BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)

CLEAN COALITION REPLY COMMENTS ON ORDER INSTITUTING RULEMAKING REGARDING POLICIES, PROCEDURES AND RULES FOR DEVELOPMENT OF DISTRIBUTION RESOURCES PLANS

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I. INTRODUCTION

Pursuant to the Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769 issued August 14, 2014 ("OIR"), the Clean Coalition offers the following responses to Party comments on the Preliminary Scope and questions posed by the OIR.

The Clean Coalition is a California-based nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement, interconnection, and realizing the full potential of integrated distributed energy resources, such as distributed generation, advanced inverters, demand response, and energy storage. The Clean Coalition also works with utilities to develop community microgrid projects that demonstrate that local renewables can provide at least 25% of the total electric energy consumed within the distribution grid, while maintaining or improving grid reliability. The Clean Coalition participates in numerous proceedings before California, other state, and Federal agencies throughout the United States.

II. DISCUSSION

The Clean Coalition wishes to respond to the comments offered by Commission Picker and Energy Division staff at the initial September 17th Distribution Resource Plan ("DRP") workshop calling for a definition of "optimal locations" for Distributed Energy Resources ("DER"), and note broad consensus regarding this need among the opening comments of most parties. The Clean Coalition specifically identified defining criteria in our opening comments. We note, however, that the definition of "optimal" locations is inherently dependent upon the combination of goals and associated factors being optimized. As such, while we may adopt and utilize a set of specific and largely objective criteria, the appropriate composition of the set will vary in accord with the related planning goals. We therefore recommend approaching "optimal" as a value associated with discrete goals, and overlaying such discrete optimization values as needed to establish the total net weighted value for an applicable set of goals. In this way, DRPs may reflect a baseline definition of "optimal" founded on the operational and capacity needs determined for locations throughout each utility's system and the direct avoided cost valuation of provisioning these services and capacities. Upon this base optimization, the relative cost effectiveness of locations may be overlaid to reflect the additional deployment (if any) required to meet a variety of goals or mandates.[1] For example, while the baseline avoided cost optimization (for direct ratepayer savings) may be founded on mitigating identified local congestion through DER, increased local power quality and reliability goals would be reflected in a second optimization value layer (for ratepayer value). Likewise, local customer demand for self-generation, targeted economic development priorities, or environmental benefits, may each be reflected in a total optimization value.[2]

The Clean Coalition would also like to acknowledge Commission Picker's call for simplicity from the perspective of the DER provider. Clear guidance and a simplified path to both bring DER online and to receive predictable compensation is vital to successfully attract the desired response from customers and other DER providers. As we have consistently advocated, the processes through which DER services are procured, associated facilities interconnected, and compensation offered, must avoid acting as barriers to participation as such barriers increase the risk and cost of offering services and thereby forego benefits or increase costs to ratepayers. Once DRPs have established the opportunities for DER to provide cost effective capacity and

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[1] Please note that in the referenced optimal location DER modeling the Clean Coalition is conducting for PG&E's Hunters Point substation, the specified optimization goal is to achieve 25% local renewable generation. This goal varies from PUC §769 as defined by AB 327, however the methodology is applicable to any set of optimization criteria or goals.

[2] For example, in prior legislation the Clean Coalition had suggested basing preferred DER locations based upon:

1) potential to relieve congestion;
2) potential to avoid upgrade costs;
3) potential for Fast Track or other expedited interconnection procedure eligibility;
4) environmental impacts;
5) potential public health benefits;
6) proximity to designated Economic Development Zones; and
7) any other criteria the commission deems significant for determining the locational benefits of distributed generation.

services, communicating these locations and values must be clear and accessible enough for the typical customer to understand the opportunity to offer their DER value to the utility. "Plug and play" DER contributions to the DRPs should be a major goal of DRP implementation. This sentiment was supported by a number of Parties in filed and oral comments.

Having originally drafted legislation[3] and Briefs addressing Distribution Planning, distributed generation ("DG"), and ratepayer benefits since mid 2011, the Clean Coalition has long worked to bring attention to the need for DRPs, and offered practical criteria for defining optimal locations for DER. We have actively promoted Strategic Distribution Investment Planning and DER optimization through the California Energy Commission's ("CEC's") Integrated Energy Policy Report ("IEPR") process[4], which incorporated these goals well before the adoption of current legislative requirements,[5] and we have pursued this effort through multiple CPUC proceedings, including in the requirement for interconnection maps in the RAM proceeding, development of use case scenarios and identification of grid services in the Energy Storage proceeding, the adoption of Smart Inverter standards, interconnection queue and cost data reporting among other reforms in the Rule 21 proceeding, and current development of grid service valuation and locational variation in the Demand Response Settlement's Load Modifying DR Working Group.

As noted in our opening comments, the Clean Coalition, in collaboration with Pacific Gas & Electric, is spearheading a groundbreaking project in the Bayview and Hunters Point areas of San Francisco in support of the city of San Francisco's goal to achieve a 100% renewable electricity supply. The Hunters Point Project, part of the Clean Coalition's Community Microgrids Initiative, is demonstrating that local renewables can cost effectively fulfill at least 25% of total annual electric energy consumption for 20,000 customers while maintaining or improving power quality, reliability, and resilience. Policymakers and utility executives need to

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[3] *See, e.g.*, AB-1302 Distributed Generation (Williams 2011); SB-372 Distributed Generation (Blakeslee 2011).

[4] *See, e.g.*, Clean Coalition Comments on Interconnection of Renewable Development in California, California Energy Commission Docket No. 12-IEP-1D (May 21, 2012).

[5] The CEC's 2012 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.

see real-world solutions in action to gain confidence in accelerating the transition to local renewables. The Hunters Point Project, which is named after the substation that serves the Bayview and Hunters Point areas of San Francisco, is designed to provide a world-class example that facilitates San Francisco, and communities around the globe, to reap the benefits from significant levels of local renewables—including economic, environmental, and resilience benefits.

Phase 1 of the Hunters Point Project, to be completed next month, will result in standard specifications for modeling tools providers, so that the approach can be applied to any powerflow tool. The modeling platform is explicitly intended to identify and evaluate optimal locations of DER by modeling the capacity limits and opportunities of the existing local distribution system and simulating the ability of DER to cost-effectively address vital grid services (power, voltage, and frequency). For this project we're working with PG&E's modeling tool provider Cyme and its cost-analysis tool provider Integral Analytics to establish a replicable example that any utility or modeling platform can use to evaluate DER and Community Microgrid opportunities. Phase 2 of the Project, which is anticipated to be substantially completed by yearend 2015, will result in the actual deployment of the Hunters Point Community Microgrid. **Updated information about the Project, including the results of modeled baseline optimal DER siting analysis, is attached as a new Exhibit A.**[6] Higher levels of DG penetration and associated least cost mitigations have been modeled, utilizing conservative energy efficiency, demand response, and electric vehicle availability assumptions prior to consideration of energy storage solutions, however these results have not yet been fully vetted and in consideration we will defer release at this moment. More information about the Clean Coalition's grid planning and modeling methodology was attached to our opening comments as Exhibit B.

We further wish to emphasize that, while the existing status of utility data regarding distribution systems is not sufficient to allow both quick and detailed modeling to be applied throughout these systems, the results of modeling and studies that have been completed[7] provide clear

[6] See in particular Attachment A pages 22–26.

[7] *See* CEC-NAVIGANT, DISTRIBUTED GENERATION INTEGRATION COST STUDY (Nov. 2013). This study developed and used an analytical framework to predict potential impacts, least-cost solutions, and how

examples that offer effective guidance for initial DRP development, with the understanding that planning should be refined as additional data and modeling input processes become available.

III. Responses to Party Comments

a. SDG&E

SDG&E states in their Opening Comments (p.3):

> If DERs are to be compensated for deferring or eliminating traditional infrastructure projects, DERs must have physical performance requirements with appropriate penalty provisions for non-performance. To create economic incentives for DER performance, and to provide compatible consumption signals for end-use consumers, retail commodity rates need to be far more location-specific and time-differentiated than is currently the case. Additionally, the retail rates under which the utility's fixed costs are recovered should be more time-differentiated (i.e., a larger share of the utility's fixed costs should be recovered through demand charges based on end-users' maximum grid withdrawal during defined billing periods).

The Clean Coalition urges caution against excessive application of physical performance requirements. While we agree that the grid operator must be able to rely upon the aggregate performance of DER resources to provide a defined level of performance at specific times and locations, there is no need to require this from each individual resource. Prior requirements for the "physical assurance" of generation capacity severely hindered the ability of variable resources to be credited against Resource Adequacy requirements, effectively depressing the value of these resources even when their actual aggregate availability equaled or exceeded that of conventional facilities during peak demand hours. Where the grid operator is heavily reliant upon any individual DER facility, we agree that predictable response is important and should be supported by significant penalties for non-performance. However, DER can also be provided by

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integration costs vary as a function of location across thirteen representative individual feeder lines. This study validated Southern California Edison's approach and concluded that the cost to integrate varying penetration scenarios of localized renewable energy resources depends highly upon locational factors for both the distribution and transmission systems. Additionally, it concludes that policies to guide projects to areas better equipped to accommodate renewable distributed generation can reduce anticipated 2020 ratepayer integration costs by $3.5 Billion (~80%) in SCE territory. The CEC considers this study a first step toward the 2012 IEPR Update goals of identifying preferred areas for renewable distributed generation and minimizing interconnection and integration costs and requirements.

aggregated resources that are reliable regardless of the performance of individual contributors; while these resources should be compensated based on their performance, it does not follow that individual resources should be penalized as this would discourage participation and reduce overall DER resource availability.

As recently reported by the Sacramento Municipal Utilities District, aggregated small customer Demand Response participation has been found to be highly predictable and reliable, and very responsive to pricing signals.[8] Throughout two years of customer experience, switching customers by default to a time of use plus critical peak pricing ("CPP") rate formula achieved a 12.3% load reduction on CPP days. Customers choosing to opt in to CPP pricing reduced loads by 20–25%. We note that these programs were designed to be cost neutral for SMUD, while generally achieving modest savings for customers. Actual results indicated utility level benefit cost ratios exceeding 4:1 when applying the program as the default option for customers.

We agree with SDG&E's comment that commodity rates should reflect location and time specific value, but note that such values must be sufficiently stable and predictable to warrant any required DER investment. SDG&E's further comment regarding retail rates, while having merit, is outside the scope of this proceeding. We do agree that increased reliance on DER in place of utility owned investments or bundled energy sales requires coordinated attention in rate design and should be informed by this proceeding.

b. *Interstate Renewable Energy Council ("IREC")*

IREC suggests in opening comments (p. 5) that both the existing interconnection procedures will require additional attention as part of this proceeding. IREC believes:

> DRPs are part of a broader, necessary evolution of the serial interconnection procedures into a more integrated interconnection and distribution planning process. By taking a more holistic look at the integration of DER into the distribution system, the Commission and the IOUs will be better able to minimize the costs of interconnecting DER, and appropriately allocate both costs and

[8] NEXANT, SMART PRICING OPTIONS: THE FINAL REPORT ON PILOT DESIGN, IMPLEMENTATION, AND EVALUATION OF THE SACRAMENTO MUNICIPAL UTILITIES DISTRICT'S CONSUMER BEHAVIOR STUDY, DOE Award Number OE0000214 (Aug. 6, 2014).

benefits across customers.

The Clean Coalition shares this position, as reflected in our proposals in the Rule 21 interconnection proceeding to incorporate distribution planning and investment credit against interconnection costs in preferred (optimal) locations. The Commission and Parties are currently evaluating interconnection cost certainty proposals that include associated "plug and play" standardized interconnection procedures and charges or credits and we encourage coordination between these proceedings. Over 100,000 successful Net Energy Metered ("NEM") facilities have demonstrated the extraordinary value of simplified and predictable interconnection processes, the capacity to effectively develop and deploy vast numbers of DER facilities, and their responsiveness to clear valuation. As reflected in our proposal, DRPs can provide clear time and location specific valuation, and offer simplified interconnection for projects meeting DRP criteria, thereby enhancing the availability and net value of DER for ratepayers.

IREC also notes that (p. 5):

> the programs in place to date have not been as effective as they could be at driving DER at optimal grid locations. To improve these programs, IOUs will need to collect the information necessary to determine the best grid locations, and will also need to share this information effectively with non-utility providers and customers.

The Clean Coalition shares this rather understated observation and has long advocated for the inclusion of Locational Value in procurement programs. While the CPUC published an initial report in March 2012,[9] the purpose of which was to develop a statewide technical resource potential for local distributed PV that took into account: (a) theoretical resource potential, (b) an assessment and quantification of suitable site locations, (c) an assessment of technology costs, (d) an assessment of available distribution and substation capacity, and (e) a quantification of the locational benefits of distributed PV, and Energy Division staff subsequently convened a workshop on January 31, 2013 and solicited comments from stakeholders on August 9th of that year, no further action has been taken. The Clean Coalition respectfully urges the CPUC to give increased attention to this topic, which is now an urgent legislative mandate.

Market information providing direction is necessary to site DER in preferred locations. Value

[9] ENERGY AND ENVIRONMENTAL ECONOMICS, TECHNICAL POTENTIAL FOR LOCAL DISTRIBUTED PHOTOVOLTAICS IN CALIFORNIA (Mar. 2012).

must be recognized, communicated, and made available if it is to have any effect. The Clean Coalition has advocated that information be made available regarding the best locations for interconnection, in mapped formats as well as capacity and cost data, with the support of IREC and other Parties, and we agree wholeheartedly here that such information must be effectively shared for DRPs to be effective.

The Clean Coalition notes and supports IREC's Integrated Distribution Planning concept, which shares much in common with the Clean Coalition's above referenced Strategic Grid Investment Planning and the interconnection related Distribution Grid Upgrade Plan approaches. Each of these offers significant guidance in the development of DRPs. We appreciate the additional citations provided (p. 10) regarding DERs potential to defer transmission investments.

c. PG&E

PG&E recommends (p. 2):

> an inventory of existing tariffs, utility procedures, customer programs and operating protocols that affect the timely integration of distributed resources at all relevant points on the electric distribution system." And that this inventory should also include "a discussion of where the existing tariffs and procedures may be perceived to act as barriers to the development and integration of distributed resources under various scenarios of market penetration and customer needs, and how those barriers can be removed.

The Clean Coalition agrees as to the importance of identifying barriers to the development of DER as this is central to the successful implementation of each utility's DRP. While it may be beyond the scope of this proceeding to address all such barriers, identification of barriers to effective implementation of DRPs is necessary to inform other proceeding for these issues to be prioritized and addressed. We note that the Rule 21 proceeding has identified numerous such barriers and opportunities remain for these to be addressed if the DRP proceeding indicates.

For example, PG&E notes that it has "has enhanced its interconnection and distribution planning procedures over the last few years, and as a result PG&E has one of the fastest cycle times in the nation for processing distributed generation interconnection requests." The Clean Coalition acknowledges PG&E's efforts and some significant improvements in processing DG interconnection requests. However, while the record regarding NEM applications establishes a strong standard, the Fast Track and other processes have a decidedly more mixed record for all other interconnections, with the three major IOUs often experiencing far longer actual timelines than many other utilities, including major municipal utilities in California, such as SMUD.

Rule 21 was reformed in 2012 to allow Fast Track interconnection at aggregate penetrations up to 100% of minimum coincident load, however data regarding minimum coincident load and other limiting factors is not reliably available. PG&E has been commended for its implementation of the Clean Coalition's Pre-Application Report option, but these are individually compiled upon request. DRPs create greater and more targeted opportunities to publicize relevant information about the distribution system, especially locations identified for preferred DER deployment.

In Appendix A PG&E suggests (p. A3) that optimal locations:

> can be interpreted as the areas where new DERs can be interconnected with minimal need for additional investment by the distribution system owner to ensure the system can continue to be operated safely and reliably…[and] can also be interpreted as the areas where new DERs can provide capacity and/or reliability benefits to the distribution system.

The Clean Coalition finds a high degree of overlap between these definitions and those offered in our opening comments, while noting that this may appropriately represent a subset of criteria by which optimum locations may be defined. As noted above, multiple criteria may be applied non-exclusively to the determination of optimal locations, with the sum of values from each applicable factor contributing to the level of value associated with each location. The determination of which criteria to include is a policy matter, not simply an engineering question, as the value of DER cuts across multiple policy considerations.

However, we take issue with the example PG&E offers regarding RAM and ReMAT procurement compensation. We agree that it is important to determine what types of compensation are already being provided to DERs to avoid paying twice for existing services, and we have long called for locational value to be fully recognized in RAM and ReMAT procurement processes, but this has not been the case. If providing additional services not already procured, including new operational behavior, there is no reason to require compensation to be associated with existing procurement contracts and PPAs—all DER should have equal access and opportunity for compensation if providing a new service.

PG&E goes on to suggest (p. A4) that "it may make sense to enhance the qualification requirements without adjusting compensation. An example of this can be found in the Rule 21 OIR, where Smart Inverter standards are becoming the norm/requirement and may provide indirect benefits to the DER owner or operator." While the Clean Coalition has long recommended and strongly supported the application of advanced inverter functionality, there is no assumption or argument that such functionality should not be duly compensated—to require customers and other DER providers to incur new facility or operational costs without compensation creates a disincentive to DER deployment, contrary to the intent of this proceeding. The functionality requirement creates the ability for these devices to provide additional value to the utility grid operator, but the actual use of this ability should be driven by compensation related to its value relative to its cost.

IV. CONCLUSION

We appreciate the opportunity to offer reply comments on the questions and preliminary scope in the OIR. For the foregoing reasons, the Clean Coalition respectfully requests that the Commission consider the above recommendations and adopt them in whole or in part as appropriate within the entirety of factors.

Respectfully submitted,

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Clean Coalition
Making Clean Local Energy Accessible Now

EXHIBIT A

Optimizing Distributed Energy Resources in a Community Microgrid:

Methodology and Case Study

DRAFT: October 4, 2014

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Introduction

Distributed Energy Resources – local renewable generation from solar, wind, geothermal and biopower, combined with demand response, energy efficiency, electric vehicle charging, and energy storage – provide an opportunity to meet evolving electric system needs in a manner that is fundamentally different from the existing centralized model. Traditional system planning assumes that centralized generation and bulk transmission is the most efficient method for delivering energy to customers. While certain economies of scale exist for centralized generation, Distributed Energy Resources, or "DER," offer a cost-effective alternative while also providing substantial societal benefits, including reduced greenhouse gas emissions and improved system-wide efficiencies.

This paper provides a framework and methodology such that any utility, utility commission, or community can achieve DER deployments in an optimized, cost-effective and scalable manner using tools readily available today. This approach enables high penetrations of local renewable energy, combined with other DER solutions, while maintaining grid reliability and power quality. In sum, this methodology will accelerate a substantial, existing asset – the distribution grid – towards a more highly utilized, cost-effective, and sustainable electric system.

This approach is somewhat unique. It starts from the necessary foundation: measuring the existing, available capacity in the distribution grid to satisfy local load with locally produced electricity, or Distributed Generation (DG). This is the logical first step, as it leverages the existing asset as is, without major changes or upgrades. Historically, distribution grids were not designed to accommodate locally produced electricity. However, the distribution grid is a collection of lines, poles, transformers, voltage regulators, and other equipment, all capable of unlocking a certain amount of local generation with little or no modification, at minimal cost in terms of grid upgrades. This existing, or Baseline Capacity, offers the lowest-cost option for incorporating large amounts of local renewables into our electrical system. Using the Baseline Capacity as the foundation, we can then calculate the additional impacts in terms of increased capacity, costs, or savings that result from including other DER solutions such as demand response, energy efficiency, electric vehicle (EV) charging, energy storage, and local reserves (or baseload generation) from combined heat and power (CHP) or fuel cells. The result is an optimized DER portfolio that cost-effectively supports higher penetrations of local renewable resources. At the same time, an optimized DER portfolio provides valuable ancillary services. These include deferring distribution grid equipment upgrades, such as transformers; decreasing the amount of (and thus cost) for transmission-delivered electricity; flattening peaks, which reduces the complexities (and thus costs) of transmission system operations; and maintaining essential services during outages.

This study and its results focus on the most cost effective and optimized opportunities for utilities to realize the benefits of DER portfolios. To compare against transmission and central generation investments on a level playing field, and to fully comply with state and federal clean energy goals, the full value of DER should be incorporated into cost-effectiveness calculations. DER provide a number of significant and quantifiable benefits to ratepayers, including:

- Increasing independence from transmission system energy services
- Deferring or avoiding distribution and transmission investments
- Reducing system-wide volatility and the need for contingency reserves
- Meeting clean energy goals
- Improving local resiliency and power quality
- Hedging against fossil fuel price volatility
- Accelerating electric vehicle adoption (while avoiding grid impacts)

The costs of DER include:

- Physical costs of DER
- Network upgrade and interconnection costs
- Telemetry and infrastructure to manage DER

The impacts of DER largely depend on their location. Therefore, accurate estimation of DER costs and benefits requires a detailed understanding of distribution grid dynamics and the manner in which these resources impact those dynamics on a locational basis. A recent report evaluating the costs and benefits of DER concluded that the "…wide variation in analysis approaches and quantitative tools used by different parties in different jurisdictions is inconsistent, confusing, and frequently lacks transparency."[1] Any attempt to realistically evaluate DER costs and benefits must therefore be transparent, vetted by a large cross section of stakeholders, and include the necessary granularity required to establish the locational value of these resources.

Traditional system planners views DER as "alternatives" to transmission and central generation, beyond their operational visibility and control, and rarely prioritize DER solutions to meet system needs. At the same time, distribution planners generally fail to account for the value of DER in avoiding investments in the distribution grid as well as in transmission and central generation. An integrated approach to transmission and distribution planning is necessary to move beyond the current view of DER as Non-Transmission Alternatives (NTA), uncounted resources, or even a potential system burden. Instead, DER must be proactively evaluated as a primary means of addressing system needs.

While the distribution grid – in principle – can supply power to the transmission grid, the methodology described herein causes zero backflow to the transmission grid while also preserving voltage stability. This zero backflow parameter minimizes impacts to the infrastructure and operation of the transmission grid resulting from increased DER penetration. In fact, optimizing DER at the substation level provides better local balancing of load and

[1] A Review of Solar PV Benefit and Cost Studies, Electricity Innovation Lab, Rocky Mountain Institute, September 2013

generation, thereby maintaining a flatter load shape overall. This added benefits simplifies transmission grid operations and results in reduced costs.

In California, Assembly Bill 327 (AB-327) is a major step forward for smarter grid planning. This law requires utilities to develop Distribution Resources Plans by July 2015 to guide DER to optimal locations on the grid, while allowing utilities to rate-base any distribution grid investments that yield net ratepayer benefits.[2] One objective of this paper is to provide a detailed framework for distribution resource planning requirements in California under AB 327, as well as for other states seeking to develop similar requirements. As a blueprint for planning DER in an optimized and cost-effective manner, this paper offers a replicable and scalable approach for achieving these plans, vastly accelerating our transition to higher levels of renewable energy and a modern grid.

The Community Microgrid Opportunity

The existing power grid was designed primarily to deliver electricity in a one-way fashion: from large, centralized generating facilities across many miles to the cities and towns where it is used. Due to decreasing costs and improved operations, Distributed Energy Resources are now increasingly competitive economically, and these technologies offer great opportunity to transform our power system. Yet, both utilities and policymakers are concerned that the current, one-way power grid will become unreliable if local renewable generation provides more than 15% of peak power in a community. Due in part to this perceived limitation, solar energy today provides less than 1% of the total energy consumed in the United States, according to the Institute for Energy Research. Without evidence that local renewables can be reliably and cost-effectively integrated into the grid, this limit will continue to impede the nation's transition towards a modern and sustainable electric system.

To overcome this barrier, the Clean Coalition established the Community Microgrid Initiative. In partnership with electric utilities, community stakeholders, and energy developers, this Initiative proves that local renewables connected to the distribution grid can provide at least 25% of the total electric energy consumed while maintaining or improving grid reliability. Our Community Microgrid Initiative builds upon the existing utility infrastructure to enable more local renewable generation as part of a broader, cost-effective, and optimized portfolio of DER. This provides the following benefits:

- *Accelerates clean energy & sustainability*: Achieves higher amounts of sustainable energy, targeting at least 25% of the total electricity consumed in a community as local renewables

- *Improves grid performance, reliability & resilience*: Includes a portfolio of DER – such as advanced inverters, demand response, energy efficiency, EV charging, energy storage,

[2] California Public Utilities Code, Section 769, added by California Assembly Bill 327 (2013)

and local reserves (e.g. fuel cells, CHP) – to achieve better grid performance by increasing the balance of load and generation locally.

- *Optimizes for cost-effectiveness*: Analyzes DER portfolios in partnership with utilities to determine the most cost-effective resource mix

- *Stabilizes energy prices while distributing investments locally*: Results in more predictable and stable energy prices, reduced transmission and distribution system costs, and more investment in local economies

The Clean Coalition's Community Microgrid Initiative accelerates and scales local renewable energy and a modern grid in two important ways:

1. Planning: Via a replicable and standardized modeling solution, or "planning blueprint," based on existing tools and technology. The methodology and results are validated first using Cyme's CYMDIST power flow modeling tool and Integral Analytics software tools using the Hunters Point Project, a Clean Coalition collaboration with PG&E, as a single, substation-wide model. The resulting blueprint will be available to anyone in the industry including other tool vendors, utilities, and utility commissions, in order to help replicate, scale and accelerate DER optimization and deployments.

2. Deployment: Via identifying large-scale procurement and interconnection solutions that utilities and communities can embrace, including a wholesale model (e.g. feed-in-tariff) for larger DG systems and capitalized grid upgrades. In addition, the Capacity Planning approach enables a "plug-and-play" interconnection opportunity featuring pre-approved local generation capacity in bulk amounts and specified locations. This will further speed widespread deployment of local renewables and reduce overall costs.

The Community Microgrid Initiative brings a top-down, system-wide, scalable solution that can be implemented across utility substations – vastly different to the project-by–project method used to bring local renewables online today. Using the Community Microgrid Initiative, grid operators can quickly and accurately plan for specific and beneficial amounts of renewable capacity that can be integrated in months rather than years, as part of any substation area. This approach enables grid operators to choose from a suite of scenarios such as:

1. Low Cost: the amount of local renewable generation supported by a substation area and its existing equipment, requiring no upgrades; often this will utilizes existing voltage regulation equipment and/or smart inverter functionality to help stabilize voltage as needed.

2. Medium Cost: the amount of local renewable generation supported by a substation area that builds on the Low Cost Scenario by including an optimal and cost-effective mix of other DER, such as demand response, energy efficiency, EV charging, and lower-cost energy storage; may require minimal upgrades to existing grid infrastructure.

3. Higher Cost: the amount of local renewable generation supported by a substation area that builds on the Medium Cost Scenario by increasing storage and/or including local reserves such as CHP to achieve specific performance goals such as flattening peaks and/or maintaining essential services in case of outages; may require significant upgrades to existing grid infrastructure.

These scenarios enable grid operators to cost-effectively and rapidly meet local renewable energy and grid performance goals. The result is an efficient, reliable distribution grid based on local generation targets – achieving an operationally predictable and financially viable solution – and analogous to how the transmission grid is operated today using capacity targets and peak demand levels.

Today, solar in communities is added to the grid extremely slowly, often one rooftop at a time. This piecemeal approach causes unknown impacts to the grid, which unnecessarily restricts adoption and is a primary reason solar PV meets less than 1% of our total electric needs today. Using the Community Microgrid Initiative methodology, utilities and their regulators can establish specific, operational targets for local renewable capacity within communities, and then cost-effectively upgrade the grid to support those targets. Using these capacity targets, utilities can rapidly add substantial amounts of local renewable capacity to their distribution grids.

A Case Study: The Hunters Point Community Microgrid Project

In collaboration with Pacific Gas & Electric (PG&E), and in support of achieving at least 25% of total electric energy needs from local renewables, the Clean Coalition is developing a Community Microgrid in the Bayview-Hunters Point area of San Francisco. The Hunters Point Community Microgrid Project, named after the Hunters Point substation that serves the area, encompasses an entire substation area serving 20,000 residential, commercial and industrial customers. The Project showcases how any community and utility can reap significant economic, energy and environmental benefits – including a stronger and more resilient grid – from deploying an optimized and cost-effective mix of local renewables integrated with other DER. The Hunters Point Community Microgrid Project demonstrates that the technologies required to plan and deploy these advanced energy solutions are readily available today (for example, the Clean Coalition is using Cyme's CYMDIST tool, v5.04 r10, for dynamic distribution grid modeling.)

To reach at least 25% of total electric energy needs from local renewables, approximately 50 megawatts (MW) of new solar photovoltaic (PV) capacity must be installed. These 50 MW of new PV will be added to an existing 8 MW (PV-equivalent) already installed in the area (1.5 MW of existing solar plus 6.5 MW PV-equivalent of biopower produced by the local wastewater treatment plant). In total, the 50 MW of new PV and the 8 MW of existing PV-equivalent local renewable energy achieves 91,000 megawatt-hours MWh of annual renewable electricity generation, or 28% of the total annual load of 320,000 MWh in the substation plan. Note that this analysis is focused primarily on adding solar PV simply because other renewable resources such as wind and geothermal are not readily available in the Bayview-Hunters Point area.

Note that Hunters Point, a naval shipyard, is undergoing a multi-year redevelopment effort by the City of San Francisco, which requires a portion of this analysis to be forward-looking. Through a comprehensive evaluation of the City's redevelopment plan, including likely rooftop square footage and projected electricity demand, we have determined that 20 MW of new PV in the Hunters Point redevelopment area is conservative estimate. With the 20 MW of new PV estimated for the redevelopment area, 30 MW of new PV must be sited in the existing area served by the substation – known as the Bayview – that will not undergo redevelopment. This near-term opportunity is the basis for this study. Thus, our modeling effort adds 30 MW of new PV and optimizes DER on the feeders serving the Bayview community. These 30 MW of new PV, plus the 8 MW of existing (PV-equivalent) local renewable energy already located in that area, will provide 60,000 MWh of annual renewable electricity generation, which is 25% of the total annual load of 236,000 MWh needed to serve the Bayview area (the non-redevelopment zone).

While establishing a replicable methodology for power system planners and operators, the Hunters Point Community Microgrid Project also strengthens the local economy by increasing private investment, creating jobs, stabilizing energy prices, and keeping energy dollars close to home. Starting with the 30 MW of new PV in the Bayview area, then reaching a total 50 MW of new PV once the redevelopment zone is completed, achieves many community benefits. Using industry-accepted assumptions from sources such as the National Renewable Energy Lab (JEDI tool and emissions calculator), the California Energy Commission (cost of generation calculator), the California Independent System Operator (transmission charges and infrastructure projections), PG&E (local outage estimates), and the Department of Energy (water savings), 50 MW of new PV added to the San Francisco Bay Area would generate the following benefits over twenty years:

Local Economic Benefits:
- $200 million added to the local economy
- $100 million in increased community wages
- Over 1,700 new local job-years created

Energy Cost Benefits:
- Cost parity with new, centralized, natural gas generation: 14.9¢/kWh for new solar vs. $15.3¢/kWh for new combined cycle natural gas
- $80 million in avoided transmission-related costs ($38 million in avoided transmission access charges, $30 million in avoided costs for new transmission capacity, and $12 million in avoided costs from transmission line losses)
- $30 million saved by local businesses and homes by reduced power outages

Environmental Benefits:

- Annual greenhouse gas emission reductions of 78 million pounds
- Annual water savings of 15 million gallons
- More than 375 acres of land preserved by using rooftops and parking lots to generate energy rather than pristine land

The Clean Coalition's Hunters Point Community Microgrid Project underscores the technical and economic viability of achieving higher penetrations of local renewables and optimized DER portfolios, helping reduce system-wide electrical energy costs and complexities. Once deployed, this project will serve as a cutting-edge model for modernizing America's electrical system in the most cost-effective and beneficial manner.

Optimization Methodology for Distributed Energy Resources (DER)

As stated, the goal of this study is to establish a replicable and scalable solution for optimizing DER in a cost-effective manner. The focus is our Hunters Point Community Microgrid Project, which covers an entire substation area. Conventionally, utilities have modeled the distribution grid only to manage peak loads with all power arriving from the transmission grid to the substation transformer, and then unidirectional distribution occurring across substation feeders. Optimizing DER requires modeling in a dynamic, bidirectional way, balancing power, voltage and frequency across the distribution grid. Generation must be blended across local and substation transformer sources and analyzed regularly, such as in 15-minute increments. For the most part, this approach to grid modeling is entirely new to utility operations. In other words, the existing DG capacity for any substation, or group of substations, is currently an "unknown" quantity. Our Community Microgrid Initiative demonstrates how to use existing tools to make this a "known" quantity, helping utilities, utility commissions, and communities make informed decisions about energy system goals and costs on the path towards achieving smarter, integrated distribution grid planning.

Optimizing DER requires recognizing the complementary benefits of DER portfolios, rather than analyzing the value of individual resources in isolation. Synergistic relationships between different DER can lead to substantial improvements in efficiencies and costs. Several examples are worth mentioning. It is expected that high levels of distributed PV, peaking during mid-day, will lead to lower daytime energy prices, depending on rate design. Low mid-day energy prices, when communicated to end users through time-of-use or dynamic pricing, may spur behaviors that mitigate any potential over-generation issues. For example, low mid-day energy prices may cause customers to precool (e.g. summer weekdays) or preheat (e.g. winter weekdays) their homes when energy is cheaper – relying less on more expensive energy at other times during the day and early evenings. Also, peak PV generation impacts can be mitigated with demand response to increase daytime loads and daytime electric vehicle (EV) charging.[3]

[3] See the Clean Coalition's presentation to the California Energy Commission, Flattening the Duck (February 2014), available at http://www.clean-coalition.org/resources/february-2014-cec-presentationflattening-the-duck/

Similarly, the value of distributed PV and storage are both enhanced by turning on advanced capabilities of inverters. Advanced inverters effectively manage any over-voltage issues that occur due to high levels of distributed solar, prevent blackouts by providing reactive power close to loads, and enable conservation voltage efficiencies.[4] Understanding storage performance characteristics and its effect on a Levelized Cost of Electricity (LCOE) is required while evaluating distributed energy storage options. Curtailment of DG resources is not specifically a DER resource but rather a complementary tool for controlling the output of these resources. Given the objective to increase local renewable generation as much as operationally and financially feasible, curtailment is used as a last resort. Keep in mind that we are diligently evaluating the most cost-effective mix of DER, given the combination of local load and generation opportunities.

In examining cost effective and optimized DER in support of increasing levels of distributed PV, for simplicity's sake we'll evaluate a single substation as the basic building block. A single substation can integrate a certain amount of distributed PV at an extremely low cost from the perspective of utility infrastructure upgrades. Utility customers are paying distributed PV costs, and for net energy metered systems interconnection costs are essentially zero. Furthermore, small wholesale DG facilities – generating facilities that sell all power produced to the utility – pay their own interconnection costs. As a result, these systems cost the utility nothing, assuming we can define the amount and locations that require no upgrades to existing grid infrastructure. Thus, we can measure the maximum amount of PV resources that can be reliably integrated within a single substation at the lowest possible cost, subject to required voltage regulation and zero backflow to the transmission system. This is known as the Baseline Capacity of a given substation.

Distribution resources planning should require utilities to correctly and accurately define and publish this existing Baseline Capacity, including optimal locations and generation amounts along the feeders within a substation area. This will enable the most cost-effective and optimal amount of local renewable energy. The Baseline Capacity is also used to determine which additional DER solutions further optimize the performance of the grid in a cost-effective manner. This DER Optimization Methodology, comprised of the four steps below, is based on Capacity Planning – a more operationally and financially stable method to integrate DER:

Step 1: Baseline Powerflow. This provides the foundation and must be completed first in order to understand the quantity and dynamics of how electricity moves on the distribution grid. Without this step, we cannot understand how additional amounts of local renewables may cause grid impacts. Note that this step requires incorporating key utility data sets, including customer and transformer loads and the network model. The circuit map, including schematic, connections, wire and cable types, and equipment settings, is also crucial. Voltage, power flows, voltage regulation (e.g. load tap changers), capacitor bank operations, and the effect of series reactors will all be measured during this step. The model must run consistently and with

[4] Craig Lewis, Advanced Inverters – Recovering Costs and Compensating Benefits (October 2013), available at http://www.clean-coalition.org/site/wpcontent/uploads/2013/10/October2013_SolarServer.pdf

stability, including ongoing validation of data across load allocation, load flow, and time-based scenarios.

Step 2: Baseline Capacity ("Low Cost" scenario). The Baseline Capacity defines the potential amounts of local renewable generation that can be supported by the existing substation circuits – by individual feeder lines as well as by the entire system of connected feeders that make up a substation area. The Baseline Capacity is based largely on the current physical nature of the circuit, such as wire thickness and the capabilities of existing voltage regulation mechanisms. Maximizing the Baseline Capacity is also based on matching local generation types to local loads. For example, in the case of solar, robust feeder locations and customers with large daytime loads offer the most optimal locations. Guiding deployment to optimal locations maximizes the amount of local renewables that can be supported by a substation system with no changes or upgrades needed. This is critical information in order to design the most cost-effective solution possible. And, without this step, the next two steps have an unsteady foundation to build upon. Note that one can also find optimal locations in different combinations, such as less robust feeder locations with larger customer daytime loads, or more robust feeder locations with lower customer daytime loads. The diagram below illustrates achieving this step using resistance, or ohms, in combination with daytime load sizes.

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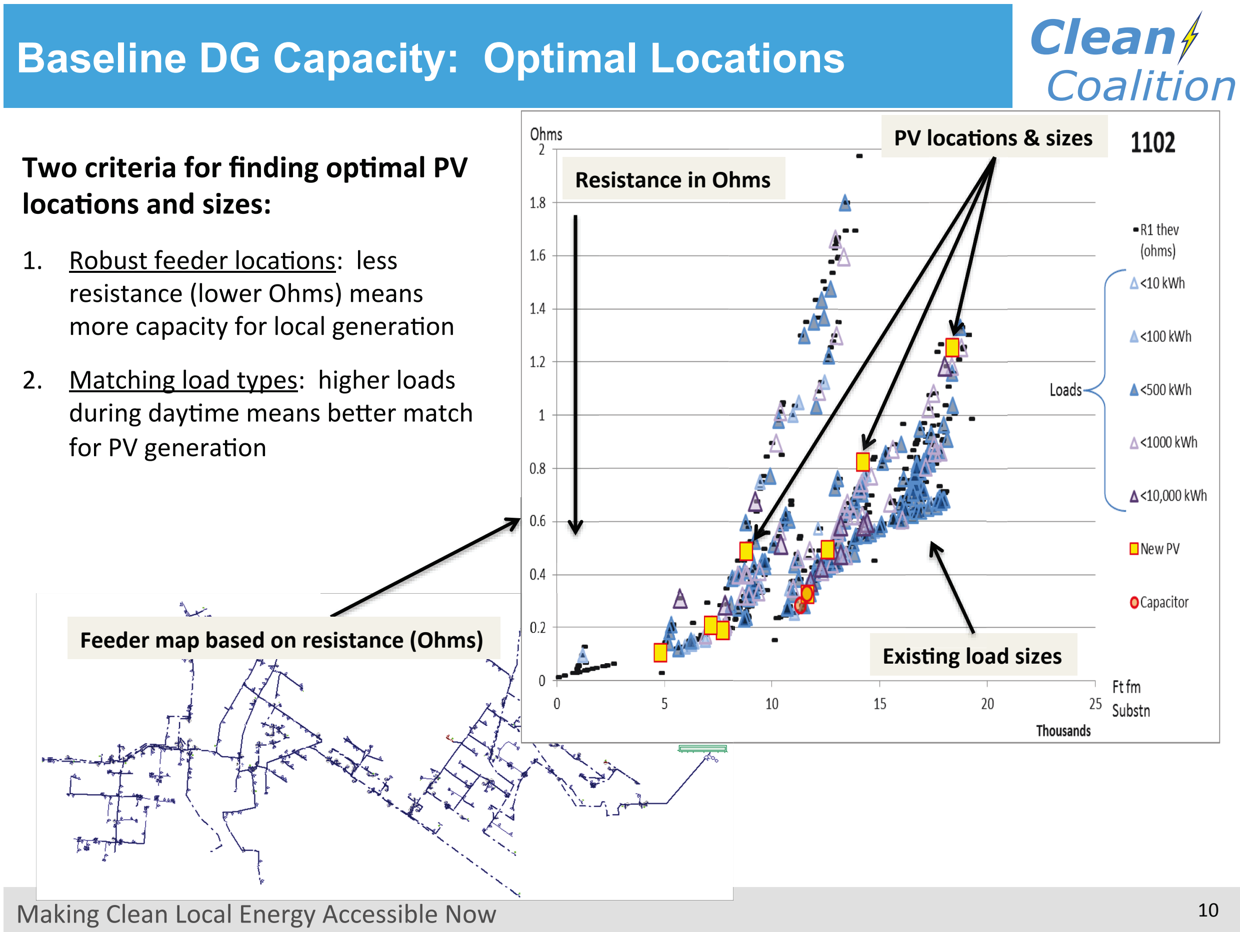


Determining Baseline Capacity Using Optimal Locations

The above diagram visually highlights an important fact: this enormous asset – the distribution grid – is currently underutilized. There is substantial existing potential within substation areas to supplement one-way power with two way, local generation. This capacity, and capability, should be realized in order to get the most out of our distribution grid investment.

Another method achieving further optimizations is connecting the feeders across a substation so they work as a single system, downstream from the substation transformer. This "Substation as-a-System" approach delivers additional efficiencies as follows:

1. **Local Balancing**: Over-generation on certain feeders can be consumed by load on other feeders connected at the substation. For example, weekend PV generation on large commercial rooftops, normally consumed locally during weekdays either onsite or on that feeder segment, can be consumed by residential customers within that substation area, during weekends when residential loads increase
2. **Optimizing Settings**: E.g. load tap changers across the substation feeders
3. **Optimizing DER:** E.g. storage and demand response across the substation feeders (see

steps 3 & 4)

As stated, defining the Baseline Capacity for DG means finding the optimal locations in a substation area by determining the most robust feeder locations and optimal customer load types that match local renewable generation profiles. This requires analyzing load shapes per customer type – e.g. residential, and commercial & industrial (C&I) loads, during both weekdays and weekends, and using minimum daytime loads to test for the "worst-case" scenario. In the case of potential voltage issues, advanced inverters can be used to maintain acceptable voltage levels through reactive power provisioning. Additional data sets required to complete the Baseline Capacity and additional capacity measurements (see Steps 3 and 4 below) include solar insolation data; weather forecasting data to reach more granular results; performance characteristic assumptions for demand response, energy efficiency, and EV charging; and performance specifications for energy storage solutions.

In addition, utilizing equipment lists, upgrade plans, and operations and maintenance schedules from utilities is critical in order to complete the Baseline Capacity and additional capacity measurements (See Steps 3 and 4 below). Equipment-related data helps identify opportunities to reduce costs by deferring equipment upgrades, such as substation transformers. Local generation reduces equipment use by reducing the electrical load delivered through the substation transformer (i.e. delivered by the transmission system). At the same time, where demand for electricity is starting to exceed local grid capacity, satisfying onsite load with some portion of onsite generation can help defer future equipment upgrade costs, such as by extending the life of customer-level (pole) transformers. Other significant cost-savings can come from reduced reliance on transmission. Each Megawatt hour produced and consumed locally reduces the amount of electricity delivered over long-distance transmission lines by an equivalent amount, achieving further system-wide savings and efficiencies.

As two examples supporting the above, Greentech Media reported in September 2014 that two leading U.K utilities – Scottish and Southern Energy and U.K. Power Networks – forecast savings of more than €300 million [$387 million] in avoidable capital expenditures by pinpointing specific "hot spots" that needed to be upgraded or addressed through distributed resources. Also in September 2014, Greentech Media reported that New York's *Reforming the Energy Vision* proceeding, known as REV, includes utility commission staff identifying a number of near-term actions for immediate implementation by utilities – starting with using DER opportunities to help defer the $30 billion the state has planned for transmission and distribution system upgrades over the next ten years. And, Consolidated Edison is already proving that this is a successful approach. The utility is seeking approval to manage electricity demand – using demand response, storage and energy efficiency – rather than building a new $1 billion dollar substation to meet unmanaged demand. This move alone is expected to save customers around $500 million.

As with Step 1, Baseline Powerflow, the metrics measured to achieve the Baseline Capacity include voltage, power flows, voltage regulation (e.g. load tap changers), capacitor bank operations, and the effect of series reactors. The model must run consistently and with stability, including ongoing validation of data across load allocation, load flow, and time-based scenarios.

Step 3: Medium Capacity ("Medium Cost" scenario). Step 3 builds on the Baseline Capacity by adding lower-cost DER solutions such as demand response, energy efficiency, EV charging, and cost-effective energy storage focused on peak reduction. These DER solutions can lower demand and/or peak loads at critical times and/or add load during daytime generation of solar if needed. The result is increased grid performance, lower overall system costs (e.g. via reduced peaks), and a greater amount of DG supported by a substation area. Step 3 requires optimizing the DER portfolio based on locations, sizes, types and costs to achieve community and/or utility targets in DER penetration and financial impacts. Implementing the lowest-cost options first, such as demand response, energy efficiency, and EV charging, will result in a more cost-effective overall DER portfolio, and this should be done prior to adding storage options such as combined PV/storage solutions located at larger customer sites to help reduce peaks. This approach results in the optimal mix of local generation and lowest-cost DER for a given substation.

As a first step, demand response and energy efficiency programs should be time-optimized to match the distributed generation assets. For example, in the Clean Coalition's Hunters Point Community Microgrid Project, solar irradiance is the primary driver of the distributed generation profile. In this case, a targeted demand response program would structure time-based incentives (kW-based or kWh-based) for participants across Residential and Commercial & Industrial (C&I) load categories to:

- Consume more electricity (e.g. preheating/precooling) on weekdays between 11am and 2pm,when solar generation is maximal
- Consume less electricity (e.g. reschedule laundry load) weekdays between 4pm and 9pm when solar generation is minimal or non-existent
- Consume less electricity weekdays between 6am and 8am when solar generation is minimal (if needed)

Weekend incentives would increase for residential segments to offset the expected shortfall in demand response participation by C&I customers on weekends. As needed, energy storage can take up any remaining weekend excess generation. (Note: Programmable Thermostats, Smart Appliances, low-cost home energy management systems, and utility incentives for businesses to acquire Automated Demand Response/ADR equipment would all be all enablers for program efficacy. Obligatory backup generator tests for critical facilities, e.g. hospitals, wastewater treatment facilities, police, and fire departments can also correspond to weekday afternoon/evening Demand Response participation).

As stated, optimization of DER for the Medium Capacity scenario pursues the lowest cost load reduction and load shaping strategies first. This "loading order" of DER Optimization for the Medium Capacity scenario, after first defining the Baseline Capacity, can be separated into two sequences as follows:

1. Sequence I
   A. Demand Response (DR)
   B. Energy Efficiency (EE)

2. Sequence II
   A. Energy Storage (ES)
   B. Electric Vehicles (EV)

<u>Sequence I: Demand Response (DR) and Energy Efficiency (EE)</u>

DR and EE programs should be designed so their impacts on the substation grid are time-optimized to match the distributed generation assets, and initially in the absence of Energy Storage. The Sequence I method used for DR & EE for the Hunters Point Community Microgrid Project (PV-focused DG resource) is summarized as follows:

Demand Response (DR):

The Hunters Point Demand Response program achieves 5% overall load shifting and relies on time-based incentives (kW-based and or kWh-based) for DR participants in Residential, Commercial, Industrial, and Agricultural load categories to achieve load shaping as outlined above, e.g. use more energy during PV generation and less energy after PV generation has fallen off.

Weekend DR financial incentives increase for the Residential segment to offset the expected shortfall in C&I participation in DR over weekends. Later and if needed, Energy Storage will buffer remaining weekend excess PV generation located at C&I locations.

Energy Efficiency (EE):

Energy Efficiency measures can be leveraged to reduce overall load, thus achieving additional low-cost optimizations. For example, in the Hunters Point Project, the Energy Efficiency measures achieve a 2% overall load-reduction based on the following four groups:

1. EE with a focused time interval impact on the weekday 4-9pm window; e.g.:
   - High Efficiency OLED Television
   - Heat Pump Condensing Electric Drier
   - Portable induction cook top units (no kitchen remodel required)

2. EE with longer time interval impacts which substantially overlap with the weekday 4-9pm window; e.g.:
   - LED Street Lighting retrofits
   - LED Traffic Lights retrofits
   - LED residential lighting reftrofits

- Ultra-low energy use office PCs and Printers
- High Efficiency Xerox machines
- Low energy use intensity office-place kitchens

3. EE with 24x7 impacts; e.g.:
    - Advanced Refrigeration (for cold-storage, academic campuses and biotech)
    - High COP (CO_2) Heat Pump Water Heater, e.g. Sanden
    - High Efficiency Ag water pumps
    - Server/Power Supply upgrades
    - Vampire Load mitigation, e.g. TV Set Top Boxes manufactured prior to 2010

4. EE with important Winter and Summer benefits; e.g.:
    - Indoor Window inserts
    - Quick High Efficiency Window retrofits
    - Solar-operated Exterior Blinds

Sequence II: Energy Storage (ES) and Electric Vehicles (EV)

As a realistic example, Sequence I is designed to achieve an overall load shift of 5% resulting from Demand Response (DR) and an additional 2% in overall load reduction from Energy Efficiency (EE). This gives us a total of 7% in load shift/load reduction with the lowest overall cost impact. Next, Energy Storage (ES) can be added to further shape and reduce loads. This incurs additional costs but results in significant added system-wide cost benefits to ratepayers, utilities, and the environment including:

- Reduced utility costs to access the energy spot market plus simplified/reduced transactions with the transmission grid
- Reduced or eliminated power demand charges for Commercial & Industrial customers
- Reduced peaker power plant GHG emissions resulting from lower peak electric demand
- Reduced air pollution due to increased EV use vs. gasoline automobiles

For the Hunters Point Project, single-load transformers of 100kW nameplate capacity or greater serving a Commercial or Industrial load as well as larger transformers serving multiple C&I loads were each identified as opportunities for behind-the-meter, stationary Energy Storage sized at ~23% of the capacitor nameplate capacity. This value reflected the most cost-effectively sized storage asset after achieving the lower-cost load shift/reduction impacts of DR (5%) and EE (2%). Customer specific Energy Storage sizing can be assisted by the local utility or a 3rd party allowed access to the actual load data by the utility customer. This loading order of DER indicates a different and less costly result than would have been the case if pursuing Energy Storage directly before having completed Sequence I DER Optimization (above) in which DR and EE are specifically sized and configured for the particular substation load profiles at the outset.

Finally for Sequence II, the existing regional adoption for Electric Vehicles is assessed in the context of the opportunity to defer or avoid distribution grid retrofits while accommodating their increased projected deployment. If indicated, an Energy Storage (ES) - Electric Vehicle (EV) co-strategy can then be crafted. There is a preference to co-locate EV chargers at C & I locations with large PV installations identified in the Baseline Capacity. In this way, the required EV charging load (after commuting into work) is well matched in time of day to peak PV energy production. This shifts a considerable component of the weekday EV charging burden away from smaller, more vulnerable transformers in the residential service areas of the substation area. (NOTE: in this current analysis, EVs are not modeled to provide additional services to the grid; however, in the future this offers a compelling mixed–use opportunity for EVs).

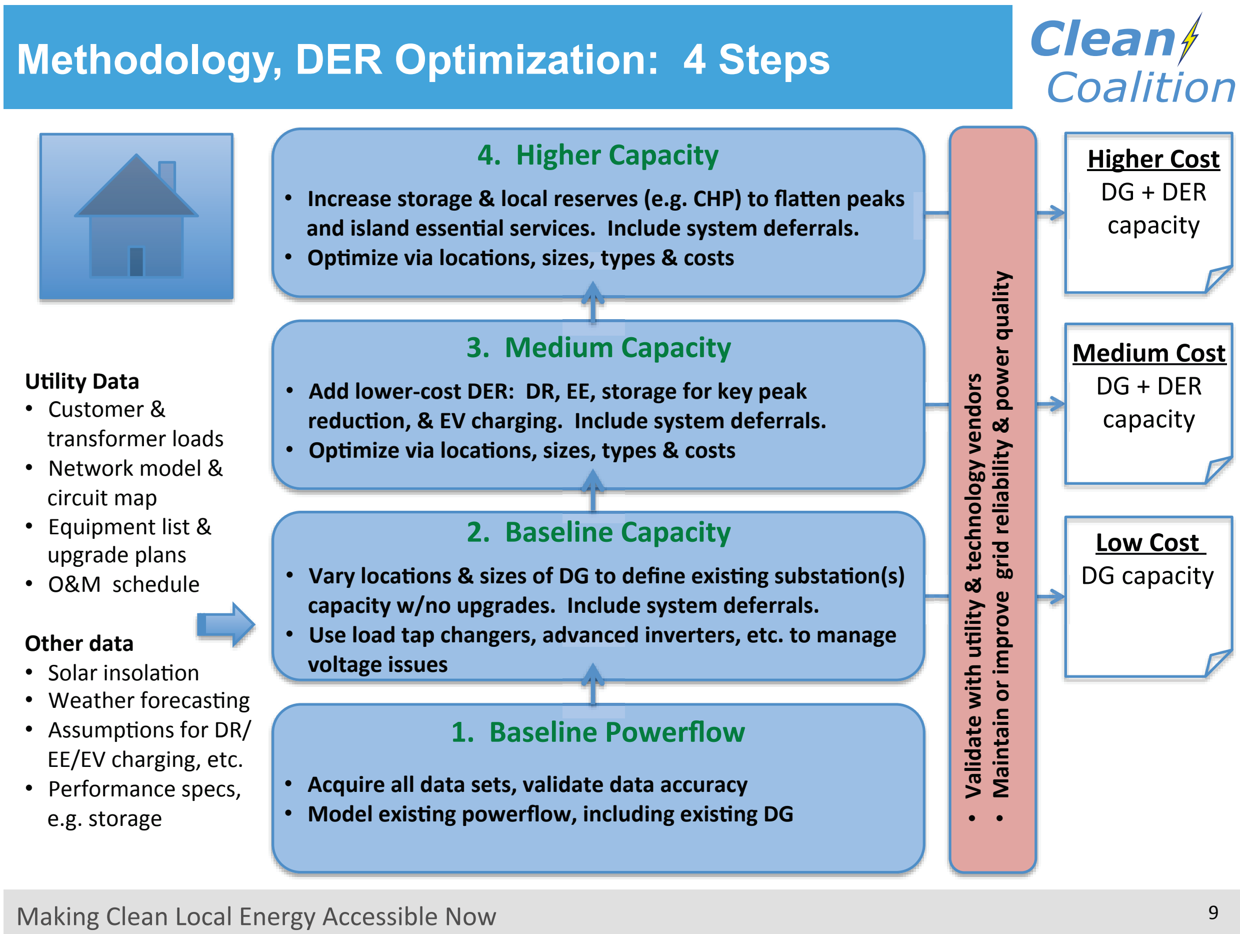
As stated, solar is the primary distributed generation resource for the Hunters Point substation. Therefore, demand response and energy efficiency programs for Hunters Point – and other solar-dominated areas – should align with daytime generation and reduce load at night. Different substations, however, are likely to have a unique mix of local renewable energy sources. For example, some communities may have a large geothermal or biopower resource. In these cases, optimal demand response and energy efficiency programs will need to modify loads accordingly, such as shifting loads to late night in order to satisfy a constant renewable energy resource after the larger, normal daytime and early evening loads fall off.

As with Step 2, the results can be optimized to achieve specific distribution grid equipment upgrade deferrals and savings in transmission costs.

Step 4: Higher Capacity ("Higher Cost" scenario). Step 4 builds on the previous steps to achieve further levels of system-wide efficiencies. In Step 4, a utility can determine the optimal and most cost-effective mix of additional energy storage (such as substation-wide flow batteries) and local, non-variable generation (such as CHP or fuel cells). Additional storage increases the amount of DG supported by the substation area without impacting grid operations. For example, with storage, any potential over-generation from local renewables can be stored and used later to satisfy evening peaks. This flattens the load shape locally, which simplifies transmission needs and operations, resulting in lower overall system costs. In addition, both the energy storage and local non-variable reserves like CHP enable essential services to be maintained during grid outages. As with DER in previous steps, energy storage and local reserves can be optimized by location, size, type and cost within a substation area, or even across substations. Step 4 results in a higher-cost deployment of local renewables and DER, however, this DER portfolio also provides a more reliable, resilient and efficient distribution grid.

As with Steps 2 and 3, Step 4 results in an optimized DER portfolio that can achieve specific distribution grid equipment upgrade deferrals and savings in transmission costs.

The diagram below illustrates this four-step methodology. Working through the steps is like building a house. One must start with a solid foundation to build upon – Step 1, or Baseline Powerflow. The Clean Coalition is employing this methodology for our Hunters Point Community Microgrid Project, in collaboration with PG&E. For our modeling, we use the commercial version of PG&E's distribution modeling tool, Cyme (specifically, CYMDIST v5.04 r10) and Integral Analytics LoadSEER, DSMore and IDROP software tools.



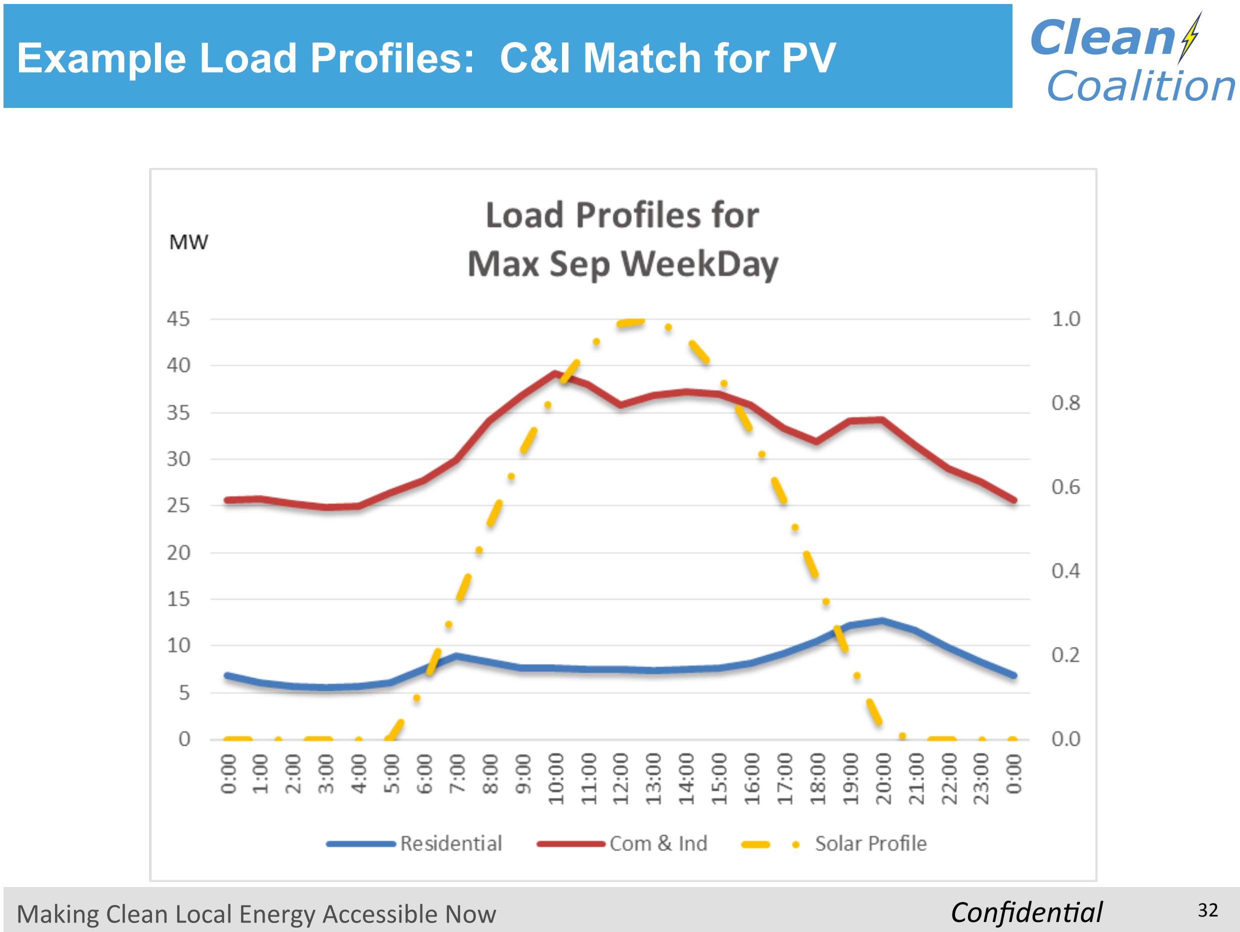
DER Optimization Methodology

By starting with the Baseline Capacity and then modeling DER portfolio combinations that leverage this baseline, a utility can determine the optimal mix of local renewables and other DER that result in the most cost-effective and resilient deployment for any given substation. In the case that a utility or community is already planning to target the higher capacity scenario – e.g. to maintain essential services in the case of outages – one option is to bypass Step 3, the Medium Capacity scenario, and go directly from the Baseline Capacity to Step 4, the Higher Capacity scenario. This is recommended only if the lower-cost DER options outlined in Step 3 are also included in Step 4. Through this methodology, the resulting DER portfolio will achieve the highest value and most cost effective outcome.

Identifying and prioritizing DG deployment at optimal locations in substation areas highlights an important fact for utility distribution planning: C&I customers are often an ideal match for DG programs, and especially PV, in these important ways:

- **Maximum Generation Potential:** C&I customers have larger rooftop and parking lot spaces that can generate larger amounts of energy.
- **Lower Costs:** Larger PV systems at C&I locations are more cost-effective to deploy than smaller residential rooftop systems, reducing overall system costs.
- **Best Locations:** C&I customers typically use much larger loads and thus are connected to more robust feeder segments. These more robust feeder segments are capable of handling more DG without grid upgrades.
- **Matching Loads:** C&I customers typically have larger daytime loads that match solar generation profiles.
- **Financial Motivation:** C&I customer typically have much larger electricity bills, thus they are more motivated to stabilize and reduce their long-term energy costs, including reducing demand response charges, through use of DG.

Given these five advantages, C&I customers offer the lowest hanging fruit to achieve scalable and cost-effective DER deployments. Utilities seeking to achieve distributed generation goals quickly and cost-effectively should design DG programs to leverage this C&I opportunity. The diagram below helps illustrate the value of a utility or community DER program focused on C&I customers. Note the load shape for the C&I customer segment, which is the red line in the diagram. As a general rule, the load requirements of the C&I customer segment reach an extended peak during the daytime, matching the generation profile of PV much more closely than the residential customer segment.

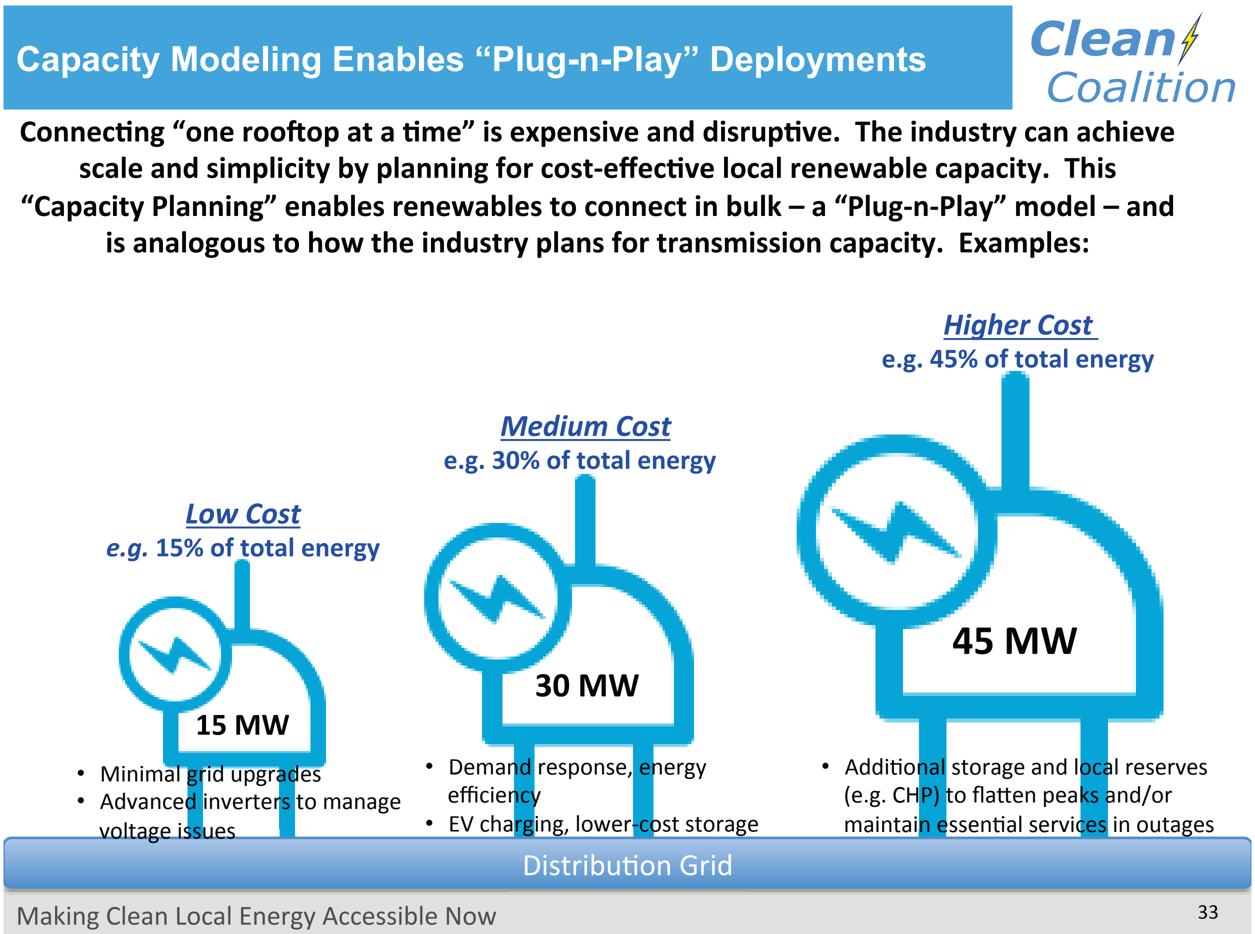


Hunters Point substation area load shapes: Commercial & Industrial vs. Residential

Note these considerations when evaluating the advantages of C&I DG programs:

- Feeders are connected within each substation. This enables sharing energy across feeders and thus across customers and customer types.
- Each urban/suburban substation or set of substations can determine the optimal mix of DER to accommodate balancing the generation and load across that substation's customer types: e.g. Commercial, Industrial, Residential.
- Both weekday and weekend load profiles must be considered.
- In general, during weekday daytimes when residential load is low and C&I load is high, a good portion or all of the C&I daytime PV generation can be consumed "hyper-locally" by C&I customers, either directly or via sharing energy across those customers.
- During the weekends, C&I customers may use less daytime load which can then be shared more broadly with local residential customers who often use more load mid-day on weekends than weekdays.
- Multi-dwelling units can be bundled with C&I given the larger rooftops and loads; however, the load profiles will match typical residential, not C&I customers.

As detailed above, the industry can achieve scale and operational simplicity, which reduces costs, by planning for the optimal mix of local renewable capacity and other DER. Once this planning process is in place, DER and supporting grid upgrades can connect in bulk – a "Plug-n-Play" model – rather than one project at a time, which is more expensive and operationally disruptive. This is similar to how the electric industry plans for transmission capacity or peak load on the distribution grid. As a simplified illustration, the diagram below proposes three generic distribution grid examples of "Plug-n-Play" deployment:



Examples of "Plug-n-Play" DG Interconnection based on Capacity Planning

This DER Optimization methodology, based on Capacity Planning, enables a bulk, Plug-n-Play model for bringing DER online, which achieves both scale and simplicity across the industry. The result is accelerating deployment timelines while substantially reducing operational costs.

Results: The Hunters Point Project

Following are the specific results using the DER Optimization methodology described herein for the Hunters Point substation area.

Results: Baseline Capacity

Using the methodology described herein to determine the Baseline Capacity of the Hunters Point substation area, following are the modeling results, validated through various methods:

1. **30 MW of new PV added to the substation feeders at optimal locations, equaling 25% of total annual energy**
    a. 20 MW added to select Commercial & Industrial sites matching low resistance locations with higher daytime loads
    b. 10 MW added to select Residential sites (multiple dwelling units) matching more robust feeder locations
    (NOTE: neither generation nor load from the redevelopment zone was included – will be added in the future)

2. **No adverse impacts to distribution grid operations**
    a. No out-of-range voltages. Maintaining voltage in accepted ranges was achieved using existing voltage regulation equipment including load tap changers. Note: Advanced inverters not needed yet, e.g., to provision reactive power.
    b. No backfeeding to the transmission system. Due to using connected feeders at the substation – "substation-as-a-system" – some "crossfeeding" between feeders occurred.

For readers who enjoy reviewing power flow details, the four tables below show the detailed results in voltage and major power flow across the four scenarios indicated in each title. Note that in each diagram, the table on the left indicates the baseline power flow results with no PV. The table on the right shows the changes resulting from adding the 30 MW of new PV into the model – 20 MW at optimal C&I locations, 10 MW at optimal residential locations.

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Baseline Capacity: Voltages & Major Power Flows, Weekdays (no PV vs. PV)

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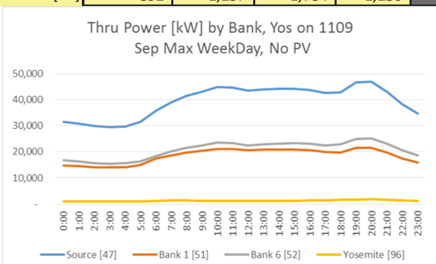
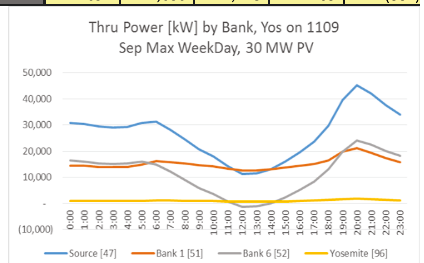
		PV: None			PV: 20 C&I + 10 Res		
		Sep WkDay Max Load Profiles			Sep WkDay Max Load Profiles		
Voltage Summary		Min	Avg	Max	Min	Avg	Max
		V_Base, all monitored pts			V_Base, all monitored pts		
22331106	Bank 1 [51]	121.6	122.9	124.6	121.5	122.9	124.0
22331105	Bank 1 [51]	121.7	122.9	124.6	121.6	122.9	124.0
22331104	Bank 1 [51]	122.2	123.8	125.4	122.1	123.7	124.7
22331103	Bank 1 [51]	119.7	122.6	124.6	119.4	122.5	123.9
22331101	Bank 6 [52]	122.0	122.9	123.9	121.2	122.8	123.8
22331102	Bank 6 [52]	118.8	120.7	123.6	118.3	121.0	123.6
22331107	Bank 6 [52]	116.5	119.2	123.5	115.8	119.4	123.5
22331108	Bank 6 [52]	118.0	119.7	123.6	117.2	119.9	123.5
22331109	Bank 6 [52]	118.9	121.2	123.7	118.0	121.2	123.6
22490401	Yos [96]	118.9	121.7	124.5	117.4	122.0	125.1
22490402	Yos [96]	122.3	123.6	124.7	118.9	123.1	125.2

Voltages in Range

Bus Rpt	kW Thru Pwr					kW Thru Pwr				
	Min	Avg	Max	Noon	NoonDif	Min	Avg	Max	Noon	NoonDif
Source [47]	29,440	39,393	46,921	43,417		11,263	26,673	45,309	11,263	(32,154)
Bank 1 [51]	14,003	18,507	21,552	20,725		12,585	15,272	21,099	12,585	(8,140)
Bank 6 [52]	15,352	20,748	25,184	22,529		(1,376)	11,310	24,036	(1,376)	(23,905)
Yosemite [96]	892	1,257	1,784	1,236		697	1,030	1,718	705	(531)

Feeder "Crossfeeding," no Backfeeding to Transmission





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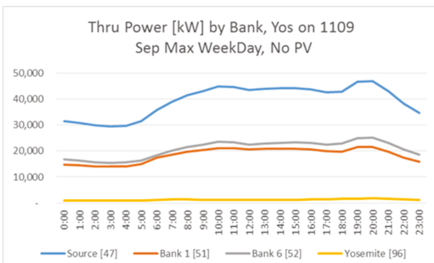
Baseline Capacity: LTC action, Per Feeder Power, Weekdays (no PV vs. PV)

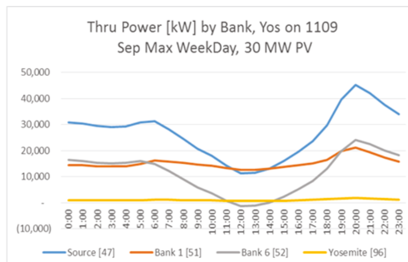
Clean Coalition

Tap Change Summary	PV: None Tap Changes	PV: None Min Tap	PV: None Max Tap	PV: None Average Tap	PV: 20 C&I + 10 Res Tap Changes	PV: 20 C&I + 10 Res Min Tap	PV: 20 C&I + 10 Res Max Tap	PV: 20 C&I + 10 Res Average Tap
Yosemite [96]	1	13	14	13	5	11	14	12
Bank 1 [51]	2	8	10	8	1	8	9	8
Bank 6 [52]	1	8	9	8	3	7	9	7

Feeders		PV: None Sep WkDay Max Load Profiles kW Thru Pwr Min	Avg	Max	Noon	PV: 20 C&I + 10 Res Sep WkDay Max Load Profiles kW Thru Pwr Min	Avg	Max	Noon
1106	Bank 1 [51]	4,142	5,483	6,496	6,389	3,406	4,338	5,948	3,406
1105	Bank 1 [51]	3,007	4,096	4,830	4,618	607	2,542	4,615	607
1104	Bank 1 [51]	3,605	4,618	5,363	5,132	3,602	4,425	5,347	4,633
1103	Bank 1 [51]	3,247	4,307	5,418	4,582	3,146	3,966	5,184	3,937
1101	Bank 6 [52]	3,098	4,211	5,309	5,033	559	2,498	4,380	559
1102	Bank 6 [52]	3,594	5,004	6,131	5,493	229	2,838	5,690	229
1107	Bank 6 [52]	2,444	3,379	4,116	3,696	141	1,991	3,982	141
1108	Bank 6 [52]	2,306	3,315	4,632	3,350	(787)	1,672	4,370	(747)
1109	Bank 6 [52]	3,904	4,830	5,810	4,949	(1,560)	2,306	5,603	(1,560)
401	Yos [96]	558	761	1,032	765	250	556	999	254
402	Yos [96]	334	495	751	470	319	474	719	451

Feeder "Crossfeeding"





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Clean Coalition
Making Clean Local Energy Accessible Now

Baseline Capacity: Voltages & Major Power Flows, Weekends (no PV vs. PV)

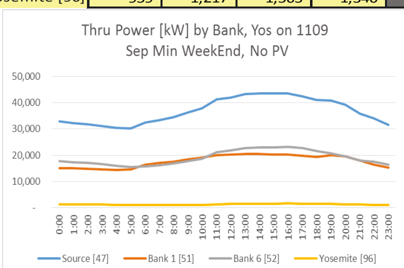
Clean Coalition

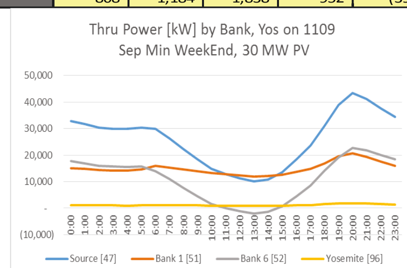
		PV: None			PV: 20 C&I + 10 Res		
		Sep WkEnd Min Load Profiles, no PV			Sep WkEnd Min Load Profiles		
Voltage Summary		Min	Avg	Max	Min	Avg	Max
		V_Base, all monitored pts			V_Base, all monitored pts		
22331106	Bank 1 [51]	121.8	122.9	124.0	121.5	123.0	124.0
22331105	Bank 1 [51]	122.0	122.9	124.0	121.7	123.0	123.9
22331104	Bank 1 [51]	122.3	123.8	124.8	122.1	123.8	124.7
22331103	Bank 1 [51]	120.0	122.6	124.0	119.4	122.5	123.9
22331101	Bank 6 [52]	122.1	122.8	123.3	121.4	122.8	123.9
22331102	Bank 6 [52]	118.9	120.6	123.2	118.3	121.0	123.6
22331107	Bank 6 [52]	116.7	119.1	123.1	115.9	119.4	123.5
22331108	Bank 6 [52]	118.1	119.7	123.1	116.9	119.7	123.5
22331109	Bank 6 [52]	119.1	121.0	123.2	118.2	121.3	123.6
22490401	Yos [96]	119.5	121.9	124.7	117.7	122.1	125.2
22490402	Yos [96]	122.7	123.7	124.8	119.2	123.1	125.3

Voltages in Range

Bus Rpt	kW Thru Pwr					kW Thru Pwr				
	Min	Avg	Max	Noon	NoonDif	Min	Avg	Max	Noon	NoonDif
Source [47]	30,132	36,890	43,613	42,023		10,040	26,029	43,540	11,200	(30,823)
Bank 1 [51]	14,322	17,746	20,440	20,124		11,982	15,015	20,705	12,345	(7,779)
Bank 6 [52]	15,444	19,020	23,232	21,748		(1,992)	10,926	22,669	(1,198)	(22,946)
Yosemite [96]	959	1,217	1,565	1,346		808	1,184	1,838	952	(394)

Feeder "Crossfeeding," no Backfeeding to Transmission



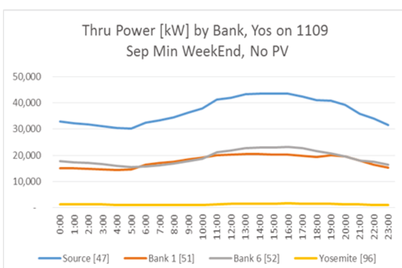


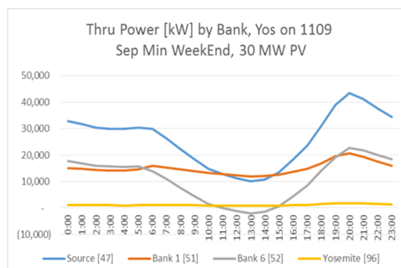
Baseline Capacity: LTC action, Per Feeder Power, Weekends (no PV vs. PV)

Tap Change Summary	PV: None Tap Changes	Min Tap	Max Tap	Average Tap	PV: 20 C&I + 10 Res Tap Changes	Min Tap	Max Tap	Average Tap
Yosemite [96]	1	13	14	13	4	12	14	13
Bank 1 [51]	1	8	9	8	1	8	9	8
Bank 6 [52]	0	8	8	8	3	7	9	7

Feeders		Sep WkEnd Min Load Profiles, no PV kW Thru Pwr Min	Avg	Max	Noon	Sep WkEnd Min Load Profiles kW Thru Pwr Min	Avg	Max	Noon
1106	Bank 1 [51]	4,106	5,190	5,966	5,962	2,959	4,048	5,682	2,984
1105	Bank 1 [51]	3,049	3,749	4,479	4,332	335	2,376	4,345	458
1104	Bank 1 [51]	3,661	4,574	5,234	5,114	3,642	4,437	5,354	4,656
1103	Bank 1 [51]	3,444	4,230	4,936	4,713	3,329	4,152	5,321	4,245
1101	Bank 6 [52]	2,914	3,653	4,437	4,328	(142)	1,942	3,680	(142)
1102	Bank 6 [52]	3,691	4,607	5,665	5,288	64	2,823	5,564	300
1107	Bank 6 [52]	2,483	3,081	3,801	3,542	16	1,954	3,829	180
1108	Bank 6 [52]	2,477	3,178	4,101	3,544	(531)	2,033	4,701	(202)
1109	Bank 6 [52]	3,868	4,494	5,254	5,038	(1,464)	2,169	4,885	(1,337)
401	Yos [96]	592	735	915	816	310	621	1,036	368
402	Yos [96]	350	481	649	530	389	563	809	583

Feeder "Crossfeeding"





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As the results above demonstrate clearly, a substantial amount of local renewables can be supported at little cost to utility operations, especially in certain substation areas. The distribution grid is currently underutilized in terms of local renewable generation potential. The existing, untapped capacity in each substation, especially urban and suburban substations, should be measured – then leveraged – as the first step in any DER Optimization effort.

Results: Medium Capacity
Results: Higher Capacity

[Note: The Hunters Point Community Microgrid study is currently in process. The results for the Medium Capacity and Higher Capacity scenarios will be provided in a subsequent version of this document]

Conclusion

As a leading and lower cost DG opportunity, solar power provides less than 1% of the total electric energy consumed in the U.S today.   Even though renewables – specifically solar – have experience rapid growth over the past few years, there is a long way to go until renewables are providing a significant portion of our national electric energy needs.

The strength of our electrical system is its breadth: power lines reach to almost every corner of the country. Until now, distribution grids have solely been used simply for unidirectional delivery of electricity – from a substation transformer to homes and businesses where the power is used. Technological advances now enable us to leverage the vast miles of distribution grid infrastructure (wires, utility poles and other equipment like load tap changers) to enable a bidirectional, dynamic grid that can integrate large amounts of local renewables and other DER.

This paper has detailed an approach to distribution grid planning that will result in cost-effective, optimized, and standardized deployments of local renewables and other DER. Every utility should develop distribution grid Capacity Planning using this methodology. And, it is consistent with a statement in a leading industry paper, the *More Than Smart* report – co-published by the Greentech Leadership Group, the Energy Foundation, and the Resnick Institute – to help establish a framework that modernizes the distribution grid:

> "…utilities continue to make significant investment in grid modernization. (One utility), for example, has incorporated fundamental changes to enable integration of DER at scale. These changes include larger distribution wire sizes and transformers that also improve safety and reliability. Given these grid modernization investments, distribution planning should start by establishing a common understanding of the capabilities of the existing system as a "baseline"."

Capacity Planning for DER, which includes evaluating the economic advantages of various DER portfolios, are indeed possible using existing commercial tools. In the case of the Hunters Point Community Microgrid Project, Cyme (CYMDIST) is used in concert with Integral Analytics software tools to help complete the picture for DER Optimization and distribution grid Capacity Planning. Note that both of these tools are already being utilized by investor owned utilities in California.

In addition, DER should be leveraged to maximize local balancing, as is economically and operationally feasible, to reduce the complexity between utilities and the transmission system operator. Too much operational complexity between utilities and transmission system operators will likely result in delayed implementation of a DER-optimized distribution grid. The more we can use DER to balance load and demand locally – e.g. on a substation basis, or across substations within a utility – the less complex the interface between utilities and the transmission system operator, which improves system-wide efficiencies and costs.

Transitioning towards a renewables-based electrical system is possible today. A road map that defines realistic deployment opportunities in the near-term, medium-term, and longer-term will guide us to an eventual ideal grid architecture. In the near-term, however, we can leverage existing, proven technologies and methodologies to achieve electrical system goals. The Hunters Point Community Microgrid Project, for example, proves that we can optimize a DER portfolio to achieve enhanced sustainability and reliability. We should move forward with these near-term deployment opportunities without delay.

Benjamin Franklin captured the imagination of the world in 1750 when he used a kite to "harness" electricity from lightning. This invention eventually led to the creation of the lightning rod. Franklin became famous for this accomplishment, giving demonstrations in Europe while the colonies were still debating whether or not to become an independent "United States."

Over a century later, in 1886, George Westinghouse founded a new company that pioneered long-distance and high-voltage alternating-current transmission, ushering in an era of centralized generation distributed over long distances. This brought lower-cost and highly available electricity service to the U.S. that is essentially unchanged today – a model we've lived with and benefitted from for over 100 years.

Now, over 125 years later, a third major wave of electricity innovation is upon us. Utilities can now plan for and deploy an optimized DER portfolio within and across substations. To begin, we can focus initially on the smaller subset of urban and suburban substations as they offer the biggest gains. With a little focus and training, we can unlock the potential of these substations and achieve a modern, more distributed energy system, wringing the most value out of this large, existing asset. The result is a truly sustainable energy solution – more sustainable financially, with predictable and stable long-term energy prices; more sustainable operationally, offering a highly resilient and simplified system-wide architecture; and of course, more sustainable for the environment. The U.S has pioneered electric revolutions twice before. We can certainly do it again – for industry, and for good. Let's get started!

EXHIBIT A: Methodology Comparisons

Two recent California studies have looked at how to increase reliable levels of distributed solar subject to various limitations. These two cases are both conceptually similar to the low cost case described above. The first study, commissioned by the CPUC, examines the technical potential for increasing levels of distributed solar within California, and also assessed the associated costs and benefits.[5] The CPUC paper was able to show that up to 15,000 MW of distributed PV can be deployed across all CA distribution networks by 2020. The central constraint used to identify this distributed PV potential is that it be consumed by local load, and not backflow from the distribution system onto the transmission system. This work uses detailed location dependent hourly generation and load profiles to assess distributed PV potential, but does not use engineering models to examine technical performance metrics of the distribution grid. One of the main conclusions of this study is that PV generation must be distributed throughout the state in rough proportion to load in order to achieve significant penetration. Substations with greater load can accommodate larger levels of PV without backflow. Sorting distributed PV projects by Least Net Cost (minimizing total system cost plus interconnection cost - avoided cost) identifies the most cost effective opportunities to locate DG in areas with high avoided costs. Interestingly, this study finds that the benefits of this approach carry through to about 2016, but disappear by 2020, when all ideal locations for distributed PV have been realized regardless of cost. Note that this CPUC study does not look at how any other DER approaches such as smart inverters, demand response, energy storage, or energy efficiency, or local reserves such as CHP can be used to increase the amounts of distributed PV that can be deployed across distribution networks while maintaining grid reliability and power quality.

The second study, commissioned by the CEC, evaluates the costs for SCE to comply with Governor Brown's *Clean Energy Jobs Plan* goal of 12,000 megawatts of distributed PV in California by 2020. SCE's share of this is 4800 MW. The study consists of a detailed engineering study of the entire SCE service territory using power flow modeling tools to evaluate the technical capabilities of their distribution networks to support distributed PV resources.[6] The CEC study looked at 3 base cases with 70% DPV in urban areas and 30% in rural areas; 30% in urban areas and 70% in rural areas; and 50% in both urban and rural areas. DG integration costs for the three base cases ranged from a low of just above $0.9 million for the urban centric case, to more than $1.3 billion for the most rural centric case. Notably, fewer system upgrades are required for DG installed in urban areas. Most costs are for interconnection to the distribution grid. In contrast, the mostly rural scenario has system upgrades that cost roughly the same as interconnection. Total integration costs from DG range from $190/kilowatt (kW) to $270/kW for the distribution system.

The CEC study takes a conservative approach for deploying distributed PV resources by limiting DG penetration to less than 15% of the feeder annual-peak load, as specified by Rule 21

[5] E3, Technical Potential for Local Distributed Photovoltaics in California, Preliminary Assessment, March, 2012
[6] The study utilizes a clustering technique to group feeders across the service territory, comparing feeder metrics and grouping similar feeder types to simplify the engineering analysis.

interconnection limits.[7] The study further constrained DG penetration by not allowing load to be offset by DG output. For example, with this constraint, a feeder rated 10 MW with 5 MW of load cannot accommodate 15 MW of DG. PV inverter power factors were also fixed in this study, limiting the ability of the DG installation to provide reactive power to the grid, and limiting its ability to manage voltage stability. This CEC study also does not take into account other DER approaches including smart inverters, demand response, energy storage, energy efficiency, or local reserves such as CHP.

Despite these limitations, the CEC study comes to some useful conclusions:

- The cost of DG integration depends highly upon locational factors, for both the distribution and transmission systems.
- Integration impacts and costs are lower when DG is installed in urban areas, where feeders are shorter and often equipped with larger conductor or cable along the entire length of the circuit.
- Integration costs increase significantly as greater amounts of DG are clustered and/or installed near the end of distribution lines.
- Distribution planning and operational criteria and practices that ensure minimal impact to reliability and system operability can limit DG integration, even on feeders where DG does not create loading or voltage violations.
- High penetrations of DG may require sophisticated communications and control systems to better manage impacts and reduce integration costs.

[7] Rule 21 is the California specific distribution interconnection tariff. More precisely, exceeding the 15% limit triggers a supplemental interconnection study.

EXHIBIT B: Feature Requirements for Tool Providers

Following is a summary of feature requests for utility tool vendors. These features, if incorporated, will further simplify and accelerate the human effort needed to achieve the described methodology and results.

To be added in Q4 2014

EXHIBIT C: Modeling Specification

Complete and Detailed Modeling Spec

To be added in Q4 2014