Clean Coalition
Making Clean Local Energy Accessible Now

May 5, 2016

President Picker and Commissioners
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: Ex Parte Letter in support of Proposed Decision of ALJ DeAngelis in A.14-11-016

Dear President Picker and Commissioners,

On behalf of our supporters and the interests of the People of California in a clean energy future, the Clean Coalition supports the Proposed Decision by ALJ DeAngelis on Southern California Edison's ("SCE") application to approve the results of its Local Capacity Requirements RFO, including re-powering the Ellwood generating station in Santa Barbara County, Application of Southern California Edison Company (U338E) for Approval of the Results of Its 2013 Local Capacity Requirements Request for Offers for the Moorpark Sub-Area, submitted November 26, 2014. As the Clean Coalition is not an official party in A.14-11-016, we submit this ex parte letter as an interested party. This letter is properly submitted as an ex parte communication under CPUC Rule 8.3 prior to the Ratesetting Deliberative Meeting of May 8th.

The Proposed Decision rightly denies the contract for the Ellwood generating station refurbishment ("Ellwood") because Southern California Edison ("SCE") has not shown by a preponderance of the evidence that its contract either meets any established reliability need or is the best alternative to meet any other identified need, including resilience and short circuit duty. As conceded by project proponents, the proposal does not meet needs based on any North American Electric Reliability Corporation ("NERC"), California Independent System Operator ("CAISO"), or California Public Utilities Commission ("Commission") Standard. Since there is no demonstrated reliability need which the Ellwood contract could fill, the contract cannot be deemed reasonable under the terms of D.16-05-050 on that basis.

Ellwood also fails to be the best solution to the novel resiliency standard suggested by the project proponents. Although not yet a formal standard, grid resilience will certainly become increasingly critical to California as climate change impacts magnify storm and wildfire impacts to the grid. However, Ellwood fails to meet grid resilience needs, let alone represent the best, most reliable, or cost-effective technology to meet any such need.

Resilience is clearly an important consideration for the safe and reliable operation of the grid, but this important consideration warrants a full consideration of the standard that should apply and full development and consideration of superior alternatives. Approving the Ellwood contract before this consideration would be highly premature and would prejudice ratepayers saddled with an expensive yet ineffective solution. Furthermore, approval of this contract would frustrate key California policy goals by precluding the deployment of Demand Response programs and renewables as preferred resources in the loading order.

Additionally, the need for short circuit duty alluded to in briefing is largely undefined, leaving the Commission, stakeholders and developers in a poor position to determine whether the Ellwood contract is either the best technical solution or the most cost effective, and therefore unable to demonstrate that the contact would be just and reasonable. Based on the limited information available, Clean Coalition is confident that renewable resources coupled with storage, demand response and advanced inverter functionality, for example, represents a technically superior and more cost-effective solution that would be precluded by premature approval of the Ellwood contract.

In summary, the identified needs must be more clearly defined and almost certainly can be better met with preferred resources at lower cost and with greater reliability, while avoiding serious health impacts to children. Therefore, the Clean Coalition urges the Commission to deny the Ellwood contract and to expand the RFO to provide an opportunity for participation by Distributed Energy Resource ("DER") providers to meet critical needs using technologies that are appropriate for California's clean energy future and consistent with Commission policy and legislative directives.

I. Description of the Clean Coalition

The Clean Coalition is a 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 and interconnection of Distributed Energy Resources—such as local renewables, advanced inverters, demand response, and energy storage—and we establish market mechanisms that realize the full potential of integrating these solutions. The Clean Coalition also collaborates with utilities and municipalities to create near-term deployment opportunities that prove the technical and financial viability of local renewables and other DER.

II. Reliability and resilience needs are not demonstrated

A. The Ellwood contract fails to meet any established standard or need and should be denied on that basis.

The Proposed Decision correctly determines that the project proponents have not carried their burden of proof to demonstrate that the Ellwood contract is needed to meet either a local capacity requirement ("LCR"), short circuit duty value, or resilience value. As the Proposed Decision correctly notes, refurbishing Ellwood does not qualify under the RFO because it is not an incremental resource and, even if it did, would exceed the 290 MW limitation that the Commission established as reasonable. The preponderance of evidence shows that the Ellwood contract is not reasonable under the parameters established by the Commission for the RFO.

B. The Ellwood contract does not represent the best solution to meet other identified resilience needs.

Additionally, the Proposed Decision also correctly notes that the project proponents have not demonstrated that Ellwood represents the best solution for value beyond existing standards or the RFO parameters. Additional values include voltage balancing, resilience, and short circuit duty.

First, regardless of the importance of these values, Ellwood cannot guarantee that those values can be delivered because run-time limitations under its air permit mean that NRG Energy cannot guarantee that Ellwood would be available to provide any services in any N-2 contingency. As the Proposed Decision properly notes, Ellwood is limited to 380 hours of operation and therefore cannot guarantee provision of any needed services beyond those hours. Furthermore, any resilience duty would require that Ellwood never be run for anything approaching 380 hours in any compliance year, because operators would have to reserve some sizeable allocation of time to be used in a rare N-2 contingency, should one occur. Thus, the resiliency duty proposed by project proponents would sharply limit Ellwood's usefulness for providing services throughout the year, further reducing its cost-effectiveness.

Furthermore, Elwood generates energy while generating significant emissions, which increases health risks to nearby individuals. It is unreasonable to approve a project that increases health risks to vulnerable populations, especially when superior alternatives exist that pose no such health risk. Even if NRG Energy or SCE were to obtain a variance to operate beyond 380 hours or to simply run Ellwood beyond permit limits, increased emissions necessarily involves increased health risks to neighborhood populations. Given that the Commission is charged with grid operation that is safe for the public, such a solution cannot be deemed to meet a standard of safe and reliable service.

C. Short circuit duty standards are poorly defined and Ellwood does not represent the best solution to meet such duty.

The Commission is in no position to determine whether Ellwood is either adequate or a best solution to any short circuit duty need in the Goleta area because that need is not clearly defined. Project proponents cite an ill-defined "short circuit duty" value of generation located in the Goleta area of the distribution grid. However, the lack of any standard or specifications regarding that need means neither the public nor the Commission can agree to the characterization of the problem, much less assess whether the Ellwood contract provides a solution. Alternative, non-polluting solutions may be technically superior and more cost-effective, but absent a request for offers ("RFO") requesting proposals to meet this need, the Commission cannot evaluate the relative merits of Ellwood relative to alternatives. It is unreasonable to approve a contract where the need is not well defined. The Clean Coalition recommends that the Commission first establish the relevant technical standards and then determine whether alternative technologies might meet this need. Approval of the Ellwood contract is premature prior to the development and evaluation of such alternatives.

D. Ellwood has not been demonstrated to be a reasonable solution to reliability needs in the event of an N-2 contingency.

Approval of the Ellwood contract to provide reliability services would be premature given the lack of evaluation of alternatives in the record. Ellwood represents neither the only nor the best solution to meet the 29.6 MW reliability need identified by CAISO to address any voltage collapse during an N-2 contingency. Indeed, the parties to this proceeding have floated a variety of approaches to address this potential need, including synchronous condensers, Demand Response and Distributed Energy Resources, but the record lacks a comprehensive evaluation of these alternatives. Demand Response may face difficulties addressing this issue (or may not) and either installation of synchronous condensers or retrofits of power facilities to serve that function may be an expensive solution to this particular issue, but Distributed Resources would be fully capable of meeting the full range of identified needs, including the generation of reactive power. However, none of these potential solutions has been properly evaluated on the record nor have other providers had adequate opportunity to develop alternative solutions.

As described below, solar generation and storage facilities using advanced inverters represent an example of a superior solution to any of these proposals to meet both generation needs and voltage stabilization needs during any N-2 event. The combination of power from solar generation and/or storage can be used to stabilize voltage by modulating the output of real power or by injecting or absorbing reactive power from the grid as reactive power compensation or dynamic reactive power control.[1] Such facilities have been deployed cost-effectively to provide grid resilience and reliability in Hawai'i, California, and elsewhere. These projects have demonstrated that these solutions can provide short circuit duty and voltage maintenance services with faster response times using advanced inverters. In fact, many existing inverters can serve this function with a software upgrade, saving the need for expensive hardware modifications to existing plants or for installations of entirely new facilities. Thus, approving Ellwood before development of superior and more appropriate resources would be premature and frustrate the key policy objectives of the loading order.

III. Distributed Energy Resources are a superior solution to delivering all reliability, resilience and short circuit duty values.

Distributed Energy Resources have a solid track record of meeting local capacity, resilience and power quality services in the event of transmission failures at cost effective price points. The combination of such resources, including demand response (DR), solar and battery storage, and advanced inverters have demonstrated the requisite performance to meet these needs without resorting to fossil fuel use. Furthermore, these alternative resources could also meet local generation needs addressed in the Moorpark RFO and provide additional reliability should the Puente Power Project be rejected by the California Energy Commission based on environmental justice concerns, failure to plan for the upper end of current estimates of sea level rise, and special status species impacts.

In particular, both the technology and available siting exists in the Santa Barbara area to fully meet the identified needs for grid services and the 26.9 MW of local capacity resources identified by CAISO. Indeed, several projects are already operating to meet similar needs nationwide. Local DER represents a viable and superior alternative to refurbishing Ellwood that clearly should be evaluated, but to date has not been fully vetted.

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[1] National Renewable Energy Laboratory, "Advanced Inverter Functions to Support High Levels of Distributed Solar," *NREL*, http://www.nrel.gov/docs/fy15osti/62612.pdf, Nov 2014.

As a result, approval of the Ellwood contracts would unreasonably foreclose DER solutions for the identified needs.

A. Solar and storage projects in the Moorpark area have demonstrated strong feasibility of the necessary components in this service area.

The clear feasibility of solar projects in the Goleta area is also demonstrated by the recent success of the 1 MW Calle Real Solar Photovoltaic project in Goleta, which has produced 10% more energy over five years than initially projected in 2010.[2] Since then costs have declined and efficiency has risen. Additionally, as noted by the Sierra Club, the Commission recently approved 15 MW of 4-hour duration energy storage in Santa Paula (part of the Moorpark area) as part of SCE's 2014 energy storage solicitation, precisely representing an example of the scale and capabilities required and available from non-emitting local resources. Furthermore, other ongoing solicitations are likely to deliver both generation and storage capacity to meet local capacity and resilience needs.

B. The Moorpark area has hundreds of megawatts of demonstrated solar siting opportunity.

Not only have the necessary technologies been deployed in cost effective projects nationally and locally, but the Santa Barbara area also hosts enough solar siting opportunity to allow for cost effective deployment of DER capacity vastly in excess of identified reliability and resilience needs.[3] For example, solar siting surveys of a similar area in Orange County have identified some 160 MW of built environment siting opportunity. Given that the initial authorization for this procurement in D.13-02-015 cited siting limitations as a rationale for proceeding quickly in the Big Creek/Ventura local area,

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[2] "Santa Barbara County Solar Project Exceeds Projected Output Resulting in initial Savings of $1.2 million," *County of Santa Barbara*, https://www.countyofsb.org/asset.c/2875, 2 May 2017.
[3] Solar Siting Survey: SCE Preferred Resources Pilot, *Clean Coalition,* http://www.clean-coalition.org/resource/solar-siting-surveys/sce-prp/.

this greater siting flexibility argues strongly for consideration of alternative DER approaches to meeting local need.

C. Kaua'i AES Solar and Storage Project delivers 20MW of resilience and reliability services at 11 cents per kWh.

Reliable DER projects of similar scale are quickly coming online to deliver precisely the full suite of services that Ellwood would provide. For example, in January 2017, Kaua'i Island Utility Cooperative and AES Distributed Energy, Inc. announced a Power Purchase Agreement for the delivery of 28 MW solar photovoltaic power and 20 MW of five-hour duration storage at a cost of 11 cents per kWh.[4] (See the press release, attached, Appendix A.) This project was developed to displace the current fossil fuel powered system and deliver incremental capacity, reliable power and stable rates to ratepayers for a utility that had already seeing up to 100% penetration of distributed PV capacity relative to peak load. This project is expected to be operational within two years of the signing of the PPA. Such systems, utilizing advanced inverters, could provide power generation, reactive power, and short circuit duty at a potentially competitive cost, relative to the adverse impacts of the Ellwood refurbishment or costs of supplemental synchronous inverters.

D. The Valencia Gardens Energy Storage project demonstrates the feasibility in California of Solar and Storage microgrid solutions.

Similarly, the Valencia Gardens Energy Storage (VGES) project in San Francisco adds 750 kW / 750 kWh of energy storage to the roughly 800 kW of rooftop solar that is already interconnected to the distribution grid within the Valencia Gardens Apartments. The VGES project will increase solar hosting capacity of the feeder line segment by at least 50% (i.e. enable at least 400 kW of additional solar to be interconnected to the local distribution grid that currently has no additional solar hosting capacity), and demonstrate the economics of

[4] "KUIC and AES Distributed Energy Announce Plan to Construct Innovative Renewable Peaker Plan on Kaua'i Utilizing a Hybrid Solar and Battery Storage System," *Kaua'i Island Utility Cooperative*, http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/pr/pr2017-0110-AES%20Solar.pdf, 10 Jan 2017.

utilizing energy storage for provisioning grid services through wholesale markets; via the California Independent System Operator (CAISO) and potentially the local utility, which is PG&E. Furthermore, with the study of islanding capacity, the project will demonstrate the full set of costs and benefits to provide Community Microgrid resilience to priority loads within the neighborhood, including those at the Valencia Gardens Apartments and other nearby PG&E customers.

IV. THE CLEAN COALITION RECOMMENDS ADOPTION OF THE PROPOSED DECISION AND EXPANSION OF THE RFO TO ALLOW FULL DEVELOPMENT OF DER SOLUTIONS.

A. The Clean Coalition urges the Commission to reject the Ellwood contract.

For the numerous reasons cited above, the Clean Coalition urges rejection of the Ellwood contract and adoption of the Proposed Decision. We also urge the Commission to expressly acknowledge the importance of full evaluations of the feasibility of meeting identified needs and values through DER solutions. In particular, we would urge addition to Conclusion of Law 6 be modified to include this consideration:

> Until more information is known about the future of Mandalay Unit 3 <u>and the feasibility of meeting residual local area needs, reliability needs, and resilience needs through DER resources (including Demand Response, solar generation, and storage with advanced inverters</u>), it is reasonable to reject a long-term contract with Ellwood, a 10-year contract and 30- year refurbishment.

B. The Clean Coalition urges the Commission to retain and expand the RFO to allow for fuller development and consideration of DER projects.

As outlined above, the Clean Coalition urges the full consideration of DER solutions both to meet the needs identified in the Ellwood contract as well as a replacement for the Puente Power Project in the event that it is rejected. We support the recommendation of CAISO that if the Proposed Decision is approved, the SCE and the Commission should procure and permit alternative resources, including DER, to meet the CAISO-identified need.

Although the CPUC declined to consider environmental consequences of its approval of the Puente Power Project under CEQA, the environmental review of that project—especially the developing science of sea level rise—is likely to indicate that the long-term viability of the project is too uncertain to warrant the investment. If so, the CEC may well reject the proposal, and the CPUC should be well-positioned to move forward promptly.

Furthermore, it is critical that the Commission not suspend any existing RFO to procure preferred resources. The RFO could serve to procure resources to meet local area needs identified by CAISO, especially for preferred resources which do not involve the pollution considerations and limitations of the Ellwood facility, and without such procurement the identified needs will be further from an adequate resolution. However, we also urge the Commission to extend and expand the RFO to facilitate the development and inclusion of DER proposals that would more appropriately meet the identified needs. A premature and short process has the impact of prejudicing the procurement outcome by creating procedural barriers to develop DER projects. SCE has not demonstrated that such combined renewable and storage projects would not be able to meet the generating capacity needs of the area in a timely fashion (given the short develop timeframes of such projects), so these projects should be considered for development.

In particular, we support the recommendations of other parties that that the Commission require the Goleta Area RFO be reopened and expanded to include the entire Moorpark sub-area. We also urge that SCE be required to solicit and fully evaluate alternative proposals in the Moorpark subarea and the Goleta-Santa Barbara area. As the Clean Coalition has highlighted, experience in California and in other states have demonstrated conclusively that DER are fully feasible and cost-effective to meet the identified needs while also implementing the policy goals of the State of California and the Commission.

Respectfully submitted,

Doug Karpa, J.D., Ph.D.

Policy Director

Attachments:

1) "KUIC and AES Distributed Energy Announce Plan to Construct Innovative Renewable Peaker Plan on Kaua'i Utilizing a Hybrid Solar and Battery Storage System," *Kaua'i Island Utility Cooperative*, http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/pr/pr2017-0110-AES%20Solar.pdf, 10 Jan 2017.
2) "Santa Barbara County Solar Project Exceeds Projected Output Resulting in initial Savings of $1.2 million," *County of Santa Barbara*, https://www.countyofsb.org/asset.c/2875, 2 May 2017.
3) National Renewable Energy Laboratory, "Advanced Inverter Functions to Support High Levels of Distributed Solar," *NREL*, http://www.nrel.gov/docs/fy15osti/62612.pdf, Nov 2014.

FOR IMMEDIATE RELEASE
01/10/2017
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KIUC and AES Distributed Energy Announce Plan to Construct Innovative Renewable Peaker Plant on Kaua‘i Utilizing a Hybrid Solar and Battery Storage System

Līhu‘e, Kaua‘i, HI – 01/10/2017 - Kaua‘i Island Utility Cooperative (KIUC) and AES Distributed Energy, Inc. (AES DE), a subsidiary of The AES Corporation (AES), today announced the execution of a power purchase agreement (PPA) for an innovative plant that will provide solar energy together with the benefits of battery-based energy storage for optimal balancing of generation with peak demand. The project consists of 28 megawatt (MW) solar photovoltaic and a 20 MW five-hour duration energy storage system.

The system will be located on former sugar land between Lāwa‘i and Kōloa on Kaua‘i’s south shore. It will be the largest solar-plus-utility-scale-battery system in the state of Hawai‘i and one of the biggest battery systems in the world.

“Energy from the project will be priced at 11 cents per kWh and will provide 11 percent of Kaua‘i’s electric generation, increasing KIUC’s renewable sourced generation to well over 50 percent,” said KIUC’s President and Chief Executive Officer, David Bissell. “The project delivers power to the island’s electrical grid at significantly less than the current cost of oil-fired power and should help stabilize and even reduce electric rates to KIUC’s members. It is remarkable that we are able to obtain fixed pricing for dispatchable solar based renewable energy, backed by a significant battery system, at about half the cost of what a basic direct to grid solar project cost a few years ago.” Bissell estimates that the project will reduce KIUC’s fossil fuel usage by more than 3.7 million gallons yearly.

“We are honored that KIUC has selected AES to help meet their peak demand with a flexible and reliable renewable energy solution,” said Woody Rubin, President of AES Distributed Energy. “We are excited to be able to leverage AES’ industry-leading energy storage platform, and 20 plus-year history in Hawai‘i in order to help KIUC modernize the grid and provide value to its customers.”

(more)

AES DE will be the long-term owner and operator of the project. The company is committed to providing innovative renewable energy solutions to its utility, corporate governmental customers. AES continues to pioneer the use of energy storage on the electric grid, starting with the first grid-scale advanced energy storage project installed in 2008. AES now operates one of the largest fleets of battery-based energy storage in the world.

The project is pending state and local regulatory approvals. If approved, KIUC expects the project to come on line by late 2018.

About KIUC

KIUC is a member-owned cooperative serving 33,000 customers on the island of Kaua'i. Formed in 2002 and governed by a nine-member, elected board of directors, KIUC is one of 930 electric co-ops serving more than 36 million members in 47 states.

About AES Distributed Energy, Inc. and the AES Corporation

The AES Corporation (NYSE: AES) is a Fortune 200 global power company providing affordable, sustainable energy to 17 countries through its diverse portfolio of distribution businesses as well as thermal and renewable generation facilities. AES Distributed Energy is one of ten businesses that make up the AES U.S. Strategic Business Unit ("SBU") providing renewable energy solutions to a diverse customer base including utilities, corporations, and governmental entities. With a workforce of 3,600 people, the U.S. SBU is committed to operational excellence and meeting the changing power needs of the United States. To learn more, please visit www.aes.com.

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PRESS RELEASE

MAY 2, 2017

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SANTA BARBARA COUNTY SOLAR PROJECT EXCEEDS PROJECTED OUTPUT RESULTING IN INITIAL SAVINGS OF $1.2 MILLION

(SANTA BARBARA, Calif.) – Today, the Santa Barbara County Board of Supervisors received a five-year update on the Calle Real Solar Photovoltaic (PV) Array project (solar panels arranged in a group to capture maximum amount of sun light to convert it into usable electricity). The first five years of the project was projected to produce 8.9 million kWh. In actuality, the project has produced 9.7 million kWh, 10 percent more power than anticipated for a total utility savings of about $1.2 million.

The solar array project was first presented to the Board of Supervisors on July 13, 2010 as a potential project in the Sustainability Action Plan with the goal of reducing electricity costs and the County's carbon footprint. Construction was completed in 2012, and within the first four months had already exceeded expected outputs.

"I am thrilled to have advocated for the Calle Real solar array infrastructure project at the time it was proposed," stated Second District Supervisor Janet Wolf. "The project has not only reduced our electricity bills for the County, but it showcases the benefits of solar energy over the use of fossil fuels. It is a message to our community that the County takes its Climate Action Plan seriously and will continue to pursue energy saving strategies."

On sunny days between 11 a.m. and 3 p.m., the project generates almost enough power to completely offset the electrical needs for the County's Calle Real Campus, which is the largest energy user for the County. The campus includes the County jail, Sheriff Administration, 911 Call Center, Public Health Hospital, Public Health Administration, Mental Health Hospital, Mental Health Administration, Agricultural Commission, Environmental Health, Elections Office and Clerk-Recorder-Assessor.

The project was financed by Qualified Energy Conservation Bonds (QECB) in the amount of $5.5 million with a 15-year term and effective rate of 1.2 percent. At the onset of the project a rebate of $1.7 million was secured from Southern California Edison Electric (SCE). The SCE California Solar Initiative rebate lowered the net capital cost to $3.8 million and resulted in a payback period of approximately 13 years and return on investment of 39 percent after the first five years of operation. Due to power produced above the anticipated amount, the County received the entire rebate in February 2017, four months earlier than anticipated. The solar array continues to work well and is expected to last at least 20 more years. Total utility savings after 25 years of operation is estimated to be $9.2 million.

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ADVANCED INVERTER FUNCTIONS TO SUPPORT HIGH LEVELS OF DISTRIBUTED SOLAR

POLICY AND REGULATORY CONSIDERATIONS

The use of advanced inverters in the design of solar photovoltaic (PV) systems can address some of the challenges to the integration of high levels of distributed solar generation on the electricity system. Although the term "advanced inverters" seems to imply a special type of inverter, some of the inverters currently deployed with PV systems can already provide advanced functionality, needing only software upgrades or adjustments to operation parameters. Advanced inverter functions allow for more elaborate monitoring and communication of the grid status, the ability to receive operation instructions from a centralized location, and the capability to make autonomous decisions to improve grid stability, support power quality, and provide ancillary services. The use of advanced inverter functions, and their role in maintaining grid stability, is likely to grow with increasing deployment of distributed solar and the formulation of supporting regulation and policy. But before advanced inverters can be implemented widely, various regulatory and policy issues need to be addressed, including compensation to generators for grid services provided, requirements for availability of grid services by inverter-based systems, system disconnect and operation standards, and inverter ownership structures.

This paper presents an explanation of grid integration challenges posed by increasing levels of distributed solar and a description of how advanced inverter functionalities address these challenges. It concludes with an overview of the policy and regulatory considerations that relate to the deployment of advanced inverters.

THE NEED FOR ADVANCED INVERTER FUNCTIONS

Distributed solar capacity is increasing rapidly as technologies advance, prices decline, markets shift, and supportive policies are implemented. With the increased deployment of distributed energy resources, the electrical system is evolving from a unidirectional network, with generation flowing to customers from a few centralized generators, to a multidirectional infrastructure with generators of many sizes, on every level of the grid. Electricity system standards and operating protocols were originally designed for a dispatchable generation fleet, but today's distributed solar systems provide mostly variable, nondispatchable power.

The electricity system is evolving rapidly as a result of technological advances, market shifts, and policy changes that support increasing levels of distributed solar. Annual distributed solar capacity additions in the residential and commercial sectors are expected to rise from 3.0 GW in 2014 to 5.5 GW in 2023 (Gauntlett and Lawrence 2014). With increasing growth, system operators face new challenges to integrating distributed PV into the distribution network and bulk power system.

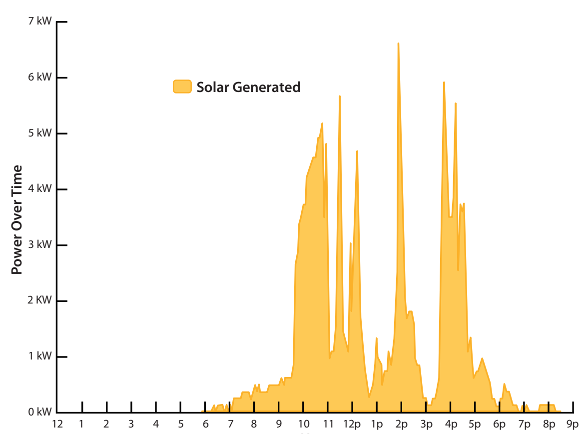

Figure 1. The Variable Generation of a Single Solar PV System. In most cases, the variability of a single system is balanced out by other systems in the vicinity.

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Figure 1 shows an example of the output of a 7 kW residential solar system over the course of one day. When clouds shade the solar panels, system output drops sharply, only to spike again after cloud cover moves away.

The voltage and frequency levels of the electricity system are impacted when any type of generation is brought on-line or taken off-line. Electricity system operators must maintain a constant frequency and voltage on the system, within a specified range. Voltage and frequency disturbances pose a risk to system stability. While the grid may not be adversely impacted by the small degree of variability resulting from a few distributed PV systems, high levels of variability within a limited area may make it difficult to keep frequency and voltage levels within specified ranges. In most cases, however, PV systems are spread across a broad area such that the variability caused by localized cloud cover is balanced out across the wider system (Wiemken et al. 2001; Lew et al. 2013).

In accordance with IEEE Standard 1547, all inverters associated with distributed PV systems continuously monitor the grid for voltage and frequency levels. The PV-grid interconnection standards currently adopted by many authorities having jurisdiction (AHJs) require that PV systems disconnect when a voltage or frequency grid abnormality exceeds predetermined levels for predetermined times (IEEE 2003; IEEE 2014). If many PV systems detect a voltage disturbance and disconnect simultaneously, a sharp reduction in generation may occur, which may further exacerbate the voltage disturbance. After an outage, many solar systems ramping up simultaneously may also induce grid disturbances. To address this possibility, recent adjustments to IEEE standards now allow some flexibility in disconnection and ramp up timing (IEEE 2014).

ADVANCED INVERTER FUNCTIONS

Advanced inverter functions can help address the grid stability problems posed by high levels of variable distributed generation. Some of these functions are described below. The inverters used today may be capable of providing some of these advanced functions with only software and operations protocol updates.

As mentioned above, current standards require that inverters disconnect the distributed PV system when grid frequency or voltage falls outside a specified range. However, inverters have the capability of "riding through" minor disturbances to frequency or voltage. These functions are called **under/over frequency ride-through** and **under/over voltage ride-through.** They direct the distributed system to stay online and respond accordingly to relatively short-term, minor events. In some cases, this function can actually help the grid to self-heal from a disturbance. Even when the ride-through functions are activated, the inverter disconnects the solar system when more severe grid disturbances warrant doing so (Beach 2003; ACEG 2014; CPUC 2014).

One way that inverters can help the grid regain stability during an under- or over-voltage event is by controlling the real and reactive power output of the distributed generation system (ACEG 2014). Voltage control is traditionally the responsibility of utilities. However, inverters can assist by changing the level of real power output from the system (**limit active power**) by controlling the rate at which real power is fed onto the grid **(controlled active power ramping),** or by injecting or absorbing reactive power into or from the grid (**reactive power compensation**, or **dynamic reactive power control**). These functions make system stability maintenance easier by keeping voltage and frequency within specified limits. While these functions currently must be set within the inverter manually, it is conceivable that they may one day be set remotely. For more information on the reactive power compensation function, see Text Box 1.

Advanced inverter functions can also help prevent the reoccurrence of a grid disturbance immediately after an outage. If many distributed generation systems come back online simultaneously, another grid disturbance may be triggered. To prevent this from happening, system operators can use a **soft start method**, which involves staggering the timing of reconnection of distributed systems on a single distribution circuit. This technique avoids spikes in the active power being fed onto the grid as it returns to normal functioning, limiting the risk of triggering another grid disturbance.

Text Box 1: Options for Providing Reactive Power Compensation with Advanced Inverter Functionality

The provision of reactive power compensation by distributed systems can help with the integration of variable resources, contribute to grid stability, and provide system-wide cost and performance efficiencies (Kueck et al. 2008). Inverters can provide reactive power compensation when the full inverter capacity is not being used to convert active power from the solar panels. The majority of distributed solar systems have inverters that are sized in accordance with the maximum capacity of the solar panels. However, over 95% of the time, an inverter is working below its maximum current rating because the solar system is not receiving peak irradiance (Zuercher-Martinson 2012). During these times, the excess capacity can be used to provide reactive power compensation.

During peak irradiance periods, the inverter has no excess capacity. If the inverter is required to produce reactive power during these circumstances, it must do so by curtailing some of the active power from the solar panels to free up inverter capacity. **Curtailing active power generation** is an economic loss to the solar generator, which affects the overall economic viability of the solar system. While there may be clear advantages to limiting solar power output from the grid operator's perspective, those adjustments have a cost for PV system owners, who are compensated per unit of energy fed into the grid. As such, providing reactive power compensation would not be in the PV owner's economic interest, unless they were paid for this service.

One way to avoid the need to curtail for purposes of reactive power compensation is to **oversize the inverter**. Oversizing ensures that there will always be excess inverter capacity to meet voltage control needs. However, installing an inverter with a higher rating adds cost to a distributed generation system, which can be a barrier, especially for small distributed generators. Again, if generators are paid for the grid services they provide, the additional cost of oversizing an inverter may not present an economic barrier.

In locations where it is relatively expensive for a utility to provide traditional, centralized reactive power compensation, or where upgrades to equipment may become necessary, the grid services provided by advanced inverters may be assigned a higher value. In locations that have relatively poor or variable solar resource quality, advanced inverters (coupled with appropriate standards) may be able to provide reactive power compensation for a higher percentage of the time. Incentivizing system owners for reactive power compensation, in addition to the active power output of their system, would increase the economic viability of distributed solar in these locations.

Providing distributed voltage control through the reactive power compensation ability of inverters can provide cost and performance efficiencies from a system-level perspective (Kueck et al. 2008). One concern with enabling the voltage control function is that it may affect the inverter's ability to provide **unintentional-islanding protection**, which disconnects the system during a grid outage. This prevents feeding PV power onto a grid that is otherwise de-energized. PV systems powering a de-energized grid could present a risk to people and equipment. There are methods to resolve the potential interference of voltage control operations with unintentional-islanding protection, and research is continuing in this area (Beach 2013; CPUC 2014).

Until recently, U.S. standards largely prevented inverters from using their under/over frequency and voltage ride-through functions or provide voltage regulation support functions, instead requiring that distributed systems disconnect at predetermined levels of grid disturbances (IEEE Standard 1547 2003; IEEE Standard 1547a 2014).

The advanced functions described above could feasibly react either autonomously or to signals communicated by system operators. There are notable benefits to establishing **communications** between inverters and facility management systems, grid operators, and regional transmission organizations or independent system operators. Today, advanced inverters are able to receive commands to improve stability, react appropriately during emergencies, or respond to market pricing signals.

REGULATORY AND POLICY CONSIDERATIONS FOR THE DEPLOYMENT OF ADVANCED INVERTERS

Decision makers are presented with several opportunities to enable the use of advanced inverter functions, to contribute to grid stability, and to support increased deployment of distributed solar technology. These opportunities include: requiring or encouraging inverter owners to provide grid services through regulation or compensation, ensuring that standards allow for the full use of advanced functionalities, and considering alternative ownership structures to support wide-spread adoption. Each of these opportunities is described below.

Text Box 2: Smoothing the "Duck Curve"

The electricity that a utility must supply to meet customer demand follows a typical pattern over the course of a day, and is depicted by an electricity demand curve, also referred to as the load curve. The demand for electricity increases in the early morning hours, peaks in the late afternoon, and remains relatively high until the late evening hours, after which it declines sharply. The black line in Figure A shows an example utility demand curve.

The generation output from a solar system typically increases sharply as the sun rises in the morning and peaks around solar noon, before declining sharply as the sun sets. This pattern is represented by the blue line in the figure. As the number of PV systems connected to the grid increases, the peak of the aggregated PV generation curve grows, as represented by the red line in the figure. Note that as more PV systems come on-line, the difference between the electricity demand and the PV generation becomes significantly smaller during the peak hours of PV generation, but the difference stays about the same during other hours of the day.

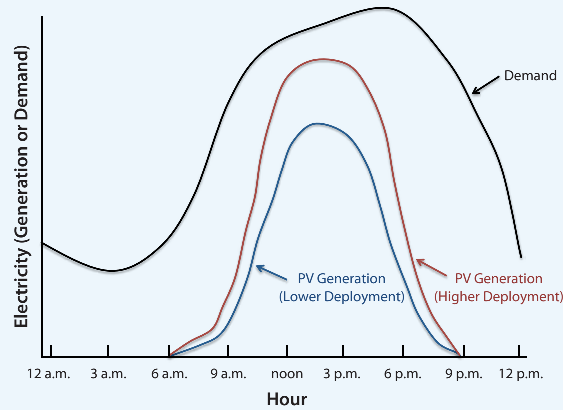

Figure A. Example Daily Electricity Load Curve and PV Generation Curves

The electricity demand curve minus the PV generation curve gives the net demand curve (also called the net load curve) for the utility. The net demand curve represents the amount of electricity demand that must be provided by the utility, taking into account the generation from distributed PV systems. As more distributed solar capacity comes on-line, the net demand curve changes shape. The depiction of this phenomenon for California's electricity system has come to be known as the 'duck curve' because of its duck-like shape (see Figure B, below). As the amount of PV generation increases, the belly of the duck grows larger since solar generation occurs primarily during the mid-day hours. As the amount of solar generation grows, there is an increasing need to ramp conventional generating resources down at sunrise and to ramp them back up quickly at sunset.

Advanced inverter functions and communication capabilities could provide at least a partial solution to the duck curve dilemma. If reductions in PV output can be anticipated, systems may be ramped down more smoothly, facilitating the transition to other generation sources. Other strategies include time-of-use (TOU) rates and demand response programs, which would help shift the time of demand on the system and further smooth the net demand curve.

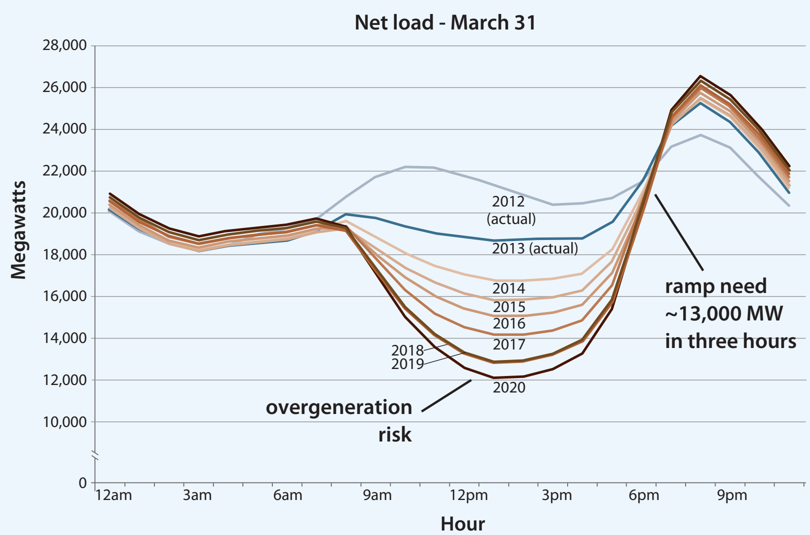

Figure B. An Illustration of California's Current and Estimated Net Load Curve - often referred to as the 'duck curve' (Source: CAISO 2013)

Requirements and Payments for Grid Stability Services

As discussed in Text Box 1, there are several ways advanced inverter functions can provide reactive power compensation. Whether or not it is an economically viable alternative to traditional, centralized reactive power compensation depends on location-specific variables such as system operation costs, solar resource quality, and the degree to which generators are paid for the grid services they provide.

Regulatory considerations include whether distributed PV generators are required to contribute to voltage control on the distribution circuit through the provision of reactive power, how much of the time owners would be required to make these grid services available, and whether they are paid for this service to the grid. Compensation for voltage control services may include payment for the reactive power generated, for the income lost through solar curtailment, and for other grid services.

There is precedent for paying for reactive power services (FERC Staff 2014), although compensation to owners of PV systems connected at the electricity distribution level is very rare. One example is that of Georgia Power, which adopted an interconnection agreement that requires even small solar generators to provide reactive power using advanced inverter functions, and specifies that generators be paid for this service (Georgia Power 2013).

Regulations pertaining specifically to the curtailment of solar generation are most common in jurisdictions where the aggregate solar PV capacity can have an impact on system stability, and these regulations can be a stipulation of interconnection. In Germany, new and existing solar PV plants must be equipped with curtailment capability (De Silva 2013). Owners of small systems have the choice of either installing a remote management system, capable of curtailing system output to overcome grid congestion, or limiting the power fed into the grid to 70% of nominal capacity. Owners of PV systems are entitled to receive compensation for lost revenues ("Inverters and Grid Integration" 2013; Lang 2014).

Updating Standards to Allow for Advanced Inverter Functionality

As discussed above, current U.S. standards require inverters to disconnect distributed solar systems from the grid when grid frequency or voltage is outside of a certain range. In some cases, the simultaneous disconnection of many systems puts grid stability at further risk. Although IEEE Standard 1547 has allowed for time-phased flexibility in disconnecting and reconnecting PV systems since 2003, jurisdictions and other implementers have not mandated the use of that flexibility to reduce that risk.

In May 2014, IEEE published an amendment (IEEE Standard 1547a) to its standard for distributed resources interconnection to the utility grid, allowing advanced capabilities for voltage regulation support and voltage and frequency ride-through. IEEE began working to address numerous recommendations for new or revised interconnection requirements to establish a more robust standard that will facilitate a higher penetration of distributed resources and the use of advanced inverter capabilities. Although IEEE has mandated that the process be completed by 2018, participants and stakeholders understand the pressing need to complete the process well before the deadline.

At the state level, a California Public Utilities Commission working group was recently tasked to make recommendations on policy changes to support the use of advanced inverter functions. These include defining new ranges that can be applied for under- and over-voltage and frequency ride-through, ramping and other functions to support grid stability under higher levels of distributed solar deployment (CPUC 2014). This work, which has been informed by experiences in Germany, may contribute insights regarding appropriate adjustments to operation standards in other regions of the United States (see Text Box 3).

Considering Alterative Ownership Options

The owner of a distributed PV system typically also owns the associated inverter. However, other ownership structures could be considered, and may offer system benefits under higher levels of distributed generation. For instance, utility ownership of advanced inverters might provide opportunities for coordination and control that would further contribute to system stability, although the same benefits may also be achievable under customer ownership. Shifting the line where utility ownership ends and customer ownership begins could, however, address cost barriers for some customers wanting to participate in distributed generation. There are, of course, many regulatory changes that would need to occur to support the utility ownership model, including adjustments to regulations, interconnection standards, utility investment planning and PV system design and deployment (SEPA 2014). Ultimately, the costs and benefits of such an arrangement would need to be evaluated for each network or jurisdiction.

Text Box 3: Deploying Advanced Inverters in Germany

By the end of 2010, Germany had about 14 gigawatts (GW) of distributed solar capacity connected to the grid. During the first six months of 2011, distributed PV provided 3.5% of the electricity generated in Germany. As higher levels of distributed solar are interconnected with the grid, there is increased risk that a rise in system frequency could trigger inverters to disconnect a large amount of PV capacity from the grid simultaneously. If frequency on the German system were to rise above the maximum level defined by existing PV interconnection standards (50.2 Hz), several gigawatts of solar capacity could potentially be disconnected at the same time. It was estimated that, in worst-case scenarios, 9 GW of solar capacity could potentially be disconnected at once, but the European grid was only designed to withstand the instantaneous loss of a maximum of 3 GW of capacity (Döring 2013). This problem came to be known as the "50.2 Hz problem."

In 2011 a multi-stakeholder working group set out to identify potential solutions to the "50.2 Hz problem" (VDE 2011). As a result of the group's recommendations, the German government passed the System Stability Ordinance (Systemstabilitätsverordnung) in 2012, requiring newly-installed distributed PV systems to reduce their output or shut down smoothly during high frequency events. Facilities of 10 MW or more commissioned before 2012 were required to be retrofitted by 2014 to comply with the new requirements. Older systems were allowed to retain instantaneous shut-off, but would have to be retrofitted to stagger their disconnections across a specified timeframe.

About 400,000 PV systems have been required to retrofit inverters to comply with the new standard. In the majority of cases, software updates or changes in the inverter operating parameters are sufficient for compliance. To limit the cost of mitigation, replacement of the inverter is discouraged. The total cost to retrofit existing systems was estimated to be between €65 million ($88 million) and €175 million ($238 million). Germany is working with other European countries to revise their over- and under-frequency protection standards for distributed generation (Bömer et al. 2011). As levels of distributed PV continue to increase in the United States, some lessons may be taken from the German experience. California's smart inverter working group is looking at adjustments to inverter operating standards for distributed systems (CPUC 2014).

The deployment of advanced inverters cannot be relied upon as the only strategy to integrate distributed variable sources of power into the grid. Other mechanisms to support increasing levels of distributed generation, such as grid upgrades and the adoption of energy storage, will have to be considered as well. Nevertheless, advanced inverters represent an option that is available, operational, and potentially cost-effective in the near term.

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