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

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

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 initial responses to the questions posed by the OIR and comments on the Preliminary Scope.

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 (DERs), 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 in California agencies and before other state and Federal agencies throughout the United States.

In collaboration with Pacific Gas & Electric and in support of the city of San Francisco's goal to achieve a 100% renewable electricity supply, the Clean Coalition is spearheading a groundbreaking project in the Bayview and Hunters Point areas of San Francisco. The Hunters Point Project, part of the Clean Coalition's Community Microgrids Initiative, will prove that local renewables can fulfill at least 25% of total electric energy consumption for 20,000 customers while maintaining or improving power quality, reliability, and resilience. Policymakers and utility executives need to 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 in 2014, will result in a replicable model that any utility or community can use to evaluate Community Microgrid opportunities. Ultimately, the modeling platform will expedite the creation of Community Microgrids by efficiently simulating the ability of local renewables and other DERs to balance vital grid services (power, voltage, and frequency) locally and cost-effectively. 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. Additional information about the Project is attached as Exhibit A.

The Clean Coalition uses sophisticated powerflow modeling and cost-benefit analysis tools to reveal how – and precisely where – local renewable energy can be supported in the distribution grid by intelligent grid solutions. The Clean Coalition team works with utilities and modeling tools providers to improve methods for distribution grid planning. For the Hunters Point project, we're working with PG&E's modeling tool provider Cyme and its cost-analysis tool provider Integral Analytics. Our team has experience with a broad range of powerflow modeling tools, but we've found that it's important to be able to show that utilities' favored tools can meet these new challenges once they have the right specifications to move forward. We're also developing standard specifications for modeling tools providers, so that our lessons learned from this experience can be applied to any other powerflow tool. More information about the Clean Coalition's grid planning and modeling methodology is attached as Exhibit B.

II. Responses to Questions Posed by the OIR

In response to the questions posed in the OIR, the Clean Coalition makes the following recommendations.

1) <u>What specific criteria should the Commission consider to guide the IOUs' development of DRPs?</u>

The Clean Coalition recommends consideration of the following optimization criteria to guide the development of the DRPs.

- Maintain or increase grid reliability and resilience.
- Encourage the development of clean DERs that cost-effectively avoid or defer alternative investments to meet projected demand for power and needs for grid services, such as investments in transmission, central generation, congestion mitigation, local peak resources, or flexible capacity.
- Leverage clean DERs to improve distribution system operational efficiency.
- Meet California's clean energy and climate goals and mandates, including AB 327 requirements for sustainable growth of distributed generation, Zero Net Energy, electric vehicles targets, energy storage targets, demand response goals, the Loading Order, and Long Term Procurement Plan requirements.
- Include all DERs that are projected to successfully bid into CAISO markets and current and future DSO procurement programs and markets.

The utilities should propose portfolios of DERs to meet these optimization criteria. For each substation, a utility should propose combinations of DERs (types, locations, sizes, and quantities), with consideration of aggregate local DER potential (cost-effective quantities projected to be available) for such substation. Each proposed portfolio should also reflect the existing mix of DERs and projects that have applied for interconnection.

Each DRP should be designed to cover the time period starting from the projected date of Commission approval of the DRP (March 2016) and ending at the last date covered by the next two General Rate Case cycles. For example, for a DRP for a utility whose next two General Rate Case cycles will cover 2017-2019 and 2020-2022, the DRP should cover March 1, 2016 through December 31, 2022. Aligning DRPs with the General Rate Case cycles is sensible because Section 769 provides that utilities will propose distribution investments through the

General Rate Case proceedings. Including the next two General Rate Case cycles is appropriate since it is both long enough to facilitate proactive planning to meet longer-term goals for transformation of the distribution system, and short enough to enable planning based on projections of DER potential and upcoming costs that DERs may avoid or defer with greater certainty in the near term and supported by the next GRC authorization.

2) What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

The Clean Coalition recommends dividing DRP requirements by three stages. By July 1, 2015, the utilities should be required to propose the following for Commission approval:

- Methodology for developing optimal portfolios of DERs for each substation based on the DRP optimization criteria described in response to question 1 above.
- Methodology for determining optimal and preferred locations consistent with the criteria in response to question 3 below.
- Methodology for calculating locational values described in response to question 4 below.
- Methodology for evaluating and proposing distribution grid upgrades for approval in the General Rate Case proceeding.
- Demonstration of application of all of the methodologies described above to at least one substation.
- Proposals for effectively coordinating existing and pending programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of DERs.
- Reasonable timeline for implementing the DRP for the entire distribution grid, including implementation of the methodologies described above, performance of grid upgrades, and deployment of DERs consistent with the optimal portfolios.
- Roadmap for continued improvement of planning, optimization and modeling of distribution systems.
- For the utility's entire territory, publish information regarding where locational value will influence the economic value of DER projects and associated interconnection costs based on the RAM interconnection maps with some enhancements.

By March 1, 2017, the utilities should be required to submit an application to the Commission with detailed DRPs that include the following:

- Proposed optimal portfolios of DERs for each substation to meet the DRP criteria, as described in response to question 1 above.
- Publicly provide preferred locations for 125% of targeted amounts of DER through searchable grid maps and databases.
- Location, description, and cost of distribution grid investments that will be proposed for approval in the General Rate Case.
- Projected net load shapes per substation in each season, and as modified by target amounts of DERs.
- Status report on implementation of DRP.

By year-end 2017, the utilities should be required to have implemented and deployed the DRP and associated DERs for at least one substation as a pilot project. The utilities should be required to submit a report to the Commission by March 1, 2018 regarding the planning and implementation of the DRP at the pilot substation, including a description of the major barriers and solutions discovered through the pilot.

3) What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs? 7) What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?
4) What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?

From a distribution grid system locational value perspective, optimal locations for DERs are those locations that avoid or defer alternative investments to meet projected demand for power and needs for grid services, such as investments in transmission, congestion mitigation, flexible capacity, central generation, local peak resources, and voltage control or conservation.

From a substation-level locational value perspective, optimal locations for DERs are the locations where the resource provides the greatest value to the grid and imposes the lowest costs to the grid. The locational value of a DER should be based on its ability to contribute toward locally balancing demand for power and preventing voltage violations. Optimal locations for distributed renewables are the locations that don't require grid upgrades (due to robust feeder locations and available capacity), match the load profile of the feeder (e.g. feeders with commercial buildings have high day time load, which matches peak solar production hours), and leverage a connected feeder system across a substation area for better local balancing such as cross-feeding (meaning back-feeding from one or more feeders to other feeders within a substation area). Similarly, optimal locations for other DERs that require interconnection are the locations that reduce the need for grid upgrades and help to smooth out the net load profile of the feeder. Advanced inverters for solar PV or storage can be strategically placed to help avoid voltage violations.

The Clean Coalition recommends the following means for encouraging siting of DER at optimal locations.

- Make it easier to identify optimal locations and capacities on the grid.
- Streamline and reduce costs of interconnection of renewable generation and storage at optimal locations, including crediting applicants for any upgrades that conform to DRP approved upgrades, comparable to the approach employed in the Transmission Planning Process.
- Develop adders for wholesale procurement prices of DER, as PSEG Long Island (formerly Long Island Power Authority) developed for distributed renewable generation in the transmission-constrained South Fork area.[1]
- Modify existing and upcoming DER programs to encourage siting at optimal locations.

5) <u>What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?</u>

[1] In connection with its CLEAN Solar Initiative II, The Long Island Power Authority (LIPA) offered a 7¢/kWh premium to 40 MW of appropriately sited solar DG facilities to encourage locational capacity sufficient to avoid $84,000,000 in new transmission costs and result in a net savings of $60,000,000. Proposal Concerning Modifications to LIPA's Tariff for Electric Service, available at http://www.lipower.org/pdfs/company/tariff/proposals-FIT070113.pdf

6) What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?

The Clean Coalition recommends the following approach and methods to developing optimal portfolios of DERs to meet optimization criteria, as introduced in response to question 1 above. First, establish the *Baseline Powerflow* to understand how much – and exactly how – electricity is delivered through the distribution system today and how the grid is impacted.

Second, define and publish the *Baseline Capacity of Distributed Renewables*, including optimal locations and generation amounts. The *Baseline Capacity* is the existing capacity of the substation area that requires no upgrades if specified generation amounts are placed in specified locations, but may include use of advanced inverters or load tap changer settings for voltage control. Although Baseline Capacity must not cause back-feeding to the transmission grid, it can incur cross-feeding among the connected feeders within a substation area. The optimal locations for distributed renewables are the locations that don't require grid upgrades and where the generation output matches the feeder load profile, as described more fully in response to question 3 above.

Third, plan for the *Additional Capacity of DERs* that should be incorporated, based on the optimal portfolios of DERs determined above. Determine the optimal locations for additional distributed renewables first, since other distributed resources (e.g. demand response and energy storage) can be used to cost-effectively integrate distributed renewables by, for example, smoothing out the net load profile and preventing voltage violations.

For more information, see Exhibit B.

10) Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?
15) What, if any, further actions, should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to

develop and implement DRPs?

The Clean Coalition recommends that the utilities be required to each deploy the approved DRP at a minimum of one substation by year-end 2017 sufficient to validate modeling and performance expectations. Such a demonstration project is critically important for ground-truthing and trouble-shooting new grid planning and modeling tools and methodologies as the DRPs are implemented across the entire distribution territory of each utility.

16) Questions regarding Appendix B.

   a. Integrated Distribution Planning: what, if any, additions or modifications would you suggest to the Integrated Distribution Planning section of this paper?

See responses to questions 1, 2, 5 and 6 above.

   b. Integrated Distribution System Operations: what, if any, additions or modifications would you suggest to the Integrated Distribution System Operations section of this paper?

The Clean Coalition fully supports the DSO-TSO model as described herein and in the separate, more detailed paper co-authored by Lorenzo Kristov and Paul De Martini.

   c. Integrated Grid Roadmap: what, if any, additions or modifications would you suggest to the Integrated Grid Roadmap section of this paper?

The Clean Coalition supports the long-term vision set forth in the Integrated Grid Roadmap. However, it is equally important to provide a roadmap for implementing realistic near-term and medium-term milestones for making progress toward these goals. Accordingly, the Clean Coalition recommends that each utility be required to deploy a demonstration project at one substation by year-end 2017 to pilot new grid planning, distribution system operations, and DER deployment methodologies and programs.

III. Preliminary Scope

The legislative intent behind Section 769 was to not only identify, but also guide DER deployment toward optimal locations. The preliminary scope set forth in the OIR includes several provisions to achieve this intent.

- "Integrate DERs into distribution system planning and operations; Specifically, propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources."
- Delineate how IOUs can more fully integrate DERs into distribution planning. Specifically, the IOUs should propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
- Consider further actions, if needed, to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs. Specifically the proceeding shall determine how any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation.

The Clean Coalition recommends that the Commission clarify that the scope of the proceeding shall include proposing methods to coordinate *pending* programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

IV. <u>Conclusion</u>

We appreciate the opportunity to offer comments on the questions and preliminary scope in the OIR. For the foregoing reasons, the Clean Coalition respectfully requests that the Commission adopt the above recommendations.

Respectfully submitted,

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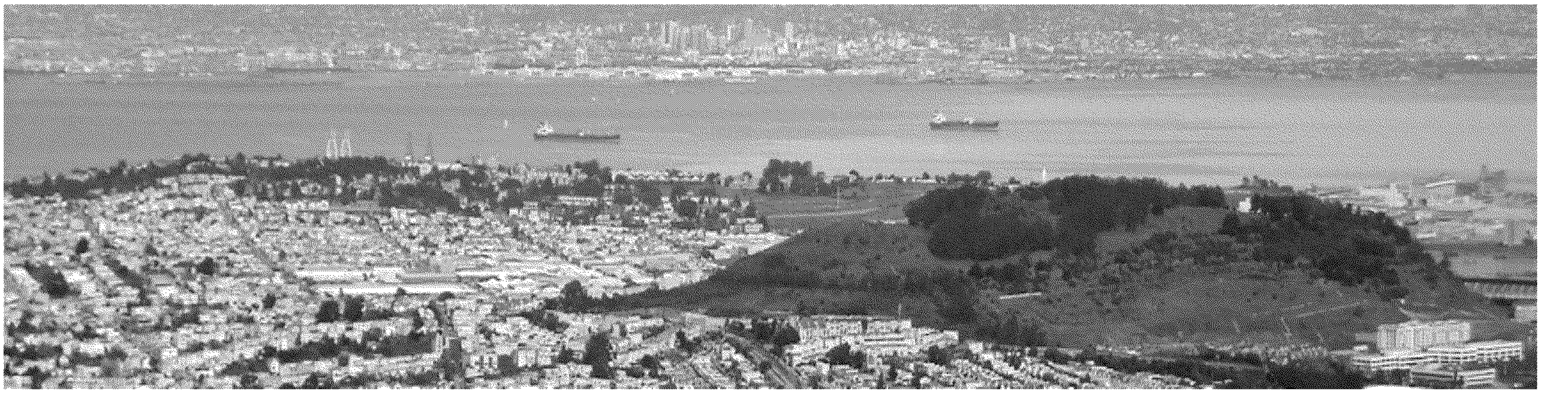
Dated: August 5, 2014

EXHIBIT A

Hunters Point Project Overview

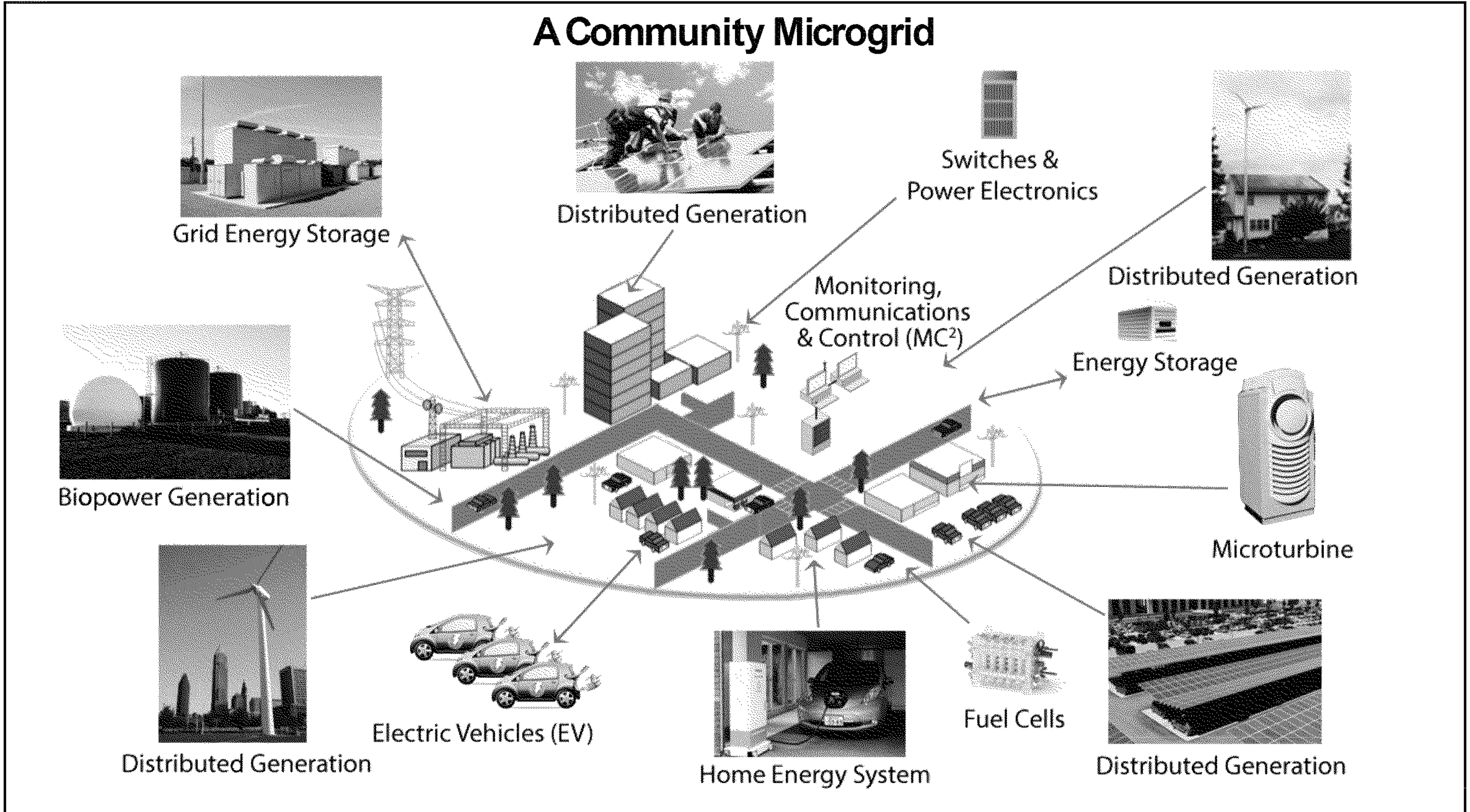
(See attached)

The Hunters Point Project: A Model for Clean Community Power



Project Overview

Bayview-Hunters Point Community



Community Microgrids, which achieve high penetrations of local renewables integrated with intelligent grid solutions like energy storage and advanced inverters, enable smarter, cleaner, and more resilient power systems.

Project Goals and Objectives

[redacted]

Phase 1 of the Project [redacted]

[redacted]

Phase 2 of the project [redacted]

[redacted]

EXHIBIT B

Optimizing Distributed Energy Resources in a Community Microgrid:
A Methodology and Case Study

(See attached)

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Optimizing Distributed Energy Resources in a Community Microgrid: A Methodology and Case Study

Greg Thomson, Director of Programs, Clean Coalition

DRAFT: *September 5, 2014*

Introduction

Distributed Energy Resources (DERs) – solar, wind, geothermal, biopower and other locally generated energy, combined with demand response, energy efficiency, EV charging, and energy storage – provide an opportunity to meet evolving electric system needs in a manner that is fundamentally different from the conventional, centralized model. Traditional system planning assumes that centralized generation and bulk transmission is the most cost effective way to deliver reliable and cost-effective energy to customers. While certain economies of scale exist for utility-scale projects, Distributed Energy Resources, or DERs, offer a cost effective-alternative while avoiding transmission costs and achieving additional policy objectives such as reducing greenhouse gas emissions and increasing resilience of the local electric grid infrastructure.

This paper provides a framework and methodology for any utility, utility commission, or community to plan for optimized DER deployments in a cost-effective and scalable manner, using tools available today. With this approach, high penetrations of local renewable energy and DER optimization are achievable while maintaining grid reliability and power quality. In sum, this methodology helps accelerate the transition of an existing, substantial asset – the distribution grid – to a modern, more cost-effective, and highly sustainable energy system.

This approach is somewhat unique. It starts from the principle that defining the existing, available capacity for locally produced energy, or Distributed Generation (DG), is the necessary foundation. Historically, the distribution grid was not designed for two-way power flow. However, the distribution grid is an existing, substantially large physical asset that, without modifications, can unlock a certain amount of two-way power capacity at no additional cost in terms of grid upgrades. This existing, or "Baseline DG Capacity," gives us the lowest-cost option for incorporating meaningful amounts of renewable DG into our electrical system. From that foundation, we can then calculate the optimal costs for a portfolio of other DERs that include demand response, energy efficiency, EV charging, energy storage, and other local non-variable generation such as combined heat and power, or CHP. In turn, this optimized DER portfolio can increase the amount of renewable DG supported by the substation. At the same time, an optimized DER portfolio can provide other invaluable services such as flattening peaks, which reduces the complexities (and thus costs) of transmission operations, and maintaining essential services in the case of grid outages.

In this study we are most interested in understanding the potential costs to utilities in order to support optimized portfolios of DERs. The grid may need an upgrade to support high levels of renewables, but what are the most cost-effective upgrade scenarios for any given substation, provided that reliability of the distribution grid is maintained?

In order to compete with transmission and central generation investments on a level playing field, and in order to fully comply with state and federal clean energy goals, all values of DERs should be accounted for in cost-effectiveness calculations. DERs provide a number of significant and quantifiable benefits to ratepayers. These include:

- Deferring or avoiding transmission and distribution investments
- Increasing independence from transmission system energy services
- Increased system efficiency
- Meeting clean energy goals
- Reducing contingency reserves
- Improving local resiliency and power quality
- Hedging against fossil fuel price volatility

The costs of DER include:

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

The costs and benefits of DERs are largely dependent on location. Therefore, accurate estimation of costs and benefits requires a detailed understanding of the local grid dynamics and the manner in which these resources impact it. 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 at realistically evaluating DER costs and benefits must therefore be transparent, vetted by a large cross section of stakeholders, and include the type of granularity required to establish the locational value of these resources.

Traditional system planning views DER as "alternatives" to transmission and central generation, and rarely proactively proposes integrated solutions to meet needs. Distribution planners, on the other hand, generally fail to account for the value of DER in avoiding investments in transmission and central generation. An integrated approach to transmission and distribution planning is necessary for moving beyond the current view of DER as Non Transmission Alternatives (NTA). Instead, we need to evaluate DER as a means of addressing system-wide needs. For example, in principle the distribution grid is able to supply power to the transmission grid. However, the methodology described herein causes zero backflow to the transmission grid

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

while preserving voltage stability. This zero backflow condition ensures that impacts to the infrastructure and operation of the transmission grid resulting from increased DER penetration will be minimized. In fact, by optimizing DERs at the substation level to provide better local balancing of load and generation – thereby maintaining a flatter load shape overall – transmission grid operations can be simplified and thus less costly, as an additional benefit.

For Community Microgrid Initiative projects, optimization of DER portfolios involves finding the most cost-effective opportunities to achieve the goal of 25% or more of the total electric energy consumed at a substation being provided by local renewables while maintaining or improving grid reliability. However, this approach and methodology can also be applied to grid planning efforts with different optimization criteria.

For example, in California, Assembly Bill 327 (AB 327) requires utilities to propose Distribution Resources Plans by July 2015 to guide DERs to optimal locations on the distribution grid, while allowing utilities to rate-base only distribution grid investments that yield net benefits for ratepayers.[2] Utilities should consider the following optimization criteria when developing the optimal portfolio of DERs for each substation, including determining the target amounts of distributed renewable generation:

- Maintain or increase grid reliability and resilience.
- Deploy clean DERs that cost-effectively avoid or defer alternative investments to meet projected demand for power and needs for grid services, such as investments in transmission, central generation, congestion mitigation, local peak resources, or flexible capacity.
- Leverage clean DERs to improve distribution system efficiency (e.g. using advanced inverters to achieve conservation voltage reductions).
- Meet California's clean energy and climate goals and mandates, including AB 327 requirements for sustainable growth of distributed generation, Zero Net Energy, electric vehicles targets, energy storage targets, demand response goals, the Loading Order, and Long Term Procurement Plan requirements.
- Include all DERs that are projected to successfully bid into CAISO markets and current and future Distribution System Operator procurement programs and markets.

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 lower costs, locally-sited renewable energy (particularly from wind and solar) is now economically competitive, 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 energy provides more than 15% of peak power in a community. Without evidence that the grid can handle greater amounts of local renewables in a

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

cost-effective manner, this limit will continue to impede the nation's transition towards a modern and sustainable energy system.

To overcome this barrier, the Clean Coalition has established a Community Microgrid Initiative in partnership with electric utilities, community stakeholders, and energy developers, proving that local renewables connected to the distribution grid can provide 25% or more of the total electric energy consumed while maintaining or improving grid reliability, as part of a portfolio of optimized and cost-effective DERs. The Clean Coalition's Community Microgrid Initiative, which embraces existing utility infrastructure combined with more local generation of sustainable energy resources, provides the following substantial benefits:

- Accelerates clean energy & sustainability: By achieving 25% or more of the total energy needed by a community as local renewables
- Improves grid performance, reliability & resilience: Using DERs such as advanced inverters, demand response, energy efficiency, EV charging, energy storage, and local reserves (e.g. fuel cells, CHP)
- Optimizes for cost-effectiveness: Via advanced grid and cost scenario modeling in partnership with utilities, leading to scalable deployment programs
- Stabilizes and shifts energy costs: To more predictable and fixed energy prices, to reduced transmission-related costs & inefficiencies, and to more local investment & jobs

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 spec, or "planning blueprint," based on existing tools & technology, that anyone in the industry can use. This methodology and results will be validated first with Cyme's CymeDIST tool and Integral Analytics' cost analysis tools using the Hunters Point Project with PG&E as a single, substation-wide model. It will then be published to other tool vendors, to other utilities, and used as a blueprint to inform utility commission planning requirements.

2. **Deployment**: By defining large-scale Procurement and Interconnection solutions that utilities and communities can embrace. Procurement recommendations include a wholesale model (e.g. feed-in-tariff) for larger locally produced energy systems with capitalized grid upgrades. Via distributed energy capacity planning, Interconnection recommendations feature pre-approved local generation amounts that connect at scale.

Today, solar in communities is added to the grid extremely slowly, or "one rooftop at a time," with often unknown impacts to the grid that unnecessarily restrict adoption. With the Community Microgrid Initiative methodology, utility commissions and utilities 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 then add substantial amounts of distributed renewable energy to their grids rapidly and at scale – achieving effectively a "plug-n-play" model.

The Community Microgrid Initiative changes the game by creating this top-down, system-wide, scalable solution across utility substations – vastly different to how local renewables are deployed today. Using this approach, grid operators can quickly and accurately plan for a precise amount of renewable energy that can be integrated into community substations in months rather than years, and based on scenarios such as:

1. **"Low Cost" scenario**: the amount of local renewable generation supported by a substation area and it's existing equipment, i.e. requiring no upgrades, and that utilizes existing voltage regulation equipment and/or smart inverter functionality to help stabilize voltage, as needed.

2. **"Medium Cost" scenario**: 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 DERs such as demand response, energy efficiency, EV charging, and storage, and that may require minimal upgrades to existing equipment.

3. **"Higher Cost" scenario**: 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 that achieve specific performance goals such as flattening peaks and/or maintaining essential services in case of outages.

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 a much more operationally predictable and financially viable solution – and analogous to how the grid is operated today via transmission capacity targets and peak demand levels.

The Hunters Point Community Microgrid Project – A Case Study

In collaboration with Pacific Gas & Electric (PG&E), and in support of achieving at least 25% of total annual energy as local renewables, the Clean Coalition has engaged in a Community Microgrid effort in the Bayview-Hunters Point area of San Francisco. The Hunters Point Community Microgrid Project encompasses an entire substation area, serving 20,000 residential and commercial/industrial customers. The project, named after the Hunters Point substation that serves the area, showcases how communities and utilities can reap significant economic, energy and environmental benefits, including a stronger and more resilient grid, from deploying higher levels of local renewable energy in an optimized and cost-effective mix with other DERs. The project demonstrates that the technologies required to plan and deploy these advanced energy solutions are readily available today (in this case, using Cyme's CYMDIST tool, v5.04 r10 for dynamic distribution grid modeling).

In order to reach at least 25% of the total energy consumed as local renewables, the community needs approximately 50 MW of new PV installed. This will be added to the 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, 50 MW of new PV plus 8 MW of existing PV-equivalent local renewable energy achieves 91,000 MWh (Megawatt hours) of annual renewable electricity generation, or 28% of the total annual load of 320,000 MWh in the substation plan.

Although the methodology described below and the existing tools can accommodate this, we initially ignore some other forms of distributed generation (e.g. small wind), partly because the Bayview-Hunters Point area does not easily facilitate other forms of local renewable generation such as small wind or geothermal (other than the existing biopower produced by the local wastewater treatment plant), and partly because solar PV is the fastest growing market segment.

Note that the Hunters Point naval shipyard is being re-developed over a number of years, requiring a portion of this analysis to be forward-looking. By evaluating the redevelopment plan's detailed estimates, including rooftop square footage and loads, a conservative amount of 20 MW of new solar can be applied to the redevelopment area. This leaves 30 MW of new PV for the remaining, existing area served by the substation – the Bayview area – that will not be redeveloped. This is the near-term opportunity and serves as the basis for this study. Thus, our modeling effort adds 30 MW of new PV and optimizes other DERs on the feeders serving the non-redevelopment zone. In fact, those 30 MW of new PV for the Bayview area, plus the 8 MW of existing (PV-equivalent) local renewable energy already located in that area, reaches 60,000 MWh of annual renewable electricity generation, or 25% of the total annual load of 236,000 MWh serving the Bayview area (the non redevelopment zone).

The Clean Coalition's Community Microgrid Initiative also grows local economies by increasing private investment, creating jobs, stabilizing energy prices, and keeping energy dollars close to home. As mentioned, achieving 25% of the total energy consumed as local renewables in the Bayview-Hunters Point area of San Francisco would add 50 megawatts of new, cost-effective local solar to the area. Using industry-accepted assumptions from sources such as National Renewable Energy Laboratory (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 megawatts of new PV added to the San Francisco bay area would strengthen the community over 20 years as follows:

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, cumulatively
- $30 million saved by local businesses and homes by reducing power outages

Environmental Benefits:

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

The Clean Coalition's Hunters Point Project highlights the technical and economic feasibility of high penetrations of local renewables and other distributed energy resources while reducing overall energy system costs – serving as a cutting-edge model and example deployment for modernizing America's electrical system in the most sustainable manner possible.

DER Optimization Methodology

As stated, the goal of this study is to establish a replicable and scalable framework for optimizing DERs in a cost-effective manner, as part of a Community Microgrid covering an entire substation area. Conventionally, utilities have modeled the distribution grid to manage peak loads only, with generation arriving via the substation transformer then distributed in one direction across the substation feeders. With DER Optimization, modeling requires a dynamic, two-way, and time-based approach, with generation blended across local and substation transformer sources and analyzed over time, in 15-minute increments, for example. For the most part, this type of modeling is entirely new to utility operations. With a change in focus, and using existing tools, we can take this "unknown" quantity and make it a "known," enabling utilities, utility commissions, and communities to make informed decisions about energy system goals and costs.

In order to optimize a DER portfolio, it is critical to account for the benefits of complementary functionality between DERs, instead of simply focusing on each individual component in isolation. Such synergistic relationships between different DER options 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. Such low mid-day energy prices, when communicated to end users via Time of Use or dynamic pricing, may lead to behaviors that mitigate this over-generation condition. For example, low 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 later in the day. Also, peak PV generation impacts can be mitigated with demand response (used to increase daytime loads) and daytime electric vehicle

(EV) charging.[3]

Similarly, the value of distributed solar and storage are enhanced by turning on advanced capabilities of the inverters, which can prevent over-voltage 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 distribution energy storage options. Curtailment of DG resources is not specifically a DER resource but rather a 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 these DERs, given the combination of local load and generation.

If we examine the cost effectiveness of increasing levels of distributed PV penetration from the perspective of the utility, the cost effectiveness curve has a relatively trivial starting point but becomes increasingly complex as we increase levels of distributed PV penetration. For simplicity, let's start by looking at a single substation. A single substation will be able to integrate a certain amount of distributed PV generation, from the perspective of incremental physical costs to the utility grid, at an extremely low cost. This is because utility customers are paying distributed PV costs, and for net energy metered systems, interconnection costs are essentially zero. Furthermore, small wholesale DG facilities pay their own interconnection costs, so for these systems the cost to the utility is also essentially zero. Therefore, the first point on the cost effectiveness curve corresponds to the maximum amount of PV resources that can be reliably integrated within a single distribution grid at the lowest possible cost, subject to the zero backflow condition and required voltage regulation.

Distribution resources planning should require utilities to correctly and accurately define and publish this existing Baseline DG Capacity including optimal locations and generation amounts along the feeders within a substation area. This will enable the most cost-effective support for high penetrations of distributed renewable energy while providing the baseline from which additional DER solutions, such as demand response, energy efficiency, EV charging, energy storage, and local reserves such as combined heat and power (CHP), can be calculated – again, at the most efficient cost to the utility and ratepayers. This DER Optimization Methodology, achieved via the fours steps described below, is based on <u>Capacity Planning</u>. It provides a blueprint for how utilities can use existing tools to achieve the utility of the future in months rather than years.

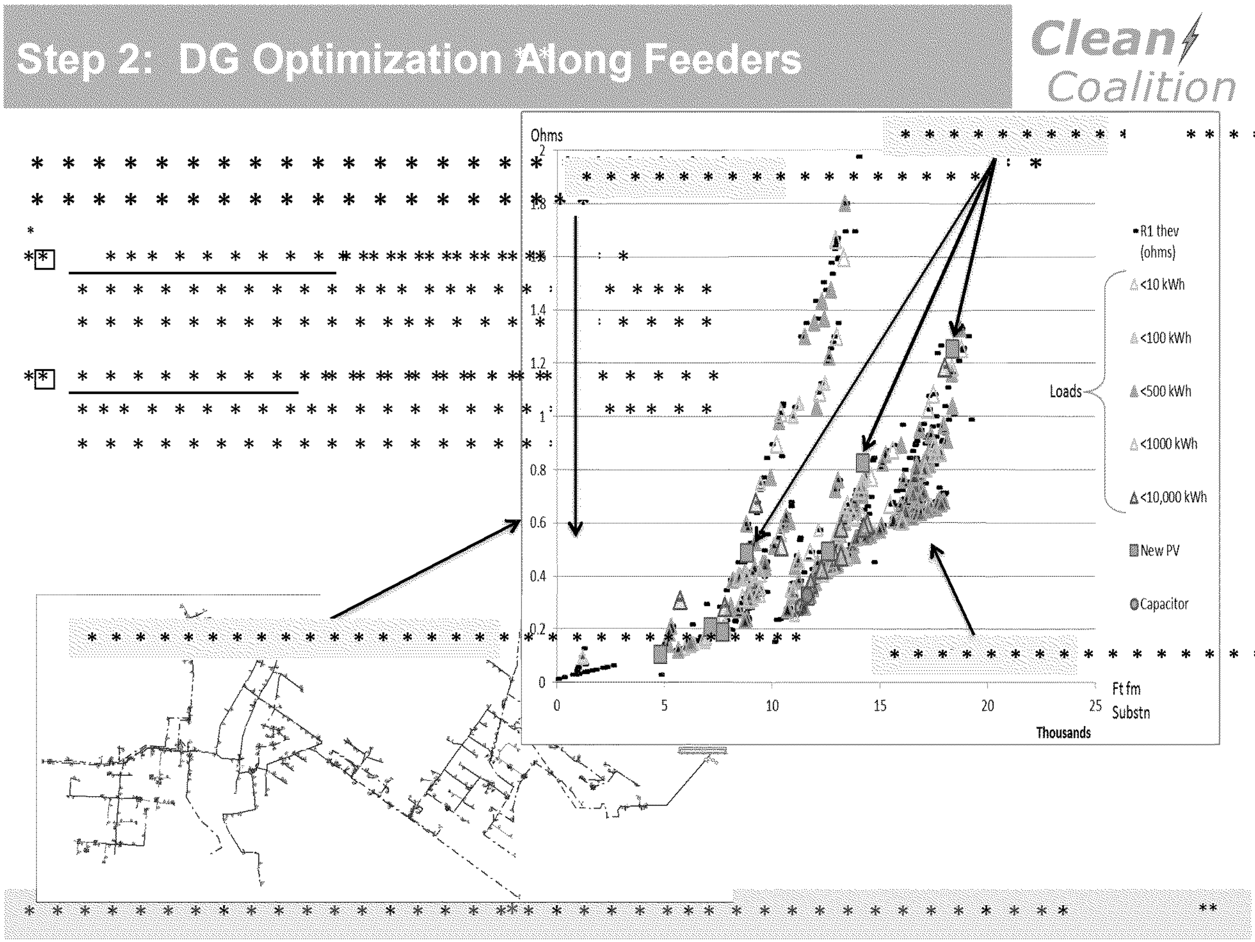
Step 1, "Baseline Powerflow," is the foundation. This must be completed first in order to understand how much – and exactly how – electricity is delivered through the system today

[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/

[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.pdf퀣□η

including grid impacts. Without this step, we cannot understand how any amount of local renewables added to the distribution grid will impact the existing system, or substation area. Note that this step requires a pre-requisite: incorporating the right data sets from utilities, which includes customer and transformer loads, network model and circuit map (including schematic, connections, wire and cable types, and equipment settings), equipment list and upgrade plans, and an operations and maintenance schedule. The latter two help incorporate the costs of potential upgrades as part of the three optimization scenarios outlined below. Metrics measured during this step 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 2, "Baseline DG Capacity," defines the potential capacity for local renewable generation that can be supported by the existing circuit – by each feeder and by the system of connected feeders that make up a substation area. This is based largely on the current physical nature of the circuit – e.g., wire thickness and length along with the current capabilities of the voltage regulation mechanisms. Achieving this step is also based on matching local generation to local loads – in the case of solar, for example, using both robust feeder locations and customers with large daytime loads to find the optimal locations to place solar along the feeders. This step provides the optimal locations and amount of local renewables that can be supported by the system today, with no changes or upgrades needed - knowledge that is critical in order to design the most cost-effective solution. And, without this step, the next two steps – the next two floors of the building, if you will – risk being over-planned and thus too costly. Note that one can also find optimal locations in different combinations, such as less robust feeder locations with large daytime loads, or more robust feeder locations with lower daytime loads. The diagram below illustrates achieving this step using resistance, or ohms, in combination with daytime load sizes.



In addition, using connected feeders across the substation enables the following substation-wide optimizations:

1. **Local Balancing**: e.g. over-generation on certain feeders consumed by load on other feeders connected at the substation. As one example, this enables weekend PV generation on large commercial rooftops that normally would be consumed locally (either onsite or on that feeder segment) during the week to be consumed by residential customers within that substation area during the weekend.
2. **Optimizing Settings**, e.g. load tap changers, across the substation feeders
3. **Optimizing DER** (see steps 3 & 4) such as storage and demand response across the substation feeders

As stated, defining the Baseline DG Capacity means finding the optimal locations for DG in a substation area by determining the most robust feeder locations and optimal customer load types that match 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 minimal daytime loads to test the "worst-case" scenario. In the case of any voltage issues, smart inverters can be used to help bring voltage back into an acceptable range by

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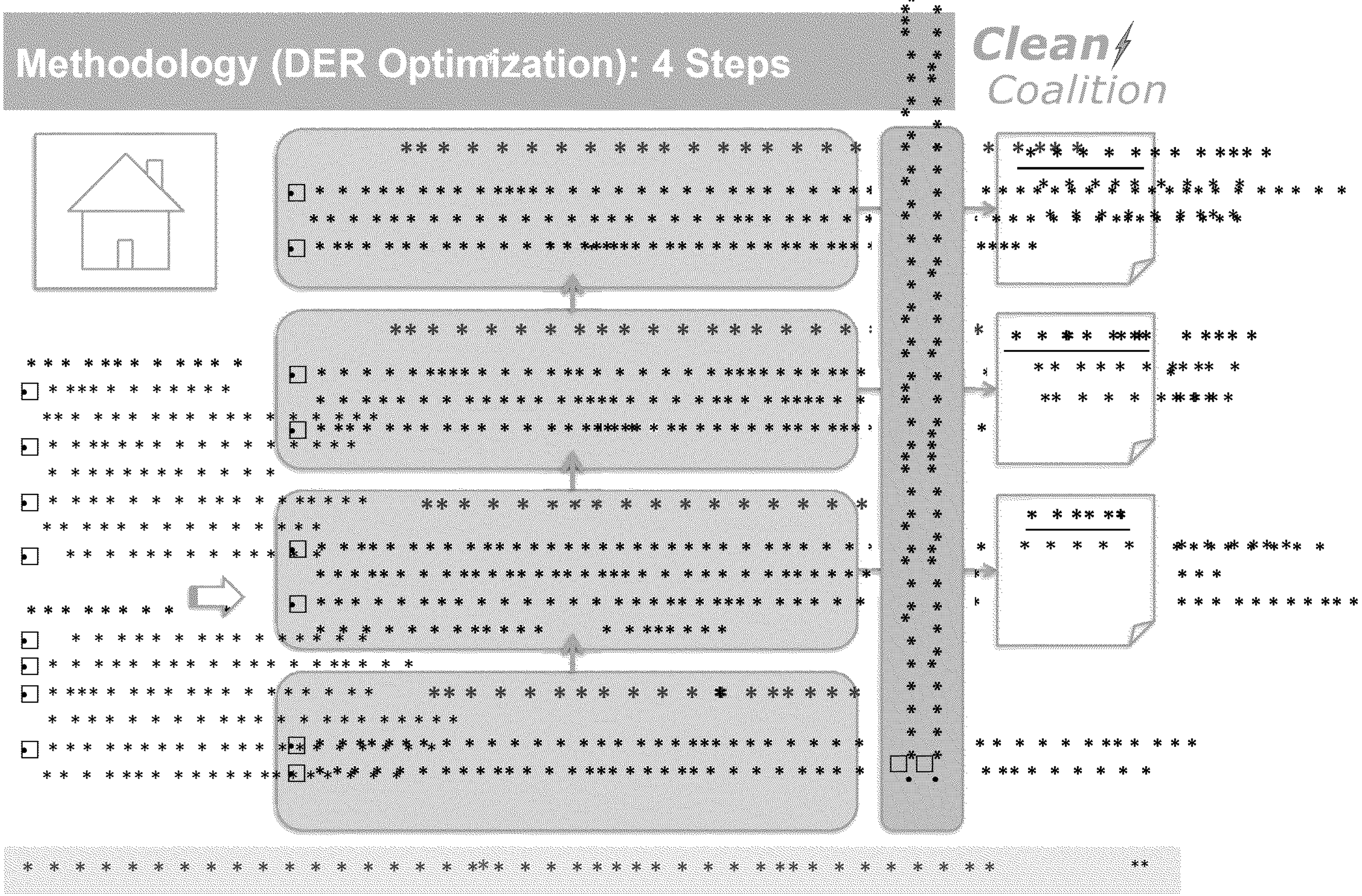
provisioning reactive power. Data sets (from utilities and/or partners) required to complete this step (and the following two steps) include solar insolation data; weather forecasting data (to reach more granular results); performance characteristic assumptions for demand response, energy efficiency, and EV charging; and other product performance specs, e.g. for various energy storage solutions. As with Step 1, metrics measured during this step 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 DG/DER Capacity," builds on Step 1 by adding lower-cost DER options such as demand response, energy efficiency, and EV charging, along with cost-effective energy storage. These DER solutions can lower demand and/or peak loads at critical times and/or add load during daytime generation of solar (if needed), thereby increasing grid performance as well as the amount of DG supported by a substation area. As above, it requires optimizing the DER portfolio based on locations, sizes, types and costs in order to achieve defined DER penetration and cost targets. Starting with presumably lower-cost approaches such as demand response, energy efficiency, and EV charging will likely result in a more cost-effective grid outcome, prior to including storage options such as onsite combined PV/storage solutions. Finding the optimal mix across these lower-cost DERs for any given substation results in the next level up, or medium-cost solution, for achieving high penetrations of local renewable energy and other DERs.

Step 4, "Higher DG/DER Capacity," builds on the previous steps to achieve further levels of system-wide efficiencies such as flattening load shapes (e.g. reducing evening peaks) to minimize the dependency on and complexity of the regional balancing authority, while at the same time being able to maintain essential local services during grid outages. In this step, 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 combined heat and power (CHP) or fuel cells. The additional storage increases the amount of potential solar generation supported by the substation area without impacting grid operations with, for example, backfeeding to the transmission grid. This "over-generation" can then be used later to reduce evening peaks, which flattens the load shape locally and thus simplifies system-wide operations of the regional balancing authority – resulting in lower overall system costs. In addition, both the energy storage and local non-variable reserves such as CHP enable essential services to be maintained during grid outages. These additional DER options can also increase the amount of local renewable generation available to the substation area. As with previous steps, the additional energy storage and local reserves can be optimized via locations, sizes, types and costs within a substation area, or across substations. This step will result in a higher-cost option for local renewables and DER, but will also result in a more stable and resilient distribution grid with improved system-wide impacts via more local balancing.

[Note: The Hunters Point Community Microgrid study is currently in process. Specific results will be provided in a subsequent version of this document to be released in Q1 2015.]

The diagram below illustrates this four-step methodology. It should be read from the bottom up. The analogy is building the foundation and floors for a building or house. One must start with the foundation and first floor, and then build up from there. This is the methodology the Clean Coalition is using for the Hunters Point Project in collaboration with PG&E, using the commercial version of PG&E's distribution modeling tool, Cyme (specifically, CYMDIST v5.04 r10) and Integral Analytics cost analysis tools.



By starting with the Baseline DG Capacity first, then modeling a portfolio of distributed energy resources in combinations that leverage that Baseline DG Capacity, a utility can determine the optimal mix of local renewables and other DERs that result in the most cost-effective and resilient deployment for any given substation, the utility, and the community.

The above methodology – using optimal locations along feeders in substation areas – highlights an important fact for utility distribution planning. The Commercial & Industrial (C&I) customer segment is an ideal match for distributed generation in general, and for solar in particular, for the following primary reasons:

- **Most Potential:** C&I customers have larger rooftop and parking lot spaces that can generate larger amounts of energy (e.g. from solar).
- **Lower Costs:** These larger solar systems 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 much more capable of handling distributed generation.
- **Matching Loads:** C&I customers typically have larger daytime loads that match solar generation profiles.
- **Financially Motivated:** 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, by participating in a utility DG program.

Based on the above five advantages, Commercial & Industrial customers clearly offer the lowest hanging fruit for utility or community programs that wish to achieve scalable and cost-effective renewable energy/DER deployments. Utilities should design and deploy programs that embrace this C&I opportunity in order to achieve distributed generation goals much more quickly and for far less cost. 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 – 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, which matches the generation profile of PV much more closely than the residential customer segment.

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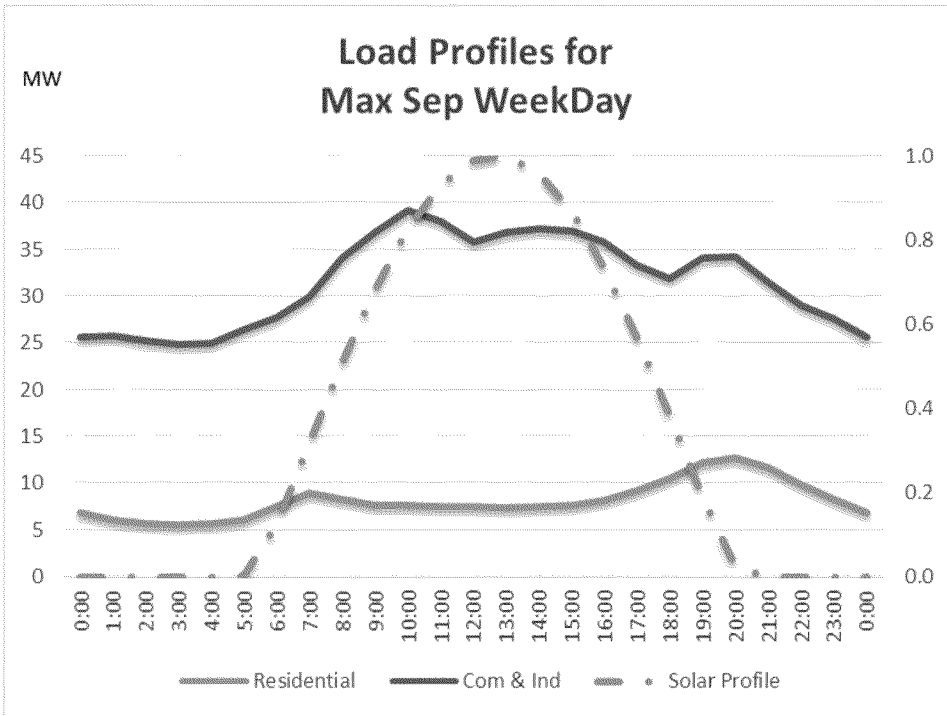
Example Load Profiles: C&I Match for PV



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Note these considerations:

- 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 find the most optimal mix between the three primary customer types: Commercial, Industrial, or 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 during weekend daytimes than weekday daytimes.
- Multi-dwelling units can be bundled with C&I given the larger rooftops and loads; however, the load profiles will match residential, not C&I.

As detailed above, the industry can achieve scale and operational simplicity – which further reduces costs – by planning for cost-effective local renewable capacity and optimized DERs.

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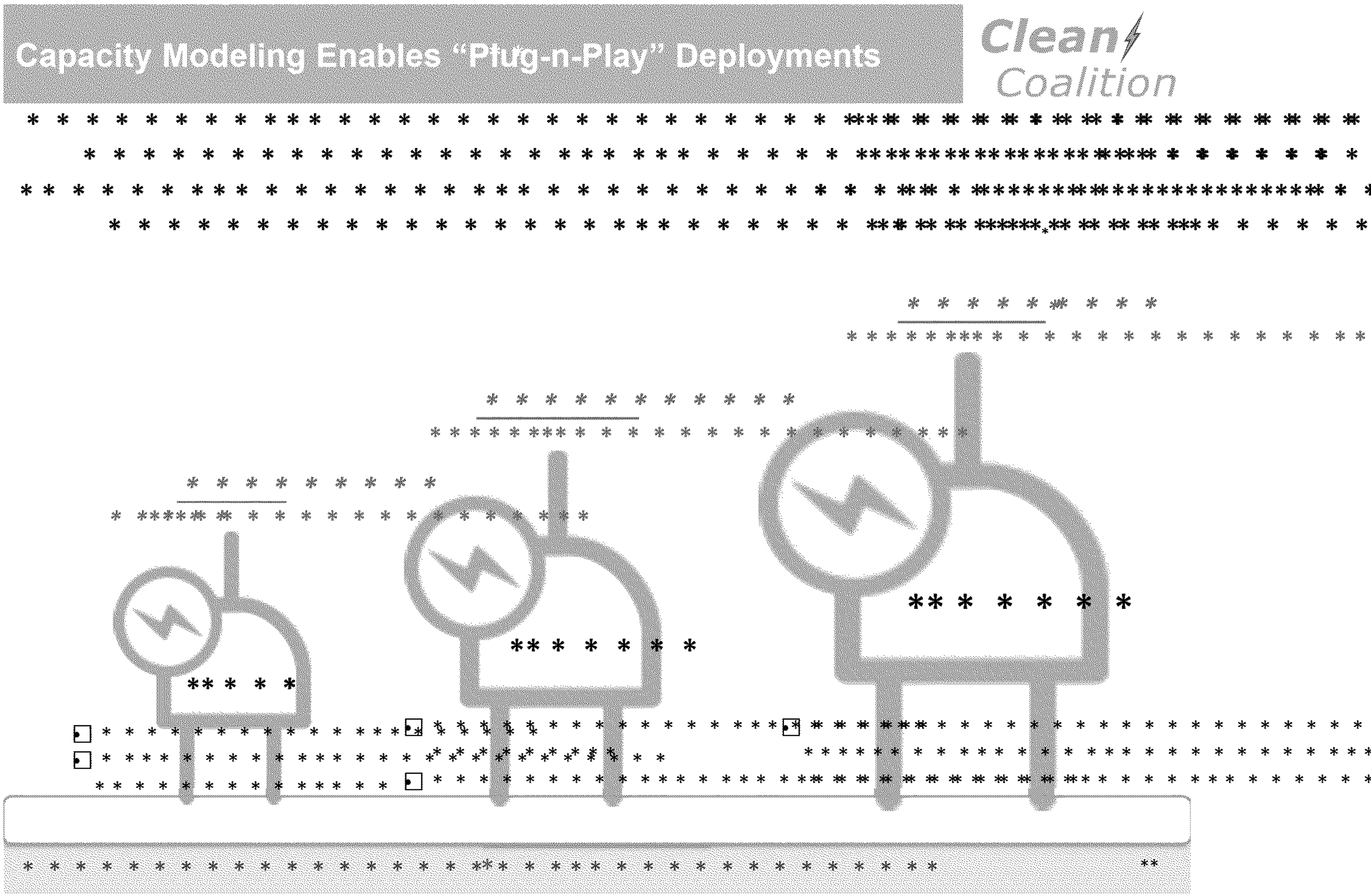
Once these plans are in place, distributed renewables and supporting grid upgrades can then connect in bulk – a "Plug-n-Play" model – rather than one project at a time, which is more expensive and operationally disruptive. This is analogous to how the industry plans for transmission capacity or peak load on the distribution grid. As a simplified illustration, the diagram below proposes three generic distribution grid examples of "Plug-n-Play" Interconnection:



Connecting and operating distributed generation in a bulk, Plug-n-Play model – which this Community Microgrid DER Optimization planning enables – will achieve both scale and simplicity across the industry, substantially reducing system-wide deployment and operational costs.

Conclusion

The strength of our electrical system is its breadth and reach to almost all corners of the country. Although the distribution grid has been used conventionally as a system for delivering electricity in only one direction – from the transformer at the substation to the homes and businesses served by the substation feeders – we can now take advantage of the vast miles of distributed electrical wires and utility poles (and other equipment such as voltage regulation) to enable a two-way, dynamic grid that supports large amounts of distributed, renewable energy and other distributed energy resources.

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