BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of the Results of Its 2013 Local Capacity Requirements Request for Offers for the Moorpark Sub-Area.	Application 14-11-016 (Filed November 26, 2014)
Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 (Filed February 11, 2016)

CLEAN COALITION COMMENTS ON MOORPARK SUB-AREA LOCAL CAPACITY REQUIREMENTS PROCUREMENT PLAN OF SOUTHERN CALIFORNIA EDISON COMPANY SUBMITTED TO ENERGY DIVISION PURSUANT TO D. 13-02-015

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I. SUMMARY: In order to provide a cost-effective renewable solution, the LCR plan must use a contingent approach in which DER have the first opportunity to meet the entire LCR need.

The Clean Coalition submits the following comments on the Southern California Edison (SCE) Moorpark Sub-Area Local Capacity Requirements Procurement Plan ("LCR Plan"), released December 21, 2017. These comments are filed prior to the revised deadline of January 16, 2018 and are thus timely.

The LCR Plan should incorporate the following approaches:

1) The LCR plan must employ a prioritized selection approach in which SCE first seeks to procure enough Distributed Energy Resources (DER) to meet the entire LCR need. Only if the DER procurement fails to meet the full LCR should transmission options be incorporated. Only if DER and transmission cannot meet the LCR should gas fired generation be incorporated. Under no circumstances should less than 21 MW of DER be procured.
2) The Clean Coalition's economic analysis demonstrates that DER provides a lower rate payer cost to meeting the LCR once a full-cost accounting includes Operations and Maintenance, return on equity, and depreciation costs (jointly "O&M costs") and the value of DER supplied energy, contrary to the unsupported statements in the LCR Plan.
3) The proposed RFO process from the Preferred Resources Pilot 2 (PRP2) is fundamentally inferior approach to a market-adjusting CLEAN program (Clean Local Energy Available Now), which offers developers the requisite price certainty and non-negotiable standard contracts to entice a robust response and lower risk and administrative costs. Instead, the Commission should require a CLEAN program with upfront transparent prices set by market conditions with price adjustment for market response and standardized non-negotiable contracts to provide certainty. At minimum, the Commission should develop a back-up CLEAN program to be triggered if the RFO fails to entice enough bids.
4) Any valuation process must allow for multi-technology DER microgrid aggregations to be evaluated as a single resource based on the characteristics of the aggregation.

5) Participating communities must have the option to retain Renewable Energy Credits (REC) for their projects, while either foregoing the REC adder in valuation or guaranteeing payment for the RECs in the procurement.

We wish to emphasize to the Commission and Energy Division that stakeholder input has been fundamentally important in the pursuit of 21st century renewable energy solutions in the Moorpark area. In the case of the Clean Coalition, we were to our knowledge the only stakeholder to demonstrate that SCE's claimed short circuit duty need for Ellwood was without merit in light of the ability of modern inverters, relays, and monitoring to provide fault detection services. Our comments have been fully vindicated now both by SCE admission that relays and monitoring can address SCD issues in the analysis required in the final Decision 17-09-034. We were also the only stakeholder before the Energy Commission to demonstrate that a full-cost analysis shows solar+storage to be the most cost-effective approach to meeting the CAISO identified LCR. Numerous community stakeholders have informed the debate without participating as a party in the CPUC proceeding. Overall, non-party stakeholders provide valuable facts and analysis to assist in realizing the Commission's vision of a fully renewable energy system.

In that spirit, we offer these comments to assist Energy Division staff and the Commission with what we hope proves to be valuable technical and policy analysis.

II. Description of the Stakeholder

The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of DER—such as local renewables, advanced inverters, demand response, and energy storage—and we establish market mechanisms that realize the full potential of integrating these solutions. The Clean Coalition also collaborates with load serving entities, DER developers, and municipalities to create near-term deployment opportunities that prove the technical and financial viability of local renewables and other DER.

III. Comments and Recommendations for Improvements to the SCE LCR Plan

SCE's LCR Plan should be revised to incorporate a mechanism by which preferred resources get preference by requiring substantial efforts procure the full 308 MW capacity in DER, and only if that approach can be shown to insufficient would transmission be authorized. Transmission is both too vulnerable and costlier than DER, as shown by the economic analysis presented here. Finally, Gas Fired Generation (GFG) is clearly outside the scope of the vision of both the Public Utility Commission and the Energy Commission and should only be deployed as a last resort.

Since timing and contract success are absolutely critical, the CPUC must ensure that DER procurements use a transparent and standardized CLEAN program to offer developers transparent upfront, market responsive pricing with standard non-negotiable contracts. With transparency, certainty, and lower administrative costs, the Utility Commission can greatly increase the amount of DER recruited into bidding, minimize contract failure, and ensure cost-effective prices. By comparison, the proposed Request for Offers (RFO) approach is opaque, cumbersome, expensive, and presents to great a risk of failure.

IV. SCE's efforts to meet LCR and resilience needs deserve full support, but should squarely give preference to preferred resources.

First, we fully endorse the need to meet LCR with local resources and avoiding large scale natural gas projects and SCE's efforts to achieve this result. Regardless of the precise mix, it is imperative that the energy future of the Moorpark area does not remain reliant on fossil fuel resources. Second, we applaud SCE's forward-thinking in supporting a resilience objective to provide for rapid re-energization of the local grid using DER. SCE clearly recognizes that the modern grid needs to provide reliability and resilience in addition to simple delivery of energy, and we look forward to SCE's continued efforts at innovating around DER-driven resilience. The Clean Coalition's looks forward to working with the Public Utility Commission and SCE on our Community Microgrid Initiative,[1] which is

[1] Clean Coalition Community Microgrid Initiative, http://www.clean-coalition.org/our-work/community-microgrids/

designed to achieve such DER-driven resilience across substation grid areas, which are the basic building blocks of the electric grid.

1. The LCR must be met with DER before other options.

The LCR program must guarantee that maximum amounts of DER are procured. Unless there is an express mechanism by which preferred resources are actually given a meaningful preference, the final procurement is likely to include non-preferred solutions. This priority adheres to the express intent of the suspension of the Puente Power Project to conduct "an expedited preferred resources procurement process."[2] Furthermore, the Utility Commission has also required that the local capacity needs of the Moorpark area "shall include review of scenarios without [proposed natural gas plants]"[3] and expressed a preference that the "Santa Barbara/Goleta needs … focus … on preferred resources." [4] Furthermore, since it has been demonstrated that DER is a lower overall cost solution than either natural gas fired generation or transmission, a fully DER-based solution should be implemented. Any alternatives should be incorporated in the final LCR only to meet any remaining requirement, if any, after maximum DER procurement.

Transmission alternatives are also inferior to a full DER solution, because the proposed transmission line costs more than the DER solution, once all costs and services are factored in (see economic model below), and as the fires and mudslides of the last few months have demonstrated, having four transmission lines crossing rugged fire-prone wildlands presents a vulnerability to that particular transmission proposal.

Although it is critical to ensure that the LCR Plan is concluded successfully, the CPUC should require triggers before transmission or natural gas plants are included within the LCR resources mix. Transmission should only be included if a streamlined DER

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[2] California Energy Commission "Committee Order Granting Applicant's Motion to Suspend and Denying Intervenors' Application to File Supplemental Response" Docket No. 15-AFC-01, November 3, 2017.

[3] Decision 17-09-034, "Decision in Phase 2 on Results of Southern California Edison Company Local Capacity Requirements Request for Offers for Moorpark Sub-Area Pursuant to Decision 13-02-015, October 5, 2017.

[4] Decision 17-09-034, Conclusion of Law 10.

procurement program yields less than 318MW LCR, and natural gas plants should only be included if a streamlined DER procurement program yields less than 76MW. Regardless, the LCR must be required to procure at least 21MW of preferred resources and continue until it is procured.

V. Transmission is not cheaper than DER and should be viewed as a first alternative to DER only if needed.

SCE proposes to rely primarily on a fourth transmission line to meet the LCR in the Moorpark area. Such an approach is highly vulnerable to foreseeable disruptions and would cost ratepayers more than a full DER approach.

1. The Full Costs of Transmission are greater than the full costs of DER reliability services.

A full-cost analysis reveals that when the costs of operations & maintenance (O&M) and the value of energy are incorporated, DER are likely to be cheaper than new transmission. SCE states without any support that "[t]he proposed transmission option reduces the LCR procurement need to 76 MW, at a customer cost that is much lower than what supply-side resources would yield." While this statement is true if only capital costs are compared, if the full costs are compared, it is likely not.

A full-cost comparison includes both all costs and an accounting for additional services. On the cost side, both options must include both capital costs and O&M costs over 30 years. On the services side, it is critical to recognize that while transmission provides only reliability services, DER capacity provides both energy and reliability services. Thus, an actual comparison of the cost of providing reliability services must account for the value of the energy that also comes with DER.

Estimated Transmission Costs

The full costs of a fourth transmission line must include the full costs of capital and the O&M costs. Based on CAISO's O&M estimates of cost increment schedule, the O&M costs over 30 years will be over five times the capital costs.[5] While the capital costs of new transmission over hilly terrain can run upwards of $1.7 million per mile,[6] the long-term ratepayer commitments to O&M, equity return for the transmission owners, and depreciation (jointly "O&M costs" hereinafter) that run 3.91 times the capital cost according to CAISO's O&M schedules.[7] With the long-term ratepayer commitments added in over 30 years, the total costs of transmission to over $8.5 million per mile or more. Based on the $45 million capital cost reported by CAISO,[8] the proposed 26-mile transmission line would cost ratepayers some $221 million over 30 years in 2018 dollars. These costs flow to ratepayers and must be included in the evaluation of the comparative costs.

Estimated DER Costs

By comparison, a solar+storage system would provide both reliability and also energy to the local community, displacing energy imports from outside the Moorpark area. Thus, the cost to ratepayers of the reliability service would be the capital and O&M costs minus the value of the energy these resources provide. Although the precise mix of the incremental DER needed to replace the transmission line to meet the LCR is somewhat flexible, one configuration that should be adequate to replace the proposed transmission line would involve 240 MW of solar and 825 MWh of batteries (comprised of 210 MW of battery power capacity with a mix of two and four hour durations), based on the load profiles presented by CAISO in the modeling of meeting Moorpark's need as presented to

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[5] The O&M, return on equity, and depreciation costs for transmission are based on CAISO O&M escalator estimates integrated over 30 years.

[6] Western Energy Coordinating Council, "CAPITAL COSTS FOR TRANSMISSION AND SUBSTATIONS: Updated Recommendations for WECC Transmission Expansion Planning" (2014) available at https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2014_TEPPC_Transmission_CapCost_Report_B%2BV.pdf&action=default&DefaultItemOpen=1

[7] For the calculations, see the "Cumulative Ratepayer Costs" tab of the attached excel model.

[8] Presentation on Moorpark-Pardee 230 kV No. 4 Circuit Project, January 11, 2018, http://www.caiso.com/planning/Pages/TransmissionPlanning/2017-2018TransmissionPlanningProcess.aspx

the Energy Commission in the Puente Application for Certification proceeding. Overall ratepayer costs after the ITC and component cost declines by 2019 and including O&M would cost on the order of $850 million. However, the 11.5 TWh of energy produced over 30 years would deliver a value of nearly $700 million, assuming a long run energy cost of $60/MWh. Thus, the residual costs of the reliability service that such a solar+storage system would be approximately $156 million, resulting in a $65 million savings for ratepayers compared to the transmission line. Under these assumptions, any long-run energy cost above $54.38/MWh drives a net rate payer savings from DER.

	Solar + Storage Alternative	**Moorpark-Pardee Transmission line**
Nameplate Solar (MW)	240	
Energy storage (MWh)	825	
2019 Installed Cost	$696,227,384	$45,000,000
After ITC benefit	$487,359,169	
MWh/year (1,600 MWh/year/MW)	384,000	0
30-year energy Total (MWh)	11,520,000	0
Operations & Maintenance ($/kW)	$50	
30-year O&M ($50/kW solar)	$360,000,000	$175,950,000
Total Cost	**$847,359,169**	**$220,950,000**
Energy Long Run Cost (per MWh)	$60	
Total Energy Value	**$691,200,000**	**$0**
Total Ratepayer Cost	**$156,159,169**	**$220,950,000.00**
Net Ratepayer savings from DER	**$64,790,831**	

Overall, whether the fourth transmission line is more expensive and by how much depends on a detailed assessment of the precise mix of DER that would replace it and the long run value of the energy provided. However, under reasonable assumptions, the transmission line would in fact cost ratepayers more for the reliability service than the DER solution.

Given that reality, there is scant justification for incorporating a transmission line as the preferred solution. Instead, SCE should be required to procure DER sufficient to meet the full LCR. Before deciding whether to approve either increased transmission capacity or a full suite of DER, the Public Utility Commissions should first evaluate both the full costs of the transmission line, including O&M, compared to the cost of the DER that would replace it, including credit for the produced energy.

2. Transmission is a vulnerable reliability solution

Although a transmission line is clearly preferable to any natural gas plant of any size, the proposed fourth line in the same right-of-way as the existing lines would be vulnerable to natural disasters, especially wildfire, landslides, and earthquakes. Although the LCR is designed to meet an N-2 contingency, the physical location of all four transmission lines in the same right-of-way increases the odds of an N-4 contingency. The right of way is located in wildlands immediately south of the Thomas fire, which may have been caused by electrical lines and was exacerbated by the failure of the grid to provide power because of the reliance on remote energy to power emergency equipment and water pumps. Last week, catastrophic mudslides wreaked tremendous damage on both sides of the proposed transmission line in Montecito and the Sun Valley/Burbank area. With greater risks of catastrophic fire under drier and hotter conditions, and mudslides under more extreme storms due to climate change, a DER solution should be deemed even more valuable for its resilience value, given the vulnerability of a transmission reliability solution to a local event that could remove all four lines from service causing an N-4 contingency.

Thus, the transmission line should be considered as an alternative non-preferred approach, only if robust and legitimate DER procurement processes fail to meet the full LCR.

3. Co-located solar+storage obviate the need for any transmission lines.

Several other arguments against the role of DER provided in the LCR Plan are simply wildly mistaken. For example, statements in the LCR plan and related presentation that "[under] an N-2 [contingency], no ability to charge battery storage units (need energy)" are completely mistaken, since of course batteries can be charged from co-located solar. Similarly, SCE states: "energy storage would be required to continuously discharge during the day in order to serve peak load and re-charge during hours when Goleta load is minimal. Given the limitations of the 66 kV tie lines from the adjacent system, there may not be enough energy in the off-peak hours to charge energy storage and serve the Goleta peak load needs the following operating day."

Of course, none of this is remotely true given the capabilities of solar+storage. In fact, the Clean Coalition modeled an hour-by-hour dispatch of solar+storage to meet the needs caused by the cancellation of Puente and Ellwood based on the load profiled provided by CAISO in the Puente Power Project Application for Certification.[9] In our modeling, the Clean Coalition demonstrated that with the 320MW of solar capacity, the addition of 130MW/480 MWh of storage (4-hour batteries) would be more than adequate to meet the LCR, including daily full charging from solar.

Given that solar+storage can meet the entirety of the projected peak load under an N-2 contingency, numerous other statements in the LCR Plan are similarly misguided. For example, SCE dismisses the capability of solar to meet LCR needs "For instance, if LCR needs are associated with peak demands and the local capacity area is summer peaking, then distributed solar resources may be valuable." In fact, storage co-located with solar would not discharge during the day, but would rather charge from co-located solar and so would not need to rely on the 66kV system for recharge, and neither would the ability of solar co-located with storage be limited to meeting peak demands during summer daylight

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[9] Puente Scenarios Cost Models (Supplemental Testimony of Dr. Doug Karpa re CAISO Study, Puente Power Project Application for Certification, Docket Number 15-AFC-01, Exhibit 7035, TN# 220961)

hours. The artificial division of technologies into individual characteristics without consideration of their joint characteristics is a serious and dramatic oversight.

Similarly, SCE mischaracterizes the operational capabilities of demand response. Today, Demand Response (DR) is not limited to a small number of calls to large industrial users, but rather includes capabilities such as automated DR of non-critical load. When SCE mistakenly suggests that "[i]f LCR needs occur only on rare occasions associated with such summer peak periods, then DR programs with a limited number of calls may be valuable" SCE is ignoring the modern capabilities of DR technologies. For example, small reductions in air conditioning or electric water heaters would be capable of repeated calls at any time such calls were needed, even if sporadic and outside of summer peaks.

In the Public Utility Commission's review of the LCR it is critical to bear the actual capabilities of DER and actual costs squarely in mind.

VI. The LCR Plan must use a CLEAN program, rather than an RFO process, to ensure maximum bid responses, minimal contract failure, and lowest cost.

It is imperative that DER procurement be efficient, cost-effective, and timely. Given the overriding importance of a successful DER procurement, it is critical that the Public Utility Commission implement a procurement process that has low administrative costs, a strong historic record of successful bid recruitment, and a track record of turning bids into built projects. The Request for Offers (RFO) process is not such a process for recruiting large numbers of smaller projects. The particular characteristics of DER projects requires a more streamlined and efficient process: the CLEAN program.

In fact, in short order, the Clean Coalition has confirmed multiple developers endorse this approach, including at least two participants considering projects in the Goleta load pocket, although the names have been withheld at this time.

CLEAN Program Framework

1) Offer standardized, transparent, non-negotiable contracts.
2) Offer streamlined interconnection processes, including batch studies.
3) Establish initial price for first tranche of capacity via market research.
4) Non-negotiable contracts are offered to the queue until tranche is full.
5) Adjust price at each successive tranche at price depending on market response to prior round (upward if response is weak, downward if strong)
6) Continue until all 208MW capacity is

Streamlining is critical because the developers of smaller projects need price certainty, transparency, contract standardization, and streamlined interconnection in order to be enticed to provide cost-optimized bids in a short timeframe. A market-adjusting CLEAN program provides all of these, while an RFO provides none. Since bids into an RFO involve hundreds of thousands of dollars in expenses with high levels of uncertainty around price, developers face bid costs that eat up a high percentage of the project value (A $150,000 bid on a $3 million project represents a 5% costs just to launch a bid for an uncertain price and uncertain contract.) As a result of high administrative costs and high uncertainties, many potential bids will simply fail to materialize and those that do will include a risk premium, driving up overall costs.

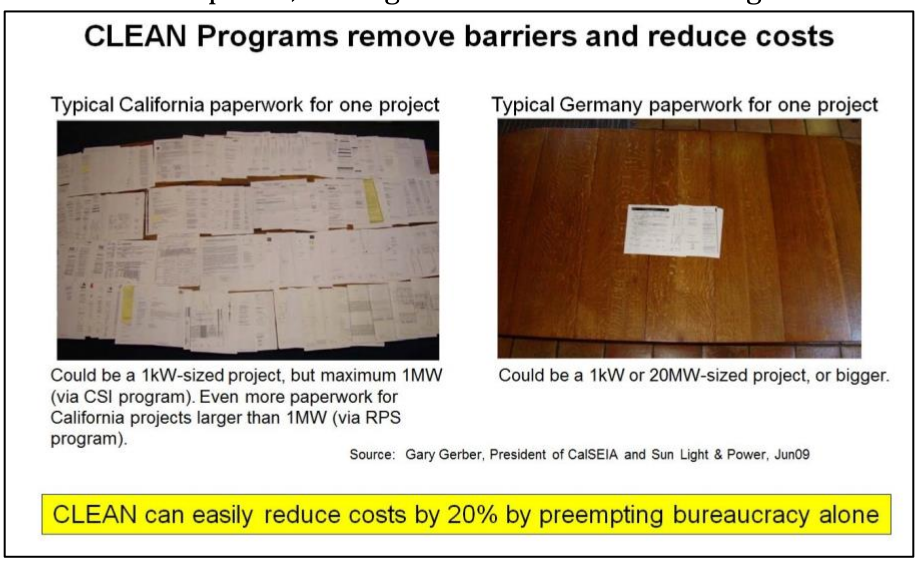
In contrast to the proven failure of the RFO approach for large numbers of smaller projects, CLEAN Programs offer transparent prices in a staged market-responsive batched reverse auction that retains the transparency and standardization benefits of a Feed-In Tariff, while incorporating pricing set by a market auction mechanism. In a CLEAN Program, tranches of procurement are offered on a first-come, first-serve basis at a fixed price, with price adjustments for each additional tranche depending on the response to the prior round. By setting the first-round price at the lower end of a reasonable range, ratepayers are guaranteed a cost-effective mix that will be cheaper than RFO procurement because developers face lower risk. Such programs offer price certainty and standard contracts to developers and clean resources and cost-effectiveness to ratepayers.

Second, developers must have publicly accessible information that allows developers to self-screen for interconnection with a fixed-fee as is done with net energy metering programs to foster faster deployment. The Clean Coalition is developing a further pilot with PG&E to develop additional improvements as part of the Peninsula Advanced Energy Communities[10] program that should inform this element of the program.

Even if the Public Utility Commission opts to instruct SCE to pursue the RFO, the Commission should consider designing a CLEAN program to be implemented later in 2018 should the initial bid Indicative Offer submittals fall short of expectations or needs.

1. CLEAN Programs are faster to deployment

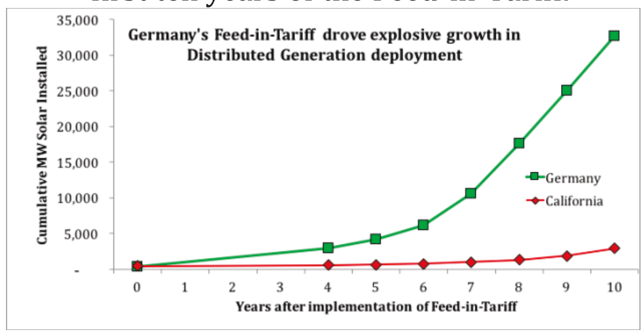
Ultimately, the CPUC and California do not have time for SCE to get the procurement wrong. CLEAN programs[11] are faster and less prone to contract failure, because they are simpler for developers to respond to and simpler for the utility to evaluate. CLEAN Programs use standardized contracts and prices, cutting out the individualized negotiation process that delays RFO procurement. Once the CLEAN program offer has been issued, developers can assess the offer and respond quickly to the standardized conditions. Developers also are more likely to bid because they face much lower risk, because projects that meet requirements are guaranteed a procurement contract from the utility until a tranche is filled. From the utility side, the selection process is a simpler and provides a faster standard review of whether a project meets requirements without cumbersome negotiations. The regulatory process is also faster, because the CLEAN program is subject to a single CPUC program authorization, rather than individualized review of every RFO contract.



[10] Clean Coalition, Peninsula Advanced Energy Community (PAEC), http://www.clean-coalition.org/our-work/peninsula-advanced-energy-community/
[11] Clean Coalition, CLEAN Programs, http://www.clean-coalition.org/our-work/renewable-utility-programs/unleashing-clean/about-clean-programs/

2. Fixed-price programs have a proven record of successful procurement

1) Germany deployed over ten times the renewable capacity California did in the first ten years of the Feed-in-Tariff.



2) Germany installed nearly all of this capacity as in front of the meter distribution grid connected projects under 2MW.
3) Germany realized rates translate into a cost in California of **between 4 and 6 cents/kwh**, after accounting for California's tax incentives and increased output under a better solar resource,

CLEAN Programs share these key characteristics with Feed-in Tariffs, which have a proven record of rapidly deploying substantial renewable capacity well within two years from offer to final installation. As a leading example, Sacramento Municipal Utility District (SMUD) received nearly enough bids to fill SMUD's entire 100 MW Feed-In Tariff solicitation on the first day the Feed-In Tariff was launched in January 2010. Within two years, 45 MW had been installed and within three years 98.5 MW had been successfully installed. This timeframe can be expedited to easily beat the schedule of the most expedited RFO process. Similarly, the AB1969 & ReMAT programs have successfully procured roughly 500MW of solar despite some significant ReMAT design flaws. The 98.5% success rate of the SMUD Feed-in Tariff and the record of AB1969 & ReMAT procurement is vastly better than SCE's record with RFO programs such as the one used in the PRP.

Similarly, other jurisdictions have used Feed-in-Tariffs to drive strong growth in renewables where there has been a strong push for rapid, cost-effective deployment. In one of the most dramatic examples of an exceptionally effective deployment of renewable energy, Germany vastly outpaced California's deployment by a factor of over 10 between 2002 and 2012, all at an effective California cost of between 4 and 6 cents a kWh.[12]

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[12] Translating the installed costs per kWh into the California context must account for the exchange rate of euro denominated costs, the favorable tax treatment of solar (30% ITC

3. CLEAN Programs deliver market adjusting cost-effective prices

By starting with an initial price that meets the cost requirements and adjusts according to the response to the initial offer, CLEAN programs guarantee procurement is cost-effective. The initial price could be established by market research or a price based on the PPA price deemed reasonable for the Puente Power Project as approved by the Commission. Alternatively, although such an approach would remove the benefits of a transparent upfront price, the price of the initial round could be set by a Japanese Reverse Auction, in which the price offered for the first batch of capacity is lowered in stages, with bids withdrawing from the round until only enough bids to fill the first capacity tranche are left.[13] Even with a more modest initial offering price, costs can be contained with a market-adjusting CLEAN Program in which the offer price adjusts depending on the response in the prior round. [Please see the accompanying Environmental Justice CLEAN Program description.] Furthermore, desired elements such as storage capacity can be either included in project requirements or induced through adders to incentivize dispatchability of the project capacity in order to ensure that the resulting offers can meet the entirety of the Moorpark Subarea procurement requirements.

4. SCE's Preferred Resources Pilot 2 is a model of how not to procure DER

The public deserves a more effective and more transparent process than an RFO based on the Preferred Resources Pilot 2 (PRP2). SCE's choice of the PRP methodology in this RFO is particularly astonishing, since SCE pointed precisely to the PRP as an example of a program that struggled to procure large amounts of DER quickly in its testimony before the

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plus other incentives), and the fact that a solar panel in California delivers 33% more energy per installed watt because of the better solar resource.

[13] For example, if the first tranche were the required 21MW, a Japanese Reverse Auction would accept all bids meeting standard contract requirement for the auction. Starting at a high price, the price is lowered in each auction round by a fixed amount. In each round, bids commit to taking that price or withdrawing until only 21MW remain. These bids receive that auction price, and the price for subsequent rounds is based on this price. 21MW is the price for all remaining bids. Such a procurement method would guarantee procurement of the minimum required 21MW of capacity at the minimum market price.

California Energy Commission in Oxnard on September 14, 2018.[14] SCE also received recommendations to adopt a Feed-In Tariff approach for that program as well, but declined to adopt that methodology. Precisely as predicted, the PRP procurement struggled to meet goals and to prevent contract failure.

Furthermore, the public is poorly served by the lack of transparency in an RFO process, because SCE faces an inherent conflict of interest between pursuing a project into which substantial costs have been sunk and procuring renewable resources. The request that the Energy Commission suspend rather than reject the Puente Power Project suggests that SCE and NRG retain an interest in Puente. Thus, allowing SCE to conduct an RFO process that is opaque due to confidentiality concerns creates a situation ripe for substandard implementation.

Where timing, price, transparency, and success are critical, the RFO process is vastly inferior to a market adjusting transparent pricing program like a CLEAN Program.

5. **The RFO process is too slow, too cumbersome, and prone to failure.**

In sharp contrast to fixed price, fixed contract programs, the RFO process is expensive, slow, and cumbersome and highly prone to failure. For example, a review of the RPS auction shows that fewer than one in ten bids result in executed projects, while the Renewable Auction Mechanism (RAM) has recorded an abysmal success rate of 28 executed bids out of 552 bids (see Figure 1 and 2). Similarly, SCE's Preferred Resources Pilot that SCE has chosen as a model failed to produce a high number of successful bids.

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[14] Transcript of 09/14/2017 Evidentiary Hearing, Puente Power Project Application for Certification, TN# 221283, Docket 15-AFC-01, pages 236 and following. http://docketpublic.energy.ca.gov/PublicDocuments/15-AFC-01/TN221283_20170921T111219_Transcript_of_09142017_Evidentiary_Hearing.pdf

The issues are entirely predictable given the cumbersome administrative process of an RFO for both developers and the utility. Under an RFO, developers prepare detailed and individualized bids without the benefit of transparency of the possible contract price or any certainty of offer acceptance. This elevated risk and customization of proposals reduces the number of bids and increases the price as administrative costs and risk premiums are folded into bids. Furthermore, the process of shortlisting, negotiation, failure, repeated negotiations, offers and then CPUC approval results in unnecessary delays in reaching a higher price and fewer procured resources. The risks for developers, negotiation failures, and delays in an RFO mean that recruitment will be weaker and the prices will be higher.

Figure 1 - Fewer than 1 in 10 bids results in an executed contract

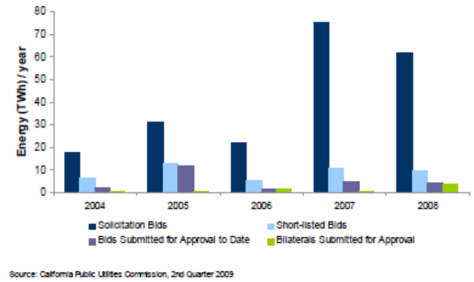

Figure 2 – RAM has resulted in a high failure rate.

VII. Evaluation Methodology is contrary to stated "preference" for preferred resources

Although SCE states that it has a "strong preference" for resources in the text of the plan, there is no meaningful express bonus to ensure that preferred resources are preferentially procured in the bid evaluation methodology. The word "prefer" means "to set or hold before or above other persons or things in estimation; like better; choose rather than."[15] However, in the current RFO preferred resources are evaluated purely based on costs and are not given preference that would "set them above other things in estimation." In order to actually be "prefer" resources, the LCR Plan must include a mechanism to give these resources preferential treatment in the valuation of bids.

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[15] Prefer definition, Dictionary.com

The Clean Coalition recommends that the procurement be conducted to first recruit 308 MW of DER and only approve the inclusion of transmission or gas fired generation should the requisite acceptable bids fail to materialize. We recommend that the procurement be conducted on a staged basis, where preferred resource providers are given the first opportunity to meet the entire LCR. Only if that fails would non-preferred resources be considered. Such a process could be handled by first launching a comprehensive CLEAN Program, like the Feed-In Tariff that the Clean Coalition recently designed for East Bay Community Energy (EBCE)[16] (or launching one if the RFO proves insufficient); and only approving any transmission or gas fired generation if the CLEAN Program fails to meet capacity targets.

In no case should SCE be allowed to procure less than the minimum 21 MW of DER capacity to ensure the full LCR is met with this procurement, and if the RFO does not succeed, a CLEAN Program[17] would unequivocally become necessary.

In fact, the valuation methodology only includes various adders that reflect avoided costs for SCE, rather than the full benefits. For example, the proposed "renewable energy credit" would be valued at zero where SCE has met its RPS targets, despite the fact that renewable energy has substantial air pollution and carbon emission benefits whether or not SCE has met its RPS targets. Similarly, the GHG adder ignores the social cost of carbon and only counts GHG compliance costs where they are passed through to SCE. Neither mechanism is adequate to give preferred resources a meaningful preference in this procurement.

Thus, the better approach is to conduct a preferred resources procurement first and only turn to alternatives should that fail. If the Commission pursues an RFO approach, the RFO should incorporate a preferred resources adder that operationalizes the value of the

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[16] Clean Coalition, East Bay Community Energy Feed-in Tariff Design Recommendations, www.clean-coalition.org/site/wp-content/uploads/2017/12/Task-3-EBCE-FIT-Design-Recommendations_DRAFT.pdf

[17] Alternatively, SCE could launch a standard contract Japanese Reverse Auction that would be guaranteed to procure at least the minimum procurement. Such a mechanism could potentially be implemented under a RAM-type authority.

preference for preferred resources. However, given the substantial problems with RFOs, this is clearly a lesser option.

VIII. Preferred Resources must be prioritized within environmentally disadvantaged communities.

Similarly, it is unclear how SCE would prioritize DER projects in environmentally disadvantaged communities. (Presumably gas-fired generation would not be considered if located in an environmentally disadvantaged community.) The Clean Coalition strongly support the preference for DER in disadvantaged communities as an approach to providing a trifecta of local economic, environmental, and resilience benefits; but this LCR plan does not fully embrace those benefits. As with the preference for preferred resources the valuation methodology does not contain a clear method for promoting such resources. The plan clearly recognizes the importance of placing renewable resources in environmentally disadvantaged communities to alleviate pollution in those communities and other communities. We are mindful that the 55MW gas-fired generation could encompass the Ellwood refurbishment, which is located within 1000 feet of a vulnerable school population. Although Decision 17-09-034 leaves open the possibility of evaluating a LCR plan including Ellwood, such a plan would be incompatible with avoiding impacts to vulnerable populations.

IX. Natural gas Fired Generation should only be considered if and only if DER procurement and transmission fall short.

Deploying gas-fired generation should not be included in the final procurement unless absolutely needed. In the decision rejecting the Ellwood refurbishment, the CPUC was clear that the LCR "shall include … scenarios without [proposed natural gas plants]."[18] This instruction clearly indicates that the SCE plan must provide for a plan to meet the LCR without natural gas. Furthermore, Decision 17-09-034 provided for SCE to include the Ellwood project, but not a generalized license to incorporate gas-fired generation at will.

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[18] Decision 17-09-034

The LCR plan currently does not expressly provide for developing a LCR package without natural gas or Ellwood.

As demonstrated in the Clean Coalition modeling related to the costs of the Puente project, the full costs of solar+storage would run roughly half the all-in cost of the comparable natural gas plant. Thus, when the full costs of resources are included, it is extremely unlikely that a natural gas plant would be a cost-competitive resource. This reality sharply undercuts the rationale for inclusion of natural gas fired generation.

Furthermore, additional natural gas plants involve much longer-term approval and construction processes and would be unlikely to be able to meet the timing requirements driven by the mandated retirements in 2021. Since SCE has repeatedly emphasized that time is of the essence, we cannot afford risking a lengthy and contentious approval process that an additional natural gas plant would entail. Inclusion of this component would greatly increase the risk of failure to procure the necessary resources in a timely manner.

Natural gas-fired generation is problematic because Ellwood's air permit limitations prevent it from reliably meeting LCR needs under an N-2 contingency and any new gas plant would face significant resistance and require a lengthy and uncertain permitting process. Therefore, natural gas should only be considered as a last resort if SCE fails to procure the minimum 76 MW of capacity.

X. The RFO methodology needs several critical improvements

1. Solar+Storage and Microgrids including Demand Response must be treated as unitary resources

The LCR Plan must include hybrid aggregated resources as a single aggregated resource category. Aggregations, such as Community Microgrids, use complementary technologies to provide an overall dispatchable resource that can provide a neighborhood or substation area with uninterruptible energy in the case of a grid failure. Unlike traditional single customer microgrids, Community Microgrids in particular constitute assemblages of DER at multiple sites and owners that can be islanded and coordinated to provide energy to local load combined with pre-established tiered Demand Response. Where an automated tiered Demand Response element is included, the Distributed Energy

Responses Management System can automatically reduce loads depending on the category of the use. Tier 1 loads are critical uses, such as emergency services, medical facilities, and units with critical medical devices, which are guaranteed energy, while Tier 2 important loads would be provided energy in most instances, while the remainder of loads are Tier 3. Unlike a crude approach of dropping entire areas, the Demand Response manages load building by building.

Aggregated hybrid resources can provide entirely different services and characteristics from the constituent technologies. Thus, Community Microgrids, solar+storage, or solar+storage with coupled automated DR can provide must be evaluated as a single resource for the purposes of evaluating dispatch capabilities and other services. Based on our discussions with developers, the Clean Coalition anticipates that many of the DER bids will be precisely this kind of combined resource. Currently the most cost-effective way to install storage is co-located with solar used to both dispatch energy and recharge the storage, since this allows storage facilities to take advantage of the current federal income tax credit. Automated DR can be coupled with solar+storage into an aggregated DER microgrid with joint controls that combines the capabilities of all technologies to create a unitary resource with characteristics unlike any of its component parts. Since the joint characteristics are distinct from those of the component technologies such aggregate resources should be evaluated based on what the assemblage of technologies can provide. Although such term sheets are anticipated (at least for IFOM and BTM solar+storage hybrids, but not solar+storage+automated DR), some statements in the LCR text (e.g., "neither distributed solar resources nor DR will be valuable to meet those needs.") make it unclear how SCE intends to evaluate the characteristics and services of aggregated resources.

2. **Participating Communities must have an option to retain Renewable Energy Credits from projects they stage within the LCR area.**

Both Santa Barbara and Goleta have established 100% renewable energy goals which would require retention of their Renewable Energy Credits to document. Thus, requirements that participating projects be applied to meeting SCE renewable goals including the surrender of RECs for these projects will depress participation from important municipal and county efforts and their partners. For example, the City of Santa Barbara has some 30 MW of solar+storage opportunity that could participate, providing such issues can be resolved, and Goleta has a large number of large C&I customers that could provide significant solar siting opportunities that may face similar obstacles.

Therefore, the Clean Coalition recommends that participating communities have the option to retain RECs and either surrender that component of the bid valuation or pay SCE fair market value for the RECs to retain the renewable energy credit in bid valuation.

3. The Discount Rate of 10% is inappropriate for modeling ratepayer costs

SCE uses an exceptionally high discount rate of 10% for its valuation methodology. However, the discount rate to assess costs to ratepayers should reflect the returns on competing investments by ratepayers, almost none of which may achieve 10%. Furthermore, by using an inappropriately high discount rate, social costs in the future would be inappropriately devalued. In fact, for social costs where there are intergenerational impacts, the discount rate should reflect a real rate of zero.

XI. Conclusion

The Moorpark LCR Plan is of paramount importance in meeting the state's renewable energy goals and has the potential to be a groundbreaking effort in a national example of meeting reliability needs with significant amounts of renewable resources. The importance of such an example cannot be underestimated. The importance of success is even greater given that the alternative gas fired plants are deeply unacceptable to local communities and the people of California.

The Clean Coalition emphasizes that it fundamentally important that the Public Utility Commission take all possible steps to ensure the success of the LCR Plan. This includes steps to streamline the procurement process and steps to ensure adequate bid recruitment. Foremost among these steps would be the implementation of a CLEAN program as either the primary or as a backstop program.

Given the importance of doing so with a reasonable ratepayer cost, it is also critical that alternatives be evaluated based on the full cost of each alternative and not using just capital costs. We believe that such an approach would lead to the most cost-effective solution, which will prove to be a full DER solution. However, should renewable resources involve a modest increment in the project evaluation process, this is warranted given the dangers of locking California into decades of additional carbon emissions.

Finally, we are grateful and respectful of the work by SCE, Energy Division, and the Commission in working to solve the critical problems involved in this LCR Plan.

Respectfully submitted,

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Clean Coalition