

CALIFORNIA PUBLIC UTILITIES COMMISSION

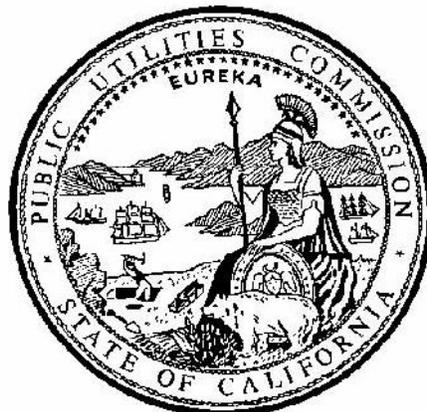
JOINT RELIABILITY PLAN

TRACK ONE STAFF REPORT

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TABLE 1: TERMINOLOGY AND ABBREVIATIONS

All Available Energy Efficiency (AAEE)
California Energy Commission (CEC)
California Independent System Operator (CAISO)
Capacity Allocation Mechanism (CAM)
Community Choice Aggregators (CCAs)
Demand Response (DR)
Distributed Generation (DG)
Effective Load Carrying Capacity (ELCC)
Energy Service Provider (ESP)
Federal Energy Regulatory Commission (FERC)
Flexible Resource Adequacy Criteria – Must Offer Obligation (FRAC-MOO)
Integrated Energy Planning Report (IEPR)
Investor Owned Utility (IOU)
Joint Reliability Plan (JRP)
Load-Serving Entity (LSE)
Local Capacity Requirement (LCR)
Long-Term Procurement Plan (LTPP)
Market Redesign and Technology Upgrade (MRTU)
Megawatt (MW)
Net Qualifying Capacity (NQC)
Office of Ratepayer Advocates (ORA)
Order Instituting Rulemaking (OIR)
Planning Reserve Margin (PRM)
Power Purchase Agreement (PPA)
Publicly Owned utility (POU)
publicly-owned utility (POU)
Reliability Must Run (RMR)
Renewable Portfolio Standard (RPS)
Resource Adequacy (RA)
Rulemaking (R.)
San Onofre Nuclear Generating Station (SONGS)
Strategic Energy and Risk Valuation Model (SERVM)
To-Expiration Value-at-Risk (TEVaR)
utility-owned generation (UOG)

I. INTRODUCTION, EXECUTIVE SUMMARY, BACKGROUND

A. INTRODUCTION

This report is intended to support the California Public Utilities Commission's (Commission or CPUC) consideration of whether multi-year Resource Adequacy (RA) requirements are necessary or beneficial to ensuring electric system reliability. In this report, the Staff of the Commission's Energy Division examines, using information presently available, the sufficiency of the present reliability framework and whether new procurement policies are justified. The issues addressed in this report are meant to support the development of the record under Track One of the Joint Reliability Plan proceeding (Rulemaking (R.) 14-02-001).

This report begins by covering the four pivotal issues identified in the Joint Reliability Plan. These are: the existing reliability framework, the availability of flexible capacity, inefficient retirements, and existing forward procurement practices. The section on forward procurement practices presents the summary results of data recently collected on existing capacity contracts held by those Load Serving Entities that are subject to the Commission's jurisdiction. Next, the report presents a menu of proposals for creating multi-year RA requirements and analyzes the pros and cons of each option. Finally, the report lays out a number of questions for party comment. The report also includes an appendix in which each of the pieces that form the state's reliability framework is explained in detail.

B. EXECUTIVE SUMMARY

California's electric system is in the midst of a transformation. Ambitious laws setting renewable energy and greenhouse gas reduction requirements are leading to higher penetrations of renewable energy, as well as the use of a variety of resources, such as energy storage, demand response, and energy efficiency to ensure electric system reliability. However, the full consequences of this transformation are not well understood today, particularly the quantity of flexible capacity needed in the next two to ten years and the specific characteristics that flexible resources will need to offer to the grid. Understanding these consequences is intertwined with the ability to know whether the resources that the system may need in the next ten years will be available. The availability of such resources may be uncertain and dependent upon the likelihood that they are under long term contracts with LSEs. To understand whether a new reliability mechanism is necessary and justified, it is critical to first understand the depth and breadth of the existing reliability framework and next to assess whether it is functioning as designed.

This report is aimed at supporting the Commission's goal of determining whether procurement policies should change in response to uncertainty around the sufficiency of the present reliability framework. It discusses four pivotal issues that must be understood better before a decision supporting multi-year RA could be made. These are:

1. Whether the current reliability framework is sufficient to ensure reliability,
2. Whether the availability of flexible capacity is, at present, uncertain,
3. Whether the Commission should be concerned about the potential for inefficient resource retirements, and
4. Whether the observable pattern of LSE forward procurement at present justifies concern.

The report proposes that multi-year requirements may be warranted depending upon the conclusions reached when considering the above issues.

On the first issue, Staff proposes that the sufficiency of the present reliability framework should be assessed by determining: a) if the interrelated parts of the framework, as developed and/or authorized by the Commission, the California Independent System Operator (CAISO), and the Federal Energy Regulatory Commission (FERC) are working as designed, and b) whether the framework provides adequate assurance that the system can adapt to future needs and that generation resources will be available to meet those needs. On the second issue, flexibility, the report concludes that it is too soon to assess the effectiveness of the recently implemented flexible procurement requirements. On the third pivotal issue, Staff proposes the terminology of “inefficient retirements” as a way to frame and define the issue, which to date has been vaguely referred to as the “risk of retirement.” Whether a resource is determined to be at risk of inefficiently retiring is dependent upon a factor test, which encompasses both the valuable attributes of the resource and its financial situation. To answer the fourth pivotal issue, the report draws upon data recently collected by Staff to show that current procurement practices compared to projected demand are providing California with sufficient system and local supply for at least two years into the future.

The report then proposes options for multi-year RA requirements for each type of capacity, by providing a menu of options for forward procurement. The menu includes two- and three-year requirements for system capacity, interim requirements for flexible capacity procurement for years 2016 and 2017 and a two-year requirement for local capacity. The report analyzes the pros and cons of adding each requirement to the existing reliability framework, compared with the option of no additional requirements. Staff also proposes two options for “trigger mechanisms” to institute one or more of the proposed options for multi-year RA. The effect of a trigger would be that, if the circumstances laid out in the mechanism occur, then multi-year procurement obligations would go into effect the following compliance year. The Commission could decide whether the requirements should be triggered by the level of forward contracting determined through the assessment ordered to be completed in Track 2 of this proceeding or by the ratio of available capacity compared against projected need (including the planning reserve margin).

This report provides the context for understanding the sufficiency of the reliability framework by summarizing all of the pieces of the framework in the Appendix, including policies and programs implemented by the Commission and other agencies.

C. BACKGROUND

The Commission opened R.14-02-001 “to consider policy proposals to refine California’s existing reliability framework for electricity procurement.”¹ The issues addressed in this report are set out in the scope of Track One of the Order Instituting Rulemaking (OIR) also known as the Joint Reliability Plan (JRP).²

5. Are there capacity needs, in the medium term, that pose a reliability risk and which are not currently being adequately addressed by the RA program?
 - a. Do these risks remain after implementation of the recent RA decision³ that adopts a flexibility framework and mandates flexible resource procurement? If so, what are they?
6. Which types of multi-year RA requirements may be beneficial to reliability and which would be most difficult to implement?
7. Is now the right time for multi-year requirements to be developed?
8. If so, when is the appropriate time for multi-year requirements to be implemented?

This report addresses questions related to medium- and long-term procurement and reliability.⁴ The purpose of Track One of the JRP Proceeding is to consider the potential for RA requirements two and three years into the future; i.e., in the medium term. Therefore, this report discusses potential impacts of medium-term procurement mandates on reliability, ratepayer cost, and uncertainty. Track Two of this proceeding calls for a “Long Term Reliability Assessment” to “assess capacity that is currently under contract or will be under contract in the next ten years.”⁵ This report provides a preview of the assessment by presenting a high-level aggregation of data collected for a preliminary draft of the assessment.

Party discussion and comment at workshops in May 2014 informed this report. A portion of the first workshop was on the record, but the second workshop was informal and hosted by Energy Division. At the workshops, Staff facilitated party presentations and discussion on the risk of retirement and the potential benefits and costs of multi-year requirements. At the second workshop, an inter-agency panel

1 R.14-02-001 at 2.

2 Order Instituting Rulemaking (R.) 14-02-001, [opened February 5th, 2014] at 8-11.

3 Decision (D.) 14-06-050.

4 The Commission defined medium term and long term in R.12-03-014 as follows: “[m]edium-term contracts are contracts of three consecutive months or greater and under five years in duration. Long-term contracts are contracts of five years or more in length.”

5 R.14-02-001, Final Scoping Ruling at 9.

presented on the feasibility and potential mechanics of a multi-year RA program, which led to valuable discussion amongst the parties, thus informing the options presented in this report.

This Staff report is not a final decision, and it does not speak for the Commission. The report at times states that the Staff “proposes” or “expects” the Commission to take certain actions—but this does not substitute for a Commission decision on any issue. Rather, the report is intended to elicit comments to inform and aid Commission decision making. If there are errors and omissions in any section of the report, parties are welcome to note them in their comments and offer clarification, which will improve the record in this proceeding.

II. THE FOUR PIVOTAL ISSUES IN THE JOINT RELIABILITY PLAN

A. THE EXISTING RELIABILITY FRAMEWORK

Is the existing reliability framework for electric procurement sufficient to ensure reliability in the next ten years?

The purpose of the JRP proceeding is to “consider policy proposals to refine California’s existing reliability framework.”⁶ Reliability framework in this context means “California’s electric resource and transmission planning and procurement processes . . . include[ing] the . . . Resource Adequacy program and Long-Term Procurement Planning proceeding as well as the California Independent System Operator Corporation’s Capacity Procurement Mechanism and transmission planning processes.”⁷ The immediate timeframe at issue in the Joint Reliability Plan is from the present to 2024, because the Long-Term Procurement Plan (LTPP) proceeding is tasked with assessing system needs ten years ahead on a rolling basis.

1. RELEVANT FACTS AND POLICIES

To understand whether a new reliability mechanism is necessary and justified for California, it is critical to understand the depth and breadth of the existing reliability framework and to define the pieces that form the framework at present. This will allow for meaningful discussion of whether multi-year RA requirements would complement or duplicate the purposes of other policies and programs. The elements that form the present reliability framework are: the RA program, the LTPP program, utility procurement portfolio management, the CAISO Reliability Must Run (RMR) program, and CAISO’s backstop authority (the Capacity Procurement Mechanism (CPM)).

⁶ R.14-02-001 at 2.

⁷ *Id.*

The RA program is designed to ensure that California Public Utilities Commission jurisdictional Load Serving Entities (CPUC-LSEs) have sufficient capacity to meet their peak load with a 15 percent reserve margin at least one year ahead. The LTPP proceeding is intended as an umbrella proceeding wherein the Commission considers all of its electric resource procurement policies and programs in an integrated manner and authorizes additional procurement for needs not met by current resources. IOU portfolio management aims to reduce future cost variability. The CAISO also plays a role in the state's reliability framework, as it ensures the safe and reliable operation of the grid. To perform this essential function, it has been granted specific authority by FERC related to the reliable operation of the grid, including the ability to designate resources as RMR and to procure "backstop" capacity through the CPM if there is a deficiency in the RA program. A full explanation of each of these elements is contained in the Appendix.

As the Commission recently noted in opening this proceeding, the "current reliability framework has provided for reliable operation of the transmission grid over the past decade."⁸ The present reliability framework is comprised of interrelated parts, which have been developed and/or authorized by the Commission, CAISO, and FERC to work together synergistically to ensure reliable operation of the grid in the medium and long term. In particular, the RA and LTPP programs have, to date, adequately ensured that appropriate resources are procured by CPUC-LSEs both in the short and long term. Furthermore, in the instances in which California has experienced an unexpected event or outage, sufficient replacement capacity has come online in a timely manner, resulting in *de minimis* reliability impacts, if any. This fact also demonstrates the resiliency and adaptability of California's electric system, thanks to policies implemented via RA and LTPP proceedings, such as the planning reserve margin (PRM).⁹

The question of multi-year requirements in the RA program has been previously considered and discussed by the Commission. The Commission took up the issue in 2009-2010 in R.05-12-013, considering whether multi-year RA should be implemented as a way to balance reliance on IOUs to adequately facilitate forward investment in new generation. At that time, the Commission found multi-year RA to be unjustified, stating: "there are significant reasons not to proceed with a multi-year forward procurement mandate at this time" because other programs, such as "RA, the Renewable Portfolio Standard (RPS) and the Locational Marginal Pricing component of CAISO's Market MRTU process should 'encourage new development.'"¹⁰ The Commission also noted that "[t]he RA program is

⁸ R.14-02-001 at 3.

⁹ The planning reserve margin was established by D.04-01-050.

¹⁰ D.10-06-018 at 32.

new, and we should recognize the possibility that the year-ahead procurement obligation will provide adequate incentive for merchant development.”¹¹

2. DISCUSSION

Any proposal related to multi-year procurement needs to consider whether a variety of programs implemented by the Commission are appropriately ensuring reliability by maintaining the existing fleet of generation and encouraging the development of new generation. More specifically, parties and the Commission may need to consider clarifying whether the burden of ensuring reliability is accomplished both through creating appropriate incentives and encouraging development of new generation and determining how this burden should be distributed across the RA, LTPP, RPS, and other proceedings.

In February 2013, as stakeholders focused renewed attention on the adaptability of the grid to increasing renewable penetration, the Commission and CAISO held a joint summit on “Long Term Resource Adequacy.” This summit preceded development of the Joint Reliability Framework document¹² released by CPUC Staff and CAISO in July 2013. At the summit, in advocating for a new, intermediate procurement mechanism, CAISO argued that:

[i]ntermediate-term procurement in the three to five-year forward timeframe would help 1) address ‘revenue adequacy’ for existing resources that possess operational attributes needed in future years; 2) inform whether an existing resource should repower or retire; and 3) provide an opportunity to commit non-generation and preferred resources that require a shorter development lead time and, which are generally not well suited to making 10-year advance commitments. Such a procurement opportunity would further advance the state’s loading order while ensuring sufficient flexible capacity resources are preserved and committed within the balancing area.¹³

The assertion by CAISO and each of the supporting statements it contains are now scoped into the JRP. This report discusses these statements in the sections that follow.

¹¹ *Id* at 33.

¹² Available at <http://www.aiso.com/informed/Pages/StakeholderProcesses/Multi-YearReliabilityFramework.aspx>

¹³ “Comprehensive Forward Capacity Procurement Framework”, CAISO, February 26th, 2013 available at <http://www.aiso.com/Documents/Public%20forums%20archive/Long-term%20resource%20adequacy%20summit%20-%20Feb%2026,%202013>.

3. CONCLUSION

The present reliability framework may or may not be sufficient to ensure reliability. An assessment of whether the interrelated parts of the framework, as developed and/or authorized by the Commission, CAISO, and FERC, are working as designed, is necessary. The Commission needs to consider whether the existing framework can adapt to future system needs and whether generation resources will be available to meet those needs.

B. THE AVAILABILITY OF FLEXIBLE CAPACITY

Is the procurement of flexible capacity in the medium/long term so critical, yet its availability so uncertain, as to create unacceptable risks that the Commission should mitigate with further regulatory action?

1. RELEVANT FACTS AND POLICIES

The Commission is currently addressing flexible capacity need and procurement through its RA and LTPP proceedings. The recently concluded RA proceeding, R.11-10-023, focused on creating assurances that an appropriate amount of flexible resources would be procured on a year-ahead and month-ahead basis to ensure reliability in a rapidly changing electricity system. In 2013, the Commission created flexible procurement targets for 2014, and identified tasks for future decisions, including: “develop[ing] counting rules, eligibility criteria, and must-offer obligations for [...] preferred resources [...] and energy storage resources.”¹⁴

Through the June 2014 RA decision, the Commission took a significant step by adopting rules, criteria, and obligations for Flexible RA, thus instituting the first binding flexible capacity procurement obligations as an additional component of RA requirements.¹⁵ “Flexible capacity need” is now defined as “the quantity of resources needed by CAISO to manage grid reliability during the greatest three-hour continuous ramp in each month.”¹⁶ “Resources will be considered flexible capacity if they can sustain or increase output, or reduce ramping needs, during the hours of the ramping period of flexible need.”¹⁷ The framework laid out via the recent decision is valid through 2017, and the Commission set forth a process to finalize ongoing assessments and set future requirements.

A key aspect of D.14-06-050 is the three Flexible RA categories it adopts. These categories represent a compromise and balance between ensuring that the appropriate amount and quality of

¹⁴ D.13-06-024.

¹⁵ D.14-06-050.

¹⁶ *Id.* at 2.

¹⁷ *Id.*

high-performing flexible resources are available to the system operator, and creating practically feasible, non-discriminatory, capacity procurement requirements.¹⁸ The CAISO developed and proposed three categories of flexibility through its Flexible Resource Adequacy Criteria – Must Offer Obligation (FRAC-MOO) stakeholder initiative.¹⁹ The CAISO then analyzed the need for each of these categories in its flexible capacity needs assessment.²⁰ The Commission adopted the CAISO’s needs assessment and the three flexible categories as obligations for the 2015 RA compliance year. These categories are defined based on the CAISO’s assessment of the flexible capacity attributes needed to address different System Ramping conditions:

Category 1 (Base Flexibility): Operational needs determined by the magnitude of the largest 3-hour secondary ramp in a given month.

Category 2 (Peak Flexibility): Operational needs determined by the difference (Δ) between 95% of the maximum 3-hour net-load ramp and the largest 3-hour secondary net-load ramp in a given month.

Category 3 (Super-Peak Flexibility): Operational needs determined by 5% of the maximum 3-hour net-load ramp of a given month.

A range of flexible capacity attributes are expected to contribute to meeting grid needs in different types of operational situations. However, a flexibility framework that attempted to address all possible variations of flexibility attributes would be far too complex to be practicable. At present, the Commission has decided that the CPUC-LSEs should base procurement on the categories of flexibility as recommended by CAISO and adopted in the recent RA Decision. The Energy Division is also developing a stochastic model using the Strategic Energy and Risk Valuation Model (SERVM) platform. This model may inform future decisions by enabling Staff to further analyze need for flexible resources.²¹

Although these requirements are expected to evolve, currently there is no sunset date. Rather, the requirements are expected to be revisited and modified as needed. For the 2016 RA year, the Commission has additionally committed to “[f]urther assess[ing] if the three flexible categories address

¹⁸ “[a]s an interim approach, we require LSEs to procure flexible resources in accordance with flexible categories based on varying must-offer obligations and energy limitations. We adopt a three- category approach with fixed monthly percentage limits. We believe this approach is simple and creates provisions for preferred resources to participate in the flexible capacity procurement framework” D.14-06-050 at A-10.

¹⁹ <http://www.aiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx>.

²⁰ In its filings in R. 11-10-023, the CAISO filed a Preliminary Assessment on April 4, 2014 and its final assessment on May 1, 2014, with an addendum on May 5, 2014. The assessment is available at http://www.aiso.com/Documents/Final_2014_FlexCapacityNeedsAssessment.pdf.

²¹ <http://cpuc.ca.gov/PUC/energy/Procurement/RA/Probabilistic+Modeling.htm>.

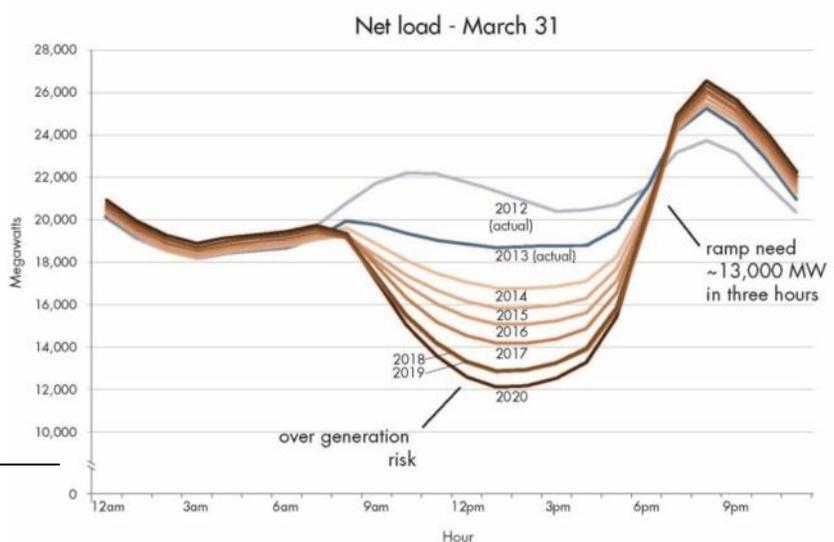
the objective of managing use-limited resources and allowing the participation of preferred resources and the appropriateness of characteristics for each category.”²²

Within the LTPP proceeding, the Commission and stakeholders are considering the most appropriate method for projecting long-term future flexibility needs. Parties to the LTPP and Staff are analyzing the results from stochastic and deterministic modeling studies to inform the question of operational flexibility needs in 2024 under one or more planning scenarios. Notably, LTPP modeling studies include built-in assumptions that some previously-authorized capacity for system and local needs can be used to meet flexibility needs, depending on the resource characteristics.

2. DISCUSSION

In the JRP OIR instituting this proceeding, the Commission specifically referred to the risk created by the changing requirements of the grid. Because of California’s ambitious RPS law, which requires that 33% of electricity be procured from renewable resources by 2020, and the possibility that the RPS requirements could be raised in the coming years, the electric grid in California is in a period of unprecedented transformation. The potential challenges associated with this rapid change are visually represented by what is now commonly called the “duck chart,” developed by CAISO. The duck chart represents a sample “extreme” one-day snapshot of the potential electricity load curve for a spring day in California’s future, but it does not simultaneously show available supply to meet load. CAISO has estimated that flexible needs will be highest in the non-summer months,²³ with the highest expected potential for renewable over-generation in the spring, when loads are moderate and intermittent renewable generation peaks in the afternoon. This timeframe is when CAISO shows, in the “duck chart” represented in Figure 1, that the system is most likely to experience two ramping events when the timing of solar generation does not follow load.

Figure 1 CAISO “duck chart”²⁴



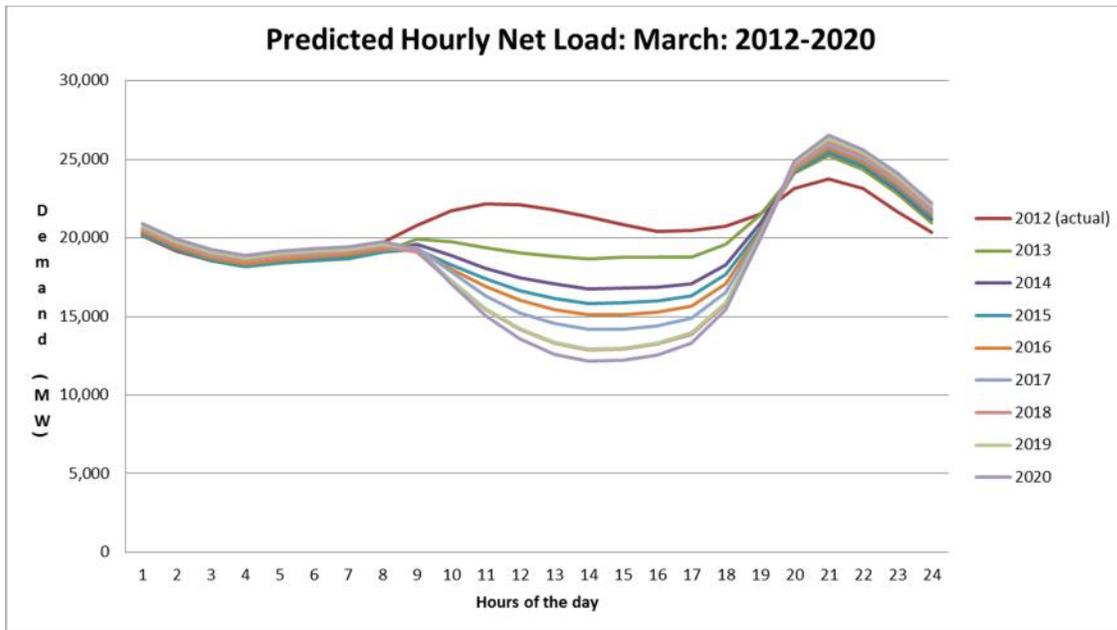
²² D.14-06-050.

²³ http://www.caiso.com/Documents/Final_2014_FlexCapacityNeedsAssessment.pdf

²⁴ Source: CAISO’s Tariff Amendment filing to FERC, August 1, 2014, at 6. Available at:

http://www.caiso.com/Documents/Aug1_2014_TariffAmendment-FlexibleResourceAdequacyCapacityRequirement_ER14-2574-000.pdf

Figure 2: “duck chart” to scale



What Staff believes CAISO intends to show through this predictive net-load curve is the potential for a non-summer day in California to exhibit two system peaks, between which lies the bulk of the state’s rapidly expanding solar generation that is interconnected to both the transmission and distribution-systems. On either end of the “belly” of the duck for years 2017-2020 are two potential extreme ramping events (one down and one up) in which non-solar generation will need to adjust quickly to balance solar generation. The curve is used to highlight the highest potential need for highly flexible resources with very fast responsiveness, or ramp rates. The potential risk displayed by the duck curve projection is that, without sufficiently responsive ramping capabilities of generation resources or potentially advanced demand response and/or storage, the integration of higher percentages of renewable generation onto the grid could create significant reliability issues for California in the near future.

In Figure 2 above, the duck chart has been recreated by CPUC Staff using CAISO data, to show how the curve appears if the y axis is shown on an equal scale from 0-30,000 MW. Staff considers this to be a more precise visual representation of the data.

There are tools already under development that could aid in developing a better understanding of the potential for near-term reliability issues. If through the LTPP preceding the Commission ultimately adopts either a stochastic or deterministic model to make projections ten or more years into the future, this will also be relevant for forecasting system flexibility needs in the two- to ten-year time frame. Therefore, although the LTPP modeling efforts are examining flexible needs beginning in 2024, the adopted model could be adjusted to analyze a different time-frame, and this may help Staff identify any indications of the insufficiency of medium-term flexibility procurement.

As discussed above, the Commission may continue to consider, through the RA proceedings, whether future needs will be better met by different categories of flexible capacity, representing more diverse characteristics that can meet grid needs in varied operational situations. The recent decision to implement flexible requirements within the RA program represents a major undertaking to strike a balance between designing a program that perfectly defines every flavor of flexible capacity the grid might need and creating implementable requirements with which LSEs can effectively comply. In their presentations at the May 2014 JRP workshops, CAISO staff re-emphasized the need to avoid premature retirement of resources required to address flexible capacity needs, similar to their comments at the 2013 long-term RA summit. CAISO is now conducting a narrowly focused study to assess the potential risk of retirement relative to the growing flexible capacity needs, and CAISO anticipates having preliminary results available to introduce into this proceeding by October 2014.²⁵

Recent discussions between Commission Staff and CAISO, both through the RA and JRP proceedings, have focused on flexible characteristics and whether the three categories of Flexible RA are sufficient. Resources with the following characteristics have been extensively discussed as potentially providing higher value to the grid operator, as compared with the more limited characteristics captured by the three categories recently adopted by the Commission:

- Dispatchable;
- Non use-limited;
- High ramp rate capability; and
- Capable of more than two daily starts.

The following two additional characteristics have been informally suggested by CAISO as relevant to flexibility in discussions with CPUC Staff, but these characteristics are not part of any adopted definition of flexibility at present:

- Low minimum load burden. This factor is related to the requisite minimum load associated with committing a resource. Committing too many resources with high minimum load may create or exacerbate an over-generation condition. This also pertains to committing a resource so that it is available to provide flexible capacity.
- Lower minimum hourly run-time limitations. A resource must be running to provide ramping; however, to avoid over-generation, CAISO may need to turn the resource off after the ramp.

²⁵ CAISO has shared with CPUC Staff that it is planning to assess the impact of meeting RPS requirements on flexible capacity energy market revenues through production cost modeling for the study years 2018, 2021 and 2024. The study will use the base case that is being used in the current LTPP proceeding, with loads and resources adjusted to 2018, 2021 and 2024. CAISO also expects the study to identify the flexible resource needs for the study years to identify increased ramping and flexibility needs going forward. The study will evaluate the differences in requirements between year 1 and year 3.

However, the minimum run time of the resource may prevent the CAISO from doing so. Resources with shorter minimum run times can be turned off more readily than resources with long minimum runs times, and may offer flexibility in addressing over-generation conditions.

Because these two characteristics are not well understood and have not been presented to the Commission for its consideration in the RA or other proceedings, further discussion would be necessary before these factors could be used to influence procurement requirements.

According to the CAISO, flexible resources with all of the above characteristics can provide the greatest benefit to the system operator to support uncertainty, variability and ramping needs. One way to ensure the continued availability of these resources may be higher capacity payments; another may be the additional energy market revenues associated with increased dispatch, which should be expected for a useful, flexible resource.

3. CONCLUSION

It is not yet possible to analyze the effects of the recent RA Decision on flexible procurement to conclude whether further regulatory action by the Commission is warranted. While the duck chart may represent the worst-case scenario for the system's flexibility needs, evidence is not presently available which suggests that the current generation fleet cannot meet the system's highest possible demand for flexibility.

C. INEFFICIENT RETIREMENTS

Under what conditions does the retirement of a generation resource, or group of resources, create a reliability risk?

1. RELEVANT FACTS AND POLICIES

In many ways, today's electric generation capacity landscape looks similar to that of 2010, when the Commission last considered multi-year RA, except that many of the transformations that were only beginning to occur then are now much further underway. As the JRP OIR states, "as new operational and market challenges emerge we recognize the need to remain aware and responsive in order to ensure reliable electricity supplies."²⁶ One significant difference is the progress that has been made under the State's RPS program. In addition, the influx of solar PV interconnected to the distribution system has also been more rapid than predicted. At the same time, LTPP decisions authorized new generation to be built around the State, including authorizations for conventional and preferred

²⁶ R.14-02-001 at 4.

resource portfolios to address local area needs, and replacement power for the San Onofre Nuclear Generation Station (SONGS).²⁷

The retirement of merchant generators due to market forces is extremely difficult to predict. While the LTPP has historically made retirement assumptions for the purposes of long-term planning, these assumptions have not always proven accurate. For example, Staff is now observing that many older generation units not utilizing once-through-cooling (OTC) technology are not retiring at the rate predicted, and some OTC units are retrofitting rather than retiring. Therefore, past predictions about future new resource needs were not highly accurate. (LTPP assumptions around resource retirements are covered in the Appendix). In assessing medium- to long-term reliability in the context of generator retirements, there may need to be inquiries regarding whether observed generator retirements over a series of years were significantly higher than predictions and assumptions upon which LTPP decisions were made.

Staff observes that the California grid still has a large proportion of older generators in operation that provide capacity to LSEs via the bilateral market. These generators are willing to offer this capacity at much lower prices than new resources because they no longer have significant capital costs and they generally have lower operating costs. In particular, there is a category of generation that is the least likely to receive long term capacity contracts: the merchant power plants that were constructed during the electricity restructuring of the late 1990s, and therefore were not built by authorization via the LTPP. At the same time, given their recent vintage, a large subset of these plants are more likely to have the flexible operating characteristics that are currently desired by the Commission and CAISO. With the implementation of the new Flexible RA requirements (discussed above), it should be the case that the flexible capacity attributes of these plants will be more valuable because their characteristics will be in higher demand. Therefore, in theory, these plants should be in demand and receiving contracts for their flexible capacity attributes. In reality, however, such capacity contracts may not be a certainty, due to the current potential overcapacity of flexible resources. These countervailing factors give rise to potential uncertainty about resource owner decisions in the medium term, which is why these resources are often referred to as being at “risk of retirement.”

2. DISCUSSION

The term “risk of retirement” has been used as shorthand for the uncertainty surrounding potential generation resources retiring in a way that is unexpected based on the plant’s age, operational characteristics, or prevailing energy market conditions. This section aims to identify this “risk” more precisely, and to better define when an individual or collective set of retirements creates a risk that the reliable operation of the statewide electric grid may be impacted.

²⁷ D.13-02-015, D.14-03-004, D.13-03-029.

The current overcapacity of System RA resources is cited by some parties as creating the conditions that could motivate resource retirements. Such concern may be justified if the Commission were to find that, within a few years, less valuable units are likely to remain in service while more valuable units are expected to retire. The possible definitions of potentially valuable attributes were discussed in the section on flexibility requirements, above.

At the first JRP workshop in May 2014, the Office of Ratepayer Advocates (ORA) presented an assessment of the “risk of unplanned early resource retirement,” a methodology for evaluating the magnitude of the risk and a determination of whether such a risk exists today. The focus of their assessment was to estimate the total capacity value of resources likely to retire (in MWs). ORA defined the challenge as “the risk of early retirement of existing flexible fossil plants needed for integrating renewables and meeting Once-Through Cooling compliance mandates.”²⁸

ORA’s methodology places existing generators into three categories: OTC units with flexible capabilities that are expected to retire by 2020, non-OTC flexible units (of which those more than 40 years old are expected to retire), and a renewable/baseload category (encompassing non-renewable or non-thermal generators, and use-limited renewable resources). ORA’s analysis then focuses on the non-OTC flexible units that are 32 years old or less, and are not owned by an investor-owned utility (IOU)- or publicly-owned utility (POU). ORA further sifts out units in local areas, and units with existing long-term contracts. Overall, ORA estimates that the remaining units without contracts comprise an estimated 2,400 MW of system capacity, or an estimated 1,400 MW of flexible capacity.

ORA’s analysis presents a first step towards assessing the potential magnitude of the risk posed to the system from unplanned retirements. ORA states that they have taken a conservative approach with their methodological decisions by excluding any capacity in a local area, and choosing 1982 as a determinative dividing year for the age of plants.

ORA’s methodology also acknowledges the reality that parties and decision makers will always lack perfect information to predict resource retirements. For example, ORA assumes that 30 year old plants may still be desirable. Plant vintages that are less than twenty and more than ten years old may pose the greatest cause for concern as these may be both more flexible and also less likely to be utility owned or operated. These distinctions highlight the forecasting uncertainty regarding resource retirements that impedes the Commission’s ability to quantify the potential for future resource retirements to create system instability.

²⁸ ORA’s presentation from the JRP workshop is available at <http://ora.ca.gov/general.aspx?id=2804>.

3. PROPOSAL

Staff proposes the new term “inefficient retirement” for party consideration. Staff also proposes the following factor test to determine whether a reliability risk is created when generation resource that is valuable to the grid inefficiently retires. A resource would be found to be inefficiently retiring if the resource is not receiving adequate payments from both the capacity market and the energy market to allow it to:

1. Operate at a profit in the next five years, or
2. Make upgrades necessary to continue operating, or
3. Make upgrades necessary to operate in a way that provides an essential service to the grid, and there are no other/insufficient existing resources that can provide this same service,

and, this resource is valuable because it has unique characteristics that make it critical for reliability in the medium term, such as:²⁹

- a) It is a critical resource in a local area that will remain transmission or generation constrained in the medium term, or
- b) It is an efficient and necessary transition generation resource that will be needed in the medium-to-long term while other transmission or generation resources are being considered, and expected preferred resources are coming online.
 1. Such resources may be characterized as resources with high ramping capabilities and/or quick-start capabilities that are able to operate flexibly and responsively while maintaining high heat rates.

Some resources may not meet all of the criteria to be considered an “inefficient retirement” and yet are critical for reliability. It is not within the scope of the JRP OIR to attempt to create a durable system to ensure that all generators are economically competitive--there will likely always be certain resources that are retained via the Reliability Must Run program (as explained in the Appendix). The first step in determining what should be done about potential inefficient retirements is to identify these generators individually or as a class, and to assess the risk possibly created by their individual or collective retirements.

²⁹ Each of these brings with it the assumption that in the next 5 years this risk of retirement could be “removed” by making the resource “competitive” in the market. Therefore the “at risk” resource would potentially receive an RA contract and even potentially receive a premium RA price as either a local or flexible resource.

4. CONCLUSION

The Commission may choose to establish new terminology as well as a factor test for “inefficient retirement” to help discern whether there may be resource retirements at any point in the next five years that create reliability risks, and if so, this knowledge may justify new procurement policies such as multi-year RA.

D. EXISTING FORWARD PROCUREMENT PRACTICES

What can the observable pattern of forward procurement for system and flexible capacity tell us about the need for multi-year RA requirements?

1. RELEVANT FACTS

In May 2014, as the first step in the Reliability Assessment for Track 2 of this proceeding, Staff sent data requests and/or issued subpoenas to all CPUC-LSEs³⁰ requesting information on capacity presently under contract and projected future capacity procurement for system, local, and flexible capacity types. “Projected procurement” is defined only as procurement that is covered by an existing contract period, contract extension, or option. The data collected from the CPUC-LSEs includes monthly contracted capacity information for each LSE starting in January 2014 and continuing through December 2024. The data collected for the JRP Track 2 assessment is not the same as that collected for the 2012 RA report, because the 2012 RA report covers exclusively RA-only contracts.³¹

Data was requested regarding each generating unit’s technology type, contract type, and physical characteristics, such as: whether the unit is a combined heat and power facility, utilizes once-through cooling, is an RPS-eligible resource, and is utility-owned. The request also asked for information regarding the nature of the LSE’s contract with the facility: whether a public Power Purchase Agreement (PPA) (such as a standard offer contract) or a confidential PPA (bilaterally negotiated). Finally, the request asked for data on maintenance outages, demand response, and imported capacity.

Market Sensitive Information: Staff displays summary level information about capacity contracting practices in the state in the graphs following this section. This report contains only information on the quantity of contracting, not prices, because market sensitivity would result from releasing price data for this quantity of future contracting. The information is only presented at an aggregate level—combining data for all 17 LSEs that are required to comply with the RA program.

³⁰ The 17 CPUC-LSEs are: Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, 3 Phases Renewables, Calpine PowerAmerica-CA, L.L.C., Commerce Energy, Inc., Commercial Energy of California, Constellation New Energy, Inc., Direct Energy, L.L.C., EDF Industrial Power Services (CA), LLC., GEXA Energy California, Glacial Energy of California, Liberty Power Holdings, Marin Energy Authority, Noble Americas Energy Solutions, Pilot Power Group, Inc., Shell Energy North America, Tiger Natural Gas.

³¹ <http://www.cpuc.ca.gov/PUC/energy/Procurement/>.

Capacity Needs and Demand Forecasts: Determining the demand values to use as a point of comparison for the contracting data was a challenging task because the needs forecast for a given RA year is only determined shortly before the year-ahead compliance showings. This task was further complicated for flexible capacity, where new requirements were recently created in 2014. Therefore, for year 2014 and 2015, the system capacity needs displayed in the following graphs are simply the RA requirements for CPUC-LSEs for the month of August.³² The projected system demand for years 2016-2024 was estimated using existing and agreed-upon demand forecasts created through the CEC's Integrated Energy Planning Report (IEPR) and CPUC's LTPP. The system-demand-forecasted values are consistent with the IEPR alignment process and the associated forecasts can be found on each organization's website as they are public information.³³ The CAISO flexibility needs assessment processes informed the projected flexible demand for 2016.

Adjustments to years 2016-2024: Staff compared the CPUC-LSE contracted system capacity data to the IERP and LTPP demand forecasts, and adjusted by a factor of 8.37 percent. This adjustment factor is an interim value determined by CEC and CPUC Staff to account for the fact that load served by CPUC-jurisdictional LSEs comprises approximately 91.63% of the total CAISO balancing area load. Because of this high percentage of CPUC-LSE load, it serves as a reasonable proxy for the entire CAISO balancing area. Staff has added 15% to this adjusted value to represent the "forecasted need" (equal to forecasted demand plus PRM).

Timing of Assessment: This data was collected in May 2014 and represents a snapshot of procurement at that time. Because it is impossible to collect, analyze, and release data instantly and because LSEs conduct ongoing procurement activities, regardless of when the snapshot of procurement is taken, it will become out of date shortly thereafter. Given the nature of RA requirements and the timing of this report, CPUC-LSEs have since and will continue to procure additional capacity to meet their summer 2014 and 2015 capacity requirements. CPUC-LSEs are also expected to continue procuring flexible capacity based on the recently-adopted requirements, and therefore flexible-capacity procurement may have increased since May. Thus the graphs presented below are not reflective of capacity procurement at the time of this report's release.

LSE Contracting Practices: In responding to the data requests, the CPUC-LSEs reported the contracts that they expected would meet the definition of flexibility laid out in the 2013 RA decision.

³²With one exception: for the 2014 RA year flexible capacity is only a "target" not an RA requirement indicating "need" D.13-06-024.

³³The IEPR alignment process is explained in detail at http://www.caiso.com/Documents/CEC_CPUC_ISO-FollowUpLetter-SenatorsPadilla_Fuller_Jan31_2014.pdf. A diagram illustrating the IEPR, LTPP, and TPP process interdependencies is contained in "02.CEC-CPUC-ISO Process Diagram v3.8.pdf", available at http://demandanalysisworkinggroup.org/documents/2014_07_22_DR_pup/2014_07_22_DAWG_Materials.zip. IEPR: http://www.energy.ca.gov/2014_energy/policy/; LTPP: <http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/>; TPP: www.caiso.com/planning/Pages/TransmissionPlanning/.

Notably, for many resources, contracts in place allow for unilateral extensions of the contract by the LSE. For purposes of this report, LSEs were allowed to include these extensions in the contract period.

2. OBSERVATIONS & DISCUSSION

The high-level take-away from the graphs shared on the following pages is that the CPUC-LSEs were, as of May 2014, nearly 90% contracted for system capacity through 2016, and were over-contracted for flexible capacity through 2016. Staff cannot draw conclusions beyond 2016 for flexible capacity because the Commission and CAISO have not agreed on a method for determining flexible-capacity requirements beyond 2015. Drawing any conclusions beyond also requires making predictions about future RA requirements.

Figures 3 and 4 show a projected demand line for 2016-2024 based on the IEPR, with adjustments, as explained above. Because this data was captured in the spring of 2014, it does not reflect any additional capacity procured in preparation for the peak summer months of 2014 or for the 2015 RA filings due in October. Therefore, if data collection were duplicated in September, higher procurement values may be found.

System (Generic) Capacity Contracting: This snapshot of LSE-contracting practices shows that for the 2015 RA year, system capacity procurement was above 95% of projected need as of May 2014. For 2016, procurement is estimated to be above 85% of projected demand. Significant drops in contracted system capacity are not seen until after 2017. Therefore, even without a multi-year RA requirement, CPUC-LSEs, in aggregate, have already procured well over 2/3 of the forecasted peak need in 2017 (projected August peak load plus PRM). Staff observes that this level of forward system-capacity procurement may be sufficient to allay parties' concerns about reliability and buffer against some inefficient resource retirements in the medium term.

As the 2015 RA year approaches, Staff expects that LSEs will continue filling in any "open" positions they have for any month in 2015.

The likely reasons that CPUC-LSEs are currently procuring multiple years into the future are many. Firstly, penalties for non-compliance motivate CPUC-LSEs to assure, as far in advance as practicable, that they will be in compliance at the time of RA showing. Secondly, there is a trade-off between contract length and price: typically, longer-term contracts have lower \$/MW-month ratios, and therefore the LSEs may often prefer to negotiate for longer terms. Third, by some accounts, the market in California seems to be relatively stable, and neither LSEs nor generators appear to be holding out for a better contract price. Finally, as discussed in the Appendix, various Commission policies encourage LSEs to enter into contracts that guarantee lower probability of price shocks both for the utility and ratepayers.

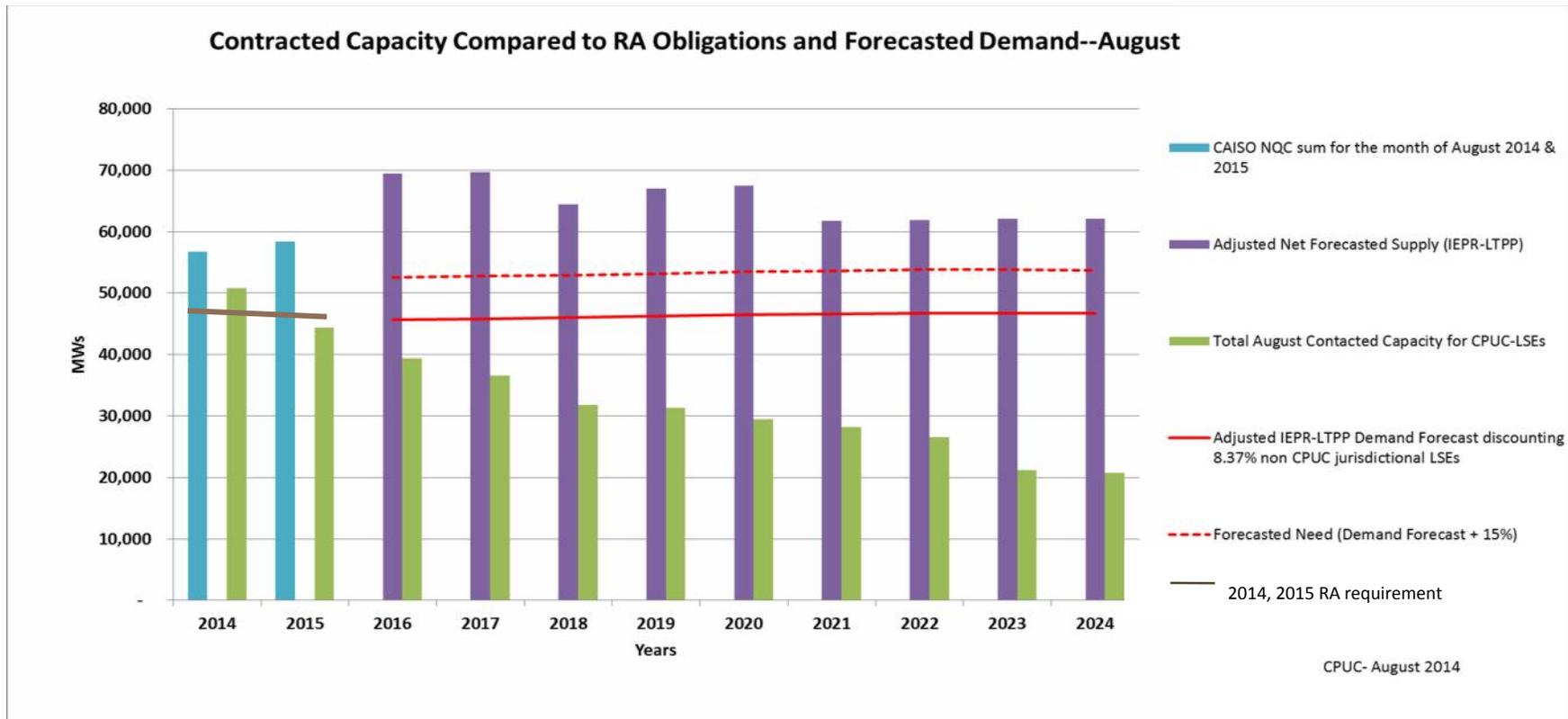
Flexible Capacity Contracting: The flexible capacity contracting data shown in Figures 5 and 6 are more difficult to interpret and draw conclusions from, because, as discussed above, the recent RA Decision has created a new set of flexible capacity requirements for all LSEs beginning in 2015. This data

snapshot was taken before the Decision, and so it does not specifically reveal how much contracting statewide fits into the new flexible definition. Rather, it represents only how much contracting for flexible capacity was put into place by D.13-06-024, which created targets for 2014. The data-collection process for flexible capacity was based on the flexible-capacity definition laid out in D.13-06-024 and not the three categories adopted in D.14-06-050. Therefore, CPUC-LSEs were reporting data for generation contracts that now fall under both Category 1 (base flexibility) and Category 2 (peak flexibility) resources. However, Staff's preliminary analysis of the contracting data reported is that approximately 55% of the capacity reported would meet the Category 1 definition of base flexibility, and the remaining 45% would meet the Category 2 definition of flexibility, as defined in D.14-06-050.

The methodology for determining the system's flexibility requirement will also likely be adjusted from 2015 onwards. The contracted flexible-capacity values captured here may change if the flexibility definition evolves in future RA proceedings. However, as definitions evolve, contracts could be modified, and physical modifications to many facilities may not be necessary. Therefore, even if flexible definitions change in 2015 or 2016, a major decrease in the quantity of capacity under contract, compared with what is shown in this report, is unlikely to result.

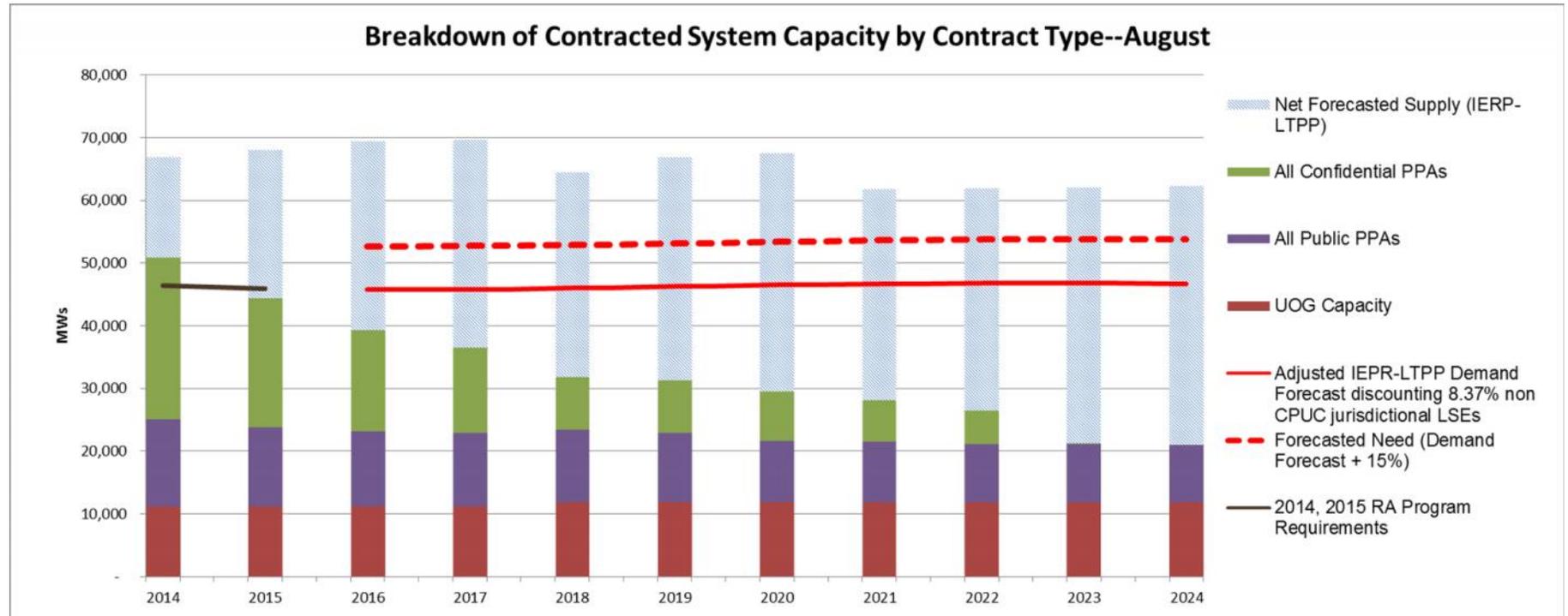
Regardless of the institution of a new, interim flexible-capacity definitions and requirements, these graphs are illustrative and helpful in understanding the overall quantity of flexible capacity available, and the quantity currently under contract, both of which far exceed the projected near-term need.

Figure 3: Contracted System Capacity vs. Requirements and Forecasted Peak



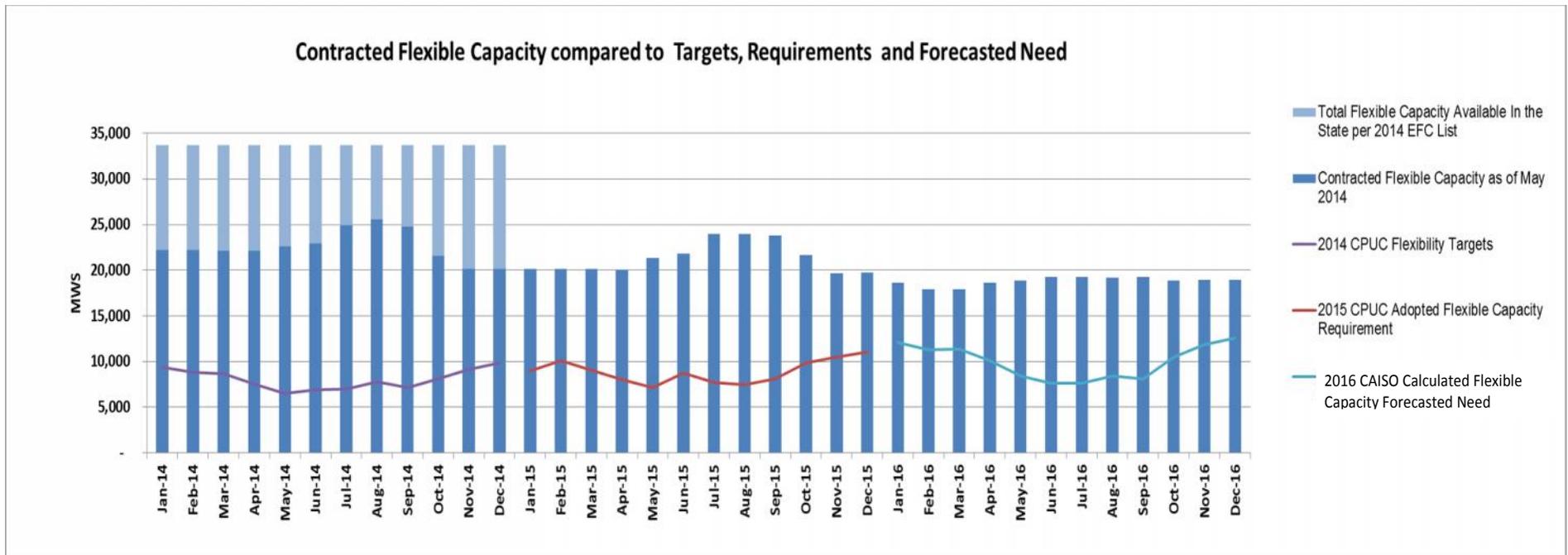
- The green bars in this graph represent the aggregated CPUC-LSE contracted capacity data for August of each year. The purple bars represent the adjusted IEPR-LTPP supply-forecast values. The blue bars in 2014 and 2015 are available system-capacity values (NQC values).
- The 2014 Net Qualifying Capacity (NQC) value is as published by the CPUC available at http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm; 2015 NQC value as published by the CAISO available at <http://www.caiso.com/Documents/2015NetQualifyingCapacity-ResourceAdequacyResources.htm>.
- The brown line in 2014 and 2015 represents the actual RA requirements for August 2014 and 2015.
- For years 2016-2024, the solid red line represents CEC IEPR demand-forecast values, adjusted downward by 8.37% to represent projected demand for CPUC-LSEs. The forecasted need for years 2016-2024 is represented by the dashed red line. This was calculated using the planning reserve margin, equivalent to the adjusted IEPR demand forecast plus 15%. The demand forecast used in this analysis is adjusted for mid-case projections of “all available energy efficiency (AAEE)” as determined by the Demand Analysis Working Group. (www.demandanalysisworkinggroup.org) The “mid 1 in 2 Case” of the statewide IEPR forecast increases minimally: ~2,200 MW in the 2014-2017 timeframe due to the projected 1,600 MW of “mid case” AA EE.

Figure 4: Breakdown of Contracted System Capacity by Contract Type



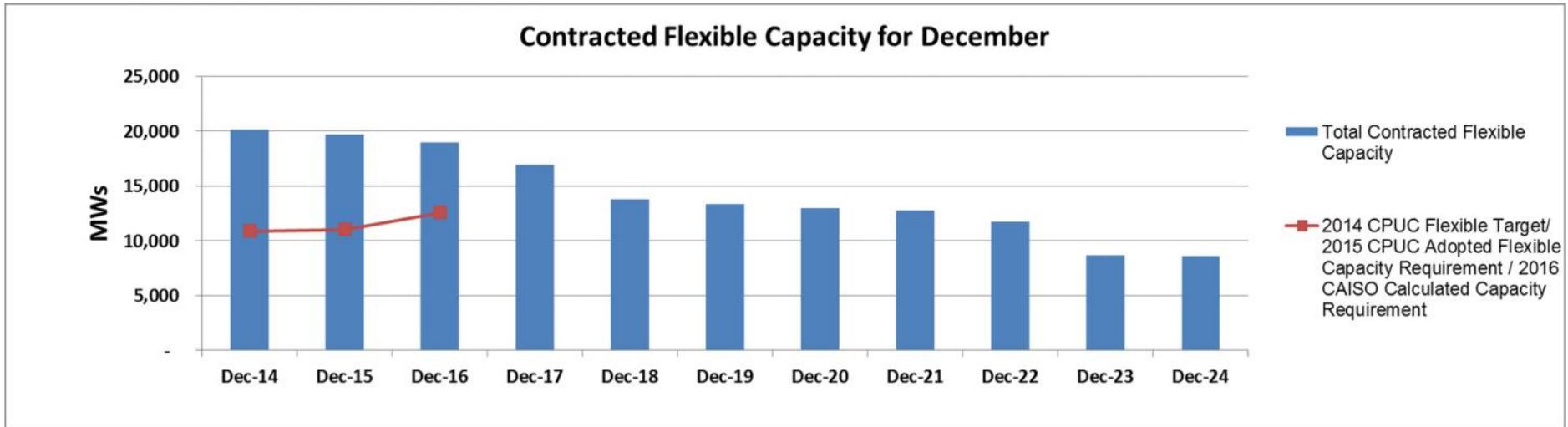
- This graph represents the same data as the first system graph, but with a more descriptive breakdown of the type of contracts that the LSEs hold. It shows utility-owned generation (UOG), Confidential PPAs (such as bilateral contracts) and Public PPAs (such as standard offer contracts) as separate red, green and purple bars. The shaded blue bars stacked on top represent the available net forecasted supply.
- This graph shows the quantity of procurement resulting from confidential PPAs for the next nine years. While the quantity of UOG and public PPAs has been transparent to the public, the quantity of other contracting has not been, until now. This graph demonstrates that there is a significant amount (over 15,000 MW) of procurement resulting from confidential PPAs through 2016. The value drops slightly below 14,000 MW in 2017, and then below 9,000 MW thereafter.

Figure 5: Contracted Flexible Capacity vs 2014 targets/2015 requirements/2016 forecast



- This graph represents all CPUC-LSEs flexible capacity under contract for 2014-2016.
- For 2014, this graph also represents all additional available flexible capacity in the CAISO service territory capacity—the light blue bars stacked on top of the darker blue bars for 2014.
- The purple line represents the flexible-capacity targets that the LSEs were encouraged to demonstrate for 2014, consistent with D.13-06-024, and the red line represents the total monthly flexible-capacity requirements set forth in D.14-06-050(Appendix A). This is the total of Category 1, 2, and 3 requirements. The blue line represents CAISO’s calculated needs projection for 2016.

Figure 6: Contracted Flexible Capacity for December 2014-2024



- This graph represents all CPUC-LSE flexible capacity under contract for December of each year. December was chosen because it is the month with highest flexible requirement as adopted by the Commission and/or calculated by CAISO’s flexible capacity needs assessment.
- The blue bars represent all contracted flexible capacity for CPUC-LSEs.
- Consistent with Figure 5, the red line represents the CAISO calculated flexible-capacity requirement for December of each year, as adopted by the RA decisions as a target for 2014 and a requirement for 2015. The 2016 value comes from CAISO’s flexible-capacity needs assessment. CAISO has not calculated flexibility requirements beyond 2016. For years 2017-2024, Staff is still working closely with CAISO to ascertain the appropriate estimates for future flexibility requirements.

3. CONCLUSION

The data collection and analysis conducted by Staff shows that CPUC-LSEs are conducting a significant quantity of forward procurement: capacity equivalent to more than 2/3 of the forecasted need is under contract through 2017. If annual updates to this data demonstrate similar procurement patterns, it would suggest that multi-year RA requirements may have minimal effects.

III. OPTIONS FOR MULTI-YEAR RESOURCE ADEQUACY

Multi-year RA requirements may be warranted depending on the Commission's conclusions regarding the four pivotal issues described above. This section contains a menu of proposed options for multi-year RA requirements and also proposes conditional triggers for instituting requirements. For each proposed option, Staff analyzes the pros and cons, but Staff does not make a recommendation for each type of requirement. These proposals are preceded by:

- a) The inter-related policies that should be considered as a precursor to setting multi-year RA requirements, and
- b) The criteria that should be used in evaluating the proposed options.

A. INTER-RELATED POLICIES

This section outlines a number of existing policies and requirements that the Commission should consider before moving forward on the question of multi-year RA program, given their inherent relationship to a potential program. These are: the state's Loading Order (as implemented by the Commission policy on preferred resources), the Planning Reserve Margin, and existing procedural rules for Commission review of PPAs..

1. IMPACT ON PREFERRED RESOURCES

The state's "Loading Order" requires that all development of preferred resources—energy efficiency, demand response, and renewable energy—be pursued before authorizing new non-renewable generation.³⁴ The Commission may need to consider how multi-year RA may impact the State's use of preferred resources in the future.

Staff has not identified any specific potential risk that procurement of preferred resources will be repressed by a multi-year capacity requirement. The Commission has several policies in place to

³⁴ Ca. Pub. Util. Code Chapter 2.3. The loading order was established by two legislative acts, [Assembly Bill 1890](#) (1996) and [Assembly Bill 995](#) (2000). See Energy Action Plan 2008 Update available at <http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF>.

encourage the development of preferred resources and their inclusion in the RA program. The Commission is considering new policies that might help ensure that preferred resources can compete for capacity contracts under the new RA flexible requirements.

On the one hand, additional forward procurement may help secure contracts for new preferred resources. On the other hand, locking in forward procurement may squeeze out preferred resources that are not yet available to the market, or whose capacity values have not yet been established (and will have less opportunity to compete if the utilities' forward positions are already sold to existing and/or non-preferred resources).

2. INTERCONNECTEDNESS: PLANNING RESERVE MARGIN AND POTENTIAL FORWARD REQUIREMENTS

The existing PRM, established by the Commission to be 15% above annual expected peak load, is interconnected with multi-year RA because it is included in setting annual RA requirements.³⁵ The Commission uses the 15% PRM as an insurance policy against a range of possibilities, such as higher than expected loads, lower than expected supply, and extreme events. The goal of a PRM is also similar to that of a possible multi-year RA program: both would seek to ensure sufficient system capacity to guarantee reliability.

Because RA requirements are currently set with inclusion of the 15% PRM, for simplicity of comparison, the future year requirements proposed here would also be set with a target for achieving procurement of at least 115% of peak load.

3. PROCEDURAL RULES FOR CONTRACT REVIEW

If the Commission adopts multi-year RA, the logical expectation would be that forward procurement levels would increase. However, requiring multi-year procurement may not have this expected and desired effect, because under Commission rules, any IOU-bundled procurement contract longer than five years must be approved via Application. Medium-term contracts, with durations greater than three months but less than five years, can be approved within the utilities' bundled procurement plans and without contract-specific review by the Commission. The Application requirement may act as a deterrent to long-term contracts sufficient to decrease the expected effect of a two- or three-year RA program.

³⁵ D.04-01-050.

B. EVALUATION CRITERIA FOR MULTI-YEAR RA PROPOSALS

This section sets out a number of evaluation criteria, including: effectiveness, ratepayer costs, feasibility of setting requirements, and the workability of implementing a new requirement in the existing RA program.

1. EFFECTIVENESS/ADVERSE EFFECTS

Would new multi-year RA requirements have a positive effect on procurement practices, leading to enhanced reliability? What is the value of certainty with regards to forward procurement? What is the potential for adverse effects?

In evaluating each option for its effectiveness, the foremost question is whether a specific multi-year RA requirement would positively affect CPUC-LSEs forward procurement practices in such a way that lessens the risk of inefficient retirements and enhance reliability. Theoretically, the signal sent by an effective multi-year requirement would be strong enough to inform the decision of a generation resource considering retirement.

The related potential benefit of requiring multi-year procurement would be certainty regarding resource procurement; in other words, having greater confidence that within a reasonable margin of error, sufficient capacity is being procured in the state to meet capacity needs for the next two or three years. This confidence could lead to certainty that valuable resources are less likely to inefficiently retire within the same timeframe.

Many reliability events are unpredictable and unplanned—the 2006 summer heat wave, the 2007 San Diego firestorm, and the 2012 SONGS outage—and multi-year RA requirements would not necessarily have lessened the impact of these events. Therefore, this report considers whether a multi-year requirement would have more than a *de minimis* effect on the resiliency of the system. Staff is not proposing a specific metric by which to value the benefit of certainty in the context of reliability, but rather is acknowledging that having a metric would be helpful in comparing and evaluating options.

Finally, with respect to effectiveness, this report aims to identify potential adverse effects and considers the likelihood that an unexpected reaction from a new requirement could produce the opposite of what is intended, thus triggering a decrease in reliability.

2. RATEPAYER COSTS

Will there be incremental costs borne by ratepayers as a result of multi-year RA? What will they be and how could they be minimized?

In evaluating each option for its potential costs, this report considers the potential for increased costs to LSEs and the likelihood that these would be passed on to ratepayers. In general, Staff expects that ratepayer costs would increase with extending RA requirements beyond one year. LSEs will be

required to lock in forward capacity contracts at presumably at higher levels– which may lead to higher costs. Greater complexity within the RA program may also increase capacity prices.

Because of the uncertainty around load forecasts discussed below, the incremental change in procurement needs between compliance year “one” and “three” would either require LSEs to conduct additional incremental procurement, or cause over-procurement (relative to actual needs). Buying and selling small amounts of capacity may be inefficient and so it is possible that the prices paid for this incremental procurement would be higher than average RA prices.

Staff has observed that procurement by non-IOU LSEs drops off dramatically after the compliance year, but then remains at a relatively constant level for following years. This suggests that a multi-year RA program would have higher incremental costs for non-IOUs, at least in the short term.

Instituting multi-year procurement may shift risks from generators onto ratepayers, especially for costs related to possible over-procurement. For example, if an LSE procures to meet expected needs three years ahead, but load forecasts drop as the years roll forward, ratepayers would be left with stranded over-procured capacity that the LSE might not be able to re-sell. Staff acknowledges in weighing options that it might be impossible to design a program that minimizes all stranded costs, as was discussed at the JRP workshops.

3. FEASIBILITY OF IMPLEMENTATION

How feasible will it be to set accurate multi-year RA requirements? What factors will affect the ability to set a reasonably accurate requirement two to three years in the future?

An evaluation of the feasibility of implementing a multi-year requirement is presented for each type of capacity. Creating enforceable, meaningful requirements in a statewide resource adequacy program is difficult, and there are tradeoffs between having an RA program that ensures sufficient capacity in every possible form to maintain reliability, and a program that is actually implementable and enforceable. There is an inherent risk of setting inaccurate requirements for implementation two or three years into the future. Also, the more complex the RA program becomes, the more difficult it will be to implement from the regulatory perspective.

The following list of uncertainties represents various reasons why Staff finds that setting accurate RA requirements for multiple years forward will be challenging, and therefore, must be considered in weighing proposals:

- a) Load Forecasting uncertainty (forecast error): the difficulty in accurately predicting load beyond “year one” for RA will make it difficult to create accurate future requirements. Year-ahead forecasts will almost always be more accurate than multi-year estimates, and so, the target for “compliance” may shift from year three to year one:

- Load is affected by difficult-to-predict factors such as: economic conditions, population changes, climate change, success of energy efficiency, Demand Response (DR) and Distributed Generation (DG) programs
 - Staff has observed a significant margin of error over a period of five years for IEPR and LTPP load forecasts against recorded peak load. Based on recent analysis Staff has concluded: the farther out in time the study predicts, the less accurate it becomes. For example, the 2012 managed demand LTPP forecast predicted actual 2012 load within 2%, but the one-year-ahead prediction was off by 8%. For the 2013 peak, the 2010 LTPP prediction was off by 15%.
 - If multi-year RA were in place, the difference between forecasts three years and one year ahead could create the need for incremental procurement. Procuring small quantities of capacity might be inefficient, and so it is possible that the prices paid for these small amounts of procurement would be higher than average RA prices.
- b) Load migration uncertainty: migration between CPUC-LSEs has varied over time, so it will be difficult to predict load shifts three years in advance and to set LSE requirements accurately.
- Load migration may increase due to the introduction of new Energy Service Provider (ESP) models,
 - CPUC-LSE load may change due to load migrating to municipal utilities, or
 - The creation of new Community Choice Aggregators (CCAs) and expansion of existing CCAs may cause load to migrate away from IOUs.
- c) Uncertainty with respect to transmission upgrades and new transmission projects: local capacity requirements are significantly affected by transmission constraints. Predictions of future local needs (conducted by CAISO) are based on expected changes to the transmission system that are hard to predict.
- As transmission constraints are addressed by new transmission projects, Local RA requirements change. The difficulty posed by various agencies agreeing upon when those projects will likely come online may impede the ability to set meaningful forward Local RA requirements. Given the potential for such projects to significantly reduce and even eliminate local capacity needs, these assumptions would be extremely important.
- d) Uncertainty regarding renewable energy capacity: there is significant uncertainty regarding the rate at which renewable generation reaches commercial operation.
- It is not possible to predict with precision when new large, transmission interconnected renewable projects will come online. Because flexible capacity need is directly affected

by the rate of new renewable resource penetration, changes to flexibility needs over time will always have significant range of error.

- e) Uncertainty regarding renewable energy capacity: there is significant uncertainty regarding the future valuation of renewable generation resources.
- The not-yet-implemented mandate to determine the Net Qualifying Capacity for wind and solar resources via an Effective Load Carrying Capacity (ELCC) methodology³⁶introduces greater uncertainty regarding the total qualifying capacity value of renewable generation.
 - ELCC is a percentage that expresses how well a resource is able to meet reliability conditions and reduce expected reliability problems or outage events (considering availability and use limitations). It is calculated via probabilistic reliability modeling, and yields a single percentage value for a given facility or grouping of facilities. The new calculations may show that system capacity values previously assigned to resources were either too high or too low.³⁷
 - ELCC values are set relative to other resources via energy system modeling--if other resources or load perform differently than expected over the course of a few years, then all ELCCs will change to account for that. Therefore, ELCC may change the qualifying capacity values for wind and solar.
 - This introduces uncertainty regarding future procurement, because the value of present RA resources will change. This uncertainty could mean that under a multi-year RA program compliance requirements for system RA could change dramatically over a period of three years, .
 - Also, if ELCC values for contracted system RA resources change, this would necessitate LSEs buying/selling incremental capacity to account for the changed values of previously procured resources.
- f) Uncertainty regarding future flexible resources: future flexible needs will be affected by implementation of ELCC.

³⁶ Flexibility demand values for 2014-2016 are those adopted by D.14-06-050.

³⁶ In Senate Bill (SB) 2 (1X)(2014), the Commission was ordered to “determine the effective load carrying capacity of wind and solar energy resources on the California electrical grid,” and to “use those effective load carrying capacity values in establishing the contribution of wind and solar energy resources toward meeting [...] resource adequacy requirements.”

³⁷ D.14-06-050.

- As discussed above, ELCC will change the valuation of System RA resources, and may lead to a change in the proportion of wind vs. solar resources. However, Staff cannot predict how this mix may change. What Staff can predict is that overall flexible needs will continue to increase based on increased renewable penetration.
 - Therefore, given that the proportion of intermittent renewable resources on the grid determines flexible capacity needs, the magnitude of the change of flexible capacity need will not be well understood until the ELCC mandate is fully implemented.
- g) Regulatory uncertainty: any proceeding that contemplates changes to procurement policy may create regulatory risk.
- LSEs and generators may avoid entering into contracts until they find the uncertainty to be sufficiently removed or mitigated – a delay with negative implications for reliability.

4. WORKABILITY

What are the potential workability challenges in running a multi-year RA program? What challenges will be faced by the CPUC, CEC and CAISO in aligning each organization's processes with the others?

Each of the proposed options will discuss any workability issues that need to be considered before altering the RA program. During the second workshop on Track One of the JRP, Staff facilitated a discussion focusing on workability issues related to multi-year RA requirements. This highlighted the collaboration between the Commission, CEC, and CAISO that would be required to develop process alignments for multi-year RA. The following are just a few examples of issues where the three organizations would need to reach consensus around new procedures.

How will load forecasts be generated for multi-year requirements?

Currently the CEC produces load forecasts ten years out within the IEPR. For the year ahead, forecasts are submitted by each LSE and reviewed by the CEC. Often the CEC determines that the LSE forecast is accurate enough to be used as-is with no adjustment. This leads to the question: would be appropriate to have LSEs to produce their own forecasts out two or three years ahead? Even if it were, Staff expects that other data and information would need to be developed and considered by the CEC and CPUC to provide an additional check on the LSE multi-year forecasts. Also, it may be necessary to consider several different demand scenarios.

Would a multi-year RA program have Annual and Monthly Showings?

While the RA program has an “annual showing” requirement and each LSE is required to demonstrate procurement to meet the system’s expected summer demand, the actual binding constraint of RA compliance is the monthly showing. This leads to the question: what will compliance look like for years two and/or three? Would there actually be 36 months of distinct requirements? Or,

would there only be an annual peak demonstration for years two and/or three? Information currently available suggests that requirements for each individual month from 13-36 would be extremely difficult to implement or oversee. Therefore, the proposed options suggest only a demonstration that procurement has been met for peak months in the multiple years ahead.

Would penalties be imposed for under-procurement for years 2 and 3?

Without the ability to penalize for under-procurement of RA capacity multiple years ahead, a multi-year requirement would be toothless. The argument against penalties is that no imminent harm would result from future under-procurement as long as utilities meet their one-year-ahead requirements by the preceding October. The reverse is that, without the ability to penalize, the requirement does not result in any change in behavior. Another layer of complexity is that in a one-year program, penalties are based on how well the LSE complies with forecasts at the time of compliance—a structure that does not account for the higher level of forecast error that would be expected multiple years ahead.

Both JRP workshops and CAISO stakeholder meetings have focused discussion on the related nature of Commission penalties and CAISO's backstop authority as motivation for RA program compliance, and parties to the JRP have raised that if CAISO mirrored multi-year RA penalties through its backstop mechanism, the cost of backstop procurement for future years would represent a double penalty. Therefore, Staff proposes that as the CPUC considers multi-year forward obligations, Staff works with parties and stakeholders to identify and consider RA penalties and backstop procurement interactions.

C. PROPOSED OPTIONS FOR MULTI-YEAR RA FOR SYSTEM, FLEXIBLE AND LOCAL CAPACITY

Staff developed the following proposed options based on examination of the forward procurement data presented in this report, projections regarding future system, flexible and local needs, and feedback received at the two JRP workshops held in May 2014. For each type of capacity, there is also a "no additional requirements" option which is proposed mostly to provide a point of comparison for the likely positive and negative effects of a multi-year requirement. Therefore, the "no action" option is evaluated more succinctly as it represents the status quo. Staff more thoroughly weighs the benefits of no action by providing and enumerating the "cons" to each potential new requirement.

Staff has evaluated the options using the criteria explained above: effectiveness or adverse effects, potential ratepayer cost, feasibility of setting requirements, and workability as part of the RA program.

1. OPTIONS FOR SYSTEM RA REQUIREMENTS

Option 1: 90% in year 2, 80% year 3

Option 2: 90% year 2 only

Option 3: 80% year 2, 70 % year 3

Option 4: No additional requirement

A. EXPLANATION AND DISCUSSION OF OPTIONS

As discussed in the Appendix, the RA program requires LSEs to demonstrate procurement for 90% of the upcoming compliance year's summer months' System RA obligation. This is often referred to as the "annual" requirement. This requirement is developed to be inclusive of the 15% planning reserve margin. For the options outlined here, we assume that the annual obligation in years two and three would be verified in the same manner. Therefore, option 1 means that CPUC-LSEs would be required to demonstrate that at least 90% of their system capacity need is procured for the summer months in compliance year two and similarly 80% is procured for compliance year three. Options 2 and 3 follow this same rule.

Staff considered whether Options 1-3 could be simplified to require a showing limited to the peak month (i.e., August) for compliance years two and three, but concluded that the proposed multi-year requirement should mirror the current annual showing process. LSEs would submit forecasts to the CEC to be compared with IEPR forecasts, and adjusted as needed to create a forecast value that the CEC, the Commission, and CAISO find to be reasonable.

In proposing this range of System RA requirements, Staff is taking into account informal and formal comments made at JRP proceeding workshops. The feedback Staff received indicates party agreement that if system requirements are not set at the high end of a 0-100% range, then such requirements would be wholly ineffectual. Further, many parties argued that to reduce the risk of inefficient retirement, a requirement for year 2 and year 3 would need to be very close to today's one-year requirement. The issues around uncertainty and feasibility informed the options that Staff finds to be reasonable. The basis for the lower requirement of Option 3 is the high likelihood of forecast error and the potential for significant load shifting from one-year to the next.

Due to the similar design and expected outcomes between options 1-3, Staff is discussing the pros and cons of these options together, and then providing a separate comparative analysis which differentiates and compares the benefits of 1, 2, and 3.

B. PROS (OPTIONS 1-3)

- Effectiveness
 - *Investment Signal*: Setting requirements at any level above 70% should provide some investment signal to generators statewide regarding whether or not they will be valued in the medium term. Any generators that have not secured a contract for any portion of the following three years will understand that the opportunity for contracting is diminished,

because the residual amount of procurement occurring in those two years would be either: 10, 20 or 30% of statewide load.

- *Market Certainty:* While the implications of any incremental procurement motivated by multi-year requirements has not yet been modeled or studied, Option 1, 2, or 3 may improve system reliability through greater market certainty. These requirements could allow more transparent planning signals for generators in the mid-term, especially during the OTC transition period between today and 2020. Staff expects that the higher the percentage of mandated procurement, the greater the degree of certainty generators will have regarding their value in the market, which they can assess based on whether or not they receive medium term procurement contracts.
- *Efficient Retirements:* Generators not awarded multi-year contracts might, in a more predictable or systematic way, announce and plan for retirement. If more generators receive multi-year contracts, more would be given a clear market signal and would choose not to retire. Those not receiving contracts would also better understand their relative position. Therefore, this should increase the likelihood that retirements will be anticipated and planned multiple years into the future.
- *Certainty:* If the State increases the present limits on direct access, the amount of forward procurement may be reduced since direct-access providers conduct comparably less forward procurement than IOUs. Absent a multi-year RA requirement, direct access providers may not conduct the same quantity of forward procurement that the IOUs do, which could create system reliability problems if such providers gain greater market share.
- Costs
 - The incremental ratepayer cost for multi-year procurement for Options 2 and 3 may be low given that Staff currently observes that the majority of LSEs are already procured above 70% three years forward. Signing longer-term contracts may have the benefit of efficiency, resulting in lower \$/MW prices paid by LSEs and their ratepayers. However, this benefit may not extend to smaller LSEs and direct access providers, who exercise less purchasing power than the IOUs.
- Workability
 - Staff expects that the burden of implementing a multi-year program for generic system capacity would be fairly low, because the Commission can leverage existing processes and extend RA program implementation through years 2 and 3. LSEs could include years 2 and 3 in their annual filings, and all procurement could be reviewed as a whole, maintaining efficiency.

C. CONS (OPTIONS 1-3)

- Effectiveness
 - *Investment Signal*: Given the current overall LSE procurement practices and patterns, the need for future contracting in the intermediate term might actually be minimal, meaning that generators may only receive weak market signals, if any. If a strong market signal regarding the need for future investments is not sent, any range of multi-year requirements will be ineffectual in raising overall contracted capacity levels. As Figures 3-6 (in section II.D. above) demonstrate, CPUC-LSEs currently procure a majority of projected capacity need three years into the future. Currently, the IOUs are close to fully procured two-to-three years out, likely motivated by TeVAR (see explanation in appendix) and contracting efficiencies. Therefore, the number of RFOs for contracts for future years may be very minimal and may simply mirror existing procurement patterns). This would mean that any incremental market signal sent by additional RFOs for residual levels of procurement may be very limited. Additional future contracting for System RA may also be lessened by the advice letter requirement, discussed above.
 - *Inefficient Retirements*: If the purpose of multi-year RA is to increase system reliability by ensuring that the resources most valuable to the electric grid are incentivized to remain in service for the medium term, then a multi-year requirement for generic system capacity may not contribute to meeting this goal. A generic capacity procurement requirement may have the effect of keeping only older resources with lower operating costs in service, because these are the resources that are willing to offer their capacity at the lowest cost. Therefore, multi-year system requirements may not result in procurement of resources that have more valuable attributes and may not decrease risks of inefficient retirements.
 - *Option 3*: Further “feathering” of requirements may decrease or negate benefits from forward contracting. If the requirements are too low, many resources may not receive longer-term contracts, and because contracting at lowest cost means that any valuable resources on the margin will not receive a multi-year contract, they therefore may still plan to retire. If this occurred, it would likely negate the purpose of the new requirements entirely.
- Costs
 - Higher multi-year procurement requirements may likely lead to higher procurement costs (price per MW) if there is scarcity in the market. The data presented in section II.D.: “Existing Forward Procurement” suggests that this scarcity is not currently present, but this is not meant to predict future market conditions. Potentially these costs would represent additional payments to generators who would have otherwise been contracted in the year ahead. These “unnecessary” additional costs will be hard to predict or measure. The costs

to any direct access or CCA customers may be higher due to the risk of over-procurement created for these LSEs whose future load is less certain.

D. COMPARATIVE STRENGTHS OF OPTIONS 1-3

If there are validated concerns regarding the need to prevent inefficient retirements, then implementing option 1 would be the most effective at diminishing these concerns. Weighing the goal of effectiveness with the reality of workability would lead to a choice of Option 2, because Option 2 recognizes that the further out requirements are set, the higher the likelihood that they will be done incorrectly, possibly resulting in excess procurement system-wide, with high costs for smaller LSEs. If implementing a requirement with the lowest potential ratepayer cost and reduced risk for adverse effects is the goal, then Option 3 would be preferred. However, option 3 is likely the least effective option at reducing the risk of inefficient retirement for valuable resources, which are generally more expensive to procure and so would be left out of multi-year contracting if the requirements are set at 80% and 70%.

E. OPTION 4: NO ADDITIONAL REQUIREMENTS

This Option represents maintaining the status quo, which thus far has produced system reliability in the state. There is, at present, an overabundance of generic system capacity. Therefore, it would be unjustified for 100% of physical capacity to have RA contracts, because this would lead to over-procurement at ratepayer expense. The data shared in this report suggests that the existence of a one-year procurement requirement is effectively motivating some level of forward procurement. Therefore, a multi-year procurement requirement may represent a revenue shift from ratepayers to generators.

2. OPTIONS FOR FLEXIBLE CAPACITY REQUIREMENTS

Option 1: 90% of Flexible procurement for year 2

Option 2: 90% in Year 2, 80% in Year 3

Option 3: No action until 2017

A. EXPLANATION AND DISCUSSION OF OPTIONS

The multi-year Flexible RA requirements proposed here would be for a single peak month for each year, representing a showing of 90% or 80% of need for that month. The peak month would be the month that CAISO estimates to have the maximum ramping need within that year; this would need to be defined in an RA decision two or three years in advance. For example, for 2015, the month with

maximum ramping need is December, as established by the 2014 RA decision.³⁸ Alternatively, the Commission could require showing a peak month and two “shoulder” months, as predicted for those future years.

Staff intends these options to represent requirements of limited duration, to maintain consistency with the recent flexible RA decision, D.14-06-050. As discussed earlier, this decision created an “interim flexible capacity framework” for three categories of flexibility for 2015 and adopts a method for setting requirements through 2017 only.³⁹ This decision balances the need for requirements with concerns over feasibility and workability. Staff therefore presents two options for future requirements acknowledging that these may also be “interim” because, if adopted, the Commission would likely revisit the requirements in 2017 alongside the entirety of the Flexible RA framework. Also, the recently adopted Flexible RA categories may not be appropriate for requirements for two and/or three years forward, and thus Staff does not propose specific ratios of procurement for the three Flexible RA categories.

Given the recently adopted 2015 flexible requirement of 90%, these options consider requiring a 90% showing year 2, and an 80% showing for year 3, expecting that the earliest these may apply is for 2016. Under Option 2, the decrease in the year 3 requirements should account for potential error in forecasting flexibility need and/or change in flexibility modeling before 2017.

Staff currently sees an over-supply of contracted flexible capacity for the next three years based on a review of the procurement data (presented in Figures 5 and 6) and the three flexible categories adopted in the recent RA decision. Through 2016, the data collected demonstrates that there is approximately 10,000 MW of excess contracted capacity that meets either Category 1 or 2 requirements, compared with 2015 adopted requirements. This present reality informs Staff’s analysis of the Cons to Options 1 and 2, as well as the benefits of deferring the consideration of multi-year Flexible RA altogether (Option 3).

The theory behind creating an interim three-year Flexible RA requirement is that LSEs are now procuring to meet their 2015 flexible requirement; but, they may not procure beyond 2017 because of regulatory uncertainty. This uncertainty stems from the indication by the Commission that the requirement is expected to evolve and the three categories of flexibility requirements will be revisited before or during the 2017 RA year. So, while the LSEs are procuring for 2015, they will probably sign more than one- year contracts, but less than four-year contracts. Therefore, it would be illogical to put in place a permanent requirement for multi-year procurement of flexibility based on the recent RA decision. In contrast, it may be logical to require the LSEs to show up-front that they have procured for

³⁸ See D.14-06-050.

³⁹ *Id.* at 2.

the years 2015, 2016, and 2017, and this may be a more efficient way to procure this interim capacity need.

Effectiveness

The potential effectiveness of multi-year Flexible RA requirements would depend largely on the effectiveness of the recently-adopted Flexible RA requirements. If the newly approved categories of flexibility are ineffective, in that they do not encourage procurement of the resources that are critical to maintain grid reliability in a changing electric system, then similarly, extending the procurement of these resources will have little or no positive effect on reliability. It is too early to assess the effect of the recent RA decision, and so the timing for consideration of multi-year procurement requirements for flexibility may be premature.

However, there is great uncertainty with regards to the flexible needs of the system, especially regarding seasonal and monthly variation, and there is no adopted method for projecting flexible need beyond 2016. This makes it difficult to discuss the necessity of forward contracting beyond 2016 and to assess the likely costs and benefits of such forward requirements. Recent criticism for the three flexible categories adopted by the RA decision has focused on insufficient load studies to form the basis for flexible generation projections.

Given the new Flexible RA requirements, it should be expected that contracts entered into for this capacity will be multi-year contracts for “peak” month or months of flexibility. Therefore, none of the proposed options discussed here include a feathered requirement from year one to two because the proposals only include a requirement to show procurement for the peak month.

The certainty of future RA requirements is directly related to the potential for reducing inefficient retirements. The sooner generators know if and how they are currently valued in the capacity marketplace, the sooner they can determine if or how they may need to upgrade their plants to be available as flexible capacity in the future.

Costs

Because the new flexibility requirements take effect for the 2015 compliance year, no data on the range or average costs of Flexible RA are available. Therefore, Staff cannot make predictions about incremental costs associated with additional years of Flexible RA procurement.

Feasibility

Because the current methodology for setting Flexible RA requirements has not been tested or proven to accurately reflect need, if the Commission were to set multi-year requirements for flexibility, Staff is doubtful regarding the feasibility of requiring the LSEs to show that they have secured sufficient flexible capacity for each month in a 36-month timeframe. It is also important to consider whether projections of flexibility need are reasonable before requiring forward procurement to meet those

projections. Therefore, the analysis here addresses the Commission's anticipated review and adjustment of the new Flexible RA requirements through an improved needs methodology.

B. OPTION 1: 90% FLEXIBLE, YEAR 2

Implementation of this option would mean, in practice that, LSEs would be required to demonstrate, through some type of interim RA filing (pre-October 2015), that they have procured flexible capacity in 2016. As explained above, the requirement would mean that LSEs would need to show procurement for only the peak month in 2016 in advance, and then would demonstrate 100% compliance only in the month ahead.

PROS

- *Effectiveness:* Current data on forward contracting demonstrates that existing RA requirements motivate procurement beyond the compliance year. So, new procurement requirements would normally be expected to encourage procurement in many years forward. However, because the Commission has made clear that it intends to revisit the flexibility requirements in 2017, it seems less likely that forward procurement for flexibility will occur in the absence of an additional requirement. Therefore, providing certainty regarding requirements for the next three years may be warranted. The system may benefit from more flexibility procurement in the next three years if stronger price signals are sent to existing generators to make upgrades for flexible operation, or to conduct costly maintenance to remain in service.
- *Cost:* The 2014 RA decision requires LSE to enter into new contracts, and it could be more efficient for those contract terms to cover two years, rather than one. By providing regulatory certainty for requirements for two years the Commission could encourage more efficient contracting, which could benefit ratepayers. So, the incremental cost of the additional procurement should be low.

CONS

- *Effectiveness:* Contracting for one extra year may not lead to any reduction in inefficient retirements. If a generator is unsure whether to make the necessary investments to operate flexibly now or in the future, an extra year's worth of capacity payments may not sufficiently tip the balance in favor of investment in maintenance or upgrades.
- *Adverse Effects:* Some parties in the RA proceeding commented that the energy market should compensate for flexible attributes and that a capacity requirement should not be necessary in the long term. The CAISO has recently restarted its "Flexiramp" initiative, and generator revenues for flexibility services may be on the horizon. Therefore, creating a year 2 requirement might further skew the appropriate balance of revenue between capacity payments and energy payments.

- *Feasibility:* There is still uncertainty coming out of RA decision regarding what flexible capacity requirements should be post 2015, and CAISO has been unable to determine requirements beyond 2016. Many parties to the RA decision found that CAISO's flexible load studies were insufficient. The Commission may need to learn from implementation of the flexible requirements in 2015 before creating longer-term obligations. Any additional procurement requirements may encourage contracting for specific capacity characteristics, which might no longer be required in a few years.

C. OPTION 2: 90% YEAR 2, 80% YEAR 3

Under this option, LSEs would be required to demonstrate procurement for flexible capacity two and three years ahead. As explained above, the requirement would mean, in practice that LSEs would need to show advance procurement for only the peak month in 2016 and 2017, and then would demonstrate 100% compliance only in the month ahead.

PROS

- *Effectiveness:* The multi-year requirement may encourage generators to make some facility improvements by providing further revenue certainty for the next three years. (This is assuming that there may be upgrades with less than three-year paybacks). Cumulatively, these upgrades could have overall system benefits.
- This requirement will provide certainty to parties and stakeholders that there is sufficient flexible procurement in the next three years to ease the transition to a grid with higher renewable penetration and mitigate the otherwise adverse effects of a duck-like net load curve. In order for this new requirement to maximize desired effects, the current interim flexibility requirements should either be made permanent, or re-defined in the next 12 months.
- Since the Commission is now implementing one-year interim flexible requirements, it may be more efficient to put in place a three-year flexible capacity requirement that allows the LSEs to procure three year contracts efficiently in the immediate future, and send signals to generators who are procured that they should remain in service for at least the next three years.
- *Costs:* The current requirements may already be motivating LSEs and generators to enter three-year contracts, so the incremental cost of the additional two years of procurement, based on this policy, would be minimized.
- *Workability:* Creating an interim multi-year requirement is much more workable than attempting to implement a permanent multi-year requirement for flexibility, because the RA decision set up a process to re-evaluate the flexible requirements in a few years to compare them against better data and projections of future need.

CONS

- *Effectiveness*: Similar to the reasoning for Option 2, a second and third year of capacity payments may not be sufficient to encourage valuable generators at risk of inefficiently retiring to make investments necessary to operate flexibly, or to continue operating in the long term. For example, if a facility wants to make major upgrades with a 5-6 year payback period, then a generator would want to sign a contract for 6 or more years before making those capital investments.
- Because the current categories of flexibility are quite broad, it is likely that there will still be an oversupply of flexible capacity in the system in two or three years (as represented in *Figure 5* above). Therefore, a multi-year flexibility requirement may not result in additional contracting with the most flexible units. This outcome would leave the system with the same level of risk of inefficient retirements that it has today because the most flexible units, which may be more highly valued under an evolving RA requirement, would still not receive multi-year contracts and therefore would not be discouraged from retiring.
- *Adverse effects*: As discussed under option 1, this additional requirement might also skew the appropriate balance of revenue from capacity payments vis-a-vis energy payments.
- *Costs*: If the load studies used to set flexible requirements are inaccurate, requiring contracting three years ahead based on these predictions will incur unnecessary costs. The need for flexible capacity is determined by numerous factors, some of which are inherently unpredictable; e.g., predicting during which month a major heat wave might occur.
- *Feasibility*: The CAISO has not developed flexibility need estimates beyond 2016, which would be required before this option could be implemented. During the RA proceeding many parties expressed concerns over the methodology used by CAISO to predict monthly flexible needs. So, setting accurate requirements for 2017 may not be feasible until those issues are worked out in the RA proceeding. The Commission may need to learn from implementation of the recent RA decision to see if adjustments need to be made to flexibility requirements before creating longer-term obligations.

D. COMPARATIVE STRENGTHS OF OPTIONS 1 AND 2

Option 2 has a greater likelihood of sending market signals that may dissuade valuable flexible resources from retiring, and therefore it would be the more effective option. However, if the Commission is most concerned with minimizing incremental ratepayer costs from additional procurement, then Option 1 is preferable as it will likely be less costly overall, because the farther out flexible needs are predicted, the less likely they will be accurate. This is especially true because the tools used to determine these needs are not fully developed and are presently being refined.

E. OPTION 3: NO FLEXIBLE MULTI-YEAR REQUIREMENT UNTIL 2017 (NO ACTION UNTIL LATER DATE)

PROS

- Waiting to implement multi-year requirements for flexibility will decrease the risk of unnecessary costs because parties and the Commission will be given more time to understand the impact of new Flexible RA requirements—and further hone the forecasting methods and resulting requirements. An important unknown factor is how much flexible capacity is available in the current electric system in California. The RA proceeding did not definitively rule on how existing flexible capacity should be counted, or on the role of imports in flexibility requirements. Another unknown is whether existing RA contracts might be modified to allow more resources to make upgrades in order to become flexible. Given the difficulty in characterizing future flexible need, combined with the present oversupply of flexible capacity, reliability problems are not obvious from an evaluation of the status quo.

CONS

- Certain parties, in particular the CAISO, will likely remain concerned over retirements of valuable resources with flexible attributes, which the system may not be valuing appropriately at present. “Inefficient retirements” may therefore continue and the absence of a multi-year requirement for flexible capacity may result in a decreased likelihood of generators investing in flexible upgrades. During recent workshops held in this proceeding, generators expressed that, in the absence of regulatory certainty regarding how flexibility will be characterized in the future, they are unlikely to make significant plant upgrades to meet the current categories of flexibility (particularly category 1) given that they expect these definitions will likely change with time. In other words, the interim nature of the current flexible categories may not create sufficient certainty to motivate generator investment, so it may be unlikely that the RA decision on its own will lead to major upgrades or encourage generators to avoid retirement.

3. OPTIONS FOR LOCAL CAPACITY REQUIREMENTS

Option 1: 90% requirement for year 2

Option 2: No additional requirement (status quo)

A. EXPLANATION AND DISCUSSION OF OPTIONS

The showing proposed for year 2 would mirror the current annual showing for local capacity requirements, and therefore would be a demonstration of procurement for each month during the period for months 13-24. This proposal only includes a year 2 requirement for large local areas, because

Staff finds it impracticable to create an additional requirement for small local areas where only a few generators are present.⁴⁰

Option 1 proposes a 90% local requirement, because there is an over-procurement risk if LSEs are required to forward procure 100% of forecasted requirements two and/or three years forward. Given uncertainty over changing local requirements and effectiveness of future transmission upgrades, a timeframe of two years may be more reasonable than three for Local RA. Currently CAISO Local Capacity Requirement (LCR) studies are done for the year ahead and for five years out. The year-ahead requirements tend to fairly accurately represent needs, but the five-year predictions are less proven.

For the reasons discussed below, a three-year requirement would be overly speculative given the inability to accurately predict local capacity needs multiple years in the future.

Effectiveness

One major factor to consider is that for some local areas, historically, capacity procurement has been mandated for every available MW of local supply. The result is that Local Capacity in constrained areas is currently the highest valued capacity type (per MW). This fact may also mean that for constrained local areas, inefficient retirements are unlikely. Therefore, to aid the decision making process, it might be helpful to assess what proportion of local areas experience a low risk of inefficient retirements due to operators possibly exercising local market power.

Furthermore, the Commission-adopted methodology for LCRs is conservative in that it is based on a “1 in 10 year” planning standard, using a CAISO developed methodology.⁴¹ This means that there are already a reserve margins inherent in the local requirements, so further requirements may be ineffective or unnecessary.

Costs

Based on feasibility issues, if multi-year Local RA was mandated, significant over-procurement would be a likely result for smaller areas. While the cost of this over-procurement may be mitigated by the fact that all local capacity procurement also counts towards system requirements, because local capacity receives a premium price, this over-procurement could represent a significant, unjustified cost. Therefore, setting multi-year requirements for small local areas may not be reasonable and is not proposed here.

⁴⁰ Only local areas with CPUC-jurisdictional load greater than 2000 MW would have requirements, as determined by the most recent CAISO LCR study.

⁴¹ D.06-06-064.

Feasibility

Some local areas have experienced dramatic changes in required capacity from one LCR study to the next. LCRs have shown significant swings in need from year to year (both up and down). Primarily, the drivers of these changes are transmission approvals and increases (or decreases) in load. (Removing extreme cases related to the SONGs retirement from this analysis). For example, in many years the variation for most local areas is less than 5%.⁴² Larger local areas seem to generally have less variation than smaller areas, but it can still be significant. For example, the San Diego local area experienced a 9% decrease in LCR from 2011 to 2012,⁴³ attributable to the Sunrise Powerlink transmission project. In the same time-frame, the Bay Area experienced a 14% decrease that was not attributable to a transmission project. Smaller areas, such as Big Creek/Ventura, Kern, and Fresno have recently experienced changes of ~30% or above.⁴⁴

Significant swings in LCR from year to year may be expected, but agreeing on projections is often controversial as it requires agreeing, many years in advance, on when an expected transmission upgrade will be completed. Even on a one-year basis, these swings make procurement inefficient because they are somewhat unpredictable and do not follow any sort of trend. This difficulty is likely masked in Central/Northern California, where smaller local areas in PG&E territory are aggregated.

B. OPTION 1. 90% LOCAL YEAR 2 (ONLY CERTAIN LOCAL AREAS)

PROS

- *Effectiveness*: Benefits to reliability from forward contracting may be created, by providing certainty for any critical generators in constrained local areas where a majority of retirements of generators utilizing Once-Through-Cooling technology may occur. In some local areas one significant, unplanned, unexpected, or premature plant retirement could create reliability problems for the entire area. A multi-year procurement requirement should result in increased revenues to valuable local resources, and should increase the likelihood that existing resources can make environmental or other technical upgrades which may be necessary to continue operating. There are a large number of planned resource retirements in certain local areas, like Southern California, and therefore, the risk created by the possibility of other *unplanned* retirements is magnified.

⁴² These values were derived by analyzing the changes in LCR values from 2010-2011, and 2011-2012. The 2011 and 2012 LCR reports are available at <http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx>.

⁴³ *Id.*

⁴⁴ *Id.*

- *Workability:* CAISO has stated in recent JRP workshops that it would commit to producing a two-year LCR study and that it would not be particularly burdensome to do so. This study would be a necessity for setting a two-year Local RA requirement. The Commission would need to engage with CAISO on study assumptions; e.g., timing of additional transmission, etc.

CONS

- *Effectiveness:* In many local areas generators are already receiving a premium price per MW compared to System RA resources. A valid argument may exist that these conditions already provide sufficient market signals to prevent inefficient retirements. Some resources, which may in fact be likely candidates for inefficient retirement, may be just outside a local area boundary. Therefore, this would diminish the effectiveness of this policy.
- *Costs:* Because most local capacity resources are already paid a premium, the cost of forward contracting with these resources will likely be much higher per MW than other types of capacity. In many local areas, generators exercise market power, and therefore, a multi-year requirement may serve to disproportionately increase procurement costs where capacity choices are already slim. Market power mitigation will be a significant factor in ensuring that, if multi-year requirements are instituted for local capacity, ratepayers are not bearing the burden of non-competitive contracting that favors generators.
- Because of the difficulties in accurately projecting LCRs into the future, there would likely be unnecessary procurement costs incurred if requirements are set too high, resulting in excess procurement.
- *Feasibility:* Because transmission upgrades are often slow to be completed and it is difficult to predict when transmission improvements will remove constraints, setting a year 2 requirement will be challenging.

C. OPTION 2: NO LOCAL MULTI-YEAR REQUIREMENTS

PROS:

- Local resources should already be receiving sufficient price signals, and new transmission upgrades should improve certain local reliability concerns in local areas in Southern California. ORA's risk of retirement evaluation methodology, as discussed in section II.C. "Inefficient Retirements," removes the two biggest local areas from concerns: LA Basin & San Diego, because they preliminarily concluded resources in those areas would not be at risk. Furthermore, many local areas are observed to already be in stasis where the supply is exactly equivalent to forecasted demand from year to year. There may be minimal value in having a local multi-year program only for the Bay Area or other small Northern CA local areas because it would have a high administrative burden for potentially minimal benefit.

CONS:

- In the recent past, many reliability problems have been constrained to local areas, indicating that it could be valuable to use multi-year RA for local capacity as a way to test theories regarding reducing inefficient retirements.

D. PROPOSALS FOR “TRIGGERS” FOR MULTI-YEAR RA REQUIREMENTS

Trigger Option A: A multi-year requirement for generic, flexible or local capacity should be triggered when, based on the assessment conducted under Track 2 of the JRP, procurement three years from the current compliance year falls below 70% *for that type of capacity*. The percentage would be based on projected system peak as set out in the IEPR-LTPP forecasts. This should be measured annually in October (after RA filings are submitted and reviewed). For example, in October 2014, Staff could evaluate capacity procurement for 2017 for system and local capacity. If the results of this evaluation showed that CPUC-LSEs were less than 70% procured for system, as compared to the IEPR-LTPP forecast, the Commission would institute one of the proposed options for multi-year RA for system capacity.

Trigger Option B: As an alternative, Staff proposes that the Commission implement multi-year requirements when a five-year outlook evaluation of system, flexible or local capacity demonstrates that during that timeframe, the available supply for that capacity-type is equal to the Planning Reserve Margin, $\pm 5\%$. This evaluation would be based on the LTPP assessment of available capacity in the State. In practice, this would mean that the Commission would annually conduct a study of available system, flexible and local capacity for years 2-6. If this study showed that available capacity was equal to 120% or less of forecasted requirements for that capacity type for any of the following five years, then multi-year RA requirements would be triggered.

IV. QUESTIONS FOR PARTY COMMENT

Comment is requested from parties on the conclusions and proposals made in this this report, with emphasis on:

- a. The conclusions reached under each of the “four pivotal issues,”
- b. Potential risks posed by inefficient retirements (and the factor-test proposed),
- c. Staff’s interpretation of the data on forward contracting practices,
- d. Whether the menu of proposed options for multi-year procurement requirements is appropriate,
- e. Whether alternatives to multi-year RA requirements should be considered in the suite of solutions to potential reliability concerns,
- f. The appropriateness of the proposed trigger mechanisms, and potential alternatives.

Staff also encourages parties to present their analysis of any of the following questions:

1. Are there valuable generation resources that are not receiving any medium- or long-term contracts, and are therefore at risk of inefficiently retiring? (Refer to definitions in section II.C “Inefficient Retirements”).
2. What would motivate such resources to “inefficiently retire”?
3. Is the new Flexible RA requirement sufficient to encourage retention of the existing flexible resources and/or investment in new necessary flexible resources that will be needed in the next ten years?
4. Will a multi-year RA requirement change the quantity of inefficient retirements, or the potential impact from such retirements?
5. Is it reasonable and appropriate to develop and implement multi-year RA requirements at the present time, and why or why not?
6. How should uncertainty be dealt with in setting multi-year RA requirements, and how might this proceeding mitigate the effects of regulatory uncertainty?
7. What method could be used to ascertain the ratepayer cost from additional forward procurement for each proposed option in section III?
8. How could any potential reliability benefit from multi-year RA be monetized so that the costs and benefits can be compared by decision makers?
 - a. How can non-monetary reliability benefits, such as certainty regarding future procurement, be quantified?

APPENDIX: PROGRAMS AND PRACTICES THAT MAKE UP THE RELIABILITY FRAMEWORK IN CALIFORNIA

1) THE RESOURCE ADEQUACY PROGRAM AND ITS PURPOSE

The Resource Adequacy (RA) program was developed in response to the 2001 California energy crisis. The program is designed to ensure that California Public Utilities Commission (CPUC) jurisdictional Load Serving Entities (CPUC-LSEs)¹ have sufficient capacity to: meet their peak load with at least a fifteen percent reserve margin, ensure local area reliability, and meet flexible ramping needs associated with renewable integration. The RA program began implementation in 2006 and continues to provide the energy market with sufficient forward capacity to meet peak demand. This capacity includes System RA, Local RA, and Flexible RA, all of which are measured in megawatts (MW). The annual and monthly System, Local, and Flexible-RA requirements for CPUC LSEs are set by the CPUC. Local and now flexible requirements are adopted through the annual proceeding based on CAISO studies.² The RA proceeding occurs annually, providing a recurring forum for discussing and responding to changing system needs and any changing procurement conditions with potential rule and/or policy changes.

Each October, the RA program requires CPUC-LSEs to make an annual System, Local, and Flexible compliance showing for the coming year. For the System showing, CPUC-LSEs are required to demonstrate they have procured 90% of their System RA obligation for the five summer months. For the Local showing, CPUC-LSEs are required to demonstrate they have procured 100% of their Local RA obligation for all twelve months. The local requirements reflect both transmission constraints and LSE load share. For the flexibility showing, CPUC-LSEs are required to demonstrate that they have procured 90% of their Flexible RA requirement, based on the CAISO's estimate of maximum ramping need for all twelve months.

In addition to the annual RA requirement, the RA program has monthly requirements. On a month-ahead basis, CPUC LSEs must demonstrate they have procured 100% of their monthly System and Flexible-RA obligation. Additionally, on a monthly basis from May through December, the CPUC-LSEs must demonstrate they have met their revised (due to load migration) local obligation.

The RA program works hand in hand with the LTPP process which aims to help incent the siting and construction of new generation resources for reliability purposes. Additionally, the CPUC adopts the ISO's annual LCR study which contains area-specific reliability needs and local area deficiencies.

¹ D.06-06-064.

² R.11-10-023.

These local area requirements and deficiencies act as market signals to help incent the siting and construction of new resources needed for reliability.

2) THE LONG TERM PROCUREMENT PLAN PROCEEDINGS

The Commission initiated LTPP proceedings to continue its efforts to ensure a reliable and cost-effective electricity supply in California.³ The LTPP Proceeding is an umbrella proceeding wherein the Commission considers all of its electric resource procurement policies and programs in an integrated manner and authorizes further procurement for needs unmet by other programs and resources. As such, it is the primary means for ensuring long-term reliability in the State by authorizing new generation. The intent of the LTPP is to ensure that IOUs procure sufficient resources to meet the demands of their customers in a safe, cost-effective manner consistent with the Loading Order. To achieve this, the LTPP proceeding oversees biennial evaluations of supply and demand ten and twenty years into the future. These evaluations are based on assumptions and scenarios developed in conjunction with the CEC and CAISO and subject to stakeholder feedback.

If a need for resources is found through the LTPP, the Commission issues decisions authorizing procurement of additional resources. These targeted authorizations are delineated in terms of capacity (MW), location (i.e., in given location capacity regions), and resource attributes such as the ability to ramp up or down in response to grid needs. Per Public Utilities Code Section 454.5, the LTPP provides the IOUs with upfront standards leading to pre-approval and transparent requirements for compliance, obviating the need for an after-the-fact reasonableness review.

The LTPP assesses future capacity needs based on many factors, but one of the assumptions built into the LTPP assessments is resource retirements. The LTPP built into the models that resulted from the proceeding retirements that are fairly certain, such as generators utilizing Once-Through-Cooling. For other retirements, both the 2012 and 2014 LTPP assume a fairly constant rate of 1100 MW through 2017. The 2014 LTPP predicts, ~1800 MW-2000 MW retiring annually from 2018-2024. These values are only adjusted slight upwards from the 2012 LTPP scenario tool.

3) THE COST ALLOCATION MECHANISM (CAM) AND LONG TERM RELIABILITY

D.06-07-029 adopted a process known as the Cost Allocation Mechanism (CAM), which allows the Commission to designate IOUs to procure new generation within their distribution service territories, with the costs and benefits associated with development for these new resources to be allocated to all benefiting customers. All benefiting customers are to include: bundled-utility customers,

³ D.07-12-052.

direct-access customers, and CCA customers. The Load Serving Entities serving these customers are allocated the rights to the capacity in each service territory, which are applied towards meeting the LSE's RA requirement. The LSEs receiving a portion of the CAM capacity pay only for the net cost of the capacity, which is the net of the total cost of the Power Purchase contract price minus the energy revenues associated with dispatch of the contract.

D.11-05-005 eliminated the IOUs' authority to elect or not elect to use CAM for generation resources. In addition, the decision permitted CAM for utility-owned generation and allowed CAM to match the duration of the contract.

The Commission has considered changes to CAM many times in the past, most notably in R.05-12-013, which considered multiple options for CAM opt-out provisions. However, the Commission rejected such provisions while noting that the issue of CAM and the ability to opt out is closely linked to the establishment of multi-year RA requirements.

4) UTILITY CONTRACTING PRACTICES AND TEVAR

Utility portfolio management activities can be characterized by their TEVaR, or "To-Expiration Value at Risk", which is an expression of the potential future cost variability (the width of the distribution of likely future portfolio costs). Hedging plans are put in place by each utility to ensure that TEVaR stays within reasonable limits. Addition of fixed-price resources to the portfolio, such as many renewable resources, also reduces TEVaR (i.e., such resources narrow the cost distribution because their costs are known in advance).

The magnitude of TEVaR is generally expressed as a percentage of Customer Risk Tolerance (CRT). The Commission currently sets CRT to 10% of each IOU's system average rate (D.12-01-033). If TEVaR is greater than this value, the utility must meet with its Procurement Review Group (PRG) and consider "remedial action," but the remedial action is not required. However, utility hedging plans may commit to action based on TEVaR levels relative to CRT. These hedging plans are developed by each IOU and approved by the Commission. The hedging plans drive forward procurement by IOUS in addition to the RA requirements.

5) CAISO'S RELIABILITY PROGRAMS:

CAISO plays an obvious and significant role in the State's reliability framework, as it ensures the safe and reliable operation of the grid. To perform this essential function, it has been granted specific authority by FERC related to the reliable operation of the grid.

A) THE RELIABILITY MUST RUN (RMR) PROGRAM AND ITS PURPOSE

Pursuant to the CAISO tariff:

“A Reliability Must-Run Contract is a contract entered into by the CAISO with a Generator which operates a Generating Unit giving the CAISO the right to call on the Generator to generate Energy . . . or to procure Ancillary Services . . . to ensure that the reliability of the CAISO Controlled Grid is maintained.”⁴

“The CAISO will, subject to any existing power purchase contracts of a Generating Unit, have the right at any time based upon CAISO Controlled Grid technical analyses and studies to designate a Generating Unit as a Reliability Must-Run Unit.”⁵

The CAISO performs an annual RMR study to identify which generator resources are needed on-line in order to reliably serve the local area load. Generating resources with existing RMR contracts must be re-designated by the CAISO for the next compliance year and presented to the CAISO Board of Governors for approval by October 1st of each year. Designations for new RMR contracts are more flexible, and may arise during the relevant compliance year. RMR resources are placed into two classes: Condition 1 contracts are allowed to operate in the energy market even if not dispatched by the CAISO for reliability purposes, and Condition 2 units are generally not allowed to operate in the energy market but are under the full dispatch of the CAISO for reliability purposes. Both types of RMR contracts are paid for by all customers in the transmission area.

Condition 1 units are able to competitively earn revenue in the energy market in addition to the capacity payments under the RMR Agreement. In D.06-06-064, the Commission ordered that capacity from Condition 1 RMR contracts be allocated to LSEs to count towards the LSEs’ Local RA obligations only, while Condition 2 RMR units may be counted towards both the System and Local RA obligations. Because they are able to participate in the market, Condition 1 units are allowed to sell their System RA credit to a third party. This decision also authorized the CPUC to allocate the RMR benefits as an RMR credit that is applied towards RA requirements.

Pursuant to the stated policy preference of the Commission⁶ Local RA requirements began to supplant RMR contracting for the 2007 compliance year, and a significant decline in 2007 RMR designations occurred. That trend continued through the 2011 compliance year, with only one

⁴ CAISO Tariff § 41.1.

⁵ CAISO Tariff § 41.2.

⁶ D.06-06-064, § 3.3.7.1.

remaining RMR contract (with the Oakland Power Plant) and no change in RMR designations from 2011 to 2014.

B) THE CAISO’S BACKSTOP AUTHORITY—THE CAPACITY PROCUREMENT MECHANISM (CPM)

The CAISO’s tariff provides a mechanism for the system operator to ensure that, in the case of an LSE filing a deficient RA showing, or in the event of an unexpected change to the system, the CAISO has sufficient capacity available to maintain reliable operation of the grid. Currently, the CPM serves to backstop any possible RA deficiencies for both annual and monthly showings for system and local capacity, and also provides for supplementary procurement in the case of significant events or exceptional dispatch. Additionally, CAISO’s tariff provides them with the ability to designate resources that are at “risk of retirement,” but which the CAISO finds are necessary to ensure reliable grid operation in procurement “year two.” This is commonly referred to as the “risk of retirement backstop.” All of these provisions can be found in §§ 43.3-43.4 of the CAISO’s tariff. CAISO is currently developing a proposal for replacement of the current CPM tariff provisions via a stakeholder initiative process. At present, the proposal calls for a competitive solicitation process to replace the current administrative CPM price.⁷

⁷ Information about CAISO’s current CPM Replacement Stakeholder Initiative is available at: <http://www.caiso.com/informed/Pages/StakeholderProcesses/CapacityProcurementMechanismReplacement.aspx>.