Reliable and Clean Power Procurement Program
Staff Options Paper

CPUC Energy Division
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Contents

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1. Summary

In this paper, California Public Utilities Commission (CPUC) staff describes options for the design of a new procurement program to determine the amount of reliable and clean resources that are required to be procured, by whom, by when, and what the reliability and greenhouse gas (GHG) parameters to demonstrate compliance should be. This "Reliable and Clean Power Procurement Program" will establish new long-term contracting requirements for load serving entities (LSEs) to procure the resources needed to meet their share of total system reliability and clean energy resource procurement needs. It will be enforceable, with penalties and/or backstop procurement to ensure sufficient resources are secured. The new program will align with the existing integrated resource planning (IRP) process.

The options described in this paper are not intended to be mutually exclusive, nor do they represent the only possible programmatic structures that could be implemented. Staff is using this paper as a means of advancing the conversation with stakeholders on the design of the new procurement program.

2. Background

The CPUC's regulation of California's electricity market consists of the following programs:

- The Resource Adequacy (RA) program requires contracting for capacity for system, local, and flexibility needs in the near-term and ensures that such capacity has a must-offer obligation to bid into the California Independent System Operator (CAISO) markets.
- The IRP process establishes long-term planning goals for new resource needs to meet reliability requirements and GHG-reduction targets, and the IRP process can order new resource procurement for reliability needs.
- The Renewables Portfolio Standard (RPS) program addresses LSEs' planning, procurement, and compliance with RPS statutory requirements.
- Demand-side resources have been addressed in the Integrated Distributed Energy Resource (IDER) proceeding (Rulemaking (R.) 14-10-003), the High DER proceeding (R.21-06-017), the Demand Flexibility proceeding (R.22-07-005), and other resource-specific proceedings.

This regulatory framework has been stable since the early 2000s, with the notable replacement of the former Long-Term Procurement Plan (LTPP) proceeding with the IRP proceeding for reviewing the 10-year outlook for reliability need and administering procurement orders for new resources. At the same time, key market fundamentals have been changing, requiring the CPUC's regulation of the market to adapt. Staff has observed three overarching trends in recent years:

- Increased role of Community Choice Aggregators (CCAs)
    - The role of California's three large investor-owned utilities (IOUs) in resource procurement is shrinking, and most new procurement decisions are now being

made by more than 40 CCAs and Electric Service Providers (ESPs), as well as the IOUs.
    - The CPUC's oversight role over contracts approved by self-governed CCAs is different than for IOUs.
    - In 2016, the CPUC transitioned from a proceeding that obligated the IOUs to predict and litigate the capacity needs of their service territory (LTPP) to one that requires all LSEs to plan for their own load (IRP). Under the LTPP process, the CPUC considered all available preferred resources before ordering the IOUs to procure natural gas resources on behalf of all customers. In the beginning of the IRP process, the system capacity resources appeared to be in surplus, and many LSEs did not expect to need new resources to meet their reliability obligations in the near term. As modeling assumptions evolved to reflect changing circumstances in the energy market, including the need to address the expected retirements of the last once-through-cooling (OTC) units and Diablo Canyon nuclear power plant, as well as a decrease in expected imports, the CPUC utilized the IRP proceeding to order new near- and mid-term resources and required all LSEs to bear some responsibility for their costs.
    - Prior to the expansion of the CCAs into procurement, the CPUC relied heavily on the IOUs' bundled procurement plans (formerly called the short-term procurement plans) to establish and enforce parameters and obligations for contracting for existing resources beyond the resource adequacy program. Via the bundled procurement plans, the CPUC requires the IOUs to contract for a certain amount of forward energy and capacity to minimize financial risk to bundled customers. The CCAs are not similarly obligated to maintain forward contract positions (or share them with the CPUC) for energy and capacity.
- Increased capacity market tightness
    - The CPUC's current regulatory policy structure has facilitated the orderly retirement of over 20 gigawatts (GW) of aging, inefficient natural gas power plants through contract authorizations for new high efficiency, natural gas power plants, as well as tens of GW of new renewable and storage resources. By running at lower heat rates and lower capacity factors, and complemented by increasing quantities of clean energy resources, the new gas fleet has helped achieve significant GHG reductions during the transformation of the fleet over the past 20 years.
    - The CPUC's current regulatory policy structure has generally provided a system capacity surplus, and the broader western markets have also generally been in a state of capacity surplus. At times, this surplus has given rise to concerns of insufficient forward contracting of existing resources, which could cause unexpected retirements of aging resources that are difficult to maintain with one-year contracts. The CPUC's consideration of multiyear forward resource adequacy requirements has been driven by this concern.
    - In recent years, California and western markets have been facing capacity tightness as aging, inefficient powerplants in both California and neighboring states retire due to market and regulatory pressures. Recent capacity tightness has led to significantly higher RA capacity prices.
    - Due to the lack of ease of market entry, any sustained period of capacity shortfall could expose consumers to higher costs if suppliers of new or existing generation

can exert market power over buyers or simply due to high energy prices during scarcity conditions.

- Increasingly ambitious GHG-reduction goals
    - Significant amounts of new clean energy resources are needed beyond what is required by current RPS mandates to meet California's increasingly ambitious climate policy goals, such as those defined in SB 100.[1]
    - Meeting these clean energy goals while maintaining reliability will likely require the addition of significant amounts of new clean, firm resources. New natural gas units have not been authorized in many years, primarily because they appear to be at odds with the state's GHG-reduction goals in general, and SB 100 in particular.
    - It is important to ensure that California's regulatory framework encourages LSEs to make timely, orderly, and cost-efficient procurement decisions to meet the state's GHG reduction goals at least cost.

In light of these trends, it is important for the CPUC to ensure its procurement framework incentivizes all LSEs to secure needed resources and to make economically efficient procurement decisions. To address this situation to date, the IRP proceeding has adapted the LTPP's approach of ordering "new steel in the ground" capacity, via Decision (D.)19-11-016[2] and D.21-06-035,[3] which ordered LSEs to procure to meet near-term and mid-term reliability needs. Although the IRP process was designed for potential procurement authorization to be considered during both Reference System Plan (RSP) and Preferred System Plan (PSP) adoption, both procurement decisions were issued outside this established framework and cadence due to the urgent nature of the procurement need.

These circumstances have raised concerns that IRP lacks a formal process for how procurement may be ordered or authorized as part of adopting and implementing IRP plans, or how the adopted system level portfolio relates to the CPUC approving or certifying LSEs' plans. Moreover, the order-by-order approach to procurement has proved unpredictable for LSEs, cannot fully address load migration, does not facilitate proactive LSE self-provision of the needed resource attributes, and does not expressly address existing resource retention, which can result in uncertainty for LSEs and the broader market, ultimately posing a barrier to efficient procurement and putting reliability at risk.

In recognition of these concerns, the CPUC issued a staff proposal in November 2020 outlining a resource procurement framework in IRP and recommending how the main steps should be undertaken.[4] The November 2020 staff proposal discussed various options for connecting procurement action by the CPUC to the IRP planning track, including some that fit with a programmatic approach. One broad recommendation made by staff, which has since been formalized by CPUC decision, is that procurement is a core function of serving load and hence LSEs should be required to self-provide rather than be able to opt-out.

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[1] Available at https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB100
[2] D.19-11-016 Decision Requiring Electric System Reliability Procurement for 2021-2023, available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF
[3] D.21-06-035 Decision Requiring Procurement to address Mid-Term Reliability (2023-2026), available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF
[4] Available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M351/K577/351577337.PDF

More recently, the February 2022 Preferred System Plan decision (D.22-02-004) committed to further evolving the CPUC's IRP process by developing a programmatic approach to procurement to achieve the proceeding's three goals of reliability, GHG reductions, and least-cost procurement. Staff is using this paper to advance that effort. It involves discussion of potential approaches to programmatic procurement, some of which may be new to stakeholders, some which have been raised in IRP before, and some that may be familiar from other places, including items raised before the establishment of IRP, such as the Joint Reliability Plan (proceeding R.14-02-001), and from other venues, such as the RA proceeding (R.19-11-009). In raising such potential approaches, staff is acknowledging that there may be unique reasons to consider them again here, in the context of a program to drive investment for reliability and GHG-reduction over the medium-to long-term.

3. Objectives

The Reliable and Clean Power Procurement Program should accomplish the following:

1. Support realization of the goals of Senate Bill (SB) 350 and SB 100, in particular regarding reliability and GHG-reduction, safely and equitably, and in light of the current market structure, historical procurement and procurement in progress, and the need to ensure a predictable and stable long-term transition of the electric fleet.
2. Achieve economically efficient procurement.
3. Incentivize compliance through a predictable and orderly program design that enables LSEs to anticipate, understand, and comply with their obligations while also making it difficult and burdensome to avoid compliance.
4. Complement the IRP planning track, while transitioning away from the current order-by-order procurement paradigm for new resources.
5. Complement the RA program, which is focused on the near-term and existing resources, to address the need for both retention of existing and new resources in the medium-to-long term.
6. Complement the RPS program to meet GHG goals through 2030 and beyond.
7. Ensure LSE procurement responds to evolving demand forecasts (reflecting high electrification, extreme climate impacts, and load migration among LSEs).
8. Ensure reasonable competition for both supply- and demand-side procurement solutions to fill long-term needs.
9. Ensure existing resources persist and new resources get built such that reliability can be predictably maintained.
10. Allow for some resource-specific procurement action to occur in parallel with the program (e.g., central procurement of large and/or long lead-time resources).
11. Co-optimize transmission planning with procurement.
12. Recognize retail choice and allocate requirements and costs fairly.
13. Mitigate risks of market power.
14. Fulfill the relevant objectives of the Environmental and Social Justice Action Plan.

Further to objectives 1 and 10 above, staff suggests that the procurement in scope of the new program is not necessarily all procurement required to meet SB 100 goals. In other words, the CPUC may need to take procurement action for specific purposes in parallel with establishing and maintaining the program, potentially within IRP itself. This viewpoint recognizes firstly the requirement, referred to in section 2, for LSEs to self-provide in most instances, and secondly the principle followed in IRP procurement so far of defining procurement need in as general terms as possible. A technology agnostic approach leaves competitive market processes to identify the optimal resource types and locations, and is probably appropriate for a large portion of the procurement required to meet SB 100 goals. However, there may need to be exceptions to this[5] to promote resource diversity or pursue large-scale and/or long lead-time (LLT) resources with a

[5] As allowed for in Public Utilities Code Section 454.52 (a)(2)(B): "The commission may approve procurement of resource types that will reduce overall greenhouse gas emissions from the electricity sector and meet the other goals specified in paragraph (1), but due to the nature of the technology or fuel source may not compete favorably in price against other resources over the time period of the integrated resource plan."

distinct strategy, such as for offshore wind. Staff suggests that if the program is designed to accommodate these exceptions and drive LLT resource procurement, rather than just complement it, the design would be significantly complicated. Specifically, staff expects that resource-specific procurement requirements, and allowing LSEs to opt-out of self-providing these, would likely result in an approach to procurement that is more order-by-order in nature than programmatic. This is due to the impacts these features would have upon procurement need determination and cost allocation, respectively.

Finally, the Reliable and Clean Power Procurement Program should be feasible to adopt and implement in 2023, and maintain thereafter, from a staff workload and stakeholder perspective.

4. Designing a Procurement Program

4.1. Fundamental Elements of a Program

The new program will function as a set of rules and incentives with the following key elements. It is likely that any new procurement program would need each of these elements:

1. **Need determination**: Use technical analysis to specify the needed quantities of resource attributes, such as effective capacity, firm energy, and/or clean energy attributes, over a specified period of time.
2. **Need allocation**: Specify what quantity of the required attributes each LSE should be required to provide, considering factors such as load migration and the LSE's existing portfolio.
3. **Compliance**: Develop an approach for collecting the necessary information from LSEs to monitor their compliance with procurement requirements.
4. **Enforcement**: Establish penalties and/or backstop procurement mechanisms to address an LSE's failure to meet its obligations.

The new procurement program should be designed to address the main externalities stemming from operation of an unconstrained energy market. Staff sees these externalities as reliability, environmental, financial, and market power; refer to the Appendix for a description of these externalities. Fundamental elements for designing for the reliability and environmental externalities are introduced here. In section 7, staff raises other program design considerations associated with the financial risk and market power externalities.

For addressing reliability, the simplest approach would be to define the total system reliability need, allocate that need to LSEs, define how each resource counts towards that need, establish enforcement actions for noncompliance, and let LSEs and generators minimize procurement costs to meet the need through competitive procurement processes. For determining and allocating need, the new program could utilize the IRP planning track's loss of load probability modeling to define a capacity requirement to reach the CPUC's physical reliability standard (currently 1-day-in-10-years loss-of-load expectation (LOLE), and subject to review and potential update through a stakeholder process). The program could use either average or marginal effective load carrying capabilities (ELCCs), aligned with the use of ELCCs in the IRP planning track. An alternative approach would be to translate the capacity contracting requirement into a firm energy contracting requirement. For compliance and enforcement, the metrics would be consistent with the need determination and allocation: capacity-oriented, or a translation of capacity into firm energy terms.

A similar approach could be used for clean energy attributes to meet GHG-reduction targets. The new program could define the total need for either GHG reduction or clean energy, identify the share of that need each LSE must procure, define how to measure compliance towards that need, and set penalties for noncompliance. It could be similar to the RPS program, but would include all GHG-free resources, not just RPS-eligible resources. As in RPS, one method for setting the need is to define an annual energy target with multi-year compliance requirements for each LSE based on the LSE's procurement of credits, where each credit equals one megawatt hour (MWh) of clean energy generation. An alternative method for setting/allocating need and counting resource contributions is hourly GHG accounting as utilized in the "clean system power" (CSP) tool in the IRP planning track.[6]

Though discussed separately here and in sections 5 and 6, a comprehensive procurement program would afford LSEs the ability to satisfy both reliability and clean energy needs simultaneously and with the same compliance filing. There would be different methods for determining and allocating procurement need and different enforcement actions for noncompliance based on the technical specifications of each requirement. Straw options for doing so are described in section 8.

4.2. Additional Design Features

Adjustments to the fundamental elements of the program design introduced above, or additional rules within the design, will be warranted to ensure the new program achieves its stated objectives while considering the unique regulatory environment in California. Additional design features may include:

- **Defining procurement subcategories as part of need determination**. Procurement subcategories could include minimum amounts of firm clean resources, long-duration storage, and specifications around new vs. existing resources. For example, a reliability procurement program may focus on procuring the total system reliability need, accounting for both existing and new resources, and it may also define that some minimum portion of the need be met with new resources.
- **Managing changes over time between the program's need determination and the real-time energy market**. Many things may shift between the time a compliance showing is made 5 years out, say, and real-time market conditions that eventually emerge. Examples including changes in system loads and resources that will impact the system need and the value of different resources to meeting that need. Additional design features could be added to manage such changes, including by requiring near-term forward showings with more granularity than those 5 years out.
- **Requiring that procurement is conducted via centralized auctions or standard offer processes**. The status quo of mid-to long-term contracting by CPUC-jurisdictional LSEs is bilateral procurement processes. However, centralized auctions[7] could be considered for the program given the potential benefits of all LSEs regardless of size receiving the same offers, counterparty risk management via a centralized clearinghouse, and transparency to aid quality control. Standard offer processes could help improve the transactability of the products and support understanding of their quality.
- **Ensuring need allocation and compliance flexibility to address future load migration between LSEs or market exit**. Given California's retail market structure, a program must be flexible to allow adjustments of obligations as load migration occurs.

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[6] The CSP tool assigns emissions associated with the CAISO system's dispatchable thermal generation and unspecified imports to each LSE based on its planned resource portfolio. The tool uses clean energy generation profiles to calculate how much the LSE plans to rely on CAISO system power to meet its load on an hourly basis.
[7] For example, a centralized auction could involve all suppliers providing the volume-price pairs for the resource attributes they can offer, and LSEs doing likewise to bid for these, and then a clearing price being found where the supply and demand volumes meet.

- **Risk mitigation strategies to account for inaccuracies or errors in need determination, allocation, compliance, and enforcement**: The new program could have features to identify and mitigate errors by staff, the CPUC, LSEs, and suppliers. Some would be inherent to a programmatic approach (e.g., routinely updating forecasts and assumptions) whereas some could be additional features (e.g., requiring compliance showings far enough in advance to enable backstop procurement to occur).

Similar to the fundamental elements, some of these additional features of the program design may be formalized in the IRP proceeding, some may be better addressed in other venues (Power Charge Indifference Adjustment (PCIA) reform, Provider of Last Resort (POLR) regulations, etc.), and some may be deemed unnecessary.

5. Designing for Reliability

This section describes the range of approaches to be considered under each of the four program elements.

5.1. Need Determination

A reliability need determination sets the system reliability need that will be met through the new procurement program. There are three key questions for how to set the need.

5.1.1. Technical Methods for Determining Reliability Need

The collective procurement of all LSEs must add up to the "Total Reliability Need" of the system, which must include a cushion to account for a variety of uncertainties. The first step to setting this need is the determination of a physical "reliability standard." Most, but not all, utilities and regional transmission organizations (RTOs) in the United States have adopted a physical reliability planning standard to minimize the risk of rotating outages. Historically, the LTTP and IRP process have planned to, and based procurement orders on, a probabilistic reliability standard consistent with common industry practice: loss of load events must be limited to no more than 1 day every 10 years. Staff notes that loss of load probability (LOLP) modeling considers the performance of all existing and planned resources during all hours of all simulated years. Thus, both the energy and capacity dimensions of the reliability challenge are assessed.

Using this probabilistic reliability standard, a LOLP model can be used to determine the total effective capacity[8] megawatts (MW) needed to achieve that standard across a broad range of potential weather and load conditions. This is akin to the planning reserve margin (PRM) study undertaken in the IRP planning track as part of setting LSEs' filing requirements for their 2022 IRP plans. This study is using Strategic Energy & Risk Valuation Model (SERVM) to calculate the Total Reliability Need in perfect capacity MW, which can be expressed as a PRM percentage relative to the median peak demand. The new program's need determination could be routinely updated by LOLP modeling in the IRP planning track. Methods for counting resources toward the need will be discussed in the "Compliance" section below. These should take into account renewable generation conditions as well as the possibility of forced outages of generating units. Aligning resource counting methods with the method used to set the total reliability need would provide efficient procurement incentives.

There are alternatives to using a probabilistic reliability standard and LOLP modeling to set total reliability need. A simple deterministic model could be used, such as planning to a constant PRM (as the CPUC did with a 15 percent PRM for many years) using a resource stack analysis and applying effectiveness assumptions to particular resources. Alternatively, a combination of probabilistic and deterministic approaches can be utilized to explore certain extreme conditions that drive reliability need. It is worth noting that PJM, Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), Southwest Power Pool

[8] The terms effective load carrying capability (ELCC), effective capacity, and perfect capacity are all commonly used as synonyms to clarify that the MW of capacity being referenced are measured relative to the equivalent reliability contributions of a perfect capacity resource. This conceptual resource is fully dispatchable and has no uncertainty associated with its availability and input fuel or resource.

(SPP), and ISO New England (ISO-NE) all use a regularly-updated probabilistic reliability analysis to set forward capacity procurement requirements, as do many vertically-integrated utilities in their integrated resource plans. These independent system operators (ISOs), RTOs, and utilities take this approach to ensure that reliability procurement matches system needs as loads and resources evolve.

The recently adopted monthly 24-hour slice approach for the RA program is effectively a hybrid of probabilistic and deterministic approaches to set the total reliability need. The new RA framework will set the hourly demand plus a reserve margin for each month based on the day of that month which has the highest coincident peak (using the median load forecast).

The RA program also establishes local reliability needs, and historically the LTPP proceeding authorized procurement for local resources. If local reliability requirements were to be incorporated into the new procurement program, it is presumed they would align with the existing local capacity technical study methods used by the CAISO to set local reliability obligations.

If a marginal ELCC based approach to compliance were taken, discussed in the "Compliance" section below, then to determine the need, the total system reliability need would be adjusted to represent the marginal system reliability need during the net peak.

5.1.2. Expression of Reliability Need

The LOLP-based method for determining need expresses the need in terms of effective capacity, which is useful for a capacity-based approach to compliance. However, the need could be translated from capacity into firm energy terms if the compliance element of the new program were designed to be based on energy contracts. It would be necessary to develop a methodology to translate from the Total Reliability Need in perfect capacity MW to an equivalent annual energy amount, in firm MWh. "Firm" MWh would refer to the fact that the energy must be supplied at the right time in order to maintain reliability.

5.1.3. Scope of the Need Addressed by the Procurement Program

Once the total reliability need of the system is known, the new procurement program would be used to either address this entire procurement volume in forward procurement requirements or only a subset of the need deemed to be most critical. The current IRP procurement track has ordered procurement only for the new resources required to fill the gap between existing and in-development resources (minus planned and forecasted retirements) and the estimated total system reliability need. Meanwhile the planning track of the IRP process requires each LSE to identify a mix of new and existing resources to meet their load share. Plans most recently filed by LSEs in the IRP proceeding collectively demonstrate that LSEs expect to procure additional new resources than those required by current procurement orders. However, the absence of an actual requirement for the planned additional procurement is causing some market uncertainty that can be addressed by the CPUC adopting and implementing the new procurement program in 2023. The IOU bundled procurement plans already require IOUs to layer in contracts for existing resources to maintain stable procurement costs and the ability of IOUs to meet RA program obligations. The CCAs and ESPs submit their individual IRPs, but they do not have a CPUC-enforced obligation to procure energy or capacity beyond the current requirements of the RA and RPS programs, and the IRP procurement orders.

Weaving the need to maintain LSE autonomy as well as reliability within the confines of the CPUC's regulatory authority, there appear to be three key options for the scope a new program that establishes mid-to long-term forward procurement obligations on LSEs:

1. **All resources (existing plus new)**: An expanded scope for this new program could consider existing resources as well as new resources. This approach would allow LSEs to procure from existing resources, new resources, or any combination they desire, through competitive bilateral procurement solicitations. This approach would recognize that existing and new resources ultimately provide the same reliability attributes (e.g., an existing solar resource provides the same marginal reliability value as a new solar resource of the same size). A holistic program that includes both new and existing resources requires that all of the forward reliability requirement be procured to ensure that the total existing plus new contracted capacity will be sufficient to meet reliability goals. Such a program allows direct competition between existing and new resources to determine market entry and exit.
2. **New resources only**: Alternatively, the current IRP focus on new resources could be continued, via a programmatic approach to set and track the ongoing procurement requirements for new resources. This approach would require that new resources are built, remain contracted to CAISO LSEs, and are continuously offered into the CAISO market. This approach would not facilitate direct competition between existing and new resources as part of the program, instead requiring the CPUC to assume how many existing resources will remain, and rely on the CAISO wholesale market, the RA program's near-term contracting requirements, and/or backstop procurement mechanisms to maintain existing resources as needed.
3. **New resources and partial coverage of existing resources**: This program type would set a total forward reliability obligation with a sub-requirement for new resource procurement. This type of sub-category is similar to the RPS program's requirement for a portion of an LSE's procurement to be met with long-term contracting, which tends to drive new resource procurement even though new resources are not required. This option could cover all of the forward total reliability need, or it could cover a portion of the total need, in which case it would rely on the CAISO wholesale market, RA program, and/or backstop mechanisms to retain the remaining resources needed. Existing and new resources would not be in direct competition because a separate obligation for new resources would be defined; however, LSEs could choose to procure more than their new resource requirement as an alternative to contracting with existing resources.

5.2. Need Allocation

Reliability need allocation starts from the total need determined and allocates that need to each LSE.

5.2.1. Allocation Approaches

In the RA program and past IRP reliability procurement orders, the allocation of system need to LSEs was done based on each LSE's share of the year-ahead CAISO managed peak, as determined by the RA proceeding and the California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) forecast. This approach uses the single hour of the CAISO managed peak forecast in the IEPR to allocate system need. It is a simple calculation and generally captures the contributions of each LSE to the system peak.

The appropriate LSE load share to use could depend on what resource counting rule is used, as discussed in detail in the "Compliance" section below. If an average ELCC approach is used for resource counting for compliance, then the Total Reliability Need, which can be represented by the peak demand plus a planning reserve margin, is allocated to LSEs. This allocation would be done using managed peak share or the gross peak share, which in practice would be calculated with an adjustment to the managed peak to account for behind-the-meter resources counted on the supply side via ELCC. If, instead, a marginal ELCC-based approach is taken for resource counting, then an improvement could be to utilize the LSE load share during the *net peak* instead of the *managed or gross peak*, i.e., the system load after accounting for both customer solar, utility-scale solar, utility-scale wind, and possibly other non-firm resources like energy storage as well. While the managed peak already captures some shift of reliability-challenged conditions to the later evening, using net peak share would more precisely align the allocation of need with the hours of greatest system stress.

Under the RA program's 24-hour slice approach, LSEs must meet their 24-hour gross load forecast plus a reserve margin, for each month. The 24-hour forecast to be used is for the day of the month with the highest coincident peak in the median load forecast.

If designing a program that required compliance in the form of energy contracts rather than capacity contracts, the reliability need in terms of firm MWh would require allocation to LSEs using a similar 'causation' principle as above. It could be based on each LSE's share of peak load or share of energy.

5.2.2. Frequency of Allocation

The frequency of updates to LSE need allocation should generally align with the frequency of the forward showings. For instance, LSE need allocation could be updated at the start of each two-year IRP cycle. Updates could occur annually if compliance showings were required on an annual basis. If the allocations were updated as load share changes the issue of load migration could be somewhat mitigated, although the allocations should be locked in for a suitable time window before being subject to the next regular update, to ensure sufficient clarify for LSEs.

5.3. Compliance

Regular reliability compliance filings via standardized reporting templates will allow LSEs to show that their procurement is sufficient to meet their forward reliability obligations. There are key program design questions for setting these compliance requirements. Backwards-looking reviews to confirm that the required resources actually came online, or remained online, would also be necessary. These reviews are more straightforward and are not laid out in detail at this stage.

5.3.1. Resource Counting Towards Compliance

For reliability planning and procurement, resources count towards an LSE's allocated need based on the rules established by the CPUC. These resource counting rules should be established in a modeling framework that is consistent with that used for the need determination. For instance, if LOLP modeling is used based on a target reliability standard, then LOLP modeling using that same model and same reliability standard should be used to credit resources for compliance. LOLP modeling can be used to estimate the ELCC of each resource type. This is a metric for the expected contribution to reliability that the resource type will make over a given period of time (staff expects an annual ELCC is appropriate for procurement for the mid- to long-term, whereas the RA program uses monthly ELCCs). For ELCCs, there are three options and choosing among them is dependent on many factors, especially the scope of the program chosen per section 5.1.3, and discussed below:

1. **Marginal ELCC**: Resources would be credited based on their marginal contributions to reliability with all other resources within the portfolio included. For instance, if solar penetrations have shifted the net peak outside of the solar hours, then solar resources would tend to have a low marginal ELCC. Marginal ELCCs are most aligned with principles of economic efficiency to value a product based on its marginal value to the market. The CPUC already uses marginal ELCCs for new procurement valuation in the IRP and RPS programs, to ensure that economically efficient marginal resource decisions are made. To use them comprehensively for both existing and new resources, the total procurement need is adjusted by the difference between the total portfolio ELCC of all resources and their marginal ELCC value. The resulting value is known as the "marginal reliability need" and can be conceptualized as the resource need during the net peak hours. This value will actively adjust as the portfolio evolves over time. This adjustment reduces the MW targeted based on lower MW counted using marginal ELCCs. It does not impact system reliability or the total portfolio ELCC achieved.

   Refer to the Appendix for a diagram and further explanation of the implementation of a marginal ELCC approach.

2. **Average ELCC**: Resources would be credited based on their share of the total reliability contributions of the resource portfolio. This method requires measuring the ELCC of a portfolio of resources (e.g., a portfolio of solar, wind, and batteries) and then developing methods to allocate that total to individual resource types within the portfolio (e.g., solar, wind, and battery resource types). If solar penetrations have shifted the net peak outside of the solar hours, then under an average ELCC framework, the solar resource type would be assigned the reliability value associated with that shift in its accreditation percentage, as well as its share of any interactive effects with other resource types, even though it has much lower value on the margin. Because average ELCC values capture the total reliability contribution of each resource type, their sum would equal the total reliability need of the system. This also means they do not represent the marginal benefit of each resource type, and therefore do not provide an economically efficient measurement of the marginal benefit of market entry or exit.

3. **Vintaged marginal ELCC**: Resources would be credited based on their marginal ELCC when they enter the market, and this value is vintaged as additional resources are added to

the system. For instance, if solar penetrations have shifted the net peak outside of the solar hours, then under a vintaged marginal ELCC framework, the first increment of solar would get high value, the next less value, and the last increment would get low value, based on the marginal ELCC in the year of its addition. This approach attempts to assign reliability value for each resource based on the order in which they entered the market. However, it becomes complex in application, because load growth, load shape changes, and resource changes all impact the reliability value of past procurement. Therefore, separate additional ELCC studies must be completed for each vintage of procurement (e.g., a pre-2020 vintage, a 2021-2022 vintage, a 2023-2024 vintage, and so on), and average ELCCs must be developed to allocate interactive effects within each vintage. Moreover, this method can result in resources that are in all ways identical, except for their online dates, being accredited differently. This method will be workload intensive for staff to implement and determine compliance with obligations. This method could also make it challenging for LSEs to predict compliance (in the event a resource is delayed, it may also reduce the resource counting value of the resource, leaving the LSE short on their obligation).

The benefit of using any ELCC approach is that the metric captures each resource's contribution to system reliability across a wide range of system conditions, such as decades of historical weather conditions studied in the LOLP model. Additionally, ELCC methods inherently capture saturation effects that cause declining reliability values within a resource type, as well as interactive effects between different resource types. They also inherently capture both capacity and energy constraints, depending on the system being modeled. As an example, for a high solar and battery storage portfolio, ELCC modeling will capture both whether the system has enough capacity during the net peak hours, and whether the system has enough energy to sufficiently charge the storage. If the system becomes too energy constrained to charge the storage, then after LOLP modeling is performed to update the resource counting "compliance metrics", the marginal ELCC of storage will decline and the marginal ELCC of energy-providing resources (such as solar and wind) will begin to increase. Thus, from a technical reliability planning perspective, a separate energy-based requirement would be redundant.

The specific options for compliance metrics for resource counting will follow from the scope of the program design. Specifically, a marginal ELCC approach might logically be continued for a program focused on new resources only, unless the allocation of new resource procurement to LSEs requires accrediting existing resources to measure each LSE's relative capacity position. For a program that covers both existing and new resources, any of the three ELCC methods may be used, though each has its pros and cons. Note that all ELCC methods are based on forecasts of future system portfolios, based on online and in-development resources today, and on a forecast of additional resources needed (like the portfolios developed in the IRP planning track).

Scope of Program	Allocation Method	Compliance Metric for New Resources	Compliance Metric for Existing Resources
New resources only	"Peanut butter" based on peak load share	• Marginal ELCC	• N/A
	LSE capacity position-based	• Marginal ELCC	• Marginal ELCC • Vintaged Marginal ELCC • Average ELCC
Existing plus new resources	Share of total system need	• Marginal ELCC • Vintaged Marginal ELCC • Average ELCC	

Assuming a program that covers both existing and new resources, the pros and cons can be summarized as:

Compliance Metric	Pros	Cons
Marginal ELCC	• Provides an efficient investment signal for marginal resource decisions (e.g., what is the reliability value of adding another solar plant) • Feasible to implement	• Assigns less credit to specific LSEs for their past procurement
Average ELCC	• Assigns more credit to specific LSEs for past procurement (e.g., which LSE bought the solar that lowered and shifted the net peak) • Feasible to implement	• Does not provide economically-efficient measurement of the marginal benefit of market entry or exit
Vintaged Marginal ELCC	• Provides an efficient investment signal for marginal resource decisions	• Complex to implement • Differently credits resources, that are otherwise identical, based on their online date

The RA program's 24-hour slice approach uses different types of compliance metrics for different resource types. For wind and solar, it uses an exceedance methodology, i.e., an hourly production forecast that the resource is sufficiently likely to meet or exceed, instead of the previously adopted ELCC method. For standalone batteries, the LSE must show sufficient excess capacity in other hours to charge batteries in support of their dispatch.

A program that uses an energy-based (instead of a capacity-based) accounting system may use another compliance metric to value different resource contributions to LSE need. One such approach to compliance is the standardized fixed-price forward energy contract (SFPFC) requirement discussed in the RA proceeding R.19-11-009.[9] Staff proposed this mechanism as an option to address reliability concerns in the RA reform track. The approach assumes that requiring LSEs to enter mid- to long-term forward energy contracts with suppliers gives those suppliers a stronger incentive to meet demand for all hours of the year than under a capacity-based requirement, and this reasoning is discussed further in section 7 in the context of market power risk. Although the SFPFC requirement was not adopted for the RA program, the approach could be considered for this program.

A SFPFC would be defined as a contract for 1 MWh of energy over the compliance period (e.g., a year) with an hourly shape that is retroactively adjusted based on the *realized* system load. For example, if total system load in the year turns out to be 1,000,000 MWh, with load of 500 MWh in hour 1 and load of 1,000 MWh in hour 2, then a single SFPFC would represent a commitment in hour 1 of 0.0005 MWh (500 MWh divided by 1,000,000 MWh, multiplied by 1 MWh) and 0.00010 MWh in hour 2. The use of the realized shape is to incentivize suppliers to proactively manage the risk that demand in any given hour may be higher than expected. In contrast, if their contracted hourly quantities are precisely known in advance, they may have incentive to offer the portion of their supply that is in excess of these quantities at significantly higher prices. Each LSE's allocated firm energy procurement need would be in terms of a certain number of SFPFCs for the compliance period. Because the SFPFC hourly contractual quantity is based on realized *system* load, LSEs would still need to consider their own risk management and product innovation to affect the difference between system load and their own load shapes.

LSEs or their suppliers would need to show that the underlying resources owned or contracted by the suppliers are sufficient to support the SFPFC obligations. This would be based on the same LOLP modeling described above to calculate each resource type's ELCC, translated into a firm energy equivalent. For example, for 1 MW nameplate capacity of a resource type with a 10 percent annual ELCC, the supplier would be eligible to sell only up to a certain amount of SFPFCs for a particular annual compliance period: 8760 hours multiplied by 0.10, which is 876 SFPFCs.[10]

5.3.2. Forward Compliance Requirement

Once each LSE's need is established, as well as the method for counting resources against that need, then the LSE needs to know what the CPUC expects for forward contracting relative to the need. The following are key components of defining a forward compliance requirement:

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[9] Refer to 'Addendum to Staff Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009', February 26, 2021, available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M372/K082/372082582.PDF

[10] For more information on the SFPFC approach, refer to:

- RA 3.B.2 January and February 2021 workshop materials available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history
- D.21-07-014 available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF
- Game-based investigation of standardized forward contracting for long-term resource adequacy https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/SFPFC_paper_published.pdf

- **Years covered:** Compliance requirements will set which years are covered by each filing. As an example, upon program start-up, the first year of coverage could start 5 years ahead, and the last year of coverage could be 10 years ahead. In this case, if the LSE is filing in year 2024, it would need to show some amount of forward contracting for the years 2029-2034. Once the program has reached steady state, say by 2028, the LSE would be showing forward coverage for all years through 2038. Compliance would be based on the rolling 10-year-ahead period. As an alternative, to avoid overlapping with RA program showings, there could be some form of conversion of need and compliance requirements at around the 3-year-ahead mark.
- **Volume of need covered in each year:** For each year covered, the CPUC will need to define what fraction of LSE reliability need must be met by resources under contract. For example, 100 percent of the 5-year-ahead LSE need could be required to be under contract, declining to 25 percent of LSE need 10 years ahead. Continuing with the same example, by 2028 the LSE is showing 100% of its need is covered through 2033, declining to 25 percent of its need in 2038.
- **Proof of contracting:** The CPUC will need to specify how LSEs will demonstrate that they have executed the requisite contracts. This could range from legal attestations to providing the actual contracts. Alternatively, resources could be assigned tradable certificates akin to Renewable Energy Certificates (RECs) to reflect their reliability "attribute," i.e., their total credited effective capacity or firm energy.
- **Persistence of the attributes:** The effectiveness of the program may be undermined if the new resources that are committed via forward contracts to provide the necessary attributes to the CAISO system are able to serve other balancing areas after coming off contract. This matter ties to the scope of the need determination discussed in section 5.1.3. If the scope is all resources (existing plus new) then the program could inherently incentivize LSEs to retain the optimal new and existing resources over time, to meet their rolling requirements. However, if the scope is new resources only, additional compliance features may be necessary to encourage or require persistence.
- **Frequency of compliance filings:** Compliance filings could be annual, aligning with relevant milestones of each two-year IRP cycle, or could be more or less frequent. More frequent filings increase the administrative burden for the CPUC and LSEs, but adapt more quickly to LSE load migration and changing system conditions.

5.3.3. Streamlining Filings

All LSEs are already required to submit annual compliance reports to demonstrate procurement of renewable resources needed to comply with the RPS. These filings are submitted in the RPS proceeding, R.18-07-003. To minimize time and effort for LSEs and staff, the program design should consider whether the new procurement reporting and tracking requirements can be combined with the current annual RPS compliance reports.

5.4. Enforcement

Enforcement strategies are critical, particularly for reliability planning, to ensure that LSEs that fail to meet their obligations do not threaten grid reliability for the system as a whole. To address

LSE non-compliance, financial penalties, backstop procurement, or both, can be considered. Any enforcement would be consistent with the CPUC's Enforcement Policy.[11]

5.4.1. Triggers: When Enforcement Becomes Necessary

For a forward reliability program, there are multiple stages when enforcement may be required, including:

- Failure to file a compliance showing;
- Failure to contract for some portion of the required compliance showing;
- Failure to show sufficient amounts or types of underlying resources to support their contracts;
- Failure of contracted or owned resources to meet significant project development milestones;
- Failure to bring enough resources online and/or to retain existing resources to meet the requirements, even if the LSE previously filed a sufficient compliance showing;
- Failure of LSE-contracted resources to perform when called upon in the CAISO real-time market.

Staff notes that to be effective, enforcement would likely need to be triggered based on the performance of each LSE, irrespective of whether LSEs' collective procurement is sufficient.

5.4.2. Financial Penalties

Financial penalties are one tool to disincentivize non-compliance. D.21-06-035 – the mid-term reliability procurement order – established penalties,[12] and the existing RA program recently increased penalties for non-compliance. Given that this new program will be on a multi-year forward basis, financial penalties could begin when LSE fails to show sufficient forward contracting as dictated by the program requirements. If the first showing in 2024 covers 5-10 years out, then LSEs could be charged financial penalties for failing to show sufficient contracting in 2024 for resources delivering in the 2029-2034 period. As the program reaches a steady state, LSEs could also be charged financial penalties for failing to show sufficient contracted existing (depending on the program's scope) and/or new resources in the 0-5 year timeframe, whether via the program or via the RA program's year-ahead view. This would continuously penalize LSEs over multiple years for failing to procure their share of system needs.

For the penalty amount to be high enough to promote compliance, it should make the costs of non-compliance greater than the cost of compliance. It could be set at a multiplier of the net cost of new entry (net CONE) for a new resource. Without a multiplier, and absent other financial consequences, LSEs may be indifferent to paying the penalty versus paying for a new resource. A "net CONE with multiplier" is a common penalty metric in other RTO reliability planning programs.[13] In SPP, the multiplier increases or decreases based on by how much the amount of procured resources exceeds the total reliability need. The closer the procured amount

[11] Available at this website: https://www.cpuc.ca.gov/regulatory-services/enforcement-and-citations

[12] At section 10.2 of the dicta of D.21-06-035, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF

[13] For example, at section 14.2 of Attachment AA of the SPP Tariff, available at: https://spp.etariff.biz:8443/ViewerDocLibrary/MasterTariffs//5FullTariff.pdf

is to the total need not being met (i.e., SPP's established planning reserve margin), the higher the multiplier.

Financial penalties could have unintended consequences such as getting passed through to ratepayers without improving reliability, or prompting suppliers to make offers higher than they otherwise would have. The CPUC will have to consider this when establishing what sort of penalties should apply to the new program.

Under the forward energy contracting approach using SFPFCs, if the checks on the firm energy equivalent of the supplier's resources found them insufficient, that supplier would be required to sell some of its firm energy obligations. Market dynamics would determine what reduction they receive relative to their originally awarded contract price. Direct penalties would be reserved for acts of complete noncompliance or negligence by LSEs.

5.4.3. Non-financial Enforcement

It may be appropriate for the program design to consider the role of a non-financial enforcement action such as the suspension or removal of an LSE's license to serve load. Such enforcement may be warranted given the significant implications of the electric sector not being reliable or the state not meeting its GHG-reduction goals, and would likely be applicable in instances of repeated non-compliance rather than as an initial enforcement action.

5.4.4. Backstop Procurement

While penalties would financially penalize non-compliant LSEs, the new program must still ensure reliability procurement needs are met. Therefore, backstop procurement may be necessary, with costs assigned to the deficient LSEs. The program design will need to strike a balance between ordering backstop procurement with enough lead time for successful construction of new resources and allowing non-compliant LSEs to come back into compliance (while paying their penalty costs). The program will also need to be clear which entity or entities should conduct the backstop procurement, and whether they should also face the threat of backstop related to their own procurement obligations.

If backstop procurement is necessary, then the program design will need to consider the suitability of the modified cost allocation method (MCAM), which is applied to the two existing IRP procurement orders (D.19-11-016 and D.21-06-035), to determine whether it is feasible on a long-term basis. MCAM allocates procurement costs by IOUs on behalf of a subset of LSEs, whether for backstop or front stop[14] reasons; however, it does not address load migration. Ensuring that backstop procurement costs follow load migration could require customer tracking in IOU billing systems, which could be difficult and slow to implement. Without customer tracking, backstop procurement costs could be shifted on to the remaining LSE customers, which could be significant if there is large-scale load migration or LSE failure.

[14] Staff notes that 'front stop' procurement, which is procurement performed by the IOUs for LSEs that opted out of self-providing as allowed for in the first IRP procurement order (D.19-11-016), is not contemplated in the context of program design. Per section 2, the more recent CPUC requirement is for all LSEs to self-provide perpetuates with limited exceptions.

6. Designing for GHG-Reduction

6.1. Need Determination

6.1.1. Establishing 2030 and post-2030 Targets

In order for the new program to reduce emissions, a GHG reduction target will need to be established for specific years. The IRP planning track has an established process for determining GHG planning targets for the electric sector. In 2022, the 2030 target was set at 38 million metric tons (MMT), and two 2035 planning targets were set at 30 MMT and 25 MMT based on the trajectory to meet 15 MMT in 2045, consistent with the SB 100 clean electricity goal as modeled in that scenario. A program requires translating these planning targets into an actionable metric for jurisdictional LSEs. Any future changes to the electric sector GHG target are expected to be made in the IRP planning track. Translating that GHG target into a procurement obligation could occur via this program's design. The need for procurement to reduce emissions will be based on the planning track's GHG target and the number of new resources required to achieve that target.

6.1.2. Hourly vs. Annual-based

There are at least two options for translating the planning track GHG target into a programmatic requirement for LSEs:

1. **Hourly emissions accounting**: The hourly "need" would be set based on the GHG target in the planning track. Then, LSE requirements would be established as mass-based GHG emission targets (e.g. 38 MMT CO2-equivalent in 2030). LSEs would count resources towards this GHG limit based on a similar approach to the IRP planning track, using the Clean System Power (CSP) hourly emissions accounting calculator. Separate CSP calculator-like tools may need to be developed for a forecast of hourly system emissions (for forward showings) and for actual historical system emissions, depending on whether and how the CPUC decides to check LSE compliance against actual system conditions that occurred (load levels, hydro availability, thermal plant dispatch, etc.).
2. **Annual energy-based accounting**: The annual "need" would be established by translating the electric sector GHG target into an annual energy-based requirement. This approach is aligned with the current RPS program, in which LSEs count generated MWh within a compliance period toward a MWh target. Energy requirements could be set based on the latest RSP or PSP adopted in the IRP proceeding. The percentage requirements may increase if load forecasts increase, so that the CPUC can ensure the electric sector overall will still meet its mass-based GHG planning target.

6.1.3. Clean Energy Standard

If an annual energy-based accounting approach is used, one implementation option would be to create a Clean Energy Standard (CES), potentially modeled on the RPS program, where procurement requirements are based on the latest system optimization model runs in the planning track to meet the electric sector GHG target.

A new CES would have a definition of eligible resources adjusted from the standard RPS rules. Non-RPS eligible resources that are zero-carbon, such as large hydropower and nuclear, could be eligible for the CES. Some RPS-eligible resources like unbundled RECs may be ineligible for a CES if they do not contribute to reducing emissions to support meeting the CAISO's electric sector GHG target. The CES percentage could be defined based on the CES percentage in the latest RSP or PSP.

It should be noted that SB 100 explicitly added non-RPS eligible zero-carbon resources to its 2045 policy goal of serving retail loads with 100 percent RPS and zero-carbon generation. Therefore, adoption of a CES could facilitate the transition of SB 100's 100 percent clean electricity by 2045 goal into a post-2030 compliance obligation for LSEs. The RPS program could exist side by side, or it could eventually be combined into a single program if allowed by statute.

At face value, increasing the RPS requirement would also increase the level of LSEs' renewable generation, thereby reducing emissions and helping to meet the electric sector GHG target. However, increasing the RPS would not create a compliance framework for SB 100, which means that a programmatic GHG reduction mechanism such as a CES or an hourly mass-based approach that allows for non-RPS-eligible renewable and zero-carbon generation and implements SB 100 would still be needed.

6.2. Need Allocation

Under an hourly emissions-based approach, the need is expected to be allocated based on the LSE-level share of CAISO-wide or statewide load and GHG emissions (LSE load share within each IOU service territory multiplied by the annual emissions ascribed to each service territory). An hourly CSP-based GHG target allocation would follow the same approach as currently used in the IRP planning track to establish LSE level GHG targets, based on LSE share of statewide load in the latest IEPR forecast. In that case, the LSE need metric is a mass-based GHG target (tons CO2-equivalent).

An annual energy-based CES approach could follow the same allocation method as currently used in RPS by setting a CES percentage of load target, with each LSE's need being defined as its annual energy sales multiplied by the CES percentage. In this case, the LSE need metric would be an annual MWh target for CES-eligible generation.

6.3. Compliance

Compliance could be demonstrated by LSEs according to the following options.

For the hourly accounting mass-based target, LSEs could input their contracted portfolios into a CSP calculator. The CSP calculator could be integrated into the LSE IRP filing, showing only the existing and contracted resources (without the "planned" resources that are the focus of the planning track). The CSP calculator would show that LSEs meet their share of the electric sector GHG target in each year required as part of that compliance showing, based on a specified amount of GHG-based forward contracting required determined by the CPUC. For example, 100 percent of the 5-year-ahead LSE need could be required to be under contract, declining to 25 percent of LSE need 10 years ahead.

One challenge of this approach is the necessity to use a forward-looking projection of power plant dispatch and hourly emissions rates. Actual dispatch and emissions during the compliance period will necessarily depart from the forward-looking assumptions used during the procurement period, and periodic "ground-truthing" analysis would likely be needed to compare actual emissions to modeled emissions and determine if adjustments are needed to the forward-looking assumptions. Hence, an additional program design consideration is whether "backward-looking" compliance checks would also be necessary. One option for backward-looking compliance checks would be using actual historical loads, resource availability, and thermal dispatch in another CSP calculator-like tool that would measure whether LSEs met their GHG target based on actual system conditions. This backwards-looking compliance check could be integrated in some way with the reporting to customers done in the CEC's Power Content Label to show historical emissions content for each LSE. Another option could be simply assessing whether LSEs brought online all the resources that they included as contracted resources in their forward-showing CSP calculators. When assessing different backwards-looking compliance options and how to reconcile them with forward showings, it is important to consider that utilities and electric generators are also subject to cap-and-trade and the Power Content Label requirements. These complementary regulatory structures should inform the level of rigor needed within the Reliable and Clean Power Procurement Program to ensure ex post facto emissions reductions.

A complication of a backward-looking approach is whether changes to power plant dispatch, e.g., paying a premium to import additional hydropower from the Northwest rather than dispatching a California gas generator, would have an impact on compliance with the GHG target. Such an activity would result in lower GHG emissions in the CAISO area, but may not be able to qualify under a program focused exclusively on forward resource procurement. Another complication of backwards-looking compliance is that LSEs generally do not control the dispatch of their contracted facilities—the CAISO does. As such, LSEs would likely need to hedge against the risk of their resources being dispatched differently from expectations to avoid a GHG-free energy shortfall at the end of a compliance period.

For the energy-based CES, LSEs' compliance could also be demonstrated through a combination of forward showings and backwards-looking checks. The RPS program already includes forward and backwards showings. Under a CES, the forward showings could be similar to RPS procurement plans whereby the LSE would submit filings to show how it is planning to meet its procurement requirements. The forward showings could demonstrate that LSEs have a certain portion of their program procurement obligation under contract. The timing of these showing could be coordinated with when an LSE submits its forward reliability filings.

The backwards-looking compliance checks under a CES would be designed to show that the LSE-procured resources actually generated the required quantity of clean or renewable energy, and could follow the same approach as the RPS program today where compliance is assessed after a multi-year compliance period using a compliance instrument akin to a REC. Given the historical success of RPS in driving new renewable energy development and its familiarity among LSEs, there could be merit in intentionally designing a CES to closely resemble many of the rules and regulations of RPS. This could include:

- **Compliance periods** to allow for inter-annual variability in loads and resources. These could be set to align with the 3–4-year compliance periods of the RPS program or some other time interval more aligned with the IRP planning track or the proposed forward contracting requirements of this program.
- **Western Renewable Energy Generation Information System (WREGIS)-based certification of generated MWh** to create credits that must be retired at the end of a compliance period. An expanded WREGIS database capable of tracking GHG-free generation would be needed. The credits eligible for compliance could include RECs and a new WREGIS-certified credit instrument—Zero Emission Credits.
- **REC eligibility rules** defining which Product Content Category (PCC) buckets qualify as GHG-free generation for compliance use in the CES.
  - PCC 1: A renewable resource located within the state of California or, a renewable resource that is directly delivered to California without energy substitution from another resource.
  - PCC 2: A firmed and shaped renewable resource that is out-of-state and delivering to California, where the Renewable Energy Credits are paired with a substitute energy resource imported into the state.
  - PCC 3: An unbundled REC from a resource, delivered without the energy component.
  - PCC 0: A REC from a procurement contract or ownership agreement signed, or utility-owned generation in commercial operation before June 1, 2010.
- **Banking** of GHG-free energy and whether it should be permitted for a CES program. Staff is not aware of any statutory restrictions that would prevent banking under a CES.
- **Resource eligibility rules** to define which technologies, beyond those already eligible under the RPS, would qualify as GHG-free. Large hydro and nuclear resources would likely qualify, but program design should consider the eligibility of others such as natural gas with carbon capture and sequestration, demand-side resources, and distributed energy resources.

The benefit of giving LSEs both forward-showing and after-the-fact compliance obligations is that the forward showing requires LSEs to maintain a trajectory toward achieving their long-term goals and enables earlier use of enforcement actions that may compel earlier procurement. The after-the-fact obligation keeps LSEs accountable to their procurement plans and gives all parties more incentive to achieve a project's commercial operation date. An after-the-fact compliance obligation can also create more options for LSE compliance, enabling greater use of short-term contracts and spot market transactions, particularly if this is paired with a reduction in the share of an LSE's compliance obligation that needs to be shown through a forward-contracting requirement. Requiring some minimum amount of compliance to be met through forward contracting would be a similar concept to the existing requirement in the RPS program, where 65 percent of procurement must be derived from long-term contracts.

Finally, another compliance consideration that would inform program design for GHG-reduction is that while SB 100 sets a state policy that 100 percent of all retail sales of electricity should be supplied by renewable and zero carbon resources by 2045, there is not currently a regulatory framework or compliance program in place to ensure that LSEs are on track to achieve that goal. As noted earlier, program design should seek to create that regulatory framework and ultimately be used to ensure that all CPUC-jurisdictional LSEs comply with the 100 percent renewable and zero carbon resource requirement of SB 100.

6.3.1. Streamlining Filings

All LSEs are already required to submit annual compliance reports to demonstrate procurement of renewable resources needed to comply with the RPS. These filings are submitted in the RPS proceeding, R.18-07-003. To minimize time and effort for LSEs and staff, the program design should consider whether the new procurement reporting and tracking requirements can be combined with the current annual RPS compliance reports.

6.4. Enforcement

Triggers may include an LSE failing to show its minimum portion of renewable/clean energy under contract to meet its GHG-reduction requirement in its forward showings, as well as failing to show "after the fact" that it achieved those reductions.

Under a mass-based approach, penalties could be assessed on a $/ton basis for GHG emissions in excess of the LSE's forward contracting requirement for GHG reductions, or a backwards-looking after-the-fact assessment of LSE progress based on their after-the-fact CSP calculator emissions or based on an assessment of whether the LSE brought online all its contracted resources. Similarly, under the CES approach, penalties would be assessed on a $/MWh basis. As with the RPS program, penalties could be based on a specified schedule, and the size of the penalty may increase when the shortfall is greater; however, a cap on the total penalty may be warranted.

Program design should consider whether and how to assess penalties in cases where the LSE had met the contracting requirement for GHG reductions in previous IRP cycles, but nevertheless did not achieve those reductions after the targeted year had passed.

7. Other Program Design Considerations

The preceding sections discuss ways of addressing the reliability and environment externalities. Here staff discusses the financial risk and market power externalities. Refer to the Appendix for descriptions of these.

Staff also raises the matter of past and centralized procurement. It relates to both reliability and GHG-reduction, and would affect LSEs' compliance.

7.1. Financial Risk and Risk of LSE Market Exit

The CPUC has adopted and implemented a process to return customers to the IOU in the event of a CCA failure. The IOU is also entitled to receive reasonable cost recovery for being designated and providing service as the POLR. The CPUC currently has an open proceeding (R.21-03-011) to consider new rules that might be needed to ensure that state reliability and GHG compliance programs are maintained and on track and that the POLR can recover its costs to avoid shifting new costs onto bundled customers. The POLR proceeding will also consider the requirements and processes to designate an alternate LSE to serve as POLR. Most issues related to this program that would emerge in the event of LSE bankruptcy would be within scope of the POLR proceeding, however there may be other issues related to the risk of LSE bankruptcy that could be within scope of this program design. For example, the program design will need to consider how the POLR meets the reliability and GHG reduction targets for the load of the returning customers that it might assume, and how the associated costs are recovered.

Another consideration for this procurement program is whether the CPUC can and should regulate the financial risks being taken on by LSEs within the context of their retail load service, to mitigate any risks of stranded costs being shifted onto bundled customers. The SFPFC approach described in section 5 requires firm energy contracting that may sufficiently mitigate LSEs' financial risk, or alternative approaches may be necessary.

7.2. Risk of Market Power

Some of the features of the SFPFC approach are designed to mitigate the risk of market power being exerted in the electricity market. To the extent that the RA program and the new program focus on capacity contracting (with only must offer obligations but no energy bidding requirements) rather than energy hedging, consumers could be exposed to high energy prices due to the bidding behavior of resources with RA-only contracts. This exposure could arise from individual LSEs not hedging sufficiently, and procuring much of their energy from the short-term market. RA-only contracts fulfil the existing regulatory obligations of RA and much of the first two IRP procurement orders, but they allow resources to bid high prices during scarcity hours and extract high energy rents. Currently, IOU-controlled resources subject to CPUC bidding behavior rules, as well as energy hedging by ESPs and CCAs, help mitigate this market power, but the proportion of the total supply stack that is affected may not be high enough. A regulatory requirement for LSEs to enter firm energy contracts, such as via program design using the SFPFC approach, should place strong incentives on generators to provide energy when it is needed, rather than bid or take other actions that result in their capacity being withheld. To progress with the SFPFC approach would likely require assessing generator market power and finding that current incentives for LSEs to hedge, existing arrangements such as the Resource Adequacy Availability Incentive Mechanism, or other new physical capacity-based requirements, are insufficient to mitigate it.

If the SFPFC approach was taken in the way described in 'Addendum to Staff Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009'[15] it would involve centralized auctions rather than bilateral procurement processes. Staff observes potential benefits of transparency this would offer, including quality control over the awarded contracts. Staff notes the centralized auctions are also aimed to mitigate the risk of market power of large LSEs over small LSEs. Specifically, the use of a clearinghouse to pool counterparty risk is in part intended to enable LSEs, regardless of size, similar access to contracts with suppliers. Staff expects that the CPUC would need to assess this form of market power to be significant enough to warrant taking a centralized auction approach, noting the associated concerns raised in R.19-11-009 regarding potential FERC jurisdiction and other potential implementation challenges. Implementation delay concerns were raised by some parties, who contended that use of a centralized auction and clearinghouse approach to price and procure energy would result in legal and jurisdictional challenges about increased oversight by FERC. Such concerns were not resolved in R.19-11-009.

7.3. Past and Centralized Procurement

As flagged in section 2, under California's retail choice paradigm, each LSE is generally expected to self-provide to meet the needs of its customers. However, there are instances such as load departure and centralized procurement that cause one LSE to procure on behalf of the customers of other LSEs. In those instances, as noted in the recent IRP decision D.22-05-015 adopting MCAM, the CPUC seeks to follow the cost causation principle where costs are borne by, and benefits are credited to, the customers on behalf of whom they were procured.

Under the Cost Allocation Mechanism (CAM), the attributes as well as the cost of centrally procured resources count toward their RA obligations. As such, LSEs might be similarly able to claim the capacity and renewable/GHG-free attributes of resources subject to CAM in the new procurement program.

Under the PCIA, the allocation of attributes was addressed in D.21-05-030, a CPUC decision that considered the use of a Voluntary Allocation and Market Offer (VAMO) mechanism for RPS, GHG-free, and RA attributes of IOU procurement subject to the PCIA.

- For RPS attributes, D.21-05-030 approved VAMO and established a process where IOUs offer PCIA-eligible LSEs an allocation of the RPS attributes of an IOU's PCIA-eligible RPS portfolio and attempt to sell any unallocated resources through a subsequent market offer process. VAMO has been established for the current RPS compliance period, and will be re-evaluated in advance of future compliance periods.
- For non-RPS GHG attributes, D.21-05-030 rejected VAMO citing a lack of sufficient record to support adoption or rejection of a GHG-free allocation methodology.

[15] Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M372/K082/372082582.PDF

However, the CPUC has separately approved interim allocations of PG&E's and SCE's nuclear and large hydro GHG-attributes.

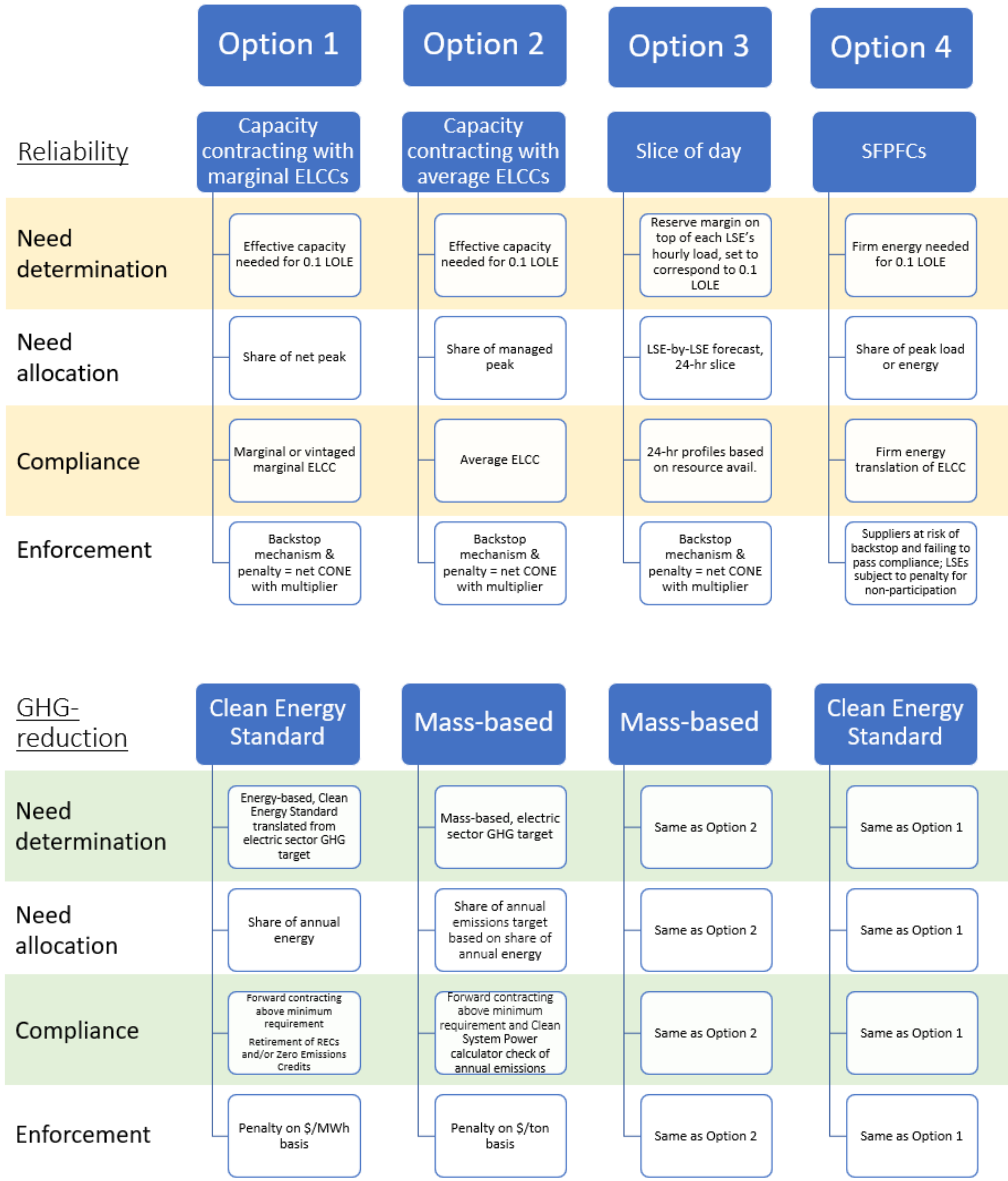
- For RA attributes, D.21-05-030 rejected VAMO citing several reasons specific to the application of the specific VAMO proposal to the RA program.

Staff sees these aspects of D.21-05-030, and any future decisions affecting resource attributes, as particularly relevant to how past and centralized procurement would be treated for compliance with the new program.

8. Straw Options

The following options represent different permutations of the procurement design elements and additional features described above. In some instances, staff defines these straw options with very specific elements and features in order to help illustrate more clearly the meaning of the design concepts; staff expects that there may well be other design settings that could be just as, or possibly more likely, to achieve the program's objectives. Further, staff notes that particular reliability and GHG-reduction design elements and features have been grouped simply to illustrate how they could work together. In practice, staff does not expect that the choice of reliability design necessitates particular GHG-reduction designs, and vice versa.

Schematic summary of staff's straw options:



Detailed description of staff's straw options:

Design Element or Additional Feature	Option 1	Option 2	Option 3	Option 4
Summary	LOLP-based forward capacity contracting requirement using marginal ELCCs Energy-based CES. Mix of forward showings in CPUC-approved filing templates and after-the-fact reliability capacity checks and energy credit retirements.	LOLP-based forward capacity contracting requirement using average ELCCs. Mass-based GHG reduction requirements. Forward showings in CPUC-approved filing templates and after-the-fact reliability capacity checks.	Slice of day capacity requirement using estimates of resource availability per slice. Mass-based GHG reduction requirement. Forward showings in CPUC-approved filing templates, and after-the-fact reliability capacity checks.	LOLP-based forward energy contracting requirement using firm energy equivalent of ELCCs. GHG reduction via energy-based CES using a mix of forward showings in CPUC-approved filing templates and energy credit retirements.
General				
Procurement entities	All LSEs must self-provide			(Even for SFPFCs LSEs self-provide via bilateral procurement processes. i.e., under this option there would not be the centralized auctions that were proposed as part of the SFPFC approach discussed in R.19-11-009)
Scope of the need addressed	All resources (existing plus new)			
Compliance – showings	LSEs provide all contract information in a resource data template (RDT)-like template, which will then be analyzed using a reliability tool and a clean energy assessment tool. LSEs would additionally need to retire RECs and/or Zero Emission Credits sufficient to meet their CES requirements.	LSEs provide all contract information in an RDT-like template, which will then be analyzed using a reliability tool and a GHG calculator tool.	Same as Option 2 and noting the reliability tool and GHG calculator tools may be able to be combined into a single tool that analyzes a portfolio's reliability and GHG emissions at the same time because they have similar hourly granularity.	Same as Option 1 and noting that an LSE in bundled clean energy contracts could have their SFPFC obligation reduced by the firm quantity of the clean energy contract, or monetize the firm attributes of the contract in the secondary SFPFC market
Compliance – forward requirement – years covered	Rolling 10 years ahead. Upon program initiation, the first year of coverage starts 5 years ahead and the last year of coverage is 10 years ahead. After 5 years the new program would reach a steady state, with a rolling forward requirement covering years 0-10 ahead.			
Compliance – frequency of showings	Annual filings, with every other year aligning with IRP Planning Track filings. In addition, LSEs need to retire their required quantity of RECs and/or Zero Emission Credits at the end of each 3–4-year compliance period, timed to align with RPS compliance periods.	LSE submits annual filing, with every other year aligning with IRP Planning Track filings.		Same as Option 1
Approval	Rely on the CPUC's existing requirements for approval of IOU procurement, including applications			SFPFCs are standardized to meet new program requirements and so IOUs have pre-approval to enter these, similar to how they can enter contracts in accordance with their Bundled Procurement Plan

Design Element or Additional Feature	Option 1	Option 2	Option 3	Option 4
Reliability-related				
Need determination	System Marginal Reliability Need to meet 0.1 LOLE, routinely updated by LOLP modeling in the IRP planning track	System Total Reliability Need to meet 0.1 LOLE, routinely updated by LOLP modeling in the IRP planning track	Need is set in conjunction with allocation to LSEs described below. The reserve margin is to apply to all months and should be set so that system reliability meets the 0.1 LOLE standard.	Firm energy translation of effective capacity necessary to meet 0.1 LOLE, routinely updated by LOLP modeling in the IRP planning track
Need allocation	LSE's Marginal Reliability Need set based on their share of total system need, measured as net peak demand plus PRM	LSE's Total Reliability Need set based on their share of total system need, measured as managed peak demand plus PRM	For each month LSEs must meet their 24-hour gross load forecast plus a reserve margin. 24-hour load forecast is for the day of the month with the highest coincident peak.	Set based on LSE's share of peak load or share of energy. To facilitate translation of this into a mandated financial forward energy hedging requirement, the CPUC defines a SFPFC. 1 SFPFC is 1 MWh, with the hourly energy requirement retroactively adjusted to the realized load shape. For each annual compliance period out to 10 years in the future, on a rolling basis, each LSE is set amounts of SFPFCs that they are required to procure, based on their share of total system need.
Need determination & allocation – frequency	LSE Need could be updated annually before compliance showings are due or bi-annually at the start of each IRP cycle.			
Compliance – resource counting	Marginal or vintaged marginal ELCC	Average ELCC	24-hr profiles based on resource availability	LSEs must show enough SFPFCs to cover their need. Suppliers must demonstrate the physical feasibility of the underlying generation and storage sources. This would be based on the ELCC for each resource type, multiplied by the number of hours in the compliance period, to set the maximum amount of SFPFC energy a supplier can sell.
Compliance – forward showings	100 percent of the 0 to 5 year ahead LSE reliability need must be under contract, with that declining to 25 percent of LSE need 10 years ahead. To avoid overlapping with RA program showings, there could be some form of conversion of need and compliance requirements at around the 3 year ahead mark. Resources must have must offer obligation (except under Option 4 where this is replaced by suppliers having a strong financial incentive to be available and bid at marginal cost). Where LSEs are showing contracts that are supported by new resources they need to demonstrate physical feasibility with evidence of meeting applicable development milestones sufficiently in advance of the compliance period (e.g., executed interconnection agreement).			

Design Element or Additional Feature	Option 1	Option 2	Option 3	Option 4
Compliance – backward showings	Similar to above, where new resources are involved, LSEs must show evidence of online status. If the RA program is in place then this is unnecessary since it already addresses physical capacity.			
Enforcement	Backstop procurement mechanism. Penalty for non-compliance set at a multiplier of the net cost of new entry (CONE), with the multiplier increasing or decreasing based on by how much the total amount of procured resources exceeds the total reliability need. The closer to the total need not being met, the higher the multiplier.			Backstop procurement mechanism with cost allocation to the supplier. Suppliers are at risk of selling SFPFCs at a discount if they do not pass physical feasibility checks. SFPFC approach obviates explicit capacity or energy-based penalty structure on LSEs however CPUC would reserve right to serve an unspecified penalty on a LSE for not participating.
<u>GHG-related</u>				
Need determination	CES. LSE is assigned an annual clean energy percentage requirement.	Mass-based GHG requirement. LSE is assigned annual GHG benchmarks (MMT) for a subset of years across the planning horizon based on the electric sector GHG target, and shows compliance with their benchmarks using an hourly emissions calculator.		Same as Option 1
Need allocation	Set CES percentage of load targets, with each LSE's need being defined as its annual energy sales multiplied by the CES percentage.	Set LSE level GHG targets, based on the LSE share of CAISO-wide or statewide load in the latest IEPR forecast and GHG emissions. LSE load share within each IOU service territory would be multiplied by the annual emissions ascribed to each service territory to calculate individual LSE GHG targets.		Same as Option 1
Compliance – resource counting	Every MWh of contracted renewable energy or non-RPS-eligible clean energy would be demonstrated through a REC and/or Zero Emission Credit. LSEs would report their forward-contracted and planned clean and renewable energy amounts in an RDT-like tool that could be analyzed to assess an LSE's projected CES percentage.	Every MWh from contracted renewable and clean energy is entered into the CSP calculator, which is assessed for annual emissions based on an hourly load-resource balance calculation.	Same as Option 2 and noting the reliability aspects may be able to be integrated into the CSP calculator because they have similar hourly granularity.	Same as Option 1
Compliance – forward showings	50 percent of the 5- year- ahead LSE clean energy need must be under contract, with that declining to 12.5% of LSE need 10 years ahead. The forward showing requirement is less than 100% because the use of credits creates more options for how LSEs can show compliance.	100 percent of the 0 to 5 year ahead LSE GHG need must be under contract, with that declining to 25% of LSE need 10 years ahead.		Same as Option 1
Compliance – backward showings	100 percent of an LSE's required RECs and/or Zero Emission Credits must be	LSE must show that it brought or kept online all the resources that it included as contracted in its forward showings at the end of a 5-year compliance period.		Same as Option 1

Design Element or Additional Feature	Option 1	Option 2	Option 3	Option 4
	retired at the end of a 3–4-year compliance period.			
Enforcement	Penalty set on a $/MWh basis, similar to the RPS program, based on a specified schedule	Penalty set on a $/ton basis for GHG emissions in excess of the LSE's forward contracting requirement for GHG reductions.		Same as Option 1

9. Conclusion

In this paper, staff presents a list of objectives for development of a new procurement program in IRP focused on ensuring that LSEs procure the reliable and clean resources needed to achieve the state's goals. Staff describes a range of fundamental design elements and as well as additional features that may be needed for the program to be successful. Building upon those design elements and other considerations, staff has developed several straw options, representing different potential programmatic structures, that could be implemented to achieve staff's stated objectives.

These options are not intended to be mutually exclusive—indeed some design elements could be mixed and matched across two options, while others may be incompatible—nor do they represent the only possible programmatic structures that could be implemented. Staff is using this options paper as a means for advancing the conversation with stakeholders on the design of a procurement program to be adopted by the CPUC.

10. Appendix

10.1. Why Procurement Regulation is Necessary

California's electricity system continues to be shaped by decisions made during the era of market restructuring in the 1990s. This process facilitated the development of new energy market institutions such as the competitive electricity market operated by the CAISO. The CAISO's optimization ensures least-cost operations through its day-ahead and real-time energy markets. However, energy markets themselves are insufficient to incentivize key investments required for California's energy goals. Two key market failures or "externalities" of the wholesale energy market are:

1. **Reliability**: In most – but not all – wholesale energy markets, including in California, electricity prices are capped to prevent excessive customer costs during scarcity conditions. While this allows generators to recover their variable costs of operations, it does not allow them to recover their fixed costs of building new "steel in the ground," i.e., constructing new power plants to enter the market – even with the additional capacity payments to generation through the short-term RA program. This externality must be addressed to ensure that new resources are built to replace retiring generation and meet load growth.

2. **Environment**: Without policy intervention, energy markets will select only the least-cost resources to operate, not the least-carbon resources, and while in some cases low-carbon and/or carbon-free resources are lower cost than carbon intensive resources, this is not guaranteed. Consequently, since California has set the ambitious goal to meet economywide carbon neutrality by 2045 and has adopted a trajectory of decreasing emissions from the electric grid, this externality must be addressed. Methods for addressing the environmental externality include internalizing the cost of emissions (as via the California Air Resources Board (CARB) cap-and-trade carbon price) and/or adopting policies to ensure LSEs serve their load with increasingly lower emissions portfolios of resources.

There are two other potential externalities that a programmatic approach to procurement could address:

3. **Financial Risk**: If LSEs are insufficiently hedged via physical or financial hedging instruments, they may face high costs to cover their load during scarcity conditions. These types of conditions are increasingly probable as the system is in load and resource balance and increasingly experiencing variations due to the high penetrations of variable renewable energy interacting with already highly variable loads. If extreme conditions lead to high prices, these LSEs may be unable to pay the costs incurred to serve their load and are no longer able to operate, and their losses may end up socialized across all ratepayers. This externality can be addressed by a regulatory program that provides some amount of hedging or risk management requirement for LSEs, similar to existing guidelines and approval of risk management strategies that the CPUC approves for IOUs through the adoption of their Bundled Procurement Plans (BPPs).

4. **Market Power**: When a market participant is able unilaterally to impact the market price of a product, by manipulating the level of supply and/or demand, that market participant has market power. There are various ways that market power may occur in a bilateral retail energy market like California's. Generators may have market power over LSEs . Certain LSEs could, in theory, also have market power over other LSEs, absent sufficient regulation. There are various options to mitigate market power, depending on the type.

While each of these four externalities represents a unique and different challenge for the CPUC's administration of the California system, it will be important for the CPUC to evaluate how its regulatory approach facilitates achievement of each of these objectives. Each procurement decision an LSE makes will have an impact on the system's ability to achieve each of these objectives; for example, procurement of a solar resource provides significant quantities of clean energy, but will provide decreasing reliability and risk hedging value as daylight hours become saturated over time with solar energy. A holistic approach is needed that will recognize the distinct but interconnected nature of these challenges while providing strong incentives for LSEs to make least-cost procurement decisions.

The IRP planning track is exploring improvements to align the forward capacity planning aspect of LSEs' IRPs with the determination of total reliability need and resource counting metrics, derived from robust loss of load probability modeling. This framework could be used to inform the design of the reliability aspects of the new/extended procurement program; some of the design options discussed in this document explore this, whereas others use different approaches.

The environmental externality is currently addressed for electric generation via the CARB cap-and-trade price, the RPS program, and the IRP planning track. In the IRP planning track, the CPUC has adopted a GHG target of 38 MMT by 2030, which IRP modeling shows requires further investment by LSEs than would be incentivized via the cap-and-trade price or the RPS program. Therefore, additional programmatic solutions are warranted to incentivize LSEs to construct the GHG-free resources necessary to achieve the GHG reduction target.

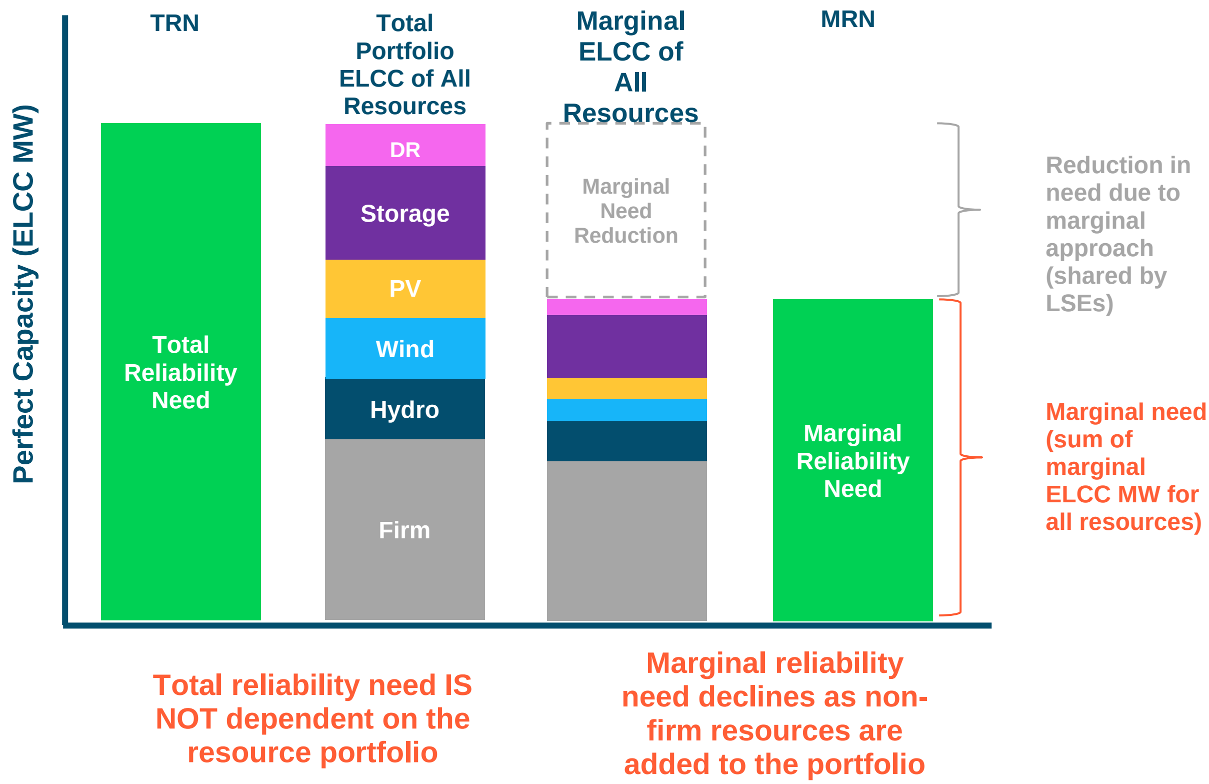
While the reliability externality could be solved by a robust physical reliability capacity procurement program, the financial risk externality may be best addressed by a forward energy and/or hedging requirement for LSEs. This could be similar to guidelines and approval of risk management strategies the CPUC previously approved for IOUs through the adoption of their BPPs. However, other LSEs may have different goals and market risk preferences than the CPUC would have previously set for IOUs.

10.2. Implementing a Marginal ELCC Approach

Further to the discussion in section 5.3.1, implementation of a marginal ELCC approach is illustrated in the following diagram. A marginal ELCC approach uses lower marginal ELCC percentage values but also reduces the MWs that LSEs need to show.

- Need Determination: Use the Marginal Reliability Need (MRN) instead of the Total Reliability Need (TRN)

- MRN is calculated as the sum of marginal ELCC MW for all resources in the portfolio
- Need allocation: can use LSE load share during net peak (or managed peak if not available)
- Resource counting: Use marginal ELCCs for all resources
  - Effectively captures resource contributions during net peak hours



10.3. Interim Approaches to Programmatic Procurement

Staff understands that establishing the new program will require significant stakeholder and CPUC focus and in addition, there may be implementation tasks that risk delaying the program taking effect. To help manage risks of delay, staff poses ideas on interim approaches that could be taken in parallel with development of the new procurement program.

Both of staff's interim options build off the stakeholder engagement in the IRP proceeding regarding "bottom-up" procurement discussed during the development of the PSP in 2021. The PSP ruling[16] and comments considered possible ways for the CPUC to take procurement action in conjunction with adopting the PSP.

[16] August 2021 ALJ Ruling Seeking Comments on Proposed Preferred System Plan, available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M399/K450/399450008.PDF

The first interim option would require LSEs to procure directly what they include in their individual integrated resource plans, whereas the second would put that in terms of resource attributes.

10.3.1. Resource-specific Interim Option

Under this option each LSE must procure each resource type according to the amounts and timings in their plan.

For example, if an LSE included 100 MW of thermal, 100 MW of solar, and 100 MW of wind in their 2022 IRP for the year 2030, then in 2024 they would be required to show forward contracting of some percentage of those resource types. Under this interim approach, LSEs would be responsible for implementing a percentage of their 2022 IRPs, with the percentage measured as a share of the total MW in their plans. To implement this option, LSEs would need to submit compliance filings, which might be similar to those that LSEs file for the existing IRP procurement orders, to show that they have the required resources under contract. Non-compliance would be subject to enforcement proportional to the extent of non-compliance.

10.3.2. Attribute-based Interim Option

Under this option each LSE must procure the GHG-free GWh and effective capacity in their plan sufficient to achieve their assigned GHG benchmarks and reliability need.

For example, if an LSE included contracted and planned resources in their 2022 IRP sufficient to meet their 2030 GHG benchmark and reliability need as measured by the CSP calculator and Resource Data Template (RDT), then in 2024 they would be required to show forward contracting of resources with attributes sufficient to meet some percentage of their 2030 GHG benchmark and reliability need. Under this interim approach, LSEs would be responsible for implementing a percentage of their 2022 IRPs, with the percentage measured as a share of their GHG benchmarks and reliability need. To implement this option, the existing CSP and RDT templates would likely need to be re-designed for compliance reporting. Non-compliance would be subject to enforcement proportional to the extent of non-compliance.

10.4. List of Acronyms

ALJ	Administrative Law Judge
BPP	Bundled Procurement Plan
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CCA	Community choice aggregator
CEC	California Energy Commission
CES	Clean Energy Standard
CO2	Carbon dioxide
CONE	Cost of new entry
CPUC	California Public Utilities Commission
CSP	Clean System Power
D.	Decision
DR	Demand response
ELCC	Effective load carrying capacity
ESP	Electric service provider
GHG	Greenhouse gas
IDER	Integrated Distributed Energy Resources
IEPR	Integrated Energy Policy Report
IOU	Investor-owned utility
IRP	Integrated resource planning
ISO	Independent system operator
ISO-NE	ISO New England
LOLE	Loss of load expectation
LOLP	Loss of load probability
LSE	Load-serving entity
LTPP	Long-Term Procurement Plan
MRN	Marginal reliability need
MISO	Midcontinent Independent System Operator
MMT	Million metric tons
MCAM	Modified Cost Allocation Method
MW	Megawatt
NYISO	New York Independent System Operator
OTC	Once-through cooling
PCC	Product Content Category
PCIA	Power Charge Indifference Adjustment
PJM	PJM Interconnection
POLR	Provider of last resort
PRM	Planning reserve margin

PSP	Preferred System Plan
R.	Ruling
RA	Resource adequacy
RDT	Resource Data Template
REC	Renewable Energy Credit
RPS	Renewables Portfolio Standard
RSP	Reference System Plan
RTO	Regional transmission organization
TRN	Total reliability need
SB	Senate Bill
SERVM	Strategic Energy & Risk Valuation Model
SFPFC	Standardized Fixed-Price Forward Energy Contract
SPP	Southwest Power Pool
WREGIS	Western Renewable Energy Generation Information System

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