BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902E) for Authority to Implement Optional Pilot Program to Increase Customer Access to Solar Generated Electricity.	Application 12-01-008 (Filed January 17, 2012)
Application of Pacific Gas & Electric to Establish a Green Option Tariff.	Application 12-04-020 (Filed April 24, 2012)
In the Matter of the Application of Southern California Edison Company (U338E) for Approval of Optional Green Rate.	Application 14-01-007 (Filed January 10, 2014)

OPENING BRIEF OF THE CLEAN COALITION REGARDING SOUTHERN CALIFORNIA EDISON'S APPLICATION TO ESTABLISH GREEN RATE AND COMMUNITY RENEWABLES PROGRAMS

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May 2, 2014

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I. Introduction

The Clean Coalition recommends that the methodology for calculating the costs and benefits of Southern California Edison's Green Rate and Community Renewables programs include avoided new generation costs and locational value to maintain ratepayer indifference and meet the requirements of SB 43.

- Avoided New Generation Costs. To the extent that the Long Term Procurement Plan proceeding finds that new generation is needed to meet system needs or state goals, and to the extent that such proceeding finds that SB 43 generation can be used to meet these needs, Green Rate and Community Renewables program participants should receive a credit for the value to nonparticipating ratepayers of offsetting the need to procure new generation.

- Locational Value. SCE's cost-benefit analyses should include locational value to avoid shifting the benefits of resources located closer to load to nonparticipants. Further, recognizing the locational value of local projects is necessary to meet SB 43's requirements for utilities to "seek to procure eligible renewable energy resources that are located in reasonable proximity to enrolled participants" and "provide support for enhanced community renewables programs to facilitate development of eligible renewable energy resource projects located close to the source of demand."

The Clean Coalition is a California-based 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, interconnection, and realizing the full potential of integrated distributed energy resources, such as distributed generation, advanced inverters, demand response, and energy storage. The Clean Coalition also works with utilities to develop community microgrid projects that demonstrate that local renewables can provide at least 25% of the total electric energy consumed within the distribution grid, while maintaining or improving grid reliability. The Clean Coalition participates in numerous proceedings in California agencies and before other state and Federal agencies throughout the United States.

II. Avoided New Generation Costs

To the extent that the Long Term Procurement Plan proceeding finds that new generation is needed to meet system needs or AB 32 obligations, and to the extent that the proceeding finds that SB 43 generation can be used to meet these needs, program participants should receive a credit for the value to nonparticipating ratepayers of offsetting the need to procure new generation. While participants should be responsible for the additional costs of procuring energy from SB 43 projects when (a) the utility otherwise has no need to procure additional generation or (b) the utility would otherwise procure conventional generation, participants should receive a credit for avoided additional costs of procuring new generation when such procurement is used to satisfy system needs and state goals. This value should be calculated as the avoided rate impact over the length of the contract.

For example, if the Commission found that a utility must procure an additional 400 MW of generation of any type to meet local area needs within the program period, and it found that 200 MW of SB 43 generation could be used to meet these needs, then program participants subscribing to the applicable portfolio should receive a credit for the avoided rate impact of new generation over the length of the contract. Failure to credit the value of SB 43 subscriber procurement to non-participating ratepayers would otherwise unfairly transfer the costs of meeting the utility's increasing energy demands to participating ratepayers in violation of the principle of ratepayer indifference.

III. Locational Value

Southern California Edison's cost-benefit analyses must include the locational benefits of local resources to ensure ratepayer indifference and avoid shifting the locational benefits of local resources to nonparticipants. Full cost-benefit analyses of distributed renewable generation must include avoided conventional generation costs and locational value.

Distributed generation has significant locational value to ratepayers, including avoided transmission costs, line losses, and transmission and distribution upgrade costs. Such value especially applies to any portion of the generation that is deemed "deliverable" and does not exceed 100% of the coincident load at the substation, as all such generation avoids use of transmission system and associated access charges. This local generating capacity may also avoid, reduce, or defer the need for additional new transmission capacity. For example, the Long Island Power Authority (LIPA) has recently proposed offering a 7¢/kWh premium to 40 MW of appropriately sited solar DG facilities to encourage locational capacity sufficient to avoid $84,000,000 in new transmission costs that would otherwise be incurred, resulting in a net savings of $60,000,000.[1]

As shown in the graphic below, the City of Palo Alto Utilities estimated in 2012 that avoided transmission costs and line losses had a value of 2.56 cents per kWh, nearly 20% of the total value of local solar energy.

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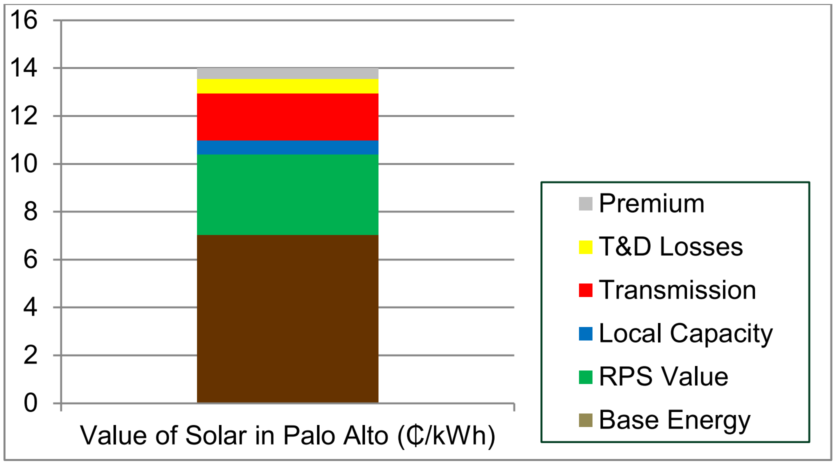
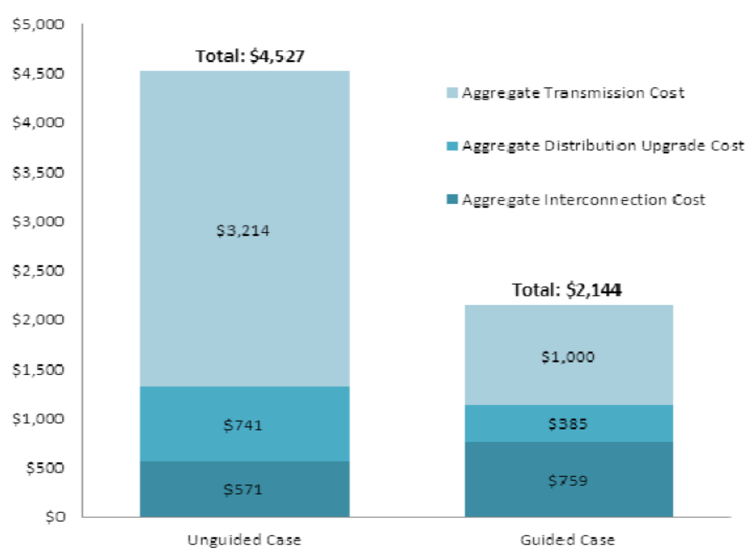
1 Proposal Concerning Modifications to LIPA's Tariff for Electric Service, available at http://www.lipower.org/pdfs/company/tariff/proposals-FIT070113.pdf. LIPA's guidance states: "The rate will be a fixed price expressed in $/kWh to the nearest $0.0000 for 20 years applicable to all projects as determined by the bidding process defined below, plus a premium of $0.070 per kWh paid to projects connected to substations east of the Canal Substation on the South Fork of Long Island."



Value of Solar calculated by the City of Palo Alto Utilities (2012)

Similarly, a May 2012 study by Southern California Edison found that transmission upgrade costs for their share of the Governor's goal of 12,000 MW of distributed generation could be reduced by over $2 billion from the trajectory scenario. The lower costs were associated with the "guided case" where 70 percent of projects would be located in urban areas, and the higher costs were associated with the "unguided case" where 70 percent of projects would be located in rural areas.[2]



Southern California Edison Comparison of Costs of Primarily Local vs. Primarily Rural Distributed Generation[3]

[2] The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System, SCE, May 2012
[3] Id.

Recognition of the locational value of local projects is necessary to meet the statutory requirement that utilities "seek to procure eligible renewable energy resources that are located in reasonable proximity to enrolled participants"[4] and "provide support for enhanced community renewables programs to facilitate development of eligible renewable energy resource projects located close to the source of demand."[5] Without recognition of these values, utilities will either (i) procure projects further from customers to take advantage of lower real estate costs, or (ii) procure well-located projects without crediting the Green Tariff or Enhanced Community Renewables portfolios with the locational value of such projects, and raise participation costs accordingly. The second scenario violates the legislative intent of the statutory requirement that utilities facilitate development of projects located close to demand; reflecting the significant locational value of Enhanced Community Renewables projects in participation costs is essential for keeping the costs of participation in an Enhanced Community Renewables program low enough to attract consumers.

The Public Utilities Code also recognizes locational value and requires utilities to submit plans to maximize locational benefits of distributed resources. AB 327 (2013) added Public Utilities Code Section 769, which requires utilities to submit Distribution Resource Plans by July 1, 2015 to identify optimal locations on the distribution grid through cost-benefit analyses,[6] and guide distributed resources towards optimal locations on the grid. Each Distribution Resource Plan must "Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources."

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[4] Public Utilities Code Chapter 7.6, Section 2833(e)

[5] Public Utilities Code Chapter 7.6, Section 2833(o)

[6] Each Distribution Resource Plan must "Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation." Public Utilities Code Section 769(b)(1).

Southern California Edison's rebuttal testimony argues against a credit for avoided transmission and distribution charges for Community Renewables subscribers, arguing that "the customer's subscription to a community renewables facility does not mean that electricity will necessarily flow from the facility to the customer; rather supporting the development of the community renewables facility of their choosing to be incorporated onto California's general electric grid. Furthermore, even if a community renewables facility's generation did perfectly match a subscribing customer's electricity demand and flow to that customer directly for some portion of the day, the customer would still require energy from the grid when the facility is not producing."[7] If followed to its logical conclusion, this is an argument for not giving Green Rate and Community Renewables customers credit for any of the benefits to the grid that can be linked to the Green Rate and Community Renewables projects. Rather than dismissing all of the potential transmission and distribution savings, the Commission should consider the extent to which these projects will actually reduce transmission and distribution costs for ratepayers.

Before the Commission has approved a methodology for evaluating locational value for individual or categories of distributed generation in connection with the implementation of Assembly Bill 327, the utilities should use the following streamlined rules for determining the locational value of individual Green Rate and Community Renewables projects for avoided Transmission Access Charges (TAC), avoided future TAC rate increases on all transmission dependent energy, local capacity value, avoided transmission system impact costs, and avoided line losses.

a. Avoided Transmission Access Charges

Transmission related costs of delivering energy from remote generation are often combined into costs that are charged by the transmission operators. In California, these costs are called Transmission Access Charges (TACs). This is a flat "postage stamp" fee for every kWh delivered to the distribution system from the transmission grid. TACs are

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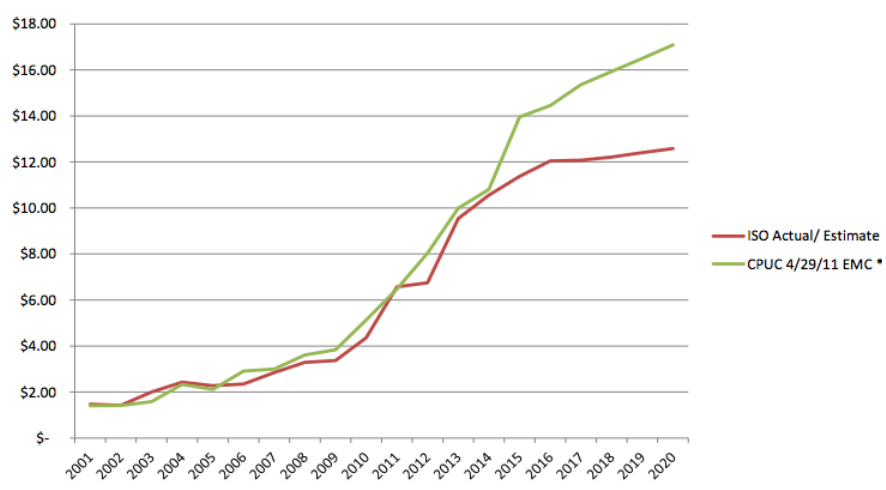
[7] Rebuttal Testimony of Southern California Edison, at 13.

avoided by energy that is delivered directly to the distribution system to serve loads on the same substation.

The High Voltage TAC is currently charged at $8.86/MWh and is consistent throughout the CAISO system. The Low Voltage TAC applies to the CAISO operated portion of systems within each individual utility service territory. For PG&E, the use rate charged is currently $6.057/MWh, resulting in a total 2013 charge of $14.92/MWh (1.492¢/kWh). While the threshold definition of sub-transmission voltage and ISO operation varies between utilities, comparable cost allocation occurs either through ISO charges or internal utility accounting.

TAC rates have increased at an annualized rate exceeding 15% since 2005 as new transmission dependent generation has been approved, and new transmission capacity is far more costly than maintaining existing capacity. CAISO mid value estimates for the rate of increase in TAC charges will be substantially less than the recent trend and prior CPUC estimates, as illustrated below. Utilizing CAISO's current projected average future estimate of 7% nominal escalation (5% real) over the next 20 years, the levelized current value of avoidable TAC charges applicable to a 20 year distributed generation power purchase agreement is 2.4¢/kWh.



CAISO Historical and Projected High Voltage Transmission Access Charges ($/MWh)[8]

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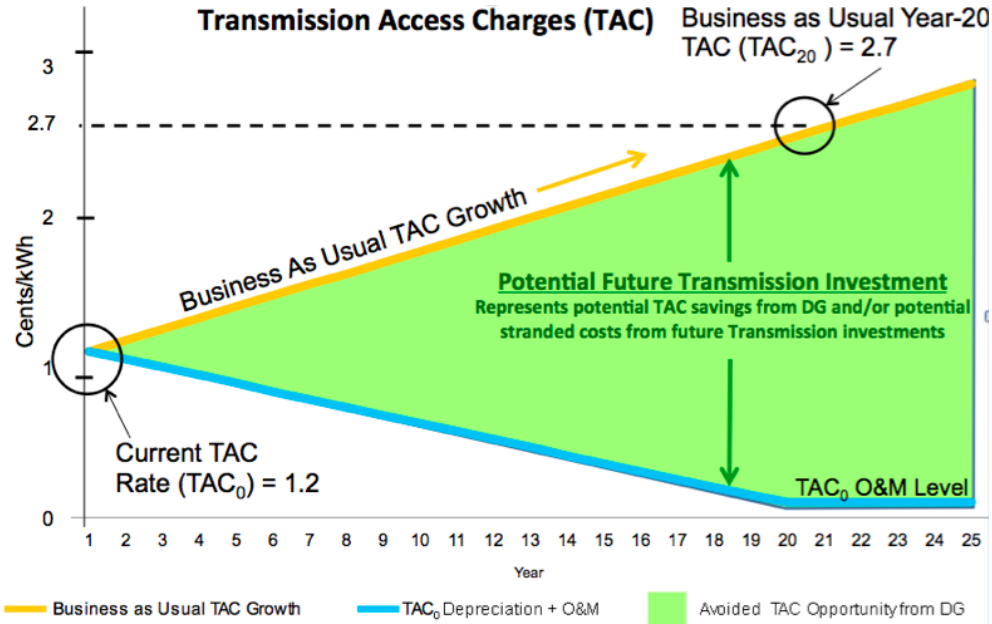
[8] CAISO projections available at http://www.caiso.com/Documents/BriefingLong-TermForecastTransmissionAccessCharge-Memo-Nov2012.pdf

The Clean Coalition recommends the following test for assigning avoided TAC costs to the value of an eligible project. Any portion of the generator's output that is below minimum coincident load (MCL) at the substation level will not utilize the transmission system, and therefore should be credited for avoided TAC costs. Any portion of the generator's output that is above MCL at the substation level will be deemed to backfeed to the transmission system and will not be credited for avoided TAC costs.

For example, if 90% of the output of a generator falls below MCL, and 10% of the output is above MCL, then the 10% of the output would be presumed to backfeed to the transmission system and would be associated with TAC charges. The project would be associated with the additional value of avoided TAC charges and avoided future TAC rate increases for 90% of its output over the course of its 20-year contract.

b. Avoided future TAC Rate increases on all transmission dependent energy

Deploying distributed generation projects that displace transmission sourced energy during peak demand periods avoids the need to increase transmission capacity, which allows existing transmission investments to depreciate and preempts future investments in transmission – both of which reduce future TAC rates, as reflected in the diagram below.



Clean Coalition estimate of TAC increases (2012)

The orange "Business as Usual" line represents the expected growth in TACs as more investment is made in the transmission system to accommodate additional remote generation. The blue line represents the decrease in TACs that is possible if that net additional remote generation was entirely replaced with distributed resources (the down ramp is based on a 40-year average depreciation schedule for TACs-related assets like transmission lines). Thus, the green wedge represents the potential cost savings achieved with distributed resources and continued operation of existing transmission capacity.

Reduced demand on transmission will reduce or defer the need for additional investment to expand transmission capacity, slowing the growth in TAC rates that is driven by the need to recoup new investment costs. Reducing the need for new investment in transmission will reduce charges across the board for all energy utilizing the system in a Merit Order Effect.

Transmission costs vary widely between projects, but if an average figure of $1 million is used as the marginal cost per megawatt of new transmission capacity, the savings are seen to accrue rapidly. While existing transmission will still be broadly utilized to supply energy during hours in which local intermittent DG is not available, even intermittent DG can offset its full generation capacity in new transmission capacity required for peak annual transmission loads.

With approximately $20 billion in planned future investments, 1 gigawatt of aggregated avoided new transmission capacity resulting from procurement of DG represents a 5% reduction in the basis for future TAC rates, or 0.005% per fully qualifying MW. Taking a levelized 20-year TAC rate of 2.4¢/kWh, a 0.005% reduction results in a savings of 0.0012¢/kWh. This appears a very small number, but this savings would be realized by virtually all of the 254,000 GWh[9] consumed within CAISO transmission system electricity by 2020 which is subject to TAC charges. These Merit Order cost savings in TAC charges at 0.0012¢/kWh would equal $30,540 in annual CAISO wide ratepayer savings for each MW reduction in required transmission capacity, assuming a 1:1 peak annual capacity reduction. Applied to a DG PV output of 1,500 MWh/MW/yr, this results in an added ratepayer value of 2¢/kWh. While the applicable transmission capacity reduction will depend on CAISO projected relationship between the generation and peak demand profiles, the value of avoided future transmission capacity cost is too large to ignore.

c. Local Capacity Value

We recommend that the utility proposals with respect to Resource Adequacy value explicitly include the local capacity value of projects located within a transmission constrained local resource adequacy area. For example, in calculating the avoided cost value of local generation when developing the standard offer price for the Palo Alto CLEAN Program PPA, the City of Palo Alto Utilities estimated the value of avoided local capacity purchase costs at 0.7¢/kWh.

d. Avoided transmission system impact costs

[9] California Energy Demand 2012-2022 Final Forecast Volume 1: Statewide Electricity Demand and Methods, Mid Energy Demand

The Renewable Auction Mechanism adjusts the value of projects based on whether transmission upgrades to be reimbursed by ratepayers will be required.[10] The Clean Coalition recommends using the same test for assigning avoided transmission upgrade costs to certain projects as part of the project ratepayer impact comparison methodology.

e. *Avoided line losses*

Where line losses are avoided, these should be recognized in determining the value of a resource. Average transmission losses are tracked by CAISO for each regional transmission zone and average 3% statewide (with the exception of the LA Basin).[11] Losses also occur on the distribution system, averaging 3%, and proportional to the distance between energy supply and load. Where generation is located in closer proximity to load, these losses may also be reduced. System wide losses are substantially higher due to congestion factors during peak demand periods, averaging approximately 10%, and time of delivery differentials should be recognized.[12]

For the foregoing reasons, the Clean Coalition respectfully requests that the Commission adopt the above recommendations.

Respectfully submitted,

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[10] Commission D.10-12-048
[11] CAISO, *2012 Local Capacity Technical Analysis Final Report and Study Results*, April 29, 2011
[12] Table ES-1: Comparison of Loss Factors, *A Review of Transmission Losses in Planning Studies*, August 2011, California Energy Commission, CEC-200-2011-009

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Dated: May 2, 2014