BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking To Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 (Filed February 11, 2016)

REPLY COMMENTS OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION ON THE ENERGY DIVISION STAFF PROPOSAL FOR IMPLEMENTING INTEGRATED RESOURCE PLANNING

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In compliance with the schedule set forth in the Administrative Law Judge's Ruling Modifying Schedule issued June 13, 2017 (Ruling), the Independent Energy Producers Association (IEP) is pleased to provide these reply comments related to the Staff Proposal on Process for Integrated Resource Planning (issued May 16, 2017). In response to parties' opening comments, we address the following matters: (1) LSE IRP Planning and Procurement Obligations, (2) Expedited Procurement, (3) Backstop Procurement, and (4) SB 350 Compliance.

1) LSE IRP Planning and Procurement Obligations

Public Utilities Code Section 454.52(a)(1) directs the Commission to adopt a process for each jurisdictional load-serving entity (LSE), as defined in Section 380, to file an integrated resource plan (IRP) (subject to periodic updates) to ensure that the CPUC-jurisdictional LSEs achieve seven specific goals as prescribed therein. In addition to these seven common goals, the Commission was directed to ensure that electrical corporations fulfill their obligation to serve their customers at just and reasonable rates.[1] In IEP's Informal Comments filed October 2016, we noted that the PU Code effectively demands that the Commission determine whether the individual LSE's IRP Plans collectively represent a portfolio of resources to match the goals and objectives prescribed in Section 454.52(a)(1).[2]

A number of parties addressed the extent to which all jurisdictional LSEs will be treated uniformly with regard to establishing a process to file an IRP at the Commission. The investor-owned utilities (IOUs) support uniform treatment across all jurisdictional LSEs.[3] On the other hand, advocates for community choice aggregation (CCA) argue that the IRPs of the individual CCAs only need be "consistent" with the IRP criteria established in Section 454.52(a)(1) given Section 454.52(a)(3).[4] The CCAs also recommend adoption of a new IRP guiding principle: namely, that the IRP process should not authorize or require IOUs to procure resources to serve load that is reasonably expected to depart.[5] The CCAs suggest that the need for additional RPS resources and resources for system reliability is very unlikely in the near and even medium term, and they argue that entering into additional procurement would not be prudent, would increase risk, and would provide little benefit.[6]

IEP offers a number of observations related to this issue. First, the IRP Framework must clarify the roles and obligations expected of CCAs as part of the integrated resource planning process. IEP is concerned that the Staff Proposal fails to address exactly what is expected of the CCAs even though they are a critical input into statewide integrated resource planning and

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[1] PU Code Section 454.52(a).
[2] Informal Post-Workshop Comments of the Independent Energy Producers Association on the Proposed Analytical Framework for Integrated Resource Planning (October 14, 2016), p. 13.
[3]Opening Comments of Pacific Gas and Electric Company, p. 7; Comments of Southern California Edison Company, p. 6ff; Comments of San Diego Gas & Electric Company, p. 9ff.
[4] Comments of the California Community Choice Association, Appendix A-2.
[5] Ibid, p. 7.
[6] Ibid, p. 24.

subject to the Commission's authority with regards to implementing Section 454.52. The CCAs reference the Staff White Paper indicating that the amount of load served by non-IOU providers could more than triple from 25% at the end of 2017 to 85% in the mid 2020s.[7] As a practical matter, IEP fails to understand how the Commission can realize its obligations under the statute to ensure that the individual LSEs "do" that which is prescribed in Section 454.52(a)(1) without applying comparable, if not completely uniform, processes and standards of review on all CPUC-jurisdictional LSEs including CCAs.

Second, IEP is concerned that the lack of specificity in the Staff Proposal related to CCA obligations risks undermining the achievement of the specific criteria established in Section 454.52(a)(1). The CCAs have proposed "self provision" as the standard of review for CCA compliance with their IRP obligations.[8] Self provision entails some risk that one or more CCAs fail to take actions to achieve the criteria/goals prescribed in Section 454.52(a)(1). At what point does the Commission determine that "self provision" is inadequate? The Commission's adopted IRP Framework must provide a specific step in the biennial process at which the Commission (a) determines whether the individual CCA is "doing" that which is prescribed by statute and (b) authorizes actions to make up for deficiencies in CCA IRP planning and procurement.

Third, IEP notes that SB 350 did not remove the core responsibility and obligation borne by the IOUs to serve their customers. While the CCAs argue that the Commission should not authorize or require IOUs to procure resources to serve load that is reasonably expected to depart, the Commission can and should act to ensure safe, reliable service for *all* IOU customers (while meeting state policy objectives) that are customers at the time the Commission takes action.

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[7] Comments of the California Community Choice Association, pp. 23-24.
[8] Ibid, p. 6.

Finally, IEP supports the statement by California Unions for Reliable Energy (CURE) where it notes that the Staff Proposal on page 75 should be modified to clarify that "the relevant IOU will be directed to procure the necessary resources and the cost of this procurement be covered by all customers of the relevant IOU in accordance with existing policy. If there is a gap in resources needed to achieve other state policies, such as GHG reduction or a diverse and balanced portfolio, the CPUC will allocate the costs of the additional necessary procurement to all benefitting, including those of CCAs and ESPs."[9]

2) Expedited Procurement

As noted by IEP in Informal Comments submitted October 14, 2016, planning complexity can undermine timely decision-making. Accordingly, we urged an IRP process designed such that one might reasonably expect to be completed in two years.[10] In opening comments, a number of parties urged the Commission to consider an expedited procurement in the 2018-2019 timeframe in light of these complexities and the risk of delay.[11] IEP concurs.

In support of consideration of expedited procurement, TURN recommends that the Commission take note of the declining federal tax benefits for certain renewable technologies and the value these credits bring to California consumers in the form of lower costs for renewable development. TURN appropriately observes that these federal tax credits significantly reduce the cost of electricity from these resources. Moreover, the declines in the expected cost for new solar and wind projects are not expected to offset the lost value of expiring

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[9] CURE Opening Comments on Staff Proposal on Process for Integrated Resource Planning, p. 3.

[10] Informal Post-Workshop Comments of the Independent Energy Producers Association on the Proposed Analytical Framework for Integrated Resource Planning (October 14, 2016).

[11] Comments of the Center for Energy Efficiency and Renewable Technologies, p. 3; Comments of The Utility Reform Network, p. 13; NRG Energy, Inc., Responses to Questions, p. 5.

tax benefits. Thus, the opportunity cost of delayed procurement could be significant.[12] Similarly, CEERT recommends that procurement should result from the 2017-2018 IRP plans to ensure high capital cost, long lead time, and high benefit resources are procured in a timely manner; to maximize ratepayer savings due to expiring federal incentives; and to account for the known need to replace the output from Diablo Canyon.[13] Finally, NRG Energy notes that it may take more than one IRP cycle to develop a framework that will produce reliable results across all scenarios and futures studies. Therefore, NRG concludes it would not be prudent to defer any and all procurement indefinitely while waiting for the IRP process to mature.[14]

IEP agrees with the value and necessity of taking advantage of the present conditions to minimize impacts on ratepayers' bill as prescribed by SB 350. Certainly the declining value of federal tax incentives for renewables is a compelling reason to conduct an expedited procurement in the 2018-2019 timeframe. As noted by TURN, to realize full value of federal tax incentives, contracts must be approved in early 2019 so that developers can begin construction by the end of 2019 so as to qualify for the full value of the existing federal tax incentives. TURN correctly notes that, although contracts must receive final approval by early 2019, the agreements can be structured to delay an LSE's obligation to purchase electricity to better align with that LSE's actual needs.[15]

IEP concurs with these parties' comments. We recommend that the IRP Framework be more explicit about how and when the Commission may take advantage of unique circumstances to compel expedited procurement to lower costs to consumers. Furthermore, we urge consideration of an expedited procurement in 2018 to ensure access to the full value of the

[12] Comments of The Utility Reform Network, p. 13.
[13] Comments of the Center for Energy Efficiency and Renewable Technologies, p. 10.
[14] NRG Energy, Inc., Responses to Questions, p. 5.
[15] Comments of The Utility Reform Network, p. 13.

existing federal tax incentives to lower customer costs. To ensure selection of the least-cost and best-fit resources to meet future need and lower customer costs, the Commission should employ an all-source, competitive procurement mechanism when implementing the expedited procurement.

3) Backstop Procurement

TURN urges the Commission to develop mechanisms now that could be needed to develop new large-scale system resources that provide benefits to all customers and which are not easily justified based on the needs of a single LSE. TURN offers three mechanisms for consideration:

- Joint LSE Coordination via Master Long-Term Contract;
- IOU-based Procurement on Behalf of All LSES in their service territory; and
- State Agency/CPUC Regulated Third-Party Procurement Entity.

IEP shares TURN's concerns. The disaggregation of load among many small LSEs, including CCAs, undermines economies of scale and, thus, unnecessarily risks an increase in costs and ratepayer bills. The concepts present by TURN merit detailed consideration. Any alternative mechanisms should be evaluated against the need for creditworthy counterparties, timely execution, and transparency.

4) SB 350 Compliance

The Staff Proposal is silent about what happens if an LSE falls short of its efforts to realize the goals prescribed in Section 454.52(a)(1). In our Informal Comments, IEP noted that if an LSE fails to meet reliability standards, consistent with Section 454.52(a)(2)(A), the

Commission should order procurement to ensure grid reliability and to see that each load-serving entity meets the goals prescribed in Section 454.52(a)(1).[16]

As noted above, in addition to meeting the greenhouse gas emission reduction targets established by the Air Resources Board, all CPUC-jurisdictional LSEs pursuant to Section 454.52(a)(1) are obligated to do the following: procure at least 50 percent eligible renewable energy by December 31, 2030; minimize impacts on ratepayer bills; ensure system and local reliability; strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities; enhance distribution systems and demand-side management; and minimize localized air pollutants and other greenhouse gas emissions.

As noted by TURN, the Staff Proposal provides few meaningful and explicit criteria for determining whether individual LSE IRP plans are consistent with state goals and the "preferred resource plan" other than GHG reduction.[17] Equally important, the Staff Proposal lacks a full discussion of what happens if an LSE is determined to be out of compliance. We urge the Staff to fill in this information gap, because the matter of integrated resource planning will depend on the extent to which the obligations are real or ephemeral.

In conclusion, IEP appreciates the opportunity to provide these reply comments on the important topic of IRP. As noted above, IEP submitted Informal Post-Workshop Comments on October 14, 2016 related to the matter of the IRP Framework. We incorporate those comments here as Attachment A for the record as these comments related in whole or in part to parties' formal comments submitted on June 28, 2017. We look forward to continue working with the

[16] Informal Post-Workshop Comments of the Independent Energy Producers Association on the Proposed Analytical Framework for Integrated Resource Planning (October 14, 2016), p. 15.
[17] Comments of The Utility Reform Network, p. 17.

Commission on developing an IRP framework and to coordinate long-term procurement planning requirements.

Respectfully submitted July 12, 2017 at San Francisco, California.

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By *<u>/s/ Steven Kelly</u>*
Steven Kelly

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Attachment A

Informal Post-Workshop Comments of the Independent Energy Producers Association on the Proposed Analytical Framework for Integrated Resource Planning (October 14, 2016).

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INDEPENDENT
ENERGY
PRODUCERS

October 14, 2016

INFORMAL POST-WORKSHOP COMMENTS OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION ON THE PROPOSED ANALYTICAL FRAMEWORK FOR INTEGRATED RESOURCE PLANNING

As requested by the Energy Division, the Independent Energy Producers Association (IEP) submits these informal post-workshop comments on the analytical framework for Integrated Resource Planning (IRP) presented at the IRP workshop on September 26, 2016. IEP will offer some general observations regarding the analytical framework and then respond to the questions posed by staff on September 30, 2016.

I. General Observations

The IRP workshop was focused on developing an analytical framework for the Commission's IRP process. In prior comments to the Commission, IEP noted that the statutory obligation faced by the Commission, i.e., to develop optimal portfolios for purposes of integrating renewables in a least-cost and best-fit manner,[1] while maintaining grid reliability, does not require the Commission to employ complicated optimization and/or powerflow modeling. For the record, IEP repeats that observation here. IEP's overarching recommendation has been to simplify the IRP process to the maximum extent practical to ensure transparency and, equally important, effectuate timely decision-making with regards to the procurement of needed

[1] Public Utilities Code Section 454.51: "The commission shall do all of the following: (a) Identify a *diverse and balanced portfolio of resources* needed to ensure a reliable electricity supply that provides *optimal integration* of renewable energy in a cost-effective manner." [Emphasis added.] All section references are to the Public Utilities Code.

resources.[2] IEP recognizes the difficult task of designing and implementing an efficient and effective IRP process. In this context, we offer our thoughts regarding the proposed IRP Analytical Framework discussed at the workshop on September 26.

A. Planning Complexity Can Undermine Timely Decision-making

IEP is concerned that the intricate and very complex IRP process being considered will not result in timely procurement to meet the reliability needs of the electric grid. The Commission's Long-Term Procurement Plan (LTPP) proceeding was intended to take two years to complete from the commencement of the proceeding to a Final Decision. In practice, however, the process often took 2.5 years to render a Final Decision that was no longer appealable, because of the time required to process applications for rehearing. Thus, an accurate mapping of the LTPP experience historically would show a planning process that often took 30 months to complete.

The proposed IRP Analytical Framework is derived from the LTPP process. The proposed process does not eliminate any of the key steps in the LTPP. Rather, the proposed IRP Analytical Framework adds a time-consuming phase to the LTPP process. Specifically, once a CPUC-approved IRP Reference System Plan (analogous to the LTPP Final Decision) is adopted, the proposal is to initiate a new, additional planning phase to coordinate the Preferred IRP Plans of the various load-serving entities (LSEs) with the CPUC's adopted Reference System Plan. This new phase triggers at least three critical new steps in the planning process: (a) each LSE must develop its own IRP in light of the guidelines and modeling established in the CPUC's Reference System Plan, and they must submit such plans to the Commission for review; (b) the Commission must review, integrate, and essentially cross-check the individual LSEs' Preferred IRPs for overall consistency with the CPUC Reference System Plan; and (c) the Commission

[2] See Informal Pre-Workshop Comments of the Independent Energy Producers Association on the Staff Concept Paper on Integrated Resource Planning, submitted August 31, 2016.

must render a decision approving the individual electric utility's IRP Plans or certifying a Community Choice Aggregator's IRP Plan.

IEP's experience suggests the additional activity presented in the IRP Analytical Framework will easily consume 6 to 12 months above what was typically expended in the LTPP process. These additional activities likely will require at least two Commission rulings or decisions, each of which should properly be subject to stakeholder comments and reply comments. We conclude that the proceeding under the proposed IRP Analytical Framework will not be completed within 24 months as suggested, but *it more likely will take 30-36 months to complete the planning process*.

One of the downsides to a lengthy planning and procurement process is the inevitable dis-connect between the original data inputs and assumptions and the actual conditions in the market at the time final decisions approving resource procurement and agreements need to be rendered. Historically, this gap has been approximately 3(+) years. Under the proposed IRP Analytical Framework, the gap may well reach 5 years or more. This time gap between original data inputs and final decision-making will foster litigation. This long delay will enable parties opposing selected resources to argue that circumstances have changed, that the resource is no longer needed, or that the procurement of the resource is inconsistent with state needs. This litigation would result in further delay in decision-making.

Moreover, while the proposed IRP Analytical Framework assumes near flawless and seamless integration of modeling from other entities (e.g., the California Energy Commission (CEC), the California Independent System Operator (CAISO), and the individual LSEs), IEP is concerned that these critical planning activities and their necessary data inputs into the IRP process likely will get out of sync with the Framework schedule. Historically, as a precursor to the Commission's LTPP process, the CEC developed a Demand Forecast in the first year of its biennial Integrated Energy Policy Report (IEPR). Similarly, upon receipt of the Demand Forecast (from the CEC) and Scenario Assumptions (from the CPUC/CEC), the CAISO initiated its one-year Transmission Planning Process (TPP), which also is conducted on a two-year cycle, but this cycle lagged the CEC planning process to align the two processes with the Commission's biennial LTPP process. While the biennial CEC IEPR and the biennial CAISO TPP planning processes integrate reasonably well with the biennial LTPP, IEP is concerned that these processes will not align well with what may be a 3-year IRP process.

B. Complexity Undermines Transparency and Stakeholder Participation

The time devoted to modeling activities in the proposed IRP Analytical Framework is an indicator of the complexity involved and the prospect for delay. Based on the calendar graphic presented at the workshop, fully 6 months of the 24-month planning process is set aside for modeling activity: (a) 3 months to conduct loss of load probability (LOLP) Modeling (CPUC) and Power Flow Modeling (CAISO) in Year One, and (b) 3 months to conduct Capacity Expansion Modeling (CPUC) in Year Two. This represents 25% of the months available to complete the planning process. Clearly, this represents a tremendous investment in modeling. While the IRP calendar flowchart shows the LOLP and Powerflow modeling occur in parallel over 3 months, from a stakeholder perspective the time and resource commitment to participate in each 3-month endeavor actually represents six months in total devoted to modeling. When the 3 months for Capacity Expansion Modeling is added to the mix, the expected stakeholder commitment of time and resources to modeling activities is the equivalent of 9 months of effort.

The magnitude of this commitment of time and resources is a barrier to stakeholder participation. Ultimately, as stakeholder participation declines, the transparency of the planning process to stakeholders also will decline. IEP is concerned that the lack of participation and transparency will foster litigation and prolong decision-making.

Furthermore, to the extent that individual planning processes conducted on a biennial basis (e.g., the CEC Demand Forecast and/or the CAISO TPP) become misaligned with what appears likely to be a three-year IRP planning process, the validity of many of the key inputs into the IRP will be questioned, due to factors such as the staleness of data inputs and changed market circumstances. IEP is concerned that this process will undermine the integrity of the record on which the Commission must base its final decisions regarding IRP adoption and any procurement authorizations that result. This ought to be of concern to all parties.

II. The IRP Planning Cycle Should Be Compressed To Ensure Timely Completion Within 2 Years

IEP has expressed concern that the proceeding proposed in the IRP Analytical Framework is not likely to be completed in 24 months. Rather, it looks to be a 30-36 month process. When combined with the typical 18-24 month procurement process (from preparation of the solicitation documents to Commission approval of the resulting power purchase agreements), the proposed IRP Analytical Framework will likely result in a planning and procurement cycle of five years or more, which cannot be considered to be timely and effective decision-making.

The Public Utilities Code requires individual LSEs to submit IRP plans to the Commission.[3] The Code requires the Commission to review those IRP plans.[4] The plans of Community Choice Aggregators (CCAs) are to be consistent with specified policy objectives.[5] Finally, the Code provides the Commission the discretion to authorize electrical corporations to procure additional resources to ensure compliance in a timely manner with the policy objectives, if the Commission determines individual LSEs are not making reasonable progress toward the

[3] § 454.52(a)(1).
[4] § 454.52(b)(1).
[5] § 454.52(b)(3).

specified policy goals.[6] Moreover, the Code enables the Commission to allocate any costs of such additional procurement by the electrical utilities to all customers, including the customers of non-utility LSEs.[7]

To fulfill the Commission's IRP role, the proposed IRP Analytical Framework envisions 5 steps in the IRP planning process: (1) Develop Assumptions; (2) Evaluate Reliability Needs; (3) Develop Reference System Plan (CPUC); (4) Develop Preferred LSE Plans (individual LSEs); and, (5) Evaluate and Approve LSE Preferred Plans (in the context of the CPUC Reference System Plan). This process entails extensive modeling, and much of the modeling appears redundant, as illustrated below:

- Step 2: Evaluate Reliability Needs - This step requires *LOLP modeling* (by the CPUC) and TPP *Power-Flow Modeling* (by the CAISO) to assess system and local needs, before the LSEs develop their IRP plans for review;
- Step 3: Develop Reference System Plan – This step requires *Capacity Expansion Modeling* (by the CPUC) to generate optimal portfolios for a set of pre-defined futures in order to calculate a number of metrics to inform the choice of a CPUC-prescribed Reference System Plan, including the need for flexible resources; and
- Step 5: Evaluate and Approve LSE Preferred Plans – This step requires *production cost modeling* to validate system reliability and greenhouse gas (GHG) emissions of aggregated LSE plans.

This approach entails at least 4 separate and relatively complicated modeling efforts. While each modeling effort may provide a discrete and nuanced forecast of what may happen in the future, the future is inherently dynamic such that today's forecast will never match tomorrow's reality, particularly when the modeling effort is looking out 10 or 20 years.

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[6] § 454.52(a)(2)(A).
[7] § 454.52(c).

IEP recommends an alternative framework that is fairly simple; avoids analytical complexity and redundancy; and is more likely to support timely decision-making and effective investment outcomes. This approach is fully consistent with section 454.52.[8] We offer the following alternative framework.

- ***Step 1 (6 months): Along with adopting common assumptions for use by the LSEs, the Commission will develop Portfolios establishing "pathways" to achieve Preferred Policy Objectives:*** In addition to adopting common planning assumptions for use by the LSEs, the Commission should develop clear policy objectives against which LSE IRP Plans and investment will be measured and certified. Moreover, the Commission could recommended a range of portfolios or "pathways" for consideration by LSEs when developing their individual IRP plans to achieve the specific preferred policy objectives (e.g., 50% RPS goal; 50% increase in Energy Efficiency Portfolio; Demand Response portfolio, if any; Combined Heat and Power Portfolio, if any; Storage Portfolio, if any, etc.).

[8] Public Utilities Code section 454.52 prescribes the following:

- (a)(1) "[T]he commission ***shall adopt a process for each load-serving entity, as defined in Section 380, to file an integrated resource plan, and a schedule for periodic updates to the plan, to ensure that load-serving entities do the following", i.e.,.*** meet GHG reduction targets set by the Air Resources Board; procure 50 percent eligible renewable resources; minimize ratepayer bills; ensure system and local reliability; minimize local air pollutants and other greenhouse gas emissions, etc. [Emphasis added.]
- (b)(1) "Each load-serving entity shall ***prepare and file an integrated resource plan consistent with [public policy goals …] on a time schedule directed by the commission and subject to commission review."*** [Emphasis added.]
- (c) "To the extent that additional procurement is authorized for the electrical corporation in the integrated resource plan or the procurement process authorized pursuant to Section 454.5, the commission shall ***ensure that costs are allocated in a fair and equitable manner to all customers consistent with 454.51, that there is no cost-shifting among customers of load-serving entities, and that community choice aggregators may self-provide renewable integration resources consistent with Section 454.51."***

- ***Step 2 (6 months): Evaluate Reliability. This evaluation needs to be based on developed assumptions and scenarios to ensure overall grid reliability.*** This modeling effort remains necessary to assess how best to achieve overall policy objectives while not undermining local and system reliability.
- ***Step 3 (6 months): Direct the LSEs to submit their Preferred Plans consistent with the common assumptions and addressing each of the preferred portfolios or "pathways."*** By moving directly to this step, the Commission would eliminate the Analytical Framework's proposed step to develop a Commission Reference System Plan. By adopting common assumptions and preferred portfolios, and following that work with reliability assessments of local and system needs, the Commission does not need to develop a Reference System Plan. Certainly, there is no need to develop a Reference System Plan for the LSEs who will submit their own plans for certification.
- ***Step 4 (6 months): Review and Approve LSE Preferred Plans (or Certify CCAs' Plans).*** Complete the review/evaluation of the individual LSE IRP Plans for application of the common assumptions, and assess their ability to achieve the prescribed policy outcomes. To the extent these individual IRP Plans fall short of reasonable progress to achieve the prescribed policy outcomes, the Commission should take action, consistent with section 454.52(a)(2)(A) to ensure that each load-serving entity meets the prescribed goals. Section 454.52(a)(2)(A) authorizes the Commission to direct the electrical utilities to conduct additional procurement (via an all-source solicitation) to ensure that each LSE meets the prescribed policy goals. Moreover, to the extent that additional procurement is authorized by the Commission, Section 454.52(c) directs the Commission to ensure that the costs of the additional

procurement are allocated in a fair and equitable manner to all customers of LSEs consistent with section 454.51.

This alternative framework is consistent with the Public Utilities Code. Moreover, this 4-step process is designed to be completed within a 2-year timeframe, which is consistent with the LTPP timeframe that proved fairly successful in developing new and preferred resources in a timely manner while maintaining overall grid reliability.

III. Changed Circumstances Indicate the Commission Should Conduct an All-Source Procurement in 2017/2018 to Help Ensure Grid Reliability

Under the proposed IRP Analytical Framework, 2017 essentially is used as a "test" year to assess modeling efforts and data inputs. Beginning in 2018, the IRP process begins anew with an expected completion in the first or second quarter of 2020. Following a Final Decision, it generally takes 18-24 months for a competitive solicitation mechanism to run its full course ending in the Commission's final and non-appealable decision approving a power purchase agreement. It typically takes 1-3 years for the financing, permitting, and construction of new resources. Thus, as a result of all these steps, resources resulting from capacity addition decisions deferred to the completion of the 2018-2019 IRP process may not be available prior to 2024-2025.

The Commission, however, has recognized the potential need for additional procurement to maintain grid reliability on an as-needed basis during the development phase of the IRP process.[9] In light of the risk of changed circumstances, the Commission stated that it would include long-term system and local reliability needs in the scope of the IRP and, if circumstances

[9] Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements, September 9, 2016, pp. 24-25.

change (as they did with the unexpected retirement of SONGS in 2013), it may become necessary for the Commission to consider any reliability issues that arise.

Since the Commission articulated this policy, two contingencies have emerged that change circumstances sufficiently to warrant consideration of additional procurement in 2017-2018 to help ensure grid reliability. First, in assessing local reliability in Southern California, the CEC Staff Report, "Mitigation Options for Contingencies Threatening Southern California Electric Reliability,"[10] projects electricity surplus or deficit on an annual basis from 2015 to 2025 for five local capacity areas (sub-areas) throughout the Los Angeles Basin and San Diego. The staff employed the Local Capacity Annual Assessment (LCAA) Tool to conduct its assessment. The baseline results show deficits in two key areas—the West LA Basin subarea and the San Diego-Imperial Valley local capacity area—beginning in 2021 and steadily increasing through 2025.[11] The Report states that the baseline results for the combined LA Basin-San Diego subarea closely match CAISO studies for 2021 and 2025.[12]

Second, with regard to the proposal to shut down the Diablo Canyon Nuclear Generating Station, Section 2 of the Joint Proposal presented in PG&E's application proposes to procure about 4,000 GWh of gross energy efficiency and other GHG-free energy to replace the energy production of Diablo Canyon. Diablo Canyon, however, is capable of generating more than 18,000 GWh per year. If the Joint Proposal is approved without change, approximately 14,000 replacement GWh will need to be secured to help ensure grid reliability in 2025, when Unit 2 retires, and each year thereafter. Many parties oppose one or more aspects of the Joint Proposal, including Section 2. As a result of the broad array of issues contested in the Diablo Canyon proceeding, the Commission should anticipate that a final, no longer appealable decision in the

[10] California Energy Commission, Staff Report, Mitigation Options for Contingencies Threatening Southern California Electric Reliability, August 2016 [CEC-200-2016-010].
[11] California Energy Commission Staff Report, "Assessing Local Reliability in Southern California Using a Local Capacity Annual Assessment Tool: 2016 Update." August 2016. Page 14. [CEC-200-2016-011]
[12] Ibid., pp. 14-15.

Diablo Canyon proceeding may not result until 2019 or later. Importantly, initiating replacement of the significant output from Diablo Canyon cannot wait until the litigation concludes. Rather, the Commission should assume that the nuclear units will close at the end of their existing operating permits, and begin the process for replacing the resource in 2016-2017. All resources should have an opportunity to compete to replace the output from Diablo Canyon. Accordingly, an all-source competitive solicitation is the most efficient and cost-effective means to ensure that resources are ready to operate when the individual nuclear units go off-line.

In addition, IEP notes that delaying procurement of renewable resources in light of the expiring federal tax credits and bonus depreciation rules risks significantly higher costs for renewables in the future, when renewables compete in an all-source procurement to meet system needs identified in 2021-2024. In comments on the 2016 utility RPS Procurement Plans, IEP employed the Commission's RPS Calculator to determine the impact of declining federal tax incentives and bonus depreciation between 2019 and 2022.[13] IEP's analysis revealed that the cost of solar and wind resources, which are expected to provide a invaluable supply of energy and capacity to meet the state's policy objectives between now and 2030, increase significantly with the expiration of the federal incentives. For example, the absence of the federal tax credits increases the levelized costs for solar plants by 25%, while the loss of federal incentives available to wind projects increases the levelized fixed costs of wind in 2022 by 13% compared to 2019 costs. Even when taking into account the decline in future technology cost, for every 1,000 MW of resources contracted at the 2022 levelized cost of energy (LCOE) instead of the 2019 LCOE, the **annual** costs would <u>increase</u> by $54 million per year for solar PV ($1 billion over 20 years) and $30 million per year for wind ($600 million over 20 years).

[13] Comments of IEP on RPS Plans, September 1, 2016, Rulemaking 15-02-020.

Accordingly, while the Commission works on perfecting the IRP Analytical Framework in the 2017-2019 timeframe, the Commission should initiate in parallel an all-source procurement process in 2016-2017 to address the resource deficiencies that have a high probability of occurring beginning in 2021 (i.e., South Coast) and again in 2024 and 2025 (Diablo retirement). An all-source, least-cost and best-fit procurement authorized in 2016-2017 would better enable new resources to be fully operational in the 2021-2023 timeframe, rather than risk waiting until 2024 or 2025 if decision-making is left to the process suggested by the IRP Analytical Framework.

IV. Response to Questions Posed by Staff

In this section, IEP responds to specific questions posed by the Energy Division staff related to aspects of the proposed IRP Analytical Framework.

Reliability

1. How often should Loss of Load Probability (LOLP) modeling be updated? Is a full LOLP analysis needed for each IRP, or can a Planning Reserve Margin (PRM)-like metric be used in some cases? *[slide 43,54/69]*

The Commission should continue its important work on developing a reliable and durable LOLP model. Pending additional evidence that the LOLP modeling is reliable and durable, the Planning Reserve Margin metric ought to be employed to help provide an measure of assurance that the grid will remain reliable in the future. IEP notes that the Commission's work on the ELCC mechanism for assessing the capacity benefits of intermittent renewables is important as well in developing a reliable and durable framework for assessing grid reliability. The Commission should work on perfecting the LOLP (and ELCC) as quickly as practical with a goal of updating the modeling no later than biennially.

2. Does LOLP-based system reliability assessment also need to be repeated in Box 5 in order to validate all Load Serving Entity (LSE)-preferred IRPs together, or can this validation be deferred until Box 2 of the subsequent IRP two-year planning cycle? *[slide 43,54/69]*

As a practical matter, the Commission will need to determine whether the individual LSE-preferred IRP Plans collectively represent a portfolio of resources to match the goals and objectives of section 454.52. To achieve this, IEP expects that a LOLP-based system reliability assessment will be needed under the proposed framework.

3. How often should local reliability needs be checked? What vintage of CAISO TPP analysis should be used, considering a potential one-year lag in the demand forecast associated with the CAISO TPP analysis? *[slide 43,54,59-61/69]*

IEP recommends an annual check on local and system reliability needs. As the state increasingly relies on preferred resources, which may include untested emerging technologies, the risk of failure to start and maintain operations may increase. An increasing reliance on distributed resources will not mitigate the need to annually check on local and system reliability needs, certainly in the initial start-up of the IRP (i.e., first 10-years).

4. How important is it for the system reliability assessment to be able to evaluate intra-hour and chronological commitment and dispatch of resources (considering the possibility that the generation fleet may be moving from an era of significant over-capacity to an era where flexible gas generators retire due to insufficient revenues)? *[slide 43,47,49,50,54/69]*

From a long-term planning perspective, over a 10-, 20-, and 30-year time horizon, intra-hour assessments seem of less utility given the every dynamic and changing electric grid. Thus, in terms of IRP planning over a long time horizon, e.g., 10 years or more, it is not necessary to develop optimal portfolios using intra-hour data to determine how best to integrate renewable resources in IRP planning. On the other hand, an assessment of intra-hour and chronological commitments may prove important for purposes of least-cost and best-fit resource *procurement*, i.e., for purposes of bid-evaluation and resource selection, and to identify grid needs that may be obscured by hourly modeling.

Reference System Plan & LSE Plans

5. What other naming conventions should staff consider for plans currently referred to as "Reference System Plan" and "Preferred System Plan?" ***[slide 43/69*****]**

IEP has no comment on this question at this time.

6. What is a tractable technical approach for CPUC to provide guidance to LSEs regarding how LSEs should reflect the resources selected as a part of the Reference System Plan to fulfill system-wide needs within LSE-preferred plans? For example, should CPUC require that LSEs submit at least one portfolio that includes a load-based share of any new system resources that appear in the Reference System Plan? ***[slides 43,49/69]***

As IEP recommended in its presentation of an alternative approach to the proposed IRP Analytical Framework, the Commission should eliminate the Reference System Plan for the IRP process. Rather, the Commission should (1) adopt common assumptions, articulate consistent goals, and suggest resource portfolios as a means to achieve those goals; (2) evaluate the common assumptions and portfolios with regards to local and system reliability needs; (3) impose on each LSE the obligation to develop its IRP plan consistent with those assumptions, policy goals, and reliability assessments; and (4) review the LSE IRP plans and take the steps authorized by the legislature to direct procurements by electrical corporations to fill any gaps.

LSE Plan Evaluation

7. For Community Choice Aggregators (CCAs), what methodology and/or metrics should CPUC use to determine whether a CCA-proposed alternative to a renewable integration solution identified in the Reference System Plan meets the statutory criteria for CPUC approval? ***[slides 43,49,66/69; see also PUC 454.51(d)]***

IEP recommends eliminating the Reference System Plan from the IRP process, as described above. The metrics of review ought to be (a) does the LSE IRP Plan consider and address the common assumptions and reliability needs, and (b) does the LSE IRP Plan show a realistic and reasonable path forward to achieve progress toward the prescribed policy goals given their expected load and resource mix.

8. Should CPUC conduct any additional modeling of the aggregated LSE Plans as part of the evaluation process? If so, what type of analysis is needed? *[slides 43,47,49,50,57/69]*

This question is unclear. Is the question focused on whether additional, incremental modeling using the existing tools should be conducted or, alternatively, whether new modeling tools should be employed? Additional modeling of the aggregated LSE Plans may be necessary to ensure that the resulting portfolio of resources meets the requirements of section 454.52. IEP has no view on whether new modeling tools will be needed, but urges the Commission to promote transparency by matching the modeling tool with the level of information and detail that the Commission needs to make its decisions. However, as a general rule barring evidence to the contrary, IEP does not believe that additional analysis is helpful.

9. If the aggregate of LSE plans fails to meet reliability, GHG, or other standards, should CPUC perform additional modeling or other technical analysis? For example, should CPUC conduct modeling to try to determine the extent to which each LSE plan contributes to the failure? If so, what type of modeling could be used and how should it be performed? *[slides 43,47,49,50,57/69]*

If the aggregate of LSE plans fails to meet reliability standards, consistent with section 454.52(a)(2)(A), the Commission should quickly order procurement to ensure grid reliability and to see that each load-serving entity meets the goals prescribed in section 454.52(a)(1).

10. Regardless of whether or not the aggregated LSE plans fail to meet any specified standards, should CPUC conduct any additional modeling to assess whether a specific LSE's plan is appropriate in the context of the Reference System Plan (or to validate an LSE rationale for a significant deviations from the System Plan)? If so, what type of modeling should be used? *[slides 43,47,49,50,57/69]*

First, IEP recommends eliminating the Reference System Plan from the IRP process, as described above. Second, IEP has no comment on this question at this time other than to note that additional modeling likely will extend the proposed IRP process at least 6 months.

IEP appreciates the opportunity to comment on this critical subject. We look forward to working with the Commission on developing and IRP process that can be implemented in an open, transparent manner while providing timely decision-making to meet the needs of the electric grid and the policy objectives of SB 350.

Respectfully submitted,

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