BEFORE THE PUBLIC UTILITIES COMMISSION
STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U-338-e) for a Permit to Construct Electrical Facilities With Voltages Between 50 kV and 200 kV: Presidential Substation Project	Application No. 08-12-023 (Filed December 22, 2008)

THE CENTER FOR BIOLOGICAL DIVERSITY

OPENING TESTIMONY

TESTIMONY OF BILL POWERS, P.E.

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I. Introduction

My testimony addresses the capability of the distributed generation non-wires alternative, combined with energy efficiency and an expanded air conditioning cycling demand response program, to meet the need that Southern California Edison Company ("SCE") proposed to address by building the Presidential Substation Project. My testimony supports the feasibility of the Environmentally Superior Alternative identified in the Draft Environmental Impact Report ("DEIR"), which does not include a new distribution substation.

I am a registered professional mechanical engineer in California with over 25 years of experience in the energy and environmental fields. I have permitted five 50 MW peaking turbine installations in California, as well as numerous gas turbine, microturbine, and engine cogeneration plants around the state. I organized conferences on permitting gas turbine power plants (2001) and dry cooling systems for power plants (2002) as chair of the San Diego Chapter of the Air & Waste Management Association. I am the author of the October 2007 strategic energy plan for the San Diego region titled "San Diego Smart Energy 2020." The plan uses the state's Energy Action Plan as the framework for accelerated introduction of local renewable and cogeneration distributed resources to reduce greenhouse gas emissions from power generation in the San Diego region by 50 percent by 2020. I am the author of several 2009 articles in *Natural Gas & Electricity Journal* on use of large-scale distributed solar PV in urban areas as a cost-effective substitute for new gas turbine peaking capacity. Further qualifications are provided in my resume provided as Attachment 1.

II. Regulatory Context - SCE's Distributed Generation and Energy Efficiency Obligations Support the Feasibility of the Environmentally Superior Alternative

The DEIR states that the purpose of the Presidential Substation Project is to meet the forecasted electrical demands in the cities of Simi Valley and Thousand Oaks, as well as adjacent areas of Ventura County. This Electrical Needs Area (ENA) is presently served by three 66/16 kV distribution substations, which are fed by the Moorpark 66 kV system. These three substations, Thousand Oaks, Potrero, and Royal Substations, provide electrical service to approximately 60,000 metered customers. The three existing substations were placed in service in the 1960s. If the proposed project is built, the ENA would be served by the three existing 16

kV distribution substations and the proposed Presidential Substation.[1] According to the PEA the capacity of the existing ENA is 400 MVA.[2]

SCE estimates the capital cost of the Presidential Substation Project at $55 million. The CPUC assumes amortization of transmission capital expense over 40 years.[3] The annual capital recovery amortization factor used by the CPUC is 0.1246 over 40 years using the RPS Calculator developed by Energy & Environmental Economics, Inc. (E3) for the CPUC.[4] Therefore, the annual cost to ratepayers of the Presidential Substation project, over 40 years, will be $55 million x 0.1246 per year = $6.85 million per year.

The brief DEIR description of the distributed generation (DG) non-wires alternative to the Presidential Substation Project improperly downplays the feasibility of DG to support the Environmentally Superior Alternative. The write-up acknowledges that the state has a target of 12,000 MW of new local renewable energy by 2020, to consist of "*localized energy as onsite or small energy systems located close to where energy is consumed that can be constructed quickly (without new transmission lines) and typically without any environmental impact*."[5] SCE represents approximately 28 percent of statewide electricity demand.[6] As a result, about 3,400 MW of new local renewable energy generation must be added in SCE service territory by 2020 to meet the target.

The state's Joint Investor-Owned Utility (IOU) *Long-Term California Energy Efficiency (EE) Strategic Plan*, developed as an element in a CPUC regulatory proceeding, is framed by two core concepts - net zero energy (NZE) buildings, both in new construction and existing structures, and substantial reductions in the electricity demand of air conditioning systems.[7] NZE

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[1] DEIR, p. 2-3.

[2] *See* SCE, Proponents Environmental Assessment ("PEA"), Table 1.1: Electrical Needs Area Substations Capacity and Peak Demand, p. 1-2; SCE, PEA, Figure 1.2: Electrical Needs Area Substations Capacity and Peak Demand, 1-7. *See also* Center for Biological Diversity, Comments on Draft Environmental Impact Report for Presidential Substation Project (A. 08-12-023), Exhibit 2: Comments on the Presidential Substation DEIR by D. Marcus, p. 3. (filed Nov. 15, 2011).

[3] Energy & Environmental Economics, Inc., *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis*, prepared for CPUC, January 2010 update, Table 11, p. 15. See: http://www.cpuc.ca.gov/NR/rdonlyres/932CFFAA-0610-474E-905D-30CD1D76C651/0/InputsandAssumptions_UPDATE.pdf.

[4] January 5, 2010 e-mail, Arne Olson, E3, to Bill Powers, Powers Engineering.

[5] DEIR, p. 3-39.

[6] SCE allotment of 2020 statewide 4,000 MW CHP target is 28.4 percent. Assume this same SCE percentage allotment applies to 2020 statewide 12,000 MW target for new local renewable energy. See: SCE, *QF Settlement Agreement Overview - QF Meeting*, PowerPoint, Rosemead, CA, July 22, 2011, p. 6. See: http://asset.sce.com/Documents/Environment%20-%20Renewable%20Energy/QF_CHP_SettlementOverview_MeetingPresentation.pdf.

[7] See CPUC decision adopting Energy Efficiency Strategic Plan: http://docs.cpuc.ca.gov/published/FINAL_DECISION/91068-06.htm#TopOfPage

buildings incorporate both energy efficiency measures and rooftop PV. The *EE Strategic Plan* sets a goal of a 30 reduction in electricity consumption by residential and commercial buildings through EE measures by 2020, compared to a 2008 baseline. Rooftop PV is utilized in combination with EE measures to achieve NZE buildings. I calculate that approximately 14,600 MW of new rooftop PV will be necessary to meet the 2020 goals in the *EE Strategic Plan*, or about 4,150 MW in SCE service territory.[8] These calculations are provided in Attachment 2. Yet the DEIR dismisses DG, with no supporting documentation, as "nascent" and "not currently a significant energy resource."[9]

SCE has a 500 MW urban rooftop DG PV project in construction.[10] The anticipated completion date is 2014. 250 MW of the 500 MW total will be owned by SCE. The remaining 250 MW are being developed by third parties with the output sold to SCE. SCE posts online a service territory map indicating preferred distribution substation locations for DG PV development within the context of this project. The ENA is included in the SCE map. The CPUC is also in the process of implementing the SB 32 Feed-In Tariff (FIT) legislation. That objective of this legislation is the installation of 750 MW of DG PV by approximately 2014. SCE's allocation of SB 32 FIT capacity is approximately 213 MW.[11]

The current SB 32 proceeding at the CPUC includes an analysis of where the addition of DG PV would be most economically effective in reducing transmission and distribution (T&D) system upgrade costs in each IOU service territory. This T&D adder would be a locational adjustment to the FIT tariff to provide an economic incentive to local DG PV resources where they would be most effective in avoiding T&D expenditures. Distribution system hot spots in SCE territory show the highest economic T&D avoided cost benefits from DG PV additions of any California IOU, with a benefit of $0.0775/kWh in T&D avoided costs.[12] Presumably the three existing distribution substations in the ENA are identified by SCE as hot spots, given SCE's position that the peak demand in the ENA is approaching maximum available distribution capacity.

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[8] See Attachment A. 14,600 MW × 0.284 = 4,146 MW.
[9] DEIR, p. 3-39.
[10] SCE, *Solar Photovoltaic Program for Independent Power Producers - 2011 Request for Offers for Renewable Energy from Solar Photovoltaic Generating Facilities*, May 2011, p.1. See: http://asset.sce.com/Documents/Shared/2011_RFOParticipantInstructions.pdf.
[11] 750 MW × 0.284 = 213 MW.
[12] E3, *Workshop Discussion: Using Avoided Costs to Set SB32 Feed-in Tariffs*, PowerPoint, SB32 Workshop September 26, 2011, p. 26.

DG also includes combined heat and power (CHP) plants 20 MW or less, typically natural-gas fired units located in hospitals, schools, and commercial facilities. California has established an ambitious target for new CHP in the context of AB 32, the California Global Warming Solutions Act. The California Air Resources Board (CARB) is the lead agency tasked with implementing AB 32. The December 2008 *AB 32 Scoping Plan* developed by CARB proposed the following targets related to energy: 1) reduce demand by 32,000 GWh via energy efficiency measures, 2) add 4,000 MW of CHP by 2020 to displace 30,000 GWh of conventional generation, 3) reduce natural gas consumption by 800 million therms via energy efficiency measures, 4) add 200,000 solar hot water heaters in compliance with AB 1470, 5) achieve 33 percent RPS by 2020, 6) achieve one million solar roofs, 3,000 MW, by 2017, and 7) implement a CO_2 cap-and-trade program.[13]

SCE is responsible for achieving 28.4 percent of the statewide target of 4,000 MW of new CHP by December 31, 2020.[14] This converts to 1,136 MW of new CHP in SCE service territory.[15]

SCE has a target of at least 4,500 MW of new renewable and natural gas-fired DG by 2020. This is more than ten times the 400 MVA capacity rating of the three existing distribution substations in the ENA.[16] These new DG resources will be added at a time when SCE peak demand and annual electricity consumption is flat or declining.[17] As a result of new DG, combined with EE measures and peak load reduction through air conditioner cycling and efficiency improvements, the ENA will experience a substantial drop in peak and average loads over the next decade.

Yet the DEIR states, in dismissing DG as viable:

> "The distributed generation industry is still a nascent industry that survives despite some difficult market conditions. There are numerous institutional, industry and market barriers that have impeded the growth and adoption of the industry to date. Although the potential is recognized, distributed generation is not currently a significant energy resource."

The DEIR goes on to state: "A Distributed Generation Alternative would involve deployment of distributed generation in the form of many small projects within the ENA at a pace more

[13] California Air Resources Board, *Climate Change Scoping Plan*, December 2008, pp. 41-53.
[14] SCE, *QF Settlement Agreement Overview - QF Meeting*, PowerPoint, Rosemead, CA, July 22, 2011, p. 6. See: http://asset.sce.com/Documents/Environment%20-%20Renewable%20Energy/QF_CHP_SettlementOverview_MeetingPresentation.pdf.
[15] 4,000 MW × 0.284 = 1,136 MW.
[16] For the sake of discussion power factor is assumed to be 1.0 such that MW = MVA.
[17] Direct Testimony of David Marcus on Behalf of the Center for Biological Diversity, p. 5-6. (filed Jan. 6, 2012).

aggressive than SCE anticipates." These statements do not address the issue of whether SCE has control over the institutional barriers to accelerated adoption of DG in its service territory, and imply that it is solely SCE's decision to determine if it will comply with the state's DG targets. The DEIR fails to comprehensively identify: 1) DG requirements that SCE is subject to over the next decade, 2) what the barriers are to SCE meeting its DG obligations and how those barriers can be overcome, 3) why SCE will presumptively fail to meet these targets.

III. Distributed PV Is at the Top of the Energy Action Plan Loading Order and Supports the Feasibility of the Environmentally Superior Alternative

The CPUC and CEC developed the "Energy Action Plan" in 2003 to guide strategic energy decision-making in California. The Energy Action Plan establishes the energy resource "loading order," or priority list that defines how California's energy needs are to be met. Energy Action Plan I was published in May 2003.[18] Energy Action Plan I describes the loading order in the following manner:

> "The Action Plan envisions a "loading order" of energy resources that will guide decisions made by the agencies jointly and singly. First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to "get to scale," the agencies also will support additional clean, fossil fuel, central-station generation. Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation."

Energy Action Plan I, Under "Optimize Energy Conservation and Resource Efficiency," states:

> "Incorporate distributed generation or renewable technologies into energy efficiency standards for new building construction."

Energy Action Plan I identifies rooftop PV as a de facto energy efficiency measure with this statement. Energy Action Plan I also states, Under "Promote Customer and Utility-Owned Distributed Generation":

> "Distributed generation is an important local resource that can enhance reliability and provide high quality power, without compromising environmental quality. The state is promoting and encouraging clean and renewable customer and utility owned distributed generation as a key component of its energy system. Clean distributed generation should

[18] Energy Action Plan I: http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF

enhance the state's environmental goals. This determined and aggressive commitment to efficient, clean and renewable energy resources will provide vision and leadership to others seeking to enhance environmental quality and moderate energy sector impacts on climate change. Such resources, by their characteristics, are virtually guaranteed to serve California load. With proper inducements distributed generation will become economic.

- Promote clean, small generation resources located at load centers.
- Determine system benefits of distributed generation and related costs.
- Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program."

Energy Action Plan II was adopted in September 2005.[19] The purpose of Energy Action Plan II is stated as: "EAP II is intended to look forward to the actions needed in California over the next few years, and to refine and strengthen the foundation prepared by EAP I." Energy Action Plan II reaffirms the loading order stating:

"EAP II continues the strong support for the loading order – endorsed by Governor Schwarzenegger – that describes the priority sequence for actions to address increasing energy needs. The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation."

The CEC's *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report* (December 2009), underscores the integration of building PV as a critical component of NZE use targets for new residential and commercial construction, under the heading "Energy Efficiency and the Environment," explaining:[20]

"With the focus on reducing GHG emissions in the electricity sector, energy efficiency takes center stage as a zero emissions strategy. One of the primary strategies to reduce GHG emissions through energy efficiency is the concept of zero net energy buildings. In the 2007 IEPR, the Energy Commission recommended increasing the efficiency standards for buildings so that, when combined with on-site generation, newly constructed buildings could be zero net energy by 2020 for residences and by 2030 for commercial buildings.

A zero net energy building merges highly energy efficient building construction and state-of-the-art appliances and lighting systems to reduce a building's load and peak requirements and includes on-site renewable energy such as solar PV to meet remaining energy needs. The result is a grid-connected building that draws energy from, and feeds surplus energy to, the grid. The goal is for the building to use net zero energy over the year."

[19] Energy Action Plan II: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF
[20] CEC, *2009 Integrated Energy Policy Report (IEPR) – Final Committee Report*, December 2009, p. 56.

The CPUC, with support from the Governor's Office, CEC, and the CARB, adopted the *EE Strategic Plan* for 2009 to 2020 in September 2008.[21] The *Plan* was updated in January 2011. The *Plan* is a framework for all sectors in California including industry, agriculture, large and small businesses, and households. Major goals of the plan include:

- All new residential construction will be zero net energy by 2020,
- All new commercial construction will be zero net energy by 2030,
- Heating, ventilation, and air conditioning industries will be re-shaped to deliver maximum performance systems,
- Existing residential and commercial buildings achieve near-NZE and NZE in step increments over time.

IV. The Benefits of SCE's Large-Scale Distributed PV Project as an Alternative to Transmission Support the Feasibility of the Environmentally Superior Alternative

SCE expressed confidence in its March 2008 application to the CPUC for a 250 to 500 MW urban PV project that it can absorb thousands of MW of distributed PV without additional distribution substation infrastructure, stating "SCE's Solar PV Program is targeted at the vast untapped resource of commercial and industrial rooftop space in SCE's service territory"[22] and "SCE has identified numerous potential (rooftop) leasing partners whose portfolios contain several times the amount of roof space needed for even the 500 MW program."[23]

SCE stated it has the ability to balance loads at the distribution substation level to avoid having to add additional distribution infrastructure to handle this large influx of distributed PV power.[24] SCE explains:

> "SCE can coordinate the Solar PV Program with customer demand shifting using existing SCE demand reduction programs on the same circuit. This will create more fully utilized distribution circuit assets. Without such coordination, much more distribution equipment may be needed to increase solar PV deployment. SCE is uniquely situated to combine solar PV Program generation, customer demand programs, and advanced distribution circuit design and operation into one unified system. This is more cost-effective than separate and uncoordinated deployment of each element on separate circuits."[25]

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[22] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, p. 6.
[23] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 44.
[24] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, pp. 8-9.
[25] Ibid, p. 9.

SCE also notes that it will be able to remotely control the output from individual PV arrays to prevent overloading distribution substations or affecting grid reliability:[26]

> "The inverter can be configured with custom software to be remotely controlled. This would allow SCE to change the system output based on circuit loads or weather conditions."

As SCE states, "Because these installations will interconnect at the distribution level, they can be brought on line relatively quickly without the need to plan, permit, and construct the transmission lines."[27] This statement was repeated and expanded in the CPUC's June 18, 2009 press release regarding its approval of the 500 MW SCE urban PV project:[28]

> Added Commissioner John A. Bohn, author of the decision, "This decision is a major step forward in diversifying the mix of renewable resources in California and spurring the development of a new market niche for large scale rooftop solar applications. Unlike other generation resources, these projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts. By authorizing both utility-owned and private development of these projects we hope to get the best from both types of ownership structures, promoting competition as well as fostering the rapid development of this nascent market."

The preferential location of a significant portion of SCE's 500 MW DG PV project in the ENA is one tool available to SCE to address any projected peak load growth in the ENA over the next decade and to assure the feasibility of the Environmentally Superior Alternative.

IV. Locating As Much As 120 MW of DG PV Capacity in the ENA with No Significant Upgrades to the Existing Distribution System Supports the Feasibility of the Environmentally Superior Alternative

The CPUC has calculated, for the entire inventory of approximately 1,700 existing IOU substations in California, the amount of DG PV that could be accommodated with minimal interconnection cost based on the following reasoning:[29]

> "Rule 21 specifies maximum generator size relative to the peak load on the load at the point of interconnection at 15%. So, for example, if a generator is interconnected on the low side

[26] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 27.
[27] Ibid, p. 6.
[28] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009.
[29] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, p. 15.

of a distribution substation bank with a peak load of 20 MW, the maximum Rule 21 interconnection criteria would allow a 3 MW system (3 MW = 15% * 20 MW).

However, the 15% criterion, which is established for all generators regardless of type, was adjusted to 30% for the purposes of determining the technical potential of PV. The 15% limit is established at a level where it is unlikely the generator would have a greater output than the load at the line segment, even in the lowest load hours in the off-peak hours and seasons (such as the middle of the night and in the spring). Since the peak output for photovoltaics is during the middle of the day, PV is unlikely to have any output when loads are lowest. Therefore, a 30% criterion was used for technical interconnection potential estimates. The discussion was held with utility distribution engineers, however, we did not consider formal engineering studies or Rule 21 committee deliberation since the purpose of the analysis was only to define potential."

As a component of the DG PV FIT development process, the CPUC requested data on peak loads at all IOU substations from the IOUs and compiled that information graphically as shown in Figure 1.

SCE has developed a map of its service territory showing preferred locations for distributed PV to be installed under its 500 MW distributed PV project. SCE shows a sub-transmission available capacity of 1,082 MVA for SCE Area 29, which includes the ENA. This map is provided in Figure 2. According to the DEIR the ENA has a capacity of 400 MVA. The probable DG PV interconnection capacity with no significant modification to distribution grid protection schemes, assuming the 30 percent maximum generator size criterion, would be approximately 120 MW.[30]

[30] MVA = MW at a power factor of 1.0.

Figure 1. IOU Substation Peak Loads, 30 Percent of Peak Load

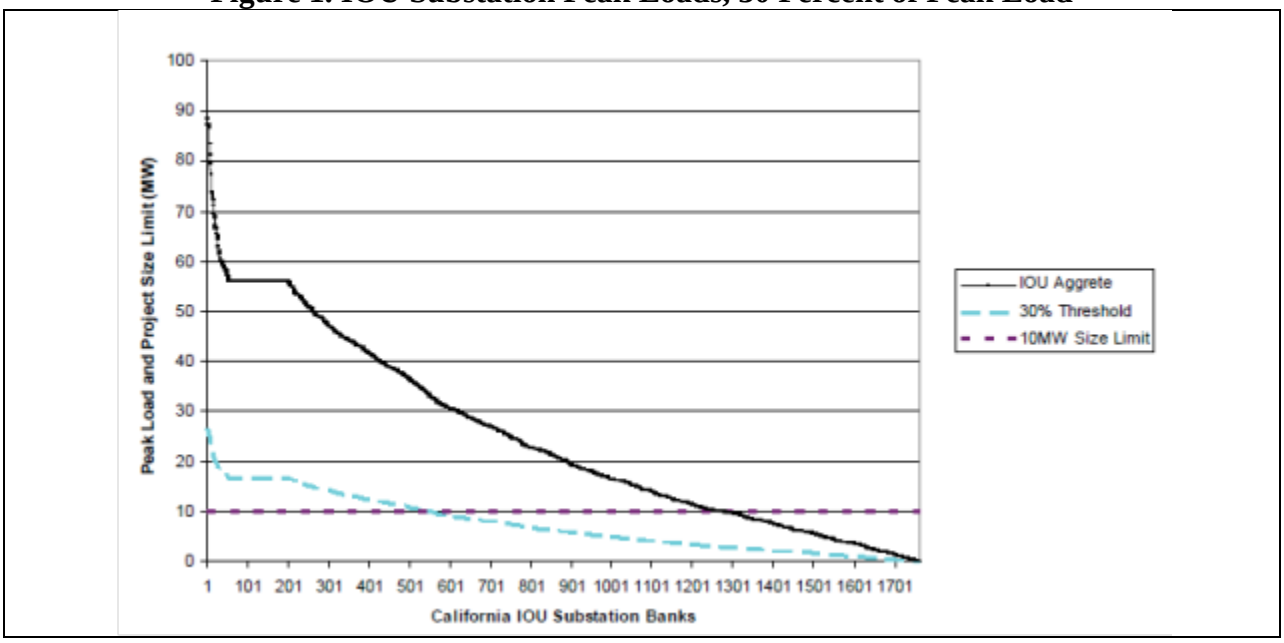
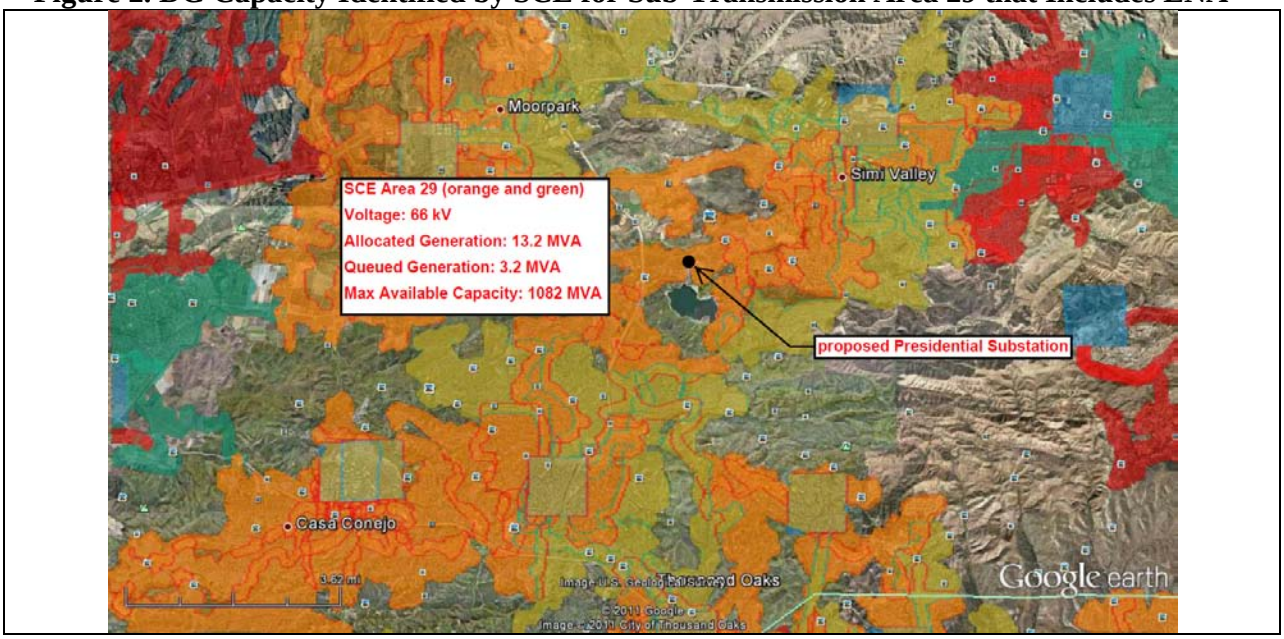


Figure 2. DG Capacity Identified by SCE for Sub-Transmission Area 29 that Includes ENA[31]

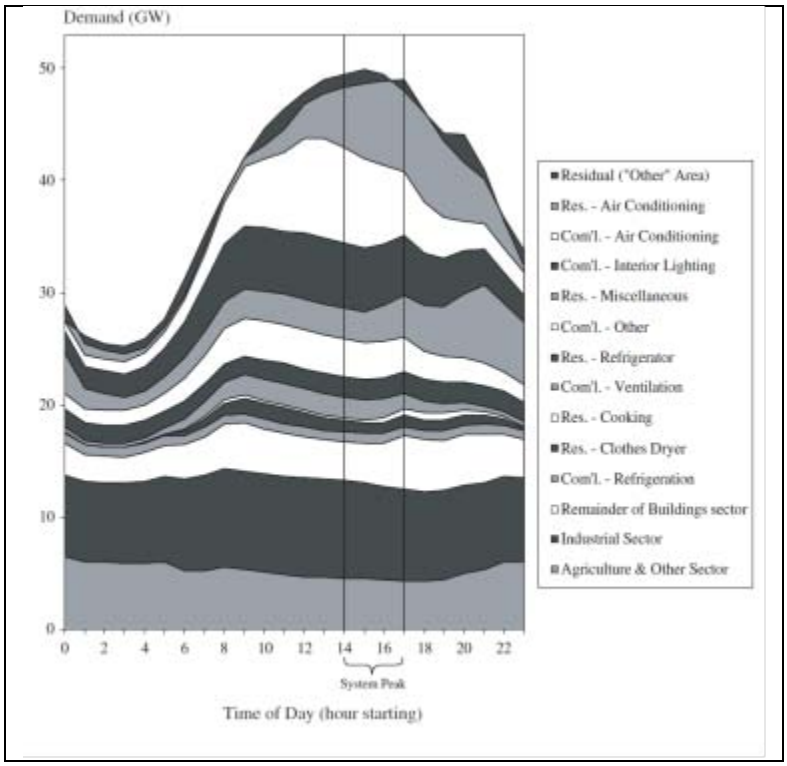


[31] See (scroll down to "SCE Interconnection Maps"): http://www.sce.com/EnergyProcurement/renewables/spvp-ipp/spvp-ipp.htm.

VI. HVAC Demand Response Potential to Reduce Peak Loads in ENA Supports the Feasibility of the Environmentally Superior Alternative

Air conditioning is the nearly exclusive additional summertime load in California, accounting for more than 30 percent of total load at the peak hour.[32] Figure 3 shows the sources of demand on California peak summer days.

Figure 3. Summer 24-Hour Demand Profile in California and Sources of Demand[33]



One off-the-shelf solution to reducing peak load in the ENA is to enroll the 60,000 customers in the ENA in SCE's Summer Discount Plan central air conditioning unit cycling program.[34] Assuming a four-month summer season, the incentive SCE pays for customers enrolled in the Summer Discount Plan is approximately $70 per customer per summer season.[35] The ENA is located in a non-coastal climate zone where it is likely that most customers have air conditioning, as shown in Figure 4. Assuming all 60,000 customers in the ENA have central air

[32] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 53. See: http://www.cpuc.ca.gov/NR/rdonlyres/A54B59C2-D571-440D-9477-3363726F573A/0/CAEnergyEfficiencyStrategicPlan_Jan2011.pdf.

[33] Xenergy, Inc., *California's Secret Energy Surplus – The Potential for Energy Efficiency*, September 23, 2002, p. A-6.

[34] See: http://www.sce.com/summerdiscount/summer-discount-plan-details.htm.

[35] Ibid. Assume Schedule GS-2, TOU-GS-3, or TOU-8, off 15 minutes out of every 30 minutes, Enhanced Plan Credits per calculated ton per month = $4.20/ton-month. Assume average residential central air conditioner is 4 ton unit. 4 ton × $4.20/ton-month × 4 month/season = $67.20 per summer season.

conditioning and all enroll in the Summer Discount Plan, the approximate incentive payment cost would be 60,000 customers x $70/season = $4.2 million per season. The Presidential Substation Project will cost $6.85 million per year for 40 years. Assuming that air conditioner load is 30 percent of maximum existing ENA distribution system capacity of 400 MVA/400 MW, air conditioner load would be 120 MW. Assuming all customers are enrolled in the Summer Discount Plan and half of the air conditioners are off at any given moment, this cycling program alone has the potential to reduce peak demand in the ENA by 60 MW.

Central air conditioning cycling programs designed to reach a large number of customers are already in place in California. For example, PG&E has a central air conditioning cycling program intended to reach 25 percent of the 1.6 million PG&E customers with central air conditioning units.[36] The 25 percent participation target is based on the expected result of an aggressive marketing campaign. Cycling the set-point of one-half of the central air conditioner population from 72 ^{o}F to 78 ^{o}F for 10 or 15 minutes, and repeating this cycling with the other half of the population for 10 to 15 minutes, reduces the instantaneous MW load during critical peak demand periods by hundreds of MW with almost no impact on the comfort of end users.

Residences with sensitive populations, such as the elderly or chronically sick, would be kept out of this type of program. Customers have the ability to opt-out if a reason was provided after the customer had been included in the program for a time and had experienced the effect, or lack of effect, of air conditioning cycling on the comfort level within the residence.

Another readily available option to SCE is to direct EE funding to customer purchase of state-of-the-art central air conditioning units. Currently no SCE incentive funds are directed specifically at assuring that customers have a financial incentive to minimize the electricity demand of new central air conditioning units.[37]

[36] PG&E, *PG&E 2007-2016 Long-Term Procurement Plan*, Volume I, p. IV-16.
[37] See: http://www.sce.com/residential/rebates-savings/rebates-savings.htm.

A requirement for cost-effective, state-of-the-art residential central cooling system upgrades would be simple to implement. For example, SCE would advise local heating and cooling system contractors that utility rebate funds will pay the difference between the base price for a central air conditioning system that meets the 2006 federal SEER 13 standard and a state-of-the-art SEER 21 unit.

The average SEER rating of existing central air conditioning units is approximately SEER 10.[38] Carrier Corporation is a leading provider of central air conditioning systems. The energy demand of a 3-ton Carrier Corporation SEER 10 central air conditioning unit is approximately 4.0 kWh under hot summertime conditions.[39]

Figure 4. ENA Climate Zone[40]

The company advertises a 56 percent reduction in electricity demand for its Infinity® 21 (SEER 21) model compared to a SEER 10 unit.[41] Assuming average central air conditioning usage in the ENA is in the range of 800 to 1,000 hours per year, as much as 2,000 kWh of energy demand would be eliminated over the course of the summer peak season by selecting the Infinity® 21for the upgrade.[42]

The 2006 federal standard for new central air conditioning units is SEER 13. The difference in the installed cost prior to rebates of a reference case Carrier Corporation 3-ton SEER 13 residential central air and heating unit, which costs approximately $9,000, and a state-of-the-art Infinity® 21 unit (SEER 21) is around $2,000.[43] Carrier offers a rebate on high efficiency units that reduces the cost difference between the SEER 13 and SEER 21 alternatives by about $1,000.

[38] S. Okura, M. Brost – RLW Analytics, Inc., and R. Rubin – SDG&E, What Types of Appliances and Lighting Are Being Used in California Residences?, 2005.
[39] Carrier product bulletin for SEER 10 model 38TKB036-34 3-ton air conditioning unit, 2004, p. 24.
[40] CEC, California Building Climate Zones map: http://www.energy.ca.gov/maps/building_climate_zones.html
[41] San Diego Union Tribune, Carrier central air conditioner advertisement, p. A-17, September 9, 2007.
[42] (4.0 kWh × 1,000 hours) –[(4.0 kWh × 1,000 hours) (10/21)] = 2,100 kWh saved. This is the electricity savings of 3-ton SEER 21 unit compared to a 3-ton SEER 10 unit over 1,000 hours of operation.
[43] Avalanche Mechanical (Carrier installer) quote to B. Powers for 3-ton SEER 21 central air conditioning and heating unit, September 4, 2007. Quote includes cost of new insulated ductwork.

Assume the typical summer central air conditioner usage in the ENA is about 1,000 hours.[44]. The SEER 21 unit would save approximately 1,172 kWh relative to the SEER 13 unit over 1,000 hours.[45] Summer peak savings would be $350 per year, assuming a Tier 5 residential rate of $0.30/kWh.[46] The simple payback for the $2,000 additional cost of the Infinity® 21, without the Carrier rebate, would be about 6 years. With the $1,000 Carrier rebate, the simple payback would be 3 years.

In addition, the typical reduction of about 2 kW in residential electricity demand when upgrading from an existing 3-ton central air conditioning unit to a SEER 21 unit would eliminate $600 per year in peaking gas turbine fixed costs. This is the cost associated with new peaking gas turbine capacity that would otherwise be built to meet the peaking load.[47]

In this example, the value of upgrading to a highly efficient 3-ton central air conditioning unit is close to $1,000 per year. This includes the avoided cost of new peaking gas turbine capacity that would otherwise be built to meet the demand ($600 per year), and the value of high-cost electricity that is not needed because of the lower electricity demand of the state-of-the-art unit ($350 per year).

Central air conditioning units have an average age of 10 to 11 years.[48] Assuming this average age is representative of replacement frequency, about 50 percent of current central air conditioning units will be replaced over the next 10 years. If each replacement on average reduces unit electricity consumption by 50 percent, the electricity consumption of the entire population of central air conditioning units will drop about 25 percent over the next decade.

Integrating air conditioning cycling capability into each new state-of-the-art central air conditioning unit sold would facilitate near universal capability to participate in the air conditioner cycling program. Air conditioner cycling capability would be incorporated into each new unit prior to sale. This capability would reduce the instantaneous electricity demand of this population of air conditioners by 50 percent, as half these units would be in offline at any given time while the other half are operational.

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[44] This equates to approximately 8 hours per day of central air conditioner usage over a 120-day (4 month) period.
[45] (4 kWh × 1,000 hr) × [(10/13) – (10/21)] = 1,172 kWh. This is the electricity savings of a 3-ton SEER 21 unit compared to a SEER 13 unit over 1,000 hours of operation.
[46] See: http://www.sce.com/CustomerService/billing/tiered-rates/understanding-tiered-rates.htm.
[47] CEC, Comparative *Costs of California Central Station Electricity Generation*, January 2010. Table B-4, p. B-5. Fixed cost of a new conventional 50 MW peaking gas turbine in 2009 is $303/kW-yr. Therefore, annual cost of 2 kW of peaking capacity: 2 kW × $303/kW-yr = $606/yr.
[48] S. Okura, M. Brost – RLW Analytics, Inc., and R. Rubin – SDG&E, *What Types of Appliances and Lighting Are Being Used in California Residences?*, 2005.

The *EE Strategic Plan* sets a goal of a 50 percent reduction in air conditioning loads by 2020. The 3-ton central air conditioning unit example shows that a 50 percent demand reduction can be achieved cost-effectively over time as existing units wear out and are replaced with off-the-shelf high efficiency alternatives. Shifting rebate funds to the air conditioning unit wholesale distribution level would assure that every new central air conditioning unit sold incorporates maximum energy efficiency.

VII. Conclusion

SCE is subject to aggressive EE, DG PV, CHP, and central air conditioner demand reduction targets over the next decade that will substantially reduce electricity consumption and peak demand in the ENA. The DEIR fails to identify the DG and EE requirements that SCE is subject to over the next decade, or what the barriers are to SCE meeting its DG and EE obligations. These DG and EE obligations will substantially reduce the demand in the ENA and reinforce the feasibility of the Environmentally Superior Alternative.