impose a start-time requirement as is needed for the real-time flexible RA products.

[23] The MIC allocation process is described in section 40.4.6.2 of the ISO tariff.

EIM resources

The eligibility criteria detailed above for EIM resources to provide real-time flexible RA capacity will also apply to any resources wishing to provide the day-ahead load shaping product.

Purely External Resource

The ISO proposes to allow purely external resources to provide the day-ahead shaping product. As with the 15-minute flexible RA product, the ISO will require 15-minute bids. All physical resources supporting these imports must be identified. Finally, any LSE relying on such a resource would have to have sufficient MIC allocation to support the import.

5.4.2. Must-offer obligation

5.4.2.1. Real-time products

Internal Resources

As a general rule, internal resources providing flexible RA will be required to submit economic bids for the full shown EFC value into both the day-ahead and real-time markets for all 24 hours for all flexible capacity for which the resources has been shown. The one exception the ISO has identified to this rule is VERs. VERs may not be capable of providing the full shown EFC value during all hours. However, as noted above in Section 5.2.1, this does not mean VERs are not able to provide flexible capacity benefits. However, to minimize the number of flexible RA products procured, the ISO has elected to not define multiple must offer obligations (i.e. 24 by seven vs. daytime only) as recommended by CEDMC, First Solar, and Six Cities. Instead, the ISO proposes to hold VERs to a 24 by seven must offer obligation. However, the VER must offer obligation will be to the lower of the shown EFC value or the resource's forecasted output. This means a solar resource would have to bid up to its shown EFC during daylight hours and 0 MW overnight.

EIM resources

The eligibility criteria for EIM resources allows the ISO to track resources from IFM through the real-time markets. While this facilitates similar must-offer obligations to internal resources, there are some minor differences.

If the System Resource is shown for 15-minute flexible RA capacity, then it must submit in RTM an energy bid range for the trading hours and a capacity for the shown EFC value in addition to any scheduled Day-Ahead product in DAM/RUC, which can be self-scheduled or bid.

For the five-minute product the TG must be used instead of a System Resource. The TG must submit an energy bid range for the trading hours and a capacity no less than the shown EFC for 5-minute product in to the real-time markets in addition to the fifteen-minute product shown as flexible RA capacity and any scheduled Day-Ahead product in DAM/RUC, which can be self-scheduled or bid.

The System Resource or TG, and the associated Mirror System Resource and the EIM Participating Resource will all be settled for imbalance energy separately applying existing settlement rules.

Additionally, the ISO proposes that transmission capacity must be secured prior to the DAM and must be shown in the e-tag from the EIM Participating Resource all the way to the ISO Scheduling Point. Further, this transmission capacity must be specified in the DAM/RTM bid for the System Resource. The OASIS field on the e-tag must specify the System Resource name, as registered in the Master File and with an association to the EIM participating resource ID shown for flexible RA capacity.

Purely External Resources

Currently, external RA resources are only required to provide real-time bids if they receive a day-ahead commitment. The ISO proposes to change this only for resources providing real-time flexible RA products. Purely external resources will be required to submit economic bids into both the day-ahead and real-time markets. All bids must be submitted in 15-minute intervals and cannot be submitted as hourly block schedules.

For purely external resources, only a System Resource or Intertie Generating Resource (TG) is needed with the required e-tag. In this case SIBR will validate the bid from the System Resource or the TG, but it will not validate the external resource because it does not participate in the market.

5.4.2.2. Day-ahead load shaping product

Internal Resources

All resources that provide the Day-ahead load shaping product must submit an economic bid into the day-ahead market for all capacity shown. Resources must make all capacity committed or awarded in the IFM available in the real-time market. However, unlike the flexible capacity products today, this committed or awarded capacity may be either economically bid or self-scheduled into real-time markets. Additionally, the ISO proposes that any resources that were not committed in the day-ahead market but can be committed in the real-time market must make its shown flexible RA capacity available in the real-time market.[24] If the resource is committed in the IFM to less than full shown EFC, then the resource must economically bid the uncommitted shown EFC capacity but may self-schedule day-ahead awards.

[24] Depending on the STUC horizon, this may require additional bidding from medium and long start resources.

EIM resources

The ISO proposes that EIM resources provided only the Day-Ahead Load Shaping product have a day-ahead MOO requiring the System Resource to submit an energy bid range into the day-ahead market for all flexible RA capacity shown. If the System Resource is scheduled in the DAM/RUC, it must also bid in the real-time markets. However, because the resources only providing the Day-Ahead Load Shaping product, a self-schedule or energy bid with an Upper Economic Limit (UEL) at the RUC Schedule will satisfy the obligation.

Purely External Resources

Purely external resources providing day-ahead load shaping product must submit economic bids into the day-ahead and real-time market for all capacity shown. All bids must be submitted in 15-minute intervals and cannot be submitted as hourly block schedules. Similar to internal resources, purely external resources' committed capacity may be either economically bid or self-scheduled into real-time. Any purely external resource not committed in the day-ahead market will have met its must offer obligation and will not be required to rebid into the real-time markets.

5.4.3. Flexible RA Counting Rules

A foundational counting rule for meeting flexible RA requirements is that capacity procured to meet a higher quality product will automatically be counted towards meeting the lower quality requirements. For example, the fifteen-minute flexible capacity requirement will be stated individually, but any capacity procured towards meeting the five-minute flexible RA requirements will count towards meeting the fifteen-minute requirement. If the total fifteen-minute flexible RA requirement was 7,500 MW and the five-minute flexible RA requirement was 3,500 MW, then the total incremental procurement needs to fulfill the requirement for fifteen minute flexible capacity would an additional 4,000 MW of fifteen minute flexible capacity.

Due to fact that a substantial amount of the ISO's uncertainty can occur at any time, the ISO proposes to limit the quantity of solar capacity providing any single flexible RA product to 25 percent. This limitation provides a somewhat conservative estimate of the need for 24 hour uncertainty. However, it will provide a reasonable opportunity to allow solar resources to provide flexible RA capacity while allowing the ISO to establish greater comfort with both the capacity and energy market tools designed to address uncertainty. To the extent these tools work effectively, the ISO may explore modifications to this limitation. Proxy demand resources typically have similar production profiles as solar resources. However, because this may not be universally true, the ISO is not, at this time, including proxy demand resources in this cap. Finally, wind resources are explicitly not included in this limit as these resources may have 24 hour fuel available and could meet over-night uncertainty.

5.4.3.1. Real-time products

Internal Resources

At the most basic level, resource counting for this product would be based on the number of MWs the resource can ramp in the relevant time interval: five or fifteen minutes. For example, a 100 MW resource with a 10 MW/minute ramp rate would be eligible to provide 50 MW of five-minute RA flexible capacity, but 100 MW of the 15-minute product.

While the operating characteristics and EFC for many resources are fairly predictable, VERs have additional uncertainty caused by daily weather patterns. This makes determining their reliably deliverable EFC more challenging. As described in section 2.5, above, PG&E submitted two proposals for calculating the EFC for VERs. The ISO explored two others.

The ISO believes PG&E's "simple" approach offers a potential option for VER EFC calculation.[25] However, the ISO's initial assessment of the "complex "option is that it seems fairly data intensive and the benefits may be limited. For example, it is not clear how or if an EFC could be developed for a VER resource for each product. However, as an initial step, PG&E's simple approach would facilitate an EFC for each product. Further, as shown in section 5.5, this proposal is not significantly dissimilar to the allocation methodology the ISO proposes.

In addition to the proposals put forward by PG&E, the ISO considered the following two options for calculating the EFC for VERs:

1) An ELCC-like assessment of only ramping hours
2) An exceedance methodology for hours only ramping hours

Both options allow for an effective unbundling of the EFC and NQC, primarily for non-summer months. However, there are significant trade-offs between these two options. Option 1 relies on a methodology similar in nature to that which is used for system RA counting rules. However, developing an ELCC for only a subset of hours and conditions would make for a complex and time consuming process. Option 2, while somewhat inconsistent with NQC counting rules is much easier and can be implemented on a much quicker time frame. In balance, the ISO believes an exceedance methodology is a reasonable starting point to determine VERs' monthly EFC values.

[25] PG&E's proposal can be found at http://www.caiso.com/Documents/PG_EComments_DraftFlexibleCapacityFramework.pdf.

Therefore, the ISO is seeking stakeholder feedback regarding whether PG&E's simple option or a simplified exceedance methodology would be the best option for calculating and EFC for VERs.

EIM resources

The ISO proposes to use the same counting rules for EIM resources as are used for internal resources. The primary difference, is that EIM resources will be deemed deliverable for purposes of EFC calculations. However, as noted above, all resources must have an associated MIC allocation for an LSE to actually count the resources towards its flexible RA requirements.

Purely External Resources

The ISO does not have detailed access to the operational attributes of purely external resources. However, because the ISO proposes to require details regarding the purely external resources, the ISO expects to have sufficient information to count external resources comparable to internal resources.

5.4.3.2. Day-ahead load shaping product

Internal Resources

The basic counting rules for the day-ahead shaping product will remain the same as those used today for the Effective Flexible Capacity (EFC) value for most resources. However, to manage the Pmin burden of long-start resources, the ISO declines to remove the start-time as a means to determine if the PMin is flexible as recommended by Calpine.[26]

EIM resources

The ISO proposes to use the same counting rules for EIM resources as are used for internal resources. The primary difference, is that EIM resources will be deemed deliverable for purposes of EFC calculations. However, as noted above, all resources must have an associated MIC allocation for an LSE to actually count the resources towards its flexible RA requirements.

Purely External Resources

As noted above, the ISO expects to have sufficient information to count external resources comparable to internal resources.

[26] As noted in the fifteen-minute product, additional changes will be required to identify EIM resources providing flexible RA capacity to ensure the EIM Balancing Area Ramping Requirement is properly adjusted, crediting the ISO with that flexible capacity and avoiding double counting. Additional modifications may be needed to base scheduling processes to ensure all MOOs are followed.

5.4.4. Determination of Adequate Flexible RA and Need for Backstop Procurement

The ISO proposes to continue using current practices for determining the adequacy for flexible RA showings. Specifically, the ISO will continue to assess if sufficient flexible RA capacity has been shown by looking at all showings and for each product first. If there is sufficient flexible capacity shown system wide for a given flexible RA product, then the ISO will not assess individual showings. If there is a deficiency, then the ISO will look to determine which LRA(s) is deficient and then which of its jurisdictional LSEs are deficient. The ISO will notify LSE's of any deficiency and provide an opportunity to cure the deficiency. If the deficiency is not cured, the ISO may conduct backstop procurement and allocate costs to any deficient LSE. If there are deficiencies in multiple products, and the ISO exercises its backstop procurement authority, then the ISO will look to procure capacity that meets that highest quality deficient product first and will allocate costs first to the LSE(s) that was deficient in the highest quality product. Any procurement needed to fill remaining deficiencies of lower quality products will be allocated to the entities deficient in that product. These costs will be allocated proportionally to the original deficiency.

5.4.5. Assessment of Flexible RA showings

The ISO has conducted a limited assessment of historic flexible RA showings to determine if existing flexible RA procurement practices would fulfill the new flexible RA framework defined above. This assessment relies on 2018 EFC list[27] and the new counting and eligibility rules defined above with the exception of the EFC deliverability study requirement. The reason for this limitation is that it is not possible to determine the overall willingness and availability of resources external to the ISO at this time.

[27] The 2018 Final EFC list is available at http://www.caiso.com/Documents/FinalEffectiveFlexibleCapacityList-2018.xlsx

Table 4: Assessment of Historic Flexible RA Using Proposed Flexible RA Requirements and Counting Rules

	MW Available			Showings			Need			Deficiency		
	5 minute	15 minute	DALS	5 minute	15 minute	DALS	5 minute*	15 minute	DALS	5 minute	15 minute	DALS
Jan-17	10,133	14,458	33,099	4,228	5,974	14,059	4,001	7,789	13,947	0	1,815	0
Feb-17	10,033	14,347	32,959	4,231	5,778	13,609	4,098	8,697	12,681	0	2,919	0
Mar-17	10,104	14,494	33,073	3,807	5,383	13,484	4,140	7,763	13,300	333	2,380	0
Apr-17	10,321	14,934	33,469	4,030	5,489	13,409	3,980	6,941	13,053	0	1,452	0
May-17	10,338	14,862	33,353	3,693	5,044	12,416	3,326	6,971	11,857	0	1,927	0
Jun-17	10,404	15,068	33,027	3,248	4,221	11,216	3,457	6,750	10,728	209	2,529	0
Jul-17	10,385	15,015	32,935	3,222	4,288	10,449	[redacted]	[redacted]	9,766	[redacted]	[redacted]	0
Aug-17	10,358	14,962	32,855	3,518	4,550	10,338	[redacted]	[redacted]	9,686	[redacted]	[redacted]	0
Sep-17	10,211	14,626	32,525	3,518	4,575	11,734	[redacted]	[redacted]	11,295	[redacted]	[redacted]	0
Oct-17	10,224	14,580	32,603	3,843	4,908	11,824	3,434	7,606	11,326	0	2,698	0
Nov-17	10,229	14,621	32,780	4,826	6,284	15,263	3,699	5,264	14,814	0	0	0
Dec-17	10,253	14,670	32,907	5,031	6,536	15,428	4,236	7,638	14,418	0	1,102	0
Jan-18	10,133	14,458	33,099	4,433	5,808	13,674	4,001	7,789	13,253	0	1,981	0
Feb-18	10,033	14,347	32,959	4,311	5,753	14,379	4,098	8,697	14,252	0	2,944	0

As shown in Table 5, there will be adequate capacity available to meet each of the new flexible capacity products. As such, there appear to be no market power concerns. The ISO has not done a locational assessment of each product. However, as noted above in section 5.4.1, unbundling NQC and EFC, inclusion of VER and external resources will provide ample opportunity for LSEs to procure flexible RA capacity.

Based on flexible RA showings to date, there appears to generally be sufficient five-minute and fifteen-minute flexibility shown system wide. This is important to note. The ISO has not conducted LSE specific assessments (specific allocations would need to be derived first). There would need to be modifications to flexible RA procurement and/or showings to ensure sufficient 15-minute flexible RA capacity is available to the ISO.

5.5. Allocation

Proper allocation of flexible capacity requirements must be based on reasonable causation principles. The methodology currently employed by the ISO to allocate flexible capacity requirements is based on LSEs procurement practices. The ISO considered modifications to this practice, including allocating flexible capacity obligations to generating resources. However, the ISO has determined that the primary driver operational needs identified here continue to be driven by LSE procurement to meet state policy objectives.[28] As a result, the ISO proposes to maintain its current practice of allocating flexible capacity requirements based on an LRA's jurisdictional LSEs' contribution to the requirement.

As noted in Section 2, above, many stakeholders recommended that the ISO simply rely on the existing allocation methodology used for the current flexible RA allocation process. While this methodology may be a reasonable reflection of the need for three-hour net load ramps, it may not reflect the drivers of uncertainty. For example, reductions in solar output are large driver of three-hour net load ramps. However, load may be the primary driver for uncertainty. As such, relying on the existing methodology could result in incorrectly allocating an uncertainty need to an LSE with stable and predictable net-load, but a significant impact on the three-hour net load ramp.

The ISO proposes to allocate flexible capacity requirements based on the three primary contributing factors to each product. Specifically, the ISO will allocate based on the contributions from load, wind, and solar. This is similar to current practice. However, unlike current flexible RA allocation practice where the ISO applies a single allocation factor to all three flexible RA products, the ISO will apply this allocation methodology to each flexible RA product. This means that the ISO will

[28] In their comments, NRG summarized LSE procurement practices as the driver need. Specifically, NRG asserts "[i]nasmuch as the driver for the proliferation of variable resources is state policy, the costs associated with this procurement should be allocated in a manner to those that are deriving the benefits from the underlying state policy (e.g., to load)."

determine the relative contributions to load, wind, and solar to each of the proposed products. These contributions can be different for each product. The proportion of each factor's contribution will be determined based on the relative contributions to the most significant observations. The ISO uses the five largest forecasted three-hour net load ramps today to determine the contributions of load, wind, and solar. The ISO proposes to continue this practice for the day ahead load shaping product. For the real-time flexible RA product, the ISO proposes using the average contribution of each factor during both the top 5 percent of upward and downward uncertainty observations (i.e. a total of 10 percent of observations). This will ensure a statistically significant sample of the most significant events and eliminate the impact more manageable uncertainty could have on those percentages.

Because the attribution to a given cause of uncertainty is done using a robust set of the uncertainty observations it is not necessary to try to attribute the cause to a specific resource. Instead, the ISO proposes to allocate the requirements caused by wind and solar based on relative proportions of resources contracted (i.e. 10 percent of total solar fleet contracted would result in an allocation of 10 percent of the overall contribution caused by solar for a given product). The ISO proposes to allocate contributions caused by load for the real-time products based on load-ratio share. However, the ISO seeks stakeholder input regarding other means for determining allocation.

Table 5 provides a conceptual example of how this methodology would work for five hypothetical LSEs.[29] Table 5 goes from the highest quality product flexible RA product to the lowest (i.e. five-minute to fifteen-minute to Day-Ahead Load Shaping products). The overall requirement for each product can be found by summing the contributions from load, wind, and solar for each product. For example, the overall five minute product requirement can be found by summing 1500, 750, and 250, from load, wind, and solar, respectively, for a total of 2500 MW. Those contributions are determined by the methodologies described above. Then, the percent of each LSEs contracting or peak-load ratio share would determine the LSEs portion of each contributing factor. Again, LSE1's portion of the five-minute product caused by wind would be 750 times 30 percent, or 225 MW. Summing each LSE's contributing factor then yields its responsibility for that product. Finally, given the rule that higher quality products help fill the need for lower quality products, the ISO shows what the residual procurement that what be needed for a given product once the higher quality product is taken into account. For LSE1, they would be responsible for 522.5 MW of incremental procurement of the fifteen-minute product because 662.5 MW of the five-minute product already count towards their 1185 MW fifteen-minute requirement.

[29] As noted above, allocation will be provided to LRAs of when there are multiple LSEs under a single LRA. However, the idea of LSE is used here purely for convenience.

Table 5: Example of Requirement Allocations

5 min	Total Cause			Percent to LSE			MW to LSE			LSE Product Obligation	Residual Need Above Higher Quality Products
	load	wind	solar	load	wind	solar	load	wind	solar		
LSE1	1500	750	250	25%	30%	25%	375	225	62.5	662.5	
LSE2	1500	750	250	20%	25%	20%	300	187.5	50	537.5	
LSE3	1500	750	250	35%	30%	30%	525	225	75	825	
LSE4	1500	750	250	15%	5%	5%	225	37.5	12.5	275	
LSE5	1500	750	250	5%	10%	20%	75	75	50	200	
Total				100%	100%	100%	1500	750	250	2500	

15 min											
	load	wind	solar	load	wind	solar	load	wind	solar		
LSE1	2750	1200	550	25%	30%	25%	687.5	360	137.5	1185	522.5
LSE2	2750	1200	550	20%	25%	20%	550	300	110	960	422.5
LSE3	2750	1200	550	35%	30%	30%	962.5	360	165	1487.5	662.5
LSE4	2750	1200	550	15%	5%	5%	412.5	60	27.5	500	225
LSE5	2750	1200	550	5%	10%	20%	137.5	120	110	367.5	167.5
Total				100%	100%	100%	2750	1200	550	4500	2000

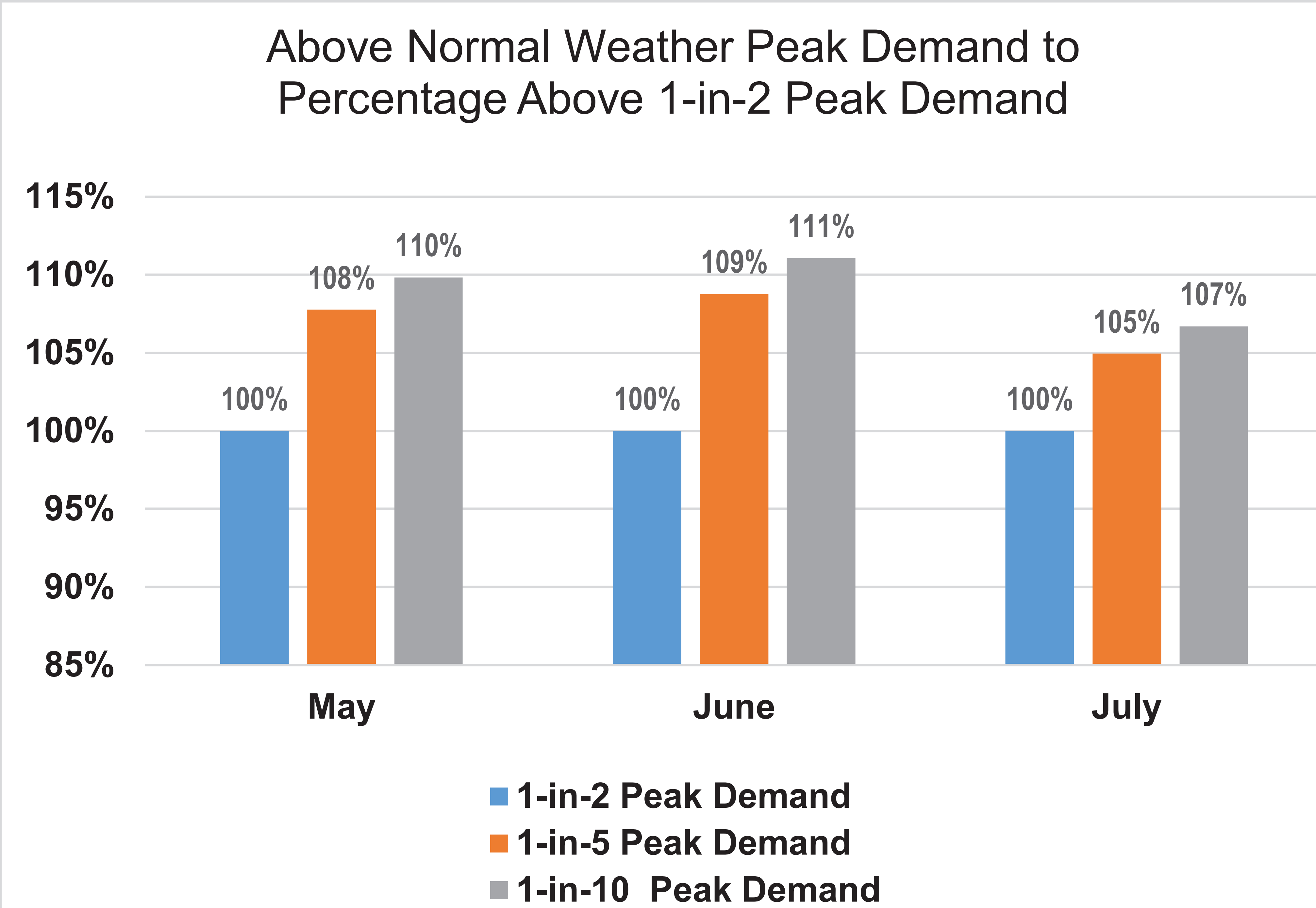
Day Ahead Load Shaping											
	load	wind	solar	load	wind	solar	load	wind	solar		
LSE1	4000	1500	2500	25%	30%	25%	1000	450	625	2075	890
LSE2	4000	1500	2500	20%	25%	20%	800	375	500	1675	715
LSE3	4000	1500	2500	35%	30%	30%	1400	450	750	2600	1112.5
LSE4	4000	1500	2500	15%	5%	5%	600	75	125	800	300
LSE5	4000	1500	2500	5%	10%	20%	200	150	500	850	482.5
Total				100%	100%	100%	4000	1500	2500	8000	3500

6. Next Steps

The ISO will discuss this Revised Draft Flexible Capacity Framework proposal with stakeholders during a Stakeholder meeting on February 7, 2018. Stakeholders are asked to submit written comments by February 21, 2018 to initiativecomments@caiso.com.

Attachment C

2017 Load Forecast Analysis


Above Normal Weather Peak Demand to
Percentage Above 1-in-2 Peak Demand
115%
110%
105%
100%
95%
90%
85%
100%
108%
110%
100%
109%
111%
100%
105%
107%
May
June
July
1-in-2 Peak Demand
1-in-5 Peak Demand
1-in-10 Peak Demand

Attachment D

CAISO's October 2017 CAISO-CPUC Joint Workshop Presentation on Slow Response Local Capacity Resource Assessment

California ISO

Slow Response Local Capacity Resource Assessment

CAISO-CPUC Joint Workshop

October 4, 2017

Revision as of 10/11/17: Revisions were made on page 62 and page 64 is marked for deletion

Agenda

Time	Topic	Presenter
10:00 – 10:05	Welcome	Kim Perez, CAISO
10:05 – 10:15	Introduction and purpose	Bruce Kaneshiro, CPUC
10:15 – 12:00	**Slow Response Local Capacity Resources Technical Study:** 1) Framing the discussion 2) Study design, methodology overview, and results update 3) Party discussion and Q&A panel with participating transmission owners	1) John Goodin, CAISO 2) Nebiyu Yimer, CAISO and Catalin Micsa, CAISO 3) CAISO, PGE, SCE, SDGE
12:00 – 1:00	Lunch	All
1:00 – 1:15	PDR and RDRR slow response barriers	Delphine Hou, CAISO
1:15 – 2:00	**PDR discussion:** CAISO's 15-minute market and bidding options for real-time imports and exports	Don Tretheway, CAISO
2:00 – 3:00	**PDR discussion:** Party discussion on feasibility of import/export options for PDR	All, moderated by CAISO and CPUC

Agenda (cont'd)

Time	Topic	Presenter
3:00 – 3:15	**RDRR discussion**: CAISO limitations under the RDRR settlement	John Goodin, CAISO Delphine Hou, CAISO
3:15 – 3:45	**RDRR discussion**: Party discussion of limitations and possibilities	All, moderated by CAISO and CPUC
3:45 – 4:00	Next steps	Bruce Kaneshiro, CPUC John Goodin, CAISO

California ISO

Slow Response Local Capacity Resources Technical Study: framing the discussion

John Goodin, Manager, Infrastructure and Regulatory Policy, CAISO

Separating technical studies from market and policy issues

- Presentations in the morning focus on studies identifying the "technical potential" of slow response resources in the local area.
  - Therefore, simplifying assumptions are made to conduct the analysis (see page 8).
- Market and policy issues will be addressed in the afternoon.
- Eventually, the studies and the market realities will need to be aligned but for now the we would like to address each in turn.

California ISO

Slow Response Local Capacity Resources Technical Study

Results Update

Nebiyu Yimer, Regional Transmission Engineer Lead
Catalin Micsa, Sr. Advisor Regional Transmission Engineer

October 4, 2017

Changes from previous study

- Hourly load scaling method changed. Only five days around the peak are now scaled to CEC 1-in-10 forecast. Remaining 360 days are scaled to 1-in-2.
- 2013 recorded data was replaced with 2016 data (SCE & SDGE)
- SDG&E existing slow-response DR amount updated from 10 MW to 52 MW. Scenarios changed to 2%, 5% and 10% of peak.
- ISO Step 2 analysis performed for the 5% scenario in addition to existing scenario.
- Refined ISO Step 2 power flow analysis: i.e., reduced reactive power capability proportionally when reducing active power output of a generator

Introduction

- The study assesses availability requirements for slow-response resources (such as DR) to count for local resource adequacy based on precontingency dispatch:
  - annual, monthly and daily event hours
  - number of events per year and month
- The study assumes
  - slow response resources will be dispatched in anticipation of loading conditions that would be problematic if contingencies occurred.
  - no emergency declaration from ISO Operations is required.
  - they are called last and therefore have the <u>lightest</u> possible duty.
  - idealized “perfect” forecast and dispatch capabilities – operational implementation issues are not in the study scope

Methodology

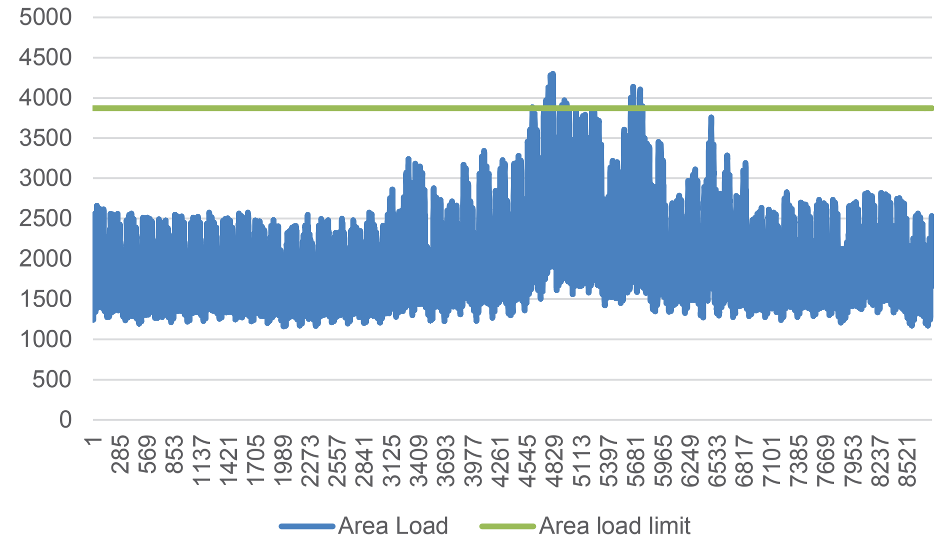
- LSEs selected LCAs and sub-areas to be studied and provided assessment using study step 1 – which assumes all resources are equally effective within a study area
- ISO:
  - reviewed LSE results
  - Evaluated selected areas using study step 2 – which tests locational and reactive capability impacts within the study area
  - evaluated results against existing DR program characteristics
- Study is based on hourly load data for 2017 derived from three years of recorded data.

Areas and scenarios studied

Performer	Areas studied	Slow-response resource amounts studied
SCE	- All LCAs, - All sub-areas	- Existing DR (Slow Response) - 2% of study area load - 5% of study area load - 10% of study area load
PG&E	- All LCAs	
SDG&E	- San Diego sub-area	
ISO	- Voltage stability limited areas in southern California	- Verify LSE Results - Existing DR (Slow Response) - 5% of study area load

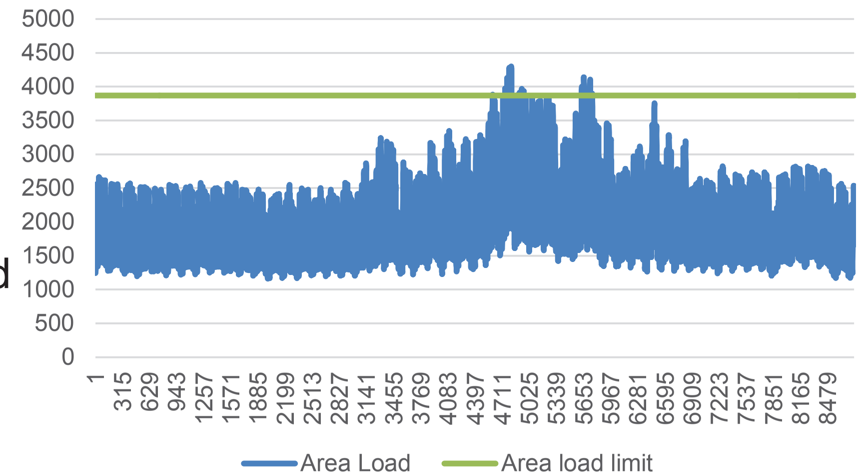
Study Sequence – Step 1 (LSEs)

1. Get hourly forecast load data for the LCR area or sub-area under consideration
2. Calculate forecast area peak load minus slow response resource amount
3. Using a spreadsheet, identify instances where the forecast hourly load for the area exceeds the level obtained in step 2. Record relevant data.
4. Repeat steps 2-3 for the various slow response resource amount scenarios
5. Repeat steps 2-4 for each LCA and sub area to be assessed



Study Sequence – Step 2 (ISO)

1. Get hourly forecast load data for the LCR area or sub-area under consideration
2. Starting from the marginal 2017 LCR base case reduce online generation in the LCR area by the amount of slow response resource
3. Apply the limiting contingency, which should cause loading, voltage, etc. violation
4. Reduce area load proportionally until the loading, voltage, etc. is acceptable. Record the resulting area load
5. Using a spreadsheet, identify instances where the forecast hourly load exceeds the level obtained in step 4. Record relevant data.
6. Repeat steps 2-5 for the various slow-response resource scenarios
7. Repeat steps 2-6 for each LCR area and sub area to be assessed



SCE/SDG&E Area Results

Adjustment for non-coincident calls among overlapping areas

- A resource located in a sub-area can be called due to need in the sub-area or overlapping LCA and sub-areas
- Non-coincident calls in overlapping areas must be included in the sub-area results where applicable

Resource location	Areas resource can be called for
El Nido	El Nido, Western LA, LA Basin
West of Devers	West of Devers, LA Basin
Valley-Devers	Valley-Devers, LA Basin
Western LA	Western LA, LA Basin
LA Basin	LA Basin

Resource Location	Areas DR can be called for
Rector	Rector, Vestal, Big Creek Ventura
Vestal	Vestal, Big Creek-Ventura
Santa Clara	Santa Clara, Moorpark, Big Creek-Ventura
Moorpark	Moorpark, Big Creek-Ventura
Big Creek - Ventura	Big Creek-Ventura

SCE existing DR with >20 min response time

Program name	Max annual hours	Max event days per month	Max event hours per month	Max event duration in hours	Max events per day	Additional restrictions	MW Capacity
BIP-30	180	10	N/A	6	1	N/A	516
CBP	N/A	N/A	30	4,6,8	1	Monday-Friday, 11 a.m. - 7 p.m.	86
AMP	N/A (varies by contract)						45

Program name	Level of Dispatch	Notification Time	Triggers
BIP-30	System-wide, SubLap, A-Bank	30 minutes	System, local, distribution reliability
CBP	System-wide, SubLap	Day Of: 1 hour, Day Ahead by 3 p.m.	Economic criterion (15,000 Btu/kWh heat rate)
AMP		Day of: 1 hour	varies by contract

SCE slow-response resource amounts assessed, MW

Area	Existing Slow DR	2% of Peak	5% of Peak	10% of Peak
El Nido	34.3 (2.1%)	33.2	83.0	165.9
West of Devers	9.4 (1.3%)	14.4	36.0	72.0
Valley-Devers	18.8 (0.7%)	52.7	131.8	263.6
Western LA Basin	354.9 (3.1%)	230.0	575.1	1150.1
LA Basin	566.7 (3.0%)	374.9	937.3	1874.6
Rector	16.6 (1.5%)	21.9	54.7	109.4
Vestal	27.7 (2.2%	25.7	64.2	128.3
Santa Clara	30.1 (3.7%)	16.3	40.7	81.4
Moorpark	37.5 (2.3%)	32.0	80.1	160.1
Big Creek Ventura	79.7 (1.8%)	86.0	215.0	429.9
Total	646.4	460.9	1152.3	2304.5

- Percentage values are relative to respective area 2017 peak load

Step 1 & 2 area load limits with existing slow DR

Area	Area load MW (A)	Step 1		Step 2	
		Existing Slow DR MW (B)	Area load limit (A-B)	Required load reduction from power flow (C)	Area load limit (A-C)
El Nido *	1,659	34.3	1,625	34.3	1,625
West of Devers *	720	9.4	711	9.4	711
Valley-Devers	2,636	18.8	2,617	N/A	N/A
Western LA Basin	11,501	354.9	11,146	N/A	N/A
LA Basin	18,746	566.7	18,179	N/A	N/A
San Diego	4,817	52	4765	N/A	N/A
Combined LA Basin/San Diego *	23,466	618.7	N/A	1184	22,282
Rector	1,094	16.6	1,077	N/A	N/A
Vestal	1,283	27.7	1,255	N/A	N/A
Santa Clara *	814	30.1	784	34.9	779
Moorpark *	1,601	37.5	1,564	38.6	1562
Big Creek Ventura	4,299	79.7	4,219	N/A	N/A

* Areas further assessed using Step 2.

Step 1 & 2 area load limits with 5% slow resource

Area	Area load MW (A)	Step 1		Step 2	
		5% of Peak Slow DR MW (B)	Area load limit (A-B)	Required load reduction from power flow (C)	Area load limit (A-C)
El Nido *	1,659	83.0	1,576	79	1,580
West of Devers *	720	36.0	684	52	668
Valley-Devers	2,636	131.8	2,504	N/A	N/A
Western LA Basin	11,501	575.1	10,926	N/A	N/A
LA Basin	18,746	937.3	17,809	N/A	N/A
San Diego	4,817	240.8	4,576	N/A	N/A
Combined LA Basin/San Diego *	23,466	1,178	N/A	1,916	21,550
Rector	1,094	54.7	1,039	N/A	N/A
Vestal	1,283	64.2	1,219	N/A	N/A
Santa Clara *	814	40.7	773	51	763
Moorpark *	1,601	80.1	1,521	96	1,505
Big Creek Ventura	4,299	215.0	4,084	N/A	N/A

* Areas further assessed using Step 2.

SCE total annual event hours (3-year max.)

	Existing DR*		2% of Peak		5% of Peak*		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	6	10(14)	6	9	17	21(25)	35	44
West of Devers *	3	6(12)	5	5	15(35)	18(36)	74	75
Valley-Devers	3	6(13)	8	11	13	22(29)	20	40
Western LA Basin	7	8(12)	3	6	13	14(22)	32	32
LA Basin*	6(12)	6(12)	5	5	12(22)	12(22)	24	24
Rector	9	14	9	15	17	26	33	57
Vestal	12	14	12	15	22	25	37	55
Santa Clara*	22(26)	26(30)	13	17	26(37)	34(44)	79	90
Moorpark*	3(4)	11(12)	3	13	8(10)	23	26	45
Big Creek Ventura	9	9	11	11	19	19	36	36

* Areas and resource levels further assessed using Step 2. Results are provided in parenthesis where different. Step 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- BIP-30 ≤ 180 hours/year, RDRR 48 hours per term (June to Sept. & Oct.-May)

SCE maximum monthly event hours (3-year max.)

	Existing DR*		2% of Peak		5% of Peak*		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	6	10(14)	6	9	17	21(25)	35	36
West of Devers*	2	6(12)	3	5	10(22)	12(22)	35	35
Valley-Devers	3	6(12)	8	8	13	13(22)	20	28
Western LA Basin	7	8(12)	3	6	13	14(22)	24	25
LA Basin*	6(12)	6(12)	5	5	12(22)	12(22)	24	24
Rector	9	14	9	15	17	26	29	42
Vestal	12	14	12	15	22	25	35	40
Santa Clara*	14(16)	14(16)	9	11	16(23)	19(23)	42	42
Moorpark*	3(4)	9	3	11	8(10)	19	21	34
Big Creek Ventura	9	9	11	11	19	19	34	34

* Areas and resource levels further assessed using Step 2. Results are provided in parenthesis where different. Step 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- CPB ≤ 30 hours/month

SCE max event duration in hours (3-year max.)

	Existing*		2% of Peak		5% of Peak*		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	6	6	6	6	7	7(10)	11	11
West of Devers*	2	4(5)	3	3	4(6)	5(9)	6	9
Valley-Devers	1	4(5)	3	3	4	5(9)	7	9
Western LA Basin	4	4(5)	3	3	5	5(9)	9	9
LA Basin*	4(5)	4(5)	3	3	5(9)	5(9)	9	9
Rector	4	4	4	4	7	7	8	9
Vestal	4	4	4	4	7	7	9	9
Santa Clara*	5	5	4	4	6(10)	6(10)	11	11
Moorpark*	3	3	3	3	5(6)	5(6)	9	9
Big Creek Ventura	3	3	3	3	5	5	8	8

* Areas and resource levels further assessed using Step 2. Results are provided in parenthesis where different. Step 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- BIP-30 ≤ 6 hours, CPB ≤ 4,6 or 8 hours, RDRR ≥ 4 hours
- This limitation applies to run-time limited fast response resources such as fast DR and battery storage as well

SCE run-time limited resources (MW)

Area	Existing Slow DR	Existing Fast DR	Procured DR & Storage*	Total DR & Storage	Load (2017)	Percent of load
El Nido	34	8	17	60	1659	3.6%
West of Devers	9	10	0	20	720	2.7%
Valley-Devers	19	48	0	67	2636	2.5%
Western LA Basin	355	113	271	739	11,501	6.4%
LA Basin	567	225	271	1063	18,746	5.7%
Rector	17	45	0	62	1,094	5.7%
Vestal	28	60	0	88	1,283	6.8%
Santa Clara	30	5	0	45	814	4.3%
Moorpark	38	13	0	60	1,601	3.1%
Big Creek Ventura	80	123	0	212	4,299	4.7%
Total	646	348	271	1275	23,045	5.5%

* Excludes hybrid gas/battery storage projects

SCE total annual event days (3-year max.)

	Existing DR*		2% of Peak		5% of Peak*		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	2	3	2	3	3	4(5)	4	7
West of Devers*	2	3(4)	2	3	5(12)	6(12)	21	21
Valley-Devers	3	5(6)	3	5	4	7(8)	4	10
Western LA Basin	3	3	1	2	3	3(4)	7	7
LA Basin*	2(3)	2(3)	2	2	3(4)	3(4)	6	6
Rector	3	4	3	4	4	6	7	12
Vestal	4	4	4	4	5	6	8	12
Santa Clara*	6	8	6	8	6(7)	8(9)	13	13
Moorpark*	1	5	1	5	2	5	6	8
Big Creek Ventura	4	4	4	4	4	4	6	6

* Areas and resource levels further assessed using Step 2. Results are provided in parenthesis where different. Step 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- RDRR ≥ 15 events per term (minimum)

SCE maximum monthly event days (3-year max.)

	Existing DR*		2% of Peak		5% of Peak*		10% of Peak	
	Local	Overall	Local	Overall	Local	Overall	Local	Overall
El Nido*	2	3	2	3	3	4	4	4
West of Devers*	1	2(3)	1	2	3(7)	3(7)	9	9
Valley-Devers	3	3	3	3	4	4(5)	4	6
Western LA Basin	3	3	1	2	3	3	4	4
LA Basin*	2(3)	2(3)	2	2	3	3	4	4
Rector	3	4	3	4	4	6	5	7
Vestal	4	4	4	4	5	5	6	7
Santa Clara*	3	4	3	4	3(4)	4	6	6
Moorpark*	1	4	1	4	2	4	4	5
Big Creek Ventura	4	4	4	4	4	4	5	5

* Areas and resource levels further assessed using Step 2. Results are provided in parenthesis where different. Step 2 assessment for LA Basin is based on the combined LA Basin-San Diego LCA.

- BIP-30 ≤ 10 events/month

SDG&E area assessment

Slow resource amounts assessed, MW

LCR Area	Existing Slow DR	2% of Peak	5% of Peak	10% of Peak
San Diego	52 (1.1%)	96	241	482

SDG&E existing DR with >20 min response time

Program name	Max annual hours	Max annual event days	Max annual hours	Max event hours	Max events/day	Additional restrictions	MW Capacity
Summer Saver	60	15	60	4	1	May – October only; 2 minimum hour per event; max 3 in a week	10 MW
Base Interruptible Program	120	120	120	4	1		2 MW
Capacity Bidding Program	264 (May-Oct)	33 to 184 days (depending on how many hours are called per event).	44 hours per month (May-Oct)	4 to 8	1	May-October only	11 MW
Critical Peak Pricing*	126	18	126	7	1		~29 MW
						Total	52 MW

* Currently the impact of the Critical Peak Pricing Program is included in the CEC demand forecast

San Diego area results (3-year max.)

	Slow resource amounts			
	Existing DR*	2% of Peak	5% of Peak*	10% of Peak
Total annual event hours	2 (12)	5	17(22)	34
Monthly maximum event hours	2(12)	5	17(22)	30
Max event duration in hours	2(5)	6	8(9)	10
Total annual event days	1(3)	2	3(4)	6
Monthly maximum event days	1(3)	2	3	4

* Slow-response resource levels further assessed using Step 2. Results are provided in parenthesis. Step 2 assessment is based on the combined LA Basin-San Diego LCA

Conclusions

- Availability needs increase as the amount of DR increases and vary from area to area
- At current levels, most existing slow-response DR resources and the ISO RDRR model appear to have the required availability characteristics needed for local resource adequacy with the exception of run-time duration limitation.
- The most limiting characteristic is the run-time limitation. At current levels, a minimum of 5 hour duration is needed in most areas not taking into account other energy-limited local capacity resources such as fast-response DR and energy storage.

Conclusions – cont'd

- When the amount of slow and fast response energy limited resources is combined the minimum run-time need could reach 9 hours in many areas including LA Basin and San Diego areas.

PG&E Area Results

Existing Sublap DR programs Identified by PG&E with >20 min response time

Program name	Notification time	Max annual hours	Period	Max monthly event days	Days	Max monthly hours	Hours of the day	Max event hours	Capacity MW
BIP	30 m	180	any	10	any	N/A	any	N/A	102.4
CBP	3Hr /1500		5/1-10/31	30	M-F	N/A	11:00 19:00	1-6	14.1
SmartAC™	N/A	100	5/1-10/31	N/A	any	N/A	any	6	53.9

Note: Capacity MW represents August 2017 portfolio adjusted 1-in-2 weather conditions. The figures from April 3rd 2017 CPUC Annual DR Load Impacts Filing. They exclude LCRA 'Other' and reflect PG&E peaking conditions.

PG&E slow-response resource amounts assessed, MW

Area	Existing DR	2% of Peak	5% of Peak	10% of Peak
Humboldt	6.0	2.9	7.2	14.4
N Coast & N Bay	11.2	29.4	73.4	146.9
Greater Bay	44.9	162.3	405.7	811.3
Sierra	13.7	23.7	59.4	118.7
Stockton	19.9	25.8	64.5	129.0
Fresno	28.9	63.4	158.4	316.9
Kern	45.8	34.4	86.0	172.0
Total	170.4	323.9	809.8	1619.5

Sierra, Stockton and Kern process book definitions (herein) do not align with local capacity area definitions.

Note: Existing DR represents August 2017 portfolio adjusted 1-in-2 weather conditions under PG&E peaking conditions. The figures from April 3rd 2017 CPUC Annual DR Load Impacts Filing.

Humboldt (heat wave over average year)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	4	2	4	10
Monthly # of hours	4	2	4	9
Monthly event days	1	1	1	3
Weekend Events	0	0	0	1
Events outside 11-7	1	1	1	4
Days in a row	1	1	1	4
Other	Need is November-March only	Need is November-March only	Need is November-March only	5 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

N Cost & N Bay (heat wave over average year)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	1	2	3	7
Monthly # of hours	1	2	3	6
Monthly event days	1	1	1	2
Weekend Events	0	0	0	0
Events outside 11-7	0	0	0	0
Days in a row	1	1	1	2
Other	-	-	-	5 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Bay Area (heat wave over average year)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	2	2	4	20
Monthly # of hours	2	2	4	14
Monthly event days	1	1	1	3
Weekend Events	0	0	0	0
Events outside 11-7	0	0	0	1
Days in a row	1	1	1	2
Other	-	-	-	7 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Sierra (heat wave over average year)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	2	2	8	16
Monthly # of hours	2	2	8	16
Monthly event days	1	1	3	5
Weekend Events	0	0	0	0
Events outside 11-7	0	0	0	1
Days in a row	1	1	3	5
Other	-	-	-	5 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Stockton (heat wave over average year)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	3	4	8	20
Monthly # of hours	3	4	8	20
Monthly event days	1	1	3	4
Weekend Events	0	0	0	0
Events outside 11-7	0	0	0	2
Days in a row	1	1	3	4
Other	-	-	-	6 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Fresno (heat wave over average year)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	4	7	23	41
Monthly # of hours	4	7	23	40
Monthly event days	2	3	5	6
Weekend Events	0	0	0	1
Events outside 11-7	0	0	3	5
Days in a row	1	3	5	6
Other	-	-	6 hours/day	9 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Kern (heat wave over average year)

Parameter	Existing DR	2% of Peak	5% of Peak	10% of Peak
Yearly # of hours	8	5	12	65
Monthly # of hours	7	5	9	27
Monthly event days	2	2	2	8
Weekend Events	0	0	1	1
Events outside 11-7	2	0	2	6
Days in a row	2	2	2	6
Other	-	-	6 hours/day	8 hours/day

Result values do not take into account observed non-coincidence of DR calls among areas and sub areas.

Conclusions

Current programs suitable for:

1. Overall constraints in:
    - North Coast/North Bay,
    - Bay Area,
    - Sierra and
    - Fresno

Current programs not suitable for:

1. Humboldt - due to season and time of need
    - *With exception of BIP*
2. Overall constraints in Stockton and Kern
    - *Due to gross definition mismatch, which would require correcting*
3. Any sub-area constraints
    - *PG&E has indicated that they are not intending to use for sub-areas due to number of sub-areas, sub-area definition and data requirements*
4. Any deficient sub-areas
    - *Events and hours will be grossly understated based upon current methodology*

Other considerations

- Availability requirements increase as the amount of DR (or other slow response resources) counted for local RA increases.
  - Setting a target limit could help in establishing minimum requirements.
- Study assumes critical N-1/N-1 contingencies are monitored in or close to real time in order to pre-dispatch slow-response resources exactly when needed.
  - How precisely can these needs be forecast and the resources dispatched?

Other considerations – cont'd

- The availability results are for local resource adequacy purposes. Upward adjustments may be needed to account for other non-coincident uses:
  - in response to price or triggers
  - for system events or by PTOs for distribution system issues
  - due to planned outages and unforeseen events
  - for program evaluation
- Historical hourly load profiles were used for this study, which does not capture future changes in load shape due to increasing load modifying DR, BTM PV and battery storage charging.

Other considerations – cont’d

- DR contracts typically have a short term and future availability may be impacted as event burden increases. This is a concern in particular in areas where slow-response DR is used to avoid investment in transmission or other assets with longer contract terms.

Study Contacts

PTO	Contact Info.
SCE	Garry Chinn, Transmission Planning, Garry.Chinn@sce.com
PG&E	Xiaofei (Sophie) Xu, Transmission Planning, x1x1@pge.com
SDG&E	H. McIntosh, Transmission Planning hmcintosh@semprautilities.com
ISO	Nebiyu Yimer, Regional Transmission, nyimer@caiso.com Catalin Micsa, Regional Transmission, cmicsa@caiso.com

Thank you

California ISO

Slow Response Local Capacity Resources Technical Study: Party discussion and Q&A panel with participating transmission owners

CAISO, PG&E, SCE, SDGE

California ISO

Proxy Demand Resource (PDR) and Reliability Demand Response Resource (RDRR) slow response barriers

Delphine Hou

Manager, State Regulatory Affairs, CAISO

Transition from planning to market

- Morning presentations reflected a “technical potential” assuming market and administrative barriers do not exist and usage based only on contingency analysis.
- Afternoon presentations discuss the potential options and remaining challenges to reaching the technical potential.
- We will need additional discussions and market experience to understand resource capabilities and market performance. This will help us understand the gap between actual usage and the technical potential.
  – We will need to develop a process to incorporate these lessons learned back into planning analysis.

PDR and RDRR slow response barriers

- Discussion excludes “fast response” resources
- Major issues to address for “slow response” are slightly different between PDR and RDRR
- Observation: many barriers for slow response PDR overlaps with general market barriers.

	≤ 20 minutes ***“fast response”***	**>20 minutes** ***“slow response”***
PDR	Qualifies for local RA	Barriers include: 1. Unable to respond to 5 minute dispatch / discrete dispatch 2. Need a notification time with no load drop 3. Pmin may be zero 4. Uncertain of commitment costs (start-up and minimum load) 5. “Pre-dispatched” for contingency 6. Others? *Potential solution with import/export options*
RDRR	Qualifies for local RA	Barriers include: 1. Unable to respond to 5 minute dispatch 2. Need a notification time with no load drop 3. “Pre-dispatched” for contingency 4. Others? *Significant barriers from Settlement Agreement*

PDR and RDRR slow response barriers (cont'd)

- For PDR, CAISO has an idea for stakeholders to consider, which leverages existing policy and functionality:
  - CAISO believes that the proposal (presented next) may successfully address the barriers listed for slow response PDR and for fast-response PDR resources that are facing similar market challenges.
  - Additional market rule changes may be needed.
- For RDRR, CAISO would like to walk through the barriers in greater detail to understand where opportunities may exist for change.

California ISO

ISO’s 15-minute market and bidding options for real-time imports and exports

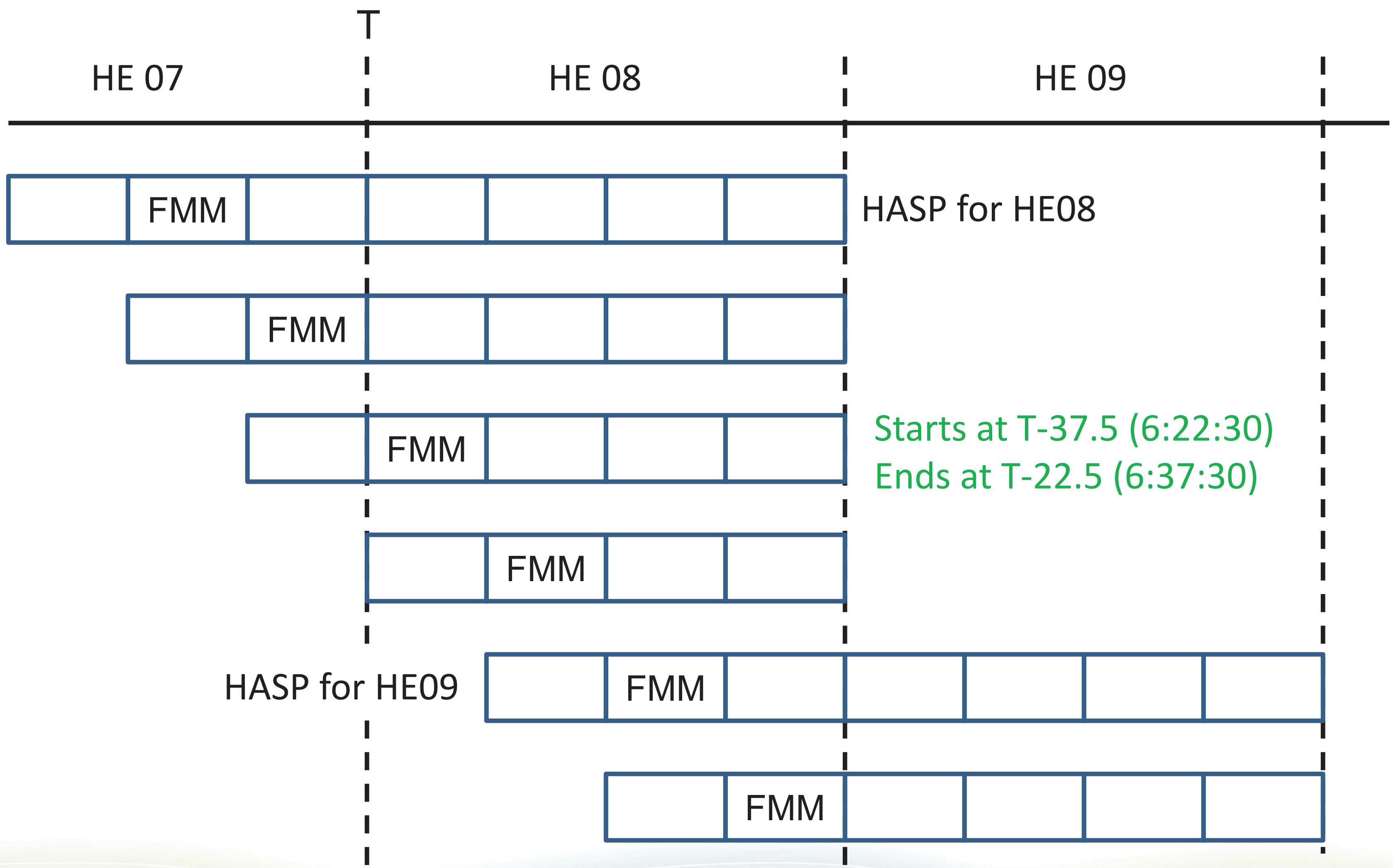
Don Tretheway
Senior Advisor, Market Design Policy, CAISO

October 4, 2017

15-Minute Market fine tunes day-ahead schedules to meet actual system conditions

- Multi-interval optimization with 15-minute granularity
  - 7 to 4 intervals
- Clears imports, exports and generation against ISO forecasted demand
- Procures incremental ancillary services
- Commits short start units and introduces the flexible ramping products
- 15-minute deviations from DA hourly schedule paid 15-minute LMP

15-minute market (FMM) provides binding awards 22.5 minutes prior to flow



With introduction of FMM in Spring 2014, the ISO expanded economic bidding options to imports/exports

- Hourly block
- Hourly block with a single intra-hour economic schedule change
- 15-minute dispatchable

FERC Order No. 764 did not change the WECC tagging deadline. Market results needed before T-20 tagging deadline.

Hourly block bid option allows an hourly schedule, but does not have price certainty

- RT bids for the hour submitted at T-75
- In hour ahead schedule process, enforce constraint that all 4 15-minute intervals must be at the same MW quantity
- If economic over hour, receives a binding hourly schedule. Prices are advisory.
- Binding schedule communicated 52.5 minutes prior to flow
- In binding FMM run, the schedule is a price taker

Hourly block with single schedule change bid option allows an hourly schedule with <u>some</u> price certainty

- RT bids for the hour submitted at T-75
- In FMM, enforce constraint that all remaining 15-minute intervals in the hour must be at the same MW quantity
- If economic over remainder hour, receives a binding schedule at FMM price in binding interval, advisory for remaining intervals
- Binding schedule communicated 22.5 minutes prior to flow
- In remaining FMM runs, the schedule is a price taker

15-minute dispatchable schedules have price certainty

- RT bids for the hour submitted at T-75
- If economic in FMM, receives a binding schedule at FMM price
- Binding schedule communicated 22.5 minutes prior to flow
- Eligible for bid cost recovery

Interties assumed to have infinite ramp rates

- Results in block energy

- If scheduled at 120 MW for 15-minute interval,
  - Instructed imbalance energy (IIE) is 10 MWh for each 5-minute interval in the 15-minute interval

- Differences between instructed imbalance energy and meter uninstructed imbalance energy (UIE)
  - Settled at the RTD price for the five-minute interval
  - Flexible ramping cost allocated based on UIE
  - May also be subject to other uplift costs

Links to additional information

- FERC Order No. 764 initiative webpage
  - http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedClosedStakeholderInitiatives/FERCOrderNo764MarketChanges.aspx

- Settlement examples
  - Hourly block tab
  - 15-minute tab
  - Dynamic transfer tab (settlement of internal resource)
  - Doesn’t have the one and done option
  - http://www.caiso.com/Documents/RevisedSettlementExamples-FERCOrderNo764.xls

California ISO

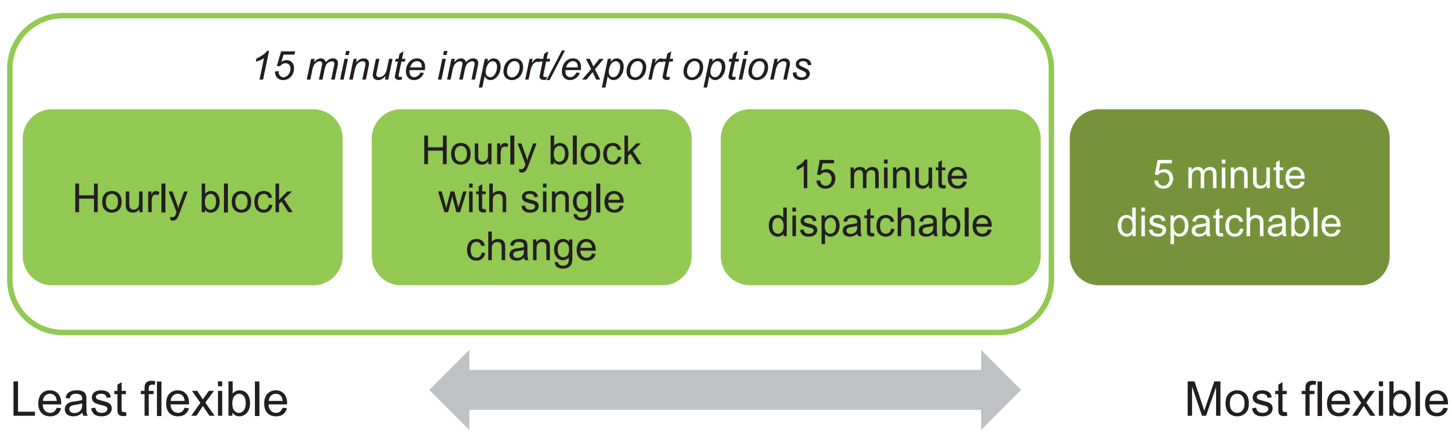
PDR discussion: Party discussion on feasibility of import/export options for PDR

All, moderated by CAISO and CPUC

Introduction by Delphine Hou, Manager, State Regulatory Affairs, CAISO

Benefits of leveraging import/export options

- Functionality already exists – though only available for imports/exports
  - Would need tariff change
- Modeling of PDR remains largely the same
- Is presented as an option for all PDR, in addition to current model and generator bidding parameters
- Continuum of real-time dispatch options for PDR



Have slow response PDR barriers been addressed?

Red font text is revised from 10/4 version.

	Slow response PDR barriers	Import/export option offers:	Comments
1	Unable to respond to 5 minute dispatch / discrete dispatch	3 additional options: hourly block, hourly with single change, 15 minute	• Bidding can be in one or more segments and will be dispatched as block energy per segment. • There may be instances of marginal dispatch. • 15 min dispatch uses MasterFile ramp rate but hourly block is infinite ramp rate. • Would make the "min run time" field more relevant
2	Need a notification time with no load drop	22.5 minute notification (52.5 minute if hourly block)	~~This leads to a natural dividing line where:~~ ~~≤ 22.5 min = fast~~ ~~>22.5 min = slow~~
3	Pmin may be zero	Pmin is not modeled	n/a
4	Uncertain of commitment costs (start-up and minimum load)	Pmin is not modeled	Optimization will still use ramp rate in MasterFile

- Barriers listed above may also affect fast response PDR.

Have slow response PDR barriers been addressed?

	Slow response PDR barriers	Import/export option offers:	Comments
5	"Pre-dispatched" for contingency	Real-time bidding to meet RA MOO	Requires additional policy change (see below)
6	Others?	?	?

"Pre-dispatched" for contingency

- For local area contingencies, the CAISO uses the minimum online commitment (MOC) constraint in the integrated forward market (IFM) to commit resources.
  - Similarly, the residual unit commitment process may commit resources.
- Once committed, the resources must submit economic bids into the real-time market per resource adequacy policy.
- For vast majority of PDR, the start-up times are short enough that the resource is reoptimized in the real-time.
- Proposed policy change: If MOC commits resource regardless of start-up time, the resource has "binding" commitment and a real-time must offer obligation (MOO). This would apply to all resources, not just PDR. PDR resources can use the intertie scheduling options to meet their MOO.

REMOVE SLIDE

Questions for parties

- Would applying the import/export option help some PDR programs operate better in the market and count towards local RA?
- How many MWs of PDR would benefit from the import/export option?
- Are there other barriers we haven't addressed?
- Complications or new issues?
- Others?

RDRR slow response barriers

- Of all the barriers, the most significant for CAISO is the Settlement Agreement which would preclude any "pre-dispatch" of the resource.

	>20 minutes ***"slow response"***
RDRR	Barriers include: 1. Unable to respond to 5 minute dispatch 2. Need a notification time with no load drop 3. "Pre-dispatched" for contingency 4. Others?

Limitations for CAISO under RDRR

- Per the Settlement Agreement, for CAISO to use RDRR for reliability, we must declare a ‘Warning’ or ‘Emergency Stage’
- See: http://www.caiso.com/Documents/4420.pdf
  - **Warning** - The ISO issues a Warning notice when the Real-Time Market run results indicate that Contingency Reserves are anticipated to be less than Contingency Reserve requirements and further actions are necessary to maintain the Contingency Reserve requirements.
  - **Stage 1** - The ISO issues an Emergency Stage 1 when Contingency Reserve shortfalls exist or are forecast to occur, and available market and non-market resources are insufficient to maintain Contingency Reserve requirements.
  - **Stage 2** - The ISO issues an Emergency Stage 2 when it has taken all actions listed above and cannot maintain its Non-Spinning Reserve requirement as indicated by the EMS system.
  - **Stage 3** - The ISO issues an Emergency Stage 3 when the Spinning Reserve portion of the Contingency Reserve depletes, or is anticipated to deplete below the Contingency Reserve requirement and cannot be restored. The Contingency Reserve requirement states that Spinning Reserve shall be no less than 50% of the total Contingency Reserve requirements.

Limitations for CAISO under RDRR (cont'd)

- Does not make sense to call a 'Warning' or 'Emergency Stage' in the day-ahead market so that RDRR can be "pre-dispatched"
- Calling a 'Warning' or 'Emergency Stage' sets off reporting requirements:
  - NERC/WECC standards dictate that when an ISO declares an "Emergency," the ISO must report to our reliability coordinator (Peak Reliability) and it is seen as a declaration that the CAISO does not have sufficient resources to manage grid conditions.
  - CAISO reports to Peak Reliability any time there is an Emergency declaration and this in turn goes into metrics measuring CAISO against other ISOs.
  - See: http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf

California ISO

RDRR discussion: Party discussion of limitations and possibilities

All, moderated by CAISO and CPUC

California ISO

Next steps

Bruce Kaneshiro, Program Manager for the Demand Response, Customer Generation and Retail Rates Branch, CPUC

John Goodin, Manager, Infrastructure and Regulatory Policy, CAISO

Next steps

- PDR Issues: what actions/work can be undertaken in the next 3-4 months with regard to the CAISO proposal and stakeholder comments on that proposal?
- RDRR Issues: what actions/work can be undertaken in the next 3-4 months with regard to the discussion on the limitations and possibilities for RDRR resources?
- Another workshop is likely needed. What topics should be covered then?
- Please submit comments on the workshop to regionaltransmission@caiso.com by close of business October 18.