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Impacts of Distributed Generation

Final Report

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Background

This report is prepared in response to Assembly Bill (AB) 578 (Blakeslee, 2008) which specifically requires the California Public Utilities Commission (CPUC) to submit to the legislature a report on the impacts of distributed energy generation on California's transmission and distribution (T&D) systems.

On January 1, 2009, Section 321.7 of the Public Utilities Code was created requiring the CPUC to do the following:

321.7. (a) On or before January 1, 2010, and biennially thereafter, the commission, in consultation with the Independent System Operator and the State Energy Resources Conservation and Development Commission, shall study, and submit a report to the Legislature and the Governor, on the impacts of distributed energy generation on the state's distribution and transmission grid. The study shall evaluate all of the following:

> *(1) Reliability and transmission issues related to connecting distributed energy generation to the local distribution networks and regional grid.*
> *(2) Issues related to grid reliability and operation, including interconnection, and the position of federal and state regulators toward distributed energy accessibility.*
> *(3) The effect on overall grid operation of various distributed energy generation sources.*
> *(4) Barriers affecting the connection of distributed energy to the state's grid.*
> *(5) Emerging technologies related to distributed energy generation interconnection.*
> *(6) Interconnection issues that may arise for the Independent System Operator and local distribution companies.*
> *(7) The effect on peak demand for electricity.*
> *(b) In addition, the commission shall specifically assess the impacts of the California Solar Initiative program, specified in Section 2851 and Section 25783 of the Public Resources Code, the self-generation incentive program authorized by Section 379.6, and the net energy metering pilot program authorized by Section 2827.9.*

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Executive Summary

This report provides an overview of the current status of California's distributed energy generation resources[1] and highlights some of the current challenges and activities around interconnecting these resources to the utility grid.

The CPUC has oversight of policies and programs related to distributed generation (DG) resources in California's investor owned utility (IOU) territories. Since the 1980s, the use of DG resources has increased dramatically in California due to policies related to interconnection, net energy metering, and procurement, as well as programs related to advancing the integration of clean, DG resources, such as the California Solar Initiative (CSI) and the Self-Generation Incentive Program (SGIP).

California's policies and programs related to distributed generation include the following:

- Interconnection policy – The utilities have interconnection procedures for distributed energy resources. Smaller resources use the utility Rule 21 tariffs, and larger resources interconnect using the Federal Energy Regulatory Commission (FERC)'s Small Generator Interconnection Procedure (FERC- SGIP).
- Net Energy Metering policy – The utilities have net energy metering tariffs available for solar photovoltaics (PV), wind, fuel cells, and biogas.
- Procurement policy – The utilities have a variety of procurement programs for distributed energy resources that export electricity to the grid, including:
  - The qualified facilities (QF) program in the 1980s spurred the growth of over 8,655 MW of QF facilities, many of which were distributed generation (DG) facilities.
  - The Renewable Portfolio Standard (RPS) program has annual competitive solicitations for new renewable resources which are open to distributed energy resources.

[1] Distributed energy resources (DER) typically encompass distributed generation, energy storage, load management and can include energy efficiency. For the purposes of this report, DER is limited to distributed generation and energy storage; referred to herein as DG resources.

  - Since February 2008, the utilities all have Small Renewable Generation feed-in tariffs for the purchase of renewable generating capacity from small facilities throughout California.
  - The utilities have each proposed a solar PV procurement program. The CPUC approved the Southern California Edison (SCE) program in June 2009, and the Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E) programs are still pending.
  - In December 2009, the CPUC approved policies and procedures for the purchase of excess electricity from eligible combined heat and power (CHP) systems.

- Rebate Programs – The three large regulated investor-owned utilities (IOUs) fund customer rebate programs to provide rebates for small, clean distributed energy resources that are designed to serve customer onsite load (not designed for export).
  - The CSI, beginning January 1, 2007 provides rebates to solar PV projects, with a goal of installing 1,940 MW of capacity in the IOU service territories by 2016. The New Solar Homes Partnership (NSHP) provides rebates to solar PV projects on new homes and has a goal of 360 MW Statewide. In addition, the publically-owned utilities are expected to contribute 700 MW of additional PV capacity in their service territories towards the overall State goal of 3,000 MW.
  - The SGIP provides rebates to wind, fuel cells, and distributed storage. Prior to January 1, 2007 the SGIP program included PV projects greater than 30 kW and prior to January 1, 2008 it included technologies such as microturbines internal combustion engines and gas turbines. Beginning January 1, 2001 through September 30, 2009, 345 MW have been installed using incentives through this program through September 30, 2009.
  - The California Energy Commission's Emerging Renewables Program (ERP) was initiated in 1998 and provided incentives to grid-connected PV systems, small wind, and renewably fueled fuel cells smaller than 30 kW in capacity. ERP installed approximately 91 MW of PV capacity from 1981 through 2006. An additional 29 MW installed during 2007 and 2008 as the PV portion of the program wound down and was replaced by the CSI program and the NSHP.

This report includes information related to the above mentioned policies and programs. In particular, the report focuses on the current work related to the following two prominent CPUC efforts underway to understand the issues and impacts of distributed energy on the T&D grid.

- The CPUC's Long Term Procurement Planning (LTPP) and RPS proceedings are examining the complex issues around interconnection of DG resources. Specifically, the Renewable Energy Distributed Energy Initiative (Re-DEC) is looking at the potential issues created by high penetration of DG resources on the California grid, including the distribution circuits operated by the IOUs. Re-DEC is a working group led by the CPUC that will bring together utility grid operators, renewable DG project developers, and renewable DG technology experts to better understand the issues and identify solutions.

- The CPUC conducts ongoing evaluation of the impacts of the SGIP and CSI programs, including T&D impacts. We present the evaluation results conducted on the SGIP and CSI programs examining DG impacts on peak electricity and on the T&D system.

Compared to the rest of the Unites States, California has a significant amount of DG installed on the grid, particularly solar. We will illustrate that as yet there are no noticeable impacts on the distribution and transmission infrastructure, based on performed studies. However, with the continued expected growth of DG, we identify in the following Chapters opportunities to develop consistent interconnection policies and the need for continued evaluation of penetration of DG on distribution feeders and DG's contributions to reducing peak demand through existing technology and technologies still being developed.

3

Background on Distributed Generation Resources

3.1 Definition of Distributed Generation Resources

This report focuses on a variety of policy efforts and programmatic activities related to distributed energy resources. We do not limit ourselves to a narrow definition of Distributed Generation (DG) for the purposes of the report; instead, we include information on a variety of DG resources in an effort to be as comprehensive as possible.

One reason for not limiting our definition of DG resources in this report is the perception of what constitutes a DG resource has evolved over time. The Public Utility Regulatory Policy Act (PURPA) of 1978 was the genesis for what was originally termed qualifying facilities (QFs) and eventually has become known as DG facilities.[2] Developed in response to the oil crises of the 1970's, the intent of PURPA was to encourage new sources of electricity as an alternative to traditional generation facilities, in part by exempting these facilities from certain existing federal and state utility regulations.[3] QFs include combined heat and power facilities (termed cogeneration facilities back in the 1980's) and other small power producers.[4] These non-traditional generation facilities had to meet certain Federal Energy Regulatory Commission (FERC) rules on fuel use, size, fuel efficiency, and reliability to qualify as small power producers. Small power producers in particular, could not be larger than 80 megawatts (MW) in installed electricity generating capacity and were required to use renewable resources (i.e., wind, biomass, solar, geothermal or water-based resources) as their primary fuel.[5] The Energy Policy Act of 1992 (EPAct) helped facilitate increased development of non-utility generation by allowing FERC to order transmission owners to carry power for other wholesale parties.

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2 The term distributed generation may have been coined by PG&E research and development staff according to testimony provided by Susan Horgan (Distributed Utility Associates), CEC workshop on Distributed Generation Strategic Plan, February 5, 2002

3 Qualifying facilities were not considered as utilities. As such, qualifying facilities were exempt from regulation under the Public Utility Holding Company Act (PUHCA) and the Federal Power Act (FPA).

4 Combined heat and power facilities produce both process heat (e.g., steam) for on-site uses and power. In general, the generated electricity can be used to offset electricity otherwise purchased from the utilities with surplus electricity being sold to the utilities.

5 Small power producers could not use any more than 25 percent of their annual energy input from non-renewable resources.

In 1999, the CPUC issued Decision (D.) 99-10-065 establishing the procedural roadmap for a new rulemaking into distributed generation. Under D.99-10-065, the CPUC considered DG to be "small scale electric generating technologies installed at, or in close proximity to, the end-user's location." In Rulemaking (R.) 99-10-025, the CPUC further delineated that "distributed generation can be installed on the end-user side of the meter, or on the grid side."[6] In its 2002 strategic plan for distributed generation resources, the CEC adopted a similar definition of DG stating "DG is electric generation connected to the distribution level of the transmission and distribution grid usually located at or near the intended place of use."[7]

Other than the original FERC definition for small power producers that limited the installed capacity to 80 MW, there has been no clear definition of a size cap on DG technologies. In a 2002 primer on DG technologies developed for the Department of Energy, DG was defined as "relatively small generating units (typically less than 30 MWe) located at or near consumer sites to meet specific customer needs, to support operation of the existing power grid, or both."[8] Similarly, in its cogeneration and distributed generation roadmap, the CEC limited the definition of DG technologies to those less than 20 MW.[9] In developing estimates of the potential for distributed generation from the United States commercial sector, Lawrence Berkeley National Laboratory (LBNL) investigators defined DG as generating units smaller than 5 MW and cross-referenced in the U.S. Energy Information Administration's National Energy Modeling System.[10]

Perhaps the most useful definition of distributed generation is one that focuses on connection and location rather than generation capacity. Based on comparisons of different characteristics and impacts of electric generating systems, researchers from the Swedish Royal Institute of Technology's Department of Electric Power Engineering defined distributed generation as "an electric power source connected directly to the distribution network or on the customer side of the meter."[11]

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6 OIR 99-10-065, October 21, 1999, Section III,C

7 Distributed Generation Strategic Plan, California Energy Commission, P700-02-002, June 2002, page 2

8 Distributed Generation Primer (first edition), Science Applications International Corporation for the Department of Energy, DOE/NETL-2002/1174, May 2002, page 9

9 Distributed Generation and Cogeneration Policy Roadmap for California, California Energy Commission, CEC-500-2007-021, March 2007, page 4

10 "Distributed Generation Potential of the U.S. Commercial Sector", LaCommare, Kristina Hamache, et al, Ernesto Orlando Lawrence Berkeley National Laboratory, LBNL-57919, May 2005

11 "Distributed generation: a definition," Ackermann, Thomas, et al, Department of Electric Power Research, Royal Institute of Technology, Electric Power Systems Research, Vol. 57, p.p. 195–204. 2001

A more general definition for DG has been used by the CPUC in evaluating the possibility of using significantly increased amounts of renewable DG resources to help meet the state's Renewable Portfolio Standard (RPS) target of 33 percent by 2020. In that evaluation, renewable DG resources ranged in size from systems less than 10 kW to over 20 MW and were considered to be those resources "able to come on line without substantial new transmission."[12]

DG facilities are most frequently defined as non-centralized electricity power production facilities less than 20 MW interconnected at the distribution side of the electricity system. DG technologies include solar, wind and water-powered energy systems; and renewable and fossil-fueled internal combustion (IC) engines, small gas turbines, micro-turbines and fuel cells.

3.2 Short History of Distributed Generation Resources in California

The passage of PURPA in 1978 and the adoption of long term standard-offer contracts by the CPUC sped the growth of QF facilities in California during the 1980s and informs current practices.[13] More than 8,000 MW of QF renewable and cogeneration facilities were added to California's electricity mix by 1990. However, most of the QF facilities were interconnected to the utility high-voltage transmission system rather than to the lower voltage distribution systems. A number of the QFs ranged in size from 100 to 200 MW; one of the largest QF facilities is the Arco-Watson cogeneration facility sized at 385 MW.

Table 3-1 shows the growth of non-utility generation in California from 1985 through 2000.[14]

Table 3-1: Growth in Non-Utility Generation in California (1985-2000)

Year	Total state generation (GWhr)	Utility owned (%)	Non-utility owned (%)
1985	210,172	68.2	4.7
1990	252,355	55.2	20.2
1995	256,367	58.1	23.4
2000	284,132	46.9	42.4

Note: Electricity restructuring as a result of AB 1890 (Brulte, 1996) spurred power plant ownership changes led to the growth of non-utility owned resources between 1995 and 2000.

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12 "33% Renewable Portfolio Standard: Implementation Analysis Preliminary Results," California Public Utilities Commission, June 2009, Appendix C, page 83

13 Standard offer contracts had 15 to 30 year terms that required the utilities to purchase power from QFs at prices rising sharply over time

14 The California Electricity Crisis: Causes and Policy Options, Weare, Christopher, Public Policy Institute of California, 2003

In the 1980s, the CPUC adopted standard offer contracts for QFs, greatly increasing the quantity of DG generation. In 2004, the CPUC considered the issue of renewal of the original QF contracts in R.04-04-003. As shown in Table 3-2, QFs provide a mix of both fixed (firm) and as-available capacity to utilities throughout the state.

Table 3-2: QF Capacity in California

Type	PG&E	SCE	SDG&E	Total QF Nameplate Capacity
As-Available (MW)	824	1615	21	2,460
Fixed (MW)	3,429	2,547	219	6,195
Total (MW)	4,253	4,162	240	8,655
As-Available %	19%	39%	9%	28%
Fixed %	81%	61%	91%	72%
Total %	100%	100%	100%	100%

Source: D. 07-09-040, Table 5.

QFs represented the first introduction of large quantities of distributed energy resources within California. The late 1990s saw the emergence of smaller generation facilities that connected directly at the distribution level of the electricity system. Within California, DG growth was helped through several government-sponsored incentive programs. The California Energy Commission’s Emerging Renewables Program (ERP) was funded as a result of AB 1890, and provided support to emerging renewable projects on the customer-side of the meter. The CPUC’s Self-Generation Incentive Program (SGIP), started in response to the energy crisis in 2001, offered incentives for DG projects located at utility customer sites but were sized slightly larger than the CEC's ERP facilities. Both the CEC's ERP program and the CPUC's SGIP program were designed to give rebates to facilities sized to offset all or a portion of the onsite electricity needs.

Historically, the U.S. electricity system developed on the premise that electricity would be generated by central station power plants and then transferred by the transmission and distribution (T&D) system to end-use customers. End users simply purchased power; they were not expected to generate power. Within California, interconnection of QF facilities had followed utility procedures available in the 1980s version of Rule 21. QF generators that connected to the grid had to abide by strict requirements to maintain high levels of power quality and reliability; avoid disruptions and prevent safety issues. The emergence of small-scale DG systems located on the customer side of the meter challenged standard operations of the T&D system. It was more difficult for these small DG resources to interconnect following the standard utility procedures originally designed for QF projects that primarily exported power. DG project developers, even for very small facilities, faced requirements that varied from utility to utility; uncertainty in interconnection costs; and delays in obtaining interconnection approval.

At the federal level, DOE collaborated with the Institute of Electrical and Electronics Engineers (IEEE) in 1998 to begin work on the development of uniform standards for interconnecting DG resources with the existing electric power systems.[15] The P1547 working group was established to develop interconnection standards that would apply to small scale DG resources. In May of 2000, the P1547 working group issued a ten point action plan that would address technical, business practice and regulatory barriers to DG interconnection.[16] In 2003, the IEEE standards board approved IEEE standard 1547 for interconnecting distributed resources with electric power systems.[17]

Within California, the CPUC recognized there was a need to improve DG policies for both wholesale (exporting) and customer-side (primarily non-exporting) DG facilities. In December of 1998, the CPUC opened R.98-12-015 "to develop specific policies and rules to facilitate the deployment of distributed generation and DER in California."[18] As a result of the rulemaking, a Rule 21 working group was established to review and update Rule 21 interconnection standards, operating and metering requirements for distributed generators. In December of 2000, the CPUC approved a new Rule 21 for use by the regulated IOUs.[19] The new Rule 21 included a Model Tariff, Interconnection Application Form, and Interconnection Agreement.[20] The CPUC indicated that it preferred Rule 21 language to remain consistent across the three utilities.

Rule 21 reform in the early part of this decade represented a major step forward in making interconnection utility-neutral. It helped to clarify and make more uniform the costs, procedures, and technical requirements of interconnection for DG resources in California, in particular for small resources. It also helped aid DG growth by including utility guidelines that reduced interconnection times and interconnection costs. Interconnection times were found to be reduced by a factor of nearly five, while interconnection fees dropped from

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[15] "Interconnection Standards for Distributed Generation," Mark McGranaghan and Bob Zavadil, Electrotek Concepts, Inc., Electrical Construction and Maintenance, April 2001 from http://powerquality.ecmweb.com/mag/power_interconnection_standards_distributed

[16] "IEEE 1547- Electric Power Resources Interconnected with the Electric Power System," Presentation by Richard DeBlasio, NREL, at U.S. Department of Energy Office of Power Technologies Distributed Power Program/Industrial DG Annual Review, January 29-30, 2002

[17] Presentation by Tom Basso, "IEEE 1547 Interconnection Standards," IEEE PES Meeting at NREL, June 9, 2004

[18] Order Instituting Rulemaking into Distributed Generation, CPUC OIR 99-10-025, Oct. 21, 1999

[19] Decision Adopting Interconnection Standards, CPUC Decision D.00-12-037, December 21, 2000

[20] See www.Rule21.ca.gov.

$5,000 to a range of $800 to $1,200 per application on average.[21] The past decade has seen tremendous growth of DG on the customer-side of the meter in facilitated by CPUC policies to streamline and simplify interconnection of small DG facilities, as well as in response to customer-driven demand.

While the Rule 21 Working Group has not met recently, the CPUC has an open rulemaking R. 08-03-008, in which ongoing Rule 21 issues can be addressed. In February 2005, the California Energy Commission issued "*Recommended Changes to Interconnection Rules*", and in June 2008, the CPUC hosted a workshop on open Rule 21 issues (see Section 4.3 below for more information on Rule 21 issues).

3.3 Current California Distributed Generation Interconnections

There is no readily available information on all DG interconnections within California. The interconnection data collection process, now discontinued, was previously spearheaded by the Rule 21 Working Group. However, there is data available on DG interconnections through the CPUC's SGIP program, the NEM-biogas tariff pilot program and various solar programs, including the CSI. Based on this information, there have been over 50,000 small DG facilities interconnected in California. It will be time-consuming for the utilities and the Commission to collect comprehensive interconnection data as utilities do not keep data in consistent formats. However, the Commission expects to make a renewed effort to get interconnection information from all utilities in 2010.

DG Installed Under the SGIP

The Self-Generation Incentive Program (SGIP) was established by the CPUC in 2001 in response to peak demand issues facing California. Located at utility customer locations, SGIP DG systems are designed to offset all or a portion of the utility customer load. As such, SGIP facilities help to meet load directly at the demand center, help alleviate congestion problems by reducing the amount of electricity that has to be delivered through the T&D system and assist in addressing peak demand. Since its inception in 2001, the SGIP has installed over 400 MW of DG capacity in the three large IOU service territories. Table 3-3 provides a summary of DG technologies installed under the SGIP through September 30, 2009 broken down by IOU service territory and type of DG technology.

[21] "Developing Standardized Interconnection Rules in California," Mark Rawson, California Energy Commission, presentation at EPA Clean Energy-Environment Technical Forum, February 9, 2006

Table 3-3: DG Facilities Installed Under the SGIP as of 9/30/09

	PG&E*		SCE		SDG&E		Total	
		Capacity		Capacity		Capacity		Capacity
Technology	Number	(MW)	Number	(MW)	Number	(MW)	Number	(MW)
PV	503	82.45	291	41.01238	105	14.19	899	137.6
IC Engines	123	66.96	131	93.223	21	12.12	275	172.3
Fuel Cells	18	10.91	36	8.14	4	2.25	58	21.3
Micro-turbines	55	10.25	72	15.926	18	2.03	145	28.2
Small Gas Turbine	4	4.77	3	13.6	2	9.13	9	27.5
Wind	2	0.47	5	12.6486	0	0.00	7	13.1
Total	705	175.79	538	184.55	150	39.72	1393	400.1

Solar DG Installed

The California Solar Initiative was started in 2007 and builds upon two decades of solar interconnections in California. Table 3-4 shows all solar interconnections in IOU territories. According to the most recent data on all solar interconnections, California's three large IOUs have 509 MW of grid-connected solar at 52,714 projects. The total solar capacity installed in IOU territories is half a gigawatt (GW); equal in size to an average coal or natural gas fired power plant. This total solar capacity includes sites installed under the CSI program since 2007 (there were 21,159 sites and 257 MWs as installed under CSI by September 2009) as well as capacity from systems from the NSHP Program, the SGIP (from Table 3-3 above), and the Emerging Renewables Programs (ERP). Table 3-4 distinguishes Net Energy Metered (NEM) solar customers and Non-NEM solar customers. NEM is available to solar customers, and while most of them participate in NEM, it is not always the preferred tariff rate. A significant number of customers (i.e., 245 customers with 43 MW of installed capacity) do not participate in NEM tariffs. For comparison purposes, Table 3-4 also shows there are an additional 1,493 MWs not yet interconnected, but in various stages of implementation under the CSI.

Table 3-4: All Solar Interconnections in Investor-Owned Utility (IOU) Territories

	PG&E	SCE	SDG&E	Total
NEM SOLAR Customer-Generators22	33,642 customers	11,423 customers	7,404 customers	52,469 customers
Non-NEM SOLAR Customer-Generators	206 customers	39 customers	0 customers	245 customers
Total SOLAR Customer-Generators	33,848 customers	11,462 customers	7,404 customers	52,714 customers
NEM SOLAR Customer-Generators, rated generating capacity (MW)	276 MW	132 MW	58 MW	466 MW
Non-NEM SOLAR Customer-Generators, rated generating capacity (MW)	23 MW	20 MW	0 MW	43 MW
Total SOLAR Customer-Generators, rated generating capacity (MW)	299 MW	152 MW	58 MW	509 MW
MW remaining in CSI general market program (not yet installed from the 1,750 MW total program goal)	622 MW	715 MW	156 MW	1,493 MW

Source: CPUC data request to PG&E, SCE, SDG&E, data through September 30, 2009.
Note: MW figures are all reported based on the CEC-AC rating of solar systems

Biogas Digester NEM Pilot Program

California is the largest diary producing state in the nation. California is home to over 1,800 dairies and 1.7 million cows.[23] A small number of California dairies have been converting dairy wastes using anaerobic digestion systems and using the captured biogas as fuel in DG facilities. Recognizing that biogas-fueled DG systems represent a diversified DG resource, the California Legislature passed Assembly Bill 2228 (Negrete-McLeod, 2002) in 2002 to help facilitate growth of biogas DG systems.[24] AB 2228 established a pilot program for net energy metering of eligible biogas projects. Eligible biogas projects were limited to 1 MW each in capacity, were required to be interconnected to the grid and sized to offset all or part of the customer's electrical load. To date, only a handful of biogas projects are participating in the NEM biogas pilot project. Table 3-5 lists the biogas projects participating in the NEM pilot project as of December 2009.

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[22] Includes some hybrid solar/wind systems, less than 1 MW statewide.

[23] California Animal Waste Management, Environmental Protection Agency, Region 9; http://www.epa.gov/region09/animalwaste/california.html

[24] Assembly Bill 2228 (Negrete-McLeod), September 24, 2002

Table 3-5: NEM Biogas Facilities (2009)

	PG&E	SCE	SDG&E	Total
# facilities	4	4	1	9
Capacity (MW)	0.985	2.49	0	3.475

Source: "California's BioEnergy Programs," Paul Clanon and Judith Ikle, CPUC, December 2009 BioEnergy Working Group

Small Power Producers and Cogeneration Facilities

The IOUs also continue to purchase a significant amount of power from qualifying small power producers and cogeneration facilities. Power is purchased under power purchase agreements (PPAs) with rates defined under D.07-09-040. As shown in Table 3-6, IOUs were purchasing power from 477 cogeneration and small power producer facilities representing over 8800 MW of capacity as of July 2009.

Table 3-6: Cogeneration and Small Power Producer Facilities (July 2009)

	SCE[25]		PG&E[26]		SDG&E[27]		Total IOU	
Resource	# of proj	(MW)	# of proj	(MW)	# of proj	(MW)	# of proj	(MW)
Biomass	16	168.9	35	507.55	7	4.53	58	680.98
Waste-to-energy	-	-	7	111.75			7	111.75
Cogeneration	54	2232.4	77	2456.82	40	337.71	171	5026.93
Geothermal	18	728.49	2	2.9			20	731.39
Small hydro	34	46.76	86	215.91	3	2.29	123	264.96
Solar	11	383.09	1	0.007			12	383.10
Wind	60	1074.26	26	572.14			86	1646.40
Totals:	193	4633.9	234	3867.08	50	344.53	477	8845.51

25 SCE cogeneration and small power producer facility numbers and capacities from http://www.sce.com/AboutSCE/Regulatory/qualifyingfacilities/dataanddocuments.htm

26 PG&E cogeneration and small power producer facility numbers and capacities from http://www.pge.com/includes/docs/pdfs/b2b/qualifyingfacilities/cogeneration/jul2009cogen.pdf

27 SDG&E cogeneration and small power producer facility numbers and capacities from http://www2.sdge.com/srac/

3.4 Projected DG Growth in California

Distributed generation installations in California, led predominately by solar PV systems, will likely continue their rapid growth in terms of MW and number of sites. This growth will continue on the customer-side of the meter through State incentive programs like the SGIP and CSI. However, growth is also expected to come from wholesale procurement and utility-specific programs to meet their RPS targets.

Customer Side of the Meter

In June 2009, the CPUC Annual Program Assessment of the California Solar Initiative[28] noted a number of reasonable statewide trends on the expected growth rate of solar PV capacity in the large IOU territories. Specifically, the large IOUs connected 78 MW of new solar PV capacity in 2007 and 156 MW in 2008, approximately a 100 percent increase in the installed solar capacity per year (annual growth rate). The annual growth rate in prior years had been between 30-40 percent. In fact the annual growth rate has been positive every year for over a decade. In addition, while the initial numbers of sites and MW were relative minor compared to the entire system, the CPUC suggested three scenarios about the growth rate and timeframes for meeting the CSI goals:

- **High Growth Scenario.** If it were possible for the annual growth rate in new installed capacity to continue to double year over year under the CSI Program, then the program would install ~1,750+ MWs by 2011. (Assumes 158 MW/year in 2008, and ~300 MW/year in 2009)
- **Medium Growth Scenario.** If the annual growth rate in new installed solar capacity continued to grow at just 50 percent per year (which is closer to the per annum growth rate over the past decade, then the CSI Program would install ~1,750 MW by the end of 2012. (Assumes 158 MW/year in 2008, and ~230 MW/year in 2009.)
- **Flat Growth Scenario.** If the annual growth rate in new installed solar capacity were flat (i.e. the state continued to install new solar PV capacity at the exact same amount as 2008 (Assumes 158 MW/per year), then the CSI Program would reach 1,750 MW of solar PV capacity by 2018.

These growth scenarios assume a linear trajectory over the time period. We believe that based on the global slowdown in 2009 and the collapse of the financing and tax equity markets that 2009 will likely be a slower growth year compared to others in the past.

[28] CPUC, California Solar Initiative, Annual Program Assessment, June 2009. http://www.cpuc.ca.gov/PUC/energy/Solar/apa09.htm

One variable that will stimulate growth of PV installations in the future is the continued decreasing cost of solar systems (e.g. the over 25% price reduction of PV systems during 2009). NREL recently released a study that predicts further PV cost declines and associated increases in PV penetration rates.[29] Decreasing capital costs and other mechanisms to decrease the upfront capital costs of solar systems such as leases and Property Assessed Clean Energy (PACE) financing will help make solar affordable to more consumers.

Like the CSI program for solar PV, the SGIP currently provides incentives for wind, fuel cells and advanced energy storage, although eligible technologies have changed over time. SB 412 (Kehoe, 2009) will change that mix again as the CPUC investigates technologies with the potential for significant greenhouse gas (GHG) emission reductions and adds them to the mix of SGIP eligible technologies. This is expected to help further stimulate demand for DG.

Wholesale DG

On the utility side of the meter, the procurement programs and policies under consideration or underway at the CPUC are likely to increase DG adoption. These include:

- The Renewable Portfolio Standard (RPS) program has annual competitive solicitations for new renewable resources which are open to distributed energy resources.
- Since February 2008 (AB 1969 (Yee)), the utilities all have Small Renewable Generation feed-in tariffs for the purchase of renewable generating capacity from small facilities throughout California. Additionally, other renewable future feed in tariffs are under consideration (R. 08-08-009 and SB32 Negrete-Mcleod, 2009) with decisions likely by mid-2010.
- The utilities have each proposed a solar PV procurement program. The CPUC approved the Southern California Edison (SCE) program in June 2009, and the Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E) programs are still pending with likely decisions in 2010.
- In December 2009, the CPUC approved policies and procedures for the purchase of excess electricity from eligible combined heat and power (CHP) systems.

In addition, the DG market may be enhanced if the creation of a tradable REC market for RPS compliance moves forward. In December 2009 the CPUC issued a Proposed Decision on the use of renewable energy credits for RPS compliance (R. 06-02-012) creating a ceiling price of $50/MWH, which is much higher than the current voluntary price.

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[29] NREL, Break-Even Cost for Residential Photovoltaics in the United States: Key Drivers and Sensitivities, December 2009, http://www.nrel.gov/docs/fy10osti/46909.pdf

33% RPS- High DG Penetration Scenario

In parallel to policies encouraging DG, the State has an established RPS goal of procuring 20% of its electricity from clean, renewable resources by 2010. An Executive Order from the Governor[30] and proposals currently in the Legislature would increase the target to 33% by 2020.

Both the CPUC and California Energy Commission have endorsed this increase from 20% to 33%. In addition, it is a key GHG reduction strategy in the California Air Resources Board's (CARB) AB 32 Scoping Plan. The CPUC recently issued a report, the *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results* (June 2009)[31], that drew upon the many lessons learned by the CPUC that can help guide the design of a higher mandate. The staff at the CPUC developed this report in order to provide new, in-depth analysis on the cost, risk, and timing of meeting a 33% RPS.

One scenario considered in the 33% Implementation Analysis was a High DG Penetration Scenario. This scenario assumed that only limited new transmission corridors would be developed to capture additional renewable resources needed to achieve a 33% RPS from traditional central station power plants. Transmission constraints would require extensive deployment of smaller-scale, renewable DG interconnected to the distribution system or close to transmission substations in order to meet the 33% target by 2020.

For this scenario, the analysis assumed that there is a potential of 18,355 MW of DG in the state of California. The majority of this supply would come from PV (17,301 MW) located at utility customer sites on roof tops and ground mounted facilities (note: CSI target is 1,940 MW). These systems would be dispersed at the feeder, the distribution bank, and the substation and in many cases would begin to exceed 15% of peak demand at the feeder lines.

Initially identified as part of the State's Renewable Energy Transmission Initiative (RETI)[32] approximately 1,300 sites near utility substations were identified that could each accommodate up to 20 MW of wholesale PV capacity as well as additional MWs of small systems "behind the meter".

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[30] Executive Order S-14-08; from http://gov.ca.gov/press-release/11073/

[31] *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results*, Paul Douglas, Project Lead; Elizabeth Stoltzfus, Project Manager; Anne Gillette and Jaclyn Marks, Lead Authors (June 2009) Report can be found at www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm

[32] RETI is a statewide initiative to help identify the transmission projects needed to accommodate the renewable energy goals of the Stat and facilitate transmission corridor designation and transmission and generation siting and permitting, which have been major hurdles in the development of renewable generation. Participants in RETI include the CPUC, the CEC, and CAISO

Based on the efforts of RETI, the CPUC's June report concluded that a High Penetration DG Scenario could facilitate achieving a 33% RPS in 2020 as well as mitigate some of the need for transmission and transform the market for solar PV technologies. This scenario compared to other scenarios including the base case, high wind supply and out of state development avoids major limiting factors including:

- environmental impacts of new transmission and new central station generation;
- difficulties in siting new transmission lines; and
- speed to market.

With a High Penetration Scenario however, there is a need to quantify potential factors including:

- willingness of building owners to install PV systems or allow such systems to be installed on their rooftops;
- energy costs of these systems;
- impacts on grid reliability with a higher penetration of intermittent DG;
- effectiveness of the pending utility programs focused on this size; and
- the capacity of the equipment and labor supply chains, from manufacturing through installation, to meet this goal.

Because of the assumed high penetration of distributed solar PV, with large numbers of smaller systems, using DG to meet the 33% RPS is presumed more costly than other scenarios. However, as mentioned earlier, installed costs for solar PV have dropped dramatically and this trend is expected to continue globally.

Going forward, even with limits to siting new transmission lines and possible restrictions on the development of solar generation on federal lands, the State should continue to examine impacts of developing DG resources. In particular, we should evaluate geographically specific load growth forecasts and take steps to accelerate our understanding of the impact of distributed generation on feeder lines, substations and transformers, as well as other distribution system impacts. In the meantime, analysis of the SGIP and CSI, the two largest customer side DG programs in the US, provides some insights into possible impacts. Each program produces annual impact evaluations and the CSI provides quarterly updates. In addition, the CSI Research, Development, Deployment and Demonstration (RD&D) program is examining advanced solar energy technologies and products to help achieve sustainable growth of a California solar market. The first solicitation of the CSI RD&D program is focused on developing and deploying technologies and products that will help California benefit from high penetration of solar resources within the electricity system.

At the same time, the Renewable Distributed Energy Collaborative or Re-DEC, a multi-stakeholder effort, is examining barriers to implementation of a High DG Penetration Scenario. A more detailed description of ReDEC is in Appendix A, but Section 4 of this document summarizes the issues under consideration.

4

Issues Related to Distributed Generation Resources

DG resources impact the electricity system in a number of ways. First they represent a fundamental change in the historical pattern of regulated electricity service that traditionally provided energy almost exclusively from central station generating facilities. Additionally, DG resources affect the way in which utilities operate and maintain the T&D system, including the allocation of costs. As discussed earlier, many of the impacts and problems associated with DG only arise with higher and concentrated DG penetration. Some of the more critical issues are discussed below.

4.1 Reliability and transmission issues

Regulated electric utilities have a mandate to "keep the lights on." That is, they are responsible for the reliability of electricity service. The U.S. electric power system is among the most dependable in the world, typically delivering power with over 99 percent reliability.[33] Power quality, or the ability to provide power without variation in voltage or current, is also a critical component of the electricity system. The emergence of DG technologies and the role they play in the electricity system provide both opportunities and challenges to system reliability and power quality.

DG systems can potentially provide the following opportunities for increasing electricity system reliability[34]:

- adding generation capacity at the customer site for continuous power and backup supply;
- adding overall system generation capacity;
- freeing up additional system generation, transmission, and distribution capacity;
- relieving transmission and distribution bottlenecks; and
- supporting maintenance and restoration of power system operations by providing potential generation of temporary backup power;

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33 "Edison Electric Institute, "America's Electric Utilities: Committed to Reliable Service," May, 2000

34 "Reliability and Distributed Generation," white paper by Arthur D. Little, 2000

However, DG facilities can also complicate a utility's ability to provide reliable and high quality power. For a utility to ensure reliable, high quality power, it must have adequate generation, transmission, and distribution capacity and must be able to control the voltage and the frequency of the electricity system. If the electricity system becomes significantly imbalanced, it could result in significant interruption of service, serious failures, and even danger to health and property. For example, overloaded transformers and control systems pose a real fire threat, particularly in hot dry climates throughout the State.

To avoid these issues, the utility must keep generation and demand exactly balanced at all times. The utility has to provide adequate "voltage support" on the lines; has to keep sufficient distribution capacity on all lines to move the power being used; and has to maintain sufficient generation, transmission, and distribution capacity to respond to contingencies, including the failure of lines or generators or the sudden addition or loss of large loads.

Determining where to locate generation and voltage support depends on the location-specific load and the design of the distribution system. As a result, utilities must plan the manner in which load, generation, and distribution facilities interact. The process is made even more difficult by the interconnected nature of the electricity system. Every connected generation source affects the system and is affected by the system, even if it does not export power. Additionally, the variety of DG technologies, the different ways in which they interact with customer load and the intermittent nature of some of the renewable DG sources (e.g., wind and solar) make it difficult to integrate these resources while maintaining high system reliability and power quality. Section 5 illustrates (using SGIP and CSI studies of customer side of the meter generation) that penetration levels are currently not to this level. However pursuing the High DG Penetration Scenario referenced in Section 3 will require additional analysis and measures.

4.2 Interconnection Issues Related to Grid Operation and System Capacity

As noted earlier, DG systems can help alleviate transmission and distribution congestion and provide additional generating capacity to help meet peak demand. However, for DG systems to operate in this fashion, they must be interconnected, controlled, measured, and operated as an integral part of the electricity system. Integration of DG resources is controlled at the transmission level by the California Independent System Operator (CAISO) and at the distribution level by the local distribution companies.

California ISO (CAISO)

The CAISO is responsible for all transmission planning and implementation activities within California. Historically, each utility received transmission interconnection requests and conducted the power flow, stability, feasibility, fault current, and other studies within their own respective utility system. The requestor paid the costs of conducting such studies. However, with increased interest in renewable generation that would cut across single utility service territories, the CAISO initiated studies into renewable transmission interconnection. One of the earliest investigations by the CAISO was the Participating Intermittent Resource Program (PIRP). The PIRP is a CAISO program that allows intermittent generation resources (such as wind energy systems) to schedule energy in the forward market without incurring imbalance charges.

Due to their smaller generating capacities, DG facilities by themselves pose little direct impact to the transmission system which we will illustrate in Chapter 5. However, with increased growth in DG facilities or those considered under the High DG Penetration Scenario outlined above, the cumulative penetration of DG resources may potentially impact transmission within California.

Beginning in 2004, the CAISO worked in conjunction with the CEC on a study investigating the integration of large quantities of intermittent renewable resources into the California grid.[35] The Intermittency Analysis Project (IAP) study examined the possibility for integrating sufficient renewable energy capacity at the transmission node to meet the 33% renewable energy target by 2020. The IAP study showed the feasibility of integrating large quantities of renewable energy resources into California's electricity system.[36]

At present, the CAISO has assumed the responsibility for conducting all transmission interconnection studies related to integration of renewable projects. In general, projects requiring a transmission interconnection fall into a queue. There are over 500 positions in the queue list with service dates ranging from 2010 to 2017. Until recently, projects were handled sequentially in their order within the list. In order to get through the large number of facilities listed in the queue, the CAISO started grouping the submittals into clusters. Cluster studies begin every six months around the beginning and the middle of the calendar year. Depending on when the submittal was made and when the CAISO picks a date for conducting studies, time spent in the queue varies significantly, potentially creating more risk for the project developers.

In addition, projects applying to the CAISO for interconnection agreements fall into two general classes: facilities greater than 20 MW and facilities 20 MW or less. The latter

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35 "Intermittency Analysis Project," presentation by Dora Yen Nakafuji, California Energy Commission, August 15, 2006

36 "CAISO's Plan for Integration of Renewable Resources," presentation by David Hawkins, CAISO, July 21, 2008

facilities can apply under the less expensive and more expedited FERC-SGIP. For example, solar projects that are 20 MW or less submit a FERC-SGIP application to the CAISO, pay for a queue position based on the anticipated megawatt capacity, and receive a queue position number. The projects must wait until the CAISO can conduct the transmission and sub-transmission studies. These projects can be constructed and be commercially available to meet the RPS requirements quickly but the CAISO process can delay construction. Overall, while sometimes lengthy, the interconnection process at the **transmission** (emphasis added) level through CAISO is a well understood and agreed upon method.

Local Distribution Companies

For DG projects under 20 MW, interconnection may involve working with the individual local utility companies providing distribution depending on the procedures at the different utilities. There is no uniform size limit among the utilities regarding interconnection to the distribution grid.

Prior to 2001 and Rule 21 reform discussed below, DG facilities applying for interconnection agreements faced different and sometimes conflicting series of requirements; and a high level of uncertainty on interconnection costs. Among the types of issues encountered by DG projects included:

- high application fees
- requirements for interconnection studies
- interconnection hardware
- operational constraints
- utility imposed testing (pre-operational and operational)
- standby and backup rates
- demand ratchets

Rule 21 was modified in the early part of the decade to address interconnection issues, streamline the interconnection process, and address the other kinds of issues encountered in developing DG projects. Nonetheless, there are still open questions that need to be addressed within Rule 21, some of which are highlighted below.

4.3 Policy and Technical Barriers to Connection of Distributed Generation Energy to the Grid

Since enactment of Rule 21, California has made significant progress in developing and interconnecting DG resources. However, implementing high penetration of DG resources to achieve the 33% RPS target will require additional coordination between DG project developers, the electric utilities and the CAISO. The CPUC kicked off such an effort on

December 9, 2009 called the Renewable Distributed Energy Collaborative or Re-DEC. The results of Re-DEC will impact implementation of the programs described above as well as development of the timeline for the High DG Case for purposes of LTPP.[37] Appendix A to this report includes a presentation to the December 9, 2009 ReDEC Working Group meeting. The presentation describes the approach that was taken in assessing DG resources that could help achieve the 33% RPS target, how the generation capacity of those resources compares to available substation capacity and the possible cost impacts associated with using high penetration of DG resources (primarily solar resources) to achieve the 33% RPS target.

Some potential policy barriers that RE-DEC may cover include:

- Open issues on Rule 21 and consistent information from the utilities on suitable areas for DG development
- Distribution system unknowns
- Environmental requirements for DG projects

Open Issues on Rule 21

Even though Rule 21 began addressing a number of issues associated with DG implementation in California, a number of issues remain to be addressed. A workshop held by CPUC staff in June 2008 of the Rule 21 Working Group listed the following policy and technical issues that still need to be addressed[38]:

Policy Issues:

- Movement from uniform towards utility-specific interconnection rules
- Repositories for Certification of DG equipment and dispute resolution records
- Consistency of utility-related cost collections to ensure equitable cost sharing between customer and rate payer
- Possible changes in distribution design criteria to allow for high penetration of PV associated with new housing developments (and more generally change the acceptable level of voltage drop on the distribution system)
- Streamlining of interconnection requirements between conflicting FERC/CAISO transmission and CPUC/IOU distribution rules
- Appropriate mechanisms to inform developers of sites more suitable for DG than others

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[37] More information on RE-DEC can be found at www.cpuc.ca.gov/PUC/energy/Renewables/Re-DEC.htm

[38] Rule 21 Working Group Workshop, presentation by Nick Chaset, California Public Utilities Commission, June 20, 2008. See http://www.cpuc.ca.gov/PUC/energy/Solar/workshops.htm.

- How utilities can share distribution grid information without compromising security issues

<u>Technical Issues:</u>

- Broadening of IEEE 1547 standard to incorporate Rule 21 technical items
- Metering and data transmission for more complex DG systems
- Additional protection needs associated with power export from DG systems
- Islanding and micro-grid issues
- Determining appropriate level of backup protection (to protect the grid from possible problems caused by DG systems) and identifying appropriate party responsible for costs
- Certification of interconnected DG systems, sunset dates for certification and resolution of "recall" issues associated with previously certified systems already installed
- Establishing a uniform measure of DG penetration as a percent of peak demand.

Distribution System Unknowns

The expansion of the Feed-in-Tariffs (FIT) being contemplated by the CPUC may increase the development and visibility of DG projects on the distribution grid. Currently, the maximum eligible project size is 5 MW on the distribution system. Expanding the project size limit to 20 MW and creating a streamlined contracting mechanism will likely unleash significant demand for project interconnection.

One area of concern is the minimal knowledge we possess about the exact impact of distributed PV installations on the distribution system as many of the sites under an expanded FIT would be PV. There are currently no distribution planning models that can accurately simulate the interaction of PV components such as the inverters with substation equipment.[39] It is a challenge for the utilities to define the process and connection requirements until the utilities have a thorough understanding of the impacts on the distribution level. A February 2008 study from the Sandia Laboratories illustrated this uncertainty listing references and a range of maximum PV penetration levels from 5 percent to greater than 33 percent of load.[40] In addition, to understanding the distribution impacts of DG, a process to provide developers

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[39] This area will be addressed through the CSI RD&D program as it was a topic under the first solicitation (grid integration of PV resources) and development of utility modeling tools was specifically identified as an area needing work.

[40] *Renewable Systems Interconnection Study: Distributed Photovoltaic Systems Design and Technology Requirements* ,Chuck Whitaker, Jeff Newmiller, Michael Ropp, Benn Norris, SANDIA REPORT, SAND2008-0946 P. Printed February 2008.

with a list of geographic areas where distribution capacity or load allow for high-value interconnection without compromising confidential information should be explored. These topics are being covered by ReDEC.

In addition other tools and policies may decrease the risk of DG development on the distribution system including: a standardized format to track the installed capacity and expansion of distributed PV; developer access to accurate and detailed data on the distribution system to facilitate modeling and analysis; a list of DG project sites already in development; and a consistent interconnection process for DG systems among the utilities.

DG Project Environmental Requirements

DG projects installed in California must comply with a number of environmental requirements including permits for air quality, water discharge, building standards (for systems that potentially impact the building environment or envelope) and waste discharge permits (for DG facilities that process solid materials or have disposable wastes).

On November 15, 2001, the California Air Resources Board (CARB) established a distributed generation (DG) air quality certification program in response to Senate Bill 1298 (Bowen, September 2000). The DG certification program requires manufacturers of DG technologies that are exempt from air pollution district permit requirements to certify their technologies to specific emission standards before they can be sold in California. Amendments to the DG Certification regulation were adopted by CARB on October 19, 2006, and became effective on September 7, 2007.

In addition, legislative changes made with respect to the Self-Generation Incentive Program, limited project eligibility to "ultra-clean and low emission distributed generation" technologies. These technologies were defined as fuel cells and wind DG technologies that met or exceeded emissions standards required under the DG certification program adopted by the California Air Resources Board on October 19, 2006.

On September 27, 2006, the Governor also approved Assembly Bill 32 (Nunez). Under AB 32, CARB is required to adopt state regulations to "achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions…."

The combination of the CARB DG certification guidelines and the need to find GHG emission reductions have provided unclear direction to DG developers who have GHG reducing technologies but they may not be defined as "low emissions". However, under SB 412 (Kehoe, 2009), the CPUC is re-examining DG technologies that are eligible for the SGIP and expects to provide some clarity around these issues. The CPUC held an SB 412 workshop on January 7, 2010 and developers provided comments to that workshop. [41]

[41] The Workshop materials are available here: http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/workshops.htm

5

Impact of Existing Distributed Generation Resources

While there are well over 50,000 DG facilities interconnected to California's electricity system, these facilities represent less than 800 MW of generating capacity, or little more than 1 percent of the approximate 67,000 MW of in-state generation supplies.[42] As a result, impacts of current levels of DG facilities on grid reliability or the transmission and distribution (T&D) system are expected to be relatively insignificant. The level of penetration on the circuit level that utilities in California believe would have significant impact is at 15 percent of line load.

There has been no comprehensive assessment of the impacts of all DG facilities currently operating in California. However, evaluations have been conducted for DG systems operating under both the SGIP and CSI programs. The evaluations assessed the impact of DG systems on peak electricity supplies; as well as on the T&D system. A summary of the results from these analyses are included in this section.

5.1 Impact of SGIP DG Resources

The latest impact evaluation of SGIP DG facilities was conducted for the 2008 calendar year, but T&D impacts were not assessed. SGIP facility impacts on the T&D system were last investigated in the 2006 SGIP impact evaluation. An in-depth assessment of SGIP DG facilities is currently underway and will be included in the 2009 SGIP impact evaluation.

SGIP DG Peak Demand Impacts

The SGIP 2008 Impact Evaluation examined the impact of SGIP DG facilities on annual and peak demand during calendar year 2008.[43]

By the end of 2008, nearly 1,300 SGIP facilities were on-line, providing over 337 MW of electrical generating capacity. Some of these facilities (e.g., PV and wind) provided their

[42] California Energy Commission, California Power Plants, from http://energyalmanac.ca.gov/powerplants/index.html

[43] "CPUC Self-Generation Incentive Program: Eighth Year Impact Evaluation," prepared by Itron for the CPUC and SGIP Working Group, June, 2009

host sites with only electricity, while SGIP cogeneration facilities provided their hosts with both electricity and thermal energy (i.e., heating or cooling). In the course of the 2008 calendar year, SGIP projects generated over 718,000 megawatt-hours (MWh) of electricity; enough electricity to meet the electricity requirements of nearly 109,000 homes for a year.[44]

While providing electricity throughout the year, SGIP facilities also provide value by generating electricity during times of peak demand. Peak electricity demand is measured statewide by the California Independent System Operator (CAISO) and at the utility level for each specific utility. The ability of SGIP projects to supply electricity during times of the CAISO peak demand represents a critical impact. By providing electricity directly at the customer site during CAISO peak hours, SGIP facilities reduce the need for utilities to power up peaking units to supply electricity to these customers. Likewise, SGIP provides some relief to the electricity system by decreasing transmission line congestion. In addition, by offsetting more expensive peak electricity, SGIP projects provide potential cost savings to the host site when tariffs have peak demand charges and/or time of use commodity charges. Table 5-1 shows the impact of SGIP DG facilities on the CAISO system peak during 2008. Figure 5-1 is a graphical depiction of the impact of SGIP DG facilities by technology type on the CAISO demand over the course of the 2008 summer peak day.

Table 5-1: Demand Impact Coincident with 2008 CAISO System Peak Load

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
Fuel Cell	19	10,700	6,889	0.644 †
Small Gas Turbine	6	17,643	14,728	0.835 †
IC Engine	223	140,490	34,788	0.248 †
Micro-turbine	129	20,692	8,509	0.411
PV	863	129,566	76,202	0.588
Wind	2	1,649	N/A	N/A
TOTAL	**1,242**	**320,740**	**141,117**	**0.440**

* indicates confidence is less than 70/30

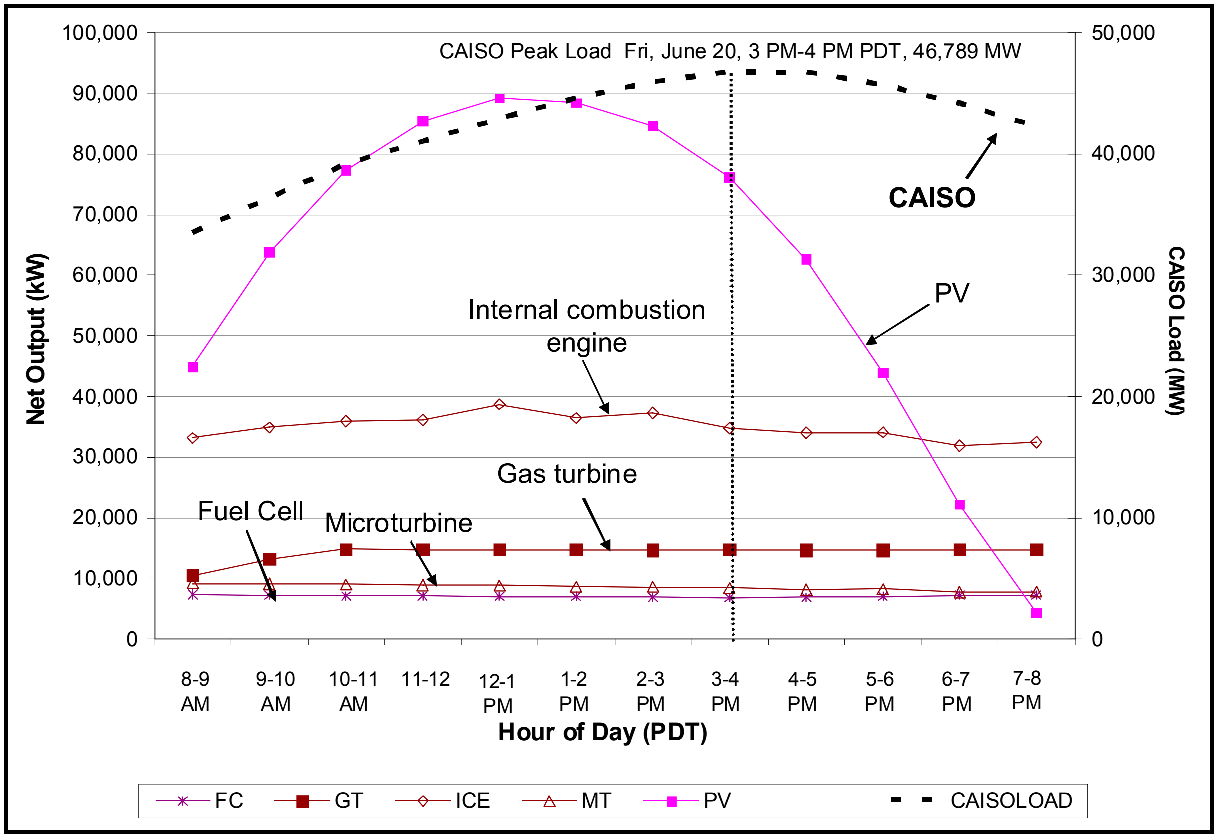
† indicates confidence is better than 70/30.

No symbol indicates confidence is better than 90/10.

[44] Assuming the typical home consumes approximately 6,670 kWh of electricity per year. From Brown, R.E. and Koomey, J.G. *Electricity Use in California: Past Trends and Present Usage Patterns.* Lawrence Berkeley National Laboratory. May 2002. http://enduse.lbl.gov/info/LBNL-47992.pdf. Value derived from Table 2 on page 8.

The CAISO system peak reached a maximum value of 46,789 MW on June 20 during the hour from 3-4 P.M. (PDT). While the total rebated capacity of SGIP facilities on-line projects exceeded 320 MW, the total impact of the SGIP projects coincident with the CAISO peak load was estimated at slightly above 141 MW. In essence, the collective peak hour capacity factor of all SGIP projects on the CAISO 2008 peak was approximately 0.44 kW of peak capacity per kW of rebated capacity.

Figure 5-1: SGIP Impact on CAISO 2008 Peak Day



SGIP DG Distribution System Impacts

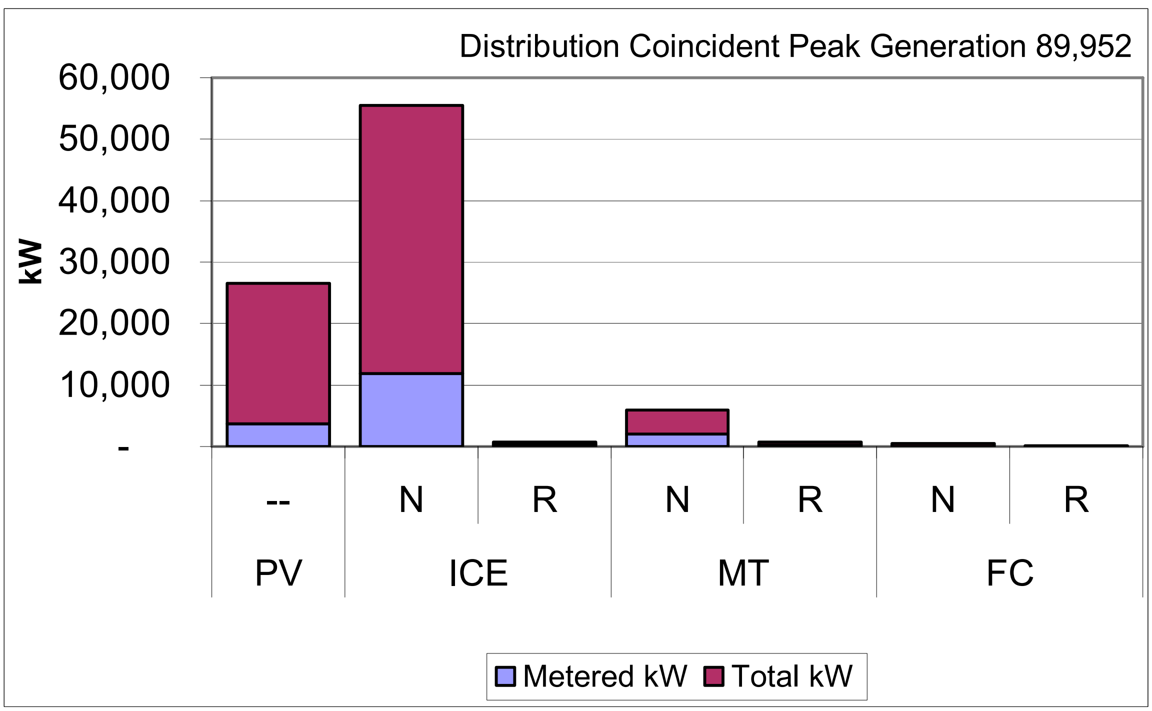
SGIP facilities can help California's electricity system by meeting electricity needs at customer sites, which alleviates the need for utilities to generate and transfer electricity to the site, thereby reducing loading on the distribution and transmission lines. The impact of SGIP DG facilities on the T&D system was investigated under the 2006 SGIP Impact Evaluation report.[45] Distribution system impacts were assessed by comparing SGIP facility hourly generation profiles against hourly distribution line loadings. There are thousands of distribution lines within California's electricity system. However, the 2006 SGIP analysis on

[45] "CPUC Self-Generation Incentive Program: Sixth Year Impact Evaluation," prepared by Itron for the CPUC and SGIP Working Group, August 30, 2007

distribution line loadings was limited to those distribution lines serving utility customers hosting SGIP DG facilities. As such, the 2006 SGIP distribution analysis is not a comprehensive evaluation but a representative evaluation of how SGIP DG facilities can help unload the distribution system. In addition, line loadings used in the analysis represented the peak loading for the individual feeders occurring at the day and hour of the peak loading of that feeder. It is important to recognize that peak loading on feeder lines will often occur on different days and hours from the individual IOU system peaks and the CAISO system peak.

Using only SGIP facility metered data that corresponded with distribution line loading data, the estimated distribution peak load reduction associated with SGIP technologies in 2006 in the three utility service territories was 46.1 MW for PG&E; 37.1 MW for SCE; 6.8 MW for SDG&E; representing a statewide total of 90.0 MW. Figure 5-2 provides a summary of the measured and estimated impact of SGIP technologies on the distribution system in 2006.

Figure 5-2: Distribution System Peak Reduction by SGIP Technology (2006)



Metered kW	3,636	11,914	360	2,024	203	0	0
Total kW	26,516	55,515	744	5,975	688	467	67
Metered #	78	55	3	28	4	1	1
Total #	569	165	9	81	16	9	2

While Figure 5-1 depicts the amount of distribution line loading relief provided by SGIP facilities during 2006, distribution system planners investigating ways to reduce distribution line peak loading from increased penetration of DG facilities will need a way to estimate the amount of peak reduction available from each DG technology. A "look-up" table that reports measured distribution coincident peak load reduction across the different SGIP technologies, utilities, feeder types, and climate zones was developed for this purpose. Table 5-2 provides estimated peak coincident load reduction factors that can be used for distribution system planning. For example, afternoon peaking feeder lines (i.e., those feeder lines peaking before 4 pm) in the coastal zone of PG&E can expect to see a line loading reduction factor of 0.56 for PV facilities entering the distribution system. This means that, based on observed performance, every rebated kW of PV installed and operating in PG&E's coastal zone will effectively act to reduce the distribution line loading by 0.56 kW of peak loading. Similarly, based on the observed data, PV technologies can be expected to provide a statewide distribution impact of 0.35 kW of peak reduction for every kW of rebated PV.

Table 5-2: Distribution Coincident Peak Reduction Factors

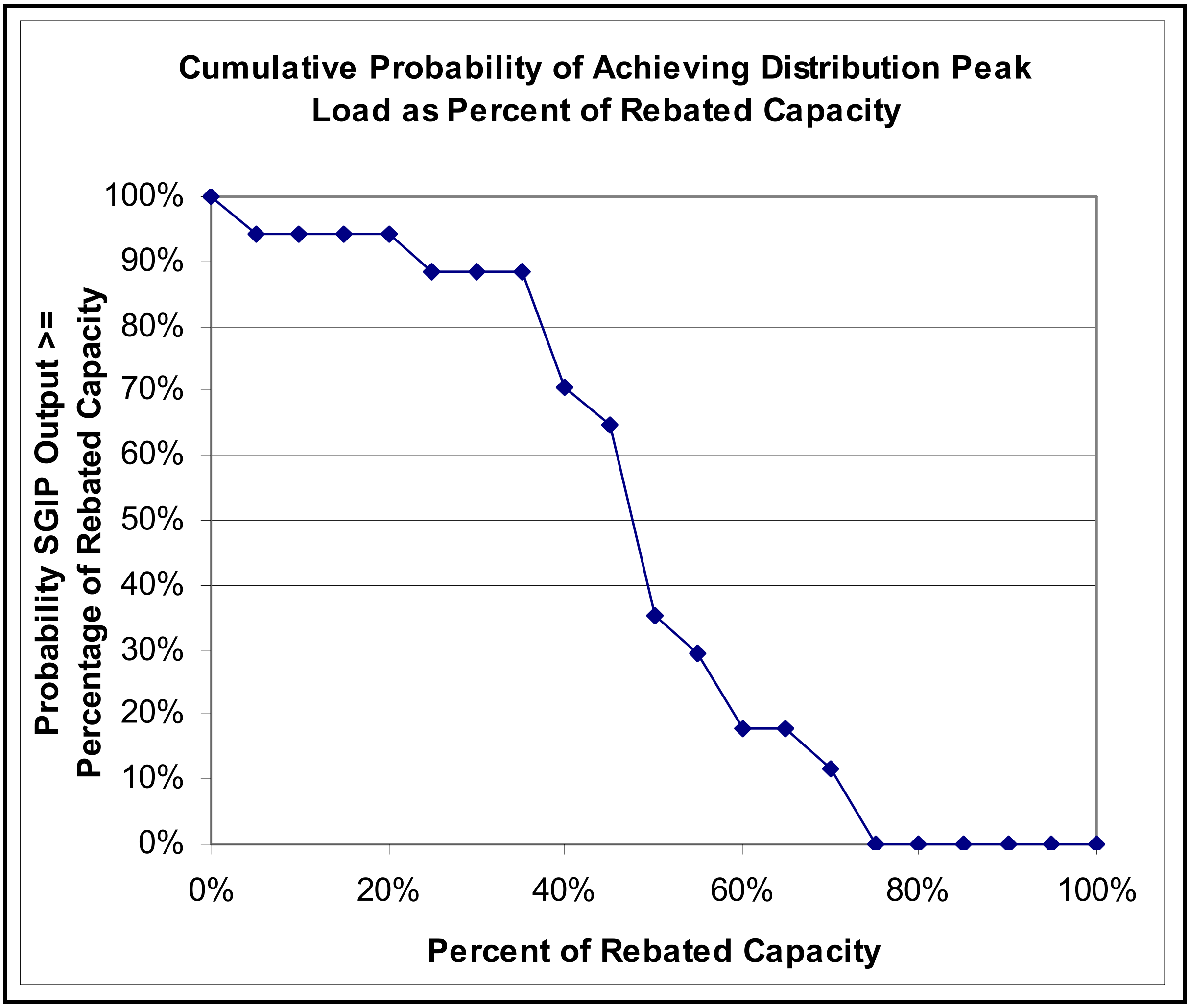
		PV	ICE		MT		FC	
		--	N	R	N	R	N	R
PG&E Coast	Afternoon	56%	85%					
	Evening	30%						
SCE Coast	Afternoon	46%	65%		44%			
	Evening	6%	48%		52%			
SDG&E Coast	Afternoon	42%	33%		40%			
	Evening	1%						
Inland	Afternoon	63%	29%					
	Evening	26%						
Total by Technology/Fuel		35%	50%	12%	50%	23%	16%	0%
Total by Technology		35%	48%		44%		9%	

Notes:
Climate Zones
PG&E Coast (CEC Title 24 Climate Zones 2, 3, 4, 5)
SCE Coast (CEC Title 24 Climate Zones 6, 7, 8, 9, 10 in SCE service territory)
SDG&E Coast (CEC Title 24 Climate Zones 7, 8, 10 in SDG&E service territory)
Inland (CEC Title 24 Climate Zones 11, 12, 13, 14, 15 for all utilities)
Distribution Peak Hour
Afternoon (Peak occurs on Hour Ending (HE) 16 or earlier)
Evening (Peak occurs after HE 16)

In order to be a useful source of distribution capacity value, there must also be measurement of the reliability that SGIP installations will be operating during the peak. Otherwise, distribution planners will tend not to rely on the load reduction achieved through SGIP DG facilities in their capacity planning. Therefore, the project team developed an uncertainty analysis based on the variation of metered SGIP units.

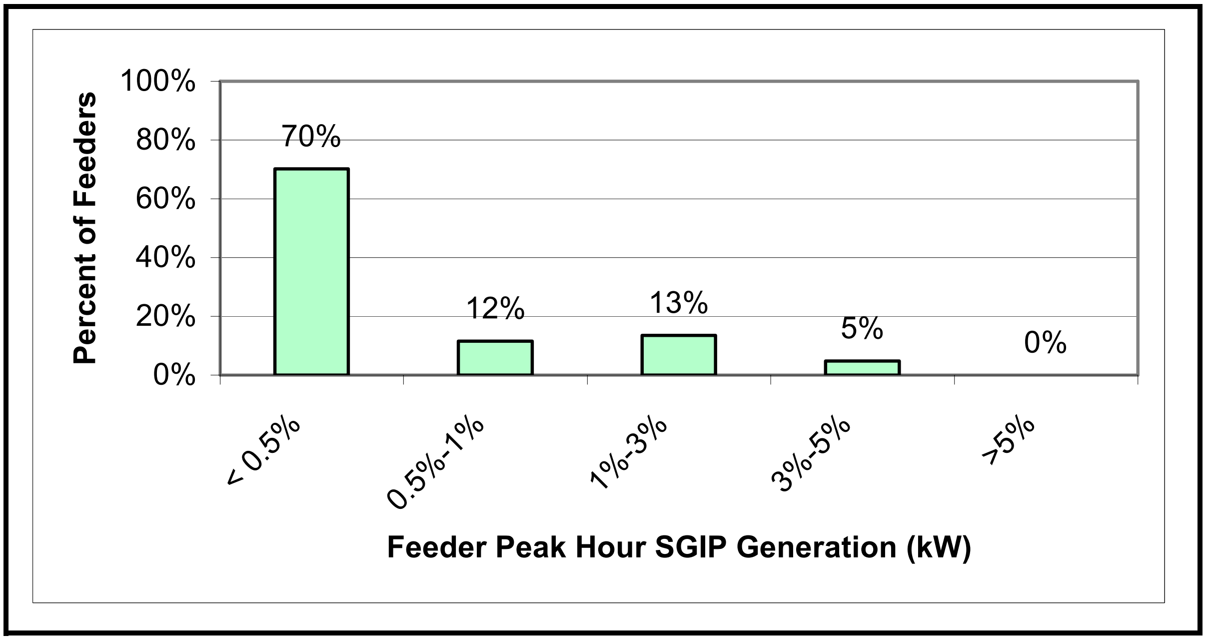
A reliability curve was developed based on the measured SGIP data that associates a probability of achieving an amount of load reduction for each SGIP technology. For example, Figure 5-3 below shows the probability profile of a PV installation achieving different distribution peak load reductions on a feeder that peaks on or before 4 P.M. There is 100 percent probability of having an output of zero or greater, a very low probability of having output equal to the rebated capacity, and a 35 percent probability of having output at least as high 50 percent of the rebated capacity. A spreadsheet tool was developed to compute combined probability distributions for multiple SGIP installations of different types on a single feeder using the measured data.

Figure 5-3: Probability of PV Output at Distribution Peak Hour (SCE Coast, Feeder Peak Before 4 P.M.)



Based on the results in Table 5-2, SGIP technologies demonstrate a potential for significant reduction in peak loading of the distribution system. However, high penetration of DG technologies will be needed to achieve significant overall reduction in peak loading across each IOU service territory. Figure 5-4 provides a summary of the amount of peak reduction actually observed to occur in 2006 due to the impacts of SGIP technologies.

Figure 5-4: Peak Reduction as Percentage of Feeders



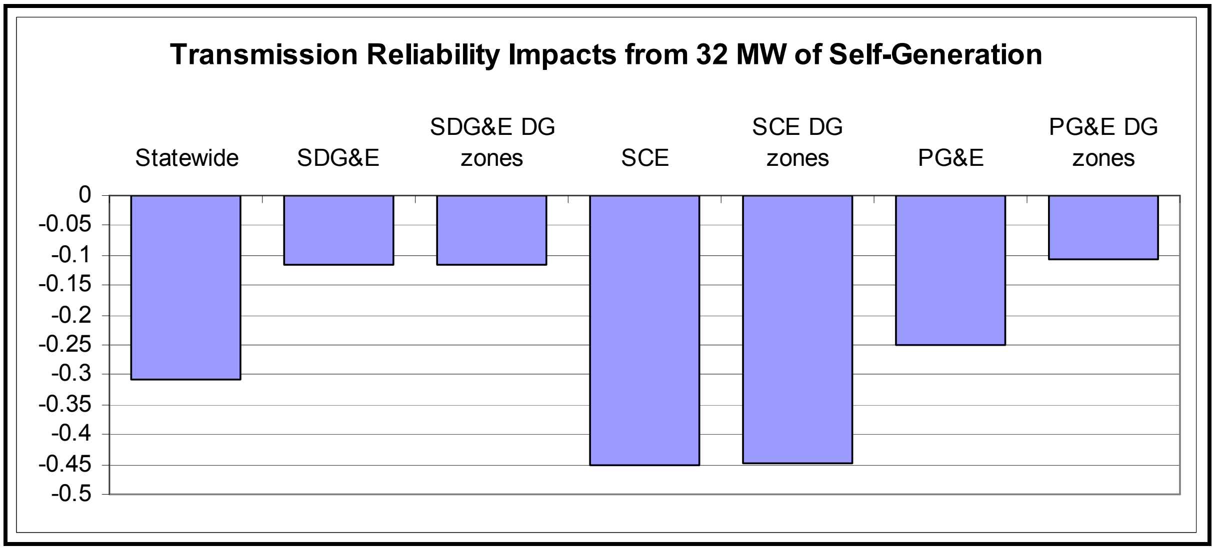
Overall, the 2006 evaluation report showed that at low penetration levels, SGIP facilities had limited impact on reducing distribution system peak program-wide. No feeders or substations saw greater than five percent reduction of their peak loading. Approximately 70 percent of the feeders had peak loading impacts that were limited to less than 0.5 percent of the peak feeder loading.

SGIP DG Transmission System Impacts

As load reduces on the distribution network due to self-generation facilities, there is a corresponding reduction on distribution transformers, sub-transmission lines, transmission substations and ultimately on the high voltage lines. However, very high penetration of DG is generally considered necessary to provide significant benefits to the high voltage transmission lines.

Transmission system impacts were assessed using measured SGIP generation data and then modeling the aggregated capacity (MW) of SGIP DG facilities at each substation. Modeling of the transmission system focused on reliability impacts. In essence, the modeling simulated the impact on transmission system reliability associated with removing SGIP generation out of the electricity system. A Distributed Generation Transmission Benefit Ratio (DGTBR) was calculated by the modeling approach and represents the net reliability impact. A negative DGTBR represents a reduction in load on the transmission system and therefore an improvement in system reliability. A positive DGTBR indicates an increase in load on the transmission system and therefore a probable decrease in system reliability. Figure 5-5 is a summary of the reliability impacts associated with SGIP DG facilities during the summer 2006 peak.

Figure 5-5: Transmission Reliability Impacts for 2006 Peak



Overall, the modeling results show that SGIP DG facilities acted to reduce transmission line loading and so improved system reliability at the transmission level. Statewide, each kW of rebated SGIP DG potentially improved system reliability by 0.3 kW of reduced transmission line loading. Within each of the IOUs, SGIP facilities had the impact of improving system reliability from 0.1 to nearly 0.45 kW of increased reliability per kW of rebated SGIP capacity.

Even though the total aggregated capacity of the SGIP DG facilities represented only 32 MW out of the 42,000 MW of demand occurring under the 2006 summer peak conditions, the DG facilities were still found to provide overall DGTBR benefits to the system. As with distribution system impacts, the low penetration of SGIP facilities within the electricity system limits the conclusions that can be made about transmission level impacts at higher concentrations of SGIP capacities.

5.2 Impact of CSI DG Resources

The 2007/08 CSI Preliminary Impact Report[46] evaluated the impacts of CSI facilities on peak electricity demand and impacts on the transmission and distribution system during calendar years 2007 and 2008. However, due to limited CSI metered data available for 2007, impact results discussed herein are limited to those associated with calendar year 2008.

CSI DG Peak Demand Impacts

Initiated on January 1, 2007, the CSI has been a rapidly growing solar DG incentive program. By the end of calendar year 2008, over 11,800 solar systems representing approximately 150 MW of rebated capacity had been installed under the CSI.[47]

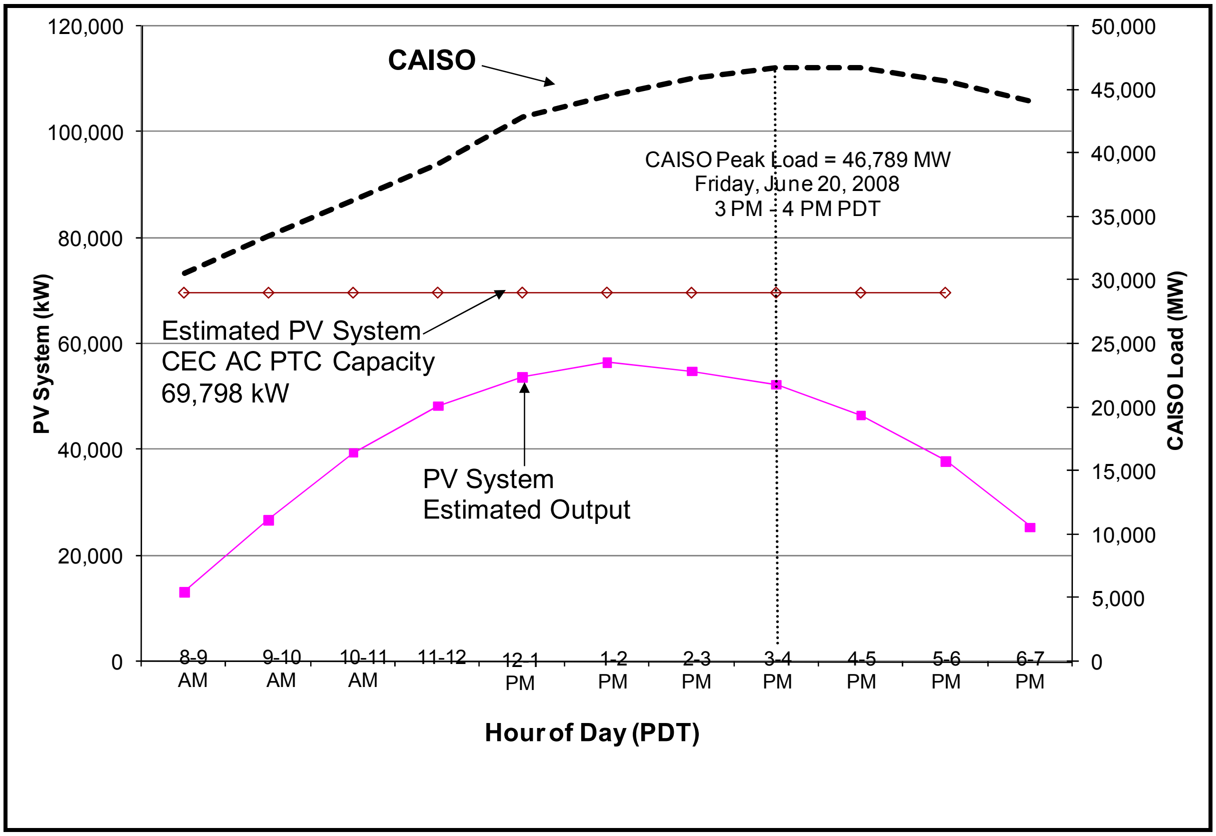
The 2008 CAISO system peak of 46,789 MW occurred on June 20, 2008, from 3 to 4 pm Pacific Daylight Saving Time (PDT). Table 5-3 provides information on the impact of CSI solar systems operating at the time of the 2008 CAISO system peak. Figure 5-6 shows the hour by hour impact of CSI systems on the 2008 CAISO system peak. Of the over 11,800 solar systems that had been installed under the CSI, an estimated 6,322 systems were on-line during the CAISO summer peak on June 20, 2008. These CSI systems had a rebated capacity of nearly 70 MW and provided an estimated 53 MW of generating capacity during the peak hour.

Table 5-3: Estimated CSI Demand Impact Coincident with 2008 CAISO System Peak

Year	Estimated PV Systems On-line During Peak (N)	Rebated Capacity (MW_r)	Estimated Peak Hour Power Output (MW_p)	Estimated Peak-Hour Capacity Factor (MW_p / MW_r)
2008	6,322	69.8	52.6	0.75

[46] Itron, "Preliminary 2007/08 Impact Evaluation of the California Solar Initiative," June 2009
[47] Ibid, page 2-3

Figure 5-6: Impact of CSI on CAISO 2008 Peak



CSI Distribution System Impacts

The total capacity (i.e., MW) of CSI solar systems installed in 2008 was small compared to the net load on the entire set of California distribution circuits. Nonetheless, there were a number of distribution circuits where the impact of CSI PV capacity was significant due to the presence of larger PV systems associated with industrial or commercial utility customers.

The 2008 CSI distribution impact analysis examined the impact of several of these large PV sites on actual utility circuits. The analysis explored the impact on both distribution circuit delivery capacity and losses. Comprehensive PV metering and circuit data was not available for 2008. Consequently, the goal for the 2008 distribution analysis was primarily to develop representative examples of distribution system impacts using a combination of utility supplied circuit and available PV performance data. SDG&E data was not available at the time of the CSI distribution analysis. Consequently, representative examples were developed only for PG&E and SCE.[48]

[48] Representative examples are currently being developed for SDG&E within the final CSI impact evaluation report.

The impact of PV generation on a distribution circuit is a function of the amount and location of the PV generation, as well as the characteristics of the distribution circuit. A circuit-specific locational analysis based on engineering analysis was used to quantify the impacts. In turn, this required an electrical model of the distribution circuit being analyzed along with its load characteristics, together with a representation of the PV systems. The analysis then compared how the circuit would operate with and without the PV generation.

PG&E Distribution Circuit Results

Table 5-4 is a summary of the circuit analyses conducted on the sample PG&E circuits. In general, the CSI PV systems located on the circuits demonstrated a modest impact on reducing the summer peak loading of the circuits; generally less than 2.5 percent of the peak loading. Similarly, daily load reductions due to the CSI PV systems were generally less than 3 percent of the daily circuit loads. However, these analyses represent a low amount of PV capacity on the selected distribution circuits. A higher capacity of PV capacity on the distribution circuit could possibly show higher load reductions.

Table 5-4: Summary of CSI PG&E Representative Circuit Analyses (2008)

Circuit	Circuit "A"	Circuit "B"	Circuit "C"
Circuit Features			
City	Rutherford	San Luis Obispo	Rocklin
Voltage (kV)	20.78	12.47	20.78
Peak Circuit Load Characteristics			
2008 Summer Peak MW	11.3	7.3	14.1
2008 Summer Peak Day	28-Aug	20-Jun	18-Jun
2008 Summer Peak Time	15:50	16:00	17:50
Circuit Power Flow Characteristics			
Peak Primary Power Loss (%)	1.6%	4.7%	1.1%
Maximum Voltage Drop (%)	1.71%	5.44%	1.43%
Locational Impacts at 2008 Summer Peak			
PV Contribution to Peak Load (kW)	69.8	347	313
Peak Contribution (%)	0.6%	4.5%	2.2%
Peak Loss Reduction (kW)	3	8	4
Peak Loss Reduction (%)	1.7%	2.2%	2.4%
Daily Energy Reduction (kWh)	990	3140	7742
Daily Energy Reduction (%)	0.5%	2.2%	3.1%

SCE Distribution Circuit Results

Detailed circuit modeling was not available for SCE circuits in the 2008 impact analysis. However, PV generation contribution was analyzed with respect to circuit summer peak load profiles for selected circuits. Table 5-5 is a summary of the circuit analyses conducted on the sample SCE circuits. Similar to the results seen with the PG&E circuits, the CSI PV systems located on the SCE circuits also demonstrated a modest impact on reducing the summer peak loading of the circuits. In general, the peak load reduction was less than 4 percent of the peak loading. As with the PG&E circuits, it should be noted that these analyses represent a low amount of PV capacity on the selected distribution circuits.

Table 5-5: Summary of CSI SCE Representative Circuit Analyses (2008)

Circuit	Circuit "A"	Circuit "B"	Circuit "C"	Circuit "D"
Circuit Features				
City	Chino	Laguna Niguel	Blythe	Visalia
Voltage (kV)	12	12	33	12
Peak Circuit Load Characteristics				
2008 Summer Peak Power (MW)	10.5	8.0	13.6	9.8
2008 Summer Peak Day	20-Jun	1-Oct	27-Jun	10-Jul
2008 Summer Peak Time	16:00	16:00	16:00	18:00
PV System Characteristics				
Maximum Output on 2008 Summer Peak Day (kW)	550	311	873	60
PV Penetration Level on 2008 Summer Peak Day (%)	5.2%	3.9%	6.4%	0.6%
Locational Impacts at 2008 Summer Peak				
PV Contribution to Peak Load (kW)	366.6	139.7	456.1	6.5
Capacity Release (%)	3.6%	1.8%	3.5%	0.1%

Based on the available PV generation data and the circuit loading information, the following conclusions can be made about the impact of CSI PV generation on the PG&E and SCE distribution systems:

1. The peak power output of PV facilities on the PG&E and SCE circuits analyzed in most cases occurred earlier than the daily peak load on the circuits under 2008 summer peak loading conditions, but a varying degree of overlap was still observed.

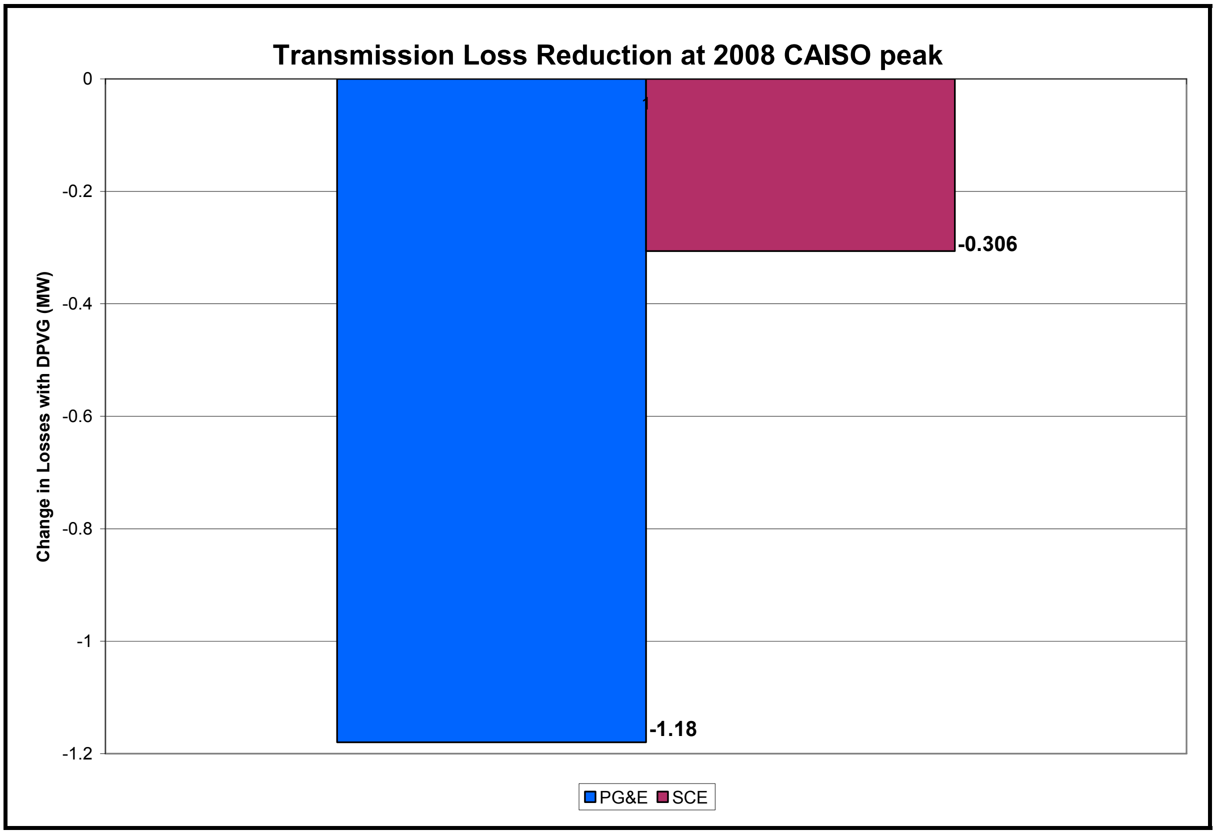
2. This overlap resulted in some reduction of 2008 peak circuit loading (thus increasing the useable circuit capacity) by 0.1-3.6% for the SCE circuits and 0.5-3.1% for the PG&E circuits, respectively.
3. As a result of the local PV generation, electrical heating losses on the PG&E distribution circuits analyzed were reduced from 1.7-2.4% at the time of peak circuit loading.
4. The presence of PV generation on a circuit can shift the time of the peak (net) circuit loading as measured at the respective substation.

In general, the CSI distribution system impacts are similar to those observed with the SGIP DG facilities. That is, there are small but discernable benefits associated with the DG facilities. However, due to the low penetration levels of DG on the overall distribution circuits observed at the time of the analyses, little can be concluded about the impacts of DG systems at higher penetration levels.

CSI Transmission System Impacts

Solar DG systems can reduce peak system losses by lowering the power delivery needed by the transmission system at the time of system peak. Distributed PV generation has the same effect as reducing the load at the distribution circuit or transmission bus where the PV power is produced. In turn, lower transmission loads result in lower transmission losses. The resulting reduction in transmission losses translates directly into a further reduction in generation requirements. Estimated reductions in SCE and PG&E service area transmission losses are shown in Figure 5-7 for 2008 summer peak conditions.

Figure 5-7: CSI Impact on Transmission System Losses at 2008 CAISO Peak



The CSI 2007/08 Impact Evaluation Report also assessed the transmission capacity benefit from the installed CSI PV projects.

CSI Transmission Capacity Benefits

Solar DG systems contribute to the deferral of transmission capacity investments by reducing demand-side consumption. Utility transmission planners typically assess impacts on the transmission system using power flow models. However, distributed PV projects are not discretely modeled in the PG&E and SCE transmission power flow models. In addition, specific impacts from such small penetrations are hard to measure on the transmission system. Therefore, in order to evaluate the peak impact of CSI generation on the transmission system, a 2008 Transmission Capacity Benefit (TCB) was calculated for both PG&E and SCE based on the PV peak impacts using the respective transmission power flow models.

The TCB is the sum of the unused line capacities in the power flow for every "branch" or circuit (i.e., transmission line and transformer) with and without the PV capacity. The difference in unused circuit capacity with PV versus without PV determines the TCB benefit for each utility. The TCB represents the increase in transmission capacity made available by adding the distributed PV generation under normal system conditions, and does not address transmission capacity under contingency conditions. Therefore, the TCB is only a metric of transmission benefit and is not useful for any system planning purposes.

The generator adjustments made to determine transmission capacity impacts were modeled in three different ways in the power flow analyses. One way was to scale the generation down in a pro rata manner in each area by the amount of PV generation in that area. Another way was to reduce area imports by the amount of PV generation in that area. Yet a third way was to back off a single (e.g., marginal cost) unit by the amount of PV generation in that area. None of these ways may accurately represent what actually happens under CAISO open market operation, but does represent a possible impact on the transmission system. Table 5-6 is a summary of TCB results from the three different modeling approaches used for estimating 2008 CSI transmission impacts within the PG&E and SCE service territories.

Table 5-6: Comparison of CSI Transmission Capacity Benefit Modeling Results (2008)

TCB Sensitivity Results	Scale All Area Generation (MW)	Area Import Reduction (MW)	Single (e.g., Marginal) Unit Redispatch (MW)
PG&E Transmission System	83.22	81.63	123.46
SCE Transmission System	46.90	50.95	17.51

Based on these comparisons, scaling area generation was chosen as the best proxy for measuring the CSI PV impacts. Consequently, CSI systems evaluated in the 2008 analysis were found to provide over 80 MW and nearly 47 MW of transmission capacity benefits within PG&E and SCE respectively.

Overall, as with the SGIP DG transmission analysis, CSI DG facilities were observed to have small but discernable benefits to the transmission system. However, as with the SGIP DG facilities, the low overall penetration of CSI systems relative to the overall loading on the California transmission system precludes concluding what impacts will occur from higher penetration of solar DG facilities.

6

Emerging Technologies

As shown by the impact analyses conducted on DG technologies installed under the SGIP and CSI programs, DG technologies can potentially have significant beneficial impacts on grid operations and system reliability. However, for DG technologies to provide successively greater benefits to the electricity system, they must provide capacity when it is needed most (e.g., to help defer peak demand or help reduce T&D line loadings). Emerging DG technologies can either provide greater ability to provide capacity when needed or enhance the ability of existing DG technologies to provide capacity when needed. Under SB 412 (Kehoe, 2009), the CPUC is investigating emerging technologies that may become eligible for incentives under the SGIP. It is unclear at this time what emerging technologies will be investigated by the CPUC and what impact these technologies will have on grid system operation or reliability. However, energy storage is currently incentivized under the SGIP and can help existing DG technologies provide capacity when needed as well as address grid reliability needs.

6.1 Energy Storage

Energy storage devices can help manage the amount of power required when the need within the electricity system is greatest. The potential application of energy storage technologies ranges from bulk storage within the transmission system to smaller storage capacity technologies within the distribution system. In addition, energy storage technologies can also help make power generation from intermittent renewable energy facilities, whose power output cannot be controlled by grid operators, more smooth and dispatchable. Energy storage technologies include compressed air energy storage (CAES), batteries, flywheels, electrochemical capacitors, superconducting magnetic energy storage (SMES), power electronics and control system devices. One of the more valuable electricity management capabilities that can be provided by energy storage systems are those involving ancillary services.

Ancillary Services

Ancillary services are those services that support the ability of the electricity system to generate capacity, supply energy, and deliver power. In general, ancillary services fall into the following categories: voltage support; regulation; operating reserves and backup supply.

Voltage support refers to the ancillary service which helps to ensure the line voltage is maintained within an acceptable range of its nominal value. Line voltage can be influenced by the amount of real and reactive power present in the system. In turn, reactive power can be impacted by several different sources including electric generators, power electronics, shunt capacitors, and static volt-ampere reactive (VAR) compensators.

Regulation refers to the minute-to-minute imbalances between system load and supply. Generation systems that provide regulation ancillary services must be on-line and equipped with automatic control systems enabling them to adjust output as needed to provide power to the grid.

Operating reserves means generation that is available to the grid when needed. In general, spinning reserves refer to generation that is on line, synchronized to the grid and can increase output as called immediately and be fully available within 10 minutes. Non-spinning reserves are those generators that are not necessarily on line when called but can be fully responsive within 10 minutes of the call for power.

Backup supply refers to generation that can be on line generally within a 30 to 60 minute timeframe.

A DOE study on benefits of DG on the electricity system found that DG technologies can provide ancillary services in several areas, including backup, reactive power and voltage support.[49] Electricity storage can enhance DG system capability to provide dispatch; load following and energy system imbalance. Power electronics can help enhance reactive power and voltage control.

6.2 Smart Grid

While solar customers are a small percentage the millions of electrical customers, within the next two years solar electrical generation will likely be exceeding 2.5% of peak demand. As the Smart Grid infrastructure is installed in the utilities' service areas throughout California, more data and services will become available for electrical customers with distributed generation on the customer side of the utility. What the services will be, the communication standards and protocols are still in their infancy as the Smart Grid is rolled out.

During this evolution and beyond the initial stages, the Smart Grid will be bolstered by the US Department of Energy's recent $3.4 billion grant awards as part of the American

[49] "The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede its Expansion," Department of Energy, June 2007

Reinvestment and Recovery Act (ARRA), and matching industry funding for a total public-private investment worth over $8 billion for Smart Grid development. While all not directed toward PV, these grants will speed the adoption of Smart Grid technology nationally. In addition to these grants the US DOE is still waiting to announce the recipients of $615 million for Smart Grid demonstration projects.

ARRA funding is also supporting a National Renewable Energy Lab (NREL) project with SCE to conduct studies, lab tests, and field measurements on distribution circuits that will have high penetration of PV generation resulting from SCE's Solar PV Program. In addition, SCE is hosting the California Energy Commission PIER-funded work of New Power Technologies to model a large distribution and sub-transmission system. This effort involves modeling a significantly larger system in significantly greater detail than other existing models. One advantage of this approach is to be able to quickly answer questions about where best to locate distributed energy resources on the system. In addition, SCE is also investigating the impact of high levels of PV and Electric Vehicles on distribution circuits.

SCE also recently won an AARA award for their Irvine Smart Grid Demonstration (ISGD) project and intend to incorporate "smart inverter" technology as part of the project. "Smart inverters" are inverters that have the capability to assist the utility in controlling voltage, frequency, and power quality. Smart meters that have two way communication capability and VAR support features can help facilitate higher penetration levels of DG resources within California's grid.

In additional to the ARRA grants, the DOE had a number Funding Opportunity Announcements (FOAs) to provide stimulus activities in a number of areas. One of the FOAs, number 00085, was targeted toward energy, specifically solar energy. The FOA explicitly sought proposals to: 1) develop the needed modeling tools and database of experience with high-penetration scenarios of photovoltaic (PV) on distribution systems; 2) develop monitoring, control, and integration systems to enable cost-effective widespread deployment of small modular PV systems; and 3) demonstrate the integration of PV and energy storage into Smart Grid applications. All of these are Smart Grid areas, with the ultimate goal of this FOA to accelerate the placement of high levels of PV penetration into existing or newly designed distribution circuits and facilitate increased growth of grid-tied PV installations.

6.3 CSI RD&D Activities

As noted earlier, the CPUC initiated a solar RD&D program in 2008 to help build a sustainable and self-supporting solar industry in California. To achieve these goals, the $50 million solar RD&D program targets two key outcomes:

- Move the solar market from current retail solar prices to levels that are comparable to the retail price of electricity and
- Increase solar market penetration in California from current levels to 350 MW or more of new solar DG systems per year.

To date, two solicitations have been released under the CSI RD&D program. Both solicitations provide funding opportunities for projects that will help solar technologies become an interactive part of a Smart Grid platform. These funding opportunities include:

1) tools for planning and modeling of high-penetration of solar within the electricity system
2) testing and development of hardware and software that will help accommodate high-penetration PV into the grid
3) the integration of PV with energy efficiency, demand response and energy storage; and
4) improved PV production technologies and business models to accelerate the adoption of solar PV within California's electricity markets.

The first CSI RD&D solicitation focused on grid integration of photovoltaic (PV) systems because integrating solar technologies into the electricity system is essential to achieving future widespread growth of solar technologies in California. At a total installed capacity of less than 500 megawatts (MW), solar technologies currently make up a small portion of California's overall electricity mix. Due to their low level of penetration in the grid, solar technologies currently do not have significant impacts on the operation of the electricity transmission and distribution systems. However, as the penetration rate of solar system increases, these facilities will have increasing impacts on the distribution system and later, the transmission system. In addition, deployment and acceptance of new technologies takes time. By focusing the first solicitation on grid integration, this allows the time necessary for market adoption of the integration tools and products to achieving beneficial high-penetration levels of solar in California's electricity system.

As the CSI RD&D funding, the Federal DOE grants, and FOAs awards begin to bear fruit over the next several years, it will be the secondary and tertiary businesses and projects that will take these effort to wider-scale deployment. In addition, studies from the CPUC Re-

DEC workgroup will help position California to achieve increase penetration of DG resources.

Overall, California's DG industry, State incentive programs, and utilities are taking proactive steps to develop DG technologies that will help improve electricity system performance, operation, and reliability. The emergence of new DG technologies with increased capability to provide needed grid support functions, enhanced use of advanced energy storage and the development of DG technologies as part of a Smart Grid platform will help integrate DG resources as a fully operational part of the electricity system.

Appendix A

Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis

Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis

Re-DEC Working Group Meeting

December 9, 2009

Energy and Environmental Economics, Inc.

BLACK & VEATCH

Renewable Energy Transmission Initiative

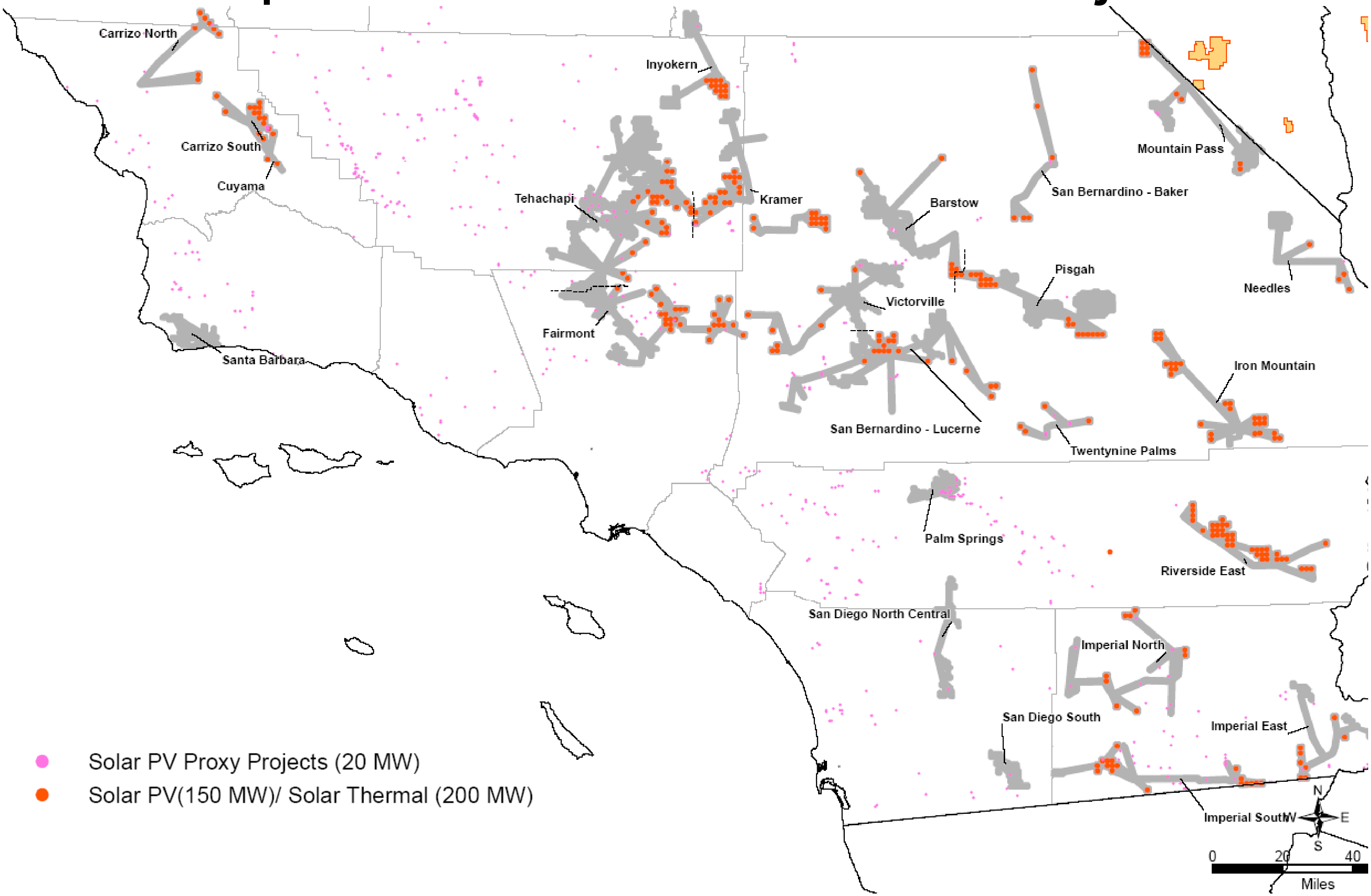
RETI is a statewide planning process to identify transmission projects needed to accommodate California's renewable energy goals.

- California law requires 20% of retail energy sales to come from renewable sources by 2010. The state has also adopted the goal of 33% by 2020.
- Development of renewable generation has slowed in CA. Transmission is a limiting factor.
- RETI is facilitating planning and permitting for competitive renewable energy zones (CREZs)

Solar in RETI

- Large Scale – 150-200 MW, solar thermal or solar PV. Detailed analysis.
- Distributed Wholesale Generation – 20 MW solar PV near substations. Very rough analysis.
- Smaller Systems – Behind the meter applications. Assumed to happen as part of RETI "Net Short" calculation.

Example RETI Phase 1 Solar Projects



- Solar PV Proxy Projects (20 MW)
- Solar PV(150 MW)/ Solar Thermal (200 MW)

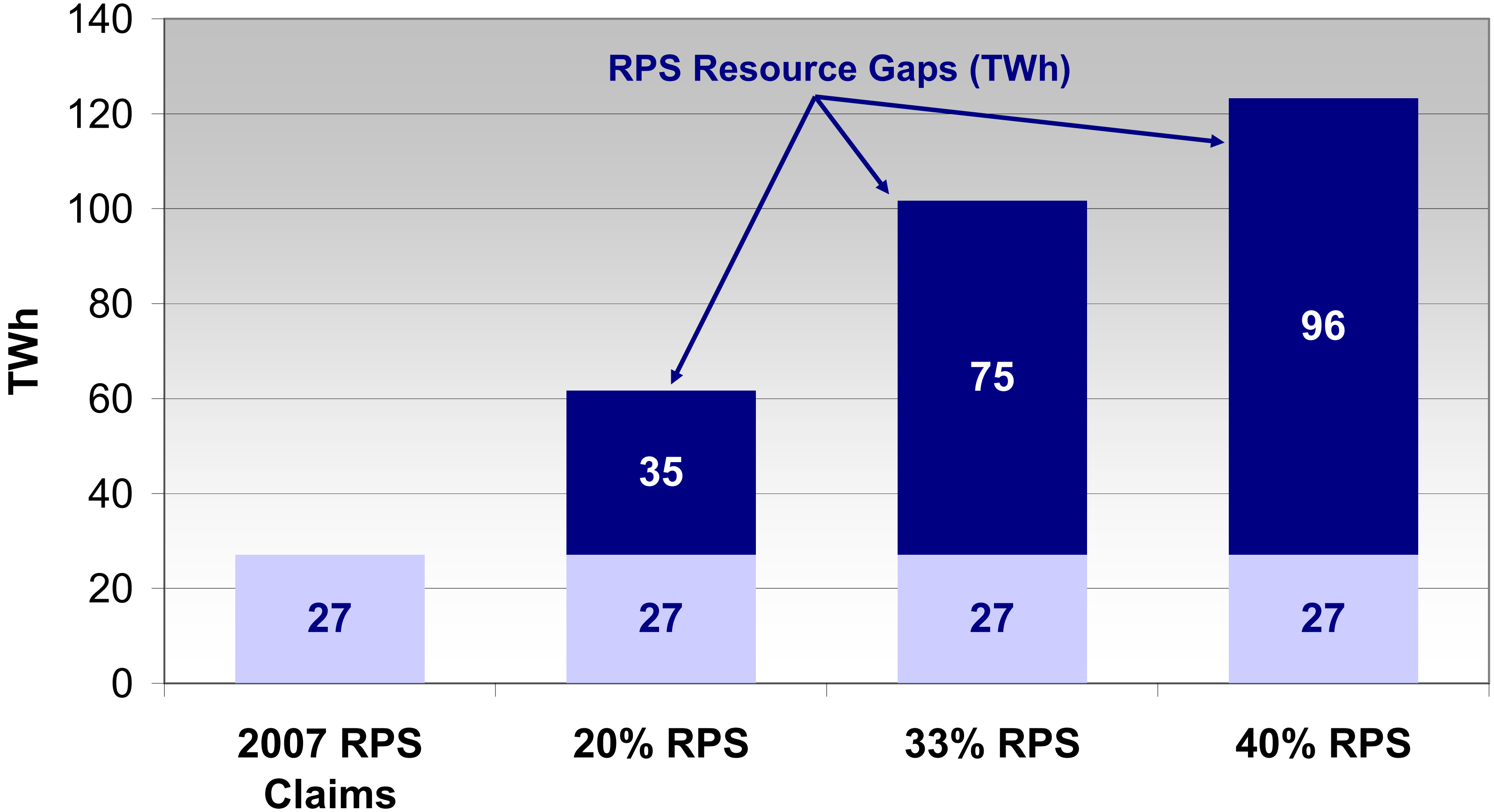
Solar PV Did Not Play a Significant Role In RETI Phase 1 (2008)

- Conventional tracking crystalline technology too expensive to compete
- Thin film technology deemed not fully proven and commercially available
- Thin film sensitivity showed potential for large scale competitiveness – if costs could be reduced (\$3700/kW_{ac})

CPUC 33% RPS Implementation Analysis

- CPUC commissioned 33% RPS Implementation Analysis as part of long-term procurement planning (LTPP) proceeding
- Goals of analysis:
  - Inform decision-makers about the likely cost and environmental impacts of implementing a 33% Renewables Portfolio Standard by 2020
  - Identify barriers to implementing a 33% RPS by 2020 and most likely timelines for achieving 33%
  - Inform decision-makers about the potential need for new transmission and new resources to integrate intermittent renewables
  - Inform California utilities' 2010 long-term procurement plans
- Report with preliminary results issued June 2009, available at www.cpuc.ca.gov/33percent

2007 Claimed RPS Resources for California Utilities and 2020 RPS Resource Gaps



Note: Gap based on 2007 CEC load forecast minus 2007 claims from CEC Net System Power Report. No adjustments for EE or CHP that is incremental to forecast.

33% RPS Cases Studied

1. **<u>20% RPS Reference Case</u>**: Existing state policy with 20% RPS
2. **<u>33% RPS Reference Case:</u>** Most likely case for reaching 33%, assuming that most contracts signed by IOUs with project developers proceed on schedule
3. **<u>High Wind Case</u>**: Meets 33% RPS resource gap with mix of new resources that includes substantial quantities of wind in California and Baja
4. **<u>Out-of-State Delivered Case</u>**: Meets 33% RPS resource gap with mix of new resources that includes wind resources in California and Wyoming and geothermal resources in Nevada
5. **<u>High DG case</u>**: Meets 33% RPS resource gap with mix of new resources that minimizes the need for new bulk transmission. These include 15,000 MW of distributed solar PV.

33% RPS Reference Case

Cost and Rate Impacts in 2020

- Total CA revenue requirement:
  $54.2 billion (16.9¢/kWh)
- Incremental to 20% RPS Case:
  +$3.6 billion (+1.1¢/kWh)
- New transmission investment:
  $12.3 billion

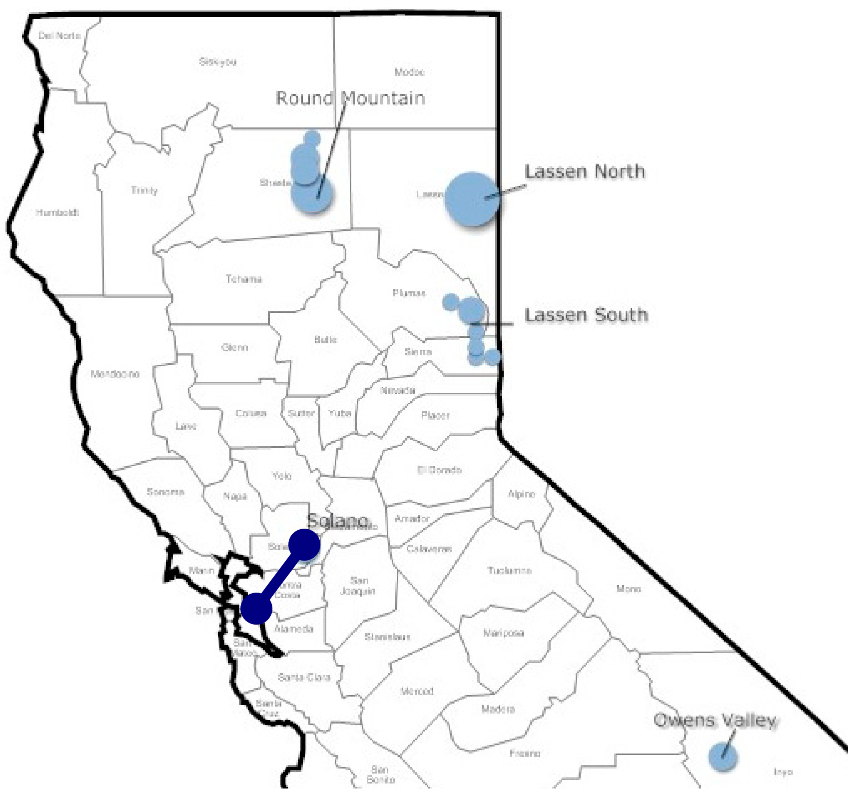
Resources Selected by Type

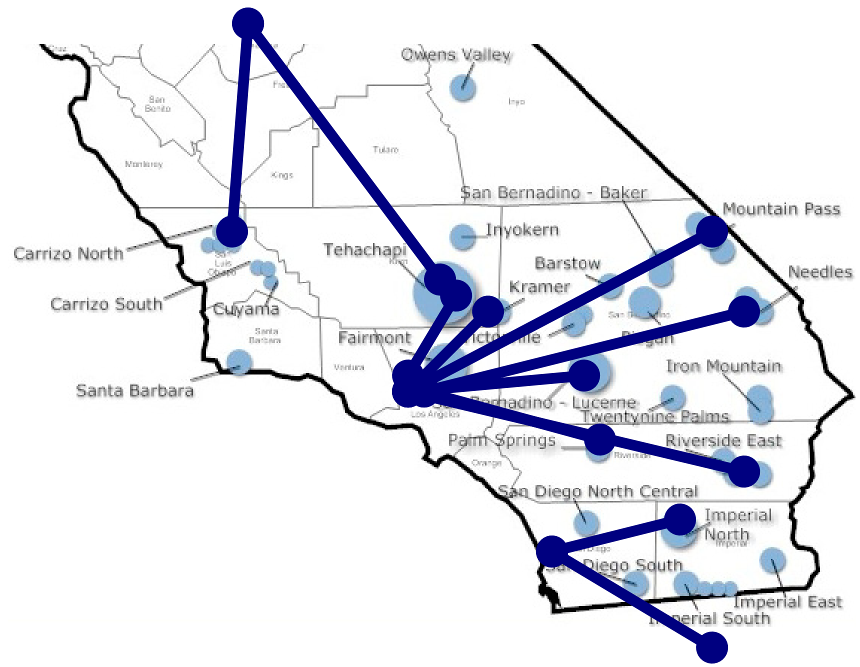
	In-State		Out-of-State		*Total*	
	MW	GWh	MW	GWh	*MW*	*GWh*
Biogas	279	2,078	-	-	*279*	*2,078*
Biomass	391	2,737	87	610	*478*	*3,346*
Geothermal	1,439	11,027	58	445	*1,497*	*11,471*
Hydro - Small	25	111	15	66	*40*	*177*
Solar PV	3,235	6,913	-	-	*3,235*	*6,913*
Solar Thermal	6,764	16,652	534	1,304	*7,298*	*17,956*
Wind	7,573	22,899	3,399	9,809	*10,972*	*32,709*
Total	***19,705***	***62,417***	***4,093***	***12,233***	***23,798***	***74,650***

Zones Selected

	MW	GWh	Notes
Total	***23,798***	***74,650***	
Tehachapi	3,000	8,862	Included in 20% Case
Distributed CPUC Database	525	3,118	Included in 20% Case
Solano	1,000	3,197	Included in 20% Case
Out-of-State Early	2,062	6,617	Included in 20% Case
Imperial North	1,500	9,634	Included in 20% Case
Riverside East	3,000	7,022	Included in 20% Case
Mountain Pass	1,650	4,041	
Carrizo North	1,500	3,306	
Distributed Biogas	249	1,855	
Out-of-State Late	1,934	5,295	
Needles	1,200	3,078	
Kramer	1,650	4,226	
Distributed Geothermal	175	1,344	
Fairmont	1,650	5,003	
San Bernardino - Lucerne	1,800	5,020	
Palm Springs	806	2,711	
Baja	97	321	

New Transmission Required for 33% RPS Reference Case





Interest in High DG Case

- A number of factors drive the CPUC's interest in studying a "High DG" case for meeting 33%:
  - High environmental impact of new transmission
  - High environmental impact of new central station generation
  - Increasing cost competitiveness and customer interest in PV – is PV nearing goal of "grid parity"?
  - Difficulties siting new transmission lines

"If it is conservatively assumed that only 10,000 MW of new high voltage transmission will be built by 2020 to realize the RETI net short target of 68,000 GWh, the estimated cost of this transmission will be in the range of $20 billion in 2008 dollars based on SDG&E's projections for the Sunrise Powerlink. How much thin-film PV located at IOU substations or at the point-of-use on commercial buildings or parking lots could the IOUs purchase for this same $20 billion? ... This equals an installed thin-film PV capacity of 14,000 to 18,000 MW for a $20 billion investment."

Bill Powers, PE, testimony in SDG&E's Sunrise Powerlink CPCN case

Resources Available for Selection in High DG Case

- Resources already selected for 20% Case
- RETI projects that can likely be interconnected without major transmission upgrades
  - Biomass: 2 projects in northern CA, 128 MW of total available capacity
  - Geothermal: 3 projects in northern CA, 175 MW of total available capacity
  - Wind: 6 projects across CA, 468 MW of total available capacity
- Out-of-state resources assumed deliverable over existing transmission (~2000 MW)
- Distributed solar PV resources

2. Identifying Potential Solar PV Sites

Overview

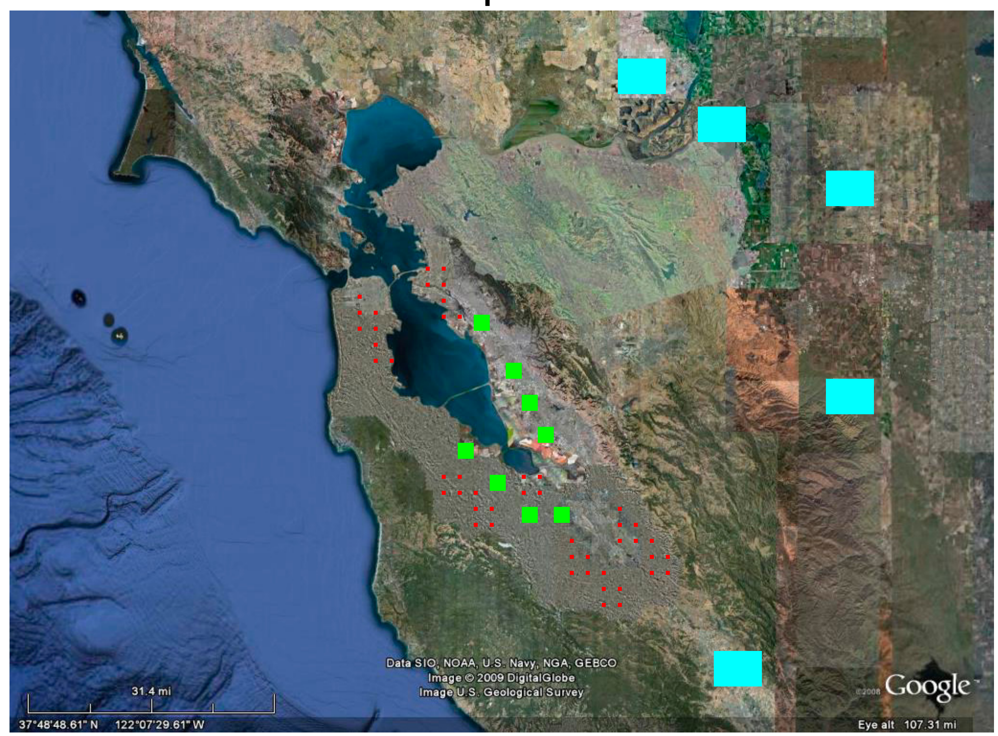
- Solar PV was assumed to be a major technology for DG
- B&V estimated the technical raw potential for DG
- Satellite imagery for rooftops and substation locations for larger utility scale

Distributed Solar PV

- 20 MW sites near non-urban 69 kV substations
- Smaller projects on rooftops, large commercial rooftops with 0.25 MW potential
- Limited by 30% peak load at a given substation

Illustrative Example of Distributed Solar PV

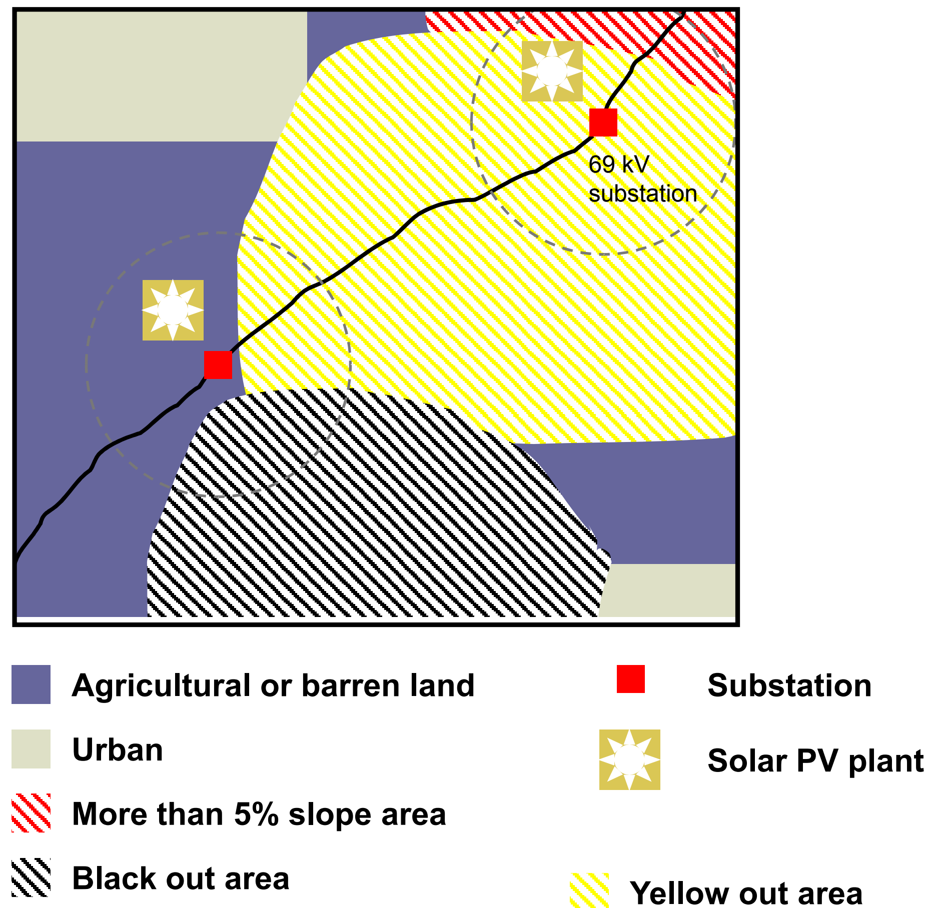
20 MW near substations
Large commercial rooftops
Residential rooftops



Ground Mounted PV

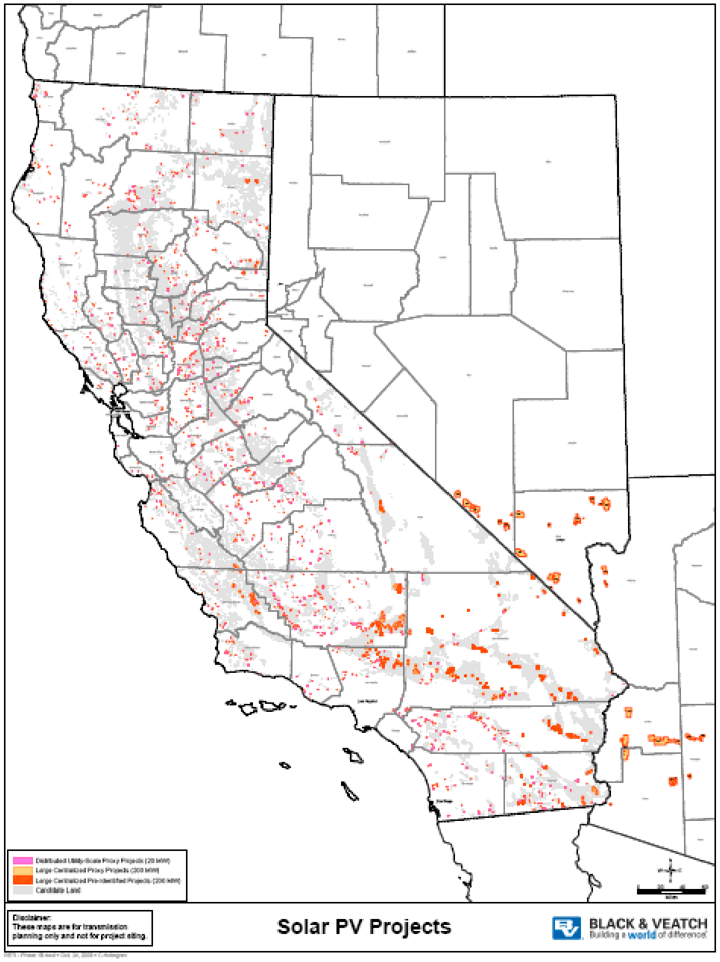
- Initial criteria
  - near sub stations equal or less than 69 kV
  - agricultural or barren land
  - less than 5% slope
- Environmental screen
  - Black out areas
  - Yellow out areas
- Land parcel
  - a continuous 160 acre plot (20 MWp)
  - within 20 miles

Example Map for Solar PV Non-Urban Projects



RETI Results on 20 MW Sites

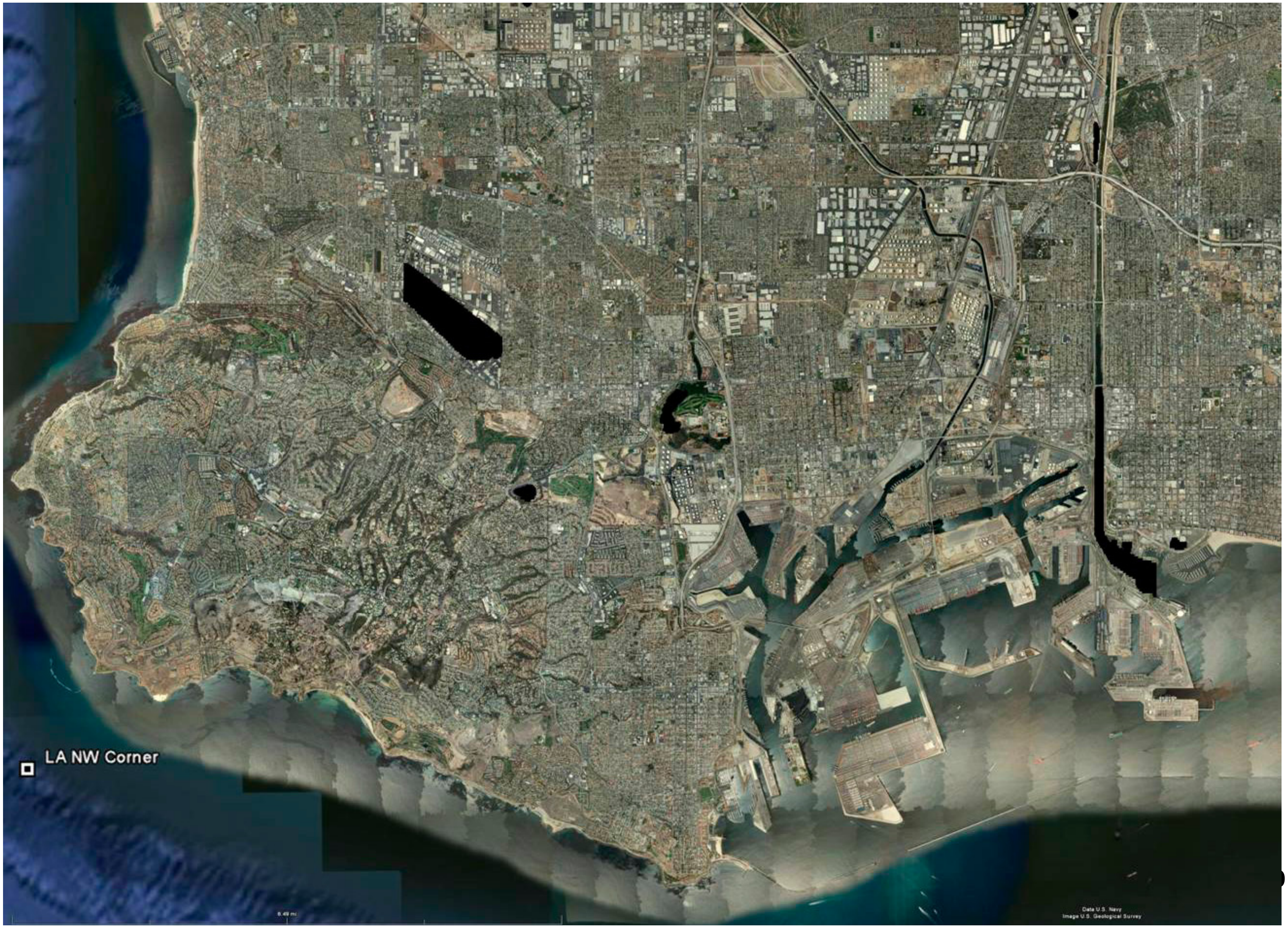
- 27,000 MW nameplate PV sites identified
- ~1300 sites identified
- Filters Applied
  - 160 acres + for 20 MW
  - No sites within 2 miles of urban zones
  - Near substations, most are 2 to 3 miles of the distribution subs with 69kV+ high-side voltage
  - Land slope < 5%
- 20 MW on substations with high side voltage of 69kV
- 40 MW on substations with higher voltage than 69kV
- Assumed not to be Rule 21 compliant



Black and Veatch Rooftop Analysis

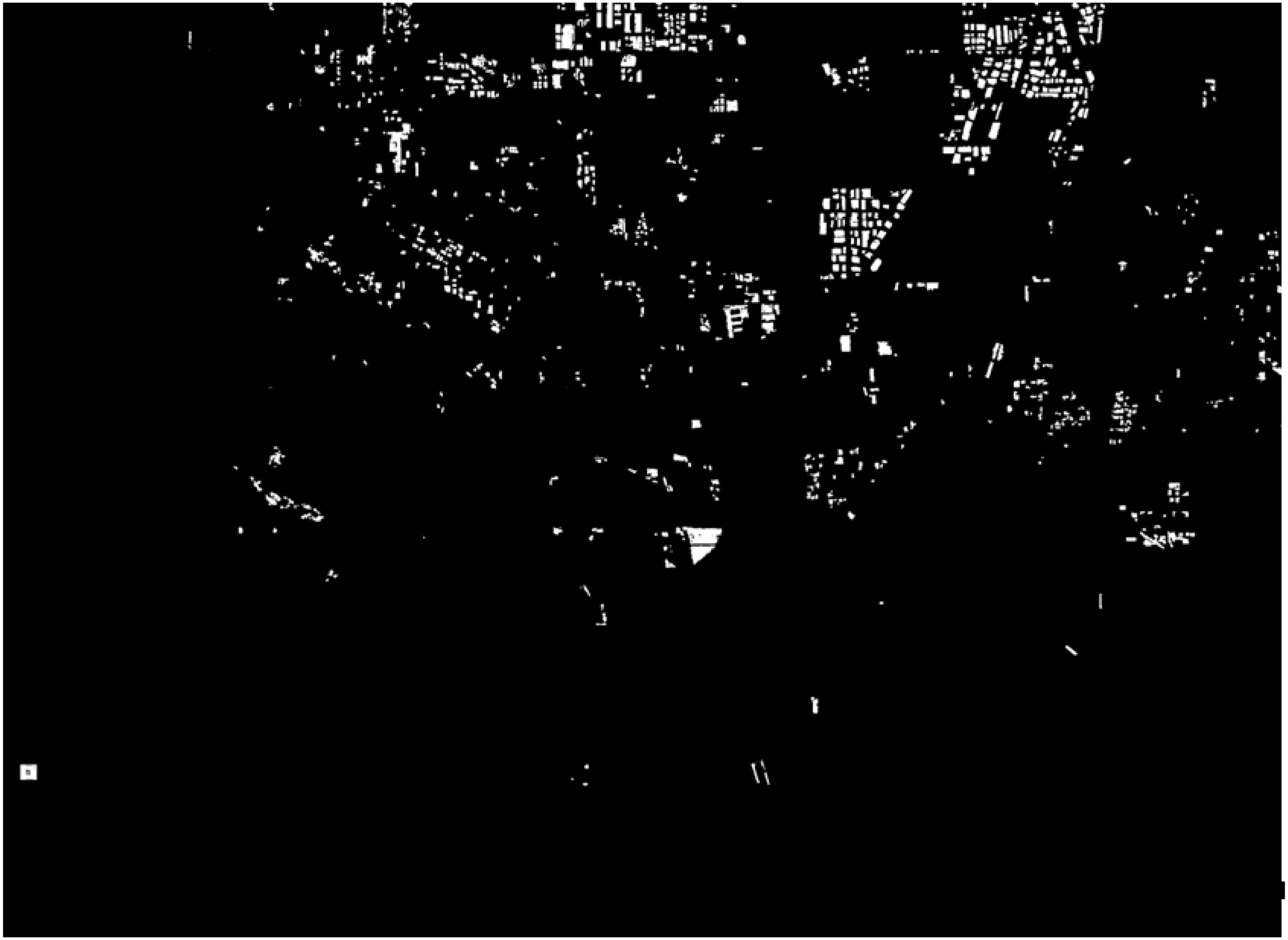
- GIS used to identify large roofs in CA and count available large roof area
- Criteria
  - ‘Urban’ areas with little available land
  - Flat roofs larger than ~1/3 acre
  - Assumes 65% usable space on roof
  - Within 3 miles of distribution substation

Solar Photovoltaic Rooftop Identification

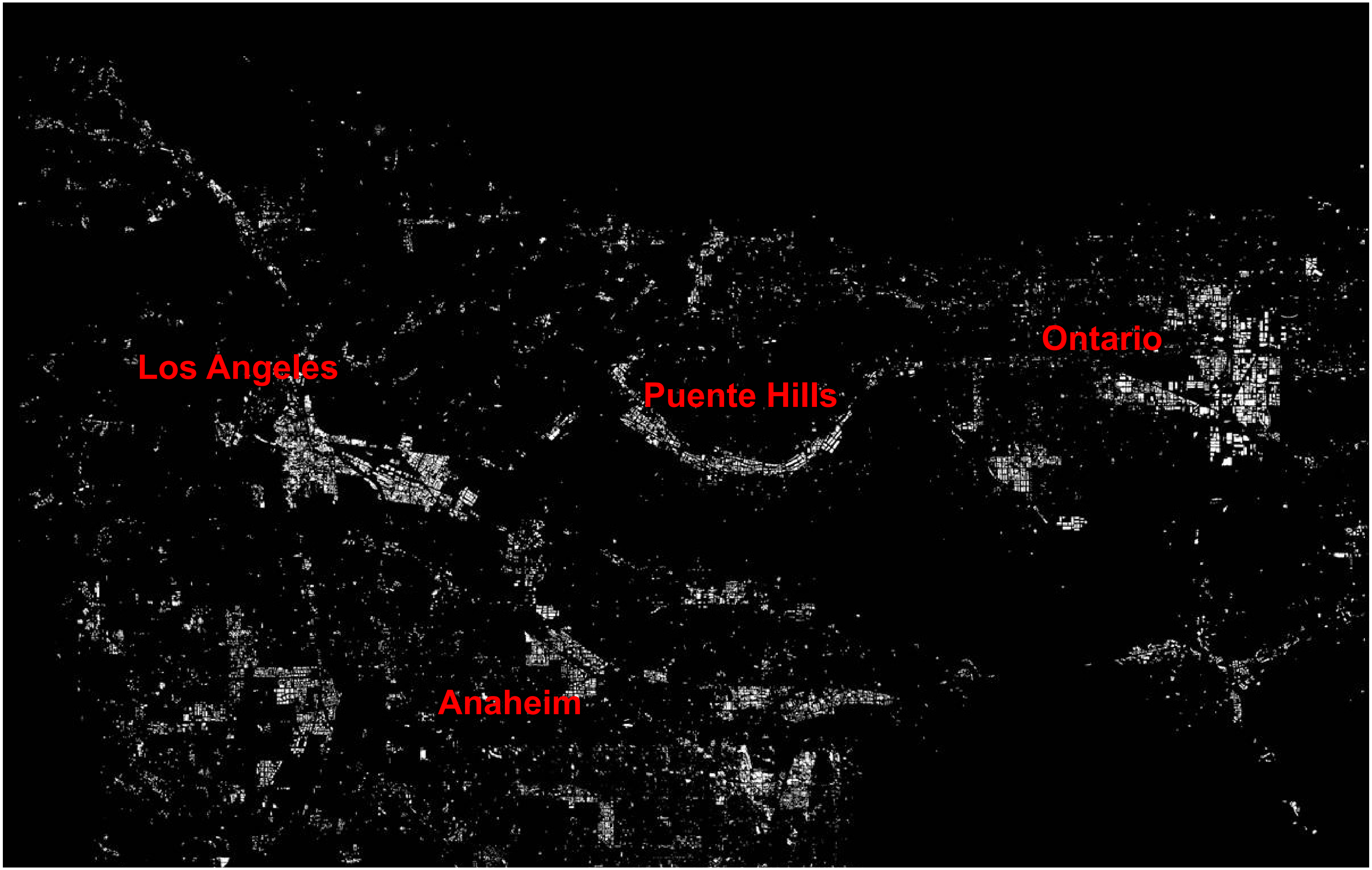


Solar Rooftop Identification

Solar Rooftop Identification

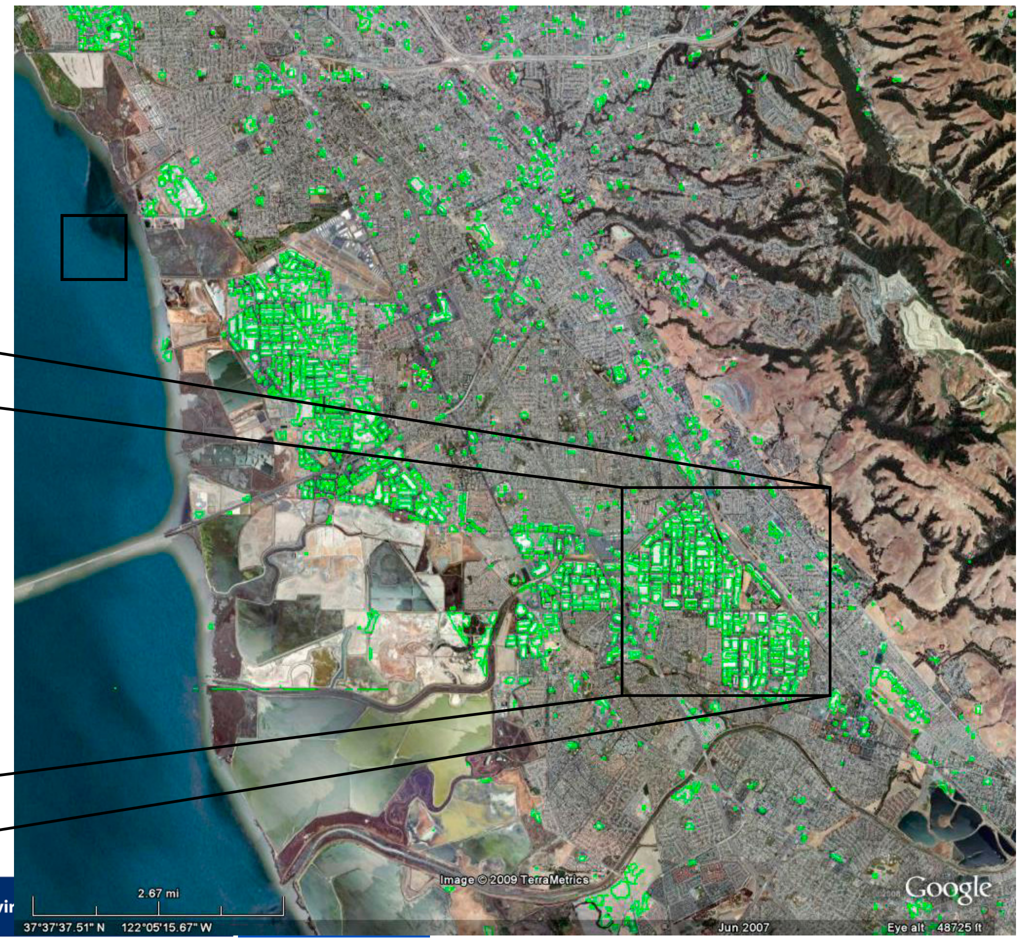


Los Angeles Area "Rooftop Resources"



East Bay Area Example

Analysis automates the counting of roof space and tallies total acreage of large roof space. Also checks proximity to distribution substation (not shown due to confidentiality).



Summary Results for Large Roofs

Raw Potential – Assuming 100% Participation

Total Statewide Large Rooftop Potential

	Large Roof Potential
PG&E	2922 MWac
SCE	5243 MWac
SDG&E	604 MWac
Other	2774 MWac
Total	**11,543 MWac**

3. DG Interconnection Screening

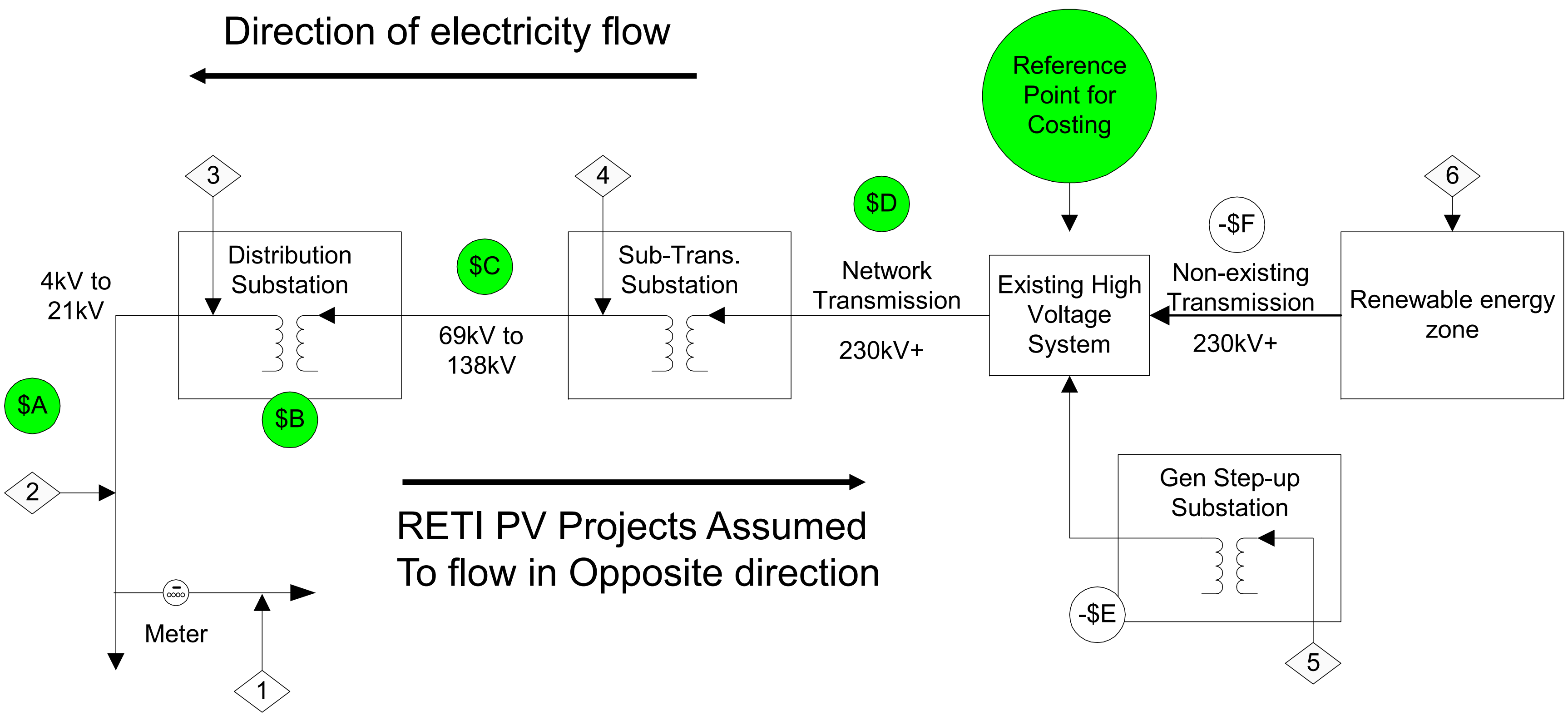
Snuller Price, E3

Energy and Environmental Economics, Inc.

Working Definitions of DG

- Distributed generation (DG) is small-scale generation interconnected at sub-transmission system or lower.
  - Broad definition includes generation that is not necessarily physically close to loads.
- Wholesale DG (WDG) is generation interconnected to the distribution or sub-transmission system
- Customer DG is generation on the customer's side of the meter
  - Does not count toward California's RPS

Diagram of Interconnection Points



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BLACK & VEATCH

Avoided Capacity Cost Assumption

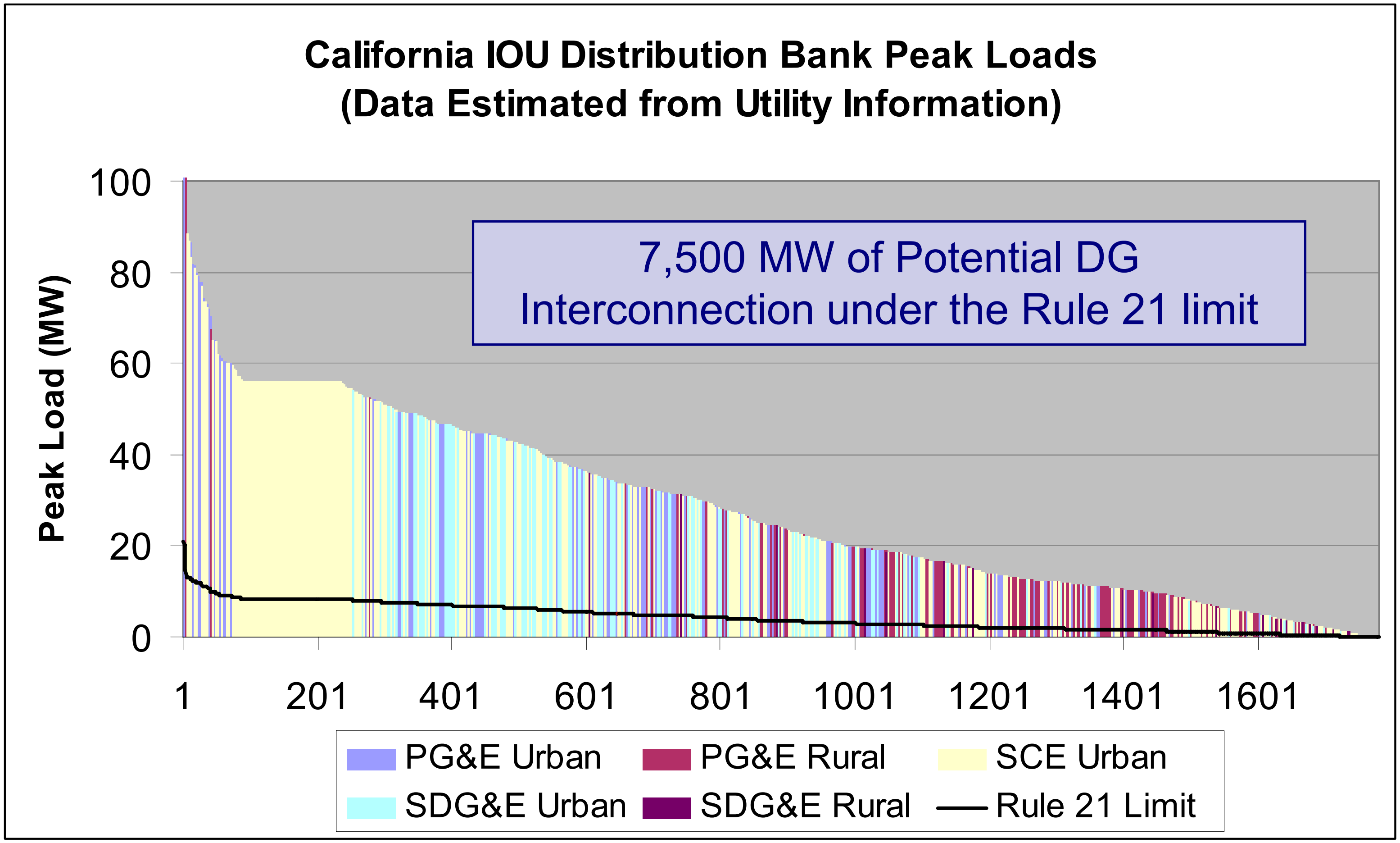
- **Distribution: $34/kW-yr**
  - Used average of EE avoided costs
- **Subtransmission: $34/kW-yr**
  - Used average of EE avoided costs
- **Transmission: $0/kW-yr**
  - Network is more difficult
  - Set to zero for 33% RPS analysis

See EE avoided costs, R.04-04-025

Issues

- Timeframe vs. geographic specificity – must use long time frame for avoided cost value
- Cost of non-Rule 21 RETI 20MW PV Installations not studied
  - Network transmission costs of $65/kW-year assumed for these resources

Utility Substation Bank Data



Rule 21 Interconnection sets 15% of line section peak limit

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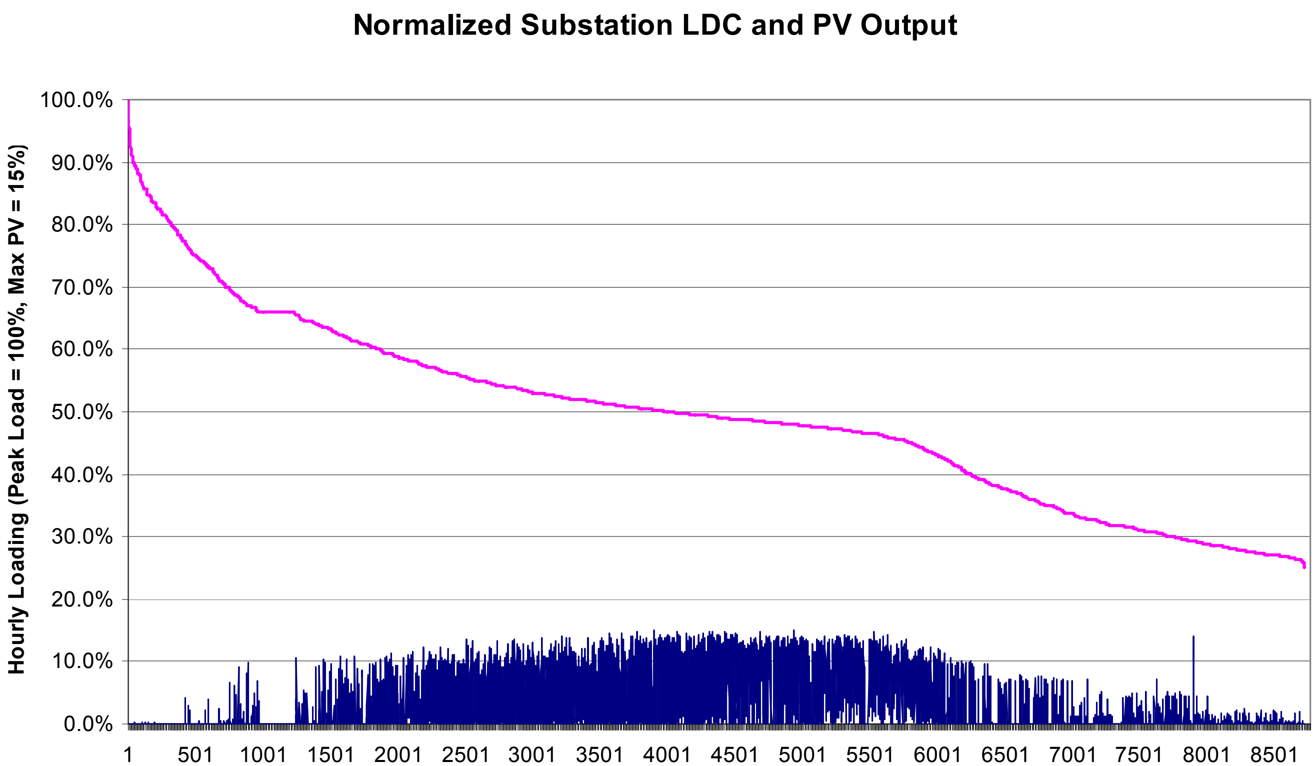
Revisit 15% threshold for some PV projects, given higher PV output at higher load levels

- Load Duration Curve compared to PV output

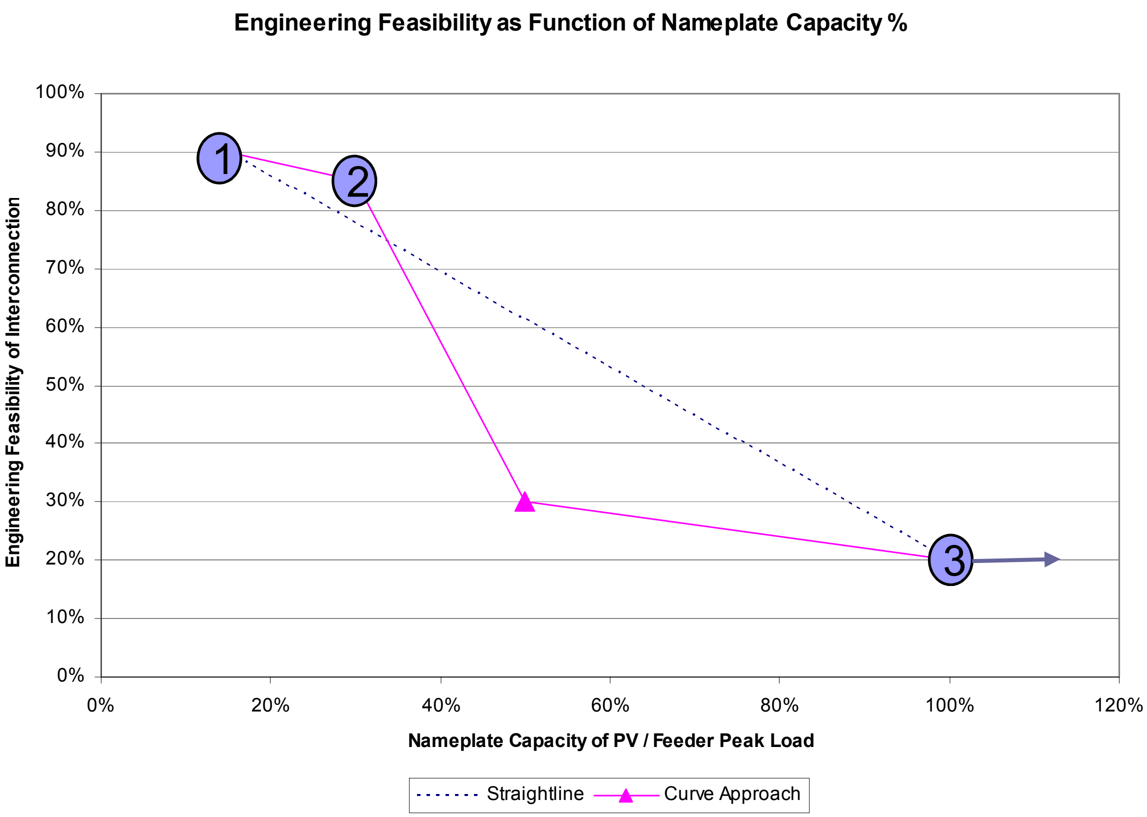


Actual data from a California public utility substation and PV installation

Technical Feasibility of PV Connections that are >15% & <100% of Peak Load

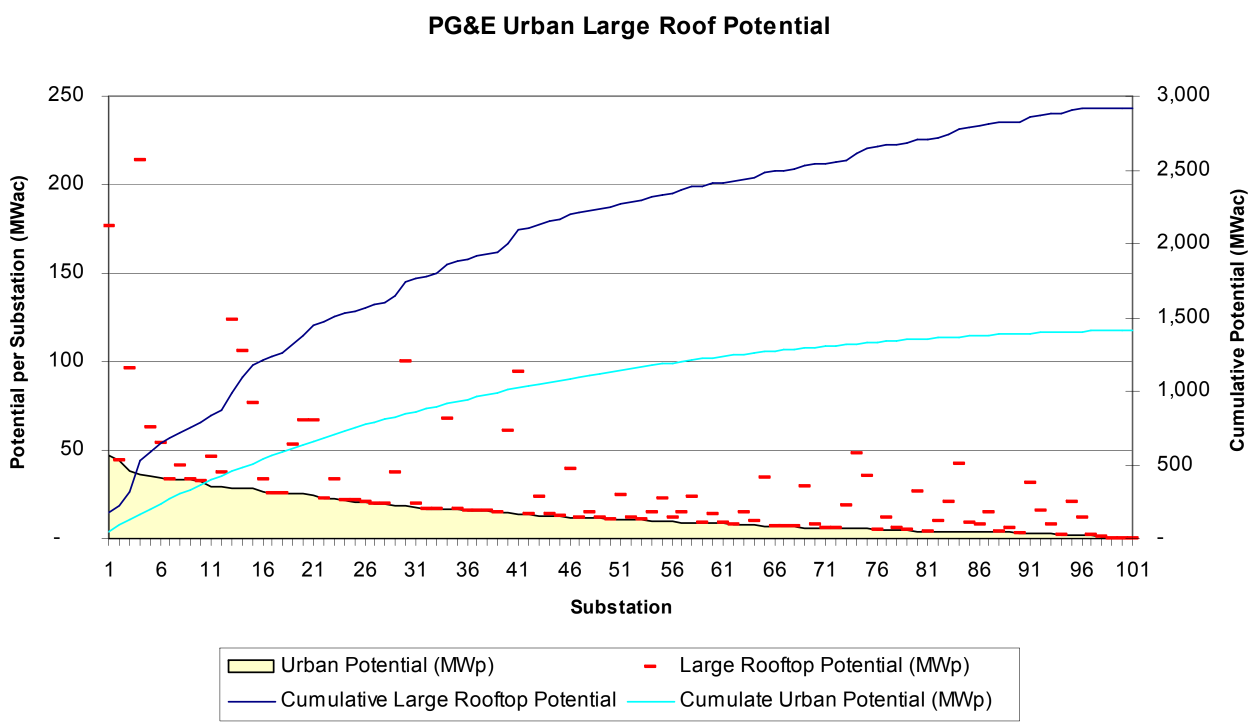
- Assumption on PV engineering feasibility

Caveat
These numbers are based on an educated guess not on any engineering analysis.



1. 15% Peak Load
   50% of in area PV
2. 30% Peak Load
   50% of in area PV
3. 100+% Peak Load
   RETI projects

PG&E Example – Bay Area



Clusters of large roofs make it impossible to do every roof and be below the 30% peak load.

PV Screening Criteria

	Land / Roof Availability	Interconnection	Participation
Urban Large Roofs	GIS Screening	Within 3 miles of substation, limited to 30% bank or feeder peak	33% Roofs max
Urban Small Roofs	Assumed available	30% bank or feeder peak	33% Roofs max
Rural <20MW	GIS Screening	30% bank or feeder peak	33% available land max
Rural >20MW	GIS Screening	Not constrained, but assigned interconnection cost of $68/kW-year	33% available land max

Total PV Availability for High DG Case by Type and Utility

Installed Capacity by PV System Type (MWac)

Utility	Ground Mounted (> 30%)	Ground Mounted	Large Roofs	Small Roofs	Total
PG&E	3,153	665	943	758	**5,519**
SCE	2,878	1,011	1,592	586	**6,067**
SDG&E	552	255	218	380	**1,406**
Other	2,417	335	1,057	500	**4,309**
Total	**9,000**	**2,266**	**3,810**	**2,224**	**17,300**

Other WDG Resources

- Biogas/Biomass
  - Resource potential developed based on discussion with stakeholders
  - Constrained by fuel availability
  - Total available capacity of 250 MW of Biogas, 35 MW of distribution-connected Biomass

Statewide DG Potential by Type

Nameplate MW	DG Type					
Connection	Biogas	Biomass	Geothermal	Solar PV	Wind	Total
1. Customer Site	-	-	-	2,224	-	2,224
2. Feeder	249	34	-	3,810	-	4,093
3. Distribution Bank	-	-	-	2,267	-	2,267
4. Subtransmission	-	128	175	9,000	468	9,771
Total	249	162	175	17,301	468	18,355

4. Results and Final Thoughts

High DG Case Results

- Case constructed to minimize the need for new transmission corridors
- Start from 20% case
- Replace central station solar and wind with 15,000 MW of mostly distributed solar PV

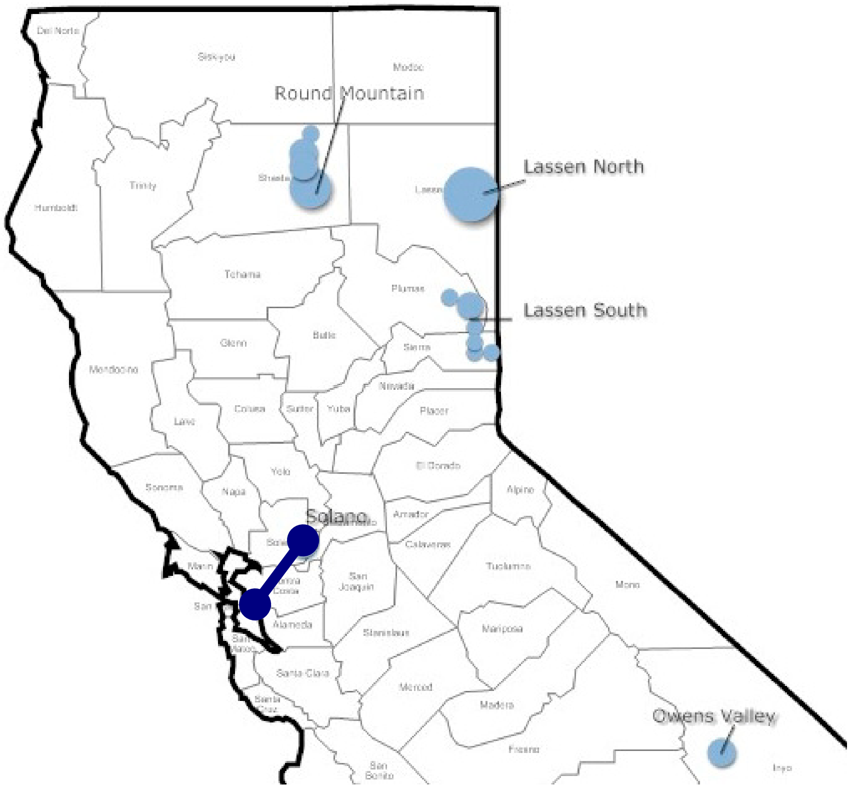
Zones Selected

	MW	GWh	Notes
Total	*26,761*	*74,650*	
Tehachapi	3,000	8,862	*Included in Reference Case*
Distributed CPUC	525	3,118	*Included in Reference Case*
Solano	1,000	3,197	*Included in Reference Case*
Out-of-State Early	2,062	6,617	*Included in Reference Case*
Imperial North	1,500	9,634	*Included in Reference Case*
Riverside East	1,500	3,507	*Included in Reference Case*
Distributed Biogas	249	1,855	
Distributed	175	1,344	
Distributed Wind	468	1,289	
Out-of-State Late	1,934	5,295	
Distributed Biomass	162	1,138	
Remote DG	9,000	19,236	
Distributed Solar	5,186	9,558	

Resources Selected by Type

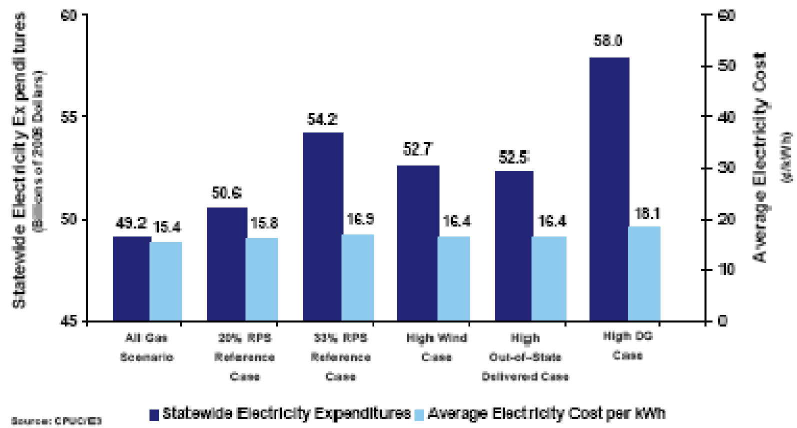
	In-State		Out-of-State		*Total*	
	MW	GWh	MW	GWh	*MW*	*GWh*
Biogas	279	2,078	-	-	*279*	*2,078*
Biomass	403	2,825	87	610	*490*	*3,435*
Geothermal	1,415	10,859	58	445	*1,473*	*11,303*
Hydro - Small	22	95	15	66	*37*	*161*
Solar PV	15,068	30,678	-	-	*15,068*	*30,678*
Solar Thermal	1,095	2,674	534	1,304	*1,629*	*3,978*
Wind	4,484	13,529	3,302	9,488	*7,785*	*23,017*
Total	*22,765*	*62,738*	*3,996*	*11,912*	*26,761*	*74,650*

New Transmission Required for High DG Case



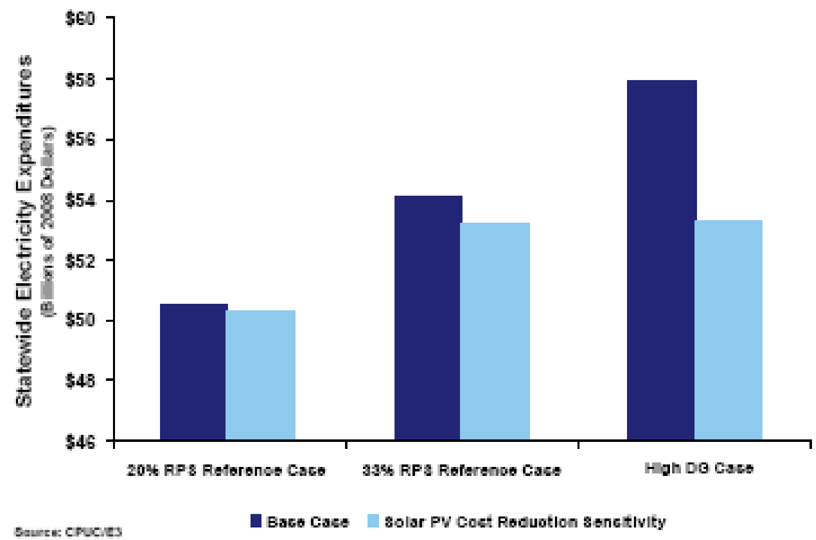
Cost Impacts of 33% RPS Cases

- Incremental cost of 33% Ref. Case in 2020:
  - +$3.6 billion relative to 20% RPS
  - Average retail rate: 16.9¢/kWh
  - 7% increase relative to 20% RPS
- Incremental cost of High DG Case in 2020:
  - +$3.8 billion relative to 33% Ref Case
  - +$7.4 billion relative to 20% RPS
  - Average retail rate: 18.1¢/kWh
  - 14.6% increase relative to 20% RPS



Solar PV Cost Reduction Sensitivity

- Delivered PV costs have come down substantially in the last year, and further reductions can be expected as the industry scales up
- We conducted a sensitivity analysis by reducing installed cost of PV from \$7/We to \$3.70/We
  - Price point developed for RETI to be in line with industry targets
  - Reduces levelized cost of PV from \$306/MWh to \$168/MWh
  - High DG case is similar in cost to 33% Reference Case



Final Thoughts and Next Steps

- We were not able to eliminate *all* transmission lines – assumed lines already approved go forward
- Much additional work could be done to refine the distributed PV potential estimates
- All cases assume indefinite continuation of current federal and state tax incentives
- We did not do any analysis on operations issues associated with high PV build
  - Ability of grid to absorb energy at PV output profile
  - Voltage and grid stability issues associated with lack of inertia
  - CAISO is now studying integration requirements of all 33% cases