The Impact of Distributed Generation Facilities on California's Transmission and Distribution System

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Abstract

Distributed generation (DG) technologies have been portrayed as an emerging face of tomorrow's electricity system. DG facilities are expected to provide a significant and wide variety of benefits to grid operations, including reduced peak loading on distribution feeders, lower congestion on transmission lines, increased system reliability, and cost reductions associated with deferred or eliminated need for new or expanded distribution or transmission infrastructure. To date, limited penetration of DG technologies has made it difficult to accurately estimate their impacts on the transmission and distribution (T&D) system. Under California's Self-Generation Incentive Program (SGIP), over 1000 DG facilities representing approximately 260 megawatts (MW) of capacity have been installed and monitored. This paper examines the impact of DG facilities operating during calendar year 2006 on the state's transmission and distribution system using measured generation performance data.

Background

By their very definition, DG facilities are non-centralized electricity power producers that connect to the distribution side of the electricity system. DG facilities evolved from "self-generation" facilities designed to help meet a customer's electricity demand. Consequently, DG facilities tend to be located directly at or near a demand source and are significantly smaller in size than their central station counterparts, with generating capacities typically below five megawatts (MW). Aside from their relative proximity to demand centers and smaller generating capacities, DG facilities can have very disparate characteristics. Fuel use among DG facilities spans a wide variety of energy resources, ranging from natural gas or propane to renewable resources such as wind or solar. Similarly, DG facilities run the gamut of prime mover technologies. Some DG facilities employ rotating machinery; for instance microturbines or engine/generator sets. Others use inverter based technologies such as fuel cells or solar photovoltaics (PV). In addition, DG facilities can have significantly different energy goals. For example, wind and PV systems are dedicated solely to electricity generation, while microturbines and fuel cells can represent combined heat and power systems that produce both electricity and heat for on-site use.

DG has been viewed as a small but critical part of the country's electricity system (Congressional Budget Office, 2003). The Department of Energy estimated that approximately 0.5 percent of the country's total electricity generation came from DG facilities in 2000 (Department of Energy, 2003). Within California, DG facilities currently represent approximately 2.5 percent of the state's total peak demand (Rawson and Sugar, March 2007). However, the market for DG technologies within the state is expected to grow rapidly, with DG resources targeted to provide enough capacity to meet nearly 25 percent of California's peak demand by 2020 (Rawson and Sugar, March 2007).

Not All Roses

While DG can provide a number of benefits to the grid, several pitfalls could make the future less rosy. DG systems, with their two way flow of power, represent a significant departure from the current generator-to-customer flow of power in the electricity system. Failure to isolate power flow generated from DG systems still connected when the grid is down poses real and critical safety hazards. In addition, replacement of a single central station power system with a large number of DG systems requires extensive and coordinated control systems to provide the same level of power (Lasseter, 2007).

Moreover, due to the low penetration of DG into the grid, it has been difficult to obtain accurate estimates of actual benefits being provided by DG systems. Several studies have studied the potential impacts of DG using various approaches, including laboratory testing, case studies, Monte Carlo simulations, etc. (Lasseter, 2007; Bollen, 2005; Hadley, 2005; Begovic, 2001). Few large scale studies have been conducted using metered performance data. California's Self-Generation Incentive Program (SGIP) provides a unique opportunity to quantify the impact of multiple DG systems operating in a utility environment.

DG Within California's Self-Generation Incentive Program

Assembly Bill 970 enacted in 2001 required the California Public Utilities Commission (CPUC) to initiate load control and distributed generation program activities to help move energy efficiency and DG technologies into the marketplace. As a result of that legislation, the CPUC issued Decision 01-03-073 on March 27, 2001 establishing the Self-Generation Incentive Program (SGIP). The resulting SGIP provided financial incentives to customers of investor owned utilities (IOUs) to install DG facilities that could meet all or a portion of their energy needs. DG technologies eligible under the SGIP include solar photovoltaic systems, fossil-and renewable-fueled reciprocating engines, fuel cells, micro-turbines, small-scale gas turbines and wind energy systems. As of June 2007, over 1000 DG systems, representing some 260 megawatts (MW) of generating capacity have been installed under the SGIP.

Itron, under contract to Pacific Gas and Electric (PG&E)[1] was retained to monitor the performance of facilities installed under the SGIP and provide measurement and evaluation services. As part of a 2006 impacts evaluation study, Itron and its team of subcontractors were directed to identify the impacts of DG facilities on the T&D systems of the IOUs participating in the SGIP. Several approaches were taken to accomplish this goal.

Approaches to Identifying T&D Impacts

Monitored DG System Performance

Net electricity capacity and energy generated by DG facilities operating under the SGIP is metered using interval meters. Generation information is typically reported at 15-minute intervals over twenty-four hours a day and 365 days per year for each metered facility. During calendar year 2006, electricity net generation output (ENGO) meters provided interval data from nearly 540 DG facilities out of the 942 DG facilities operating in 2006 under the SGIP. Table 1 provides a breakdown of DG facility by type and rebated capacity for which ENGO interval data was collected during 2006. Generation profiles developed

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[1] PG&E manages the measurement and evaluation contract on behalf of the SGIP Working Group. The Working Group is comprised of representatives from Pacific Gas and Electric; Southern California Edison; Southern California Gas Company (Sempra); the California Center for Sustainable Energy (previously the San Diego Regional Energy Office) on behalf of San Diego Gas and Electric; the California Public Utilities Commission and the California Energy Commission.

from the interval data have been used to show impacts on annual and peak electricity demand as reported in previous SGIP annual evaluation impact reports (Itron, 2002 through 2005). In the 2006 impacts evaluation report, the intent was to correlate ENGO interval data with 2006 summer peak demand information to investigate impacts at both the distribution and transmission levels.

Table 1: ENGO Metering of DG Technologies Under the SGIP in 2006

DG Technology	No. of operational facilities	Approximate Rebated Capacity (MW)	No. of facilities with ENGO metering	ENGO Metered Rebated Capacity (MW)	Rebated Capacity with ENGO Metering (% of total)
PV	632	80	296	41.8	52.3%
Fuel Cells	12	6.5	9	5	76.9%
Gas Turbines	4	11.6	4	11.6	100.0%
Microturbines	184	115.8	147	92.5	79.9%
IC Engines	108	16.9	80	11.6	68.6%
Wind Turbines	2	1.6	1	1	62.5%
Total:	**942**	**232.4**	**537**	**163.5**	**70.4%**

Distribution System Analysis Approach

Distribution system impacts were evaluated using hourly distribution loading data for each distribution feeder with direct connection to SGIP DG facilities. 2006 interval data collected for SGIP facilities were isolated to the specific date and hour of 2006 summer peak conditions for each IOU participating in the SGIP. Similarly, distribution line loadings corresponding to the same conditions were isolated to enable identification of SGIP output coincident with peak loading at each substation. The coincident SGIP peak load was then summarized by feeder type, IOU, and climate zone. This allowed extrapolation of the observed coincident peak load from interval-metered SGIP facilities to the entire SGIP DG population.

Figure 1 illustrates the concept of correlating DG generation to peak loading on a distribution feeder. In this example, the feeder has a load shape typical of residential loads, peaking at Hour Ending (HE) 16. In this example, the SGIP generator is a 31 kW PV system with peak generation of 21 kW at HE 13. During the feeder peak at HE16, however, the PV system is only producing 13.8 kW. Consequently, the 13.8 kW of PV generation coincident with the peak loading at HE 16 is used in this analysis of distribution impacts.

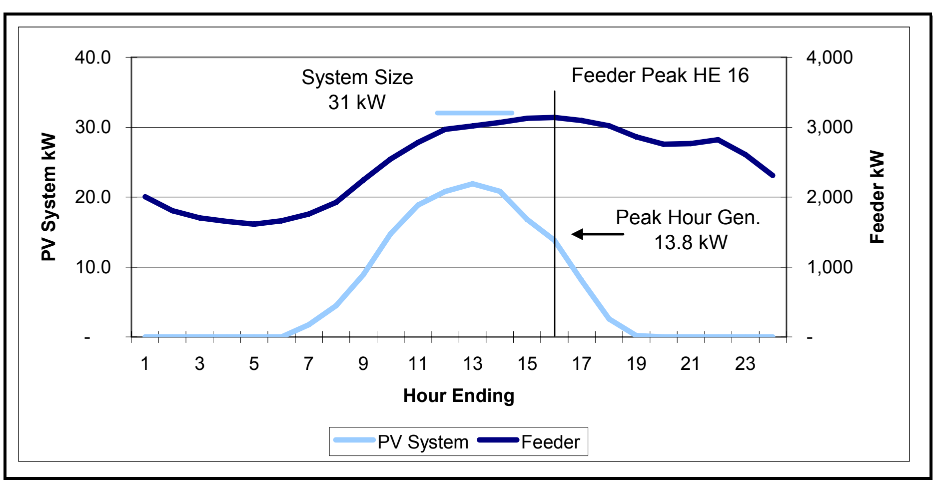


Figure 1: Example of Feeder Peak Hour Generation for PV System

Transmission System Analysis Approach

Due to the relatively small capacities of DG systems, impacts are more easily observed at the distribution level than at the transmission level. However, as the number of DG facilities increases, the cumulative capacity increases the likelihood for significant impact at the transmission level. For this reason, the approach was taken to model the aggregated capacity (MW) of SGIP DG facilities at each substation. The assumption was made that SGIP DG facilities act to reduce loading on distribution and transmission lines. Consequently, if generation from DG facilities is not available, then total load at the substations is higher by the otherwise contributed capacity of the aggregated DG facilities. The transmission substation configuration includes both the SGIP DG facility capacity and a corresponding load equal to the SGIP DG capacity. When a DG facility is considered out of service under a contingency analysis case, then the load at the substation increases because the DG facility is not available to offset the load. This representation simulates the benefits provided by DG facilities acting to reduce loading on substations and transmission lines.

The methodology for evaluating the transmission benefits of DG facilities located at different locations is termed the Aggregated MegaWatt Contingency Overload (AMWCO). Power flow simulations are completed under first contingency (N-1) conditions. One at a time, each power flow element (e.g., a transmission line, transformer, or generator) is temporarily removed from service and a power flow simulation is completed. This process is repeated for each element in the power flow case. For an N-1 simulation of the California transmission system, this can represent up to 7,000 simulations completed. One or more of these individual simulations may cause an overload on one or more elements. The percent overload of the element is weighted by the number of outage occurrences and the percent overload. The summation of the weighted overloads is the AMWCO. The difference between the AMWCO for the base case and each DG facility case divided by the capacity of the installed DG is the Distributed Generation Transmission Benefit Ratio (DGTBR). For the cases with and without the DG modeled, the Aggregated MegaWatt Overload is calculated. The difference between the two AMWCO values divided by the DG capacity determines the DGTBR. A negative DGTBR represents an improvement in system reliability. A positive DGTBR indicates a probable decrease in system reliability. This approach is based on a similar approach used for assessing transmission impacts due to integration of renewable energy facilities (CEC, 2005).

Three power flow scenarios were conducted to assess transmission impacts of aggregated DG capacities. The first scenario assessed the impact of all of the SGIP DG resources on a state-wide basis. The first power flow simulation excludes all of the DG facilities. A power flow simulation was completed for approximately 7,000 first contingency (N-1) conditions. The first contingency condition represents an outage of one transmission line or one generator. To model every line and transformer outage requires 7,000 different simulations. The second case included the SGIP DG resources. The number of simulations was slightly larger than the first simulation due to the increase in generators represented by the SGIP DG resources. The DGTBR value was determined by subtracting the AMWCO value from the first case from the AMWCO from the second case and dividing by the aggregated DG value. A negative value indicates that the aggregated DG provides a transmission reliability value to the statewide electricity system.

The second scenario assessed the impacts to each IOU. The same two simulations were completed as described above except that instead of a state-wide study, the studies concentrated on each utility system. The DGTBR was calculated using the same method employed for the state level scenario.

Each IOU divides its service area into transmission zones. Consequently, the third scenario examined the transmission impact to IOU transmission zones containing SGIP DG resources.

Figure 2 shows the total number of zones for each IOU and the number of zones that includes at least one DG facility.

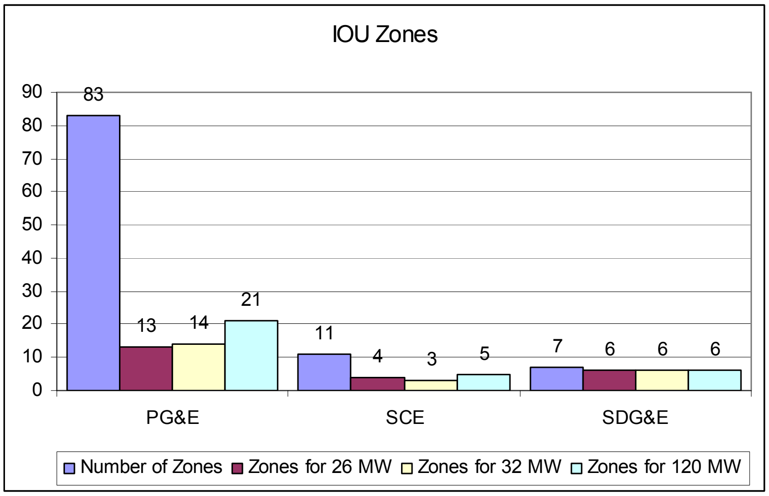
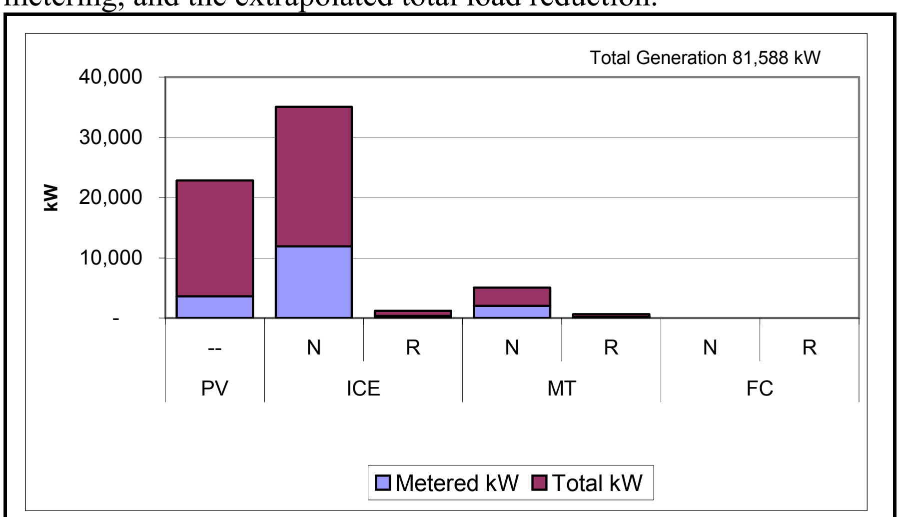


Figure 2: IOU Transmission Zones in California

Results

Distribution System Impacts

The analysis approach described above, comparing metered SGIP output and distribution substation loading was applied to all SGIP facilities in which both interval SGIP output data and the timing of the distribution substation peak was available. The estimated total reduction in coincident peak load associated with SGIP DG facilities in 2006 in the three utility service territories was 81.6 MW. Figure 3 shows the state-wide distribution-coincident load reduction by SGIP technology for SGIP facilities with interval metering, and the extrapolated total load reduction.



	PV --	ICE N	ICE R	MT N	MT R	FC N	FC R
Metered kW	3,636	11,914	360	2,024	203	-	-
Total kW	22,866	35,090	1,204	5,056	624	-	-
Metered #	78	56	3	31	4	1	1
Total #	569	165	9	81	16	9	2

Figure 3: 2006 Metered and Estimated Total SGIP Generation – California

The measured distribution peak load reduction as percentage of nameplate capacity by climate zone, utility, technology, and fuel type used in the estimation are provided below in Figure 4. The division of categories was defined in order to provide the highest number of metered observations in each category, and for usefulness as a 'look-up' table to estimate expected distribution peak load reduction for different SGIP installations. For example, the overall measured peak load reduction for PV in the state was 35% of nameplate capacity. This ranges significantly depending on the timing of the distribution peak. For those substations that peak in the afternoon (predominantly substations with mostly commercial load) the average coincidence is as high as 63% in Inland areas with afternoon peaking substations. The coincidence is significantly lower on substations with evening peaks (predominantly substations with mostly residential load) with as low as 1% measured in SDG&E service territory. The peak load reduction of facilities with renewable fuel is also measured to be significantly lower than non-renewable fuels.

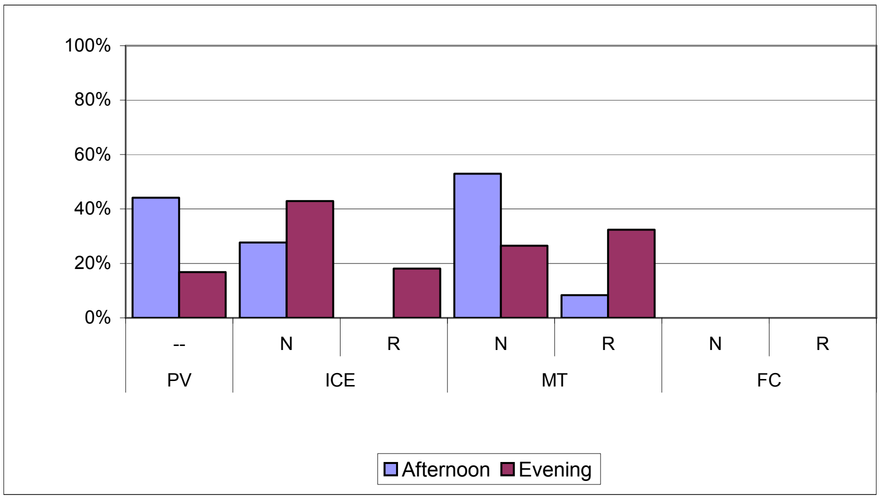
	Technology	PV	ICE		MT		FC	
Climate Zones	Fuel Type	--	N	R	N	R	N	R
PG&E Coast	Afternoon	56%	85%					
	Evening	30%						
SCE Coast	Afternoon	46%	65%		44%			
	Evening	6%	48%		52%			
SDG&E Coast	Afternoon	42%	33%		40%			
	Evening	1%						
Inland	Afternoon	63%	29%					
	Evening	26%						
Total by Technology/Fuel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

Figure 4: Distribution Coincident Peak Load Reduction as a Percent of Nameplate Capacity – California 2005& 2006

Definitions for Figure 4:

- 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)
- Distribution Peak Hour
  - Afternoon (Peak occurs on Hour Ending 16 or earlier)
  - Evening (Peak occurs after HE 16)
- Technology Types
  - PV = Photovoltaic, ICE = Internal Combustion Engine, MT = Microturbine, FC = Fuel Cell
- Fuel Types
  - N = Non-renewable fuel (predominantly natural gas), R = Renewable Fuel

Interval data was used to characterize the loading of SGIP DG facilities on the distribution system over the course of a typical day. Figure 5 shows the percent of SGIP DG capacity that is operational by feeder type during 2006. In general, PV and natural gas fueled ICE and MT facilities tend to have a substantial percentage of their capacity available during afternoons. This indicates a high likelihood that these facilities could help address peak demand.



	PV --	ICE N	ICE R	MT N	MT R	FC N	FC R
Afternoon	45%	54%		66%	33%		0%
Evening	28%	62%	0%	62%	39%		
Afternoon #	46	18		7	1		0
Evening #	17	13	1	7	1	0	

Figure 5: Percent of SGIP DG Operational Capacity by Feeder Type

Ultimately, the ability of SGIP DG facilities to offset distribution line peak loading is determined by the amount of DG generation capacity available during the peak period. Figure 6 provides a breakout of the size of SGIP DG capacity that was observed generating during the 2006 summer peak period. This analysis shows that nearly 57 percent of the feeders serving customers with SGIP generators had less than 50kW of coincident peak load reduction, and very few with greater than 1MW of distribution peak load reduction (i.e., less than 3% of the feeders).

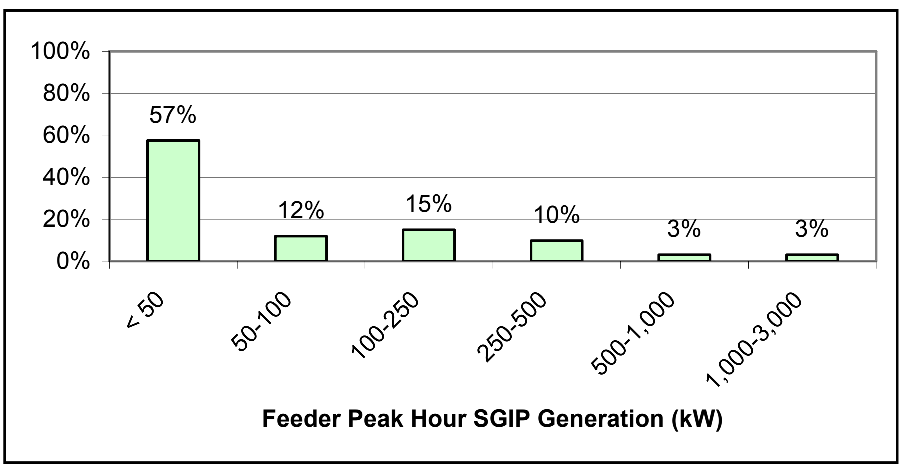
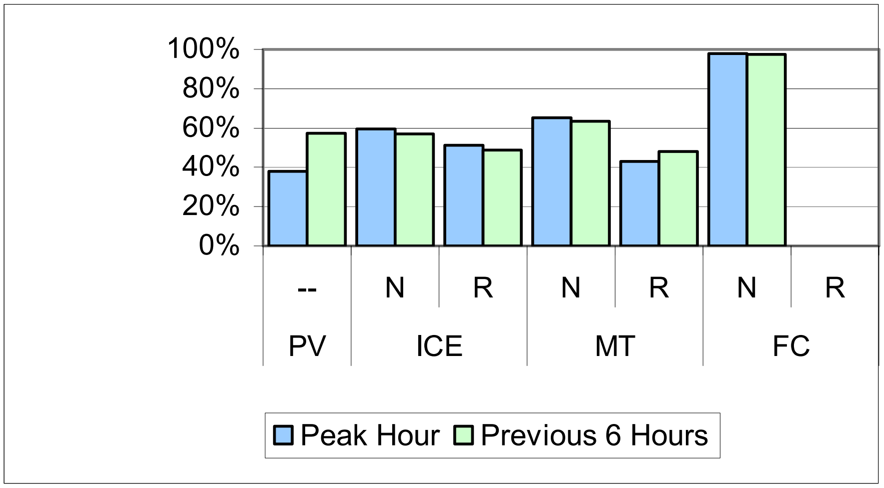


Figure 6: SGIP DG Contribution to Feeder Peak Hour Generation per Substation

Lastly, the output on the coincident peak hour is not the only indicator of ability of SGIP facilities to support peak load. DG facilities could possibly play a role in "pre-cooling" of thermally constrained distribution equipment (predominantly conductor and substation transformers) by reducing loading on the distribution feeders leading into peak periods. This "pre-cooling" could not only help mitigate heating that results in decreased carrying capacity of the distribution lines, but could also help reduce the probability of outages that occur from overheating of distribution lines. Figure 7 shows capacity factors of different DG technologies during peak hour and six hours previous to the peak period in 2006. The capacity factors show that nearly all SGIP DG facilities have capacity factors above 50% in the six hours leading to the peak period and consequently could help provide "pre-cooling" of distribution feeders. The data is shown below the figure, along with the number of operational SGIP installations evaluated to develop the percentages.



Peak Hour CF	38%	60%	51%	65%	43%	98%	
Pre. 6 Hour CF	57%	57%	49%	63%	48%	97%	
Operational	91	56	1	28	3	1	0

Figure 7: Capacity Factor for DG Facilities for Peak Hour and Previous Six Hours

Transmission System Impacts

Distribution of SGIP DG resources is shown in Figure 8. The location of these resources is approximated since their exact GIS locations are unknown. Instead, locations on the map reflect the approximate location of the connection point of the SGIP DG facilities to their associated transmission bus.

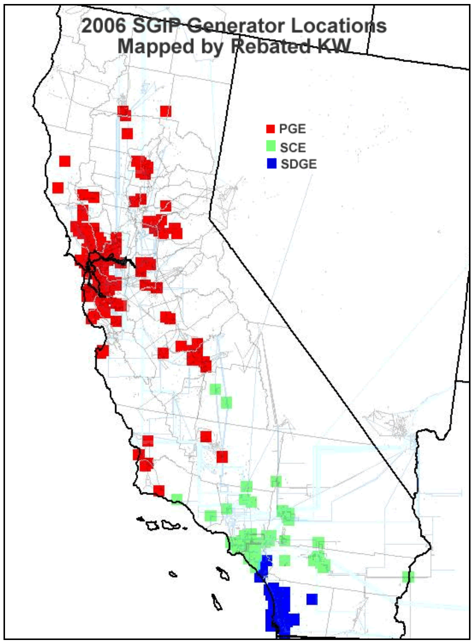


Figure 8: Locations of SGIP DG Facilities Analyzed for 2006

Figure 9 below shows the distribution of the 32 MW of peak coincident capacity of the SGIP DG for the three IOUs. The number of SGIP DG facilities for the IOU and for the IOU zones should be the same since the utility assigned the DG facilities to specific zones (and this is reflected in Figure 9) . The majority of the DG facilities showing generation coincident to the summer 2006 peak are located in SCE service area.

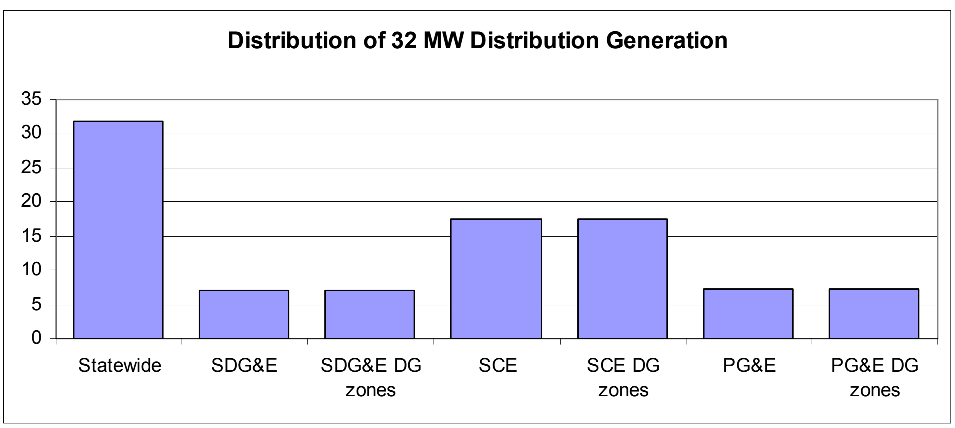


Figure 9: Self-Generation 32 MW Generation Distribution

Figure 10 shows the results of the DGTBR analysis. The DGTBR values are negative across all scenarios as expected.[2]

[2] Since DG acts as load reducers at the load centers, they are expected to show transmission benefits.

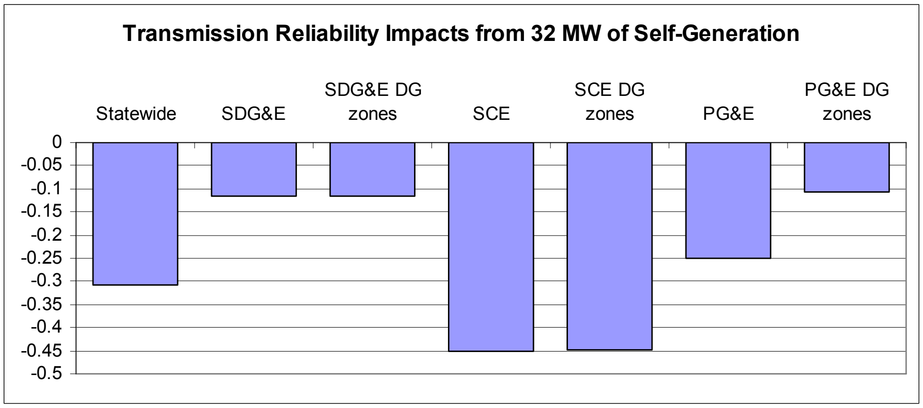


Figure 10: Transmission Reliability Impacts from 32 MW of Self-Generation

The magnitude and distribution of the DGTBR values represents an interesting set of observations. As expected, SCE has the largest number of DG facilities that contributed generation during peak demand. As a result, the benefit is expected to be higher for SCE than for other utilities. As there is not a large difference between the total number of zones and the number of zones with DG facilities, the DGTBR is expected to be the about the same.

Almost every zone in the SDG&E service area contains DG facilities. As such, the DGTBR is expected to be the same. The DGTBR values are negative and provide a transmission benefit to SDG&E even though the self-generation is only 7 MW.

PG&E results are the most interesting. As shown in Figure 2, PG&E is divided into 83 transmission zones but only 14 contain DG facilities. The DGTBR values should therefore be different for PG&E as compared to the zones having equal DG resources. The bar charts shown in Figure 10 reflect that the DGTBR values are significantly different in PG&E. The concentration of DG facilities across fewer zones results in the DGTBR being lower within the zones as compared to the total PG&E system. There is less load in the zone and fewer transmission lines to impact the DGTBR under contingency analysis. By inadvertently compressing DG facilities into fewer zones, the DGTBR may not always produce consistent results.

The total state-wide DGTBR is also shown in Figure 10. Even though the total aggregated capacity of the SGIP DG facilities is only 32 MW under the 2006 summer peak conditions, these facilities were found to provide overall DGTBR benefits to the system.

Conclusions

Distribution system analyses show that SGIP DG facilities help reduce peak loading of the distribution system, although to a limited degree. In addition, with appropriate configuration and location, increased amounts of DG could play a significantly increasing role in helping to meet distribution peak line loadings. This may be especially true if pre-cooling affects are found to be an important aspect in helping to increase the carrying capacity of distribution lines.

From a transmission perspective, DG facilities were found to provide direct benefits to the sub-transmission and transmission networks by reducing load at the load centers. Even on a transmission system that has a total connected load of over 40,000 MW, the methodology used in this analysis can calculate the transmission benefits for only 32 MW of self-generation. The IOU representation of their transmission system into zones allows for detailed power flow analysis into sub-regions. Because of the small penetration of DG capacity in the system, the DGTBR value is relatively small. However, the results seem to indicate that higher penetrations of DG capacity coincident with peak demand would result in higher DGTBR values.

Given the uncertainties associated with modeling of aggregated DG capacity at low penetration levels, the actual impacts cannot be accurately determined until a higher penetration of DG capacity is achieved along with a better understanding of the availability of DG facilities at time of peak. The analysis described in this study concentrates on the summer peak time period only. To improve the analytical results and conclusions, additional seasons such as spring and fall should be considered along with a time step analysis of self generation over a pre-determined time period.

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