BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

COMMENTS OF THE CITY AND COUNTY OF SAN FRANCISCO

The City and County of San Francisco (CCSF or City) respectfully submits these comments on the Energy Division's Long Term Procurement Planning Straw Proposal on Planning Standards (Straw Proposal). As requested by the Energy Division, the City is submitting these comments using the template for comments prepared by the Energy Division. The template with the comments is attached to this cover page.

Respectfully submitted,

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General

1. Guiding Principles

The City and County of San Francisco (CCSF or the City) **<u>supports</u>** the following five (5) key guiding principles.

- Scenarios should be informed by an open and transparent process. An exception is confidential market price data, which may be reasonably substituted with publicly available engineering- or market-based price data checked against confidential market price data for accuracy.
- Scenarios should inform whether substantial new investment in transmission and flexible resources would be needed to reliably integrate and deliver new resources to loads.
- Scenarios should be designed to inform useful policy information and infrastructure portfolios should be substantially unique from each other.
- Scenarios should inform bundled procurement plan limits and positions.
- Scenarios should be limited in number based on the policy objectives that need to be understood in the current Long Term Procurement Plan cycle.

With respect to the first principle CCSF believes the process should be careful to restrict only the absolute minimum data from being accessible to the public.

2. Planning area and planning period

The CPUC Energy Division (ED) straw proposal ("Straw Proposal" hereafter) indicates that in addition to the existing transmission system, two types of upgrades should be assumed: 1) minor upgrades, and 2) transmission projects that have been approved by both the California Independent System Operator (CAISO) and CPUC and are expected to be online within the planning period. Although CCSF **<u>supports</u>** inclusion of the second type of upgrades, the City **<u>opposes</u>** wholesale inclusion of the first type of upgrade. Currently, there is no limit to the cost of an upgrade to be declared minor, and this category appears to apply to all interconnection-driven projects regardless of their cost. One currently identified project, the West of Devers Reconductoring project, is expected to cost as much as $650 million—significantly higher than several potential lower cost alternatives. This project is an interconnection-driven project and is neither approved by the CAISO Board of Governors (BoG) under the Transmission Planning Process (TPP) nor does it have any regulatory permits.

In fact, a large number of expensive transmission projects are being processed through the CAISO interconnection process. Only 11,000MW-13,000MW of additional renewable generation capacity is needed to meet the 33% renewable portfolio standard (RPS) goal, whereas there are more than 40,000MW of renewables projects currently in the CAISO's existing generation interconnection queue.[1] Thus, many of these projects are unlikely to be needed in the end. CCSF has urged the CAISO to impose a cost-effectiveness assessment on interconnection-driven transmission projects, a request that the CAISO has denied for the bulk of the interconnection-driven transmission projects currently planned.

CCSF urges the Commission to reinstate its past practice of incorporating in its modeling the transmission cost associated with transmission projects that have not been approved by the California Independent System Operator (CAISO) Board of Governors and CPUC. If the Commission opts to ignore the costs of "minor" upgrades, it should define such upgrades to mean those projects that have *de minimis* cost impact irrespective of whether these projects are identified through the transmission planning process or through the generator interconnection process.[2]

CCSF **supports** the Straw Proposal's planning period of 20 years (For the 2012 LTPP, the first period would be 2013-2022, and the second period 2023-2034).

Demand-side Assumptions

3. Economic & Demographic assumptions

No Comments at this time.

4. Load Forecast

a. Is the most recent revised demand forecast appropriate to use in the absence of a recent adopted demand forecast?

CCSF **strongly encourages** the CPUC to utilize the most recent revised California Energy Demand Forecast released by CEC for the following reasons. First, the revised forecast provides the latest and the best information available. Second, the CAISO also uses the revised CEC load forecast in the absence of a recent adopted demand forecast.[3]

5. Incremental Energy Efficiency

Note: Some impacts of energy efficiency are embedded into the Energy Commission's IEPR forecast. The savings here are above and beyond those levels.

CCSF suggests that the CPUC use the "mid" incremental Energy Efficiency (EE) scenario developed by the CEC staff in its 2011 IEPR instead of the "low" scenario. The CPUC's Big

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[1] CAISO Board of Governors Briefing Memo, May 16, 2012.
[2] Under the CAISO tariff, transmission upgrade projects with an estimated capital investment of $50 million or more submitted through the annual Transmission Planning process Request Window require the CAISO Governing Board approval.
[3] See the CAISO 2012/2013 Transmission Planning Process Unified Planning Assumptions and Study Plan, March 30, 2012.

Bold Energy Efficiency Initiatives (BBEES) savings estimate for the "mid" scenario assumes 2,238GWh and 3,114GWh of savings in 2020 and 2022, respectively. The City opposes arbitrarily setting the contribution of BBEES to zero as was done while developing the underlying incremental EE amount for the 2012-13 planning cycle.

In particular, CCSF believes that the incremental uncommitted EE[4] savings amount needs to be at least as high as 15.3TWh in 2020, accounting for BBEES, for the following reasons. First, this would be consistent with previous EE levels; last year the CPUC assumed incremental savings to be as high as 17TWh. Second, the CEC staff's most recent estimates[5] of the uncommitted EE savings range were 15.2TWh-19.9TWh, with 17.1TWh in the mid-case. The CEC staff's estimates included an additional 1.9TWh to capture the CPUC directives that require IOUs to replace 50 percent of program savings that decay as efficiency measures wear out, starting in 2006.[6]

CCSF is also concerned that the CAISO does not model the uncommitted EE amounts in its transmission studies. It is critical that the CAISO reduce load levels at appropriate network nodes to reflect the presumed uncommitted EE amounts in the renewable net short (RNS) calculations. Otherwise, the high levels of loads in the CAISO's renewable portfolios would inaccurately indicate a need for excessive transmission upgrades.

6. Non Event-Based Demand Response

Note: Most Demand Response is accounted for on the supply-side via Event-Based programs.

No Comments at this time.

7. Incremental small photovolatics (demand-side)

No Comments at this time.

8. Incremental combined heat and power (demand-side)

[4] Uncommitted savings are associated with uncommitted programs or policies, and therefore are not included in the CEC's base demand forecast.
[5] See Table 1, in "Proposed Method to Calculate the Amount of New Renewable Generation Required to Comply with Policy Goals," CEC-200-2011-001-SF, November 2011.
[6] Incremental Impacts of Energy Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast at http://www.energy.ca.gov/2010publications/CEC-200-2010- 001/index.html.

Note: CHP is split between demand-side and supply-side. See supply-side values for incremental CHP assumed exporting to the grid.

CCSF suggests that the CPUC use the "mid" demand-side CHP scenario developed by the CEC staff instead of the "low" scenario. The City does not agree that the estimates of incremental CHP forecast developed by the CEC staff should be reduced to be more "realistic". The CEC staff's latest mid-range forecast assumed an incremental CHP value of 7.2 TWh.[7] Last year's (2011-12 planning cycle) RNS was based on the CPUC LTPP value of 7.6TWh for CHP, which was consistent with the CEC's mid-range assumption at the time. However, the latest RNS calculations (2012-13 planning cycle) developed by the CPUC set the incremental CHP value to zero. This is consistent with the CEC Staff's lower bound estimate of incremental CHP, which assumes that all new CHP generation will consist of wholesale CHP (i.e., supply-side) and will not affect the calculation of the renewable net short.

CCSF believes it is inappropriate to apply such an extreme assumption for the CPUC renewable portfolio mid-case. An October 2009 ICF Market Assessment Report PIER provided an inventory of existing CHP capacity, as well as estimates of technical and market potential for new CHP in California. This estimate took into account the AB 32 mandates and also an assumed CPUC CHP sponsored settlement agreement.[8] This report indicated that a sizable amount of existing CHP is on the customer-side of the meter. It also projected that nearly 50%-90% of new CHP capacity will be installed as demand-side CHP.

Moreover, assuming 0 MW of incremental CHP by 2020/22, as in the CEC "low" scenario, is not consistent with Governor Brown's goal of 6,500 MW of new CHP development over the next 20 years. The CEC's mid-range value is much more appropriate considering recent market studies and state policy to encourage CHP development.

In summary, the City urges the CPUC to use uncommitted incremental EE and CHP estimates that are consistent with CEC staff's most recent estimates in its "mid" case. This approach would also help the CPUC to limit the number of scenarios.

a. What capacity factor is appropriate to use?

No comments at this time.

9. Traditionally, local area and other assessments utilizing a higher <u>peak</u> forecast have been based on a middle forecast for energy and peak. If this should be changed, please explain why.

[7] See pages 20-21, in "Proposed Method to Calculate the Amount of New Renewable Generation Required to Comply with Policy Goals," CEC-200-2011-001-SF, November 2011.
[8] "Combined Heat and Power Market Assessment," October 2009, CEC-500-2009-094-D

No comments at this time.

10. Are there any significant demand-side assumptions that have been missed? If so please identify, provide sources, and the MW and GWh magnitude and likelihood.

No comments at this time.

11. Other comments on demand-side assumptions.

No comments at this time.

Supply-side Assumptions

12. Should all resources be accounted for by their NQC or a forecast of NQC?

No comments at this time.

13. What year and data source should be used for variable resources' production profiles?

No comments at this time.

14. How should transmission capacity be considered?

No comments at this time.

15. Should all "known" and "planned" (non-RPS) resources be used in all supply-side scenarios?

No comments at this time.

a. Are the definitions of "known" and "planned" clear?

Note: At the workshop, "planned" having a contract in place was clarified to mean "approved contract by the appropriate entity" (e.g. Muni approved or CPUC approved). Do you support this clarification?

No comments at this time.

- **Deliverability**

Note: The previous assumption of deliverability assumed all resources were deliverable unless otherwise noted.

b. Are any changes to the definition of future resources considered deliverable warranted?

CCSF **supports** the CPUC ED staff proposal of modeling a generation resource as "energy only" if it cannot be accommodated on existing or CPUC approved transmission. The RPS is an "energy-based" goal measured in MWh not MW, therefore the 33% RPS calculator deployed by the CPUC ED staff to develop the proposed portfolios should not restrict resources if they cannot be deemed deliverable based on the CAISO deliverability analysis.[9]

The current CAISO deliverability criteria require intermittent resources to be deliverable under extremely unlikely conditions, which adversely impact the ability of an LSE to satisfy its resource adequacy requirements. In the table below, the City indicates how the overly stringent deliverability assessment criteria applied by the CAISO can be reformed to better account for the cost implications of renewable resource additions. CCSF believes that the CPUC and CAISO, along with other interested parties, should work together in this proceeding to align the CAISO's deliverability assessment criteria with the Commission's least-cost, best-fit long-term resource planning and procurement oversight.

CAISO Deliverability Assessment Criteria	CCSF Proposal
Utilizes power flow analysis for a snapshot under 1-in-5 load conditions.	Deploy production cost simulations analysis for hourly (8,760 hours in a year) realistic load conditions.
Performs analysis of highly unlikely Category C (Common mode outage) contingencies.	Analyze Category B outages applied by the CAISO for grid operations purposes.
Models renewable generation dispatch at a considerable higher level than allowed for Resource Adequacy (RA) capacity credit.	Model renewable generation at a level consistent with the RA capacity credit allowed under the CPUC counting rules.
Does not consider significantly lower cost and appropriate solutions to deal with the criteria violations such as, congestion management or use of Special Protection Schemes (SPS), load shedding, etc.	Consider congestion management or use SPS or similar mechanisms prior to triggering expensive transmission Network Upgrades (NU).

c. How should information from other sources, such as distribution resource deliverability be incorporated?

See the above comments.

- **What additional information is needed for resource locations?**

No comments at this time.

[9] Only capacity that is deemed deliverable may be counted by LSEs for resource adequacy purposes.

- **Event-Based Demand Response**

No comments at this time.

- **Incremental combined heat and power (supply-side)**

Note: CHP is split between demand-side and supply-side. See demand-side values for incremental CHP assumed behind the meter.

d. What capacity factor is appropriate to use?

No comments at this time.

- **Renewable Resources**

e. Establishing the 33% RPS infrastructure target via the LTPP, understanding that other requirements may also need a similar calculation within the RPS proceeding.

According to the Straw Proposal, the renewable target, established by demand-side calculations, will be calculated in this proceeding (R.12-03-014), using the demand-side assumptions discussed in the Straw Proposal. When combined with the expected renewables supply calculation from R.11-05-005, the Renewables Net Short (RNS) is created. CCSF conditionally **supports** establishing the 33% RPS infrastructure target via the LTPP provided that the Commission scrutinizes the assumptions and results in the RPS proceeding as discussed in the next section (15.f).

f. Establishing the RPS supply (i.e. the "highly likely resources") in the RPS proceeding.

Parties were informed during the May 17th CPUC ED workshop on the Straw Proposal that "Highly Likely Resources" determined in the RPS proceeding (R.11-05-005) will be used for modeling purposes in this proceeding. While no definition was given for "Highly Likely Resources", it appears that the criteria for modeling these Highly Likely Resources will be significantly more relaxed than those used to determine and model "Discounted Core" resources, under the previously adopted methodology. The "Discounted Core" resources were intended to represent the most viable of the projects—those with signed IOU PPAs and all necessary regulatory permits. In previous planning cycles CCSF strongly supported these strict criteria, as the Discounted Core projects are held constant across all scenarios. Moreover, under the Discounted Core approach, a project was not "forced" into a scenario if that project would prompt the need for new transmission in the model. New transmission was only added to accommodate a Discounted Core project – and thus included in all of the scenarios – if the Discounted Core project would provide at least 67% of the energy that could be accommodated over the added transmission line. Discounted Core projects in a zone that did not meet this threshold, were entered into the larger pool of "commercial interest" projects and had to compete for inclusion in each scenario/portfolio. CCSF supported this restriction as a reasonable means to control for unnecessary transmission build-out.

The Energy Division proposes to relax this approach and use instead the so-called "Highly Likely Resources" to replace the Discounted Core category. If the Discounted Core requirements are abandoned, then Highly Likely Resources will not necessarily have a PPA or a regulatory permit. Moreover, Highly Likely Resources would in all cases be "forced" into all portfolios regardless of whether a project would prompt the need for new transmission in the model. This approach will likely result in excessive transmission. For example, consider a 300MW resource that requires a 700MW capacity transmission network upgrade (NU) with a capital cost of $700 million. If the RPS proceeding allows this 300MW project to be modeled as the "Highly Likely Resource," and the 33% RPS calculator used in this LTPP proceeding forces that project as well as the required new transmission NU in all portfolios, a resource with a transmission cost as high as $107/MWh[10] would be included in the model. A resource with a prohibitively high transmission cost should not be forced into all CPUC portfolios without any cost, environmental or policy assessment.

CCSF **strongly opposes** any relaxation of the generation criteria (PPA as well as other regulatory permits) and the new transmission usage criteria (67% of energy delivered on new transmission).

g. Base Portfolio

No comments at this time.

h. High DG Portfolio

No comments at this time.

i. Sensitivities

No comments at this time.

j. Long-term Target

No comments at this time.

- **Retirements**

[10] Assuming a 10% annualized cost of transmission project with generation resource with a 25% annual capacity factor.

No comments at this time.

k. **How many retirement assumption combinations are needed? If more than one, please list the top two most important retirement assumptions to consider sensitivities on.**

No comments at this time.

- **Are there any significant supply-side assumptions that have been missed? If so please identify, provide sources, and the MW and GWh (if appropriate) magnitude and likelihood.**

No comments at this time.

- **What is a reasonable number of overall scenarios for <u>supply-side</u> assumptions? What is the purpose behind having that number of scenarios?**

No comments at this time.

- **Other comments on supply-side assumptions.**

No comments at this time.

Allocation Methodologies

If another allocation methodology is appropriate, parties are encouraged to provide it. It is also appropriate to suggest alternative methodologies to be used in a subsequent LTPP if they may require significant development.

- **Energy Efficiency**

No comments at this time.

- **Demand Response**

No comments at this time.

- **Other methodologies for assigning resources to busbars.**

No comments at this time.

Other

- **What is a reasonable number of total scenarios + sensitivities to consider?**

No comments at this time.

I. **Briefly describe the scenarios and sensitivities that are most important to consider. Please refer to the assumptions discussed above to describe and explain this recommendation.**

No comments at this time.

- **Any other comments.**

The CAISO generator interconnection process has become the major driver of new transmission with its resulting environmental and rate impacts. However, the interconnection process for most of the projects already in the interconnection queue does not include a cost-effectiveness test. Further, generators responding to IOU renewable resource solicitations have been asked to provide resources that are fully deliverable, to ensure that IOUs can count the net qualifying capacity of these resources for resource adequacy purposes. This leads to those generators electing the "full capacity" option when they apply for interconnection with the CAISO. The result of all renewable generators seeking full deliverability is very likely to be unnecessary and excessive transmission costs. This is occurring at a time when both the CAISO and CPUC are investigating mechanisms to retain flexible generating capacity, which may face reduced revenues due to increasing renewable generation. CCSF urges the Commission and the CAISO to reassess methods of meeting the state's resource adequacy goals to ensure that resource adequacy requirements support long-term, least cost, best-fit resource plans and procurement strategies.