Rulemaking: R.12-03-014
Exhibit No.:
Witness: Jim Baak

TRACK 4 TESTIMONY OF
JIM BAAK
DIRECTOR OF POLICY FOR UTILITY-SCALE SOLAR FOR THE VOTE SOLAR INITIATIVE

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

September 30, 2013

{00187996;1}

Introduction and Summary

Q. Please state your name, business affiliation and address.
A. My name is James Edward Baak and I am Director of Policy for Utility-Scale Solar for the Vote Solar Initiative (Vote Solar), located at 101 Montgomery Street, San Francisco, CA, 94104.

Q. On whose behalf are you appearing?
A. I am appearing on behalf of Vote Solar.

Q. Please provide your qualifications.
A. My qualifications are attached at the end of my testimony.

Q. What is the purpose of your testimony?
A. This testimony responds to the May 21, 2013 revised scoping memo requesting opening testimony in Track 4 of the Long Term Transmission Planning and Procurement docket (R.12-03-014), replies to SCE and SDG&E's testimony of August 26, 2013 and responses to selected questions posed by the ALJ during the prehearing conference held on September 4, 2013.

My testimony recommends meeting the identified LCR needs in SCE and SDG&E with Preferred Resources rather than gas-fired resources, expanding SCE's proposed Living Pilot to include advanced inverters as a means of supplying voltage control, establishing procurement mechanisms to allow phased deployment of greater quantities of distributed PV, and using distributed PV in combination with energy efficiency, automated demand response and energy storage to meet LCR needs in the LA Basin and San Diego, and providing incentives for PV system owners to orient their arrays to the west to maximize late afternoon energy production.

Review of SCE Testimony

In the Track 4 testimony of Southern California Edison (SCE), the utility identifies an additional 500 MW of LCR need in the LA Basin over and above the 1,400 – 1,800 MW authorized in Track 1. This puts SCE's estimated total LCR need for the LA Basin between 1,900 – 2,300 MW, after adjustments for SGD&E load shedding. The 500 MW of new need is attributable to CAISO's analysis of need, which uses a more stringent reliability standard than was used by SCE. SCE's own studies showed a total need of only 2,800 MW, after SDG&E load shedding, which they testify is sufficient to meet NERC requirements. SCE chose to use the CAISO's more conservative assumption of 3,286 MW, however.

SCE studied four options to address this shortfall, recommending Option 3, which focuses on using a portfolio of 678 MW of Preferred Resources, which they testify translates to a 551 MW reduction in LCR need in the LA Basin. This option also includes various transmission upgrades in the LA Basin area (most significantly, the Mesa Loop-In) to achieve a reduction in In-Basin generating resources of approximately 1,200 MW. These two assumptions combine to reduce the 2022 LCR need to approximately 1,055 MW. Presumably this need will be met with conventional gas-fired resources.[1]

SCE is requesting that the Commission authorize the procurement of the additional 500 MW to meet the CAISO estimates of need, combining it with the Track 1 procurement authorization and process. Rather than specifying the type of resources, SCE requests that this need be met using an all-source procurement mechanism, adhering to the Preferred Loading Order to the extent possible, but without a specific Preferred Resources requirement.

[1] In D.13-02-015, SCE is authorized to procure at least 1,000 MW of conventional gas-fired resources, but not to exceed 1,200 MW.

Further, SCE proposes a Living Pilot Program involving Preferred Resources which is intended to gather information on how well these resources support LCR needs at peak times. The Living Pilot would be limited to the area served by two substations in Orange County, near the shuttered SONGS facility. SCE states that there is sufficient LCR in this area at present, but is proposing a contingency program to expedite development of gas-fired resources in the event Preferred Resources are unable to meet future LCR needs and/or the Mesa Loop-In project is not successfully developed.

SCE indicates that they will seek stakeholder input to the development of the Living Pilot Program to determine the types of resources, attributes and criteria for evaluating these resources. They do not specify a MW target for Preferred Resources in the Living Pilot, instead recommending matching the quantity of resources to changing load conditions in the area. The Living Pilot would continue through 2022, with evaluations in 2017 and 2022 to help "step Preferred Resources" into the rest of the SCE grid.

Response to SCE Testimony and Alternate Recommendations

While I am not in a position to dispute or endorse either the CAISO or SCE's analysis of the overall LCR need, I generally support SCE's recommendation for the Preferred Resources option to fulfill the LCR need from Track 1, including development of the proposed Mesa Loop-In transmission upgrades. The proposed transmission upgrades reduce the in-basin need by around 1,200 MW, though they do not eliminate the need for replacement generation outside the basin. I expect there will be a robust discussion about the types of resources that could satisfy this need from outside the basin, which can be met with renewable energy. I agree with SCE that the proposed transmission upgrades will significantly enhance reliability and provide more flexibility for the in-basin part of SCE's grid.

With respect to SCE's Track 4 request for authorization to procure 500 MW of new resources in an all-source RFO, I believe it's premature to commit to a path that could lead to the development of a significant amount of new conventional gas-fired resources that will be emitting carbon and other pollutants for 40+ years. This is contrary to the state's carbon reduction goals; particularly given these resources would be replacing a carbon-free resource. The Commission authorized SCE to procure up to 600 MW of Preferred Resources in Track 1. Before authorizing any additional resource procurement in Track 4, SCE should fulfill this entire 600 MW, adhering to the Commission's order to source this from Preferred Resources. Only if it is determined that the additional 500 MW requested by SCE in Track 4 is truly needed should SCE be authorized to procure additional amounts, up to the 500 MW SCE seeks to procure. However, the additional authorization should be sourced from Preferred Resources, which have shorter lead times for development and can be phased-in as needed. This approach also allows SCE to take full advantage of data and results obtained from the proposed Living Pilot to maximize the effectiveness in meeting LCR needs as well as meeting utility and customer expectations with each successive block of Preferred Resource procurement.

I generally support the concept of SCE's Living Pilot Program proposal as well, although I am not convinced of the need for the backstop gas-fired generation at this point, given SCE's testimony that there are sufficient LCR resources currently in the area to meet needs. Although SCE has not indicated the quantity of Preferred Resources it plans to include in the Living Pilot Program for the Orange County area, from their testimony it seems that the potential need for resources of any type may be low. Absent more detail on the amounts and types of Preferred Resources to be included in the Pilot, I do not believe SCE has sufficiently justified the need and expense for the preliminary siting or potential options penalties associated with contracting for gas resources at this time.

SCE's proposed Living Pilot would provide valuable data on the ability of Preferred Resources to meet LCR needs and could be used to develop best practices for implementing Preferred Resources and energy storage technologies. The Living Pilot should be expanded to include testing of advanced inverters for PV to demonstrate the voltage and frequency support capabilities this technology offers. Voltage support is an issue CAISO, SCE and SDG&E all indicated was a serious concern post-SONGS, and advanced inverters strategically located throughout the distribution grid could provide voltage support at critical areas within the distribution grid. Including advanced inverters in the pilot, coincident with deployment of smart grid capabilities, could help spur deployment of this technology while penetration levels of distributed PV are still relatively low, potentially increasing the value of distributed PV for reliable grid operation.

Also of value in meeting LCR needs in the late afternoon is orienting PV arrays to face west rather than south. A south-facing PV array maximizes annual energy output, but sacrifices late afternoon production. In contrast, a west-facing system provides maximum output later in the afternoon, but at the expense of maximizing annual energy production. SCE's Living Pilot should also include incentives to compensate system owners for orienting PV arrays to the west when it is potentially most valuable to the utility. This might include rate changes for PV system owners, including possibly time-of-use rate structures. SCE's Living Pilot program would provide a good venue to identify incentives for customers to orient PV arrays to the west.

One aspect of the program that needs further development concerns the interaction between the Living Pilot and the deployment of Preferred Resources associated with the Track 1 authorization. For the Living Pilot to be truly useful in integrating Preferred Resources, there must be a clear process for transferring the learning from the Living Pilot to the deployment of Preferred Resources authorized or requested in Track 1 and Track 4 throughout the entire LA Basin. There should be ongoing monitoring and reporting to the Commission and stakeholders engaged in the Living Pilot throughout the Pilot Program to maximize the effectiveness of these resources in meeting the LCR needs and expedite deployment in successive phases of Preferred Resources procurement cycles. Since Preferred Resources have shorter development lead times than gas-fired resources, establishing successive phases of

Preferred Resources procurement to meet changing load conditions would allow opportunities to transfer this learning into real world deployments. SCE should commit to greater levels of distributed PV within the 500 MW Track 4 procurement request than was studied in the Track 1 Preferred Resources option. The Living Pilot should include the development of incentives for deploying advanced inverters to supply voltage support. Testing of the advanced inverters, along with development of tariffs to compensate system owners for production of VARs, should begin immediately in Orange County after the launch of the Living Pilot. Upon successful completion of the testing, and within 12 – 18 months from the start of the Pilot Program, advanced inverters should begin to be deployed for the remaining Preferred Resources authorized in Track 1. This deployment would logically apply first to large commercial PV facilities, which are easier to monitor, have a larger impact on voltage support and for which the additional cost of an over-sized advanced inverter is an insignificant component of the system costs.

The issue of advanced inverter capabilities and certification is being decided in a separate Rule 21 proceeding. While there is still debate about what capabilities should be required and whether California should wait for national standards to be developed or move forward with state developed standards, these issues should be resolved within the next several months and standards developed and implemented within the next 2 – 3 years. Once standards have been developed and more manufacturers begin offering advanced inverters for small commercial and residential applications, these customer classes can then be included in the Living Pilot Program. This can be more easily achieved in targeted areas of the grid with the greatest LCR need using third party aggregators, though I am not opposed to SCE acting as an aggregator for this purpose. SCE could issue an RFO for aggregators to supply a certain amount of NQC from DG as well as voltage support on specific circuits and allow aggregators to bid.

For large commercial applications, SCE could use either a RAM-like or ReMAT-like mechanism targeting large commercial facilities on the circuits identified by SCE and CAISO as having the greatest LCR or voltage support needs. I am attaching comments provided by Vote Solar in Phase 1 of this proceeding last year as an example of how such mechanisms might be structured.

Rather than serving facility load, one option is for the large commercial program be designed so that the PV system supplies energy and reactive power directly to the grid rather than supplying energy for the customers' loads. This would greatly simplify the metering and monitoring requirements for energy consumed to provide reactive power for voltage support as well as actual watts and VARs produced. It would also allow more time for SCE to test and refine the program and for the Commission to review and approve tariffs for ongoing VAR support compensation (i.e., an ongoing payment for provision of ancillary services), paving the way for more widespread deployment and for inclusion of aggregated small commercial and residential installations. As the utility and 3rd party providers gain more experience with using advanced inverters for this purpose, the program could evolve to allow on-site consumption of solar energy along with voltage support for the grid.

Eventually including small commercial and residential customers could be more easily accomplished using a CSI-like mechanism that provides an extra incentive to cover additional costs that might be needed for oversizing the inverter to supply energy to serve customer loads while also providing voltage support to the grid. The implementation of a small commercial and residential advanced inverter program could be delayed until after the commercial program has been more fully refined. Unlike the proposed initial phase of the commercial program, the residential and small commercial program should allow for the PV system to supply the customer's energy requirements while providing additional voltage support for the grid using oversized inverters. This would require developing new metering and interconnection requirements along with tariffs to ensure energy consumed by the inverters for the production of VARs is not charged to the consumer and that the customer is fully compensated for VAR production as well as energy production. It may be possible to use the inverter-integrated metering capabilities to achieve this, though these details could be worked out in a separate proceeding or via the open stakeholder process SCE has proposed for the Living Pilot Program

I am agnostic with respect to the actual procurement mechanisms (RAM, ReMAT, or CSI-like mechanisms) to be used. SCE has indicated a desire to have stakeholder input for the development of their Living Pilot program, which I strongly support. An open, transparent process that includes meaningful stakeholder input will enable parties to work out the specifics of such a proposal and I welcome the opportunity to work with SCE, the Commission staff and other stakeholders in developing more details of this proposal.

Additional Comments on SCE's Testimony

SCE contends in its testimony that the local generation option has the lowest GHG impact of the four scenarios studied, including the Preferred Resources scenario. This does not seem like a reasonable result and I question the assumptions SCE used in making that determination. In Table III-5 on page 32 of SCE's testimony, the LA Basin Generation scenario requires 2,802 MW of new generation. Alternatively, the Preferred Resources scenario requires only 1,055 MW of in-basin generation – a difference of 1,747 MW. This should result in significantly lower GHG emissions in the basin than the LA Basin Generation scenario. Even adding in the full 1,200 MW imported generation that would be facilitated by the Mesa Loop-In upgrades, the amount of new generation required is still less than the LA Basin generation scenario. It must be noted, however, that SCE only modeled 400 MW of additional generation outside of the LA Basin for the Preferred Resources scenario[2].
SCE contends that the LA Basin Generation scenario would have lower GHG emissions because the gas-fired resources it modeled would be newer, more efficient technology. However, it appears that SCE may have only modeled generic gas-fired resources to represent the imported energy when analyzing the Preferred

[2] Track 4 Testimony of Southern California Edison Company, page 41, lines 2 – 3.

Resources scenario. The imported energy could very well come from renewable resources with zero or near zero GHG emissions, resulting in a significant reduction relative to the base case. SCE did not run the GHG emissions analysis using a cleaner mix of resources imported to the LA Basin, nor did it provide sufficient details on the assumptions used in their analysis of the relative GHG emissions reductions to allow for an accurate comparison of emissions from each scenario.

Similarly, SCE's analysis indicates the Preferred Resources scenario is the highest cost scenario, by as much as 50% when compared to the LA Basin Generation scenario. I question whether the LA Basin Generation scenario included lifetime fuel costs, as well as estimates of potential costs for obtaining Emissions Reduction Credits from the SCAQMD internal bank. As indicated on lines 25 – 26 on page 45, and continued on lines 1 – 5 on page 46 of SCE's testimony, SCAQMD is considering adding a fee for accessing the internal ERC bank under Rule 1304(a)(2). Finally, SCE's continued testimony on lines 6 – 16, page 46 discusses the potential difficulty of obtaining sites in the LA Basin for new generation. It is unclear whether SCE included a range of potential costs reflecting the very limited availability of suitable sites in the basin in their cost estimates. SCE also did not disclose its assumptions for forecasted resource capital costs or natural gas price forecasts, which can significantly alter the outcome of cost comparisons.

Comments on SDG&E Testimony and Alternate LCR Recommendations

San Diego Gas & Electric (SDG&E) provided testimony stating that there is a projected LCR shortfall of 500 - 550 MW in the San Diego area by 2022, assuming construction of the Pio Pico gas-fired generating plant is approved and moves forward.[3] This range of LCR need assumes deployment of an additional 338 MW of

[3] I am not providing an opinion on the need for the Pio Pico facility in this testimony. However, should the Commission disallow development of this facility, the 300 MW that was to be provided by Pio Pico should be included in the proposed Preferred Resources authorization.

peak reduction from new energy efficiency, 167 MW (96 MW dependable load reduction) of incremental rooftop solar, 20 MW of new CHP, 50 MW (20 MW dependable peak reduction) of additional local renewable generation (separate from the PV target above), and an unspecified amount of new DR. SDG&E does not include energy storage in these assumptions, however. The remaining 500 – 550 MW of LCR need is proposed to be met using an all-source RFO, consistent with the Preferred Loading Order.

As with the SCE proposal for an all-source RFO, I am concerned that costs assumed for renewable and other Preferred Resources, including energy storage, do not recognize the full value they provide to the grid, such as the voltage support capabilities of advanced inverters for PV and the avoided GHG and PM_{10} emissions for other Preferred Resources. The 500 – 550 MW LCR need identified by SDG&E should also be met with Preferred Resources and energy storage.

As with my proposal for SCE, SDG&E should include more west-facing PV with advanced inverters for voltage support as I described above. SDG&E should also develop a pilot program similar to SCE's Living Pilot proposal to monitor and evaluate the ability of Preferred Resources to meet LCR needs. SDG&E must also use an open and transparent process, including meaningful stakeholder input, as was proposed by SCE. Absent an independent pilot program, SDG&E should participate in the monitoring and evaluation of Preferred Resources in SCE's Orange County Living Pilot Program.

As for SDG&E's proposed energy park, while I am not opposed to the concept, I have concerns about the cost and potential bias favoring gas-fired resources in future generation decisions. Separating the cost of acquiring, permitting and developing the land from the cost calculation and comparison with Preferred Resources would unfairly advantage gas-fired resources and must be accounted for properly. I have similar concerns as stated above for SCE's proposed backstop gas proposal that SDG&E has not sufficiently justified the need or expense for such a park at this time.

If the Commission determines such a contingency is warranted, I favor the approach proposed by SCE of signing PPAs for gas-fired generation with an option to cancel the contract if no need is established for the units.

Responses to Selected Questions Posed by ALJ Gamson

At the prehearing conference on September 4, 2013, ALJ Gamson asked parties to provide answers to at least some of seven questions he posed during the conference. Below, I provide responses to several of the ALJ's questions.

Q. How much of the 1,400 to 1, 800 MW authorized procurement for LA area from Track 1 should be assumed in Track 4? Does it matter which resources are procured or what the mix of resources would be?

A. Since SCE has proposed combining its Track 4 request of 500 MW with its Track 1 procurement authorization and process, I believe it makes sense to assume the full 1,800 MW from Track 1 will be in place by 2020. If there is additional need, the remaining amount, up to the 2,300 MW requested by SCE in Track 4, should be authorized. However, as I stated in my testimony above, I believe the full amount should be met with Preferred Resources. In D.13-02-015, the Commission already authorized SCE to procure up to 600 MW of Preferred Resources (in addition to the 200 MW minimum Preferred Resources and energy storage, and the 1,000 – 1,200 MW of conventional gas-fired resources, up to the 1,800 MW limit). Given that the Commission authorized this level of Preferred Resources in Track 1, I believe it is reasonable to require SCE to fulfill the Track 1 Preferred Resources requirement <u>before</u> authorizing any additional resources in Track 4.

Q. Are there any other updates to assumptions that should be considered?
A. Although I have not been directly involved in many of the other proceedings, I believe there are several that could influence or be influenced by this proceeding, likely including the Energy Efficiency, Demand Response, Storage and Renewable

Portfolio Standard proceedings. Germane to my recommendations above regarding inclusion of advanced inverters in the proposed Living Pilot, the Rule 21 proceeding is considering what capabilities to require for advanced inverters, including maximum power factor settings and whether or not the State should develop its own standards or wait for national standards to be developed before allowing their use for such things as voltage support. Information from that proceeding should be considered in the LTPP Track 4 discussion, and the potential use of these inverters as a voltage support solution for the LA Basin and San Diego, and possibility of including them in SCE's Living Pilot Program, should similarly be considered in the Rule 21 rulemaking.

Q. What is the appropriate timeline for new resource procurement which may be authorized in Track 4? Do some resources have to come online earlier than others?

A. As I stated in my testimony, Preferred Resources should first be used to meet the remaining LCR need in the LA Basin and San Diego, above what was authorized for gas-fired generation in Track 1. Only if Preferred Resources can not be deployed in sufficient quantities or in a timely manner should gas-fired generation be considered. If the Commission favors implementing a gas backup program, I favor SCE's proposal to sign PPAs with developers that include opt-out clauses.

However, it is critical that the State not counter-effect its GHG reduction goals by building a significant amount of new gas-fired generation, particularly when one of the major resources being replaced was a zero carbon and zero emissions generator. Once these gas-fired generators are put in service, they will continue to operate for 40 or more years, displacing Preferred Resources that could have been used to help achieve carbon and emission reduction goals for the electricity generating sector.

While some utilities and others have expressed concern over the ability of Preferred Resources to meet local or system capacity requirements, the amount of these resources is still relatively small, yet continued deployment will allow utilities to gain valuable insights on how these resources can be most effectively and efficiently integrated into the grid. Preferred Resources procurement, using the mechanisms I proposed in my testimony, can be deployed in phases to more closely match needs due to their relatively short lead times and modularity, without concerns about obtaining air quality or carbon emissions permits or credits.

Q. Should there be any contingency plans in case expected levels of certain resources do not materialize in a timely manner?

A. While I am not opposed to the contingency plans for natural gas generation proposed by SCE or SDG&E, I am also not convinced of the need for advanced site preparation for reasons I discussed above. I believe SCE's proposal for signing PPAs with developers of gas-fired generation that contain an opt-out clause (and a penalty payment) is a more reasonable solution, provided the option payment is not exorbitant.

To backstop gas-fired generation and transmission development, my proposal for developing a procurement mechanism (such as a RAM-, ReMAT-, or CSI-like mechanism) would be expandable, allowing more solicitations by the utilities in the event conventional resources or transmission development is delayed or canceled. I also recommended using 3rd party aggregators to achieve Preferred Resources targets for specific circuits identified by SCE or CAISO designated as critical for LCR or voltage support needs. This would also facilitate deployment of Preferred Resources more quickly to backstop gas or gas-fired resources that fail to materialize in a timely manner.

Q. Indicate how the attributes of Preferred Resources or energy storage will meet LCR needs.

A. Distributed PV reduces demand and eases congestion on the distribution grid during the midday to late afternoon hours when summer loads are typically higher. Further easing late afternoon peak loads, PV arrays could be oriented to face west rather than south to maximize output when the power is potentially more valuable. This would require a change in rate structure, possibly moving to time-of-use rates, for distributed PV customers who would not have as much annual solar production in a west-facing configuration.

Including advanced inverter capabilities for voltage support as I have discussed in my testimony above would add further value by supplying voltage support in the afternoon when lines are heavily loaded and in need of additional VAR support.

Solar production drops off in the late afternoon (later when west-facing), requiring support from other Preferred Resources. However, energy efficiency, demand response and energy storage all complement distributed PV and can reduce LCR during the hours when the sun is not available for energy production. This would be best accomplished leveraging smart grid capabilities SCE and other utilities have been developing over the past 8 – 10 years.

Qualifications of James Edward Baak

James Edward Baak is the Director of Policy for Utility-Scale Solar for the Vote Solar Initiative, located at 101 Montgomery Street, Suite 2600, San Francisco, CA, 94104.

Mr. Baak earned his B.S. in Business Administration with a major in Business Economics from the University of South Carolina in May 1986. He was twice awarded academic scholarships and graduated magna cum laude. Mr. Baak has worked in the electric industry many sectors and in a variety of capacities for the past 26 years.

In his current role at Vote Solar, Mr. Baak is responsible for creating, influencing and implementing state, regional and federal policies, regulations, legislation and incentives to support the development of large central-station solar. Most recently, Mr. Baak has been working on regional transmission planning for the Western Electricity Coordinating Council's (WECC) Regional Transmission Expansion Planning program. He was twice appointed to serve as the Solar Technology Technical Advocate on WECC's Scenario Planning Steering Group, helping develop 20-year transmission plans for the Western Interconnection.

In support of his efforts at Vote Solar, Mr. Baak has provided written and oral testimony and comments in regulatory proceedings, has testified before state legislative committees on energy matters and has testified before U.S. House of Representatives' Natural Resources Committee at the invitation of Representative Edward Markey. Mr. Baak also serves on the Nevada State Office of Energy's New Energy Industry Task Force under two governors as an advisor on transmission and renewable energy issues. He has prepared economic analyses and presented to Nevada State legislators and at the request of Senator Harry Reid's Office in support of proposed federal legislation, was the lead contributor for the Western Governor's Association 2013 State of Energy in the West report and has been a contributor on a variety of DOE and National Laboratory reports and studies.

Before joining Vote Solar, Mr. Baak was a Senior Program Manager for PG&E from 2004 - 2008, where he was responsible for helping manage the California Solar Initiative program, focusing on metering, performance monitoring and solar thermal incentives. Mr. Baak worked with a coalition of solar advocates to successfully petition the CPUC for rule changes to enhance the CSI's metering and monitoring program. He chaired a working group to establish national certification standards for inverter-integrated meters and Co-Chaired the statewide CSI Metering Subcommittee. Prior to joining the CSI group at PG&E, he worked in the Meter Data Services group where he was responsible for investigating and resolving billing and metering issues for merchant generators and for improving the accuracy of load data analysis systems.

Mr. Baak was the Director of Utility Services for Powel Group from 2002 - 2004, providing consulting services to municipal utilities, designing time-of-use rates, and obtaining air quality permits, securing low-emission diesel alternative fuels and managing maintenance and warranty issues for large backup generators purchased by the utility to prevent rolling blackouts during the last energy crisis. He assisted EPRI in developing a 20-year strategic plan and was also responsible for sales and support of utility engineering analysis software.

From 1999 – 2001, Mr. Baak was the Director of Emerging Markets for Utility.com where he was responsible for evaluating deregulated utility markets and developing and managing national product rollouts for electricity and natural gas products. During his time there, he also negotiated a zero margin, equity only wholesale natural gas supply contract for resale in national competitive retail markets.

Before joining Utility.com, Mr. Baak was a rate analyst for Alameda Power in the Power Resources group, where he performed cost of service analyses and designed rates, including time-of-use rates for electric vehicle charging and for PV customers and reviewed purchased power bills and true-ups. In his capacity as Rate Analyst, he presented rate level and rate design recommendations to the Public Utilities

Board. He also served as Program Manager for the municipal utility's electric vehicle program, overseeing installations of charging stations and managing research and development efforts.

Mr. Baak started his career in North Carolina at the joint powers authority ElectriCities of N.C., Inc, where he performed cost analysis and rate design for member municipal utilities, often going before city councils and utility boards to present findings and recommend rate changes to elected officials, utility management and the general public.

This concludes my qualifications and prepared testimony.

Attachment

Opening Comments of the Vote Solar Initiative on the Administrative Law Judge's Ruling Seeking Comment on Workshop Topics (October 9, 2012)

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**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)

**OPENING COMMENTS OF THE VOTE SOLAR INITIATIVE
ON THE ADMINISTRATIVE LAW JUDGE'S RULING SEEKING
COMMENT ON WORKSHOP TOPICS**

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October 9, 2012

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)

OPENING COMMENTS OF THE VOTE SOLAR INITIATIVE ON THE ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON WORKSHOP TOPICS

Pursuant to the September 14, 2012 *Administrative Law Judge's Ruling Seeking Comment on Workshop Topics,* as subsequently amended by Judge Gamson's October 4, 2012, email ruling (Ruling), The Vote Solar Initiative (Vote Solar) submits these opening comments. Vote Solar's responses to the enumerated questions in the Ruling are limited to addressing the procurement of distributed solar generation.

Question 1 *What changes should be made to the rules governing the Investor-owned Utilities (IOUs') procurement process that would allow all resources (natural gas combined cycle, combustion turbine, storage, demand response, combined heat and power, renewable, etc.) to compete fairly in meeting identified needs? Please provide specific proposals for structuring an all-source procurement process.*

Vote Solar is not convinced that an all-source procurement process is necessarily better than the targeted procurement of either Preferred Resources or conventional resources. Particularly with respect to Southern California Edison's (SCE) Long Term Procurement Plan (LTPP) Track 1 needs related to the impact of once through cooling (OTC) plant retirements on Local Capacity Requirements (LCR), the hearing record includes numerous references to the possible need to enter bilateral negotiations with the existing OTC plants due their formidable market power, as well as the difficulties associated with attempting to analyze Preferred Resources and conventional resources side-by-side in all source solicitations. Furthermore, without some type of aggregation process, due to their very small scale, roof top solar installations can not reasonably participate in an all source solicitation.

Nevertheless, if the Commission determines that an all-source procurement process, as opposed to targeted procurement, should be used to procure both Preferred Resources and conventional gas resources, consistent with Vote Solar's presentation made during the September 7, 2012 joint workshop held in this proceeding and the Energy Storage proceeding (R.10-12-007), Vote Solar urges the Commission to consider adopting the distributed solar generation procurement mechanisms described in that presentation. The presentation is included as Attachment A.

If, however, the Commission determines that targeted procurement may be a better option (at least for the limited purpose of the SCE LTPP Track 1 LCR procurement), Vote Solar provides an alternative proposal in response to Question 4.E.

Question 2 *What amendments, if any, would be necessary to the most recent long-term Request for Offers issued by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) to ensure that all resources are eligible to compete in meeting future Request for Offers (RFO)? Are there any changes specific to meeting Local Capacity Requirements (LCR)?*

Vote Solar has not conducted a review of the most recent long-term Request for Offers (RFOs) issued by the California investor owned utilities, but based on a general understanding of the RFO process, the most recent utility RFOs would need considerable amending to include the procurement mechanisms described in Attachment A. Vote Solar suggests that the need to substantially change the existing RFO processes is another reason an all source RFO may not, at this time, be the optimal solution for procuring Preferred Resources.

Question 3 *What specific characteristics or attributes must any resource --*

including demand-side, energy storage, or distributed -- provide in order to meet future procurement needs? In the absence of a Net Qualifying Capacity, what methodology should be used to determine a proxy capacity value for resources lacking a Net Qualifying Capacity for use in LCR capacity accounting? How can these characteristics or criteria be turned into criteria to evaluate resources bid into a Request for Offers to meet LCR or other needs? How should those criteria be weighted?

Vote Solar does not support the California Independent System Operator's (CAISO) proposition that all new procurement needs to be as flexible as possible. With respect to LTPP Track 1, the consideration of flexibility issues remains premature until LTPP Track 2 is fully vetted. Moreover, CAISO's own modeling (referred to as the "Sensitivity" scenario), as described in the *Supplemental Testimony of Robert Sparks on behalf of the CAISO* (as entered into evidence in the LTPP Track 1 hearings, as Exh. ISO-2), demonstrates that significant incremental increases to Preferred Resources, when assessed from the demand side of the modeling and therefore without flexibility, considerably reduce supply side need, obviating the need to demonstrate Preferred Resource flexibility.

Accordingly, Vote Solar suggests that the modeling of Preferred Resources as a reduction to demand, at least at this point in time, makes immeasurably more sense than attempting to evaluate Preferred Resources as a supply side solution. If the Commission adopts a demand side modeling approach for Preferred Resources, an all source RFO solution is moot (at least for now), while the unwieldy act of fitting "square - Preferred Resource – pegs" into "round - all source RFO - holes," is avoided. The same demand side modeling approach holds true for determining proxy capacity values for resources lacking a Net Qualifying Capacity (NQC). By adopting a demand side modeling approach for Preferred Resources, the Commission saves the time and resources required to undertake an NQC analysis which will invariably be extremely contested and not even likely to render deeply useful results.

<u>Question 4</u> *What are the pros and cons of the following procurement methods with regard to: 1) local procurement considered in Track 1 of LTPP, and 2) operational flexibility and general system procurement considered in Track 2 of LTPP?*

A. Continuation of current practices for procurement with minor clarifications;

Should the Commission adopt Vote Solar's recommendations detailed in the response to Question 4.E, and mechanisms for procuring other incremental Preferred Resources are also in place, Vote Solar would support maintaining current conventional resource procurement practices.

B. A "portfolio approach" that allocates, based on strategic/portfolio considerations, the total quantity of new flexible resources among various eligible resources (for example, how could/should the allocations be adjusted periodically based on current or expected conditions?).

a. SCE provided two proposed alternatives to filling any LCR need at the September 7, 2012 workshop, one with flexibility for SCE in procuring resources via two separate tracks, and another approach using an all-source RFO. Is there some way to blend these approaches? If so, how, and should the Commission attempt to do so?

As stated earlier, Vote Solar is skeptical that an all source RFO will result in the best outcome for SCE's LTPP Track 1 LCR procurement. For these same reasons, Vote Solar favors granting SCE flexibility with regard to conventional resource procurement, ***but only with explicit Commission directives regarding Preferred Resource procurement.***

C. Establishing a set of minimum criteria for operational flexibility characteristics for all acquired resources;

Please see the response to Question 3. For the reasons stated in that response, Vote Solar is opposed to establishing operational flexibility characteristics for all acquired resources, and, more specifically, for Preferred Resources. Vote Solar does not oppose seeking flexibility from conventional resources.

D. A "strong showing" requirement that the utility must demonstrate that its procurement process was substantially open to all resource types and appropriately considered all of the values discussed above and that the resulting portfolio of resources is an optimal solution.

Vote Solar strongly opposes this ex-post approach to determining if the Loading Order was properly followed during utility procurement. While numerous arguments weigh heavily against this approach, the most overarching argument is that by the time the utility presents the "strong showing," it will be too late to unwind the process. Because the "strong showing" concept inherently requires a final procurement decision by the utility, even if the Commission determines that the Loading Order was not followed, particularly in the context of time sensitive procurement, the conventional resource procurement could not, realistically, be undone. Further, knowing that the utility is subject to this type of after the fact scrutiny may elevate counter party risk concerns, thereby increasing conventional resource prices.

E. Adjusting existing procurement mechanisms, such as the Renewable Auction Mechanism, to focus on the physical locations with needs that can be met by that programmatic resource.

Vote Solar is most supportive of this approach for the procurement of wholesale distributed solar generation, particularly with respect to the location sensitive needs of SCE's LTPP Track 1 LCR procurement. By using existing mechanisms such as the Renewable Auction Mechanism (RAM) for Preferred Resource procurement, the Commission capitalizes on known and tested Preferred Resource procurement procedures and policies, while enabling conventional resource procurement to proceed in a well-established and time-tested manner. In turn, both types of resources can be procured as expeditiously as possible, and with the ex-ante assurance that the Loading Order has been observed.

For customer sided solar, Vote Solar recommends using a mechanism similar or identical (depending on what is deemed legislatively permissible) to the California Solar Initiative (CSI). Between a location specific, RAM-like targeted procurement (LCR-RAM) and a location specific, CSI-like targeted procurement (LCR-CSI), Vote Solar believes that the Loading Order mandate for distributed generation would be fulfilled for the SCE LTPP Track 1 LCR procurement. Vote Solar is not commenting in detail on the other Preferred Resources at this time, but believes that a similar approach would also work for those resources.

If the Commission adopts an LCR-RAM and LCR-CSI approach, the Commission must also determine how many incremental MWs and/or dollars should be allocated to each of these existing (or similar to existing) programs. During Track 1 hearings, Vote Solar served testimony on this issue that was subsequently stricken from the record. The excerpted stricken testimony is found at Attachment B. ***Vote Solar includes the stricken testimony for the sole purpose of illustrating the mechanics of a possible method of allocating funding to existing programs, and in no way is suggesting or requesting that the Commission adopt the described approach.***

Vote Solar does, however, recommend a somewhat similar but vastly simpler approach. Based on the CAISO Sensitivity scenario modeling discussed in response to Question 3, for distributed solar generation Vote Solar recommends an incremental MW range of 832 to 1248 MW.[1] This range represents the incremental distributed generation assumptions in the CAISO Sensitivity scenario modeling, which is the basis for Vote Solar's recommendation of SCE's LTPP Track 1 LCR need in Vote Solar's Track 1 Opening Brief.

To split the 832-1248 MW between wholesale (LCR-RAM) and behind the meter solar (LCR-CSI), Vote Solar recommends the Commission authorize the following:

1. SCE immediately holds an LCR-RAM solicitation, but only for projects in the electrically equivalent local reliability areas. Using the same parameters for selecting non-LCR RAM, SCE selects winning projects.

[1] *Supplemental Testimony of Robert Sparks on behalf of the CAISO* (as entered into evidence in the Track 1 hearings, as Exh. ISO-2), at p. 6, lines 12-20.

2. The number of MW selected in the LCR-RAM are deducted from the 832-1248 MW allocated to distributed generation. The remaining MWs are then used to add an auxiliary step to the SCE CSI EPBB, except that the new "11th" step would only apply to solar installations in the appropriate local reliability area. This LCR-CSI would be priced at the lowest SCE step, or $0.20/watt. All other CSI rules would apply.

In Vote Solar's Track 1 Opening Brief, Vote Solar supports a conventional resource need finding of between 800 to 1700 MW. But, as stated in the Opening Brief, Vote Solar's position is entirely predicated on the Commission following the Loading Order by ensuring that the incremental Preferred Resources modeled on the demand side of the CAISO's Sensitivity Scenario are realized. Under this assumption, the incremental LCR-RAM procurement and LCR-CSI procurement offsets a portion of the additional 1300 to 2200 MW[2] of conventional resource procurement advocated for by the CAISO via the "Trajectory" scenario. Because the incremental Preferred Resources procured under the LCR-RAM and LCR-CSI avoid the need for incremental conventional resource procurement, the LCR-RAM and LCR-CSI related procurement costs are not incremental programmatic expenses. Rather, they are costs in lieu of incremental conventional resource expenditures and are, therefore, are *per se* cost effective.

Furthermore and quite notably, in the CAISO supported and preferred Trajectory scenario, Preferred Resource procurement is merely an "admirable goal,"[3] as opposed to the Sensitivity scenario, in which the Loading Order is vigorously embraced. By fully endorsing the CAISO modeling set forth in the

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[2] This range of avoided conventional generation includes the embedded impact of the transmission upgrades and the incremental energy efficiency and combined heat and power modeled in the Sensitivity scenario. During LTPP Track 1 litigation, through data requests propounded on CAISO, Vote Solar attempted to disaggregate the incremental resource and transmission upgrade impacts, but did not receive responses with sufficient granularity to proceed with a meaningful disaggregation analysis.

[3] *Supplemental Testimony of Robert Sparks on behalf of the CAISO* (as entered into evidence in the Track 1 hearings, as Exh. ISO-2), at p. 7, line 1.

Sensitivity scenario, the Commission has a strong evidentiary record upon which to authorize SCE to procure:

1) 800 to 1700 MW of conventional resources;

2) 832-1248 MW of distributed generation; and

3) an appropriate, to-be-determined MW amount of the other Preferred Resources in the appropriate LRAs,

to meet SCE's LTPP Track 1 LCR procurement needs. All of this procurement can occur in the near term, thereby resolving concerns about the timeliness of the procurement, and SCE can commence the procurement process with the knowledge that the Loading Order mandate has been met.

Vote Solar has no response to Questions 5 and 6

WHEREFORE, for the reasons stated herein, Vote Solar respectfully requests the Commission authorize the following with respect to the SCE Track 1 LCR procurement:

1. Fulfill the distributed generation element of the Loading Order by authorizing 832 to 1248 MW of additional LCR-RAM and then LCR-CSI procurement, as described herein, and find that such procurement is an offset to a portion of the avoided procurement of 1300 to 2200 MW of conventional resources;
2. Similar to the LCR-RAM and LCR-CSI approach, using existing Commission programs, or like-existing programs, allocate an appropriate amount of incremental MW to the procurement of the other Preferred Resources in the appropriate LRAs; and
3. Allow SCE to proceed with 800 to 1700 MW of conventional resource procurement in as flexible manner as possible, including the use of bilateral negotiations with existing OTC plants.

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Respectfully Submitted,

___/s/______________

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Dated: October 9, 2012

(Attachments A and B are presented in separate files)

The Role of Distributed Generation in an All Source RFO for Meeting Local Capacity Requirements

Energy Division Workshop on Meeting Resource Needs as Determined in the 2012 LTPP with Preferred Resources

September 7, 2012

Types of Distributed Generation Addressed in this Proposal

- "BMDG" -- Behind the Meter, Customer Owned (e.g. sized to load commercial or residential rooftop PV)
- "WDG" -- Renewable Wholesale (e.g. RAM or SB 32 projects)
- "CHP" – Combined Heat and Power (e.g. projects subject to the Settlement approved in D.10-12-035)

WINNING ATTRIBUTES OF BMDG, WDG & CHP

- Preferred Resources in the CA Loading Order
- Locational Flexibility/Mobility
- Faster to Site and Install
- Multi-site Aggregation
- Modular
- Optionality
- Procurement Flexibility
- Zero or lower GHG emissions
- BMDG and WDG is generally renewable

BMDG, WDG & CHP CONCERNS

- Uncertainty regarding whether DG will be built (i.e. the "uncommitted" resource).

- At least at the present time, most DG does not have significant flexible operational characteristics such as dispatchability and ramping.

- For BMDG and small WDG, attempting to fill large MW solicitation requests is impractical.

SOLUTIONS TO CONSIDER

- Method 1 applies only to BMDG because:
  1) BMDG capital costs are paid for by owner.
  2) BMDG is measured in terms of load reduction.
  3) BMDG requires aggregation.

- Method 2 applies generally to WDG & CHP, but with specific refinements for each.

- Addressing the uncertainty of "uncommitted" resources and the differences in performance between conventional resources and DG is central to both Method 1 and 2.

Method 1 for BMDG

- Aggregate MW quantities of new BMDG in relevant LRA.
- Offer the MW quantity at a fixed per watt price to be paid in one, immediate lump sum, based on the present value of yearly payments equal to the duration of the installation warranty (similar to the CSI EPBB).
- Offer is multiplied by an "Adjustment Factor" to reflect the load reduction impact.
- If the adjusted Offer is less than or equal to the marginal avoided cost of capacity for CT resources offered in the RFO, the BMDG Offer receives a higher ranking than CT resources.
- Winning BMDG Offer guarantees installation of specified MWs in relevant LRA over a certain period of time, and adjusted MWs of CT capacity displaced by winning BMDG Offers are not procured.

Method 1 BMDG Example
(this is just an example, do not quote me on it!)

Solar Aggregator offers 5 MW of new BMDG in the LA Basin LRA for a one time, up front payment of $2.5mm. This bid is analyzed as follows:

- Quantity = Q = 5000 kW
- Years = Y = 20 years (i.e. 20 year warranty)
- Avoided CT Cost = C = $144/kW-y
- Adjustment Factor = A1 = 50% (as derived from the difference between the CAISO LTPP Track 1 Trajectory and Environmentally Constrained modeling results)

Present Value @ 8% discount of [Q*Y*C*A] = $3.5mm

Solar Aggregator Offer ($2.5mm) <= $3.5mm therefore it is ranked higher than CT resources. CT procurement is reduced by Q*A1, or 2.5MW.

In addition to all the good things on the earlier "winning attributes" slide, Method 1 is a good approach to including BMDG in an All Source RFO because:

1)It guarantees incremental BMDG will be built in the LRA, removing uncertainty associated with uncommitted resources.

2)No associated debt equivalence or stranded cost risk.

3)Allows for aggregation of very small Preferred Resources in appropriate LRA.

Method 2 for WDG/CHP

- In the relevant LRA:
  1) New WDG offers all in price per kWh.
  2) New or un-contracted CHP offers capacity price.

- If Offer is less than or equal to the Market Price (MP) plus marginal avoided cost of capacity for CT resources offered in the RFO ($CT), as adjusted to account for CT production differences between WDG (A2W) or CHP (A2C), Offer receives higher ranking than CT resources.
  1) For WDG, MP = most recent RAM or SB 32 Re-MAT clearing price.
  2) For CHP, MP = most recent non LCR CHP-only RFO (D.10-12-035)

- Winning WDG or CHP Offer guarantees installation of specified MWs in relevant LRA over a certain period of time, and adjusted MWs of CT capacity displaced by winning WDG/CHP Offers are not procured.

Method 2 WDG/CHP Example
(this is just an example, do not quote me on it!)

- Solar Project offers \$0.10/kWh. MP = \$0.09/kWh from last RAM. Offer is \$0.01/kWh over MP. If \$CT*A2W >= \$0.01/kWh, Solar Project Offer is ranked higher than CT resources. CT procurement is reduced by the MW size of the Solar Project Offer as adjusted by A2W.

- CHP offers \$120/kW-y. MP = \$100/kW-y from last non-LCR, CHP only RFO. Offer is \$20/kW-y over MP. If \$CT*A2C >= \$20/kW-y, CHP Offer is ranked higher than CT resources. CT procurement is reduced by the MW size of the CHP Offer as adjusted by A2C.

In addition to all the good things on the earlier "winning attributes" slide, Method 2 is a good approach to including WDG and CHP in an All Source RFO because it:

1)Guarantees incremental WDG and CHP will be built in the LRA, removing uncertainty associated with uncommitted resources.

2)Ensures that offers above the established market (i.e. RAM, Re-MAT or CHP RFO) will only be selected if the increment is less than CT capacity that the WDG or CHP is replacing.

3)Utilizes existing Commission programs to help drive WDG and CHP offers to LRA.

LAST THOUGHT
(something to keep in mind)

Thoughtful calculation of the Adjustment Factors, referred to herein as:

1) A1 for BMDG
2) A2W for WDG
3) A2C for CHP

is very important to address operational differences between CT and DG performance.

THANK YOU!

~ and ~

GET SOME SUN.

Q. In the absence of an all source RFO at this juncture, what mechanism would you propose?

A. I propose a Preferred Resources LCR Mechanism (PRLM, or pronounced "*pree-lim*"). The PRLM fairly and transparently captures the value of the Preferred Resources, ensures that CFR are not over or under procured, addresses CFR market power, utilizes existing Commission programs and CAISO modeling, and can be implemented quickly and efficiently.

Q. At what point do you believe an all source RFO would be feasible?

A. I recognize the appeal of developing an all source RFO framework that allows for head-to-head, level playing field competition between all resources. Nevertheless, to attempt to segue to this type of approach ignores the tremendous resources already, and in many cases, recently, invested in existing Commission programs designed specifically for various types of Preferred Resources. Furthermore, attempting to build a robust and sustainable all source RFO policy which addresses the mismatch in development time scales and the load-offset profiles of each source is well beyond the scope of Track 1 of this LTPP. A more appropriate forum would be Track 2 of this or a subsequent LTPP. Indeed, working *within* the LTPP process to realize the goal of collectively comparing all resources is a far more public and transparent approach than, and thus preferable to, a conventional, utility driven RFO.

Q. Please describe the PRLM?

A. The purpose of the PRLM is to encourage the market to site Preferred Resources in the appropriate SCE LRAs. When this occurs, additional payment is made to those Preferred Resources that reflects the avoided costs that the utility would have spent on procuring CFR to meet LCRs. Ratepayers and the utility should be indifferent to the payment because it would have been made regardless of the existence of the PRLM – the PRLM simply provides a way to redirect procurement, using market encouragement, from CFR to Preferred Resources. With proper accounting in place, the PRLM will prevent acquisition of excess LCR resources by tracking the incremental impact of new Preferred Resources on lowering overall demand, and therefore overall LCR need.

The PRLM is developed using a differential analysis of two Track 1 cases modeled by the CAISO. The first case is based on the 2011-2021 CAISO Transmission Plan, high net-load trajectory assumptions, and forms the basis for CAISO's procurement recommendations for filling OTC LCR needs[1] (Case A) in Track 1 of this proceeding. The second case is based on the "sensitivity analysis" performed by the CAISO using the mid net-load, environmentally constrained case[2] (Case B). The CAISO recommends against using Case B for determining LCR in Track 1 of this proceeding because the CAISO believes that assuming the incremental, "uncommitted" amounts of Preferred Resources embedded in Case B will materialize is too risky, and thus jeopardizes grid reliability.[3]

I utilize the differential between Case A and Case B because of all the scenarios modeled in the CAISO 2011-2012 Transmission Plan, Case B is the most efficient in using Preferred Resources to mitigate LCR generation needs, and because the differential between the two provides a reasonable basis for developing funding targets for encouraging the incremental Case B Preferred Resources to site in the appropriate SCE LRAs. Essentially, under the CAISO's preferred Case A scenario, the CAISO recommends filling the amount of incremental, "uncommitted" Case B Preferred Resources with CFR. I, on the other hand, am proposing, consistent with the Preferred Loading Order, the PRLM, which redirects this CAISO proposed "chunk" of CFR procurement to Preferred Resource procurement.

Q. By using the Case A and Case B differential as the basis for the PRLM, are you endorsing the CAISO's modeling?

A. No, I am not endorsing the CAISO's modeling. As described in my direct testimony and the direct testimony of many other parties, the CAISO's modeling is problematic in a variety of

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[1] *Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation*, at p. 17 of 17, lines 4-5.

[2] *Supplemental Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation*, at p. 2 of 8, lines 12-24.

[3] *Ibid.* at pp. 4-7 of 8, lines 1-2.

ways. Nevertheless, presumably due to resource constraints, no other modeling has been presented and/or vetted as thoroughly as the CAISO modeling. Furthermore, I am not aware of anything suggesting that the CAISO's modeling will not be utilized, at least in some fashion, in deciding the disposition of Track 1 of this proceeding.

Thus, my use of the CAISO modeling as the building block for the PRLM is driven by practicality and necessity, and should not be construed, whatsoever, as my agreement with the CAISO's Track 1 procurement recommendations. I continue to support everything contained in my direct testimony. The PRLM is not a retraction of that testimony, but is instead a proposal to ensure that if the Commission does authorize procurement in Track 1, that the procurement properly reflects the Preferred Loading Order.

Q. What do you do with the differential between Case A and Case B?

A. As previously stated, the difference between Case A and Case B represents in MW the incremental Preferred Resources included in Case B, but excluded from Case A. I then re-characterize the MW differential between Case A and Case B as avoided costs. A core purpose of the PRLM is to encourage the use of Preferred Resources to fill the LCR need and thereby avoid unnecessary procurement of the CFR. To provide extra insurance that ratepayers are getting the full benefit of the Preferred Resource procurement, I discount the avoided costs by 25%. I chose 25% because it is a robust discount and leaves sufficient funds to encourage Preferred Resources to site in the appropriate SCE LCAs.

After calculating the discounted avoided cost (DAC), to determine the value over time, I then calculate the net present value of the DAC using a 20 year net present value calculation. Because I am recommending that the PRLM be iterated and reviewed on the 2 year LTPP planning cycle, this amount is divided by four to represent the four LTPP cycles between now and the year 2020. I will refer to this final amount as the Per Cycle Funding (PCF).

Consistent with the ratios of Preferred Resources embedded in Case B, I would then allocate the PCF to the various Preferred Resources, such that each class of Preferred Resource would have a separate "bucket" of PRLM funding. The funding would be utilized consistent with existing Commission programs applicable to each Preferred Resource, and to new programs as, or if, they are developed.

Q. What are the advantages of the PRLM over an all-source RFO?

A. The advantages of the PRLM over an all source RFO include but are not limited to:

1) The PRLM makes use of a sensitivity already modeled by the CAISO, thereby providing a good guide for the initial cycle. At each iteration, the Commission can evaluate whether incremental preferred resources are on track, how conditions on the ground may have changed, and incorporate improvements to the CAISO modeling. Thus, the PRLM makes good use of current CAISO analysis and provides needed nimbleness to adapt to new or improved future analysis. This open-endedness allow for an on-going dialog between the Commission, the CAISO and stakeholders on the best ways to refine future LCR analysis. Furthermore, by requiring a much smaller number of MW coming from CFR, the PRLM opens the way for more competition between types and locations of CFR and mitigates market power issues.
2) The PRLM is inherently modular. By operating on two-year LTPP cycles, the PRLM takes advantage of the shorter development times of Preferred Resources. By adjusting the buckets for each Preferred Resource as needed during LTPP cycles, the PRLM takes advantage of the granularity offered by the smaller increments of Preferred Resources.
3) Management of the Preferred Resource buckets can be informed by existing Commission programs, leveraging work already performed and minimizing incremental resource needs.

Q. Does the PRLM completely obviate the need for a CFR RFO?

A. Without conceding a need for new or replacement CFR, to the extent that the Commission finds the need to procure CFR, this would need to occur in an effort parallel to the PRLM. Based on my previously discussed analysis of the scarcity of real estate in the SCE LRAs and the related market power issues, such an effort may ultimately be best addressed through a bilateral negotiation between incumbent CFR and the utility.

Q. Is the PRLM a subsidy to Preferred Resources?

A. No, the PRLM is not a subsidy. As discussed above, funds used to encourage Preferred Resources to site in the appropriate LRAs are funds that would otherwise be spent on CFR. Appropriate PRLM accounting, such as memo accounts or other similar mechanisms, would ensure accurate tracking and would be trued up and reflected in the CAISO modeling during each subsequent LTPP cycle.

Q. Does the PRLM have a sunset date?

A. Absent changed circumstances, the PRLM should end in 2020. By 2020, all OTC related LCR needs should be addressed in a resource and cost efficient manner, and completely consistent with the Preferred Loading Order. The iterative nature of the PRLM will have enabled the Commission and the CAISO to hone in on the best ways to analyze how LCR needs can be covered by the widest range of Preferred Resources (including new ones like storage) in an integrated fashion. OTC retirements will have been mitigated, and PRLM-learned insights will be incorporated into ongoing reliability assessments.

Q. Can you calculate the PCF that would be utilized in the first iteration of the PRLM?

A. For the LA Basin, I have calculated approximately $370mm of PCF for the first iteration of the PRLM. My calculations are found at Attachment A to my testimony. I cannot, however, due to lack of transparency in the CAISO modeling and/or lack of resources, provide approximate bucket allocations. For this reason as well as others, I recommend that the Commission hold workshops to set the PCF, allocate the PCF to the various Preferred Resource buckets, and develop any other policy that might be necessary to implement the PRLM. As the owner/operator of the modeling, the CAISO would provide invaluable assistance in the workshops.

Q. Can you calculate the PCF that would be utilized in the first iteration of the PRLM for the Moorpark sub-area of the Big Creek/Ventura LRA?

A. Unfortunately, Case B covers only the LA Basin LCA, leaving me without data on the Moorpark –Big Creek/Ventura LRA and thus without an ability to calculate the related PCF. However, while all of the RPS sensitivities in the CAISO 2011-12 Transmission Plan describe 430MW of LCR need under high net-load conditions, it is quite possible that under mid net-load (or low net-load) conditions this need no longer exists. Moreover, SCE recommends that the "Commission Should Defer Authorizing LCR Generation in the Ventura/Big Creek Area Until the 2014 LTPP Cycle."[4] We endorse this recommendation, and further recommend that the Commission request an analysis from the CAISO responsive to stakeholder input, and perhaps similar in style to Case B for the 2014 LTPP planning cycle, for all applicable LRAs, for use in calculating the PCF of the PRLM.

Q. How would the PRLM address issues of flexibility brought up by the CAISO in its testimony?

A. I continue to affirm that it is premature to address flexibility needs in Track 1 of this proceeding. I will point out that if Preferred Resources are deployed according to the PRLM, transmission capacity will become more available in constrained pockets and thus flexibility needs can be met on a system-wide basis, further eliminating market power distortions that might arise from contracting for such flexibility in a specific set of locations.

Q. Have you discussed the PRLM proposal with other parties to the LTPP?

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[4] *Testimony of Southern California Edison Company on Local Capacity Requirements* at p.10, lines 12-13.

A. Yes, I have. In fact, on behalf of the California Cogeneration Council, I understand that Tom Beach will be co-sponsoring the PRLM proposal. I also understand that the Sierra Club and the Solar Energy Industries Association are generally supportive of the concept.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTACHMENT A

TRACK 1
PREPARED REPLY TESTIMONY OF
ERIC GIMON ON BEHALF OF
THE VOTE SOLAR INITIATIVE

<u>Calculation of the PCF for the first iteration of the PRLM</u>

(1) In his original direct testimony Robert Sparks recommends procuring about 2,400MW from a Case A 1,870-2,884MW-estimated range of OTC replacement need for Western LA (225MW of which covers its Ellis sub-area). In his supplemental direct testimony, Mr. Sparks identifies an OTC replacement need in the Case B scenario 1,042 MW (+ SONGS) at the most "effective" sites, with no further need in the Ellis or Moorpark sub-areas. This leads to avoided procurement of 2400MW – 1042M 1,400MW of conventional generation at the most "effective" sites. The use of an assumed 1,400 MW of avoided generation, and the CAISO's recommended split between combined cycle gas turbines (CCGTs) and combustion turbines (CTs), results in avoiding the construction of one 500MW CCGT and nine 100MW CTs.[1]

(2) The CAISO *2011 Annual Report on Market Issues and Performance* calculates that the cost of a new 500 MW CCGT, less the revenues that can be recovered in the market, is $126.6 per kW-year.[2] The corresponding above-market cost for a new 100 MW CT unit is $153.5 per kW-year.[3] Thus, the annual savings from the reduced local area requirements in Case B are approximately $200 Million

[1] In *Testimony of Mark* Rothleder *on Behalf of the California Independent System Operator Corporation*, at p 3 of 9 lines 27-28, Mark Rothleder indicated that CAISO modeled 2,800 MW of new generation with two 500 MW CCGTs and eighteen CTs. Iused exactly half of these to model 1,400 MW of avoided costs.

[2] Taken from the CAISO *2011 Annual Report on Market Issues & Performance* (April 2012), at pp.45-46, Tables 1.7 and 1.8, and Figure 1.20. I use the CAISO's calculated five-year average for the market revenues for this unit. The excerpt is found at Attachment B.

[3] *Ibid.,* at pp. 47-48, Tables 1.9and 1.10, and Figure 1.21. Again, this assumes the CAISO's calculated five-year average for the market revenues for this unit.

Per Year (an average of $143.9per kW-year), or a 20-year net present value of $2.0 billion ($1,413 per kW) at an 8% discount rate. I then multiply the $2.0 billion by 75% to reflect the discount ($1.5mm), and then divide by 4 to represent the LTPP cycles between now and the year 2020 ($370mm).