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California Energy Commission

Clean Coalition Comments on Commission Staff IEPR Workshop

Distributed Generation: Electricity Infrastructure Costs and Impacts

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Introduction

Years of work by the Clean Coalition have helped culminate in the recognition of an urgent need and legislative mandate for California's major utilities to engage in proactive grid planning that realizes the full benefits of cost-effective, optimally deployed distributed energy resources (DER). Using the framework of the recently signed AB 327 (Perea), these comments will provide the Clean Coalition's recommendations for how California's energy agencies should direct the development of distribution resources plans and how to change key programs and processes to achieve AB 327's goals on an ongoing basis.

The Clean Coalition is a California-based nonprofit organization whose mission is to accelerate the transition to local energy systems through innovative policies and programs that deliver cost-effective renewable energy, strengthen local economies, foster environmental sustainability, and provide energy resilience. To achieve this mission, the Clean Coalition promotes proven best practices, including the expansion of Wholesale Distributed Generation (WDG) by renewable energy facilities connected to the distribution grid and serving local load. The Clean Coalition drives policy innovation to remove barriers to the procurement and interconnection of WDG projects, integrated with Intelligent Grid (IG) solutions such as demand response, energy storage, and advanced inverters.

Prior to AB 327, activities were underway at each of the major California energy agencies with respect to determining the value of DER and specifically, how the locational benefits of these resources should be considered in the planning of future investments in the electrical grid.

As noted in the staff workshop, the California Energy Commission's (CEC) 2012 Integrated Energy Policy Report (IEPR) Update included a Renewable Action Plan that called out the key strategies for transitioning from purely reactive distribution grid planning to proactive distribution grid planning. The first strategy focused on identifying the optimal locations for the deployment of distributed resources. Accordingly, the California Public Utilities Commission (CPUC) is already engaged in a process to determine some of the factors that would be included in the definition of "optimal", including a multi-year study on the value of deferring or avoiding distribution grid investments.

In parallel, the California Independent System Operator (CAISO) has just proposed the most significant change in recent history to its Transmission Planning Process (TPP). This change focuses on the potential for distributed resources to replace transmission or conventional generation projects under consideration. Again, this shows the State's agencies finally recognizing the need to proactively plan grid development with full consideration of the benefits of DER.

Following the Clean Coalition's 2011 and 2012 legislative pushes for "D-Grid Upgrade Plans", AB 327 brought together the above activities by requiring the state's Investor Owned Utilities (IOUs) to create distribution resources plans that account for the concepts of transparency, accountability, locational value, future-proofing and shared grid investments.

"Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources."

Utility distribution grid planning to date has been almost entirely reactive to DER, and the General Rate Cases (GRCs) have reflected little to nothing in terms of infrastructure investment for optimal deployment. AB 327 explicitly reverses this practice, requiring proactive planning.

But although the bill assigns the primary responsibility of creating the plans to the utilities, these plans cannot be done correctly in isolation. Each utility's plan must be developed and vetted in coordination with the other utilities, the State's major regulatory agencies, and stakeholders. Thus, the Clean Coalition's ultimate recommendation is for the CEC to take on the integration of these plans under a statewide Strategic Distribution Investment Plan (SDIP). Only such an integrated plan and process will be able to produce the best outcomes for all of California's ratepayers and to exceed the Governor's 12,000 MW distributed generation (DG) goal, which was recently re-emphasized as a key part of the AB 32 Scoping Plan.[1]

With respect to the questions posed in the Staff IEPR workshop, the primary answer is that yes, the CEC should initiate a pilot planning process to develop a distribution resources plan that fits all of the AB 327 requirements. For Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E), the target area should be the San Onofre Nuclear Generating Station (SONGS) replacement area, which has already been proposed for the SCE Living Pilot and the CAISO TPP Non-Conventional Alternatives pilot. Pacific Gas & Electric (PG&E) should choose an area that exhibits similar constraints and DER potential. Thus, the distribution planning pilot will include all the relevant locational issues and solutions and will be able to show immediate coordination with the CAISO TPP pilot. The pilot can grow into the full SDIP, which will serve as the ongoing, integrated planning umbrella under which the utilities create and regularly update their distribution resources plans.

[1] "If California meets its range of existing policy goals (such as 12,000 MW of renewable distributed generation by 2020)…it could reduce emissions by 2030 to levels squarely in line with achieving the 80 percent reduction goal by 2050." Climate Change Scoping Plan First Update, October 2013, pp. 77-78.

Locational Benefits

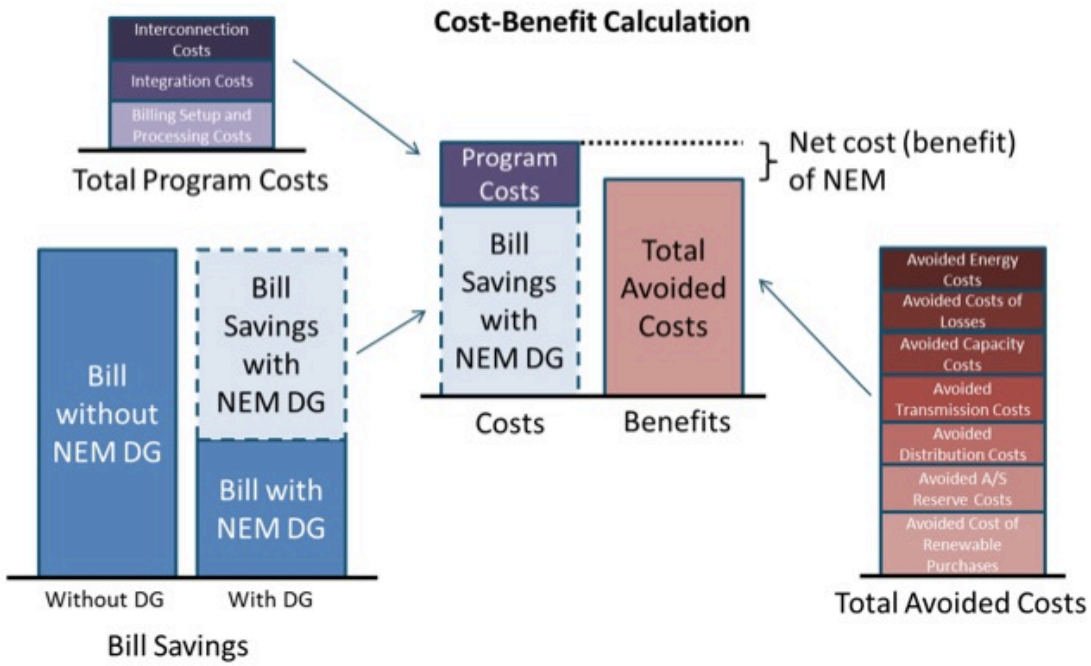
In 2011, the Clean Coalition initiated a bill, AB 1302 (Williams), to establish the idea that the State's major utilities should identify the optimal locations for the deployment of distributed generation (DG). The crux of this idea is how "optimal" is defined, i.e. what factors and calculations should be used to determine which locations are better than others. Those factors are generally termed "Locational Benefits"(LBs) and in the AB 327 context, the utilities are required to calculate those factors associated with the deployment of various types of distributed energy resources (DER), not just DG.

LBs in the form of direct cost savings to utility ratepayers include the following categories:

- Avoided costs associated with capital investments in expanding transmission and distribution grids
- Avoided costs associated with transmission infrastructure operation and maintenance (O&M)
- Avoided costs associated with congestion charges applied to energy sourced from constrained networks
- Avoided costs associated with transmission and distribution grid line losses of real and reactive power that occur as energy moves through the grid
- Value of greater electric system reliability, through greater geographic and resource diversity[2] and the distributed voltage control and voltage event ride-through capabilities of advanced inverters paired with DG and energy storage

[2] Distributed energy resources (DER) make communities less vulnerable to grid failures – the loss of several small resources would have much less of an impact on an energy system than the failure of a single central station power plant or transmission line. The DER approach allows for more geographic and technological diversity in a low-carbon energy portfolio, which decreases the impacts of generator variability on system reliability and enables renewable resources to serve a higher portion of demand. Greater geographic diversity decreases the effects of weather on aggregate output of solar and wind generators. Similarly, technological diversity makes it possible for low-carbon resources to serve demand during more hours during the course of a day.

A recent report by Energy and Environmental Economics (E3) on the value of net metering shows a spectrum of avoided costs associated with DG.



Source: NEM Study Introduction, E3, 2013

A more complete accounting of the full value of DER would also recognize LBs from economic value to citizens as well, such as those driven by separate "non-ratepayer" policy goals. These types of benefits include:

- Reduced pollution, particularly in highly impacted areas
- Planning factors such as rapid and efficient deployment, as opposed to delays and uncertainty related to central generation's environmental impact, permitting, and the availability of new transmission facilities
- Increased energy security and resilience
- Local community benefits through targeted employment, auxiliary land use, and new private investment

AB 327 delineates some specific locational benefits factors that must be included in the utility plans, but also requires the more general consideration of "any other savings the distributed resources provide to the electric grid or costs to ratepayers of the electrical corporation." The interpretation of this provision is expected to focus on the direct cost savings factors and not include the non-ratepayer benefits. Thus, these comments will only cover the non-ratepayer factors to the extent that the analysis of locational benefits by the CPUC has been too limited in scope to date.

While specific location within the distribution system is very important to consider, all resources located on the distribution system can have categorical value relative to generation feeding onto the transmission system. Thus, DER have substantial locational value since these resources are located on the distribution grid and allow utilities to avoid transmission infrastructure costs and a multitude of grid operation costs by producing and delivering power close to loads without use of transmission facilities. Such categorical values frequently exceed values specific to differences between individual locations within these categories. For example, all DG penetration below coincident peak load on the substation will avoid the significant charges associated with use of the transmission system: Transmission Access Charges (TACs), which are currently 1.5¢/kWh and rising rapidly. In addition, DG that is assigned deliverability offsets the Net Qualifying Capacity (NQC) need for far less efficient central generation and its associated transmission capacity.

Note that much of the avoided costs and locational benefits that can be credited to DER depend on a utility's ability to plan for and "see" the resources during grid operations. Critics of locational benefits efforts may point out that "behind-the-meter" DER is not visible to the utility and CAISO and cannot be planned for, and thus cannot actually save money in grid operations. However, the CAISO Non-Conventional Alternatives proposal includes use of behind-the-meter resources in preferred resource mixes to avoid investments in transmission and conventional generation.[3] Since the CAISO proposal does not include guidance on how such resources should be evaluated, the Clean Coalition recommends that the CEC take leadership on this issue.[4] For example, as described in detail in the Clean Coalition's presentation on flattening the CAISO "Duck" curve, behind-the-meter demand response programs may significantly reduce the need for "flexible" capacity by reducing daily ramps.[5] To the extent that visibility is critical for certain value factors, all of the agencies should encourage the acceleration of smart grid deployment for visibility of behind-the-meter resources.

Wholesale distributed generation (WDG) resources are generally visible to CAISO and represent the most significant opportunity for DG, by avoiding all issues associated with cost-shifting and non-owner occupied and multi-tenant properties; and representing a significant opportunity for Investor Owned Utility (IOU) investment.

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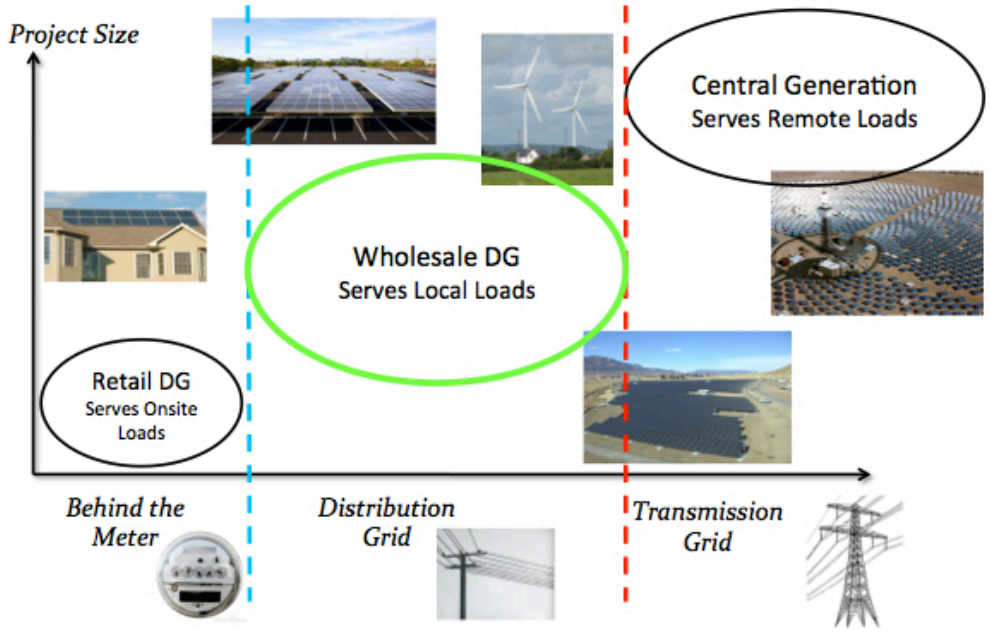
[3] Consideration of alternatives to transmission or conventional generation to address local needs in the Transmission Planning Process, September 2013. http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf

[4] Behind-the-meter DER resources include energy efficiency, demand response, retail distributed generation (RDG), electric vehicles and certain other energy storage facilities.

[5] See http://www.clean-coalition.org/resources/integrating-high-penetrations-of-renewables/

Figure 1: Energy Generation Market Segments



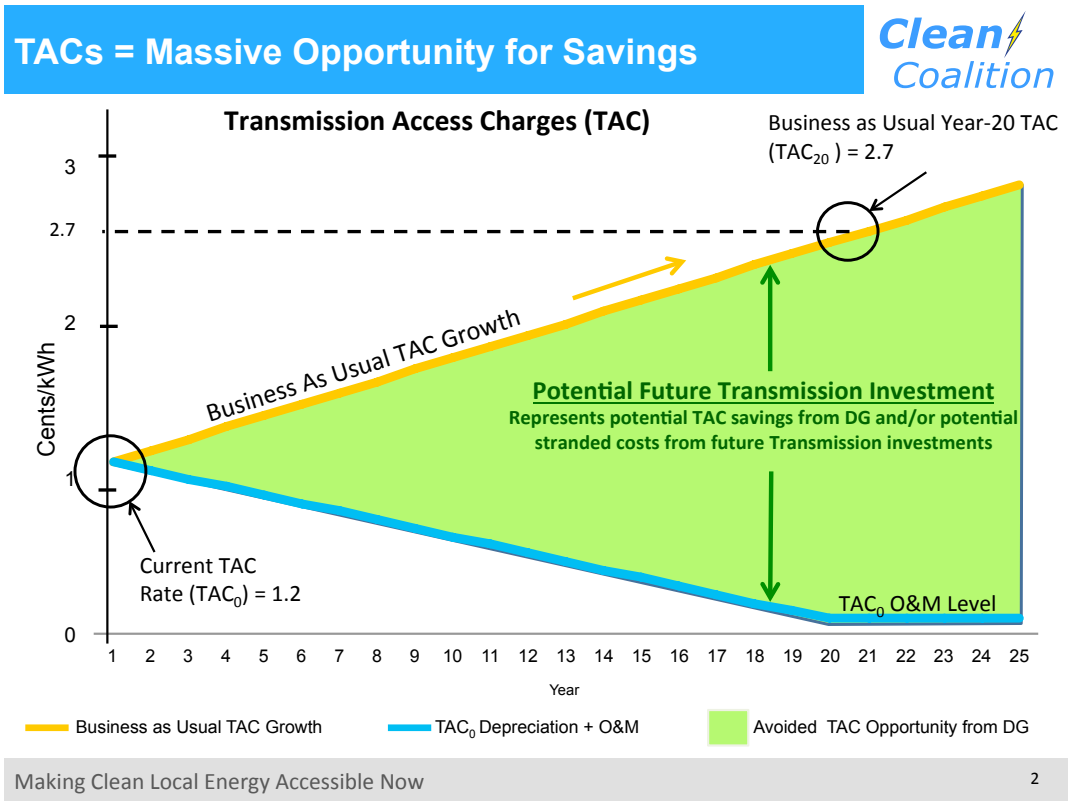
Benefits of Avoided Transmission Costs

Energy efficiency standards undertaken in California over the past 40 years have avoided the need for approximately three-dozen additional conventional power plants, and the associated transmission capacity that would have been required to deliver this avoided conventional energy to load. Clearly, reducing the need for transmission-interconnected generation directly reduces the need for transmission facilities and avoids the rapidly rising costs of new transmission facilities. The avoided transmission savings are significant and cannot be ignored. While it can be difficult to precisely determine the degree of deferred transmission and associated cost savings directly caused by each instance of distributed generation or efficiency, the aggregate impact is clear, and should be proportionally assigned to each project that contributes to deferred or avoided transmission expenditures.

Transmission related costs of delivering energy from remote generation are often combined into costs that are charged by the transmission operators. In California, these costs are called Transmission Access Charges (TACs). This is a flat "postage stamp" fee for every kWh delivered to the distribution system from the transmission grid. TACs are avoided when energy is delivered directly to the distribution system by DER to serve loads on the same substation (i.e., the transmission grid is completely avoided).

TAC rates have increased at an annualized rate exceeding 15% since 2005 as new transmission dependent generation has been approved, and new transmission capacity is far more costly than maintaining existing capacity. Deploying a DER project avoids needs to increase transmission capacity, which allows existing transmission investments to depreciate and preempts future investments in transmission – both of which reduce TACs, as reflected in the below diagram. .

Figure 2: Clean Coalition estimate of TACs



The orange "Business as Usual" line represents the expected growth in TACs as more investment is made in the transmission system to accommodate additional remote generation. The blue line represents the decrease in TACs that is possible if that remote generation was entirely replaced with DER (the down ramp is based on a 40-year average depreciation schedule for TACs-related assets like transmission lines).

Thus, the green wedge represents the potential cost savings achieved with DER. While it may be difficult to assign a specific value to each DER project, clearly DER projects should be credited with a portion of these tens of billions of dollars in potential savings.

In a recent example of avoided transmission costs, the Long Island Power Authority (LIPA) has offered a 7¢/kWh premium to 40 MW of favorably sited solar DG

facilities. This was done to encourage locational capacity sufficient to avoid $84,000,000 in new transmission costs. LIPA's analysis shows that investing in this solar DG instead of transmission will result in a net savings of $60,000,000 for its ratepayers. LIPA's guidance states: "The rate will be a fixed price…for 20 years applicable to all projects…plus a premium of $0.070 per kWh paid to projects connected to substations east of the Canal Substation on the South Fork of Long Island."[6]

Appendix A contains additional details on avoided transmission grid costs, avoided congestion benefits, and real world examples of the use of these factors.

Benefits of Avoided Distribution Costs

Generation close to load can defer or avoid the need for some distribution grid capital expenditures as well. The cost of operating, maintaining, and upgrading the electricity distribution system is a major component of the cost of delivered energy. Existing distribution systems are designed with sufficient capacity to deliver peak power loads from remote large-scale generators to every corner of a utility's service territory. When new DER are sited closer to load, less distribution capacity is required to transport electricity from remote generators. As a result, DER can allow utilities to defer or reduce the scope of capital investment in upstream distribution capacity upgrades.

The avoided distribution costs of replacement resources depend on the specific siting of replacement projects and the resource profile of these projects. These factors will determine whether local generation will reduce the costs of maintaining the existing distribution grid and displace or defer planned investment in distribution grid upgrades and expansions.

The correct methodology by which the utilities can calculate and properly credit DER for avoided distribution grid capacity costs is still an open question. Some of the latest research and thinking is being done within the California regulatory agencies. A September 2011 report commissioned by the CPUC showed that the locational benefits value of clean local energy can be greater than 5 cents per kWh from avoided distribution investments alone.[7] More recent studies on this topic are discussed below.

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[6] Proposal Concerning Modifications to LIPA's Tariff for Electric Service, FIT070113 http://www.lipower.org/pdfs/company/tariff/proposals-FIT070113.pdf

[7] E3 Using Avoided Costs to Set SB32 Feed-in Tariffs, SB32 Workshop, CPUC, September 26, 2011, available at: http://www.cpuc.ca.gov/NR/rdonlyres/90AA83C6-1AAC-4D7E-966E-299436C4A6BD/0/E3FITAvoidedCosts9262011.pdf

Benefits of Avoided Line Losses

Energy is lost throughout the system in relation to the distance, voltage, and carrying capacity of the lines involved in transmission and distribution. According to the U.S. Energy Information Administration, national transmission and distribution real energy losses average 7% of all transmitted energy.[8] Energy losses range well above average during peak load periods, when congestion and heat effects are highest; this is one reason that time-of-delivery profiles of proposed replacement resources is a major consideration in the avoided costs valuation.

Obviously, DER sited close to load will avoid much of the line and congestion losses associated with energy that is sourced from afar. The locational benefits of avoiding these losses are straightforward to quantify and thus are less controversial in designing locational benefits policy. Several examples of utilities that have quantified avoided line loss savings are as follows:

- *Austin, Texas*: Value of Solar Tariff credited DG with $0.007/kWh for line loss savings.[9]
- *PJM*: Calculated line losses as 3.4% of overall costs.[10]
- *Palo Alto, CA*: Included $0.0062/kWh over 20 years as avoided line losses for DG projects in their CLEAN Program.[11]

Local Voltage and Reactive Power Benefits

Forward-thinking utilities are now starting to develop policies to capture the benefits of the advanced inverters that are installed as part of virtually every DG and energy storage project at commercial-scale or larger (the reason for this is that almost all inverters are designed for the German market where reactive power provisioning is required in all DG projects larger than 3 kW). The capabilities of these inverters can prove highly beneficial to grid operations as well as reduce the losses involved in voltage support and reactive power provisioning. Since the losses incurred over distance are considerably higher for reactive power than for real power, the locational benefits of local reactive power provisioning from DER are very significant, as illustrated in the following chart.

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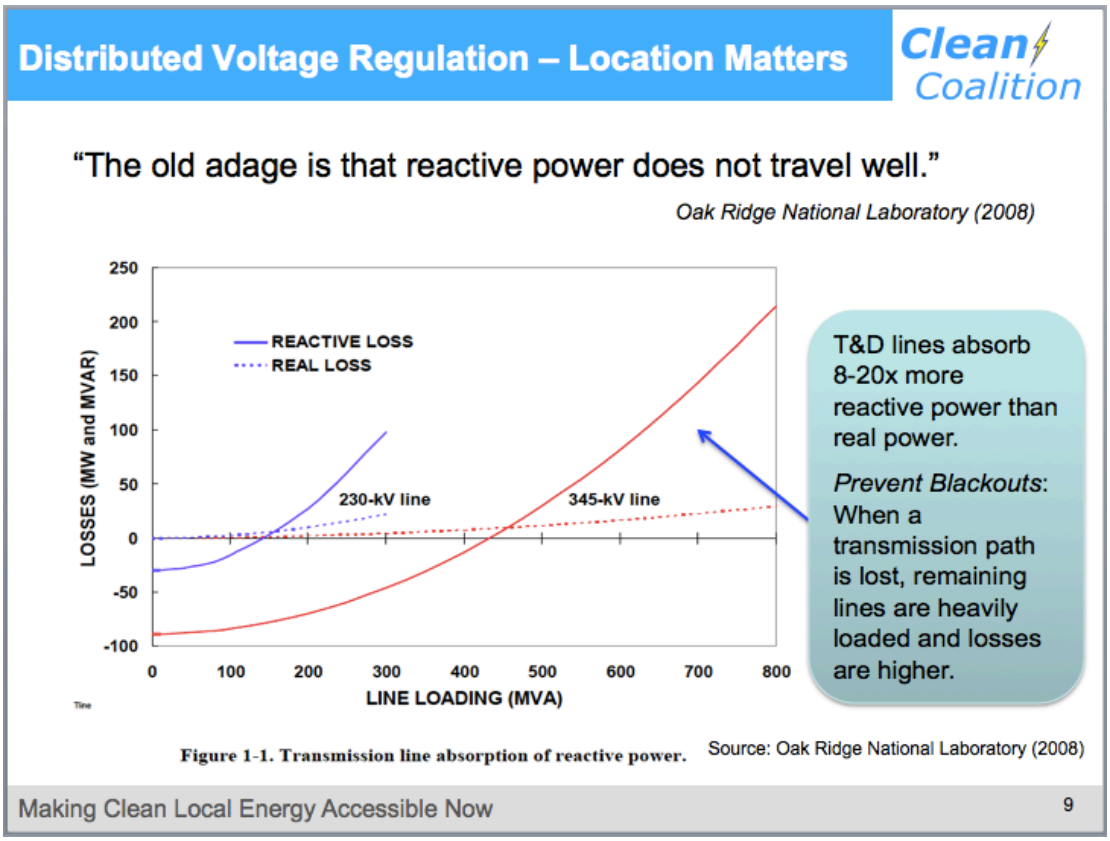
[8] U.S. Energy Information Administration, Frequently Asked Questions, "How much electricity is lost in transmission and distribution in the United States?" 2011, *available at* http://www.eia.gov/tools/faqs/ faq.cfm?id=105&t=3.

[9] The Value of Distributed Photovoltaics to Austin Energy and the City of Austin, 2006, available at: http://imaginesolar.com/wp-content/uploads/2011/09/pv-valuereport_secured.pdf

[10] Quarterly State of the Market Report for PJM: January through September 2012, Section 10: Congestion and Marginal Losses http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012/2012q3-som-pjm-sec10.pdf

[11] Overview of Parameters to Consider Regarding Implementing Feed-in-Tariffs for Solar Photovoltaic Systems in Palo Alto, February 2, 2011. Palo Alto Utilities.



Appendix B contains additional details on the locational benefits provided by advanced inverters paired with DER.

Latest CPUC Study on DG Benefits

The most recent work from the CPUC regarding the locational benefits of DER is included in the Draft California Net Metering Evaluation issued on September 26, 2013. The Cost-Benefit Analysis sections of the E3 technical report describe the avoided costs methodology that E3 used to evaluate the benefits of distributed solar PV.

Since this study constitutes the most recent precedent for the CPUC to establish locational benefits methodologies, it is important to distinguish what factors will be useful for defining optimal locations in the utilities' distribution resources plans. In general, while the studied factors provide insight into the general system value of DER as compared to remote, central station generation, the methodologies are not particularly useful in specifying where on the distribution grids the resources should be deployed.

The primary factors considered in the avoided cost analysis include:

- *Energy value based on climate zones*: This distinguishes the difference in the value of the energy with respect to demand, but only separated into 16 large zones across the state.
- *Line losses:* The value adjustment factors for line losses are set at the utility level downstream of the transmission system. Thus, transmission and related voltage conversion losses were ignored.
- *Distribution investment deferral*: This analysis was the primary factor that accounted for location specific value. However, the values here are very small relative to the other benefits factors.
- *Transmission avoided costs*: These factors were ignored by the study, missing a very significant component of locational benefits, especially as alternatives to new transmission investments
- *Ancillary services:* This study only considered services that are avoided from additional behind-the-meter DG. It did not include the services that wholesale DER could provide to the grid, such as local voltage regulation.

Locational Benefits Recommendations

In the development of the AB 327 distribution resources plans, the California agencies should establish a consistent standard by which factors are included in the determination of locational benefits and how those factors are calculated. For a truly optimal plan, all of the above-described key factors must be included with an emphasis on categorical values with the largest significance in order to avoid bogging down the process with debates over the exact categorical values having relatively negligible significance.

This standard should be based on a single, central methodology coordinated by the CEC that accounts for not only the IOU distribution planning and GRC cycles, but also the CPUC Long Term Procurement Planning (LTPP) proceeding and CAISO TPP. The IOUs can coordinate directly with the CEC to ensure consistency across factors such as:

- Evaluating system needs (in synch with the CEC demand forecasts)
- Avoided costs calculations
- Safety and reliability benefits

The CEC can also act as a bridge between the CPUC and CAISO so that the distribution resources plans do not ignore transmission system benefits and potential grid services value provided by DER. And finally, as was mentioned in the Staff IEPR workshop, the CEC has the breadth of scope to include locational benefits such as land impacts and GHG/AB32 value.

All of the work regarding locational benefits should be combined under a joint Strategic Distribution Investment Plan (SDIP) proceeding. In this manner, all of the dependencies between agencies and processes can be captured and consistency can be maintained across agency activities. This proceeding should be initiated immediately so that this consistency can be established from the earliest stages of the distribution resources plans development.

Tariffs, Programs, and Practices

Establishing a usable, consistent methodology for locational benefits and defining optimal deployment is a critical first step in distribution grid planning but is insufficient by itself. This methodology must translate into effective changes in tariffs, programs, and practices. AB 327 requires the utilities to propose these changes in two provisions:

"Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives."

"Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources."

As detailed below, current regulatory programs and activities are not well suited to achieving the objectives of these provisions.

Procurement

None of the current CPUC approved procurement programs for distributed resources have adequate mechanisms to direct deployment towards maximizing locational benefits and minimizing location relevant costs.

- Locational benefits are not considered in the Renewable Portfolio Standard (RPS) solicitations, despite statutory direction to reform the Least Cost Best Fit (LCBF) methodology for selecting RPS projects.[12]

- Despite statutory direction, the CPUC failed to include locational benefits in the implementation of the SB 32 / Re-MAT program.[13]

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[12] Second Assigned Commissioner's Ruling Issuing Procurement Reform Proposals and Establishing a Schedule for Comments on Proposals available at http://www.cpuc.ca.gov/NR/rdonlyres/5DCD1A21-838B-4D0B-866D-B00DBF9220DA/0/SecondFerronACR.pdf

[13] Decision Revising Feed-In Tariff Program… available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/167679.pdf

- The Renewable Auction Mechanism (RAM) includes an adjustment for added costs based on location relative to transmission grid issues but does not credit projects for providing locational benefits.[14]

- The LTPP only considers deployment location in the procurement plans at the level of large regional needs, such as the SONGS replacement area, but does not otherwise consider locational benefits in its procurement targets.

- The CPUC has initiated a process by which locational benefits can be evaluated for inclusion in DG procurement programs, but this study is missing many of the largest identified benefits factors and is not certain to produce meaningful results within the initial AB 327 timeframe.

- None of the programs associated with Demand Response include consideration of locational benefits. These programs are only just now considering locational dispatchability, a prerequisite for capturing locational value for demand response

- For energy storage, procurement RFPs are targeted at grid areas where storage would be highly valuable, but no storage procurement methodology has attempted to quantify and reward locational benefits.

Interconnection

Most distributed resources will use the Rule 21 interconnection tariff when connecting to the grid. Over the last several years of Rule 21 reform, there has been little progress in minimizing costs and/or directing DER deployment based on locational benefits.

Navigant Study

The narrow focus on minimizing interconnection and integration costs limits the use of the analytical framework presented by Navigant to just a portion of the determination of optimal locations.[15] Total cost, net cost/benefit, and cost allocation considerations are necessary before some of the conclusions can be applied to policy.

In addition, scenarios should include consideration of cost reducing or value enhancing technical solutions that are reasonably anticipated to be applicable

[14] Decision Adopting the Renewable Auction Mechanism available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/128432.pdf
[15] Draft Framework – DG Integration Analysis - http://www.energy.ca.gov/2013_energypolicy/documents/2013-08-22_workshop/DG_Integration_Study_Draft_Framework_Workshop_Doc.pdf

during the deployment period. Such solutions comprise a range of intelligent grid technologies and operating characteristics, including advanced inverter functionalities, auto-response distributed demand management systems, electric vehicle integration, and localized energy storage. Each of these offer applications that support higher penetrations of DG at lower cost than conventional grid modifications while also realizing substantial direct benefits.

The study recognizes differences in interconnection costs among DG siting categories, but without consideration of cost allocation in procurement decisions, this is insufficient to establish effective siting preferences. Under current practice, ratepayers do not reimburse DG developers the cost associated with interconnection or distribution grid upgrades, and are therefore indifferent to such costs per se. But, ultimately ratepayers are not indifferent to the value of such upgrades to the system, or the value of costs avoided by preferred locations and the inherent ratepayer savings.

While identification of high and low cost interconnection locations is valuable to system owners, neither the State, the ratepayers, nor the utility has an interest in "preferring" a location for which they are indifferent to the cost, especially if the cost is not reflective of the relative total value of the site to the system owner. As such, while the study methodology appears well developed, it is unclear how the results could be applied in establishing any public preferences in siting DG. The information may be useful in distribution planning, but only if efficient system upgrades are directed toward sites of interest to future system owners, which again requires consideration of both net cost and value from the system owner perspective.

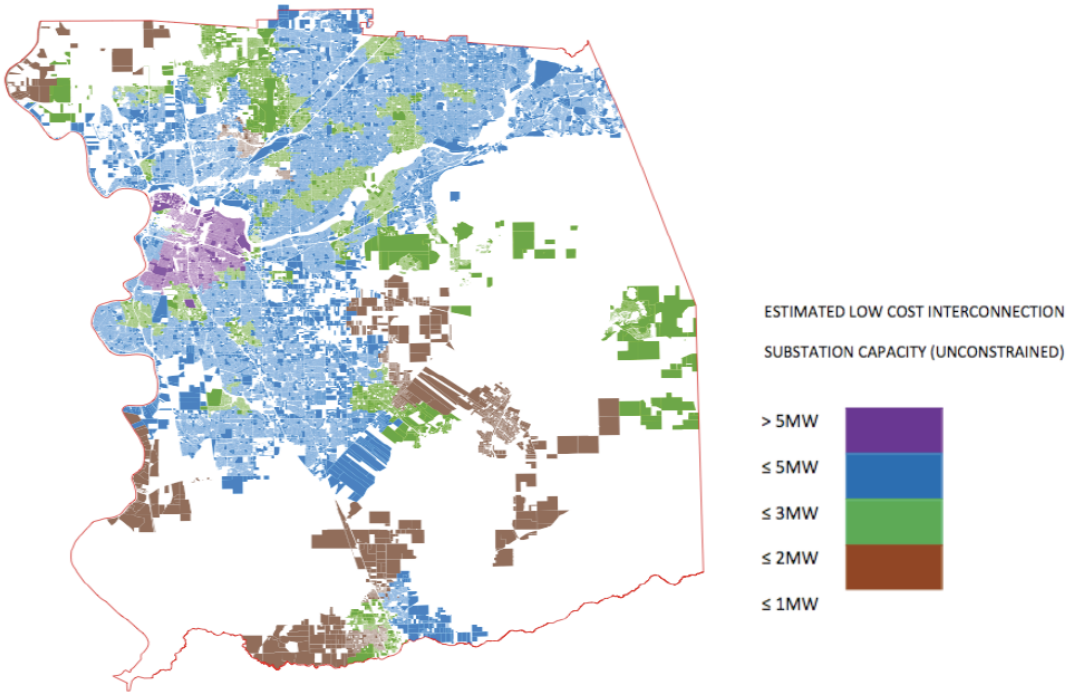
Siting Guidance

Once the locational benefits of DER have been understood and optimal locations identified, the interconnection process should be improved with the publishing of effective information to the DER market. Interconnection is often the most difficult, complex, and time-consuming aspect of the development process. This is particularly true for smaller developers, whose projects can easily be rendered uneconomic by large shifts in interconnection costs and timelines. For this reason, the Clean Coalition has been a strong advocate of increased provision by utilities of information and guidance on siting and cost containment, and access to interconnection data for applicants.

Efforts to date have been limited to interconnection of DG and have not provided guidance to other types of DER. These efforts generally include some combination of advice sheets, circuit maps, circuit capacity and queue data, dedicated web pages, pre-application reports, and/or customer support from staff. The balance between these forms of support will be specific to individual utilities based on the level of customer demand and formats in which data is already accessed. For a smaller local

utility with occasional requests, guidance can often be effectively provided by direct communication. Where demand is higher, published materials efficiently provide information before staff are needed to address questions.

Example: Sacramento Municipal Utility District released a static map to support its feed-in tariff program



In response to the level of activity in DG interconnection in California, siting maps have been released by SCE, PG&E, and SDG&E in support of their DG procurement programs. While these maps have proven somewhat useful to developers, all will likely need to be fixed or redesigned for publishing the new information that will come from the distribution resources planning processes.

For a more detailed review of current efforts to guide DG deployment as well as the Clean Coalition's further recommendations for improvement, please see Appendix C.

Planning Proceedings

Current regulatory planning processes have failed to fully consider and incorporate future DER. This shortsightedness comes from an outdated paradigm where the only DER considered to be available were energy efficiency and behind-the-meter DG, and thus the thinking was that DER could not be predicted or managed to support grid operations. In reality, future DER will be increasingly connected on the "system-side" of the meter with wholesale arrangements and grid-operator

visibility. Furthermore, even customer side DER will, in aggregate, be highly predictable based on both the operational experience of system operators and the timely record provided by near universally installed advanced metering devices.

The distribution grid investment portions of the IOU General Rate Cases (GRCs) have given minimal consideration to DER in the past. Planned capital expenditures are based on forecasts of future demand and the need to maintain reliable service as demand changes. In this way, DG is accommodated through often costly retrofits or only treated as demand reduction to which the utility can only react to, rather than anticipate and plan for. At a minimum, most major investments in the GRC should be evaluated against a possible alternative set of distributed resources, with appropriate capabilities to accommodate such resources and realize their value.

Similarly, until the most recent LTPP cycle, long-term planning treated DG only as demand reduction and the scenarios did not consider wholesale DG as a supply side resource. The disconnect here was glaringly obvious when even the High DG LTPP scenario failed to plan for as much DG as the Governor's 12,000 MW DG goal. Further disconnects were apparent when the CAISO's inputs to the LTPP scenarios gave no credit to the potential for considerable amounts of demand response resources.

However, the CAISO has recently proposed a strong step towards properly including DER in grid planning with its proposal on non-conventional alternatives to transmission and conventional generation. This proposal acknowledges that a mix of DER can be a viable alternative to expensive transmission related investments and thus, planning for DER can provide significant ratepayer savings.

Tariffs, Programs, and Practices Recommendations

The coordination of these related procurement, interconnection, and planning activities should occur under the recommended Strategic Distribution Investment Plan (SDIP) proceeding. This is the only way that the disconnects can be surfaced and the objectives of the distribution resources plans can be achieved. It is critical that the SDIP be an integrated, transparent process rather than a secret one that allows each utility to modify its programs and practices independently.

The SDIP should accelerate the incorporation of locational benefits calculations into all of the utility procurement processes. The AB 327 mandate and the DER market cannot wait for the CPUC, which has had over 4 years to make progress on locational benefits with little to show for it. As soon as practical, the current procurement mechanisms should be modified or new mechanisms created to direct deployment to the high value locations. The precedent for this has already been established with examples like the targeted storage procurement conducted by SCE as part of its LTPP requirements.

Then, the utilities should quickly upgrade the interconnection tools for providing siting guidance according to the optimal locations. Immediate fixes can help identify locations for low cost interconnection. Further redesign should begin now in anticipation of presenting optimal location data.

Finally, the LTPP and TPP processes should ensure that the next cycle of planning fully puts California on the path towards achieving the Governor's 12,000 MW DG goal. Not only has the goal recently been validated by the AB 32 Scoping Plan, the Clean Coalition expects that when the full value of DER is realized in California energy system planning, the ratepayers will be best served by deploying DER far in excess of the goal.

Future Proofing and Technical Standards

The Clean Coalition has long advocated for the concept of "future proofing" the electrical grid. Future proofing involves evaluating all grid investments in comparison to future needs of the system and ensuring that money spent today is done so wisely, in the best long-term interests of the ratepayers. In some cases, while the "sticker price" of a wise investment may look higher today, anticipating future needs saves ratepayers money in avoiding expensive retrofits or upgrades later.

This concept was expressed in the Clean Coalition's 2012 bill, AB 2341 (Williams). AB 327 then turned this concept into a requirement with Section 769 (b)(4):

"Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers."

Thus, at a minimum, the CPUC must ensure that the proposed distribution resources plans translate into the appropriate forward looking investments in each utility's GRC. Furthermore, each proposed capital project in the GRC must be evaluated and justified such that it properly prepares the grid for future deployment of DER.

Within the recommended Strategic Distribution Investment Plan (SDIP) process, the CEC can promote future proofing with respect to illuminating the technical standards and latest capabilities of distribution grid technologies. The CEC should also coordinate with the CAISO on the types of technologies that should be deployed in the distribution grid for efficient grid management of the planned distributed resources.

With regard to technical standards, the Clean Coalition has worked extensively with the CEC and the CPUC on changing interconnection requirements for reducing the barriers to deployment, as well as Intelligent Grid (IG) standards that support

higher penetrations of DER at lower cost and with full access to the extensive grid services that DER can provide – these grid services including the balancing of system power, voltage, and frequency[16]. AB 327 further calls out this work in Section 769 (b)(5):

"Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service."

One such standard is IEEE 1547 governing the use of advanced inverters. As described in Appendix B, the use of advanced inverters with distributed resources can provide very substantial locational benefits and should be a key component of the utility's distribution resources plans. Since these inverters are already in use around the world, including throughout the United States, the CEC and CPUC should expeditiously modify the regulations to allow California ratepayers to realize those benefits as soon as possible[17].

Shared Distribution Grid Investments

Ultimately, all of the Clean Coalition work on proactive grid planning culminates in a fundamental change in the approach to investing ratepayer money in the electrical system: Where the deployment of distributed resources provides better value and high benefits to ratepayers, the investment of ratepayer money in the infrastructure to support this deployment is both justified and necessary. Prior to AB 327, this was most recently expressed in the development of the Clean Coalition's 2012 bill, AB 2340 (Williams).

Thus, it is fitting that Section 769 of AB 327 concludes:

"Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable."

With this provision, California law removes the outdated paradigm that wholesale DG developers must pay for all distribution grid upgrade expenses related to their deployment. And, California policymakers and utilities must finally acknowledge that distributed resources represent far more than just costs to the system as they can provide net benefits that are worthy of ratepayer investment.

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[16] "DG+IG Enhances System Reliability and Efficiency", Clean Coalition. Available at: http://www.clean-coalition.org/resources/dgig-enhances-system-reliability-efficiency/
[17] "Advanced Inverters – Recovering Costs and Compensating Benefits", Solar Server. Available at: http://www.clean-coalition.org/site/wp-content/uploads/2013/10/October2013_SolarServer.pdf

Conclusions

For all the reasons described above, the CEC should quickly initiate a joint proceeding to develop and coordinate all the distributed resources planning under an integrated statewide Strategic Distribution Investment Plan (SDIP).

Then, as suggested in the Staff IEPR workshop, the CEC should initiate a planning pilot for the SDIP that coordinates all the activities with a focus on one or two high impact areas. This should be done immediately so that the findings and methodologies can be incorporated into the IOU distributed resources plans due July 1, 2015.

The high impact areas should be selected based on the following key attributes:

- Any area with significant Local Capacity Requirements. Distributed resources planning must be conducted quickly enough to forestall expensive transmission system investments and to prevent the commitment of ratepayer money to non-preferred resources investments.
- Any area with other special local needs. Such needs include nuclear and Once-Through Cooling (OTC) retirements and local air quality issues.
- Any area where a new conventional power plant is in consideration.

The San Onofre Nuclear Generation Station (SONGS) area is the most appropriate first choice to pilot the integrated SDIP in SCE and SDG&E territories. Many of the activities and proceedings have been converging on this region, and the plans for replacing SONGS are currently the most likely to risk ratepayer money on non-preferred conventional resources.

Although AB 327 does not specify such, the distribution resources plans should not be a one-time effort. The result of the planning pilots should be an overall framework and ongoing process for distribution resources planning and coordination. Thus, all of the experience and lessons learned from the development of the initial plans due in 2015 should be incorporated into an ongoing SDIP proceeding with the objective of producing new plans at least as frequently as the 3-year GRC cycle.

Finally, to tie the AB 327 distribution resources plan activities together with economic development, land use planning, and other areas that could experience significant benefits, the CEC and the Governor's office should create a new position similar to the recently created Zero Emission Fueling Infrastructure Ombudsman: A Distribution Resources Planning Ombudsman would similarly convene working groups and develop strategies to accelerate and remove barriers to the optimal deployment of DER.

Respectfully submitted,

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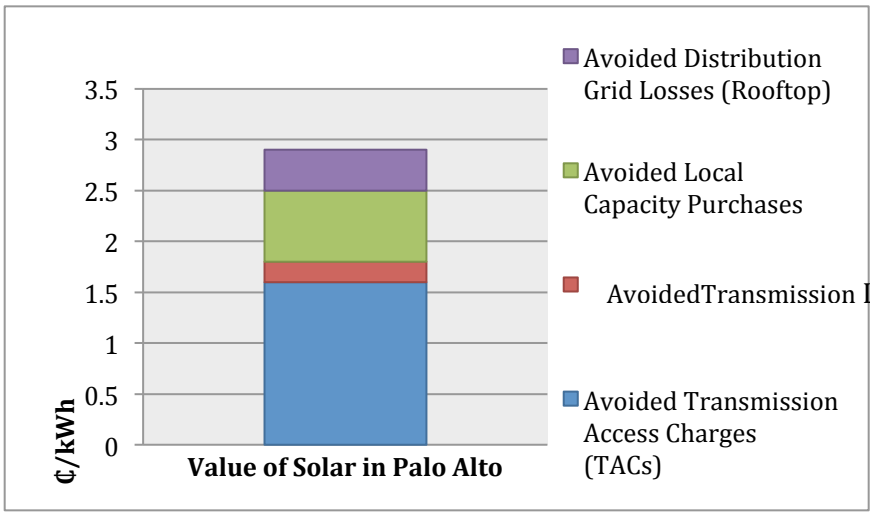
Appendix A: Transmission and Congestion related Locational Benefits

Transmission Cost Examples

The City of Palo Alto Utilities conducted a study of the value of local solar relative to non-local energy in 2011[18], including local capacity value and transmission costs, and reflected this value in its procurement offers. For Palo Alto such generation avoided charges the utility would otherwise incur for use of the external transmission system, in addition to line losses and capacity charges related to the transmission and generation resources reserved to meet the utilities peak demand.

In establishing the value of avoided transmission charges, the Palo Alto Utilities recognized that the current transmission usage charge of 1.2¢/kWh had been rising and was expected to reach 2.7¢/kWh during the 20 year contract terms of local solar generation. The utility therefore used the levelized value of these costs, calculating them at approximately 1.6¢/kWh.

Figure. 1. *Palo Alto Utilities avoided cost calculations.*



Source: City of Palo Alto

In 2012, the Los Angeles Department of Water and Power (LADWP) reached similar conclusions for its 100 MW CLEAN LA solar feed-in tariff program. "Energy from these large out-of-basin projects must be brought to LA at an additional cost of $0.03/kWh for transmission, distribution, and losses." Thus, DG serving local needs

[18] Renewable Feed-in Tariff Program Adoption Attachment E: Renewable FIT Program Pricing Methodology. City of Palo Alto, City Council Staff Report (ID # 2329) 12/12/2011. http://archive.cityofpaloalto.org/civica/filebank/blobdload.asp?BlobID=30132

was valued at 3¢/kWh above the value of non-local sources, and this differential was reflected in prices offered.

The following chart is a simplified comparison of the full cost to ratepayers of different types of generation when Transmission and Distribution costs are factored in. These numbers are illustrative of the costs in California from 2011.

Total Ratepayer Cost

	Distribution Grid					T-Grid
PV Project size and type	**100kW roof**	**500kW roof**	**1 MW roof**	**1 MW ground**	**5 MW ground**	**50 MW ground**
Required PPA Rate	**16¢**	**15¢**	**13¢**	**9-11¢**	**8-10¢**	**7-9¢**
T&D costs	**0¢**	**0¢**	**0¢**	**0¢**	**0¢**	**2-4¢**
Ratepayer cost per kWh	**16¢**	**15¢**	**13¢**	**9-11¢**	**8-10¢**	**9-13¢**

Sources: CAISO, CEC, and Clean Coalition, Nov2012; see full original analysis from July 2011 at www.clean-coalition.org/studies

Challenges to Transmission Cost Savings

A claim has been made that if the transmission required for the energy policy goals (like an RPS program) is already committed, adding DER will not avoid these transmission costs. However, this misses the critical point that reducing the use of this new transmission capacity allows every MW of transmission capacity not utilized for energy that is provided by DER to be available for other transmission requirements. Even with DER reducing the immediate need for transmission planned in conjunction with policy goals, anticipated future increases in renewable generation, if not met entirely by DER, will make use of such transmission facilities.

Meanwhile, the opportunity to defer construction until that time has very substantial value. An upgrade should be deferred if required reliability levels can be maintained without the upgrade. Incentives to attract DER to avoid an upgrade should be based on the value of avoiding the upgrade relative to the cost and value of improvements that are achieved by added DER.
(This is similar to FERC Order 1000 initiatives regarding non-transmission alternatives to potential transmission upgrades).

Likewise, to the degree that transmission planning is assumed to already include quantities of DER, it is sometimes claimed that any avoided transmission is already assumed, and therefore, no avoidable transmission costs should count. This also is fundamentally flawed reasoning – avoided costs must include the cost of the alternative/default resource that would be incurred if the option under study were not used. If DER is not deployed, all non-DER energy will need to be provided through transmission services.

The DER included in transmission planning should be assigned the value of the transmission that would otherwise have been required. Even if grid operators can use existing capacity, this existing capacity is then used up, and if this capacity is no longer available for other future needs, additional capacity will be required for those needs that could otherwise have been avoided/deferred by DER.

Benefits of Avoided Congestion Costs

Congestion refers to the existence of limitations on the grid's ability to transmit power through a specific point or path on the grid, which results in a higher cost of electricity due to increased losses as transmission capacity is approached. Congestion costs and relief values can be attributed directly to the node causing or relieving the congestion. Ideally, a generator that relieves congestion should be paid a premium that reflects the locational benefits provided, and a generator that causes congestion should receive a lower price for the congestion costs associated with the energy it produces.

Congestion is typically caused by a lack of transmission or distribution capacity, but it is often a reflection of locational imbalance between generation, load, and transmission resources. For example, generation or load pockets may exist which stress the transmission or distribution system due to limited capacity at the location of the load or generation source. The flow of power, the loading and temperature of lines, and the voltages of the system all affect system congestion.

Unfortunately, there are no uniform reporting requirements for congestion costs. Substantial data are available from the regions with organized markets (CAISO, ISO-NE, MISO, PJM, NYISO, SPP), but much less are available from the non-market regions, which cover at least 33% of the nation geographically. Furthermore, data from the regions with organized markets are often not comparable. Each RTO and ISO has its own definitions, practices, and formats for calculating and publishing Locational Marginal Prices (LMPs) and congestion costs.

For example, the regional transmission operator, PJM[19], calls congestion costs a "Loss Penalty Factor" and the following table provides an example of the relative scale of those costs to overall transmission costs.

Table 10-14 Total PJM congestion (Dollars (Millions)): January through September for calendar years 2008 to 2012 (See 2011 SOM, Table 10-14)

	Congestion Costs (Millions)			
(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778.2	NA	$26,979.0	6.6%
2009	$543.6	(69.4%)	$19,927.0	2.7%
2010	$1,134.3	108.7%	$26,249.0	4.3%
2011	$874.9	(22.9%)	$28,836.0	3.0%
2012	$425.2	(51.4%)	$22,119.0	1.9%

Source: Monitoring Analytics[20]

Depending on the utility, congestion costs may be combined with transmission planning and capacity costs, so the calculation of congestion benefits and avoided transmission benefits from DER would be combined. Most utilities' automatic reaction to congestion issues is to add more transmission facilities, so it is vital that DER be positioned for proactive consideration relative to transmission for relieving these issues.

Because the concept of proactively considering DER is foreign to most transmission operators, a useful reference is the California Independent System Operator (CAISO) proposal put forth in 2013, which states: "energy efficiency, demand response, renewable generating resources and energy storage…such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure…this paper also describes how CAISO will apply the proposed methodology in the current (2013-2014) transmission planning cycle."[21]

[19] PJM is the regional transmission operator (RTO) serving all or part of 13 states and the District of Columbia
[20] Monitoring Analytics, "PJM State of the Market -2012", http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml
[21] CAISO, "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process", http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf

Appendix B: Benefits provided by Advanced Inverters

Advanced inverters paired with distributed solar PV or storage facilities can provision reactive power 24 hours a day, regardless of whether the sun is shining. Advanced inverters can draw real power from the grid and convert it to reactive power, in the same manner as capacitor banks and synchronous condensers.

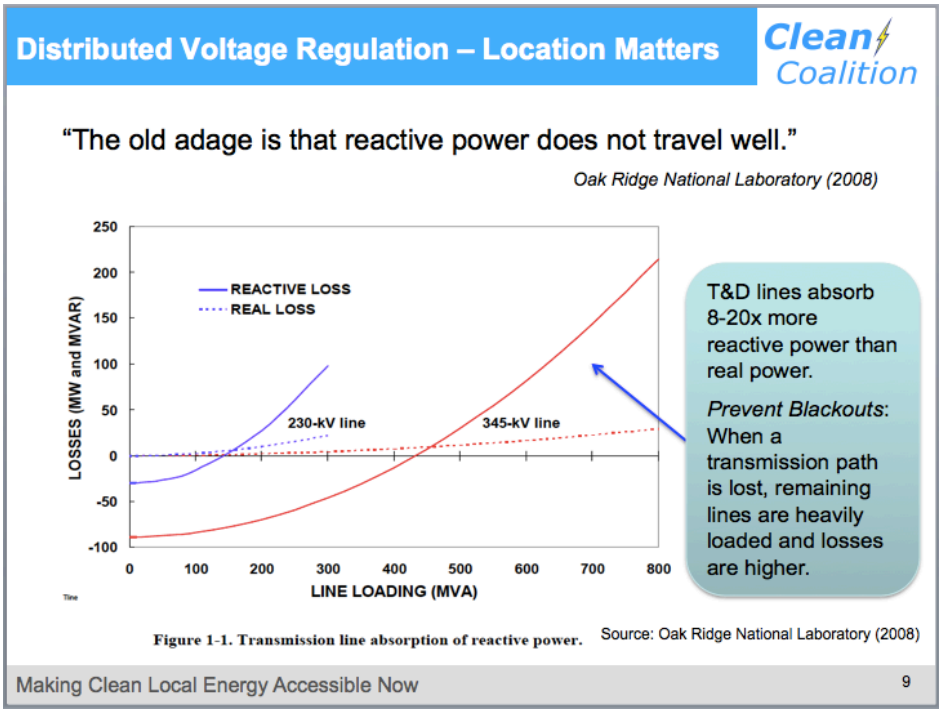
The Rule 21 Smart Inverter Working Group (SIWG) and CPUC storage use case studies have found that the implementation of advanced functions for inverters paired with distributed generation and storage can cost-effectively improve the reliability and power quality of the power grid. Further, the SIWG discovered that the European experience has shown that timely implementation is critical for avoiding costly upgrades and replacements in the future.[22]

Forward-thinking utilities across the country are embracing advanced features inherent in almost all inverters that are deployed throughout the world today. For example, Georgia Power's recent wholesale DG procurement programs require solar generators deploy advanced inverters that provision reactive power in exchange for compensation.[23] Similarly, a group of Western utilities, including the California investor-owned utilities, is working to make advanced inverters mandatory for all new solar facilities within their service territories. In a letter dated August 7, 2013, the Western Electric Industry Leaders (WEIL) urged state policymakers to encourage the "immediate" and "widespread" adoption of advanced inverters, which they called "simple and inexpensive devices" that will play a "transformative role" in voltage control.[24]

Advanced inverters are not just a solution for integrating variable renewable generators – distributed voltage control can make the power grid more reliable and efficient system-wide. A report by the Oak Ridge National Lab found that distributed voltage control significantly outperforms centralized voltage control. Reactive power suffers far greater line losses than real power, and those losses increase as a line is more heavily loaded, as illustrated in the below chart. Distributed reactive power minimizes these significant reactive power line losses.

[22] CPUC Rule 21 (R.11-09-011) "Recommendations for Updating DER Technical Requirements in Rule 21" Version 2, September, 2013, pg. 1.
[23] See Section 1.8 of https://www.weboasis.com/OASIS/SOCO/Interconnection/SGIA.pdf
[24] www.weilgroup.org/WEIL_Smart_Inverters_Letter_Aug-7-2013.pdf

Graphic 1: Distribution Voltage Regulation – Location Matters



In addition to provisioning reactive power, advanced inverters can be programmed to ride-through minor voltage fluctuations on the grid, which eliminate unnecessary grid disconnects. This feature, for example, enables distributed solar to stay connected longer than rotating machines because solar does not have mechanical resonance issues and can ride-through grid disturbances caused by such issues. As a result, distributed voltage regulation provides substantial energy efficiency while delivering power quality and preventing blackouts.[25]

Advanced inverters have been proven effective for enhancing grid reliability in Germany. Germany is one of the world leaders in installed PV capacity and as of 2012 has been using advanced inverters to manage local voltage via reactive power. Germany passed new grid codes that require PV systems to be capable of frequency dependent active power manipulation during abnormal grid conditions and to be capable of reactive power provisioning during normal grid operations. The German experience showed that advanced inverters can be set to automated mode, so no additional communications equipment or protocols will be needed.[26]

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[25] ibid.
[26] ADVANCED INVERTERS FOR DISTRIBUTED PV: Latent Opportunities for Localized Reactive Power Compensation. UC Berkeley & Clean Coalition
Energy C226, dated Spring 2013. http://www.clean-coalition.org/site/wp content/uploads/2013/10/CC_PV_AI_Paper_Final_Draft_v2.5_05_13_2013_AK.pdf

Appendix C: DG Siting Guidance in Interconnection

Knowing "what can go where" with little or no modification to the existing grid early in the decision making process helps customers establish realistic expectations regarding interconnection at their property, or intelligently choose between multiple potential locations in siting new generation – and undertaking the expensive and time-consuming processes associated with project planning and proposal submission. Best practices will focus first on making relevant information accessible to applicants, including defining low cost areas and criteria for interconnection. This will elicit well-sited and scaled proposals, leading to a high proportion of successful project deployment and an optimal use of available grid capacity. Poorly informed applications result in massive failure rates and unnecessarily burden staff and developers alike – and lead to higher costs for ratepayers.

Utilities should provide sufficient information about the interconnection queue for applicants to assess approximate timeframes for interconnection and to determine whether prior active interconnection requests may impact the local load available to be served by new applicants. Utilities might also provide information to facilitate coordination between applicants.

Examples

In response to the level of activity in distributed generation interconnection in California, siting maps have been released by several of the State's major public and investor owned utilities in support of their distributed generation procurement, including by Sacramento Municipal (SMUD), SCE, PG&E, and SDG&E. The investor owned utilities are also required to publish their interconnection queues with the status and approximate location of all wholesale DG projects.[27]

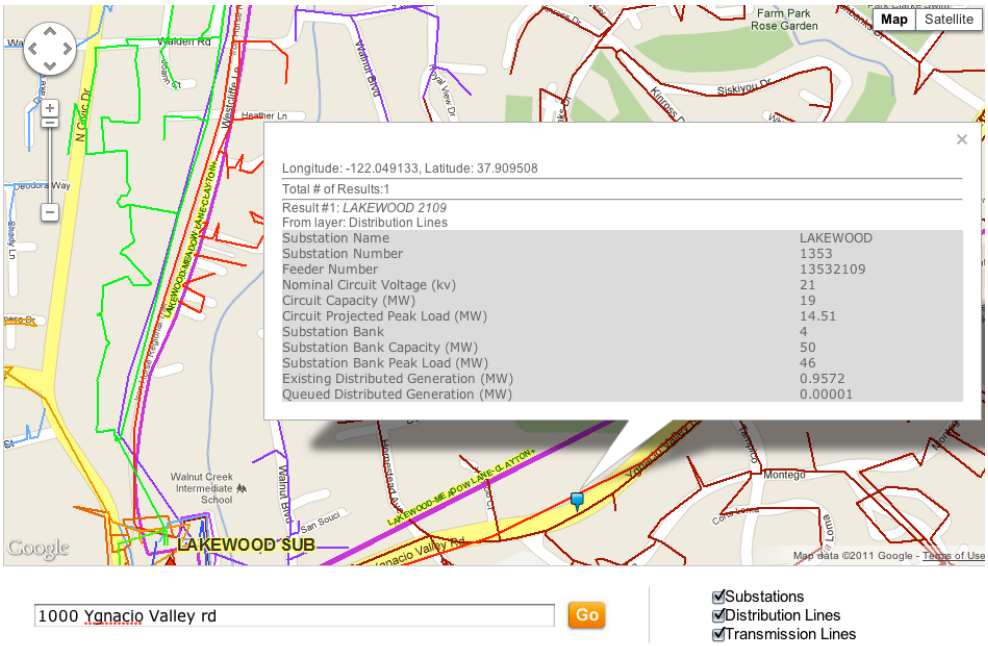
Local and state agencies have also pursued designating zones for allocation of guaranteed deliverability on full energy output, expedited permitting, planned capacity upgrades, and targeted locational incentives. Several examples of utility-created maps are shown below, ranging from printable static maps to Google Earth integrated system overlays with interactive embedded circuit data.

[27] http://www.pge.com/b2b/newgenerator/
http://www.sdge.com/generation-interconnections/wholesale-generator-transmission-interconnections
https://www.sce.com/wps/portal/home/regulatory/open-access-information

Pacific Gas & Electric (PG&E):
"Solar Photovoltaic (PV) and Renewable Auction Mechanism (RAM) Program Map"[28]

Analysis:

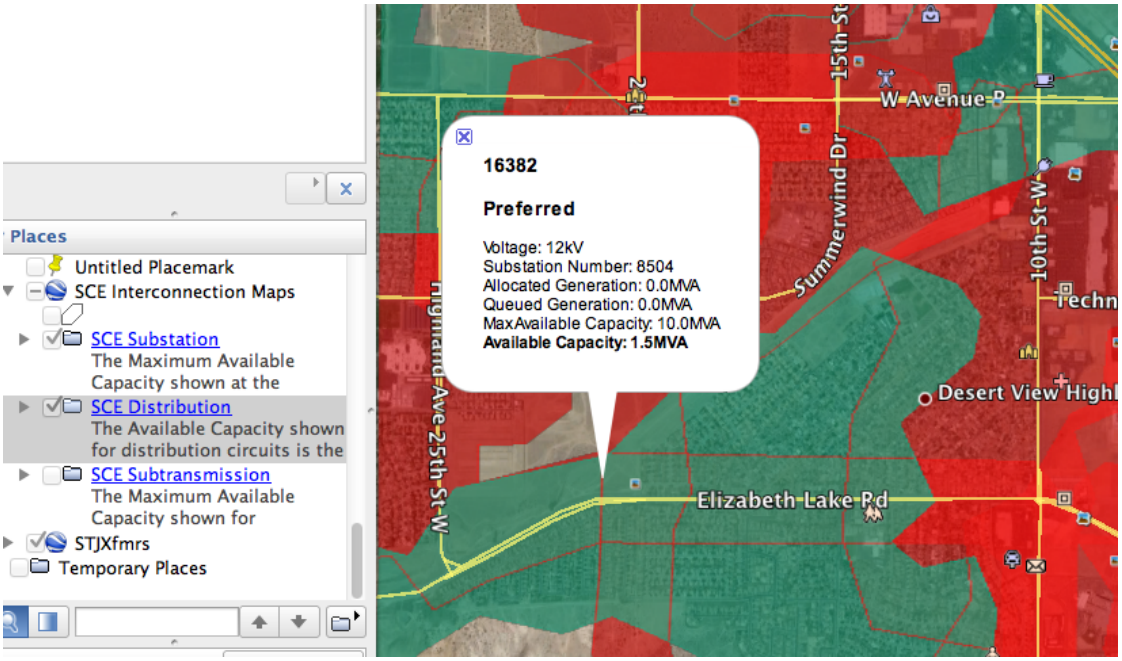
- Excellent information available, but the map provides no visual indication of where available DG capacity exists and it is difficult to go from an entry in the spreadsheet back to a location on the map.



- The spreadsheet would be very useful if one could sort by available capacity (= peak load minus allocated capacity) and restrict by zip code etc.
- Once the good circuits are identified, finding them on the map is not clear.
    - One option would be to create a map searchable by circuit number.
    - Also, addresses of substations could be listed with all circuits including a listing of the substation to which they connect.
- PG&E's map should be linked to the spreadsheet to allow viewers to sort for specific information that can be displayed on the map.
    - The current map already provides this for circuit voltage and substation transformer capacity, but not line segment capacity.
- Other improvements to PG&E's map include:
    - Detailed legend.
    - Indications of whether circuit/segment falls in a local capacity requirement area.

[28] http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/

Southern California Edison (SCE):
Renewable & Alternative Power, "Renewable Auction Mechanism (RAM),"[29]



Analysis:

- SCE's original SPVP map shows all feeder circuit lines with between 1.0 and 2.0 MVA of "Generation Interconnection Potential", presumably 15 - 30 MVA circuits. If one knows the "area number", one can select for that area only, but no identifying information is available on the map by interacting with it.
- SCE's more recent RAM map based on a Google Earth overlay uses a similar red/green designation of circuits with greater or lesser ("preferred) DG capacity allocated and pop up information on each circuit and substation, mirroring the approach seen from PG&E.

[29] http://www.sce.com/EnergyProcurement/renewables/spvp-ipp/spvp-ipp.htm

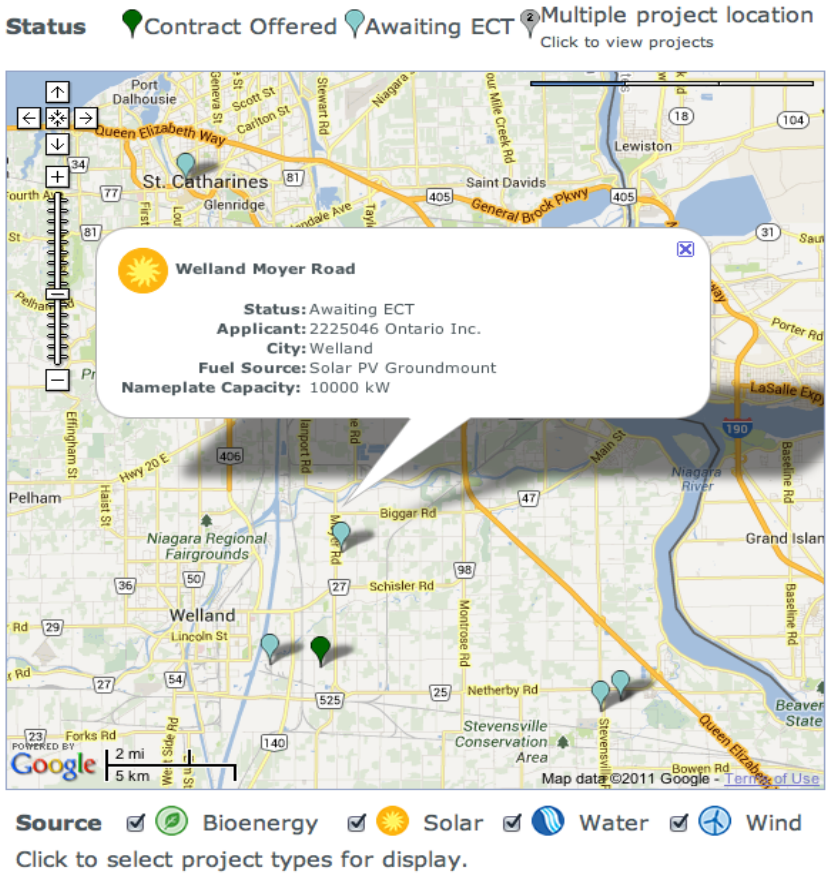
Ontario Power Authority (OPA):

OPA supported its feed-in tariff program with interactive Google maps.
The first shows in detail all the locations of renewable energy projects for which contracts have been awarded by the OPA under the FIT Program, as well as projects awaiting the economic connection test:
http://fit.powerauthority.on.ca/Page.asp?PageID=924&ContentID=10634

Another map shows regional transmission capacities in less detail:
http://www.powerauthority.on.ca/Page.asp?PageID=829&ContentID=4061&SiteNodeID=162

OPA also provides access to a pair of spreadsheets with the following information at each substation:

- Sheet 1 – Total capacity at all potential connection points.
- Sheet 2 – Allocated capacity at all potential connection points.
- By comparing Sheet 1 availability with the allocations in Sheet 2, the remaining available GIC could be calculated on a substation level.



Recommendations

After consultation with many DG developers, the Clean Coalition believes that a well-designed data visibility program will have the following attributes:

- All IOUs should at least match the detail of PG&E's map, which currently allows developers to see line voltages and substation capacities as well as peak loads and existing/queued DG.

- All maps should be developed in Google Maps (or similar program) to provide easy access to a detailed map that has sufficient geographic information.
    - For example, although the SMUD map was detailed, it was seen as far less useful than the PG&E map since roads were not identified.

- Regions should be divided by substation, and then each region should be color coded to identify how much interconnection capacity is available.
    - Each color code should represent a range of MW interconnection availability.
        - The PG&E map does a good job of this, particularly with regard to the distinctions between 12KV and 21KV lines.
    - If regions are defined in a non-standard manner, detailed information should be provided on how those regions were defined and why.
        - For example, it is unclear how the SCE SPVP map was created and whether it shows all available capacity or just selected areas/portions of capacity.

- Similar to the OPA Sheet 2 referenced above, color-coded regions should be updated regularly to reflect interconnection capacity that has been allocated to projects already in queue.
    - The value of this "allocated capacity" should be noted separately so that a developer knows how much is available with and without allocated capacity – since there is a chance that allocated capacity will not be built.

- Where available, color-coded regions should reflect planned capacity that is expected in the next 3 years as a result of the utility's long-term planning.
    - For example, using the PG&E coding, a box could be split between yellow and light orange, indicating that there are currently 20-30MW available on a 12kV line, but that in the next 3 years availability is expected to increase to 30-45MW as a result of already budgeted capital expenditures.
    - This coding is particularly important as the majority of utility capital expenditures are spent on the distribution grid, creating new interconnection opportunities that should be known in advance to developers and policymakers.

- Maps need to provide developers with the same information that is used to screen for inclusion in Fast Track and other interconnection processes.
    - While as much information as possible should be in the maps, for large amounts of data such as line segment information, utilities should provide the information via a searchable database.
    - Interconnection reform is moving towards changing the screens using percentage of minimum coincident load rather than peak load. As a result, minimum coincident load information would need to be provided on the maps as well.

While the map is useful for developers who have predetermined sites, it is also important to have maps and databases that a developer can use to search for circuits/line segments based on criteria such as available capacity).

- Providing these tools will increase the likelihood of rapid interconnections and maximize existing grid utilization.

- Data should be downloadable in a workable spreadsheet form.

Once a developer has identified a circuit/segment of interest, the developer should be able to get detailed interconnection information on that circuit/segment, including:

- Existing interconnection queue at that circuit/segment (as well as other projects that are in process of trying to connect on the circuit/segment).

- Results of previous studies (e.g. System Impact Studies) done for projects connecting to the circuit/segment (see: http://www.oasis.pacificorp.com/oasis/ppw/lgia/pacificorplgiaq.htm)

- Information on any planned upgrades to the circuit or substation.

- Existing telemetry (if any) that could be used to communicate with a new generation project.

As policies are developed with location specific value, data that affects that value should be provided and searchable on the map. Examples:

- Potential avoided transmission costs including network build-outs and congestion.
- Distribution system upgrade plans and credit.
- Any location affected by "value normalization" or otherwise adjusted to reflect differential public policy value.