NAVIGANT

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Draft Framework – DG Integration Analysis

Background

In his *Clean Energy Jobs Plan*, Governor Brown established a 2020 goal of 12,000 MW of localized energy development in California.[1] The plan generally defines localized energy, or distributed generation (DG), as projects sized 20 MWs or less, interconnected on-site or close to load, that can be constructed quickly with no new transmission lines, and, typically, with no environmental impact. This is a policy definition of DG that identifies preferred project characteristics and is useful for setting procurement targets. However, due to a variety of reasons, the distributed generation market does not align with the preferred policy definition and utilities are receiving interconnection requests for projects in locations that cause significant system costs and impacts. This issue was illustrated in a study conducted by Southern California Edison (SCE) that shows the majority of interconnection requests they receive do not satisfy the preferred policy definition.[2] SCE's study proposes that utility system costs and impacts can be mitigated by guiding projects to areas of the system better equipped to accommodate generation resources.

The California Energy Commission (CEC), in response to SCE's study, is using the state's localized energy goal as the back-drop for an analysis that is evaluating the costs and impacts of increased penetration levels of localized energy on the utility electricity system. The CEC has contracted with Navigant Consulting (Navigant) to conduct the analysis, and has partnered with SCE to use their system for the study. The purpose of the analysis is to gain a better understanding of utility system costs and impacts associated with increased DG installations in California, and how those costs and impacts change based on interconnection location, distribution feeder characteristics, load types, and project size. Results of the analysis will be presented as a 2020 forecast of the costs and impacts of SCE achieving its fair share of the Governor's 12,000 MW localized renewable energy goal, and a methodology and framework

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[1] http://gov.ca.gov/docs/Clean_Energy_Plan.pdf

[2] Southern California Edison, *The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System*, (May, 2012).

that can be utilized by other California utilities to conduct similar analysis. Additionally, based on the results of this study, CEC staff will author a white paper that explores potential regulatory and technical solutions to mitigate costs and impacts. The results of the analysis and discussion in the staff white paper will feed into the next Integrated Energy Policy Report.

Study Scope

The CEC study, which started in early 2013, seeks to determine how DG integration costs vary as installed capacity increases and according to size, type and location. The study builds upon work previously completed by SCE and reported in a study released in May 2012.[3] The SCE study resulted in a finding that integration costs vary significantly based on locational factors, with total T&D integration costs up to $4.5 billion for 4,800 MW of DG, versus $2.1 billion if locational constraints are applied.

The CEC study expands upon SCE's effort by increasing the number of distribution feeders modeled and by varying key assumptions and related parameters for DG installed on the SCE system. The intent is to validate the approach used in the original SCE study and develop, for discussion, an analytical framework that could be used by other California utilities to predict DG integration costs.

Study Assumptions

Navigant and SCE established guiding principles and assumptions that were applied to SCE's territory in order to better understand the cost and impact of high levels of DG integration, including how integration costs vary as a function of the type, size and location of installed DG.

Key study assumptions include:

- The SCE system is used as host to test the analytical framework
- The statewide 12,000 MW DG target is achieved by 2020, which includes existing DG
- The largest single DG unit is 20 MW; most DG is rated 10 MW and below as most feeders are rated 10 MW and below

[3] "The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System."

- System benefits are not included in the evaluation (E3 is evaluating benefits in its update of the CPUC DG Potential Study)
- Integration costs include DG interconnection and system upgrades (needed to mitigate impacts)
- DG interconnects to distribution lines includes feeders operating at 33kV, 16kV, 12kv, and 4kV – interconnection at higher voltages were not considered as these lines would be used for generation rated above the 20 MW limit.
- Distribution simulation models (e.g., load flow) are used to predict DG impacts and to evaluate the effectiveness of mitigation strategies and solutions
- Transmission impacts are locational, and evaluated based on CAISO Transmission Resource Plans and DG Resource Adequacy studies
- DG integration costs vary according to size, type, location and penetration, among other factors and some of these factors cannot be accurately predicted for 2020; accordingly, DG integration costs will vary based on reasonable ranges of each these factors
- DG technology includes currently available renewable generation technologies, whose cost are expected to decline by 2020; for the SCE system, DG is 90% PV, 10% biomass
- Mitigation options and solutions to address DG impacts is based on currently available technology (this is a key topic that will be brought before the PAC)

The amount of DG allocated (out of the 12,000 MW target) to the SCE system is summarized in the following table. The 4,800 MW is the study baseline and corresponds to the value SCE used in its May 2012 study. Recognizing that actual amounts of installed DG likely will vary among California's electric utilities, studies include a high case based on 25 percent above the baseline and a low penetration case at 50 percent of the baseline. The 50 percent case is used to determine how DG integration costs increase as the amount of DG reaches statewide targets.

DG 2020 Target	12,000 MW
SCE Baseline DG Penetration (May 2012 SCE Study)	4,800 MW
SCE Maximum DG Penetration (25% over baseline)	6,000 MW
SCE Minimum DG Penetration (50% below baseline)	2,400 MW

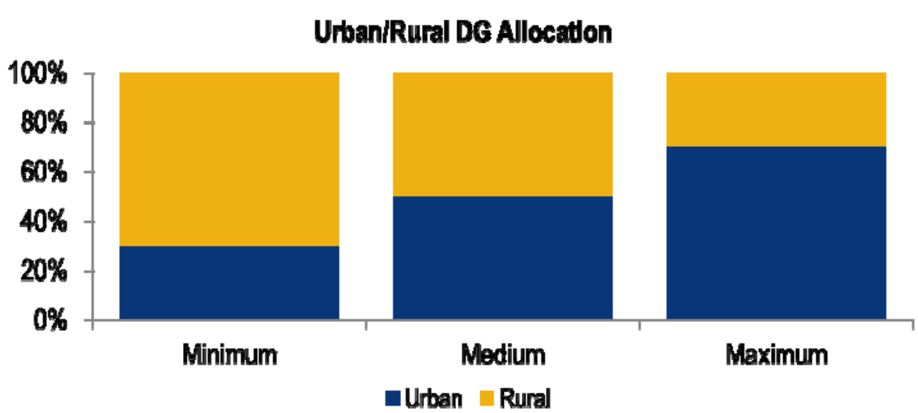
It is important to emphasize that results obtained from the study are high level and not intended to be a substitute for detailed interconnection analysis that are performed for individual DG interconnection requests.

DG Characterization & Integration Scenarios

Most DG that has been installed and that likely will be installed in SCE's service territory between now and 2020 is PV. Base case study assumptions include 90 percent PV and 10 percent biomass generation, with PV inverter-based and biomass synchronous. The size and type of PV varies accordingly to location and customer type as illustrated below. The location of PV on the feeder also will vary and will be addressed in sensitivity studies to assess how integration costs change based on location factors for different types of feeders.

Parameters:	Min	Medium	Max
DG Size – Residential	10kW	15kW	25 kW
DG Size – Commercial	15 kW	100 kW	1-5 MW
DG Size - Ground-Based	50 kW	500 kW	10 MW
Location	10% from Station	Distributed	100% End of Line

The study examines three integration scenarios in terms of allocation, illustrated below: the first or minimum case assumes most DG is located in rural areas (SCE's "unguided" case); the second assume a 50/50 split on urban and rural locations; and the third assumes most DG – up to 70 percent or higher - is installed on urban/suburban feeders (SCE's "guided" case). Final results will include a several combinations over a range of DG penetration and locations.



Feeder Selection Methodology

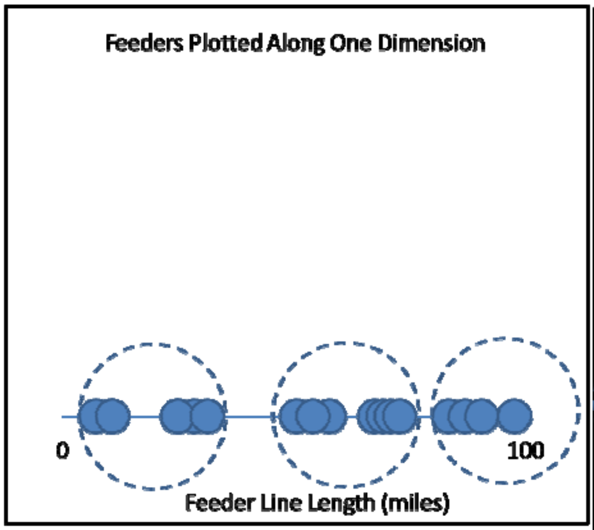
In order to evaluate the impacts of DG integration on a distribution system, Navigant selected a subset of feeders that are representative of the entire SCE system. The objective is to select a set of feeders that will simulate DG impacts given the differences in feeder attributes, location and loadings. Typically, statistical methods demonstrate that a relatively small number of feeders are sufficient to represent the entire system. For example, SCE in its May 2012 study determined that the analysis of four feeders provided a reasonable estimate of feeder upgrade costs for DG integration issues across its system. The feeders SCE selected using statistical methods include short and long feeders located in urban and rural areas. Navigant's build upon the SCE study to include additional feeders and details to address locational impacts, DG diversity and sensitivity analysis.

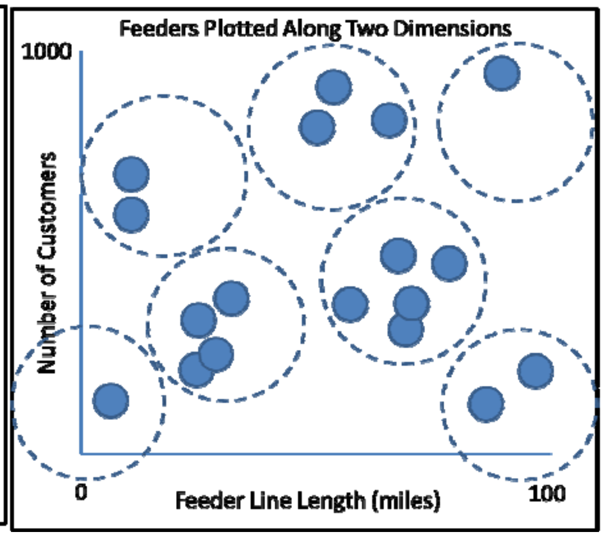
Navigant applied a similar approach to SCE to select a set of representative feeders. To develop an understanding of the types of feeders in its system, SCE provided detailed data of all of its feeders, including feeder voltage, line mileage, number of customers, customers by rate class, location, line length, three, two, and single phase line mileage, and total load served. Navigant used the data to conduct statistical studies to create feeder groups with the following attributes.

- Urban and rural location
- Lower voltage (4.16kV) versus higher voltage feeders (12.47/16/33kV)
- Short and long feeders
- Primarily residential versus primarily commercial/industrial customers
- Light and heavy load density

A heuristic 'clustering' technique was used to group the feeders, which compared the metrics of the feeders and computed a 'distance' between them, which represented the similarity between feeders. Feeders that were similar on all, or a majority, of metrics, were assigned a lower distance, while feeders that had little in common were assigned a higher distance.

The illustration below depicts a simplified version of this approach, where feeders are plotted first along a single dimension (line length), and then the same feeders are plotted along two dimensions (line length and number of customers). The dashed circles encapsulate clusters of feeders. The addition of the second dimension increases the resolution of the clustering, separating feeders that were in fact only similar in one dimension.





A mathematical distance can be computed between any two feeders (each feeder is represented by a point above). The lower the distance, the more similar are the feeders. One sets a threshold distance for feeders to be considered sufficiently similar (the radius of the circles in the diagrams above), and feeders whose distances fall below this threshold are treated as belonging to the same cluster. A high threshold – large radius – means that many feeders are placed into a few clusters (the criteria for similarity is relaxed), while a low threshold – small radius – means that fewer feeders are placed into many clusters (the criteria for similarity is strict). Adjusting the threshold distance therefore allows control over the resolution of the clustering process.

Navigant's clustering process involved calculating the distances between all of the feeders used in the analysis across nine metrics, and yielded 48 distinct clusters of feeders, of which 28 contained at least ten feeders. These 28 clusters contained 3,876 of the 3,942 feeders examined from the data set, or over 98% of the set. The 28 main clusters were ultimately combined into 13 feeder groups by merging sufficiently similar clusters and excluding clusters that were either not of interest or where details were not available. A representative feeder from each of the groups was selected for analysis, chosen from near the center of each cluster and in consultation with SCE.

The following table lists each of the 13 feeders, with the number of feeders on the SCE system that each is intended to represent in parenthetical. Note that one to two additional feeders may be added to model biomass generation, as these devices are likely to be located on segments of the system that may not be in the feeder list. Not surprisingly, results indicate that many urban feeders have similar characteristics; for example, Urban Feeder No.2 represents 536 12/16kV residential feeders. In contrast, rural feeders typically have 100 or fewer feeders represented in their respective groupings.

7 Urban classifications	6 Rural classifications
1. Urban ~4 kV (788 feeders) 2. Urban 12-16 kV Residential (536 feeders) 3. Urban 12-16 kV Commercial (397 feeders) 4. Urban 12-16 kV Industrial (332 feeders) 5. Urban 12-16 kV Residential-Commercial (1,160 feeders) 6. Urban 12-16 kV Long (20 feeders) 7. Urban 33 kV (13 feeders)	1. Rural ~4kV (82 feeders) 2. Rural 12-16 kV Short (113 feeders) 3. Rural 12-16 kV Medium (66 feeders) 4. Rural 12-16 kV Long (55 feeders) 5. Rural 12-16 kV Agricultural (65 feeders) 6. Rural 33 kV feeders (12 feeders)

Distribution Feeder Simulation Model

Any commercially available load flow model may be used, as most, if not all, should produce comparable results. Navigant uses Milsoft, a model that performs single multi-phase radial and (limited) network load flow analysis. SCE uses CYME, another commonly used model. Due to differences in formatting in model database entry, Navigant determined that it first needed to translate the CYME model databases that SCE provided to Milsoft in order validate load flow results. To convert the CYME database, Navigant combined feeder connectivity data with line impedances and related data in Milsoft to be comparable to those used in CYME. A test of this approach proved successful, as results for one of the 13 feeders were virtually identical. Exhibit 1 illustrates the data conversion and validation process.

Navigant may elect to simplify models to aggregate nodes where applicable to do so for longer complex feeders. The example we will provide at the meeting is the Aruba feeder, a 12 kV urban feeder examined in SCE's May 2012 report. We cross-checked each load flow model results with SCE's models to ensure relative accuracy and consistency before evaluating DG integration scenarios.

Transmission Impacts

Navigant does not propose to conduct independent studies of California's bulk supply system, but instead, will rely on prior or ongoing efforts by CAISO and transmission owners to assess the impact of increasing the amount of renewable DG in different transmission zones. Key sources include CAISO's most recent TRP, Resource Adequacy Studies and related DG analyses and reports. Navigant also is using the results of the most recent CAISO DG Resource Adequacy report to identify the amount of available transmission for new DG. In its latest report, the amount of available capacity is 892 MW at 57 delivery point over the entire SCE system. As expected, the level of availability varies significantly depending on delivery point location. Where DG exceeds available capacity, Navigant will work with the CEC, SCE and CAISO to identify costs associated with adding DG above current limits. However, Navigant will rely on CAISO studies and results, and does not propose to conduct independent studies.

DG Parameters and Feeder Model Assumptions

To evaluate the impact of diversified DG (i.e., DG will be installed on many different lines and locations on any given feeder), Navigant estimated the number of points of injection are needed on each feeder. Given the number of nodes on a feeder and the uncertainty of exactly where customers and developers will install DG, it is not possible nor is it practical to model each individual DG unit in the feeder load flow case studies. Accordingly, Navigant aggregated several DG devices across the entire feeder at dispersed injection point. The number of injection DG points for four representative feeders with significantly different topology and load density is outlined in the table that follows.

Assumptions about the potential number of injection points, DG project distance from substation, and distribution along the feeder (at the end, close to the substation, distributed along the line) depends on the feeder attributes, customer type and locational factors. Navigant's assumptions on DG size, type, location and number of injection points for specific customer groups are as follows:

- Residential
    - 4-12 injection points
    - Minimum 10 kW, medium 15 kW, maximum 25 kW
    - Affected by residential load locations
- Commercial (e.g., rooftop on large warehouse)
    - 1-4 injection points
    - Distributed on feeder
    - Minimum 15 kW, medium 100 kW, maximum 1-5 MW
    - Affected by commercial load locations
- Ground based (larger DG)
    - 1-2 injection points

- Minimum 50 kW, medium 500 kW, maximum 10 MW
- Affected by commercial and industrial load location

In addition, the number of load flow cases performed for each feeder includes both a base case and sensitivity for several key parameters. The sensitivity studies include varying feeder load, DG location for rural, urban and mixed urban/rural cases. The intent is to determine how DG impacts and integration costs vary as result of changing each of the factors. The maximum number of simulation cases needed for the four representative feeders listed in the table below typically is between 10 and 15, which includes a multiplier to reflect the mix of urban and rural DG penetration cases that Navigant included in its study. However, the number of actual cases likely will be lower as there either will be limited impacts or because results will be similar to other cases.

Feeder Name	Urban/ Rural	No. of Feeders	Base Case	10% from S/S	End of Feeder	Light Load	Heavy Load	Subtot	Urban/ Rural Multiplier	Total No. of Cases
Feeder 1	Urban	845	1	0	1	1	1	4	3	12
Feeder 2	Urban	483	1	0	0	1	1	3	3	9
Feeder 3	Rural	33	1	1	1	1	1	5	3	15
Feeder 4	Rural	65	1	1	1	1	1	5	3	15

Issues and questions requested from the PAC include, but are not limited to the following:

1. Is the feeder selection method appropriate to represent a utility's feeder population? If not, are there other methods that CEC should consider?
2. Is the feeder model (based on the example shown) appropriate to capture the complexity of a feeder? If not, what would be more appropriate?
3. Is the operational impact analysis appropriate? If not, are there other operational impacts that CEC should consider in this framework?

DG Integration Scenarios – Representative Cases

The following two sets of tables illustrate how DG is integrated into four typical feeders for the 2020 DG scenario (i.e. 4800 MW of DG on SCE's system). Two cases are examined: the first assumes that 30 percent of DG is installed on two urban feeders and 70 percent on two rural feeders; the second case assumes 70 percent of DG is installed on urban feeders, 30 percent rural. The four SCE feeders selected are the same as those selected by SCE for DG integration and evaluation in its May 2012 study. The amount of DG added, denoted as the "allocation factor", is based on feeder load; which assumes the amount of DG is proportional to the amount of load and number of customers located on a feeder. Navigant recognizes other allocation approaches may be warranted, and anticipates other approaches will be used for large DG installed directly onto the feeder at primary level voltages. The first table listed highlights feeder attributes, peak loads and customer mix. The "number of feeders" is the number of feeders on the SCE system that each feeder is intended to represent.

The second table highlights the total amounts of DG installed, the amount of DG installed per customer class and the number of DG injection points per feeder. The number of injection points ranges from a low of three for Feeder 2 to a high of 11 for Feeder 1. The total amount of DG installed ranges from a low of 100kW to a high of about 3,000 kW for the four feeders. The amount of DG installed on urban versus rural feeders shifts significantly as expected, the DG additions shifts from 70 percent rural to 70 percent urban. Sensitivity studies increase the maximum amount of DG installed per feeder to much higher levels.

Example: DG allocation, 30% Urban, 70% Rural, Based on feeder peak

(Based on feeder load)

SCE Feeder Data

Feeder Name	Urban/ Rural	No. of Feeders	No. of Feeders Scaled	Com & Ind Custs	Res Custs	Nominal Voltage (kV)	Total 3-ph ckt miles	Total 2-ph & 1-ph ckt	Feeder Peak (kVA)	Res Demand (%)	Com Demand (%)	Ind Demand (%)	Other/ Agri (%)
Feeder 1	Urban	845	1591	127	1421	12	9	6	9327	28%	59%	13%	0%
Feeder 2	Urban	483	909	55	702	4	3	3	1780	87%	12%	0%	0%
Feeder 3	Rural	33	505	204	471	5	3	4	1453	49%	51%	0%	0%
Feeder 4	Rural	65	995	73	71	12	35	0	6610	4%	1%	0%	94%
TOTAL			**4000**										

Estimated Integrated DG per Feeder

Res DG (kW)	Com DG (kW)	Ind DG (kW)	Other/ Agri (kW)	DG per Feeder (kW)	DG Allocation Factor	Total DG (MW)	Res Injection Pts	Com Injection Pts	Ind/AG Injection Pts
364	766	169	0	1298	0.534	1298	6	4	1
124	17	0	0	142	0.058	142	2	1	0
165	172	0	0	337	0.061	337	3	2	0
121	30	0	2841	2992	0.544	3023	0	1	3
774	**986**	**169**	**2842**			**4770**			

Estimated Residential, Commercial, Industrial, and Agricultural DG

Allocation Factor per feeder

Total DG ~4,800 MW

Estimated Residential, Commercial, Ind/Ag Injection Points

Example: DG allocation, 70% Urban, 30% Rural, Based on feeder peak

(Based on feeder load)

SCE Feeder Data

Feeder Name	Urban/ Rural	No. of Feeders	No. of Feeders Scaled	Com & Ind Custs	Res Custs	Nominal Voltage (kV)	Total 3-ph ckt miles	Total 2-ph & 1-ph ckt	Feeder Peak (kVA)	Res Demand (%)	Com Demand (%)	Ind Demand (%)	Other/ Agri (%)
Feeder 1	Urban	845	1591	127	1421	12	9	6	9327	28%	59%	13%	0%
Feeder 2	Urban	483	909	55	702	4	3	3	1780	87%	12%	0%	0%
Feeder 3	Rural	33	505	204	471	5	3	4	1453	49%	51%	0%	0%
Feeder 4	Rural	65	995	73	71	12	35	0	6610	4%	1%	0%	94%
TOTAL			**4000**										

Estimated Integrated DG per Feeder

Res DG (kW)	Com DG (kW)	Ind DG (kW)	Other/ Agri (kW)	DG per Feeder (kW)	DG Allocation Factor	Total DG (MW)	Res Injection Pts	Com Injection Pts	Ind/AG Injection Pts
848	1787	394	0	3030	0.534	3030	6	4	1
289	41	0	1	330	0.058	330	2	1	0
71	74	0	0	145	0.061	145	3	2	0
52	13	0	1218	1282	0.544	1295	0	1	3
1260	**1915**	**394**	**1219**			**4787**			

Estimated Residential, Commercial, Industrial, and Agricultural DG

Allocation Factor per feeder

Total DG ~4,800 MW

Estimated Residential, Commercial, Ind/Ag Injection Points

Performance Standards & DG Impacts

Distribution performance standards used to evaluate DG impacts are based on current industry and state criterion, applicable industry standards, SCE planning guidelines and DG interconnection requirements (per Rule 21). Related DG interconnection requirements adopted for this study include:

- DG is considered non-firm and does not provide feeder capacity support
- DG output cannot exceed main line or lateral loading limits (load cannot offset DG output)
- All DG is assumed to be off-line for at least 5 minutes following a circuit interruption (per IEEE 1547)

- Inverter power factor is fixed; that is, not allowed to provide reactive support[4]
- Load Tap Changer (LTC) and regulator operations (total number per year) must be close to the number of operations compared to feeders with none or minimal amounts of DG
- DG ride-through is not required for low voltage events
- Total DG for load transfers via feeder ties, either for maintenance of reliability, should not exceed SCE load limits or voltage criterion[5]
- The impact of intermittent renewable distributed generation on bulk system generation load following and frequency regulation is not addressed in Navigant's study
- Any single DG (or small set of large DG units – typically 1 MW or greater) that cause reverse power flow at the substation will interconnect to the subtransmission system

Based on the above criterion and assumptions, feeder load flow studies are then conducted to identify the following list of violations, constraints or impacts. The PAC is encouraged to suggest other potential impacts to add to the list.

Category	Description of Constraint or Violation	Load Flow Simulation Required	Supplemental Analysis or Data Required	Additional Requirements
Over/Under voltage	Exceeds +/- 5 % from nominal	X		None
Line/equipment overloads	Exceeds normal/emergency ratings	X	X	Equipment ratings/limits not in db
Voltage regulation	Excessive LTC operation	X	X	Detailed (minute-by-minute) PV output
Reverse power	Reverse flow on mono-directional equip	X	X	Equipment w/o bi-directional capability
Fault duty	Exceeds FC ratings	X	X	Fault duty ratings
Protection coordination	Changes in settings or new devices	X	X	SCE criterion/requirements
Operational constraints	Load transfer constraints (e.g., maint.)	X	X	SCE criterion/requirements
Power quality	Voltage flicker	X	X	Detailed (minute-by-minute) PV output
Communications/SCADA	Needed for large or high penetration DG		X	SCE criterion/requirements
Network transmission	Interface constraints		X	CAISO study results (limits, $/MW)

[4] The CEC and CPUC are currently conducting a series of working-group meetings addressing inverter operation, including the use of inverter controls to adjust power factor in response to load shifts or changes in DG output, among other potential applications.

[5] Navigant does not plan to analyze the impact of tie transfers for each feeder, but has adopted this requirement as a general rule. A small number of cases will be selected to evaluate the impact of DG following the transfer of load for maintenance or outage restoration.

Solutions/Mitigation Options

The solutions that Navigant is using to address constraints and violations outlined in the prior section generally with those SCE identified in its May 2012 study, with some additional solutions expected for situations that may not have occurred in SCE's study. Several are listed below.

Voltage regulation equipment	Automation / SCADA additions	Overload mitigation (reconductoring)
Additional switches and feeder ties	Feeder breaker upgrades	Additional protective devices
Protection upgrades	Additional communication / telecom	New distribution lines or substations

In addition to the above, Navigant will consider DG control options such as communications and controls that will enable distribution operators to remotely and temporarily disconnect DG. This mitigation option might be suitable for high DG penetration cases where impacts occur for a very few hours per year. A more sophisticated option would include use of distribution management systems to continually monitor and automatically control DG generation.[6] PAC members are encouraged to suggest other options as well.

Using Milsoft, Navigant first identifies the number and magnitude or performance or loading violations that exist for each DG case, and then chooses the least cost solution from the above list or other applicable options. For most DG integration scenarios, the threshold at which the violation occurs is determined. The amount of DG added above the threshold enables a comparison of the cost to add DG in increasing amount versus the cost of mitigation.

The cost of mitigation options also align with costs SCE used in its May 2012 study[7], with some changes expected for some options, and new costs for solutions not included in the prior study.

[6] Navigant does not plan to include the cost of lost DG output in its analysis.

[7] Some of these costs were derived from actual costs incurred from upgrades SCE identified as a result of System Impact studies conducted for DG interconnection requests.

For transmission, the cost of upgrades or redispatch is obtained from CAISO's TRP or DG studies.

Study Outcomes and Presentation of Results

The primary objective of Navigant's study is to develop a methodology for estimating the cost[8] of installing up to 12,000 MW of DG in California under a range of integration scenarios. Recognizing that it is not possible to determine in 2013 the location, type and exact amounts of DG that will be installed, the CEC directed Navigant to determine how integration costs vary as key parameters and locational factors change. To underscore this distinction, the May 2013 SCE study found that integration costs varied from $2.1 to $4.5 billion, with the lower costs associated with 70 percent of DG located in urban areas versus 70 percent rural for the higher value; that is, guided versus unguided cases.[9]

Navigant's study builds upon SCE's results and includes sensitivity analyses across a range of parameters described previously. For both the base case and sensitivity analysis, DG integration costs are estimated, include how costs increase as the amount of DG approaches the 2020 target. Results will be presented in a family of curves that quantify and illustrate how DG integration costs vary as a function of key parameters and assumptions. The CEC expects to use this information both to inform the ongoing CPUC technical potential of local distributed photovoltaic study[10] and to provide policy guidance to help achieve statewide DG installation goals.

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[8] The methodology captures distribution upgrade and transmission constraint costs but does not capture transmission upgrade costs

[9] The unguided case corresponds to expected levels of DG additions, which is mostly in rural areas as it has higher DG potential and lower land cost, among other factors. The guided case assumes policies or incentives would encourage DG owners and developers to market and install DG mostly in urban areas.

[10] http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

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Exhibit 1

SCE-Navigant CYME/Milsoft Data Flowchart