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 ON THE STANDARDIZED PLANNING SCENARIOS ATTACHED TO THE SEPTEMBER 25, 2012 ASSIGNED COMMISSIONER'S RULING

In accordance with the September 25, 2012 Assigned Commissioner's Ruling in this matter (AC Ruling), the City and County of San Francisco (City or CCSF) respectfully files these comments on the standardized planning scenarios attached to the AC Ruling. The City's concerns with the planning scenarios stem from the unprecedented growth in transmission costs in the last ten years. Over this period, just the High Voltage (HV) portion of the CAISO-wide Transmission Access Charge (TAC) has gone up from $1.40/MWh in 2001 to $6.80/MWh in 2012, and it is expected to increase to nearly $17/MWh by 2020 based upon the CAISO's transmission plan to meet the requirement for a portfolio comprised of at least 33 percent renewable energy by 2020 under the state's Renewable Portfolio Standard (RPS). The projected HV TAC increase is primarily attributed to nearly $7.8 billion of transmission upgrades to accommodate renewables.

The City's interest in this matter is two-fold. First, the City is concerned about cost increases: the City must use the transmission system to transport its Hetch Hetchy generation to its load in San Francisco and as such it is affected by the unprecedented escalation in transmission costs. In addition, City residents and businesses are affected by the escalation in overall electricity costs, regardless of whether they remain bundled customers or become Community Choice Aggregation (CCA) customers in the future. Second, unreasonable cost increases jeopardize the long term goals of meeting RPS requirements, creating a sustainable electricity system and reducing greenhouse gas emissions.

The City supports the RPS goals and acknowledges that some of the new transmission driving the cost increases was justified to allow the state to achieve its RPS goals cost-effectively. The City has no quarrel with transmission upgrades that result in lower overall costs because they provide access to less expensive generation. The City believes, however, that a combination of factors has resulted in the construction of transmission that is not needed to meet the RPS cost-effectively and that additional transmission projects are being considered that are similarly not needed. There is a large amount of existing and CPUC-approved transmission capacity that would be used to support cost-effective achievement of the 33% RPS, if appropriate planning criteria and procurement policies were in place.

Track 2 of this proceeding is intended to determine the long-term need for new system reliability resources, and will eventually result in the adoption of system resource plans. To support this determination, the Energy Division (ED) has developed a number of supply and demand scenarios (standardized planning scenarios) for the California Independent System Operator (CAISO) controlled grid and associated distribution systems. The scenarios are intended to allow the Commission to comprehensively consider the impacts of state energy policies on, 1) the need for new resources and 2) the cost to consumers. AC Ruling at 9.

Additionally, as noted in the May 17, 2012 Scoping Memo in this proceeding (Scoping Memo), "the [standardized planning] scenarios [developed in this proceeding] will form the basis for the Commission's submittal to the [CAISO] for its 2013-2014 Transmission Planning Process." Scoping Memo at 9. Thus, the standardized planning scenarios feed into the CAISO transmission planning process and are considered by the CAISO in identifying policy-driven transmission projects. See CAISO Tariff Section 24.4.6.6, CAISO Business Practice Manual for the Transmission Planning Process Section 4.8.1. To the extent that the scenarios fail to identify the lowest-cost resource options, and make unjustified assumptions that drive the need for additional transmission, the result could be the addition of at least a half-billion dollars of transmission related costs without appropriate cost-effectiveness review.

The proposed standardized planning scenarios do not adequately expose costs or address the question of how the Commission might minimize costs to consumers. The ED declined to use a cost-constrained scenario in this process, so there is no cost-based base-line against which to measure the other scenarios.[1] Moreover, despite the fact that the 33% RPS Calculator computes the annual total cost of different renewable portfolios, the Attachment to the AC Ruling makes no distinction among the scenarios from a cost standpoint. These shortcomings are perplexing in the context of an exercise that is intended to identify "[w]hat mix of resources minimizes cost to customers over the planning horizon?" See AC Ruling, Appendix at 9.

These comments highlight a number of deficiencies in the proposed standardized planning scenarios and their underlying inputs that could drive up ratepayer costs by supporting additional and unnecessary transmission projects, the costs of which have not and will not be subject to a thorough and transparent cost-effectiveness assessment:

- The ED should clearly identify the costs of all scenarios, present to stakeholders a cost-constrained scenario, and make the cost-based scenario the base case.
- The criteria for fixed generation included in each scenario (Discounted Core) should be restored to 1) having a signed and CPUC <u>approved</u> PPA and 2) having an <u>approved</u> environmental permit.

[1] A cost constrained scenario was prepared and in fact submitted to the CAISO in March of 2012, but it is no longer presented by the Energy Division.

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- Each standardized planning scenario should only include as fixed transmission those projects that have been approved by both the CAISO and the CPUC and that are expected to be online within the planning period.
- The standardized planning scenarios should make reasonable assumptions about out-of-state renewables.
- The City supports the ED's proposal to accurately account for incremental energy efficiency, demand-side management, and small solar photovoltaic projects.
- Unrealistic "No New DSM" assumptions, such as that in the Replicating TPP scenario, should be changed.

I. The ED Should Clearly Identify the Costs of All Scenarios, Present to Stakeholders a Cost-Constrained Scenario, and Make the Cost-Constrained Scenario the Base Case.

The Appendix to the AC Ruling sets forth the two questions the scenarios were developed to help answer as follows:

1. What new resources need to be authorized and procured to ensure adequate system reliability, both for local areas and the system generally, during the planning horizon? . . . .
2. What mix of resources minimizes cost to customers over the planning horizon?

AC Ruling, Appendix at 9. Notwithstanding the fact that maintaining reliability and minimizing costs are the two key objectives of the exercise, the current standardized planning scenarios do not include a cost-constrained scenario and do not clearly present the differences in cost among the scenarios. Without clear and transparent information about costs, it is impossible to work to minimize them. A least-cost planning exercise that does not focus on costs is nonsensical.

The standardized planning scenarios do not include a cost-constrained scenario, even though, in the past, and in fact until May 2012, a cost-constrained scenario was presented and used as the base-case. In 2011, the CPUC submitted a cost-constrained scenario[2] for use as a base case for the CAISO's 2011-2012 Transmission Planning Process. See June 6, 2011 letter from Julie Fitch to Keith Casey. Similarly, initially in March of 2012, in a letter from CPUC

[2] Under that proposed Cost-Constrained scenario, the total cost of a resource is weighted more heavily (70%) than the other criteria for which projects are evaluated, including *permitting* (10%), the *environmental* impact of a resource's development (10%), and the *commercial interest* (10%) in a project, as measured by the existence of a signed IOU PPA.

President Peevey, CPUC Commissioner Florio and CEC Chair Weisenmiller, the CPUC transmitted to the CAISO a cost-constrained scenario to be used as a reasonable base case in the 2012-2013 planning process. See March 12, 2012, Letter from President Peevey, Commissioner Florio and Chair Weisenmiller to Steve Berberich. Then, in May, the same representatives of the CPUC and CEC wrote a further letter to the CAISO indicating that a commercial-interest scenario[3] should be used instead as the base case. See May 16, 2012, Letter from President Peevey, Commissioner Florio and Chair Weisenmiller to Steve Berberich. In their letter, President Peevey, Commissioner Florio and Chair Weisenmiller explained that this change was in response to comments by stakeholders during an April 2, 2012 CAISO 2012-2013 TPP stakeholder meeting, that the cost-constrained scenario does not "reflect the considerable steps developers and utilities have taken to pursue projects through power purchase agreements and licensing procedures." Any such efforts do not obviate the need to have cost continue to be a key consideration in a least-cost planning proceeding. Moreover, the City does not recall there being any representatives of ratepayers present at the April 2, 2012 meeting, and the comments heard by the Commissioners were one-sided.

During the April 24, 2012, workshop, a City consultant asked the ED why the cost-constrained scenario was not only demoted from its base case status, but in fact no longer presented.[4] The response given was that the overall cost of the cost-constrained scenario was found to be comparable to the costs of the remaining scenarios and the ED dropped the cost-constrained scenario in the interest of limiting the number of scenarios. This response does not

[3] The Commercial Interest scenario weights the existence of a signed IOU PPA for a given project more heavily (70%) than the other criteria, including *permitting* (10%), *environmental* impact (10%), and *cost* (10%).
[4] A cost-constrained scenario was transmitted to the CAISO in May as one of several scenarios to be considered by the CAISO, but the CPUC/CEC recommended that the commercial interest scenario be used as the base case.

justify elimination of the cost-constrained scenario and, moreover, a review of the Total Cost results from the RPS Calculator demonstrates that it is also inaccurate.

In a proceeding designed to minimize costs, a cost-constrained scenario remains central to the process. The Commission cannot claim that it seeks to minimize costs without focusing on a cost-constrained scenario and reviewing the assumptions underlying that scenario. Stakeholders are entitled to review and examine a cost-constrained scenario because they may identify shortcomings that require correction and could result in additional cost-differences.

The commercial-interest scenario assumes as fixed generation that is in the process of development and is still relatively uncertain. While the criteria for this generation has not been clearly identified, it appears to overlap to some degree with the relaxed criteria for "Discounted Core" generation, projects with a signed PPA and having applied for (but not necessarily obtained) an environmental permit. As discussed in the section below, generation that meets these criteria is not reasonably certain.[5] In any event, using the 33% RPS Calculator, the City has determined that the costs of a cost-constrained scenario are indeed significantly lower than the costs of a commercial-interest scenario as demonstrated in the table below.

[5] It is important to note that, even if the Energy Division restored the more appropriately stringent criteria for the Discounted Core generation as recommended in the next section, the standardized planning scenarios will be improperly biased in favor of costly additional transmission if the commercial interest scenario remains the base case. This is because in the Commercial Interest scenario, in addition to Discounted Core generation, other generation under development is assumed as fixed so a more stringent Discounted Core criteria would not change the outcome much if at all. Further, because other scenarios are based on the base case, by incorporating a flaw in the Commercial Interest scenario the Commission would be assuring the flaw remains in other scenarios that use the base case as their starting point.

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Total Annual Cost of Procuring Renewable Net Short (million $)		
Scenario Criterion/ Discounted Core Criterion	New Discounted Core	Earlier Discounted Core
Commercial Interest	$1,315.35	$1,315.35
Cost Constrained	$971.29	$787.60

Moreover, using the commercial-interest scenario biases outcomes in favor of additional transmission, the cost-effectiveness of which has not been assessed. The ED staff has proposed four scenarios as high priority ones: Base Scenario (based on Commercial Interest), Replicating the TPP Scenario, Early SONGS Retirement Scenario, and High Distributed Generation, High Demand Side Management Scenarios. Since the first three scenarios are based on commercial interest, the latest version of the 33% RPS calculator (RPSCalculator_2007_v3_92712) indicates that all the three scenarios will require the following three new transmission projects (estimated capital cost): *Kramer-1* ($540 million), *Merced-1* (unknown) and *Los Banos Westley-1* ($100 million). With commercial interest being the overarching criterion, there is no economic cost-benefit assessment of these three scenarios that would, for example, question the need to build a $540 million network upgrade (Kramer-1) to incrementally accommodate 700MW of renewable generation in the Kramer CREZ. In contrast, under the cost-constrained scenario, no new transmission projects are needed beyond the existing transmission and the CPUC-approved projects.

Thus, the Commission should restore the cost-constrained scenario into the suite of standardized planning scenarios and, as it has in the past, recommend that the cost-constrained scenario be used by the CAISO as the base case in the 2013-2014 TPP. Under the CAISO Tariff, the base case holds considerable weight for purposes of identifying "policy-driven" transmission upgrades. If a particular transmission line or element is identified as required in the base case plus a significant percentage of alternative scenarios, it may be deemed to be "policy-driven", providing a strong basis for approval. See CAISO Tariff section 24.4.6.6.

II. The Criteria for Generation Fixed in all the Scenarios (Discounted Core) Should be Sufficiently Stringent.

"Discounted Core" projects are deemed to be highly certain and hence establish a baseline of generation that is not evaluated by the criteria that apply to each particular scenario.[6] As the Attachment to the AC Ruling states, the test for "Discounted Core" resources used by the ED for the current scenarios is different from the test used in the 2012-2013 TPP RPS Portfolios and harkens back instead to "the renewable resource portfolios in the 2010 LTPP." AC Ruling, Attachment at 12. In the 2012-2013 TPP RPS Portfolios, the "Discounted Core" included only resources that had obtained a signed and approved Investor Owned Utility (IOU) PPA and an environmental permit. However, the current scenarios include as Discounted Core resources, those with a signed PPA, and a data adequate Conditional Use Permit or Application for Certification. In other words, in contrast to the 2012-2013 TPP RPS Portfolios, the standardized planning scenarios include as Discounted Core resources, projects without approved IOU PPAs or issued environmental permits. It is unreasonable to assume that projects that either do not have a PPA approved by the CPUC, or have not obtained environmental permits have a high

[6] Discounted Core resources are held constant across all scenarios, provided the projects are reliable in the scenario (in other words, a project that meets the criteria for Discounted Core is not "forced" into a scenario if the project would prompt the need in the model for new transmission). New transmission is only added to accommodate Discounted Core projects, and thus included in all of the scenarios, if the Discounted Core projects would provide at least 67% of the energy that could be accommodated over the added transmission line. If a Discounted Core project in a zone does not meet the 67% threshold, then it becomes a "commercial interest" project and must compete for inclusion in each scenario on the basis of the relevant criteria for the scenario.

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degree of certainty. Neither the AC Ruling nor its Attachment provide any credible rationale for the return to the 2010 LTPP criteria for Discounted Core.

In addition to being inappropriate, the use of the 2010 Discounted Core criteria has the effect of rendering the scenario exercise largely meaningless. As a result of the change in the "Discounted Core" criteria, 26.2 TWh (95%) of the entire 27.5 TWh Renewable Net Short amount is comprised of "Discounted Core" resources and these resources are then included and considered built and operational across all scenarios. Using the Discounted Core criteria used for the 2012-2013 TPP RPS Portfolios would have allowed for 20.1 TWh of Discounted Core generation, whereas using the 2010 LTPP criteria allows for 26.2 TWh of Discounted Core generation, or most of the Renewable Net Short of 27.5TWh. This means that a very small amount of renewable resources are actually tested or selected based on a given RPS criterion (i.e., cost, permitting, commercial interest, and environmental impact) under the proposed standardized planning scenarios.

Thus, the reversion to the 2010 LTPP criteria for Discounted Core is not justified, renders the entire scenario analysis largely meaningless, and has not been explained. The Commission should direct the ED to revise the criteria to use the more defensible criteria used for the 2012-2013 TPP RPS Portfolios.

III. Scenarios Should Only Include as Fixed Transmission those Projects that Have Been Approved both by the CAISO and the CPUC and that are Expected to be Online within the Planning Period.

The scenarios include as fixed transmission (transmission that is not subject to the criteria for the scenarios) projects that have been approved both by the CAISO and the CPUC and that are expected to be online within the planning period. During the August 24th 2012 workshop,

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some parties suggested that the scenarios should include as fixed transmission, all transmission projects included in the 2011-2012 CAISO transmission plan.

The City would strongly oppose such a change. As in the case of generation, projects that have not undergone environmental review are uncertain. Further, significant and costly transmission projects in the 2011-2012 CAISO transmission plan have not undergone any form of regulatory cost-benefit analysis because they were identified in the context of the large generator interconnection process. These transmission projects include, but are not limited to, the Pisgah-Lugo 500kV project, the Coolwater-Lugo 230 kV project and the West of Devers Reconductoring project. The more future facilities that are included as fixed resources in the scenarios (particularly those that have not been subjected to regulatory cost-benefit analysis or environmental review), the less useful the scenario exercise is to inform a least-cost planning process. The least-cost planning process should assess the costs and benefits of as many future resources as possible to avoid committing ratepayers to investments that are not optimal.

IV. The Scenarios Should Make Reasonable Assumptions About Out-of-State Renewable Resources.

Without explanation, the scenarios inappropriately constrain out-of-state renewables that could be cost-effective for ratepayers. The latest 33% RPS Calculator used to develop the standardized planning scenarios allows for a category of "Out-of-State RECs" only for the following four states/zones: Arizona, Nevada C, the Northwest and Alberta. However, last year's 33% RPS calculator (RPSCalculator_2007_v15_forCAISO) allowed the "Out-of-State RECs" category (w/ zero transmission cost) along with option of "New Tx - Segment 1" for several other states/zones including New Mexico, Montana, Colorado, Wyoming, etc. The latest Calculator shows resource bundles from some of the additional states/zones, but indicates that these require additional new transmission, and hence does not select them because of the added cost.[7]

The ED has not explained why the resource bundles from these zones cannot be accommodated on existing transmission, or why the scenarios artificially constrain cost-effective out-of-state renewables.

V. The City Supports the Energy Division's Proposal to Accurately Account for Incremental EE, DSM, and small PV.

A recurring concern in this proceeding has been accurately portraying in the planning process incremental energy efficiency, demand response, and small distributed generation resources such as photovoltaics (PV) and combined heat and power (CHP). Energy efficiency and demand response remain the highest priority resources in the Energy Action Plan. Energy Action Plan 2008 Update at 14. In order to achieve the state's ambitious goals for these resources, it is important to assume sufficient new resources from these sectors, otherwise a need for other resources will defacto be identified and the opportunity to use energy efficiency and demand-response to offset these resources will be lost. Of course, in pursuing sufficiently aggressive energy efficiency and demand-response goals, it is also necessary to be realistic in order to avoid degrading reliability.

The state similarly has a strong commitment to small-scale PV and CHP. For example, last year, Governor Brown issued a Clean Energy Jobs Plan that includes a goal that California should develop 12,000 megawatts of localized energy by 2020, and a goal that California should develop 6,500 MW of additional CHP resources over the next 20 years. See Governor Brown's Clean Energy Jobs Plan. As in the case of energy efficiency and demand-side

[7] The *j - GenericProjData* tab, shows that none of the projects belonging to these states (NM, WY, MT, etc.) are eligible for Out-of-State RECs. This limitation has not been explained. Similarly there is no explanation of why, the generic projects in NM with Resource IDs *E3_005*, *E3_016*, *E3_017*, *E3_027*, and *E3_028* were eligible for Out-of-State RECs in last year's calculator, but not in the latest calculator.

management, these goals can only be achieved if an adequate level of new small scale PV and CHP resources are included in long-term planning proceedings while ensuring that assumptions are realistic and do not compromise reliability.

The ED has properly balanced these two competing priorities in developing assumptions about energy efficiency, demand-response, and small scale PV in the proposed standardized planning scenarios. The ED has properly assumed that the state will authorize new energy efficiency and demand response funding after funding that is currently approved is spent. The ED has also properly included a reasonable level of new PV in the base-case scenario, and recommended a High DG/High DSM scenario as one of the sensitivity scenarios. The City supports the ED's balanced assumptions about energy efficiency, demand-response, and small scale PV, but questions the ED's rationale to assume no additional CHP, except in the "High DG+High DSM" scenario.

The City is particularly concerned about the ED's proposal to include a no incremental demand-side management (DSM) assumption in the "Replicating TPP" scenario. As proposed, the Replicating TPP scenario mirrors a CAISO system stress case and features a high unmanaged load future, combined with 1-in-5 peak weather conditions. Attachment to AC Ruling at 10. The Replicating TPP assumes there are "limited to no impacts" associated with future energy efficiency programs, combined heat and power development, and a limited level of demand response. Attachment to AC Ruling at 15. With California's strong commitment to these resources and long history of success in promoting and deploying them, it is unreasonable to expect popular "policies related to preferred resources" to terminate in the future. The ED justifies its inclusion of this scenario "to form a point of convergence between the LTPP and the TPP." Attachment to AC Ruling at 15. However, the no new DSM assumption in this scenario is not reasonable. Further, the CAISO itself has recently shown more willingness to consider incremental DSM (non-transmission alternatives) in CAISO modeling efforts going forward. See Neil Millar Presentation.[8] The City strongly opposes the inclusion of unrealistic scenarios that assume no incremental DSM will be implemented over the planning horizon.

VI. Conclusion.

The City urges the Commission to restore the attention to costs that is appropriate in a least-cost planning proceeding such as this one, by requiring a cost-constrained scenario and making it the base-case. In addition, the City urges the Commission to require realistic assumptions about resources fixed in the various scenarios, in order to maximize the resources subject to analysis in the 2012 long-term procurement planning process. Finally, the City supports reasonable assumptions about energy efficiency, demand-response, small scale PV and CHP consistent with the state's aggressive goals for these resources.

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[8] "Other Non-Transmission Alternatives," Neil Millar, Executive Director - Infrastructure Development CAISO 2012/2013 Transmission Planning Process Stakeholder Meeting September 26, 2012.

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