Let's Make a Deal: NWAs for Traditional T&D?

Beth Reid, Joe Bourg and Devon Schmidt

Introduction

Climate change mitigation and adaptation strategies are having a profound impact on California's regulatory policies, electrical system loads, and resource planning strategies. This changing landscape is ushering in a new era of opportunity for the use of distributed energy resources (DERs) in non-wires alternatives (NWA) applications. For the purposes of this article the authors have defined DERS as resource portfolios comprised of distributed generation, energy storage technologies and flexible loads. Increased loading on transmission and distribution lines and rising demand for energy supplies are creating opportunities for DER-based NWA solutions as a result of 1) climate-related events such as heat storms and wildfires, and 2) climate change mitigation strategies such as regulatory requirements for deployment of clean energy generation and electrification initiatives to replace natural gas end-use equipment. This article explores how climate change impacts are changing the value proposition for DERs in terms of overall increased value, and specifically the increased value that DERs can provide in NWA applications.

The deployment of climate change impact mitigation strategies is causing serious challenges to maintain the reliability and resilience of California's electrical power system. Mitigation strategies such as the increased deployment of clean energy generation to meet California Renewable Portfolio Standards (RPS) of 60% carbon-free resources by 2030 and 100% by 2045, with largely intermittent resources like solar and wind, have significantly altered the state's system supply profile. In the summer months, these impacts are characterized by (1) an abundance of renewable energy in the morning and early afternoon hours, (2) a dramatic "ramping" period from 3-6 p.m. caused by decreasing renewable energy supply coupled with increasing demand driven by cooling loads, and (3) a capacity-constrained peak period between 6-9 p.m. This problem is amplified by frequent and prolonged climate-induced high-temperature events, resulting in escalating cooling loads that cause additional stress on the grid. Mitigation strategies such as electrification of cooling equipment, water heaters, and vehicles are adding demand to the grid which results in increased system strain unless these devices are operated flexibly. As these mitigation strategies multiply, there is a need to balance decarbonization strategies with maintaining the reliability and resiliency of the grid. A key theme of this article is to demonstrate how regulatory policies, valuation methodology enhancements, and DER deployment strategies can support decarbonization initiatives while providing NWA benefits of resiliency, reliability, and Transmission & Distribution (T&D) capacity upgrade deferral services.

This article reviews 1) the current NWA landscape in California, 2) the impacts of climate change on electrical system requirements and planning, 3) an overview of valuation frameworks for distribution upgrade deferral, resilience, and reliability from NWAs, and 4) and discusses the regulatory policy and valuation methodology enhancements needed to capture the full value and increase deployments of DER-based NWA strategies.

California NWA Landscape

The following sections provide an overview of the NWA landscape in California including regulatory and planning processes for deferring distribution upgrade investments and resiliency measures, completed project summaries, and current procurement methods for grid services provided by NWA projects.

Regulatory Frameworks for Distribution Deferral

Growth in DER installations has increased dramatically among residential, commercial and industrial consumers throughout California in recent years. They have purchased rooftop solar, electric vehicles, energy storage systems, smart thermostats, and other grid-enabled devices without significant central or localized planning. This has resulted in variable localized grid impacts and California's utilities have sought out various mechanisms to help balance the distribution system with customer-sited DERs.

To begin addressing the need for more central and localized planning of DERs in NWA applications, the California Public Utilities Commission (CPUC) launched the Distribution Resource Plan proceeding in 2014 to identify strategies to incorporate DERs into investor-owned utility (IOUs) grid investment planning processes. The result of this proceeding included the Distribution Investment Deferral Framework (DIDF), wherein utilities perform an annual review of their five-year grid investment priorities and identify those projects that could be replaced or deferred through DERs. The identified projects are then ranked into "tiers" of potential deferral opportunity based on cost-effectiveness, forecast certainty, and market assessment. Projects in Tier 1 are considered the best candidates for NWAs because they have the best chance of deferring investment for 10 years. Once projects are selected and ranked, the IOU conducts a request for offers (RFO) to select projects to be awarded and developed.

Across all three of California's electric IOUs {Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)}, 31 projects were proposed, involving over 100 MW of capacity. Two have been completed to date and 11 were either cancelled or were not awarded a contract. Projects were canceled, either because the substation was in a wildfire burn area or load forecast resulted in the specification of traditional distribution upgrades. The IOUs did not award contracts for other proposed projects because no subset of offers met the project requirements, or because the proposed project was deemed not to be cost-effective.

Of the projects, SCE has procured DER solutions for seven proposed deferral projects totaling 35 MW of capacity and PG&E have offered contracts for 13 DER-based deferral projects with 30 MW of capacity. SDG&E did not award any deferral contracts, or did it identify an eligible distribution investment project in either 2019 or 2020 DIDF cycles. Further detail on the results of the DIDF solicitation are shown in Table 1. (Advice Letters: 5096-E, 5095-E Supplement, 5435-E, 5688-E, 6002_E, 4342-E, 4108-E, 3904-E, 3089-E, 3245-E).

Investor-Owned Utility	Advice Letter Year	Proposed Capacity (MW)	Number of Proposed Deferral Projects	Number of Projects Awarded
PG&E	2017	4	1	0
	2018	12.6	4	4
	2019	>14.5	4	2
	2020	>19.2	7	7
SCE	2017	0	0	0
	2018	>12.7	4	0
	2019	35.4	6	6
	2020	9.6	2	0
SDG&E	2017	Not Disclosed	1	0
	2018	0	0	0
	2019	0	0	0
	2020	0	0	0

Table 1: DIDF Solicitation Results

As demonstrated by the limited number of procured project and the lack of implemented solutions, the existing DIDF process has been slow to result in NWAs effectively replacing traditional grid investments. Some stakeholders maintain that the limited efficacy is attributable to several factors. For one, the framework directs utilities to take action that is counter to the incentives established for regulated utilities. In the regulated context, utilities are incentivized to make traditional investments designed to improve system reliability because these investments allowing them a guaranteed rate of return. A 2020 Greentech Media article states “NWAs, by contrast, ask utilities to rely on third-party DER providers or aggregators to deliver the same level of reliability, and they offer no clear path to recovering costs involved, even if they’re lower than a traditional upgrade”. However, NWAs can benefit a utility by providing opportunities to distribute the risks of a project across both the utility and the DER provider. The utility internalizes the risk associated with overloading lines if the DER does not perform, while the DER provider is at risk of not getting paid if the DER is unable to perform.

As a result of the slow progress of the DIDF RFO process, the CPUC developed two more procurement mechanisms to encourage NWA deployment: 1) the IOU Partnership Pilot, 2) the Standard Offer Contract (SOC) Pilot. The IOU pilot creates a new tariff for IOUs to support DER procurement. It requires that the utilities prescreen energy solutions providers (ESPs) to help customers in targeted locations enroll their DERs into the program. The budget cap for each project will be 85% of the estimated conventional wires-based upgrade cost, ensuring at least 15% savings to ratepayers when projects are implemented. Of this budget, ESPs will receive 20% of the budget allocation for new DER installations, 30% as a capacity reservation payment, and the remaining 50% for event-based performance when dispatched by the utility.

The second proposed pilot mechanism, the SOC pilot, is a three-year program focused on securing larger-scale front-of-the-meter (FTM) solutions that address a distribution need identified in the DIDF. The SOC pilot differs from the existing RFO mechanism as it requires the utility to select one Tier 1 candidate project each year to enter into the standard-offer process. The utility will document the set of DER services necessary to defer investment and will produce a price sheet indicating the utility's willingness to pay for DER products. When 90% of the project need is met by DER provider offers, the utility will enter into a contract with the providers that submitted conforming bids.

Southern California Edison (SCE) has implemented two DER projects for NWA applications that have successfully deferred distribution investment. In 2015, SCE procured a 2.4 MW / 3.9 MWh in-front-of-the-meter battery to avoid a distribution update of a new circuit management system. The battery is maintained by a third party but is owned and operated by the utility. In addition, SCE procured 85 MW of behind-the-meter (BTM) energy storage that offers flexible capacity throughout the Western Los Angeles Basin. This flexible capacity allows SCE to balance the grid in local reliability sub-areas during critical peak times.

Regulatory Frameworks for Incentivizing Resiliency and Microgrid Installations

In support of the need for increased resilience in the California electric grid, NWA solutions and microgrids are being proposed as a strategy by regulatory authorities. In 2019, the CPUC launched the "Order Instituting Rulemaking" (OIR) to formally initiate the Resiliency and Microgrid Proceeding. The goal of this proceeding is to facilitate microgrid deployment and improve electric resiliency in the face of California's changing climate landscape. In January 2021, the CPUC initiated the Microgrid Incentive Program as part of Track 2, which authorizes a $200 million budget to fund the construction of microgrids supplied by clean energy resources and deployed in vulnerable communities. The budget set aside for the Microgrid Incentive Program is expected to fund 15 projects the three IOU service territories. Though the incentive program represents a small piece of what will be necessary to build and operate a resilient and carbon-neutral electricity system, it will facilitate demonstration projects to help address the many challenges presented by multi-property microgrids.

The need for DER-based NWAs to augment electricity resilience in California is clear. The rising risk of wildfires throughout California has frequently limited the use of crucial transmission and distribution lines. This is exemplified by the Public Safety Power Shutoff (PSPS) program, which impacted millions of customers by initiating power outage events in many communities over the last few years. This repeated lack of access to electricity for many in California, often within the same geographic areas, has led to considerable private and public investment in back-up diesel generation to support critical loads during PSPS events. In 2019, the CPUC authorized PG&E to procure 450 MW of backup diesel generation for the 2020 wildfire season. To balance the need for both clean energy and resilience requirements in California, utilities and ratepayers will have to dedicate thought and resources to the challenge of developing and implementing clean energy microgrids.

Climate Change Impacts on System Requirements and Planning

Climate change impacts on California's electrical system are systemic include reduced in resiliency and reliability due to overstretched generation resources, insufficient levels of resource adequacy (RA), drought-induced reductions in hydro-electric generation capacity, transmission lines shut down due to wildfires, and PSPS events to prevent wildfires during extreme weather events. The consequences of reduced reliability and resiliency directly impact public health and safety and disrupt people's lives and normal business operations.

In August of 2020, the California Independent System Operator (CAISO) was forced to institute a two-day rolling electricity outage in response to emergency conditions from a prolonged heat storm. These were the first rolling outages, and the first time there was more than one emergency declaration since the RA implementation in 2006, and there were many questions about what went wrong. The CAISO, CPUC, and CEC jointly prepared a root cause analysis to determine contributing factors that triggered the rolling outages. Increased air conditioning usage, lower efficiency of conventional generation, and lower hydro-electric output due to drought conditions all played a part, but the ultimate question is, "Why was there not adequate resource capacity?". The analysis identified several challenges that contributed to the emergency, the most relevant being that the unexpected increase in system demand exceeded RA and planning targets, and that while transitioning to a clean energy portfolio, planning for ramping energy needs in the early evening hours has not kept pace with grid needs.

The generation shortfalls in August 2020 had many potential main causes, including inaccurate load-serving entity (LSE) demand schedules in the day-ahead market and the unexpected loss of a generator delivering 475 MW. Many actions were taken by the CAISO to mitigate the loss of operating reserves but ultimately the CAISO initiated forced outages of 932 MW and 466 MW across two days to stay within acceptable reserves to maintain overall system reliability. Subsequent days of the heat storm required no outages due to a combination of operator actions, regional coordination, demand response programs, and successful public campaigns for consumers to reduce their energy usage.

This emergency spawned a new CPUC emergency reliability rule (R.20-11-003) ordering a new demand response program, the Emergency Load Reduction Program (ELRP), followed by an executive order creating another new DR program, the California State Emergency Program (CSEP). Each program has a fixed payment of $1/kWh and $2/kWh respectively to customers that reducing their loads after emergency notifications. However, emergency programs do little to influence the development of DERs generally or NWAs specifically. While incentives for load reduction are high, there is no certainty in emergency programs since the number or duration of events in a year in unpredictable. Yet, in Phase 2 of the Emergency Reliability rulemaking, the CPUC has identified a shortfall of as much as 5,000 MW for 2022, indicating there will likely be a need for continued load reduction from emergency programs in the coming years.

As recently as April, May, and July 2021, a state of emergency was declared in 50 California counties due to severe drought conditions, In June and July 2021 a state of emergency was also declared due to extreme heat events across the western United States. As a result of the drought and heat events, over 1,000 megawatts of capacity were lost when the low water levels in reservoirs hindered the use of hydroelectric power plants. Another 4,000 megawatts could not be imported into California from the Pacific Northwest when the Bootleg fire in Oregon shut down a major transmission corridor. As seen in recent years, prolonged elevated temperatures result in increased system demand, which in turn requires the dispatch of marginal generating units (many of which are inefficient, older, and unable to handle the stress of high operating temperatures), and results in extremely high peak energy prices. It also increases stress on the transmission and distribution grid due to congestion, increases line losses, and reduces the lines' carrying capacity.

Addressing the impacts of climate change events and mitigation strategies comes with a high cost to the electrical transmission and distribution system. In a 2018 report on the impact of climate change on the California electric grid, the CEC indicated that outages due to wildfire may cause up to $9 million in transmission costs and $61 million in distribution costs annually by mid-century. California utilities need to be prepared for increased financial uncertainty due to wildfires in the future. Regulators have taken significant actions to mitigate the worst impacts of climate change on grid operations. In response to record wildfires in 2017 and 2018, regulators instituted the PSPS program for the summer of 2019 which proactively de-energizing circuits for extended periods. While PSPS events have become less frequent, of shorter duration, and enacted within smaller geographic areas, these events continue to this day and are expected to continue for years to come. These events not only disrupt people's lives, but also impact businesses' ability to operate unless they invest in backup generators, microgrids, or energy storage equipment with the capable of operating in island mode.

Based on current statewide planning models, forecasted short-term supply shortfalls of 5 GW and medium-term shortfalls of nearly 12 GW support the need for rapid deployment of DERs and DR resources in NWA applications to bridge this supply gap. For NWAs to contribute significantly to the supply portfolio, changes are required to current planning processes to account for the full value that can be contributed by NWAs, which can be deployed more quickly, efficiently, and incrementally than conventional generation.

Consequences of Adaptation to Climate Change Impacts

One of the consequences of the PSPS program is that a large number of new fossil-fueled generators have been installed in recent years by facility owners to maintain operations during grid outages. According to a 2021 report by Mcubed there is an estimated 34% increase in backup diesel generator capacity from 2018-2021, and a 22% increase from 2020-2021, totaling approximately 12GW of capacity, which is equivalent to nearly 15% of California's generation fleet. Nearly all newly installed backup generation is diesel-fueled, and this growth in diesel-fueled backup generators is expected to increase over the coming years. Not only does the increased diesel generation capacity work against California's RPS targets and greenhouse gas (GHG) reduction goals, but this proliferation of diesel generator installations also highlights a major opportunity for clean energy technology NWAs to provide resiliency value. The increase in backup generator installations and use also highlights the delicate balance between the need for increased grid resiliency and climate change mitigation efforts, such as the RPS mandating clean energy generation targets. The RPS/GHG goals versus the need for increased grid resiliency issue came to light during the rulemaking process for the Emergency Load Reduction Program and the CSEP Programs launched in mid-2021. While backup generators had previously been allowed to operate for only emergency backup and required test events they were considered "prohibited resources" and not allowed to participate in demand response programs or dispatches. The final decision order for the Emergency Load Reduction Program allowed prohibited resource to participate in emergency events, followed by a similar approval in the executive order establishing the CSEP.

Climate change mitigation strategies will also have a significant impact on the electrical grid as homes and buildings rapidly deploy electrification measures such as chillers, water heaters, and electric vehicles, in support of all-electric buildings initiatives and in response to bans on natural gas service in new buildings in some jurisdictions. Increased building electrification and electric vehicle charging loads will significantly increase the state's peak load, which will require tripling the current electrical grid system capacity, as well as overall energy consumption in the state according to a 2021 CEC Joint Agency Report. Figure1, shows the projected impact of high building and transportation electrification on annual energy consumption in California through 2050, representing an increase of nearly 100 TWh per year. Climate mitigation strategies will put increased stress on the transmission and distribution systems and will require wide-spread and costly upgrades to keep up with the growing electricity demand, simultaneously increasing the value proposition for NWA solutions.

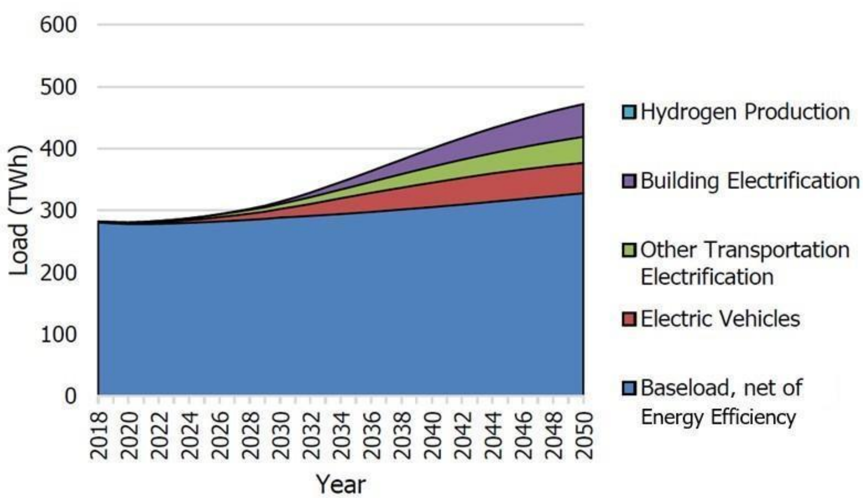

Figure 1: Projected demand growth in California through 2050 in high electrification scenario [Source: Energy and Environmental Economics, 2021]

Valuation Frameworks for DER-based NWA Solutions

This section summarizes DER valuation frameworks that incorporate the cost and benefits of NWA solutions, such as T&D capacity deferral, resilience and/or reliability services to overcome the limitations of more traditional DER frameworks.

Valuation of Transmission and Distribution Investment Deferral Benefits

Accurately valuing transmission and distribution deferral benefits in DER valuation methodologies are crucial for identifying localized project opportunities for DER-based NWA solutions in place of traditional T&D upgrades. Accordingly, the CPUC's Integrated Distributed Energy Resources proceeding, which focuses on increasing the use of demand-side resources to better serve the electricity system, has led to an additional proceeding devoted to the development of a standardized DER valuation methodology for use in California. This led to the development of the Avoided Cost Calculator (ACC), which is an annual modeling process to quantify benefits associated with demand-side resources over a specified planning period. The ACC model incorporates value derived from the avoided costs of all the activities associated with generating and distributing electrical energy. These costs are then simulated for each hour of each year in the study period. Figure 2 below illustrates (1) the types of costs included in the model (avoided GHG in blue, energy in green, generation capacity in yellow, transmission capacity in brown, line losses (not visible), distribution capacity in red, and costs due to methane leakage in light green) and (2) the changes that have occurred to the model over the last three iterations (2019-21). The 2021 version of the ACC assumes that the marginal unit of generating capacity in the evening is utility-scale storage, which will have a significantly lower cost and GHG emissions profile than the previously modeled marginal unit, a gas combustion turbine. Therefore, DERs are replacing a less expensive, lower-emitting storage unit in the evening hours with highly effective load-carrying capacity, reducing its replacement value. In addition, the 2021 version uses a production cost model to simulate future prices, rather than using historical price trends, which assumes lower energy costs in future years, further reducing the avoided cost.

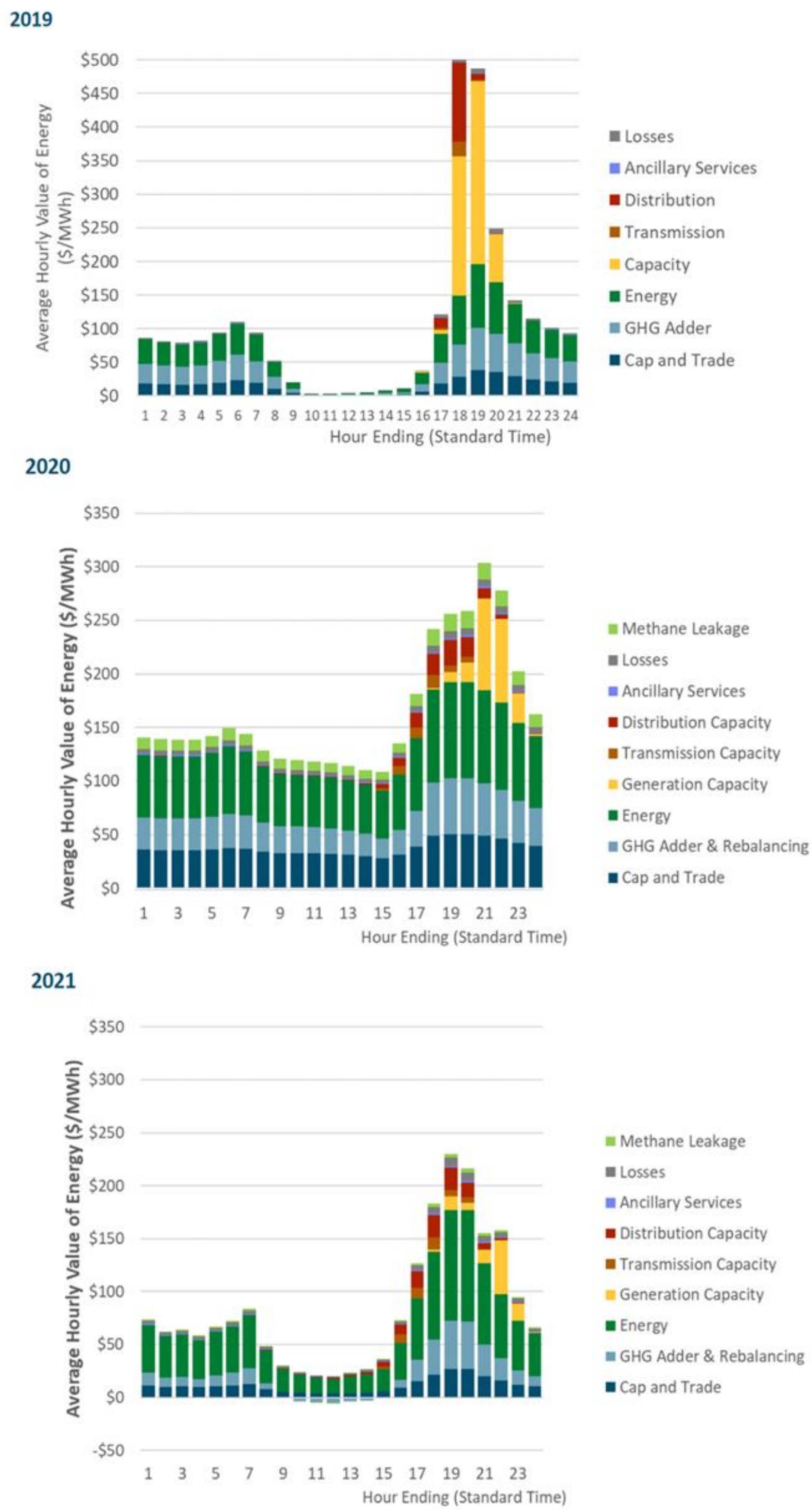

Figure 2. Estimated Hourly Avoided Costs of DER Programs [Source: Energy & Environmental Economics, 2021]

The ACC standard framework is not required for utilities to use as part of DIDF NWA solicitations. For these procurement cycles, utilities may conduct their own cost-effectiveness analysis which has traditionally not been made public. Implementing a standard framework that is transparent and compulsory for solicitation may help push more projects through the contracting process. The Standard Offer Contract mechanism may be a step in this direction. Under this mechanism, the utility communicates upfront what it is willing to pay for a particular DER service or product and thus defines a target for DER providers to aim for. The 2022 cycle will be the first to include a standard offer contract solicitation so it is yet to be determined whether this concept will help deliver more DER projects for distribution investment deferral.

For the IOU Partnership Pilot, the burden of DER valuation falls on the ESPs selected by the utilities. Under this framework, utilities define a circuit-specific budget using 85% of the cost of the estimated conventional upgrade cost to procure DER capacity for distribution upgrade deferral. Since the utility has already defined its willingness to pay for DER/DR-based NWAs, so it is up to the ESP to determine if the value set by the utility will be sufficient to justify a project and/or if there are additional value streams available to earn revenue from these same assets (i.e., wholesale market participation).

There are also still significant limitations in cost/benefit modeling in the face of extended climate-related power outages. The ACC does not assign any value to DER projects based on the ability to withstand difficult-to-predict, yet inevitable outages. This limits the potential to allocate distribution and transmission investment funds towards DER projects to support or construct community microgrids that can offer both resiliency and local capacity for distribution deferral value. Nevertheless, in light of the potential for widespread outages due to PSPS and wildfires, the CPUC set aside significant incentives in its Self-Generation Incentive Program (SGIP) to target higher uptake of customer-sited storage and renewable DERs in vulnerable areas.

In a 2019 CPUC decision, it CPUC allocated budgets for two set-aside energy storage programs: $70 million to the SGIP Equity Program and $100 million to the Equity Resiliency Program. The SGIP program offered $850/kWh for installed capacity for residential and non-residential customers located in disadvantaged or low-income communities, and the equity program offered $1000/kWh to low-income or medical baseline customers in high wildfire risk areas. These incentives were designed to expedite the construction of over 180 MWh of storage statewide. These two incentive tranches in the SGIP budgets were quickly over-subscribed, and there is currently a waiting list of approved projects with no budget available. As more resiliency-focused projects are installed, they will offer the opportunity to collect data to support the development of valuation methodologies that include resiliency as well as other value streams from NWA services.

Valuation For Resilience and Reliability

Reliability has long been at the core of grid planning, but regulators are increasingly focusing on resiliency. Conventional resource planning has focused on meeting peak system or local grid needs through a combination of generation, transmission, and distribution infrastructure. DER-based NWAs can play a much-needed role in avoiding the need for grid investment in the context of long-term system planning, deferral, and capacity. In contrast to traditional reliability metrics that are generally focused on predictable growth in demand and associated infrastructure needed to support it, resiliency is defined as the ability to respond to unplanned disturbances. The CPUC staff concept paper on resiliency highlights the “resilience” benefits a DER can provide as illustrated in Figure 3.

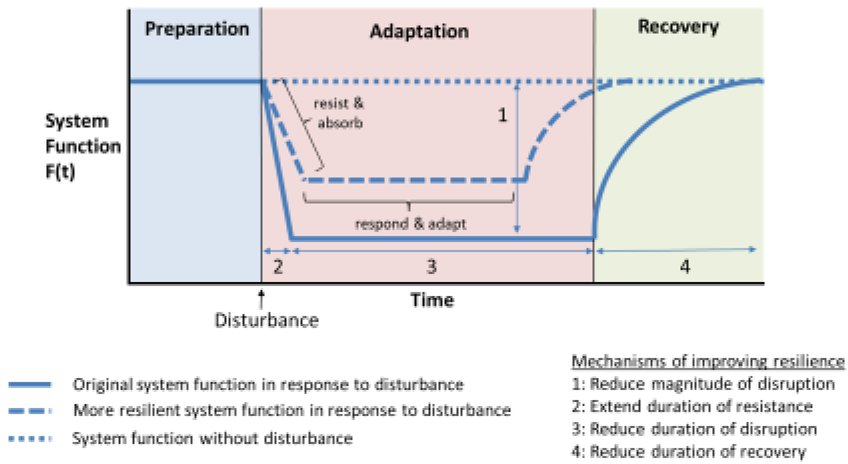

Figure 3. Resiliency and System Functions [Source: CPUC 2020]

Ascribing a specific resilience adder to conventional valuation methodologies can be challenging because there is a blurred line between system-wide benefits and individual customer benefits. DER-based NWAs are in the early stages of demonstrating their role in deferral of generation, transmission, and distribution costs, as well as in providing capacity value that contributes to resilience and reliability of the grid, despite agreement within traditional planning processes on the value of resilience and reliability. While efforts by state regulators have pushed the inclusion of NWAs into these resource planning processes, attempts to value resilience and reliability from NWAs have been inconsistent. Resilience is often not valued quantitatively in many valuation models because it is difficult to scope out and conventional reliability metrics are not easily adaptable to the new paradigm. Attempts by regulators to assign a specific value to resiliency have relied heavily on quantification of the cost of interrupted power. These valuations follow one of two main approaches: bottom-up or economy-wide. Consumer preferences are measured via “stated preferences” on customer willingness-to-pay for measures to avoid power outages and/or “revealed preferences” of actual customer purchases (e.g., backup generators and/or energy storage equipment) to avoid power outages. More holistic resilience valuation methodologies are the “economy-wide” approaches that seek to quantify the impact of sustained power outages on regional economies, including a loss of productivity, revenues, wages, and employment.

While several proceedings and research projects are addressing the need to value resilience and reliability in NWA methodologies, there has been limited progress in developing widely accepted valuation methods. A 2019 National Association of Regulatory Utility Commissions (NARUC) report stated, “At present, there are no standardized approaches for policy makers or energy project developers to identify and value energy resilience investments at the state, local, or individual facility levels.” The National Association of Regulatory Utility Commission’s report highlights several case studies where bottom-up and economy-wide approaches were used by states, cities, and institutions in their valuation of proposed NWA solutions. The report pointed out that while these case studies did enhance NWA value, each approach is limited either in scalability, outage duration, or scope of outputs to warrant adoption in a regulatory context. While there have been additional efforts to deploy DERs for resilience purposes since the report's publication, it remains the case that there is not an agreed-upon standard to value DER's ability to avoid outages or for DERs to reduce reliance on fossil-powered backup generation.

In 2019, testimony as part of the Integrated Distributed Energy Resources proceedings, VoteSolar and the Solar Energy Industries Association (SEIA) proposed an explicit "resiliency" adder of solar plus storage in avoided cost modeling used by the CPUC. In their testimony, they estimated the additional benefit of resilience attributed to solar and storage systems based on a revealed preference model, assuming that solar and storage would be installed in place of a portable fossil fuel generator. The "resiliency adder" included calculations of equipment, installation, and air quality costs of backup generators, arriving at an estimated value of $104/kW-year. The proposal for a resiliency adder was criticized by utilities and consumer advocates, both as a concept and in total value. Utilities argued that despite clear resilience benefits of DERs, there was no proper way to quantify system benefits (rather than just individual customer benefits). The Utility Reform Network (TURN) contended that solar and storage "resiliency" does not avoid ratepayer costs. Ultimately, the CPUC agreed that while there is a case to be made for valuing resiliency, there was insufficient evidence to explicitly include it in the ACC.

In summer 2020, the CPUC staff launched Track 2 of its Resiliency and Microgrid Proceeding, an extensive proposal describing barriers related to microgrid adoption, with resiliency valuation highlighted as a key objective. CPUC staff suggested that resiliency is a special case of reliability, noting that replacing aging distribution equipment would be a "reliability" enhancement while actions taken specifically to protect the system from flooding, wildfires, or other extreme weather events would be a resiliency enhancement. In this context, all NWAs provide system reliability benefits, but only certain NWA applications provide additional resiliency value. Microgrids are a specific application of DERs often targeting resiliency as the main benefit, but without a clear valuation framework, community microgrids are often found to be not cost-effective. In summer 2021, the CPUC held a series of workshops to discuss an evaluation framework for resilience, showing continued progress but still not arriving at a standardized methodology.

Summary

If climate change impacts in California, such as on-going drought, catastrophic wildfires, and heat storms are becoming the new normal, as many climate scientists suggest, accounting for their impacts in valuation modeling will result in a higher value of DERs supporting NWA solutions. These values will accrue from continued high peak energy prices, higher prices for resource adequacy as supply shortfalls continue, high incentives for participation in emergency load reduction programs, increasing value of reliability and resiliency, and cost-effective deployment of DERs/DR to defer distribution capacity upgrades. In addition, these resources provide reductions of CO_2 emissions and support the continued deployment of clean energy resources to combat climate change.

California is projected to experience supply shortfalls of 5 GW in 2022 and nearly 12 GW over the next five years. Due to the short time needed to deploy DERs compared to other supply options, DER-based NWA strategies can play a key role in bridging the gap in the supply shortfalls while providing reliability and resilience benefits to the grid. While NWA solutions are not a new concept, the implementation of these solutions has been slow due to limitations in current DER and NWA valuation methodologies, as well as the continued specification of wires-based solutions through established legacy technology solutions and planning processes. As valuation methodologies are enhanced and standardized to capture NWA values of distribution capacity deferral value, resilience and reliability, the resulting scale of these solutions will serve to alleviate the perceived risk to utility planners.

A recurring theme in this article is that a key challenge facing DER-based NWAs, and the electrical system as a whole, is the need to balance climate change mitigation measures with the increasing need for grid resilience that has historically been provided by fossil-fuel generation and other legacy technologies presents a continuing challenge - all while maintaining stable retail rates to ratepayers. Enhancements in valuation methodologies, alleviation of utility risk concerns with third-party provided NWA solutions, and continued demonstration of these commercially proven resources are critical steps to clearing the pathway for the deployment of these solutions at scale.

Bios

Coauthors:

Beth Reid is a Founder and CEO of Olivine, Inc., committed to the development and deployment of cost-effective reliable solutions to provide the energy transformation required to meet future realities.

Joe Bourg is the Vice President of Resource Acquisition and Development of Olivine where he brings over 30 years of utility resource planning expertise, including development of innovative valuation and business model strategies for DER and NWA solutions.

Contributing Author:

Devon Schmidt is an Energy Programs Associate at Olivine. As the Market Operations Lead, she focuses on wholesale market integration, optimization, and operation for Olivine resources. Devon comes to Olivine with an M.S. in Energy Systems from the University of California, Davis.

For Further Reading

Proclamation of a State of Emergency. Executive Department, State of California, 2021. https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf

Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022. California Public Utilities Commission, 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/emergency-load-reduction-program/decision_elrp_program.pdf

Final 2020 Integrated Energy Policy Report Update Volume III California Energy Demand Forecast Update. California Energy Commission, 2021. https://efiling.energy.ca.gov/getdocument.aspx?tn=237269

Frick, Natalie Mims, Lisa Schwartz, and Snuller Price. Locational Value of Distributed Energy Resources. Lawrence Berkeley National Laboratory, 2021. https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf

Resolution E-5150. Adopts updates to the Avoided Cost Calculator for use in demand-side distributed energy resource cost effectiveness analyses. California Public Utilities Commission, 2021. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M382/K179/382179225.PDF

The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices. National Association of Regulatory Utility Commissioners, 2019. https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198