The Value of "DER" to "D":

The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability

Susan F. Tierney, Ph.D.

Analysis Group, Inc.

March 31, 2016

(corrected)

The Value of "DER" to "D":
The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability

Susan F. Tierney, Ph.D.
Analysis Group

Executive Summary

Transformational changes are occurring in many local electric systems in places as diverse as Hawaii, California, Colorado, Minnesota, Georgia, New York, and Washington, D.C. Solar panels on rooftops are the most visible manifestation of these new distributed energy resources ("DER"). Much has been written about solar panels and other types of DER and the values they bring to customers and to the electric system alike.

This paper focuses primarily on two essential questions relating to DERs: How should utility regulators, distribution utilities and other stakeholders think about the value of DER to *the distribution system* ("The Value of DER to D")? And what are the implications for distribution-system planning, DER procurement and DER compensation that result from those interactions between DERs and the local distribution system?

Regulators, utilities, DER providers, and other stakeholders are working hard around the country to refine methodologies for evaluating when and where DER installations might provide net benefits to the electric system. Although intended to contribute to this broader set of discussions, this report shines a light on some of the policy topics and technical developments relating to the "Value of DER for D." The report illustrates some of the issues and insights by examining developments and analyses underway at two electric utility distribution utilities – Consolidated Edison ("Con Edison") in New York City and Southern California Edison ("SCE") in California. Their distribution systems are very different, yet both companies are actively examining how DERs can become better integrated into traditional distribution-system planning processes so that utilities can leverage these DERs And both utility companies are engaged in state regulatory proceedings affecting the evolving relationships between DER providers and the local utility.

This report highlights the following points:

- **DERs are proliferating across the US mainly due to policies aimed at higher levels of renewable portfolios with incentives tied to that deployment**. Net energy metering has been helpful in fostering rapid adoption of certain DERs (notably rooftop solar technologies), but it is increasingly seen as a rather blunt and imprecise pricing instrument that may not accurately reflect: the value of DERs to the electric system and its constituent parts (the power generation system ("G"), the high-voltage transmission system ("T"), and the distribution system ("D")); and separately, the external value of DER to society ('S").

- **Different DER technologies have different attributes and different impacts on and contributions to the electric system.** Studies indicate the Value of DER to D is typically small relative to the Value of DER to G, T or S. Most distribution-related avoidable costs are tied to deferred capital investments. Analysis conducted by the Electric Power Research Institute ("EPRI") on behalf of SCE and Con Edison confirms that the value of DERs to D depends on their location on the local grid and upon those DERs having characteristics that provide the needed characteristics of availability, dependability, and durability (sustainable supply). Analyses of Con Edison's local network, for example, indicate that the ability of DERs to resolve reliability violations on the local grid decreases substantially as the DERs' physical distance from a local reliability problem increases.

- **Conceptual frameworks for valuing DERs will need to evolve in order to better determine the value of DER to D.** Typically, valuation frameworks (such as those used to evaluate energy-efficiency programs via benefit/costs tests) show the potential for DERs to be net-beneficial, but they only go part of the way to identifying which DERs actually contribute value to D. Determining the value of a particular set of DER technologies/applications in specific distribution-system contexts will end up being much-more complex and difficult to execute than the typical simplified accounting frameworks might suggest because of the location-specific impacts of DERs with different attributes. At least for DERs designed to compete with traditional utility investments within the distribution-system resource planning process, valuation should move beyond the initial screen, which examines potential benefits, to more location-based analyses that focus on both expected and actual performance of DERs in identifying cost-effective substitutes for traditional D (and for T, and G) solutions.

- **New methods for Valuing DERs for D should be built on the timeless regulatory principles of efficiency and fairness so as to create value for all customers on the distribution system.** As part of the constructive attention being given to how DERs might play larger roles in the future of the electric system, the principles of fairness and efficiency remain important in considering cost-allocation and compensation levels for DERs and in developing ratemaking mechanisms for utilities. Doing so increases the opportunities for DERs to be incorporated in ways that create value for all customers on the local system.

- **Utilities should integrate DERs into their distribution-system planning processes so that DERs have the potential to substitute for traditional utility investments where they can provide needed attributes cost-effectively.** Most traditional fixes for anticipated local reliability problems are capital investments, many of which have long lead times. These lead times are taken into account in the utility's planning horizon and involve physical upgrades to reinforce the capability of the infrastructure to meet customers' electrical requirements. This suggests that at least in the early stages of the evolution, the integration of DERs into distribution-system planning and plans ought to focus on ensuring that DER capability is installed in sufficient amounts, locations, time frames, and attributes to assure that the DERs can provide equivalent functionality as would have been provided by a traditional solution.

- **Prior PURPA experience teaches us that market-based mechanisms led to greater value to customers compared to arrangements in which alternative power producers were paid administratively determined avoided costs.** Where the utility can fairly obtain and efficiently pay for the quantity/timing/location of DERs needed at market-based competitive prices (rather than at avoided cost), then DERs can provide net benefits – i.e., value to the system and its customers. Many states' experience in implementing the Public Utility Regulatory Policies Act indicates that customers benefitted when the industry transitioned away from initial approaches that relied on administratively determined prices. This experience offers important lessons for the current efforts to design methods to integrate DERs efficiently and effectively into distribution-utility plans and operations, and to do so in ways that balance value to all customers with compensation to DER suppliers. Competitive solicitations can reveal the portfolio of DERs with the attributes to satisfy the utility's local reliability requirements at lowest cost. The utility can then enter into contracts to assure that those DERs enter the market and help to resolve local reliability problems cost-effectively and reliably. Periodic procurements would also be able to take into account the changes that inevitably occur on the distribution system over time, with some changes pushing out the date of need and others leading to earlier reliability challenges than previously anticipated.

- **Forward contracting for DER capacity should be the focus of early-stage market developments related to DER for D.** Given that the lion's share of potentially avoidable distribution costs are capital investments, it seems important to focus initial market-design attention on procuring DERs for their capacity value to distribution systems over specific periods of time. In the future, as the markets for DER evolve, it may be worthwhile to look at the other shorter-term/ operational sources of value of DER to D, and then refine shorter-term/operational/transactional markets to compensate contracted resources for performance and for other services provided by DER to D. After the main source of value (distribution capacity) is realized, then these other value streams can be layered on top of that foundation. This prioritization of "DER-for-D" market elements – starting with a focus on forward procurements of capacity as the main event, and then moving toward more secondary and likely smaller transactional markets over time – fits with economic principles about the conditions that enable robust, successful markets to exist.

Table of Contents

The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability

Susan F. Tierney, Ph.D.[1]
Analysis Group

Introduction

Setting the stage for distributed energy resources

Big changes are underway in the power system. Headlines have captured the important role of relatively low-cost natural gas for power production, the rapid growth in wind and solar energy capacity, and the impacts of federal environmental policies. Competitive power markets have enabled many new players and technologies to break into the industry.

Equally transformative are changes occurring in many local electric distribution systems and on customers' own premises. These changes are showing up in places as diverse as Hawaii, California, Colorado, Minnesota, Georgia, New York, and Washington, D.C. Solar panels on rooftops are becoming more common. For a variety of reasons, large and small electricity users are taking steps to directly manage their own energy supply. This transition anticipates an increasingly customer-driven and decentralized electric system.

> **Distributed Energy Resources ("DERs"): Defined**
>
> People mean different things when they refer to "DERs." This particular report adopts a very-broad definition which includes relatively small-scale technologies (e.g., solar photovoltaics ("PV"); wind; storage; combined heat and power ("CHP"); micro turbines; demand-control systems; and energy efficiency) that either located "behind-the-meter" on a customer's premises (and operated for the purpose of supplying all or a portion of the customer's electric load), or connected directly to the distribution system for local reliability.

Much has been written about these new trends in DERs[2] and the values they bring to customers and to the system alike.[3] From a regulatory policy and economic point of view, there are important distinctions to be drawn between: the value of DERs to the customers who install them; the value of distribution service to those customers; and the value of DERs to the entire electric system (and therefore to all customers). Often the distinctions are blurred.

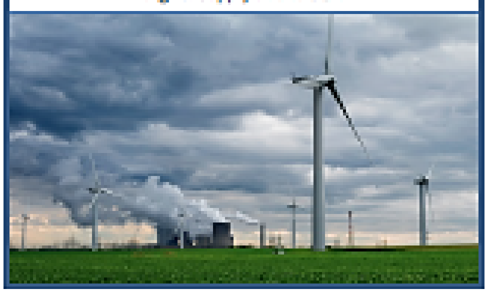
This paper examines the issues from one particular vantage point: What is the value of distributed energy resources *to the distribution system*? Stated otherwise: What is the Value of "DER" to "D"?

To put that question in context, Figure 1 presents the various lenses through which these issues tend to be viewed. As shown in Figure 1, here are the distinctions:

Retail electricity customer
using DER for self-supply when available, injecting power into the distribution system when there's surplus DER power, and/or drawing power from the grid when the DER is not available

Electric Distribution Utility
providing wires/distribution service to DER customers with surplus power to be delivered to other customers, relying on DER to avoid other costs on its local system, and providing wires service to all other customers (either on unbundled basis or as part of bundled retail electric service to the retail customer)

Utility-Scale Generation and Transmission,
providing power delivered via high-voltage lines (either on unbundled basis or as part of bundled retail electric service to the customer), with lower loads and higher supply due to DER



External Impacts,
with DER imposing negative and/or positive impacts on other things beyond the purchase and sale / production and consumption of electricity.

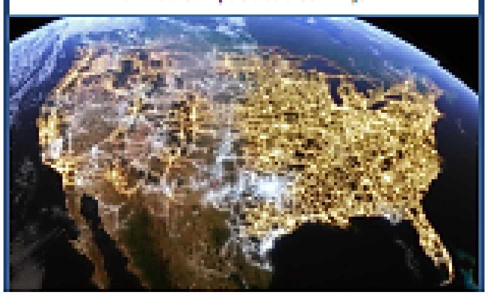


Figure 1

D and DER: The Value of What to Whom?

There are active discussions going on around the country with regard to the value of electricity to consumers, the value of DER to customers and to the system, and the value afforded to consumers with DER by virtue of being interconnected with the grid. Too often, these concepts get comingled.

A. *The "Value of D"*: the value a retail electricity customer places on the grid (either to get bundled electricity service through the distribution utility, or to use the distribution wires on an unbundled basis to get access to the wider electricity system so that the customer can have power supply on demand and/or inject surplus power from on-premises DER for use by other customers).

B. *The "Value of DER" to the electric system:* the cost net savings that result from having a specific DER (or portfolio of DER) in place, as compared to the costs associated with investing in and operating to the electric system in the absence of those DERs.

C. *The value of DER to the participating customer*: the array of net benefits that the customer having DER on his/her premises receives from doing so. Benefits might include: satisfaction of various objectives such as: improved customer service; lower environmental impacts resulting from energy use; potential hedges against price increases; ability to better manage energy price increases; increased sense of energy autonomy; potential resiliency improvements; and so forth. These benefits may or may not offset any up-front and/or on-going costs facing the customer that adopts DER.

D. *The value of DER to the local community / society*: the net impacts of DER deployment that go beyond the electric system and the producers and consumers of electricity. These impacts include lower (or higher) overall air emissions and water use, higher or lower local employment, transfer of dollars into or out of the local economy.

A. ***The "Value of D"*** is the value a retail electricity customer places on being connected to the grid. The wires allow the customer to receive bundled or unbundled electricity service through the distribution utility, or to use the distribution wires for access to the wider electricity system. For the latter, the customer may be injecting surplus power from on-premises DERs to supply power to other customers whenever that power is available and/or to provide grid services at the distribution or transmission level.

- Under traditional cost-of-service utility regulation, the "Value of D" to the customer is reflected in the distribution charge on the customer's bill. Distribution charges are one component of the local utility's electricity rate and typically reflect that customer's allocated share of the distribution utility's cost of service. These costs can be recovered through a wide combination of fixed and variable charges, differing by customer type, by utility and by regulatory policy.

- The Value of D is not the same as the full electricity price (which reflects transmission and generation and other related costs that go beyond distribution service, and typically also includes various taxes and fees). These other charges (when the customer with DER is buying power from the grid) or payments (when that customer is injecting power into the grid) will vary, depending upon the tariff under which that customer is buying electricity service, the time/location of use (or supply), and the compensation scheme that exists in the system where that customer is located.

- The Value of D is also different from the full economic value that different customers place on using electricity, which – for a particular customer – may be (and typically is) higher than the distribution rate (and total electric rate) charged.

B. ***The "Value of DER" for the electric system*** is the cost (or cost savings) that the electric system experiences as a result of having a specific DER or portfolio of DERs in place and in operation, relative to the investments and expenditures that would otherwise be needed .

- Where DERs enable reliable *distribution* service at lower cost than without them, the DERs provide a value to the distribution system (i.e., "the Value of DER to D"). Where the DER helps to avoid wholesale-level delivery costs on the high-voltage transmission ("T") system, there is a positive "Value of DER to T." And where DER helps to enable the power-generation ("G") system to meet aggregate demand at lower cost, then there is a positive "Value of DER to G."

- Conceptually, the value to the electric system (and to each of its component parts (D, T and G)) depends upon the location where DERs are placed on the grid and the timing, duration and quality of supply provided by the DERs. Depending on its technology, attributes and location/operation, a DER may have net benefits or net costs to the electric system.

- If the system can fairly obtain the right quantity/timing/location of DERs it needs at a market-based competitive price (rather than at avoided cost), then there may be net benefits – i.e., value to the system and its customers.

- Thus the full economic value of DER to the grid may not be the same as the amount paid for DER.

C. ***The value of DER to the participating customer*** is the array of benefits that the customer receives from having the DER, net of any costs to that customer of installing, operating and maintaining it.

   - Such benefits may include satisfaction of that customer's objectives, such as: quality of service; lower environmental impacts; potential to better manage and stabilize energy prices; increased sense of energy autonomy; potential resiliency improvements; and so forth. These benefits may partially or fully offset any up-front and/or on-going costs the customer incurs for its DER.

D. ***The value of DER to the local community / society*** reflects the net impacts of DER deployment that go beyond the electric system and beyond the transactions between electricity suppliers and consumers (due to environmental and other externalities). These other impacts may include lower (or higher) overall air emissions and water use, higher or lower local employment, or transfer of dollars into or out of the local economy.

   - These externalities might be considered the "Value of DER to S" (society).

   - In some jurisdictions and under some economic constructs, other societal values enabled by the presence of DER – job creation and/or job loss, or lower environmental impacts of electricity production and delivery – may be incorporated into public policy decisions about whether DER provides cost savings, but these values may or may not be reflected in prices paid to DER suppliers.

Many if not most discussions of the Value of DER tend to pull these various components into a single framework, even though each element is distinct. One common outcome of this tendency is the practice of bundling all of these aspects of value into a single form of compensation rather than in a more unbundled or disaggregated form. But just as the line-item charges on a hotel bill allows the customer to track the different components (e.g., the cost of the room versus food purchases), a fully transparent system for valuing and reporting charges for (or compensation to) DERs would separately track its implications for D, and for T, and for G, and for S.

The Focus of this White Paper: Valuing DERs to D

In light of the deep literature that exists on tracking trends in DER deployment as well as on identifying the factors that contribute to the "Value of DER" to customers, the electric system and society, this particular paper focuses attention on a subset of the issues: How should utility regulators, distribution utilities and other stakeholders think about the value of DER *to the distribution system*? And what are the implications for DER procurement and compensation that result from those interactions between the DER and the local distribution system?

Other issues described immediately below – such as why DERs are expanding so quickly, how various parties tend to view DERs' role in a transition to a cleaner, more modern, more competitive and efficient electric system, and how public policies have been designed to stimulate and compensate participants in the DER market – provide the context for examining these DER/distribution-system interactions. The focus of this particular paper remains on "the Value of DER to D."

Although regulators, utilities, DER providers, and others are working hard in many places to refine benefit/cost concepts for evaluating when and where DER installations might provide value to the distribution system, other work is needed to further evolve planning and valuation tools, ratemaking approaches, and compensation arrangements for DER. Doing so increases the chances that DERs can be planned for and reliably secured at efficient prices, thereby creating value for all customers on the distribution system.

Shining a light on the Value of DER for D in this paper is not intended to suggest that these are the only – or even the largest source – of DERs' value proposition for the electric system and for society. Indeed, as described further below, the economic value of DER to D is a relatively small part of the total value DERs provide to the full electric system and to society. Rather, the purpose of the more-narrow focus of this paper is to attempt to focus attention on some of the particular issues associated with the Value of DER to D as utility regulators and other stakeholders grapple with how to understand this particular aspect of DERs' overall economic value.

Context for the need to properly value DER

DERs are proliferating rapidly in the U.S.

Although still comprising a small fraction of the U.S. total electrical capacity and generation in the U.S., DER installations have increased dramatically in recent years. Many technologies contribute to the growing DER capacity: rooftop solar PV systems; utility-scale solar facilities connected to the distribution grid; distributed wind; energy efficiency installations; remotely controlled smart thermostats; other forms of demand-response; micro-grids; high-efficiency CHP equipment; and many other types of "behind the meter" equipment and systems that allow customers to manage their energy use and generate their own supply.

These trends result from a combination of factors, including: policies adopted by states and implemented by utilities and third parties which promote adoption of distributed systems; technology cost reductions; and high customer interest.

The most influential policy drivers over recent DER deployment trends are state renewable portfolio standards ("RPS"), state net-energy-metering ("NEM") policies, and utility procurements of DER. (There have been other drivers in federal policy, as well, including incentives provided by the American Recovery and Reinvestment Act of 2008, and various federal investment tax credits for residential and commercial solar PV systems.[4])

As shown in Figure 2, approximately three quarters of the states and the District of Columbia have an RPS or goal designed to increase over time renewable power's share of electricity sold to retail electricity customers. Most state RPS policies have led to large-scale renewable energy projects, but some states' RPS count renewable supply generated from DERs. More targeted to distributed energy resources are the policies of the states shown in Figure 3, which indicates that 22 states and the District of Columbia have RPS policies providing a 'carve-out' or specific provision designed to encourage solar PV projects and other DERs.[5] Other states, like California and New York, have separate targets for rooftop solar installations that are supported through rebates, tax credits, and other approaches.[6]

Figure 2

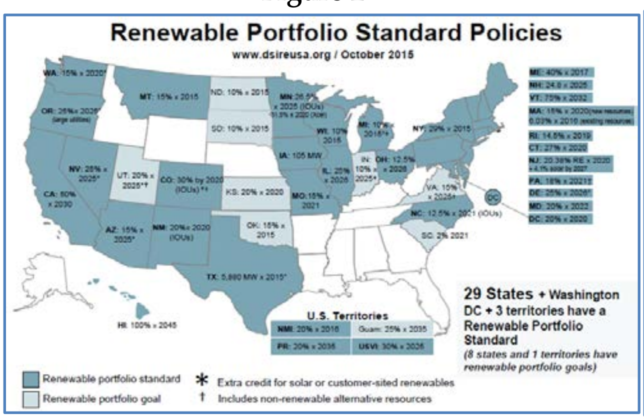
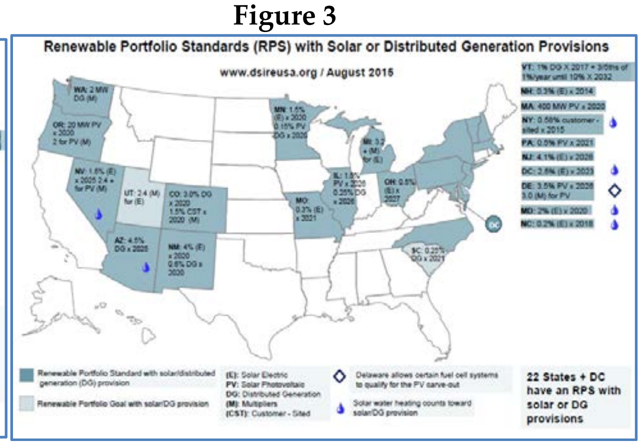


Figure 3



Source: Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/

NEM is broadly understood to have had one of the strongest roles in inducing additions of *distributed* renewable energy resources (especially rooftop solar PV systems). Eighty percent of the states have encouraged early rounds of solar installations by requiring the local electric utility to buy all of the surplus generation exported into the grid from a building with rooftop solar PV as indicated in Figure 4. States' NEM policies vary as to the level of compensation afforded to solar systems' output. As shown in Figure 5, most states compensate the customer with a solar system for surplus power at the full retail electricity rate (as indicated by those states with the darkest shading in Figure 5). Other states' policies start at the retail rate but reduce it gradually over time (states with the second-darkest shading on Figure 5). NEM, combined with rapidly declining costs of installed solar PV capacity and the ability of third parties (i.e., solar companies) to install systems on customers' roofs and then sell them the output under a long-term power purchase agreement, has stimulated significant growth in solar installations around the country (see Figure 6). Since 2010, when there were 151,000 solar PV installations providing 2,000 MW of capacity, "[t]oday there are more than 867,000 solar PV installations in the U.S., with new systems being installed at a rate of roughly one every two minutes."[7] The millionth installation is expected to occur in 2016.[8] (For context, total U.S. capacity from all generating resources was 1,072,000 MW as of the end of 2015.[9])

Figure 4

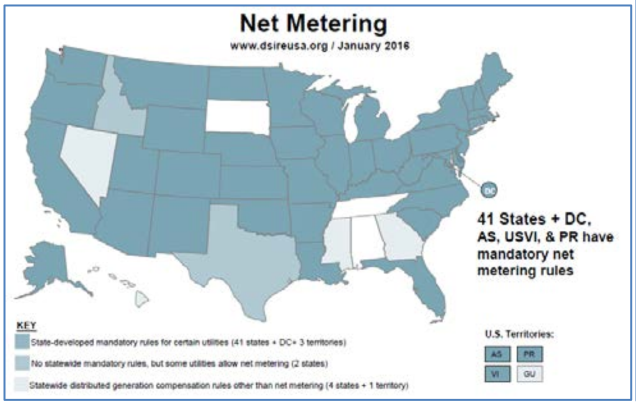
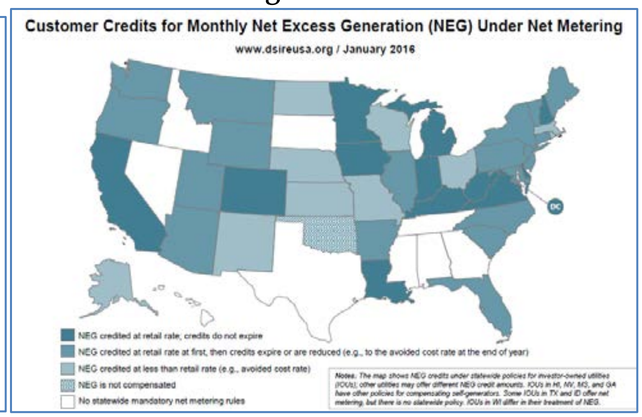


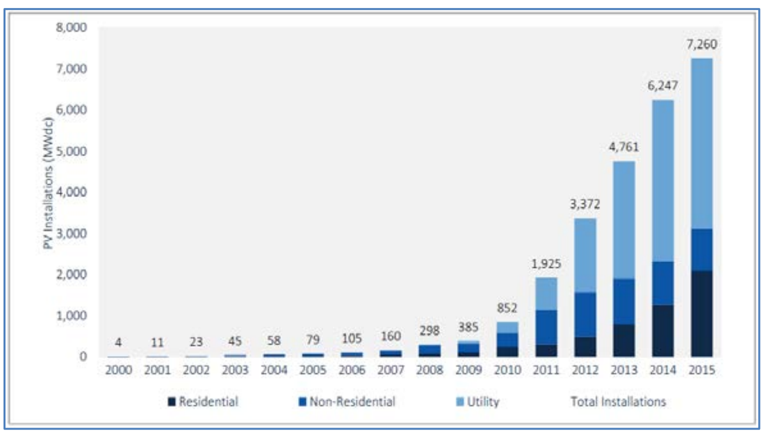
Figure 5



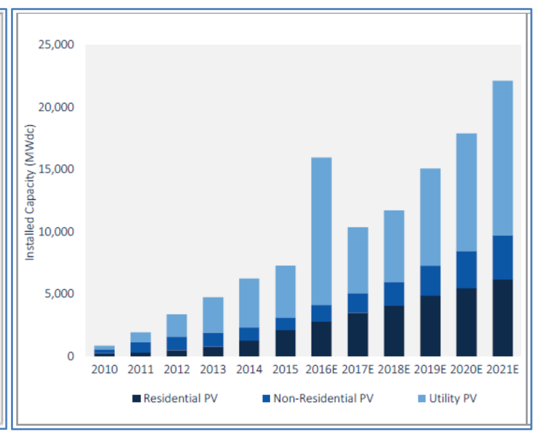
Source: Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/

Figure 6: U.S Solar PV Installations (in MW_{dc})

6a: Historic Installations



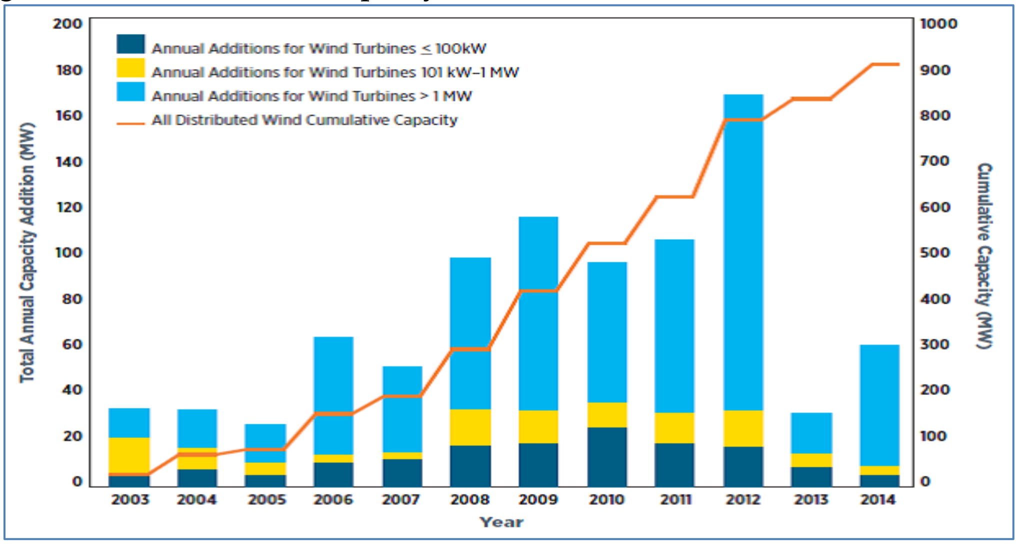
6b: Installations Forecast[10]



Source: GTM Research/SEIA, U.S. Solar Market Insight: Executive Summary, 2015 Year-in-Review, March, 2016, Figure 1.4 and 2.7

Turning to other DER technologies and options: By the end of 2014, over 900 MW of distributed wind capacity had been installed in the U.S.,[11] with the year-to-year additions and cumulative capacity installed over the past decade shown in Figure 7.

Figure 7: Distributed Wind Capacity Additions: Annual and Cumulative (2003-2014)



Source: Alice Orrell and Nikolas Foster, "2014 Distributed Wind Market Report," Pacific Northwest National Laboratory, August 2015

The most prevalent form of DER is energy efficiency, with consumers historically installing a myriad of measures to make their buildings and appliances more efficient. A retrospective review of the impact of energy-efficiency investments found that: "Without the numerous energy efficiency improvements made since 1973, the U.S. would require about 50% more energy to deliver our current GDP. The adoption of more efficient products and services is responsible for 60% to 75% of the increase in energy productivity since 1970."[12] States like Massachusetts (with its "all cost-effective energy efficiency" requirement) and California (with its "loading order" preference for energy efficiency ahead of other resource alternatives) have requirements that utilities favor energy efficiency over traditional utility investments where the former can provide cost-effective resources as part of utility service. Even though most states have required and/or encouraged utilities and third parties to offer cost-effective energy efficiency programs that overcome market barriers to customers' own adoption of energy efficiency measures, many analyses indicate that there remain deep and as-yet untapped energy efficiency savings available in most if not all parts of the U.S.[13]

Also, although CHP facilities in industrial locations and other buildings are not new, low natural gas prices combined with recent developments in efficient small-scale gas-turbines, reciprocating engines, and microturbine technologies have supported greater deployment of CHP in the past decade.[14] (See Figures 8 and 9.) Although some CHP facilities are at sites connected to high-voltage transmission lines, many are located on the property of commercial buildings and provide on-site generation at relatively constant loads across the course of a day, unlike many other DER technologies).

Figure 8:
U.S. Annual CHP Build by Size (# of Projects)

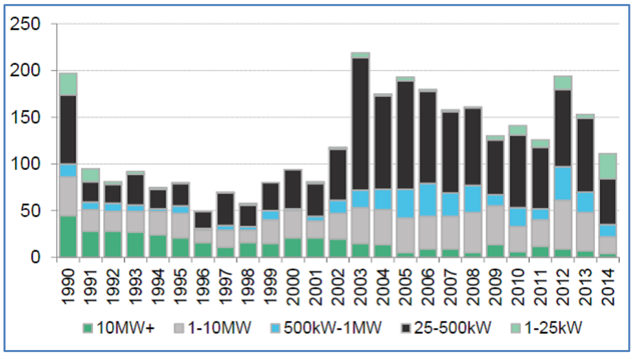
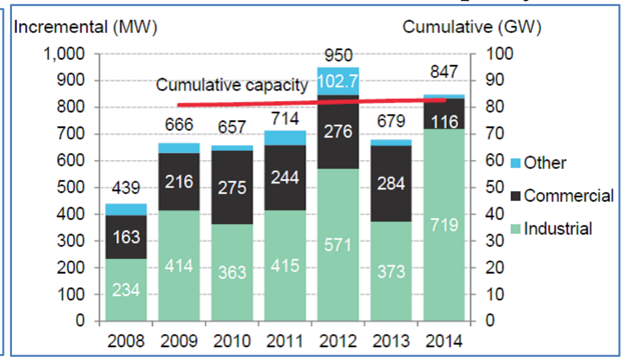


Figure 9:
U.S. CHP New Build (MW) and capacity (GW)



Source: Bloomberg New Energy Finance, 2016 Sustainable Energy in America Factbook

In recent years, centralized procurements of local capacity for reliability functions have encouraged targeted development of DERs. Two recent examples of utility procurements that resulted in contracted-for DERs are: SCE's solicitation of storage to help meet Local Capacity Requirements in the Los Angeles/Orange County regions in the wake of the closure of the San Onofre nuclear plant;[15] and Con Edison's Brooklyn Queens Demand Management Program ("BQDM") that is addressing local reliability in targeted neighborhoods of New York City.[16] Those two solicitations led to the selection of various DER technologies, including battery storage, demand response, microgrids, fuel cells, and energy efficiency, all of which have been increasing in volume across the country. (See Figure 10 for fuel cell deployments in the U.S. over the past decade). Also, procurements of demand response ("DR") by Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") have also led to increased DR capacity over the past decade as indicated in Figure 11, with the outlook for such deployments favored as a result of the recent Supreme Court decision upholding wholesale-market purchases of DR under regulations authorized by the Federal Energy Regulatory Commission ("FERC").[17]

Figure 10:
U.S. Stationary Fuel Cell
New Build (MW) and capacity (GW)

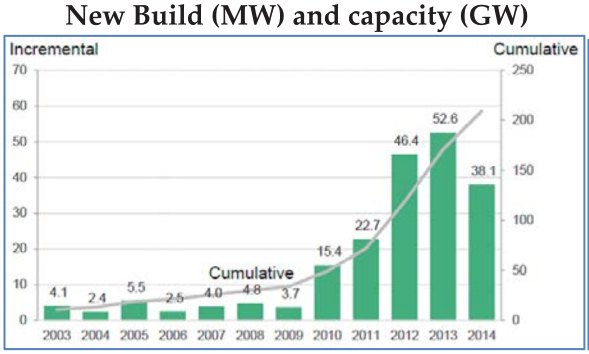
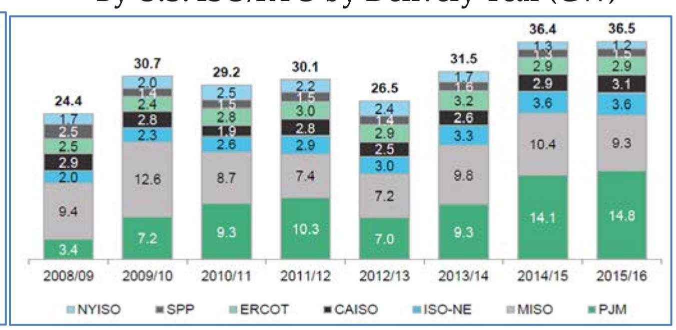


Figure 11:
Incentive-Based Demand Response (DR) Capacity
By U.S. ISO/RTO by Delivery Year (GW)



Source: Bloomberg New Energy Finance, 2016 Sustainable Energy in America Factbook

Views about the economic value of DERs are evolving

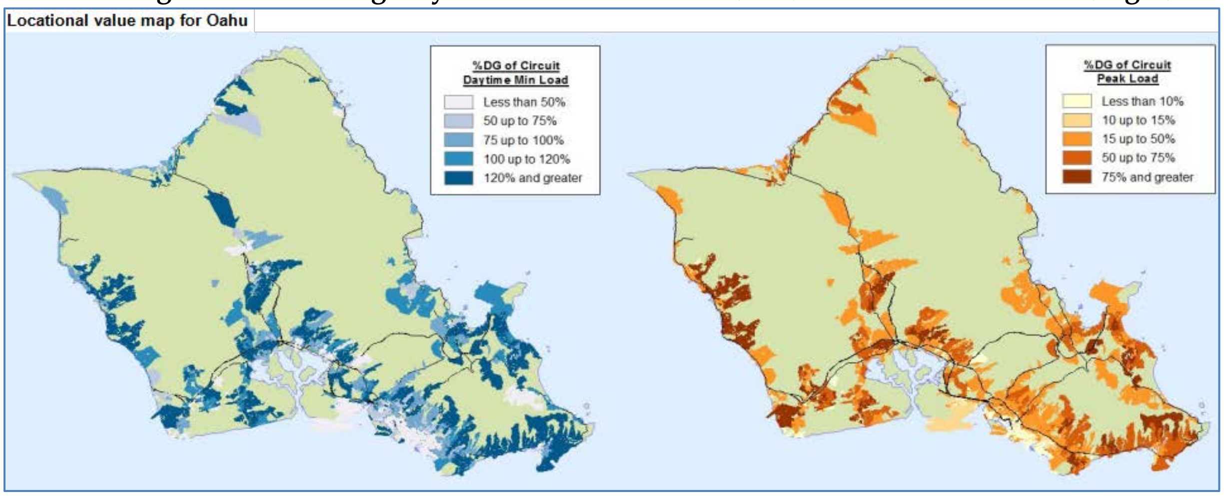
As DER installations and cumulative capacity continue to increase, many electric industry stakeholders are refining their understandings of the ways in which DER resources interact the electric system, how DERs are valued, and the prices paid to DER providers for their contribution to supporting the electric system.

Although the standard NEM approach has certainly been instrumental in spurring the development of DERs in the early stages of their deployment, net metering has recently come under scrutiny for being a too-imprecise, top-down instrument for compensating suppliers of solar DER. Different observers argue that it either over compensates or under compensates relative to the true value of DER to the electric system.[18] A recent study by Energy+Environmental Economics ("E3"), for example, which analyzed NEM in New York State's investor-owned utilities, found that with current NEM compensation, DERs had higher costs than benefits because NEM does not target DERs to places on the grid where they can avoid or defer distribution-related capital costs whereas with a more targeted placement of DERs can shift the benefit-cost ratio to positive. [19] Also, many stakeholders are concerned that NEM has led to significant cross-subsidies between those customers with NEM service and residential customers without it.[20] Approximately two dozen states have begun to examine ways to modify their NEM policies resources.[21]

For example, in Hawaii – where solar PV capacity has nearly doubled each year from 2007 through 2014 and PV panels now sit on 12 percent of electric customers' homes (compared to the U.S. average of 0.5 percent)[22] – state regulators decided in October 2015 to close the retail NEM rate for new customers and to replace it with a minimum bill approach, combined with one of two optional tariffs for compensating for solar generation.[23] (Figure 12 shows maps depicting the concentration of solar PV on distribution circuits in Oahu, with high percentages of PV systems often triggering the need for interconnection studies on the impacts of DERs on local distribution reliability. The darker colors show higher concentrations of PV relative to a circuit's minimum load (on the left) and a circuit's maximum load (on the right).) The changes introduced by Hawaii's utility regulators include a 'grid supply' option, which allows a customer with solar PV to sell output into the grid at the avoided cost of on-peak fossil generation. The other option ('self-supply') allows the participating customer to get a credit on their bill for on-site generation that is consumed on site.[24]

Further, in October 2015, New York regulators effectively removed all caps on new solar customers' ability to take service under the NEM tariff pending resolution of the state's proceeding to determine the value of DER (anticipated to occur during 2016).[25] In December 2015, Nevada regulators reset the NEM rate at the wholesale price of power, rather than the retail rate, and applied it not only prospectively to new customers but also retroactively to existing PV customers (although the latter decision is highly controversial and is currently under reconsideration as of this writing).[26] At the end of January 2016, California's utility regulators maintained NEM for new and existing customers, although new rooftop solar customers of Pacific Gas & Electric and SCE need to take service under time-of-use rates.[27]

Figure 12:
Density of Solar PV Systems on Electric Distribution Circuits
Percentage of DER During Daytime Minimum Loads (Left) and Maximum Loads (Right)



Source: EIA, "Hawaii's electric system is changing with rooftop solar growth and new utility ownership," *Today in Energy*, January 27, 2015.

And in Maine, a coalition including the state's consumer advocate, electric utilities, solar companies, and environmental groups has proposed a new market-based approach to procurement of and compensation for DERs.[28] The Maine legislature is now considering this proposal to replace the current NEM policy with a new "pay-for-production" approach in which the utilities or other designated parties would purchase and aggregate solar generation from private solar owners and utility-scale developers under long term contracts, and then bid the generation into New England's wholesale electricity markets.[29]

Clearly, a transition is underway to evolve the methodologies for valuing and compensating DERs for what they are providing to the electric system. But there is likely a large conceptual and methodological distance to be crossed between the traditional approaches (which values all DERs the same, regardless of technology and location on the distribution system), and the other methodological extreme (in which each and every DER has a different value, depending upon where it is located, what its electric generation profile looks like, and how it ends up interacting with other assets and loads on the distribution system).

The transition surely needs to move from the current extreme (using blunt valuation instruments) towards the other, without bogging down in so much technical sophistication as to be practically infeasible for ratemaking purposes.

Guidance in developing sustainable valuation frameworks for DERs for D

New valuation approaches should be grounded in the traditional utility-regulatory principles of efficiency and fairness

In anticipation of a continuing evolution towards more granularity and precision in the frameworks for estimating the Value of DER to D, many of the long-standing principles of public utility ratemaking offer useful guideposts for how to proceed.

Recall that timeless guidance on utility ratemaking set forth by James Bonbright, in his seminal book, *The Principles of Public Utility Rates*, published in 1961, emphasized the need for regulators to adopt utility rates designed fundamentally around principles of fairness and efficiency.[30] Application of these principles to distribution-related functions means designing rates so that they properly allocate costs to those customers making use of distribution service and fairly and efficiently compensate those providing functionalities that are useful to the electric distribution system. Rocky Mountain Institute's e-Lab has recently and helpfully re-interpreted Bonbright's ratemaking principles for today (with the more relevant ones reproduced in the text below):

e-Lab's Re-interpretation of Bonbright's Principles of Public Utility Rates	
Bonbright Principles	**21st Century Interpretation**
Rates should be practical: simple, understandable, acceptable to the public, feasible to apply… and free from controversy in their interpretation.	The customer experience should be practical, simple, and understandable. New technologies and service offerings that were not available previously can enable a simple customer experience even if underlying rate structures become significantly more sophisticated.
Rates should keep the utility viable, effectively yielding the total revenue requirement and resulting in relatively stable cash flow and revenues from year to year.	Rates should keep the utility viable by encouraging economically efficient investment in both centralized and distributed energy resources.
Rates should be relatively stable such that customers experience only minimal unexpected changes that are seriously adverse.	Customer bills should be relatively stable even if the underlying rates include dynamic and sophisticated price signals. New technologies and service offerings can manage the risk of high customer bills by enabling loads to respond dynamically to price signals.
Rates should fairly apportion the utility's cost of service among consumers and should not unduly discriminate against any customer or group of customers.	Rate design should be informed by a more complete understanding of the impacts (both positive and negative) of DERs on the cost of service. This will allow rates to become more sophisticated while avoiding undue discrimination.
Rates should promote economic efficiency in the use of energy as well as competing products and services while ensuring the level of reliability desired by customers.	Price signals should be differentiated enough to encourage investment in assets that optimize economic efficiency, improve grid resilience and flexibility and reduce environmental impacts in a technology neutral manner.

Source: e-Lab, "Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future," Rocky Mountain Institute, August 2014, page 38.

Thus, the utility should endeavor to pay the supplier of DERs for the fair value of the services provided by a particular DER installation (or a portfolio of them). As information and analytic techniques become more refined over time, it is likely that DERs using different technologies in the same location may provide different value(s) to the distribution system, and DERs using a common technology may provide different values to the distribution system as a function of where they are located on it. Such principles are important for three things: fairness among customers; efficiency in the expenditure of dollars dedicated to providing reliable utility service; and revenue stability and predictability to enable the utility to remain a healthy provider of grid services. These principles should apply to compensation arrangements for both 'mass-market' DERs (where installations results primarily from a customer's choice to install DERs to satisfy his/her own objectives) and DERs targeted specifically to help avoid a utility's traditional distribution-system investments.

Past PURPA experience – that market-based approaches lead to better customer results than avoided costs – is instructive for designing compensation for DERs

Another tenet to follow is avoiding mistakes that have been made in the past – in other words, taking advantage of learning the lessons from relevant past experiences in utility regulation at a time of industry transformation. In the case of the role of DERs for D and in structuring valuation approaches and procurement/compensation regimes, useful lessons come from the early years of implementation of the Public Utility Regulatory Policies Act of 1978.

Recall that PURPA is a federal law which required utilities to purchase power from eligible power producers at the utility's avoided costs – the "incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[31] FERC has delegated to the states the responsibility for implementing PURPA.

In the early years of PURPA implementation, most states initially required utilities to purchase power from PURPA facilities on the basis of energy-only tariffs that reflected a utility's short-term avoided production costs. As prospective PURPA facilities sought to provide not only energy but also capacity to the utility (and thus help to avoid the need for traditional utility investment in generating capacity), most states turned initially to formal regulatory proceedings as the means to establish administratively determined estimates of avoided cost.

Early on, these administrative proceedings produced standard-offer rates at which a utility would buy power from any PURPA facility willing to supply at that rate – sometimes without regard to the amount of generating capacity actually needed to avoid the utility's incremental capacity additions. In some cases, this led to an over-supply of output relative to the amount needed (and reflected in the administratively set avoided costs). In other cases, there was a misalignment of the attributes provided by a particular PURPA project (e.g., its technology or its location) and those the utility needed for reliability and/or energy objectives.[32]

Over time, many regulators and utilities recognized some inherent challenges of relying upon pricing set in administrative proceedings: that they can produce prices that are too low (in which case, they yield insufficient takers) or too high (where they can produce an oversubscription or increased consumer costs). Many regulators and utilities addressed these concerns through the use of competitive procurements as the means for setting avoided cost and for identifying the PURPA facilities that would get the right to supply power at that particular market-based price. This evolution eventually led to stronger pay-for-performance outcomes for competitive supplies of generation.

Paying attention to this history is important as the electric industry transitions away from the current methods to pay for DERs (typically set at the full retail rate under NEM). At the early stages of adoption and deployment of DERs, NEM has proven quite useful in stimulating the market for DERs (especially solar). This parallels the early outcomes of PURPA implementation. At present, many states are looking at administrative processes and avoided-cost methodologies to establish – in effect – the amounts to pay DERs for the resources they supply to the electric system (as described further below). But based on PURPA experience, states should quickly transition beyond such initial approaches and put in place market-based mechanisms (e.g., competitive procurements) to set prices and performance obligations for DERs selected to provide services to the electric system.

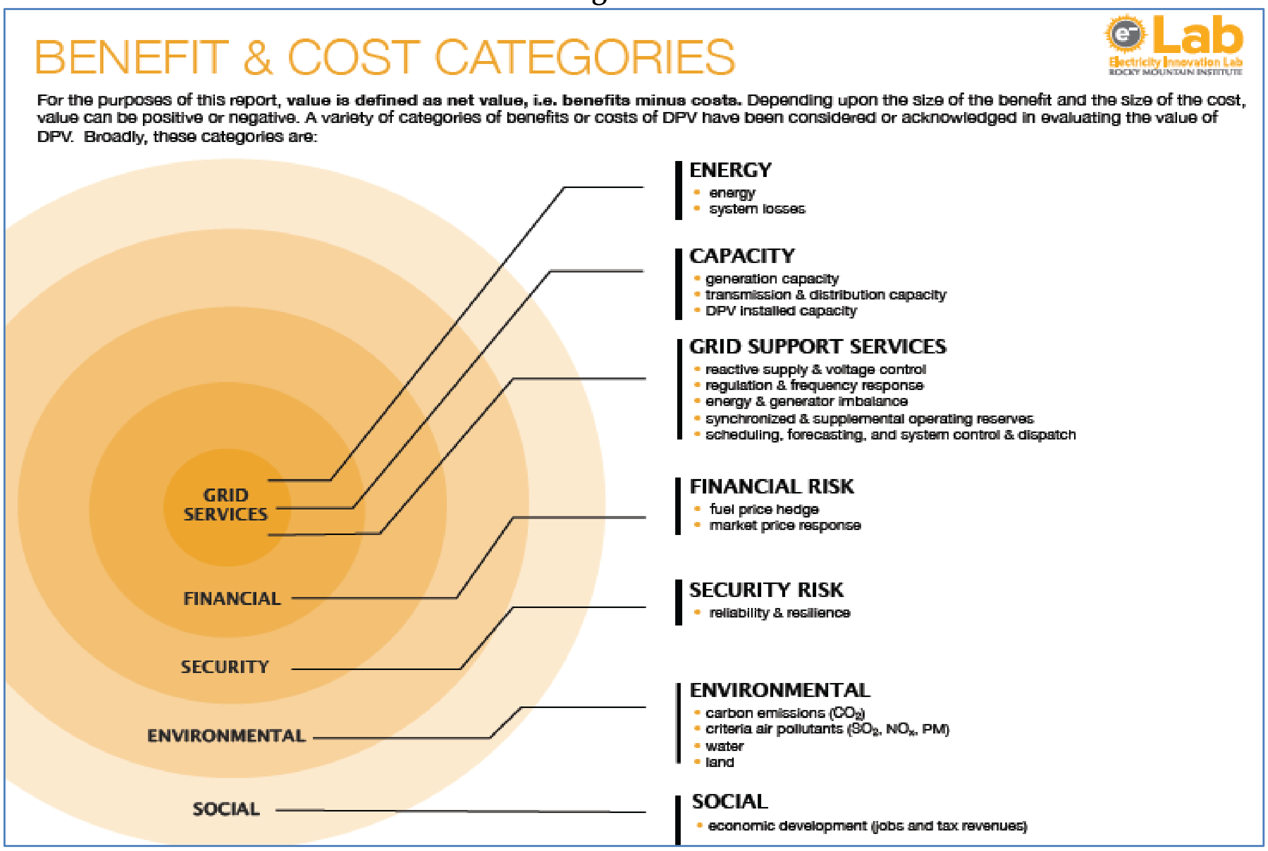
Benefit-cost studies of DERs provide indicative information about their potential to provide net benefits to the electric system, to participating customers and to society

Numerous recent studies have focused on identifying and calculating values for the full set of elements that comprise DERs' value in avoiding utility costs: their Value to D (distribution), their Value to T (transmission), and their Value to G (generation). Additionally, many of these studies also separately estimate the Value of DERs to S (society), which accounts for value not monetized within the electricity purchase/sale transaction. .

For example, e-Lab recently surveyed the literature on benefit-cost analyses of behind-the-meter solar PV resources, to examine their methodologies and their estimates of net benefits. The report identified the following categories of potential benefit and cost: *energy* (electrical energy and system losses); *capacity* (electrical generating capacity, distribution and transmission capacity, solar PV capacity); *grid support services* (including reactive supply and voltage control, regulation and frequency response, energy and generator imbalance, synchronized and supplemental operating reserves; scheduling, forecasting, and system control and dispatch); *financial risk* (fuel price hedge; market price response); *security risk* (reliability and resilience); *environmental* (carbon emissions, criteria air pollutants, water, land); and *social* (economic development: jobs, tax revenues). (See Figure 13.) These categories incorporate the valuation building blocks that appear in a wide range of studies.[33]

Across the studies reviewed by e-Lab, the portion of total net benefits attributable to the Value of Solar for D is small (and typically lumped into a category that combines avoided transmission and distribution capacity). In four of the relatively recent studies, for example, avoided transmission and distribution capacity ("T&D cap") costs represent a very-small share of total net benefits of solar (as shown in Figures 14a through 14d for studies conducted on the value of solar in Texas (Austin), New Jersey/Pennsylvania, California, and Colorado.) Although the circumstances in each place vary (e.g., total size of net benefits, size of avoided energy costs, methodological approach), avoided distribution costs are small everywhere, relative to the total estimated value of solar PV in avoiding traditional utility costs. This same conclusion was reached in E3's recent NEM/PV study in New York State, which indicated that under business-as-usual NEM policy (which does not target solar PV toward places on the grid where it can provide value in avoiding traditional distribution-system investment), the avoided costs of DERs for D is a very small share of total avoided costs.[34]

Figure 13



Source: eLab, "A Review of Solar PV Benefit & Cost Studies," Rocky Mountain Institute, September 2013 (hereafter "eLab 2013 Solar PV Study").

That said, according to eLab, one of the most significant gaps in valuation methodologies is in understanding the distribution component – that is, the benefits or costs that result from rooftop solar PV operations: their impacts on "the distribution system are inherently local, so accurately estimating value requires much more analytical granularity and therefore greater difficulty."[35]

Also, many of the benefit/cost components in these studies are externalities (e.g., carbon-emission-reduction benefits as estimated in the social cost of carbon, or macro-economic development/job impacts) that are not part of the current pricing structure of electricity. As such, they are typically not monetized within part of the electricity purchase/sale transaction. They are avoided societal costs. Depending upon the study, these may be small or larger components of full calculated avoided costs. But in the day-to-day provision of electric service, these are literally not part of the utility's avoided cost. Were the utility to compensate a DER supplier at this type of estimated full avoided cost (rather than its own avoided cost), then 'missing money' problems could arise, which should be addressed through a fair and transparent ratemaking technique.

Figures 14: Average Avoided-Cost Values Identified in Selected Studies

Figure 14a: Austin Energy (2012)[36]

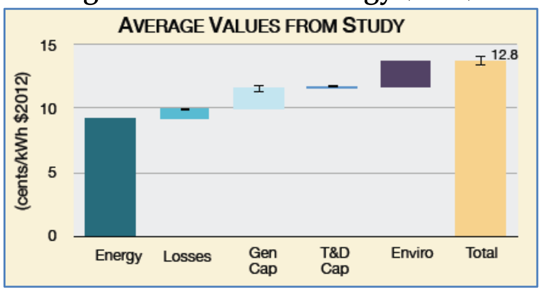


Figure 14b: New Jersey / Pennsylvania (2012)[37]

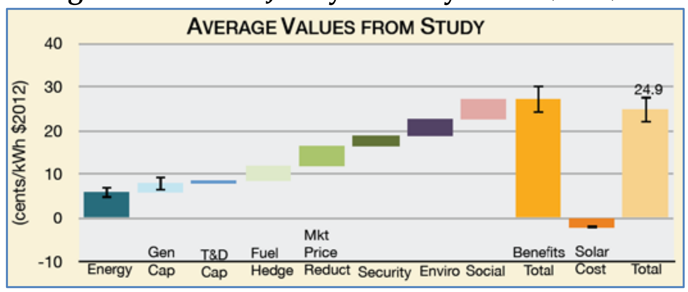


Figure 14c: California (2012)[38]

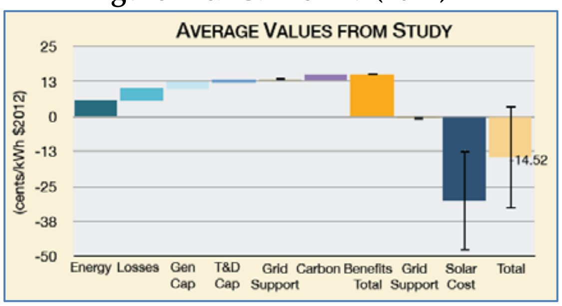
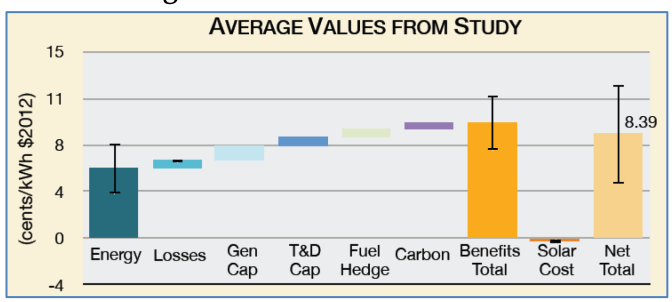


Figure 14d: Colorado (2013)[39]



Source: e-Lab 2013 Solar Study.

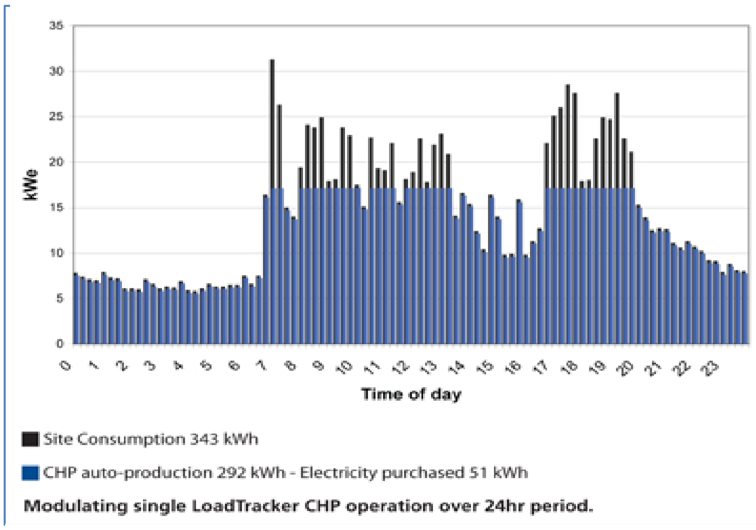
Benefit/cost methodologies are being considered in many regulatory jurisdictions to determine whether a utility's investment in DER is cost-beneficial relative to a more traditional investment (e.g., incremental distribution or transmission infrastructure). For example, as discussed further below, both California and New York are adopting benefit/cost frameworks, and then using them to evaluate whether a DER installation (or a portfolio of DERs) satisfies various (e.g., the Utility Cost Test, the Total Resource Cost test, the Participating Customer Test, the Non-Participants' Cost test (also sometimes known as the Ratepayer Impact Measure test), and the Societal test[40] – many of which have long been endorsed by utility commissions for the purpose of utility evaluations of the cost-effectiveness of energy-efficiency measures.

Valuation of DERs as alternatives to traditional distribution-system investment should account for the varied attributes that different DER technologies provide to the local grid

The DER valuation literature recognizes that different DER technologies have characteristics that enable them (or prevent them) from providing certain values to the electric system. From the point of view of the distribution system, the opportunity for greatest economic value rests with the ability of a particular DER technology and/or application (or a portfolio of DERs) to avoid specific distribution-system upgrades, and to do so with the same degree of necessary reliability and/or functionality afforded by traditional distribution investments.

Different DER technologies, of course, have different load-control and/or production profiles across the hours of any year, across years, and in different locations. For example, the figures below show the different performance of different types of DERs. Figure 15 depicts the output of a CHP unit (shown in blue) over the course of a day, thus capable of providing load-following resources over the hours, up to the maximum output given the CHP unit's size. To the extent that the customer's load was relatively flat (as opposed to the load shape depicted in Figure 15), the CHP unit could be optimized to serve most if not all of that customer's electricity requirements in a relatively reliable way, with the potential to avoid multi-hour overloads on the distribution system that might happen in the absence of the CHP project.

Figure 15:
CHP Output in Relation to On-Site Demand



Source: http://www.sav-systems.com/newsletter/issue-33-sav-loadtracker

By contrast, solar PV output will tend to vary across days and the hours of any day, in large part in relationship to cloud cover, existence of daylight, and season of the year. Figure 16 shows, for example, the output of the solar panels on my own rooftop in a recent week, with energy produced only during day-light hours and being highly variable depending upon cloud cover. The ability of my DER to help avoid distribution system overloads and defer traditional utility costs would depend upon its goodness-of-fit with the conditions on my utility's local distribution system in general and the specific segment of the circuit that serves my home.

Figure 16
Energy Produced from the Solar PV Panels on Tierney Roof
In 15-minute Intervals (kWh) During All Hours in a 7-day period (Sunday-Saturday) in July 2015

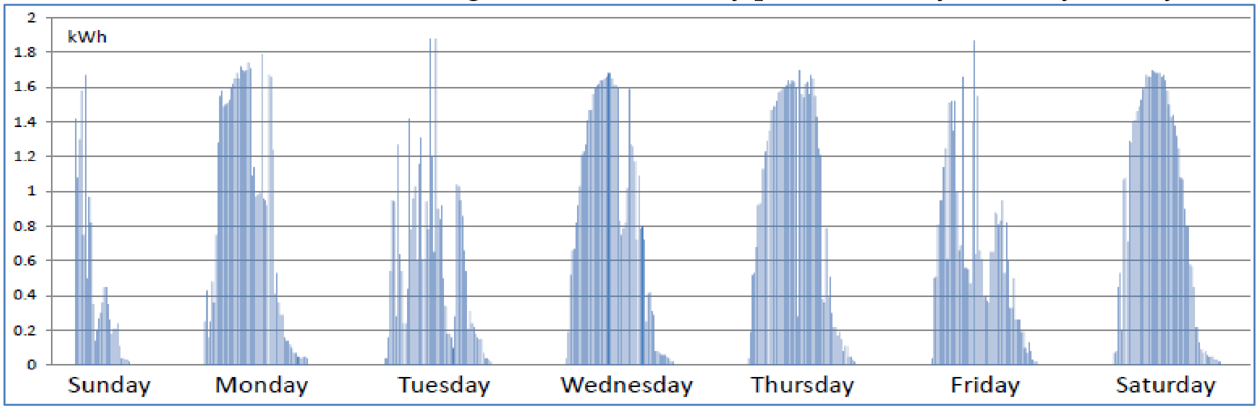
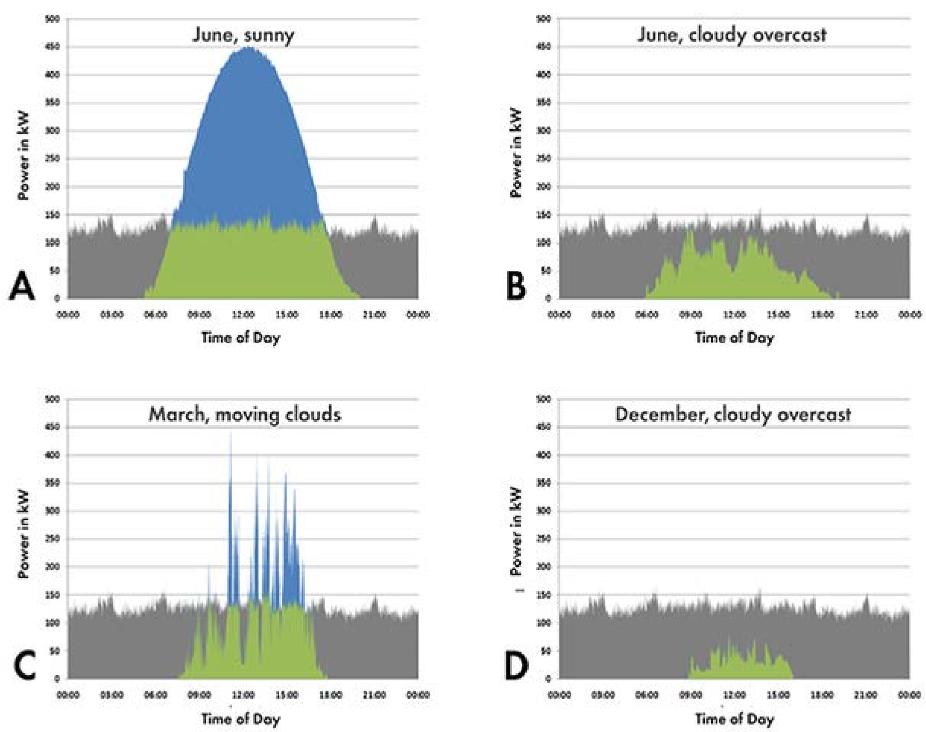


Figure 17: Solar PV Output on a Building During Several Seasons, By Time of Day and In Varied Weather Conditions



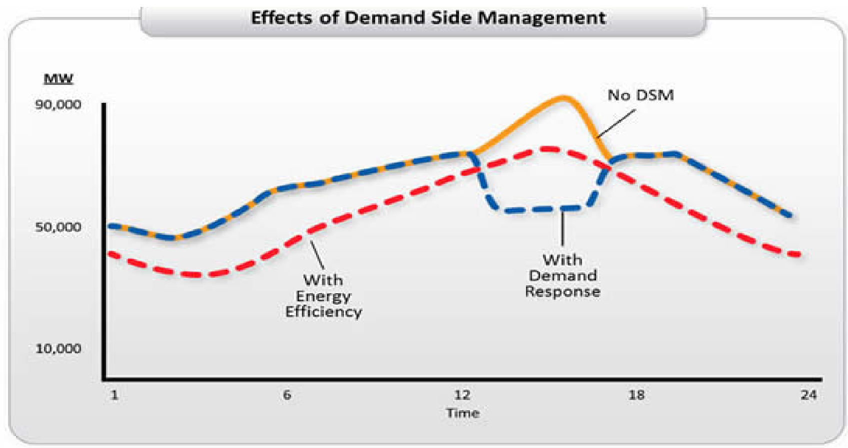
Source: http://www.sma.de/en/partners/knowledgebase/commercial-self-consumption-of-solar-power.html

Figure 17 displays the output of a different PV system under various conditions, compared with the electrical load of the building (whose electricity use is relatively flat). Solar PV output consumed by the building itself is shown in green, with output fed into the distribution system shown in blue. The patterns of solar output vary considerably across these various conditions (and in the absence of storage).

To underscore the point: Demand response is a DER that a distribution company (and/or the wholesale grid operator) might have in place so as to be called upon during critical conditions on the system to reduce loads for one or another purpose (e.g., wholesale capacity obligations; distribution-system reliability needs on a particular circuit).

Figure 18 illustrates the potential capability of demand-response resources to be dispatched to lower customers' demand at critical times, including for the purpose of assuring local reliability requirements. To date, however, DR resources have tended to be relied upon for wholesale and/or bulk-power system functions (e.g., electric-system resource adequacy) and not for distribution-system purposes. Even so, such resources have the potential to avoid and/or defer distribution upgrades where there is a good locational fit between the place(s) where distributed DR can be deployed and the spots on the distribution circuits that would otherwise need upgrades to avoid reliability problems.

Figure 18: Effects of Demand Response on Customers' Loads



Source: http://www.theenergycollective.com/david-k-thorpe/244046/demand-side-response-revolution-british-energy-policy

For the utility to confidently rely on DERs to actually defer/avoid traditional distribution investments will require assurances that the DERs will provide a level and quality of reliability comparable to what would have been provided through traditional distribution upgrades. It would not be helpful to the other customers who are counting on local electric reliability if DERs were counted on (and paid) to postpone utility distribution investments, but did not, in the end, perform at an equivalent level of service to the local grid. Any anticipated fatigue factor in DR performance, for example, will need to be understood and factored into plans that rely on DR as part of distribution-system planning.

Distribution utility planning for and procurements of DERs can help ensure that DER have attributes targeted to the utility's needs

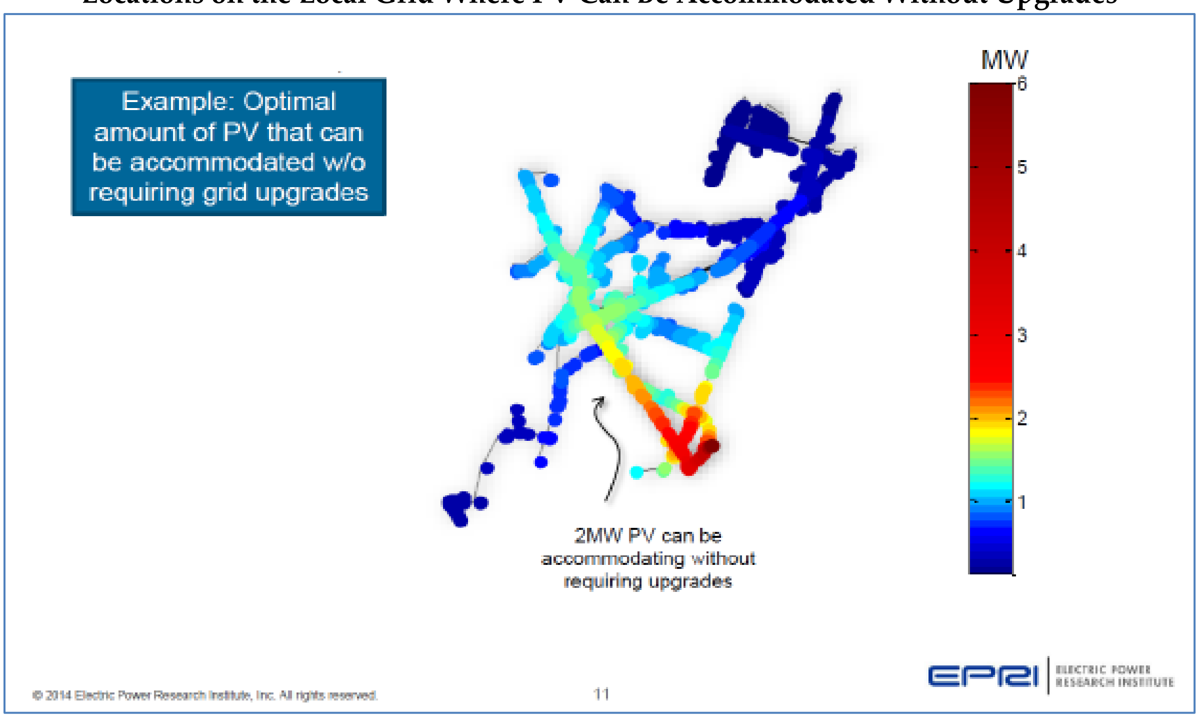
With a few notable exceptions (e.g., Con Edison's BQDM project and SCE's procurement of local DERs in the Los Angeles Basin), most DERs to date have been put in place by customers (rather than the utility) or third parties who seek the benefits of the DER for their own objectives (rather than the utility's). Some parties refer to these as "customer-driven," or "autonomous," DERs.[41] These customer-driven DERs have impacts on local distribution systems, of course: they sometimes free up room on local feeders, and in other circumstances, they can introduce operational challenges on the local distribution system.

As utilities themselves rely more upon DERs as potentially cost-effective alternatives to traditional distribution-system investments, they will need to proactively integrate DERs into their distribution-system planning and to procure those resources with attributes and locations of genuine value to the local grid. This means that the currently most prevalent forms of DER compensation – that is, utility tariffs and time-of-use rates that allow customers to opt-in to provision of DERs, often without regard to location on the distribution grid[42] – will need to evolve. To rely on DERs as part of the planned-and-operated local grid, the utility will need to have programs and/or procurements intended to lead to DERs with particular attributes and located in particular amounts and locations on the grid.

For example, utilities could target DER offers to specific customers located in certain parts of the system. Examples include:

- Utility offers to own and install solar PV systems on certain customers' premises.
- Utility incentives to encourage customers' adoption of energy efficiency measures.
- Utility information platforms and programs to indicate where DERs may be installed on the grid without additional integration costs. (This is sometimes called information about a utility's "hosting capacity" – that is, the grid's capability to host (integrate) additional installations of DER without any need to upgrade equipment to absorb the new local resource).[43] (See Figure 19, showing a map of locations on the distribution system with available hosting capacity and those with relatively high current penetrations of DERs.)

Figure 19: Illustrative Solar PV Hosting Capacity Map
Locations on the Local Grid Where PV Can Be Accommodated Without Upgrades



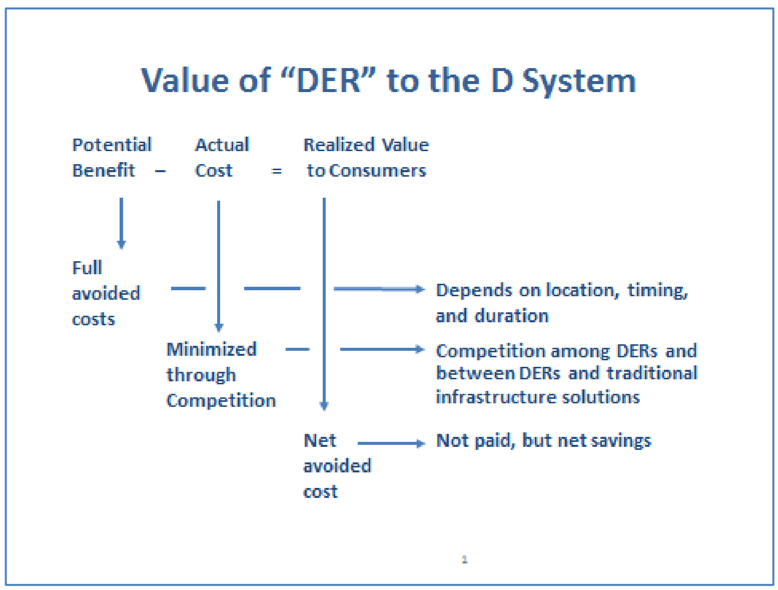
Source: EPRI map, presented in Greentech Leadership Group and CalTech Resnick Institute, "More Than Smart: Overview of Discussions Q3 2014 thru Q1 2015," Volume 2 of 2, March 31, 2015, page 42.

- Utility programs to procure DERs with particular attributes and in targeted locations in order to provide distribution functions to the local grid. Examples include:
    - Local distribution utility 'requests for information' and/or 'requests for proposals' for DERs to provide temporary and/or permanent local load relief. (See Con Edison's 2014 "Request for Information: Innovative Solutions to Provide Demand-Side Management to Provide Transmission and Distribution System Load Relief and Reduce Generation Capacity Requirements."(This is Con Edison's BQDM project solicitation.) [44])
    - Competitive solicitations for offers of DERs to provide grid-support resources to the local utility at market-based prices, with long-term contracts to support installations and future performance of such DERs. (This is what is envisioned in the Maine settlement proposal for a market-based mechanism to replace NEM.[45])

Market-based procurement and compensation mechanisms for DERs designed to displace utility investment can create real value for the distribution system and its customers

Building off of prior PURPA experience, utility methods for procuring and paying for DERs should take advantage of the potential for innovation and efficiency that can result from competitive processes. Such evolution would recognize that benefit/cost analyses of DERs (relative to utility's traditional avoid costs) are the first, but not the last step, in determining which DERs provide greatest value at lowest cost. Obtaining DERs using market-based means may result in DERs coming forward in targeted locations at competitive prices that are lower than avoided cost, and thus producing net benefits to the system as a result of incorporating DERs into distribution system plans and reliability solutions. This would be the step that would enable DERs to actually provide value to the electric system and all of its customers (by providing reliability at a lower cost than would otherwise occur, as illustrated in the "net avoided cost" shown in Figure 20[46]). Periodic procurements would also be able to take into account the changes that inevitably occur on the distribution system over time, with some changes pushing out the date of need and others leading to earlier reliability challenges than previously anticipated.

Figure 20



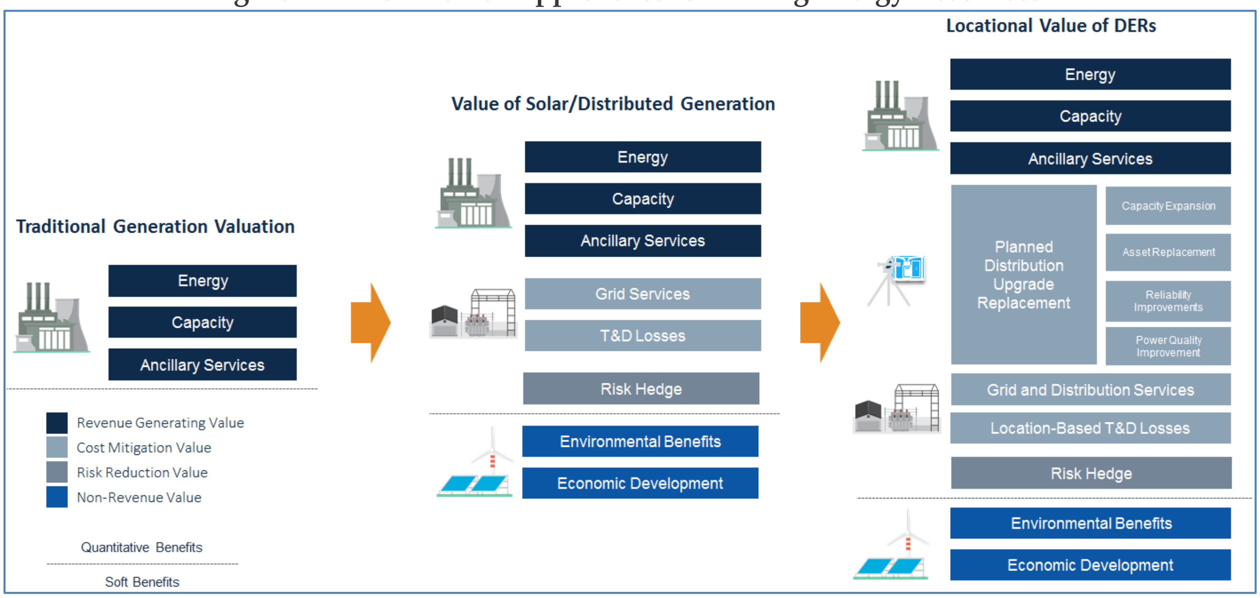
Targeted procurements and market-based compensation mechanisms send very-different economic and market signals to customers to install DERs for the benefit of the distribution system, as compared to the direct benefits that accrue to those customers themselves or to the larger electricity system. These approaches would be quite-different than current NEM compensation arrangements (which are currently subject to active debates about whether NEM tends to over- or under-compensate DER suppliers for their value to the system).

Using market-based mechanisms to procure and price DERs for their Value to D, however, does not completely answer all questions related to compensating DER suppliers for their overall value. Is this enough to provide efficient price signals, given that when DERs enable participating customers to avoid a purchase of electricity, those DERs lower the customers' payments for the generation-related portion of their electricity bill. The current proposal in Maine is addressing this question by establishing a role for the utility in aggregating the energy reduction and/or supply from DER providers and bidding them directly into the wholesale power market.

Another thorny question relates to whether and, if so, how DER suppliers should be compensated monetarily for the societal costs they avoid through their supply (e.g., avoided carbon emission costs not already internalized in wholesale power prices). By definition, any such costs are externalities and not part of payments between consumers and suppliers of electricity. Therefore, paying DER suppliers for such costs means that these are not costs that the utility itself would have avoided and would be outside of its normal cost of service. To avoid a missing money problem, therefore, long-standing ratemaking principles hold that if regulators seek to ensure that DER suppliers are compensated for this value then it also follows that regulators should also ensure such costs are fully recovered in a fair and transparent way from all customers of the electric system. This would clarify to customers that they are contributing to important social objectives (e.g., carbon reduction), above and beyond the levels currently embedded in electric-system operations.

From the point of view of the Value of DER to D (as opposed to its value to T, G and S), the industry is only beginning to fashion procurement and compensation approaches that connect payment amounts to DER providers to the value that specific DER technologies/applications provide in the context of quite-specific locations on the distribution system. As noted by e-Lab, the "[m]ethods for identifying, assessing and quantifying the benefits and costs of DPV [distributed PV] and other DERs are advancing rapidly, but important gaps remain to be filled before this type of analysis can provide an adequate foundation for policymakers and regulators engaged in determining levels of incentives, fees, and pricing structures for DPV and other DERs….Thus far, studies have made simplifying assumptions that implicitly assume historically low penetrations of DPV. As the penetration of DPV on the electric system increases, more sophisticated, granular analytical approaches will be needed and the total value is likely to change."[47],[48] As shown in Figure 21, GTM Research has depicted the gradual shift in resource mix and valuation approaches, from the electric industry's historical reliance on traditional central-station generation, to the current era in which utilities and regulators have been fashioning mechanisms to value DER in parallel with supply-side resources. Figure 20 also points to a future time when the value of DER will reflect the specific impacts (positive and negative) associated with DER technologies with different supply profiles and with applications in particular spots on the grid. (Note that GTM Research's graphic extends beyond the Value of DER for D to also include the Value of DER for T, G, and S. With respect to the elements directly affecting the Value of DER for D, Figure 20 lists the following components: Planned Distribution Upgrade Replacement, including Capacity Expansion, Asset Replacement, Reliability Improvements, Power Quality Improvements, as well as Grid and Distribution Services and Location-Based T&D Losses.)

Figure 21: Evolution of Approaches to Valuing Energy Resources



Ben Kellison, "Unlocking the Locational Value of DER 2016: Technology Strategies, Opportunities, and Markets," January 2016,

EPRI has taken a number of steps to advance the state of knowledge on such issues. In its Integrated Grid framework, EPRI points out that a "common practice in value-of-solar studies is to first establish benefit categories and then to search for contributions in the form of avoided costs—for example, avoided generation, T&D, and distribution capital costs calculated in long-term planning studies. However, if the studies did not model the characteristics of DER contributions to meeting electricity demand and did not identify the electric system costs incurred to accommodate those resources, the attributed avoided costs fall short of portraying the complete net benefit picture. That representation becomes even less credible if the location (on the grid) and type of DER are not accounted for explicitly."[49]

Implications: Integrating DERs into distribution system planning and market-based solution sets

Local distribution planning processes should explicitly consider DERs and their potential value relative to traditional distribution solutions

Ultimately, the value of a particular set of DERs to a particular distribution system depends upon two things: the goodness-of-fit between those DERs' attributes and the types/location/timing of reliability problems the utility needs to solve; and the existence of net economic benefits that result from pursuing the DERs as compared to the traditional utility solution. Distribution-system problems (e.g., thermal overloads on the system, due to load growth; voltage problems; old wooden poles that need replacement; service restoration after storms knock down poles and wires) vary in ways that are important for determining the relevance of particular DERs for addressing that problem as well as the costs of a traditional solution compared to a solution based on a portfolio of DERs. Some of these problems (e.g., deferring upgrades needed to mitigate anticipated reliability violations attributable to load growth) can be addressed by DERs with certain attributes at certain locations; but other problems (e.g., pole replacement) may not be avoidable by DERs.

In most respects, the traditional approaches to resolve reliability issues on the distribution system involve decisions in planning/investment cycles that span many years. The utility conducts distribution-system planning on cycles that anticipate the character, timing and location of changes in customer demand and other factors on its system in future years, timed with lead times of various solution sets. This suggests that in order to effectively defer or avoid traditional utility capital investments in distribution infrastructure projects, DER solutions must be identified, installed and available to operate consistent with time frames associated with the utility's normal planning and construction cycles for such projects.

Historically, distribution-system planners have endeavored to anticipate and then analyze situations where changes on any particular part of the system might lead to reliability violations in the future without a planned fix. Among other things, this planning process looks at drivers affecting demand conditions on local feeders, transformers, and other parts of the distribution system, including such factors as population changes, known development and construction projects, building abandonments and tear downs, addition of large numbers of electric vehicles, customer-driven DER installations, and changing patterns of use that might affect the peak hour of use on a particular circuit or part of the network. This type of planning focuses on changes affecting specific parts (feeders, circuits, substations) on the system to identify places where capacity and/or voltage conditions will need to be addressed in the future.

The planner anticipates that a particular circuit or part of the network could become overlooked or otherwise violate reliability standards in the future (e.g., one to five to ten years into the future[50]), and then the utility looks for actions and investments that minimize the overall cost of fixing the reliability problem while optimizing the use of existing capacity on the system. A traditional distribution-system fix might be to add greater capacity (e.g., an upgrade in the circuit) in a particular part of the system in order to avoid the anticipated reliability problem. Traditional distribution-system planning has focused on reliably and safely accommodating one-way flows of electricity from the system to serve electricity consumers' demand at all times, which is, of course, changing with the integration of DERs that produce power for export from a customer's premises on the distribution system.

Most of the traditional fixes are capital investments,[51] many of which are expensive and have long lead times that are taken into account in the utility's planning horizon. These traditional solutions are designed to reinforce the physical capability of the infrastructure to meet customers' electrical requirements including standards for reliable service delivery and safety at all times of day. These characteristics suggest that the market for reliability solutions for D – that is, the market for DERs to serve as alternatives for traditional distribution solutions – has features that resemble a long-term resource adequacy issue (i.e., in the context of utilities that rely on integrated resource planning with competitive procurements to discover the least-cost solution), or a long-term capacity market (in those regions which have adopted them in wholesale markets). This suggests that at least in the early stages of the evolution, the focus of market design and implementation ought to be on ensuring that DER capability is installed in sufficient amounts, locations, time frames, and attributes to assure that the DERs can provide the same functionality as would have been provided by the utility's traditional capital-investment solutions. And it further follows that if DERs (rather than those traditional investments) are to be incorporated into distribution-system plans and operations, then those DERs need to show up and perform when needed in order to mitigate the anticipated reliability concerns.

Integrating DERs to add value to distribution-system plans depends upon paying competitive prices for comparable performance

Taking these considerations in account, then, it seems logical that utilities should proceed to fashion and conduct competitive solicitations of DERs that can offer to provide certain reliability-related attributes in specific places on local grids. With offers in hand, the utility can analyze how combinations of offers might create a portfolio of DERs that together promise to satisfy the utility's needs at lowest cost. The utility can then enter into contracts to assure that that group of DERs actually materializes and solves the local reliability problem cost-effectively and to do so with equivalent reliability as the utility's traditional solution would have provided.

As noted previously (and shown in Figure 20), such a competitive procurement process for DERs can create efficiency and overall net savings (i.e., realized value) to consumers. Such a process moves beyond the starting point of determining administratively how DERs could potentially create value by avoiding traditional utility costs (which is the current focus of so much effort in regulatory proceedings in many states). The competitive procurement process would reveal which DERs can actually avoid the utility's investment cost-effectively and what is the efficient price for acquiring such capability. Any difference between full avoided cost and market-based price produces the net savings – again, the realized value – to all consumers from incorporating and integrating DERs into its distribution-service solution set.

Distribution utilities' competitive solicitations for DER offers should focus on providing prospective DER suppliers with information about the attributes that the utility needs to mitigate anticipated local reliability problems, in order to encourage innovative and creative solutions.[52] Attributes of interest should be provided in as granular a fashion as possible, with regard to time of day, location in a particular part of a circuit or network, number of hours of preferred performance, operational firmness, and so forth. (Such disclosures might need to be subject to non-disclosure agreements if necessary for system security reasons.) These attributes would characterize the services the distribution utility needs to obtain from DERs in order for them to concretely defer traditional distribution investments.

This latter point is worth repeating: in a world in which distribution utilities pay for and count on DERs as the means to address anticipated reliability needs and then postpone/forgo traditional investments, it will be imperative that the DERs actually perform the agreed-upon services. As explained in the recent Lawrence Berkeley National Laboratory paper,[53] the

> following steps provide a logical sequence of considerations for regulation of electricity distribution systems in a future with high DER penetration.
>
> - **Step One: Ensure physical capability and reliable operation of the distribution system.** The first, and primary, considerations derive from the fundamental question of how to plan and operate an electric system with significant amounts of customer and merchant DERs in order to ensure safety, reliability, resilience and affordability. Design choices must respect the physical laws governing the electric distribution system while achieving public policy objectives. Planning and operational concerns are primary not because they are more important, but because they provide a foundation for subsequent decisions about market design and organizational structure, which must be made to align with the operational needs of the high-DER distribution system.
> - **Step Two: Develop market and regulatory structures to fully realize DER value** The second set of considerations related to fully realizing the value of DERs for distribution (and bulk power) systems requires that they can effectively and substantially reduce T&D operational expenses and offset investment in T&D infrastructure and utility-scale generation. This in turn requires a market and regulatory framework to ensure DER availability and performance when and where needed…. Where DERs are proposed to avoid distribution or transmission investments, the much longer lead time for building the foregone traditional grid upgrade requires enforceable assignment of accountability for the DERs to be operational, and with the needed performance characteristics, by the time the grid upgrade would have needed to be in service. This means that market structures and associated regulatory frameworks need to consider the whole life-cycle, from identifying the needs that DERs could fulfill, to determining the best portfolio of

DERs to meet each specific need, to procuring, implementing, dispatching and operating the DERs to meet real-time grid operating requirements.

There are significant economic risks associated with actually posting the utility's full avoided cost as the target price in competitive solicitations for DERs as alternatives to traditional utility investment. Based on a deep body of PURPA experience, academic research [54] and best-practices in utility solicitations,[55] advance publication of full avoided costs tends to lead to results in which bidders peg their offer prices to the utility's avoided cost, rather than to their own financial requirements needed to supply the DERs to the utility.[56] As the market for DERs transitions to more competitive pricing in the future, the goal should be to design these market-based mechanisms so as to produce efficient prices – and thus to create net savings to consumers. Consistent with standard-practice rules for competitive solicitations on the generation side, there should be safeguards to assure a fair and efficient outcome.

Utility contracts with the successful DER offerers should include commitments to pay for delivered capacity (e.g., milestones for installation of the DERs) and payments tied to actual performance over time (e.g., the DER remains durably in place over time) and when called upon (e.g., solar PV output under certain peak conditions; demand-response delivering load reductions when dispatched). Penalties for failure to perform could provide incentives for more certain and more durable performance from DERs.

The combination of such forward procurements of DER capacity and contractual provisions tied to performance can facilitate DER suppliers' entry into the market for distribution-system solutions. Similarly, the approach should help build experience and assurances over time as to the reliability of DER portfolios for satisfying distribution-system requirements.

Moreover, given that most of the value that DERs may provide to the electric system and society comes from sources other than the distribution system – e.g., avoided energy and capacity in the wholesale power system; avoided transmission line losses; avoided carbon emissions from energy production and delivery – then such competitive procurements of DERs for D can help provide price discovery for what amounts of compensation are needed and efficient to come from the distribution utility in order to make the DER viable economically and financially.

Note that this discussion assumes that for the near term, at least, it is more important to focus on evolving from current NEM tariff designs toward a forward market for distribution-system DER capacity for larger facilities and for DERs explicitly solicited for solving distribution-related reliability issues (especially in the absence of storage). This also assumes it is important to gain experience in implementing that procurement/compensation model before sharpening the tools for operational markets for DERs for D. The latter may hold more promise once there is a deep penetration of DERs, allowing for many potential sellers with different technical, institutional and financial capabilities to participate actively in distribution-system operational markets.[57]

That said, there are active opportunities for distribution-system DERs to participate in existing and still-evolving wholesale electricity markets. There are numerous opportunities for DER aggregators (either the distribution utility and/or third parties) to offer DER energy and ancillary services into wholesale markets (such as those in New York, New England, and the PJM footprint).[58]

In the future, as the markets for DER for T evolve, it may be worthwhile to look at the other shorter-term/operational sources of value of DER to D (such as voltage support), and then refine shorter-term/operational markets to compensate for such non-capacity-related services provided by DER to D. After the main source of value (distribution capacity) provides the lion's share of value, then these other value streams can be layered on top of that foundation.

This prioritization of "DER-for-D" market elements – starting with forward DER capacity procurements as the main event, and then moving toward more secondary and likely smaller transactional markets over time – fits not only with the need to make progress in market and regulatory developments (without perfection being enemy of the good), but also with economic principles about the conditions that enable robust, successful markets to exist. Note that these conditions (shown at right) – e.g., many buyers and many sellers, low barriers to entry, non-discriminatory access of market participants to essential facilities necessary to participate in markets, means to mitigate the ability of market participants to exercise market power[59] – are not yet in place (much less fully designed) for the market for DERs for D. Rather, issues relating to establishing such conditions in the future are under active discussion in leading states (e.g., California, New York, Hawaii). When the standard conditions for successful markets are absent, they may inhibit efficient prices. As such, it seems premature to focus on more than getting the most important DER product markets ready for prime time in the near term.

Standard Conditions for Successful Competitive Markets

- Many Buyers and Sellers
- Low Barriers to Entry (including price levels that support (over time) entry of new investment)
- Non-Discriminatory Access of Market Participants to Essential Facilities and Other Services Necessary to Participate in Markets
- Means to Mitigate the Ability of Market Participants to Exercise Market Power
- Informed Consumers
- Transparency of Prices and Options
- Relatively Stable and Transparent Market Rules

One final point here: In light of the active role and effort that electric distribution companies will be expected to take in eliciting and putting together portfolios of DERs to provide equivalent and more cost-effective reliability functions as compared to traditional utility distribution solutions, it would seem prudent that regulators ensure that there are adequate financial incentives to align the utility's efforts with customers' interest in efficient outcomes. Such financial incentives could arise in many forms, including compensating utilities for providing value for customers through this portfolio-aggregation and/or management function (until the market is capable of providing such a service in the future).[60]

Insights from practical application of distribution-system valuation analyses: SCE and Con Edison

Case Studies: Con Edison and SCE

For now, the markets for DER for D are still in their very-early stages. Most of the attention to date has been on developing the benefit/cost tools for evaluating cost-effectiveness, rather than on designing and testing out market mechanisms to procure DERs at competitive prices (rather than administratively established prices). So far, these methodologies tend to resemble a body of accounting tools with different categories of value where the analyst can fill in the blanks with real numbers applicable to a specific distribution utility's system.

For the Value of DER for D, the seemingly straightforward task of completing the spreadsheet is likely to be fairly daunting. Determining the value of a particular DER application (or portfolio of DER technologies and applications) in specific utility contexts will likely end up being much-more complex and difficult to execute than the simplified accounting framework might suggest.

That challenge, however, should not prevent the industry from attempting to develop more evidence-based approaches to DER valuation consistent with the long-standing ratemaking principles of efficiency and fairness. At the same time, the industry should continue to attempt to produce methodologies that support the entry of cost-effective DER resources into electric distribution system planning and operations.

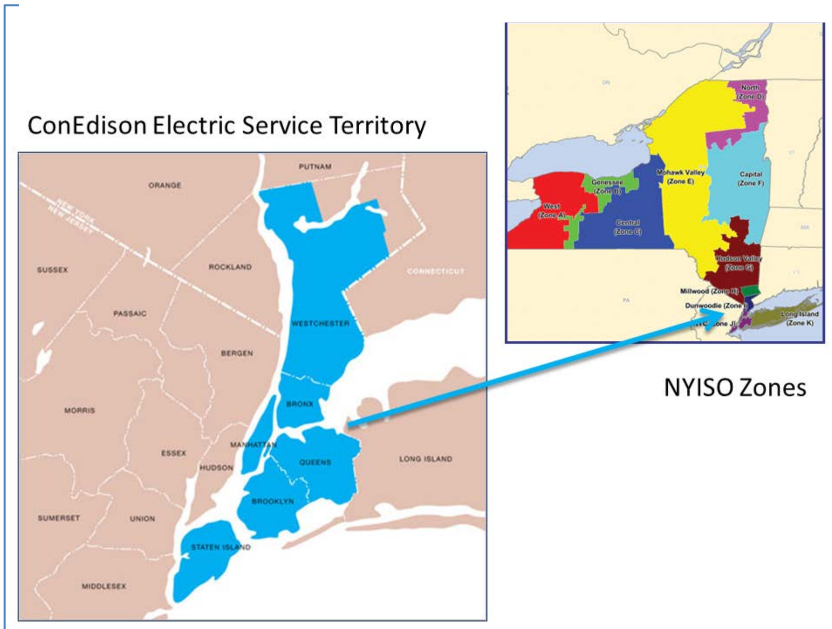
Two utilities – Con Edison in New York City and SCE in Southern California – are attempting to advance the development and application of such methodologies to understand and integrate the Value of DER to D into their distribution system planning and problem solving. Focusing here on their efforts as case studies is intended to provide insights into some of the analytic challenges as well as to inform the industry's evolving understanding of the Value of DER to D.

These two utilities are both very-large electric utilities in some of the nation's most populous states. Each company provides reliable, on-demand distribution service down to the smallest customer's meter. And each utility has experience in integrating different types of DERs onto its distribution system. There are differences between the two systems' physical configurations, however, which allows their case studies to represent the bookends of distribution-system design. SCE and Con Edison are working together by investing in analysis to better understand how the locational, temporal, and performance characteristics of DER for D interact with their distribution systems. Each utility is now working with EPRI to apply the Integrated Grid benefit/cost framework so as to elucidate some of the implications for providing cost-effective reliability solutions through DERs. This work is at its early stages, but is providing some preliminary insights which are summarized here.

FAQs about Con Edison and SCE

Let's start with some of the basic facts that characterize the two systems: Con Edison – considered the oldest electric distribution utility in the world (and home to the legacy of Thomas Edison's first central station located on Pearl Street in New York City's financial district) – provides electric service to approximately 3.3 million customers (and a population of approximately 9.2 million people) in New York City and Westchester County.[61] The system features approximately 94,000 miles of underground cable[62] (the largest underground system in the world) and a service territory covering 610 square miles (or less than 1 percent of New York State's total land area).[63] Con Edison, however, serves almost half of New York State's total population.[64] In New York State's restructured electricity market, Con Edison is primarily a wires-only company.

Figure 22:
Con Edison and NYISO Service Territories

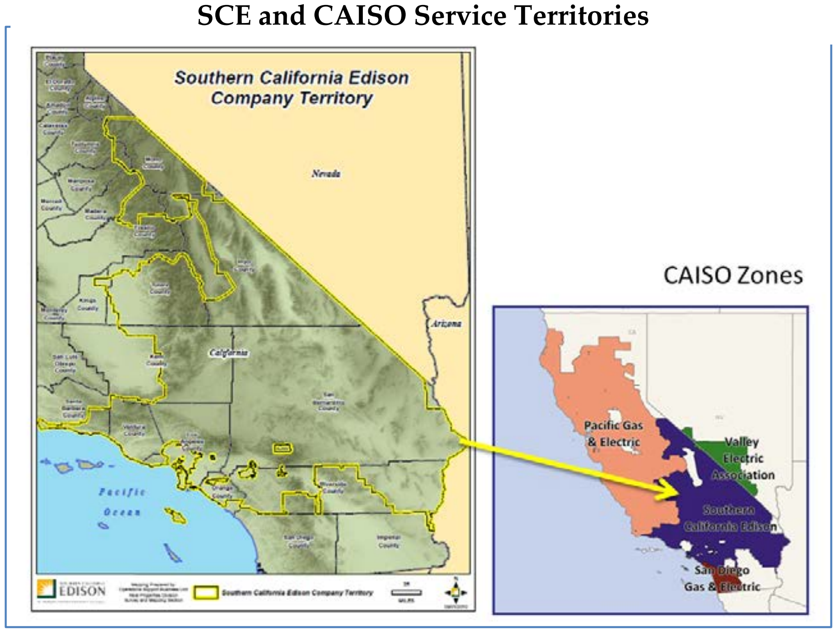


Source: Con Edison and FERC

It is the delivery company for all of the loads in the NYISO market zones "I" and "J", with a combined summer peak load estimated to be 16,773 MW in 2016 (with that load level already adjusted for the impacts of energy efficiency and behind-the-meter generation).[65]

Con Edison has estimated that up at present, there are 259 MW of grid-connected DERs, of which 94 MW are renewable (mainly solar PV) resources.[66]

Figure 23:
SCE and CAISO Service Territories



Source: SCE and FERC.

Another 144 MW is currently in Con Edison's interconnection queue. Additionally, the Con Edison system has 491 MW of energy-efficiency and wholesale and retail demand-response resources capable of reducing Con Edison's system peak.[67]

By contrast, SCE covers a much larger and less-dense region: nearly a 50,000 square-mile area,[68] or approximately one-third of the land area of the State of California.[69] One of California's largest utilities and in operation for over 125 years, SCE distributes power to 5 million customers and a population of more than 14 million people in central, coastal, and southern California (excluding Los Angeles and some other cities). SCE serves approximately one third of California's population.

California's electric industry still allows electric utilities to own generation in some circumstances. SCE is partially vertically integrated, although with the 2013 closure of the San Onofre Nuclear Generating Station, over 80 percent of its incremental supply comes from third parties. At present, SCE estimates that the following DER capacity[70] is located on its system (whose 2016 peak demand is estimated to be 23,537 MW[71]):

Distributed Renewable Generation	1,998 MW
Energy Storage	7 MW
Electric Vehicles	57 MW
Energy Efficiency	1,122 MW
Demand Response	1,177 MW

Beyond the customer-driven DERs added in the Con Edison and SCE service territories, each of these utilities has conducted competitive solicitations that were either designed to procure DERs in order to delay or avoid anticipated local distribution system reliability concerns (as in the case of Con Edison) or allowed to contribute to the package of traditional and non-traditional resources needed to help mitigate the resource-adequacy impacts of the unexpected closure of a nuclear plant (as in the case of SCE).

State policy in California and New York

Con Edison and SCE share the common fact that they provide electric service in a state where utility regulators are actively pursuing pathways to facilitate much greater reliance on DERs in the future.

As part of its carbon-reduction goals, for example, California has aggressive clean-energy targets. California policy seeks to position DERs as a mainstream tool to help maintain local electric system reliability in the future. In 2013 California enacted AB 327 which, among other things, required SCE and the other investor-owned utilities to consider, as part of their distribution planning processes, non-utility-owned DERs as potential alternatives to utility investment and as part of ensuring reliable electric service at lowest cost.[72] AB 327 (Public Utilities Code § 769) required the utilities to file distribution resources plan in 2015 and indicate optimal locations for the deployment of DERs. SCE, along with the other two regulated utilities in California, filed their distribution resources plans

("DRPs") in July 2015.[73] California has adopted spreadsheet-style methodologies for estimating avoided costs DERs: the Distributed Energy Resources Avoided Cost Calculator, prepared by E3.[74]

California's AB 327 further directed the California Public Utilities Commission ("CPUC") to develop a new NEM program to go into effect by 2017, based on "electrical system costs and benefits to nonparticipating ratepayers."[75] The CPUC recently voted to continue NEM until 2019, having found that in light of "the analytic tools and information currently available for use by the Commission, it is not possible to come to a comprehensive, reliable, and analytically sound determination of the benefits and costs of the NEM successor tariff to all customers and the electric system."[76]

California currently has various proceedings underway to support the adoption of DERs as part of distribution-system planning and service provision: One docket (R.14-08-013) is focused on the development of methodologies to determine how DERs "can meet system needs as an alternative to traditional investments, provide justification for meeting those needs with distributed energy resources instead of conventional alternatives, define the services that may be bought and sold to meet the needs, and produce maps that indicate where distributed energy resources should be sourced."[77] Another docket (R.14-10-003) aims to support the "deployment of cost-effective distributed energy resources that satisfy distribution planning objectives."[78] Together these proceedings will address development and demonstration of competitive solicitation frameworks for DERs targeted to address distribution system reliability needs, as well as the utility's role in soliciting and/or providing DERs.

New York State's strong inclinations toward greater reliance on DERs are part of the state's on-going process to "Reform the Energy Vision." Starting in 2014, New York's REV process is attempting to change the state's "energy policy to put customers first and make sure energy efficiency, increased use of renewables, and reliance on more resilient distributed energy resources like microgrids are at the core of our energy system."[79] DERs play a central role in the REV platform: "NY's new regulatory compact demands that promotion of market-driven, clean-energy innovation is in front of and behind the meter."[80] The Commission has found that "achieving a more precise articulation of the full value of [DERs] is "a cornerstone REV issue."[81]

New York regulators recently adopted a benefit/cost framework through which New York utilities will need to determine when DERs are cost-effective relative to traditional distribution planning options.[82] In parallel, New York regulators decided in October 2015 to eliminate caps on new NEM customers until after the completion of proceedings (expected by the end of 2016) to establish values for DERs providing services to local distribution companies.[83] These proceedings aim to establish more precise approaches (compared to NEM) for valuing DER in markets in the long term, "and, most immediately, to define a near-term transition from NEM."[84]

SCE's and Con Edison's electric distribution systems; configuration differences and planning similarities

Apart from the many similarities between these two electric distribution systems, there are other important differences between Con Edison's and SCE's systems, with implications for understanding the Value of DER for D.

The first and most prominent distinction has to do with the physical configuration, or topology, of their distribution systems. Con Edison's and SCE's distribution systems are fundamentally different. SCE's distribution system resembles the more common 'radial' layout of distribution facilities, which resembles in simplest form a 'tree-like' configuration in which customers are served off of circuits that are like branches of trees (as shown conceptually in Figure 24 and as illustrated with distribution-system features in Figure 25).

Figure 24:
A Radial Distribution System Resembles a Tree

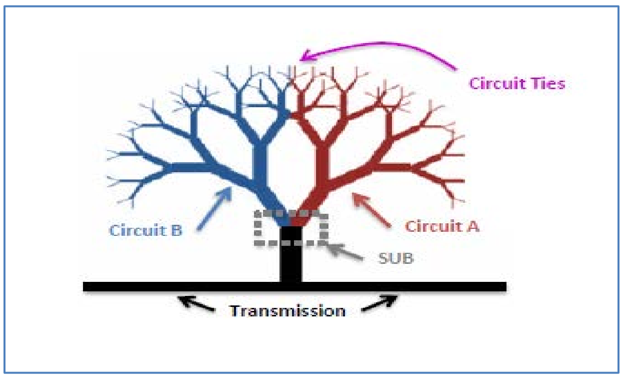
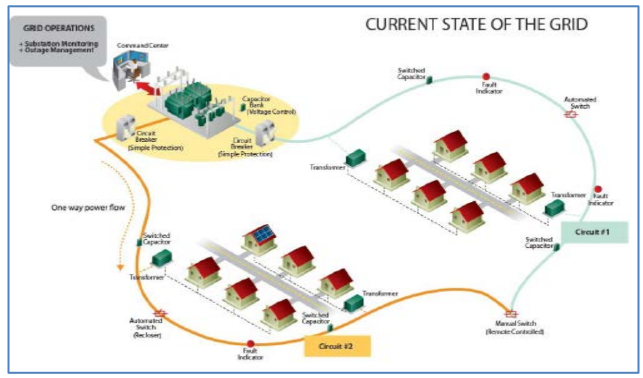


Figure 25:
Customers are Served Off of the System's Branches



Source: SCE

Con Edison's underground system in New York City is quite different from SCE's: "Although most areas of the country use simpler radial distribution systems to distribute electricity, larger metropolitan areas like New York City typically use networks to increase reliability in large load centers. Unlike the radial distribution system, where each customer receives power through a single line, a network uses a grid of interconnected lines to deliver power to each customer through several parallel circuits and sources. Power flows in multiple directions. This redundancy improves reliability, but it also requires more complicated coordination and protection schemes…."[85] Figures 26 and 27 shows the configuration of the Con Edison network.

Figure 26
A Network Distribution System Resembles a Mesh

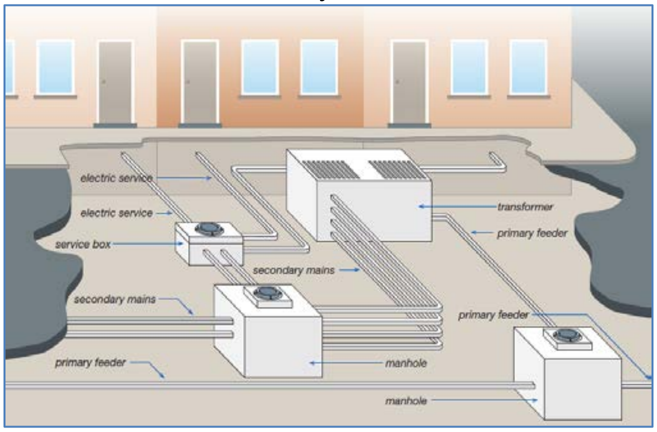
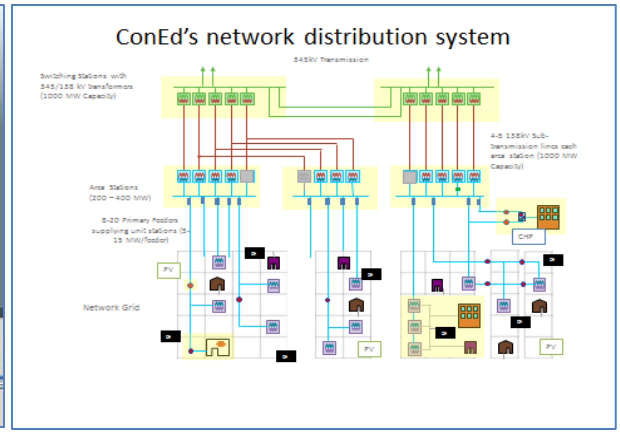


Figure 27
Customers are Served Off of Interconnected Wires



Source: Con Edison

In both systems, the distribution system changes over time, as a function of demand growth, the profile of demand over the course of a day, aging infrastructure, smart-grid investments, DER installations, upgrades to parts of the system/network, and so forth. Also in both types of systems, the utility conducts distribution-system planning (as described previously), to anticipate changing patterns and levels of electricity use that might affect the peak hour of use on a particular circuit or part of the network and to identify locations on the system where reliability violations will likely occur without a fix. The planner anticipates that a particular circuit or part of the network could become thermally overloaded, or experience voltage concerns, or otherwise violate reliability standards in the future. Traditionally, the distribution-system planner looks for actions and capital investments that minimize the overall cost of fixing the reliability problem while optimizing the use of existing capacity on the system.

Typically, the planner and system engineer would seek to solve an anticipated reliability problem so as to remedy the situation for several years (rather than only solving the problem in the most minimal way and having to resolve a greater need the following year to keep up with load growth). In this way, traditional planning has developed solution sets that provide headroom in the capacity once a major upgrade has occurred so as satisfy reliability requirements in planning cycles with solutions providing for multiple years of reliable distribution service. This occurs not just because traditional fixes tend to be lumpy investments, but also because of the goal of avoiding having to take steps year in and year out to keep up with the changing needs of the system.

Although the planner's tasks may be similar in radial and network systems, the toolkit of solutions – even traditional solutions, let alone non-traditional ones – varies across the two types of distribution systems. In a radial system, for example, the utility may be able to literally rewire the system's elements on a case-by-case basis and move some customers' loads from a soon-to-be overloaded circuit and on to a different circuit with greater load-serving capability. SCE's business-as-usual distribution planning recognizes this capability to rebalance loads before needing a larger capital investment. Figure 28a through 28c illustrate (using hypothetical data) how available distribution capacity in one part of a radial system (i.e., Figure 28a showing the SCE's "Merced" substation (serving the area shown in green) with 5 MW of anticipated capacity deficiency (i.e., anticipated load that exceeds planned capacity under high temperature and load growth). Available distribution capacity can be used to provide relief in neighboring parts of the system. Figure 28b shows potential sources of load relief in three areas: Lark Ellen (shown in yellow with 2 MW available), Bassett (shown in blue with 1 MW available), and Cortez (shown in purple with 2 MW available). Figure 28c shows the result of reconfiguring the system and shifting the loads in the deficient areas to become part of Merced, such that there is 1 remaining MVA in Merced after solving the reliability concerns in all three neighboring parts of the radial system.

Figure 28: Substation Load Growth Planning: Illustration of Load Balancing

Figure 28a: Problem Identification

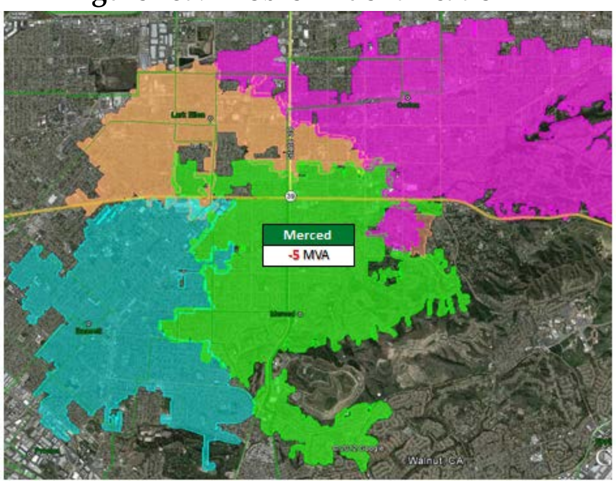
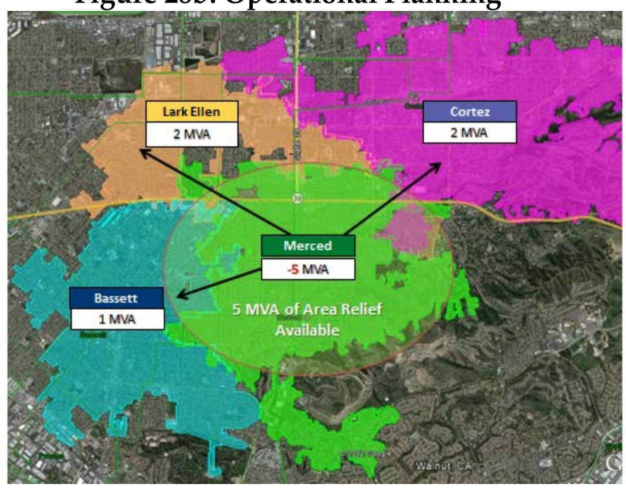
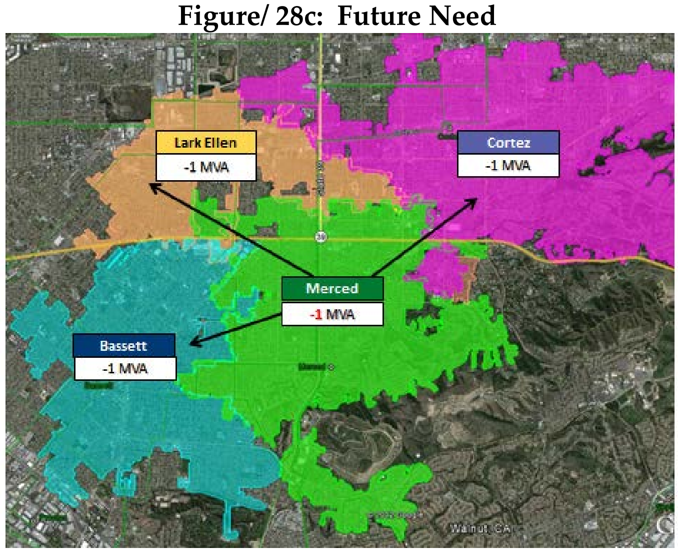


Figure 28b: Operational Planning



Figure/ 28c: Future Need



Source of illustrative diagrams: Erik Takayesu, SCE

There are various implications of this rebalancing tool for incorporating DERs into distribution-system planning and operations. First, in theory, DERs procured and installed across these neighboring regions have the potential to directly assist in mitigating reliability concerns in any of them, because of the flexibility of rebalancing the radial system. (That said, different DERs still have different impacts depending on technology and location on the system (e.g., proximity to the substation versus distance to the substation).) Rebalancing provides a relatively low-cost means to defer/mitigate problems (up to the point at which a new capital upgrade is triggered). This means that the avoided costs are relatively low in certain parts of the system at various points in time. This also has implications of Value of DERs to D over time given the dynamic and changing nature of the distribution system.

These types of strategies enable the utility with a radial system to defer or avoid making a larger capital investment to increase the capacity of the circuit. Doing something analogous would be more difficult and therefore more expensive on an underground network system, where such physical reconfigurations are economically constrained due to the complexities of the mesh system. On a network system, DERs located in one part of the network will have little ability to remedy a reliability problem located in a different part of the network. And DERs located within a network section may have diffused impacts, because the flows on the network move in so many directions.

In both types of distribution system, as noted previously, recall that most of the traditional fixes are capital investments. This suggests that the lion's share of avoided costs is in the area of avoided capacity investment. And this in turn suggests there will be opportunities to further experiment with and refine competitive procurements for DERs as the most productive market mechanism for identifying least-cost resources *as well as* price discovery for compensation.

As SCE and Con Edison each proceed to more routinely plan to integrate DERs into their distribution-system plans and solution sets, these utilities – like many others around the country – need to understand how DERs with different technological attributes, performance characteristics, costs, and integration impacts fit with the quite-local needs of each distribution system. Both SCE and Con Edison are working to better understand these locational, temporal, and performance characteristics of DER for D by investing in analytic tools to advance their understanding of the locational and temporal value of DERs at the local distribution level.

Both SCE and Con Edison have developed internal analytic tools to assess DERs in terms of how well they fit with the companies' needs. These tools take into account the duration of particular DERs' availability (e.g., four-hour battery, eight-plus-hour energy efficiency, two-hour demand response), their risk, their maturity, their flexibility and their ability to meet the particular parts of the system.[86]

And each is also now working with EPRI to apply its Integrated Grid benefit/cost framework so as to elucidate some of the implications for providing cost-effective reliability solutions through DERs. This work is just underway, but is providing some initial insights, as described briefly below

Insights from modeling of DERs in Con Edison and SCE distribution systems

EPRI modeling (overview)

EPRI has for several years been building a methodological framework for understanding the features of an integrated and modern grid.[87]

> The concept of an Integrated Grid was outlined by EPRI noting the goals to realize the full value of a transformed power system – its diverse inputs, efficiencies and innovation. An Integrated Grid should make it possible for stakeholders to identify optimal architectures and the most promising configurations, recognizing that solutions vary with local circumstances, goals, and interconnections.
>
> The question is about the ways in which DER interacts with the power system infrastructure. The formula for this answer has multiple dimensions. Beneficial and adverse circumstances can arise at differing levels of DER saturation. The interaction is dependent on the specific characteristics of the distribution circuits (design and equipment), existing loads, time variations of loads and generation, environmental conditions, and other local factors. Benefits and costs must be characterized at the local level and the aggregated level of the overall power grid.[88]

EPRI's methodology incorporates several features to help identify the potential for DERs to replace traditional investment, including: examining the hosting capacity of different spots on the distribution systems; running power-flow analyses with load-growth projections on particular parts of the system to see when reliability violations would occur; identifying a traditional fix to remedy those violations; relying on scenarios to explore the ability of different patterns of DER dispersion for solving those violations; and estimating the benefits and costs of the DER solutions compared to the traditional solutions. This methodology provides the potential for highly granular views into the locational value of DERs on specific distribution systems, taking into account the impact on the Value of DERs for D as well as the other values of DERs (for T, for G, and for S).

EPRI's preliminary modeling of Con Edison's and SCE's system

Con Edison, SCE and EPRI have developed a joint project to demonstrate the EPRI methodology and to understand implications of integrating DERs into distribution-system resource-adequacy plans and processes, with a focus on DER as "a distribution system adequacy resource." This larger project is described in the forthcoming EPRI report, "Time and Locational Value of Distributed Energy Resources (DER): Methods and Applications" (*EPRI # 3002008410)* (hereafter "EPRI's Time and Locational Value of DER Study").

As part of that joint project, EPRI has conducted preliminary analyses to apply EPRI's framework[89] to a handful of circuits on the two different SCE and Con Edison distribution-system configurations (i.e., SCE's radial system and Con Edison's network system). These preliminary applications (which will be described in EPRI's Time and Locational Value of DER Study) provide some initial insights about the roles DERs can play under certain conditions in different distribution-system types. These preliminary studies focus on discrete sections of each of the two utilities' distribution systems – the Williamsburg area of Con Edison's Brooklyn/Queens distribution system, and the Nogales Substation on the SCE system.

For both the modelled Con Edison network and SCE's circuits, EPRI evaluated two separate scenarios for DER deployment, with the two scenarios designed to be bookends for DER applications and situations that could be analyzed to provide a complete picture of DER impacts and implications.

In the first scenario, the traditional distribution-system investment is compared to a portfolio comprised of a mixed set of DERs that are strategically located on the local distribution system to solve the reliability violations. This was intended to simulate the performance of a utility procurement designed to induce DER entry into the market as part of an integrated distribution-system plan. The starting point of the initial scenario was a 2015 base case with an assumed load-growth in each year through 2025. EPRI ran power-flow analyses which identified places where reliability violations (e.g., thermal overloads and/or voltage problems) might occur in the absence of actions to address the anticipated reliability concerns. Where violations were identified, then the study identified a traditional utility solution to address and remedy each of the violations. For the same violations, two separate DER solution cases were evaluated: one in which a minimum quantity of DERs were assumed to be added just so as to solve the reliability violation and not produce any headroom on the system; and another one in which enough DERs were added to provide the same level of headroom as would be accomplished through the traditional (and typically more lumpy) system upgrade.

In the second scenario, a set of DERs was assumed to on the distribution system as a result of customer-driven actions (as compared to a utility procurement targeted in particular locations), with the DERs (all assumed to be solar PV) located randomly around the portion of the distribution grid being examined in the study. Those installations were assumed to result in certain equipment investments by the utility (to accommodate higher power flow, to mitigate the effect on local circuit voltage, and to resolve reverse power-flow effects on protection systems). Hosting capacity studies were relied upon to illuminate the impacts that needed to be addressed.

After developing these various solution sets for each utility's distribution-system examples, then EPRI prepared an economic benefit/cost analysis of each solution set: i.e., the traditional utility 'engineered solution' (e.g. upgrade); the targeted DER portfolio (at two levels of penetration – one set at a minimum amount of DERs to satisfy the reliability violation, and the other set at a level of DERs needed to provided comparable reliability and headroom as the utility's upgrade); and the randomly placed, customer-driven DERs. For the portfolio of DERs, the set of technologies was constructed so as to provide mitigation of reliability violations over multi-hour peak periods. EPRI shaped the energy profile of each DER case, depending on the DER technologies being analyzed.

For each distribution-system alternative, the costs of the distribution-system solution were compared to the benefits, using EPRI's framework that incorporates benefits in terms of any energy produced by DERs, any generating-capacity value, avoidance of losses on the transmission and distribution system, and avoided carbon prices. For the Con Edison analysis, for example, EPRI used NYISO forecasts of locational marginal prices ("LMPs") for energy and estimated avoided capacity market costs for zone J (New York City).

Preliminary results: The location and attributes of DERs matter greatly for their potential Value to D

Based on information provided by EPRI's Time and Locational Value of DER Study, the preliminary results vary across the two utility systems and across the different scenarios (and DER amounts).

- In Con Edison's network system, the analysis revealed that the placement of the DERs matters significantly in terms of the ability of a MW of DER to address a local reliability problem (e.g., a particular overloaded transformer): If all of the DERs could literally be positioned at the site of the overloaded transformer, they would have the biggest impact in terms of mitigating the problem. The farther the DERs are located relative to the problem on the network, the less impact a MW of DER has on solving the problem. This is due to the mesh character of the network itself which allows power to flow in multiple directions and which tends to disperse the impact of the DERs. Therefore, the more distributed (rather than surgically targeted) are the DERs, the more MWs are needed to remedy the reliability violation. And the more MW that need to be added, the more additional equipment (e.g., new SCADA systems) also needs to be added to address power flows. EPRI's analysis also elucidated another issue: the amount of DER that can be technically allocated to any single node or load point on the network. Availability is dictated by the kind of load or customer being served and how much DER can be physically located there. Because it is difficult, in practice, to add DERs literally at the transformer site itself, then it is likely that more, rather than less, DERs would be needed to solve a particular problem – with cost implications for the various alternatives.

- For the SCE case, where one objective in normal distribution-system planning is to maintain the operational flexibility associated with the circuit-rebalancing capability, this particular attribute of the system had to be taken into account when comparing the engineered solution relative to the other DER cases. When the DERs were targeted and placed at particular parts of the feeders where hosting capacity was available, the effectiveness of DERs in mitigating the reliability violations ended up providing less reliability relief than the randomly dispersed, customer-driven DERs; this resulted in part from the DERs being positioned in various parts of the radial system rather than a single location. EPRI's preliminary analysis indicated that: DER can provide directional relief for thermally constrained assets on a radial system, with DERs located downstream from the constrained asset potentially better able to provide relief. (That said, the location of a DER downstream of a constraint may change over time as a radial distribution system is reconfigured or rebalanced. So, distribution-system reconfiguration (a normal operational tool in radial distribution systems) can impact the locational value of DERs after they have been placed on to a system.) DER can provide bi-directional relief for voltage-constrained assets, with voltage support provided either downstream or upstream from constraint (bidirectional support) as long as the resource is located electrically close to the constrained area.

More broadly, here are the more general takeaways in EPRI's forthcoming study:

- **Individual DERs (and portfolios comprised of combinations of different DER technologies) have different and complex interactions with the electric system.** DERs have the potential to be a viable and economic alternative to a traditional utility-side investment to meet distribution system load growth requirements. To effectively defer and/or replace traditional distribution solutions, however, DERs must achieve equivalent characteristics of availability, dependability and durability.
- **DER impacts can be either beneficial or adverse, depending on a wide variety of contextual circumstances.** Each distribution system is geographically and electrically distinct from other utilities and has considerable variation within a single utility's system. This makes it difficult to generalize about the impacts of DERs; their impacts depend upon the specific characteristics of the DER technologies, the distribution circuits, existing loads, time variations of loads and generation, and other local factors. Detailed studies are needed to assess and fully understand the time and locational impacts of DERs for different utilities. Hosting capacity studies are an important analytical tool in understanding local system characteristics, and can provide a good directional indication of the amount of DERs that can be accommodated in particular places, although hosting capacity is likely to change over time for multiple reasons.
- **DER location, relative to a violation of a system limit, determines its effectiveness in relieving the violation.** In radial systems, DER location relative to the constraint is important from the perspective of energy losses, but there is only one path for power to flow on, and DER output can contribute directly to relieving the violation even at a distance as long as it is behind the violation (relative to the substation), not in front of it. In networked (mesh) systems, however, the output of DER disperses, flowing along many paths that go around the violation; the greater the electrical distance of the DER from the constraint, the

more its effect is dispersed. Network studies identified cases where the dispersion is relatively small (e.g., between 85-90 percent effective) as well as ones where it requires over 8 kW of DER to relieve 1 kW constraint.

- **Distribution reconfiguration can impact hosting capacity and locational value.** Where possible, DER can be allocated to relieve constrained assets; however, reconfiguration of the system to address possible violations of limits or other operational considerations alters power flows and may eliminate or defer the need for either utility investments or DER. Traditional upgrades or DER may be needed when reconfiguration is no longer able to prevent violations.
- **Benefits and costs of DERs need to be characterized at the local and bulk power system levels to estimate their full value.** Identifying localized benefits and costs can help distribution companies determine how best to utilize and accommodate DER as part of distribution-system planning and operations. Including costs and/or benefits that occur outside of the utility's operational and financial domain can help policy makers understand the consequences of alternative levels of DER penetration.
- **Advancements in distribution planning tools, models, and processes are needed to ensure the benefits of DER are fully realized while maintaining system reliability and performance.** This includes: studying customers' electrical demand to characterize their loads with more granularity and understand/forecast their inclination to adopt a DER technology and how they would use it; and probabilistic modeling to characterize the availability and variability of power supplied by DER to the customer and to the grid.
- **Integration of DER will require substantial changes in how distribution systems are designed and operated.**

Note that these results are preliminary. These early analyses, which are part of a larger and longer-term project, had to rely on simplifying assumptions, and were not able to be designed so as to optimize the value of DERs within the distribution systems. But they nonetheless illustrate how a number of factors (e.g., DER technology type, placement of DERs on different parts of distribution systems) affect the prospects for DERs to avoid a traditional utility solution and the costs of doing so. By design, EPRI's scenarios were bookend cases, examining the differences when customers decide to install PV systems as compared to the utility targeting the location of DERs designed explicitly to remedy local reliability problems on the distribution system. Even so, they highlight some of the challenges in developing estimates of the Value of DERs for D – and underscore the importance of moving from blunt valuation tools to ones that capture the different value of varied DER technologies located at different places on real distribution systems.

Conclusions: Insights for future considerations of the Value of DER to D

Rely on time-tested ratemaking principles to guide decisions about the Value of DERs for D

Although regulators, utilities, and stakeholders are working hard to refine benefit/ cost concepts and procurement/compensation arrangements for evaluating when and where DER installations provide net benefits, the principles of fairness and efficiency remain important in considering cost-allocation and compensation levels for DERs, and for developing ratemaking approaches for utilities.

Don't ignore the differences among DER technologies and their impacts on and contributions to the local grid in calculating their potential Value to D

Where particular DER technologies and applications enable reliable *distribution* service at lower cost than without that DER, then those particular DERs provide a Value of DER for D and to all of the utility's customers. DER's value to the electric system (and more specifically, to each of its component parts (D, T and G)), depends upon the location where DERs are placed on the grid and the timing, duration and quality of supply provided by a portfolio of DERs relative to the supply provided by the grid. Depending on the DER technologies, their attributes and the circumstances of their location and operation, a DER may have net benefits or net costs to the electric system.

Move beyond conceptual valuation frameworks that identify potential net benefits of DERs to D

There is a relatively robust literature on the appropriate conceptual framework to calculate values for DERs. Most studies have focused on the different components that affect a utility's avoided costs or on benefit/cost methodologies for determining when DERs are potentially more cost-effective than traditional investments. Avoided distribution costs tend to be relatively small compared to other avoided costs (e.g., energy, production capacity, environmental impacts). Yet determining the value of a particular DER application (or portfolio of DER technologies and applications) in specific distribution-utility contexts is likely to be relatively complicated and difficult to execute (compared to some of the other sources of value, where there are more transparent indicators of value). DERs' value to distribution systems will depend upon both the attributes of the portfolio of DERs and their location on particular distribution systems. More work is needed to illuminate this part of DER valuation proposition.

Transition distribution-system planning to incorporate DERs

As part of the evolution of the industry's understanding of the value of DERs, some state regulators and utilities are experimenting with how to integrate DERs into utilities' long-term, distribution-planning processes. These initiatives are attempting to identify where specific DERs have the potential to provide comparable functionality on the distribution system at a cost lower than traditional utility investment. Most of the traditional fixes to resolve anticipated local reliability problems are capital investments, many of which have long lead times that are taken into account in the utility's planning horizon and involve physical upgrades to reinforce the capability of the infrastructure to meet customers' needs. This suggests that at least in the early stages of the evolution, the focus of market design for DERs for D ought to ensure that DER capability is installed in sufficient amounts, locations, time frames, and attributes to assure that the DERs can provide the same functionality as would have been provided by a traditional utility solution.

Build upon prior PURPA experience that market-based mechanisms provide value to customers compared to relying on administratively determined avoided costs

Many states' experience in implementing PURPA indicated that customers benefitted when the industry transitioned from initial approaches (that relied upon prices established in administrative proceedings) to more market-based mechanisms for revealing avoided costs and the prices to be paid to winning suppliers. This experience offers important lessons for the current efforts to design methods to integrate DERs efficiently and effectively into distribution-utility plans and operations. Where the utility can fairly obtain and efficiently pay for the quantity/ timing/location of DERs needed at market-based, competitive prices (rather than at avoided cost), then there may be net benefits – i.e., value to the system and its customers. Thus the full economic value of DER to the grid and its customers may not be the same as the amount paid for DER. Competitive solicitations can reveal the portfolio of DERs with the attributes to satisfy the utility's local reliability requirements at lowest costs. The utility can then enter into contracts to assure that the winning DERs enter the market and help to resolve local reliability problems cost-effectively and reliably. The difference between full avoided costs and the costs to the utility (and its customers) is the value to consumers of having the utility incorporate and integrate DERs into its distribution-service solution set. Utility contracts with successful DER offerers should include payments in anticipation of delivered capacity (e.g., milestones for installation of the DERs), and for actual performance.

Start with forward contracting for DER capacity before focusing on operational DER markets

For now, the markets for DER for D are still in their very-early stages. Given that most potentially avoidable distribution-system costs are capital investments, it seems important to focus initial market-design attention on procuring DERs for their capacity value to distribution systems. In the future, as the markets for DER evolve, it may be worthwhile to look at the other shorter-term/ operational sources of value of DER to D, and then refine operational markets to compensate contracted resources for performance and for other services provided by DER to D. After the main source of value (distribution capacity) is realized, then these other value streams can be layered on top of that foundation. This prioritization of "DER-for-D" market elements – starting with a focus on forward procurements of capacity, and then moving toward secondary (and likely smaller) transactional markets over time – fits with economic principles about the conditions that enable robust, successful markets to exist (and which, if absent, inhibit markets from delivering efficient prices). These conditions are not yet in place (much less fully designed) for the market for DERs.

ENDNOTES

[1] Sue Tierney is a senior advisor at Analysis Group, and formerly assistant secretary for policy at the U.S. Department of Energy, Massachusetts' Secretary of Environmental Affairs and a commissioner at the Massachusetts Department of Public Utilities. For over two decades as a consultant, she has worked for a wide variety of clients, including energy customers, environmental groups, state agencies, grid operators, electric and natural gas utilities, competitive suppliers, power generators, foundations, and others. Knowing that she is a supporter of efforts to lower carbon emissions from the power sector and of competitive and reliable power markets, Con Edison and SCE approached her to write this report on the value of distributed energy resources for distribution systems, for which she retained editorial control.

[2] There is no consistent definition of "DER," in terms of technology or the size/location of the resources. For example:

- Bloomberg New Energy Finance ("BNEF") tracks "Distributed Power, Storage, and Efficiency," which includes: small-scale renewables, CHP and waste heat and power ("WHP"), fuel cells, storage, smart grid/demand response, building efficiency, industrial efficiency (aluminum), and direct use applications for natural gas." BNEF, "Sustainable Energy in America: Fact Book," 2016, page 5.
- The Rocky Mountain Institute's e-Lab includes the following as DERs: (a) end-use energy efficiency; (b) distributed generation (small, self-contained energy sources located near the final point of energy consumption, such as solar PV, CHP, small-scale wind, fuel cells); (c) "distributed flexibility & storage" (a collection of technologies that allows the overall system to use energy smarter and more efficiently); and (d) "distributed intelligence" (technologies that combine sensory, communication, and control functions to support the electricity system, and magnify the value of DER system integration). e-Lab, "A Review of Solar PV Benefit & Cost Studies," Rocky Mountain Institute, Second Edition, 2013, page 8.
- Navigant includes a wide variety of resource that can be utility-owned on the grid "in front of the meter" or customer-owned "behind the meter": distributed solar, wind, micro turbines, fuel cells; distributed storage (electromechanical, mechanical, thermal); microgrids; demand-response (direct load control, price based, incentive based, virtual power plants); utility-side loss reduction (conservation volt reduction; volt/VAR optimization; grid optimization); and electric-vehicle battery charging and discharging. Jan Vrins, "Distributed Energy Resources: Lead or Follow," Aspen Institute Energy Policy Forum, July 28, 2015.
- The Electric Power Research Institute ("EPRI") defines DER as "fulfilling the first criterion (Item 1), in addition to any one of the second, third, or fourth criteria as follows: 1. They are interconnected to the electric grid, in an approved manner, at or below IEEE medium voltage (69 kV). 2. They generate electricity using any primary fuel source. 3. They store energy and can supply electricity to the grid from that reservoir. 4. They involve load changes undertaken by end-use (retail) customers specifically in response to price or other market-based inducements." EPRI, "The Integrated Grid: A Benefit-Cost Framework," Final Report, February 2015, page 1-3.

[3] This deep literature addresses a wide set of important policy topics: the role of NEM as a vehicle to stimulate development of rooftop solar projects; the impacts of NEM designs, in terms of whether participating customers are paying their fair share of electric system costs; the implications for distribution-system and bulk-power system operations of increasing penetrations of distributed and non-dispatchable renewable resources; transitional designs of pricing and procurement strategies to assure that DERs compete fairly with traditional central-station utility and non-utility projects; and many more. More generally, see: Travis Lowder, Paul Schwabe, Ella Zhou, and Douglas Arent, "Historical and Current U.S. Strategies for Boosting Distributed Generation," National Renewable Energy Laboratory ("NREL") and Joint Institute for Strategic Energy Analysis ("JISEA"), August 2015.

[4] See, for example: https://www.irs.gov/uac/Energy-Incentives-for-Businesses-in-the-American-Recovery-and-Reinvestment-Act; http://energy.gov/savings/residential-renewable-energy-tax-credit; http://solaroutreach.org/wp-content/uploads/2015/03/CommercialITC_Factsheet_Final.pdf; http://energytaxincentives.org/business/solar.php.

[5] See the Database of State Incentives for Renewables & Efficiency ("DSIRE"), which describes the many types of incentives that exist to encourage renewable resources. Summary tables of incentives by state (including not only RPS standards, but also tax credits, feed-in tariffs, property-assessed financing approaches, and other policies) can be found at http://programs.dsireusa.org/system/program/tables. The listing of states with targeted renewable energy credits for solar PV, for example, is found at http://programs.dsireusa.org/system/program?type=85&.

[6] The California Public Utility Commission and California Energy Commission have a joint effort to encourage the installation of 3,000 MW of solar systems on homes and businesses through 2016. http://www.gosolarcalifornia.ca.gov/about/index.php. New York State has a "NY-Sun" initiative that provides incentives for relatively small-scale solar installations. http://ny-sun.ny.gov/About/NY-Sun-FAQ.

[7] North Carolina Clean Energy Technology Center, "The 50 States of Solar: 2015 Policy Review and Q4 Quarterly Report," February 2016 (hereafter, "50 States of Solar Study"), page **9.**

[8] Shayle Kann, GTM Research, "Executive Briefing: The Future of U.S. Solar – Getting to the Next Order of Magnitude," November 2015, page 5. Also: "Throughout the first three quarters of 2015, 30 percent of all new electric generating capacity brought on-line in the U.S. came from solar. As of Q3 2015, more than 50 percent of all states in the U.S. have more than 50 megawatts of cumulative solar PV installed. Totaling 18.7 gigawatts, the current utility PV development pipeline is greater than all U.S. PV installations brought on-line through the end of 2014." Mike Munsell, "US Solar Market Prepares for Biggest Quarter in History," GreenTech Media, December 9, 2015.

[9] Energy Information Administration ("EIA"), 2014 summer generating capacity, with net capacity additions in 2015.

[10] This forecast assumes the extension of the Investment Tax Credit ("ITC"); the project pipeline for installations to come on line in 2016 was relatively high, in light of the uncertainty that existed throughout most of 2015 with regard to whether Congress would extend the ITC (which it did in December 2015).

[11] This cumulative capacity (906 MW of distributed wind) as of the end of 2014 reflects 74,000 wind turbines deployed across all 50 states, Puerto Rico, and the U.S. Virgin Islands. The authors of the "2014 Distributed Wind Market Report" define distributed wind "in terms of technology application based on a wind project's location relative to end-use and power-distribution infrastructure, rather than turbine or project size. Distributed wind is (1) The use of wind turbines, either off-grid or grid-connected, at homes, farms and ranches, businesses, public and industrial facilities, or other sites to offset all or a portion of the local energy consumption at or near those locations, or (2) Systems connected directly to the local grid to support grid operations and local loads." Alice Orrell and Nikolas Foster, "2014 Distributed Wind Market Report," Prepared for the U.S. Department of Energy by the Pacific Northwest National Laboratory, August 2015.

[12] Alliance to Save Energy, "The History of Energy Efficiency," Alliance Commission on National Energy Efficiency Policy, January 2013, page 3.

[13] "By 2030 the average household would save $1,039 per year in energy costs, net of the investment required to deliver those energy savings. That is roughly the same as what the average American household spends on education and nearly as much as average household spending on medicine and produce combined. American business would save $169 billion a year, almost as much as the corporate sector paid in federal income tax in 2011." Alliance to Save Energy, "Energy Productivity 2030," Alliance Commission on National Energy Efficiency Policy, February 2013, page 27, citing modeling analysis performed by the Rhodium Group for the Alliance Commission.

[14] In some states, CHP fueled by natural gas are not considered as DERs. In some states, such as California, DERs are intended to be renewable or load shifting resources only.

[15] Eric Wesoff and Jeff St. John, "Breaking: SCE Announces Winners of Energy Storage Contracts Worth 250MW," GTM (GreenTech Media), November 5, 2014.

[16] Con Edison GreenTeam, "Brooklyn Queens Demand Management Program Update Briefing," August 27, 2015.

[17] FERC v. Electric Power Supply Ass'n, 136 S.Ct. 760 (2016).

[18] See, for example: Karl Rabago, Leslie Libby, Tim Harvey, Benjamin Norris, and Thomas Hoff (Clean Power Research (CPR)), "Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator," 2012.

[19] E3, "The Benefits and Costs of Net Energy Metering in New York," prepared for the New York State Energy Research and Development Authority and the New York State Department of Public Service, December 11, 2015 (hereafter referred to as "E3 NY Study"). E3 analyzed several scenarios that allowed for comparisons between the current NEM policy (that does not target solar PV systems to any particular location) and a modified approach that would target such systems toward locations where they could help to avoid distribution-utility investments in the local grid. Using a societal cost test, the targeting shifted the total benefit-cost ratio from 0.91 for downstate utilities and 0.98 for upstate utilities in the 'untargeted'

scenario, to 1.04 (downstate) and 1.08 (upstate) in the 'targeted' scenario. See, for example, pages 55-56 of the E3 NY Study. In the Con Edison service territory, the study indicated the following results: for the residential class, targeting the location of solar PV did not allow the systems to lead to positive benefits: the benefit-cost ratios were 0.80 (untargeted) and 0.82 (targeted). For the non-residential customer class, the benefit-cost ratios were higher and benefitted from targeting: 0.97 (untargeted) and 1.13 (targeted). See pages 96-98 of the E3 NY Study. One of E3's conclusions is that "NEM is a key component of the policy to encourage distributed renewable generation in New York, most especially solar PV. However, while NEM offers a simple and understandable tool for consumers, it is an imprecise instrument with no differentiation in pricing for either higher or lower locational values or higher or lower value technology performance (e.g. peak coincident energy production). The costs and benefits of NEM should be monitored given the fast evolution of this market…" E3 NY Study, page 7.

[20] 50 States of Solar Study, pages 9-16.

[21] 50 States of Solar Study, pages 17-18, 40-48. Also: NEM "has come under criticism recently for creating a 'cross subsidy.' That is, because solar customers are paying lower electricity bills under net metering regimes, utilities with a large portion of solar customers are faced with a shrinking customer base from which to recoup their fixed costs (e.g., the costs associated with maintaining the transmission and distribution infrastructure). Utilities have argued that solar customers do not pay their fair share to maintain the grid, and the fixed costs are being unevenly allocated to the non-solar customers in the service territory. (Wellinghoff and Tong 2015,) This argument has gained traction at the state public utility commission (PUC) and legislative levels, and by the end of 2014 there were over 20 ongoing proceedings that were examining either net metering or rate design to ensure that utilities could protect themselves against the adverse cost implications of high penetrations of customer-sited solar (GTM/SEIA 2015). Options proposed by utilities, PUCs, and state governments to deter some of these implications include: including fixed charges on solar customers' bills…; reducing the net metering credit; adopting a VOST [Value of Solar Tariff]…; redesigning rates…; imposing a minimum bill…; allowing for utility ownership of solar assets…; [and] transitioning utilities to be aggregators of distributed energy resources for delivery to grid operators. Travis Lowder, Paul Schwabe, Ella Zhou, and Douglas Arent, "Historical and Current U.S. Strategies for Boosting Distributed Generation," National Renewable Energy Laboratory/Joint Institute for Strategic Energy Analysis, August 2015.

[22] Hawaii State Energy Office, http://energy.hawaii.gov/wp-content/uploads/2011/10/HSEO_FF_May2015.pdf.

[23] Herman Trabish, "Hawaii PUC chair defends landmark decision to end retail rate net metering," Utility DIVE, October 26, 2015.

[24] EIA, "Hawaii's electric system is changing with rooftop solar growth and new utility ownership," *Today in Energy*, January 27, 2016, and "EIA electricity data now include estimated small solar PV capacity and generation," *Today in Energy*, December 2, 2015; Herman Trabish, "What comes after net metering: Hawaii's latest postcard from the future," Utility DIVE, October 22, 2015.

[25] New York regulators' decision effectively eliminated NEM caps that covered both residential rooftop solar and ground-mount projects typically associated with remote and community net metering. The New York Public Service Commission ("NY PSC") ordered stated that:

> a transition from net metering to a more accurate means of pricing and recognizing the value of DER, including PV and other forms of net metered generation, is expected in REV [Reforming the Energy Vision]. The Ratemaking Whitepaper, while affirming that net metering should remain in place for mass market customers at this time, and perhaps in other applications, notes that reforming rate design and DER compensation mechanisms, including net metering, can be accomplished upon "a strong foundation of the system value that DERs can provide." That foundation for the more robust pricing of DER is being built, opening net metering to replacement with mechanisms that more accurately price the value of DER.
>
> Valuation is being pursued on several fronts. First, studies on the benefits and costs of net metering are underway, as identified in the NY-Sun Order and as required by the recently enacted PSL §66-n. The completion of those studies is expected by the end of this year. Second, principles for conducting the benefit-cost analyses essential to properly valuing DER were set forth in the BCA Whitepaper, which presents a proposed framework for conducting a benefit-cost analysis and identifies key parameters within that framework. The analysis framework would assist in devising

> means for valuing and compensating behind-the-meter generation and other features of REV. Comments on the BCA Whitepaper have been solicited, and consideration of the issues it raises is expected in the coming months.
>
> Third, the necessary components to properly valuing the benefits of DER, as addressed in the Ratemaking Whitepaper, are its energy value, established in power markets at the location-based marginal price (LMP), and its value to the electric distribution system. This "value of D" can include load reduction, frequency regulation, reactive power, line loss avoidance, resilience and locational values as well as values not directly related to delivery service such as installed capacity and emission avoidance. While the LMP is well established and transparent, the "value of D" is not.
>
> The Community DG Order and the Ratemaking Whitepaper, however, note the importance of developing the "value of D," while the BCA Whitepaper analyses and comments inform the consideration of the "value of D." As discussed further below, a process will be created that ties these efforts together such that a resolution of "value of D" issues can be expected in 2016. While the development of the tools and methodologies required to fully implement an approach based on "value of D" is likely a long-term effort, there is sufficient time to develop and adopt more precise interim methods of valuing DER benefits and costs, as well as the design of appropriate rates and valuation mechanisms, before December 31, 2016. Those interim methods will serve as a bridge while the "value of D" tools and methodologies are developed.

New York PSC, "Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation," Case 15-E-0407 - Orange and Rockland Utilities, Inc. – Petition For Relief Regarding Its Obligation to Purchase Net Metered Generation Under Public Service Law §66-j, pages 8-9 (original footnotes omitted). A petition for rehearing is pending.

[26] Krysti Shallenberger, "Nevada regulators approve new net metering policy, creating separate rate class for solar users," Utility DIVE, December 22, 2015. Julia Pyper, "Nevada PUC to Reconsider Grandfathering Rooftop Solar Customers Into New Net-Metering Policy," GreenTech Media, January 21, 2016.

[27] Krysti Shallenberger, "California regulators preserve retail rate net metering in 3-2 vote," Utility DIVE, January 28, 2016. Note that in March 2016, the three California investor-owned utilities and TURN appealed the CPUC decision.

[28] Herman Trabish, "Maine utilities, solar advocates back new bill to replace net metering, grow solar," Utility DIVE, February 25, 2016.

[29] State of Maine Office of Public Advocate and Strategm, "A Ratepayer Focused Strategy for Distributed Solar in Maine," 2016. http://www.maine.gov/meopa/news/Maine%20VOS%20White%20Paper%20V2%202.pdf. See also: Herman Trabish, "How Maine's power players are reacting to its pathbreaking new solar proposal: The first hearings on a plan to replace net metering with market-based incentives were held in the legislature last week," Utility DIVE, March 24, 2016.

[30] In Bonbright's original book in 1961 (as compared to the Second Edition of his book, co-edited by James Bonbright, Albert Danielsen, and David Kamerschen in 1988), Bonbright uses the following language to describe the three primary objectives of ratemaking and the 'criteria of a sound rate structure': "(a) the revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies; (b) the fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service; and (c) the optimum-use or consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received." James Bonbright, Principles of Public Utility Rates," 1961, page 292.

[31] 18 CFR 292.101.

[32] See: Frank Graves, Philip Hanser, Greg Basheda, "PURPA: Making the Sequel Better than the Original," prepared by Brattle Group for the Edison Electric Institute, December 2006. This paper analyzes the PURPA experience, which certainly helped to foster the development of competitive generation markets but in some cases nonetheless led to situations where: rates were actually set above avoided costs (e.g., New York State's 6-Cent Law); capacity payments were built into PURPA rates, even in situations where the utility did not need new generating capacity, such that the utility ended up paying more than it needed to; standard offer PURPA rates lacked quantity limits, which led to oversupply of capacity in the region; long-term contracts were signed at rates established by administrative (and not competitive or market-based) processes; and

utilities paid the same rates to all PURPA facilities even if their generation profiles had very different characteristics with varied implications for their goodness-of-fit with the utility's supply portfolio.

[33] e-Lab, "A Review of Solar PV Benefit & Cost Studies," Rocky Mountain Institute, Second Edition, 2013 ("e-Lab 2013 Solar Study").

[34] E3 NY Study, page 43.

[35] According to e-Lab, the other gaps in the methodological literature are twofold: (a) "Grid support services value: There continues to be uncertainty around whether and how DPV can provide or require additional grid support services, but this could potentially become an increasingly important value." And (b) "Financial, security, environmental, and social values: These values are largely (though not comprehensively) unmonetized as part of the electricity system and some are very difficult to quantify." e-Lab 2013 Solar Study.

[36] The categories of valuation in the 2012 Austin, Texas study (K. Rabago, B. Norris and T. Hoff, "*Designing Austin Energy's Solar Tariff Using A Distributed PV Calculator,"* Clean Power Research & Austin Energy, 2012), are described as follows by e-Lab:

- "Energy: DPV output plus loss savings times marginal energy cost. Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (typically, a combined cycle gas turbine).
- System Losses: Computed differently depending upon benefit category. For all categories, loss savings are calculated hourly on the margin.
- Generation Capacity: Cost of capacity times PV's effective load carrying capability (ELCC), taking into account loss savings.
- Fuel Price Hedge Value: Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. Fuel price hedge value is included in the energy value.
- T&D Capacity: Expected long-term T&D system capacity upgrade cost, divided by load growth, times financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load.
- Environmental: PV output times Renewable Energy Credit (REC) price—the incremental cost of offsetting a unit of conventional generation."

e-Lab 2013 Solar Study, page 55.

[37] The categories of valuation in the 2012 New Jersey/Pennsylvania study (R. Perez, B. Norris, and T. Hoff, "*The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania,"* Clean Power Research, 2012) are described as follows by e-Lab:

- "Energy: Fuel and O&M cost savings. PV output plus loss savings times marginal energy cost, summed for all hours of the year, discounted over PV life (30 years). Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (assumed to be a combined cycle gas turbine ["CCGT"]). Assumed natural gas price forecast: NYMEX futures years 0-12; NYMEX futures price for year 12 x 2.33% escalation factor. Escalation rate assumed to be the same as the rate of wellhead price escalation from 1981-2011.
- Generation Capacity: Capital cost of displace generation times PV's effective load carrying capability (ELCC), taking into account loss savings.
- T&D Capacity: Expected long-term T&D system capacity upgrade cost, divided by load growth, times financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load. In this study, T&D values were based on utility-wide average loads, which may obscure higher value areas.
- Fuel Price Hedge Value: Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. The value is directly related to the utility's cost of capital.
- Market Price Reduction: Value to customers of the reduced cost of wholesale energy as a result of PV installation decreasing the demand for wholesale energy. Quantified through an analysis of the supply curve and reduction in demand, and the accompanying new market clearing price.
- Security Enhancement Value: Annual cost of power outages in the U.S. times the percent (5%) that are high-demand stress type that can be effectively mitigated by DPV at a capacity penetration of 15%.
- Social (Economic Development Value): Value of tax revenues associated with net job creation for solar vs conventional power generation. PV hard and soft cost /kW times portion of each attributed to local jobs, divided by annual PV system energy produced, minus CCGT cost/kW times portion attributed to local jobs divided by

annual energy produced. Levelized over the 30 year lifetime of PV system, adjusted for lost utility jobs, multiplied by tax rate of a $75K salary, multiplied by indirect job multiplier.

- Environmental: Environmental cost of a displaced conventional generation technology times the portion of this technology in the energy generation mix, repeated and summed for each conventional generation sources displaced by PV. Environmental cost for each generation source based on costs of GHG, SOx / NOx emissions, mining degradations, ground-water contamination, toxic releases and wastes. etc...as calculated in several environmental health studies."

e-Lab 2013 Solar Study, page 58.

[38] The categories of valuation in the 2012 California study (Energy and Environmental Economics, Inc. ("E3"), "Technical Potential for Local Distributed Photovoltaics in California, Preliminary Assessment. March 2012, prepared for the California Public Utility Commission, 2012) are described as follows by e-Lab:

- "Energy: Estimate of hourly wholesale value of energy adjusted for losses between the point of wholesale transaction and delivery. Annual forecast based on market forwards that transition to annual average market price needed to cover the fixed and operating costs of a new CCGT, less net revenue from day-ahead energy, ancillary service, and capacity markets. Hourly forecast derived based on historical hourly day-ahead market price shapes from CAISO's MRTU system.
- System Losses: Losses between the delivery location and the point of wholesale energy transaction. Losses scale with energy value, and reflect changing losses at peak periods.
- Generation Capacity: In the long-run (after the resource balance year), generation capacity value is based on the fixed cost of a new CT less expected revenues from real-time energy and ancillary services markets. Prior to resource balance, value is based on a resource adequacy value.
- T&D Capacity: Value is based on the "present worth" approach to calculate deferment value, incorporating investment plans as reported by utilities.
- Grid Support Services (Ancillary Services): Value based on the value of avoided reserves, scaling with energy.
- Carbon: Value of CO2 emissions, based on an estimate of the marginal resource and a meta-analysis of forecasted carbon prices.
- Solar Cost -The installed system cost, the cost of land and permitting, and the interconnection cost"

e-Lab 2013 Solar Study, page 50.

[39] The categories of valuation in the 2013 Colorado study (Xcel Energy, Inc., "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System," May 2013) are described as follows by e-Lab:

- "Energy: Costs are calculated on a marginal basis using ProSym hourly commitment and dispatch simulation using the TMY2 data set. The variable costs include fuel, variable O&M, and generation unit start costs. ProSym simulation implies DPV tends to primarily displace generation that is blend of an efficient CC unit (7 MMBtu/MWh) and a less efficient CT (10 MMBtu/MWh) through 2035. It is noted that, through 2017, DPV displaces a mix of gas-fired and coal-fired generation (before coal is retired in 2017).
- System Losses: Avoided T&D lines losses were assumed to achieve savings in energy, emissions, fuel hedge value and generation capacity. Distribution line losses were estimated using actual hourly feeder load data for the 58 feeders that represent 55% of DPV generation, and using an estimated value for the remainder. Average distribution losses were used to estimate savings from energy, emission & hedge value, and on a peak basis for generation capacity. Transmission line losses, based on annual, DPV generation-weighted values, were used to calculate energy, emissions, and hedge value, whereas avoided generation capacity was based on losses incurred across top 50 load hours.
- Generation Capacity: Avoided generation capacity costs are based on the market price of capacity until 2017, and after that (because of incremental need) based on the economic carrying charge of a generic CT's capital and fixed O&M costs. The avoided generation capacity cost is credited to DPV based on a ELCC study (historical system load and solar generation patterns for 2009 and 2010).
- T&D Capacity: DPV is assumed to defer distribution feeder capital investment by 1 to 2 years only if the existing feeder's peak load is at or near the feeder's capacity and the feeder's peak load is decreased by ~10%.

- Fuel Price Hedge Value: While the study notes the approach taken in other benefit/ cost studies to estimate fuel price hedge value from NYMEX fuel price forecasts, it is not explicitly stated how the fuel price hedge was ultimately estimated.
- Carbon: Annual tons of CO2 emissions avoided by DPV as calculated by the ProSym avoided cost case simulations. Change in marginal emissions over time driven by planned changes in generation fleet (primarily retirement of 1,300 MW coal in 2017).
- Solar Cost: Defined as "Integration Costs," or "costs that DPV adds to the overall cost of operating the Public Service power supply system based on inefficiencies that arise when the actual net load differs from the day-ahead forecasted net load." These costs are composed of electricity production costs levelized over 20 years."

e-Lab 2013 Solar Study, page 48.

[40] The Utility Cost test: Are the utility's costs higher or lower with the DER resources as compared to the utility's other benchmark investment? The Total Resource Cost test: Is the sum of the utility's costs and the participating DER customer's costs higher or lower than the utility's other benchmark investment? The Participating Customer Cost test: Will the customer have higher or lower electricity bills with DER than without it, taking the costs of DER into account? The Ratepayer Impact Measure/Non-Participating Customer Cost test: Will the utility's rates be higher or lower with the DER than with the utility's other benchmark investment? The Societal Cost test: Does the DER resource lead to higher or lower total costs to society, taking into account all costs and benefits (including externalities, DER costs relative to the utility's benchmark investments)?

[41] As noted previously, customer-driven DERs have resulted over the years from a combination of factors, most notably including the state regulatory policies noted previously (e.g., net-energy metering and tax incentives for solar PV investments and installations, 'loading-order' requirements favoring energy efficiency and so forth) and as well as the fundamental changes that have occurred in DER technologies/options, declines in equipment and installation costs, and the economic value proposition they provide to customers and third parties.

[42] Examples of such opt-in tariffs and rates include:

- NEM tariffs that focus on customers that elect to adopt of solar PV, without necessarily targeting installations toward various locations on the distribution system where such PV systems provide services in support of the grid.
- Time-of-use rates that aim to shift demand to off-peak periods (and thus potentially defer and/or avoid upgrades on the distribution system (and on other elements of the electric system)).
- Tariffs that permit the utility to exert operational control over particular equipment (e.g., air conditioning equipment; water heater equipment) on a customer's premises, again to shape the timing and level of demand on the system.
- Value-of-solar tariffs (like the one available in Minnesota), which allow a customer with rooftop PV panels to receive payments for the panels' output at a predetermined price, in conjunction with the customer taking service at the regular retail rate. http://www.nrel.gov/tech_deployment/state_local_governments/basics_value-of-solar_tariffs.html.

[43] "Hosting capacity is the amount of DER that can be accommodated in a system without any needs for upgrade. Distribution system level DER integration is constrained by thermal loads, power quality and protection schemes." Greentech Leadership Group and CalTech Resnick Institute, "More Than Smart, Overview of Discussions Q3 2014 thru Q1 2015," Volume 2 of 2, March 31, 2015, page 24.

[44] "In December 2014, the PSC approved a first-of-its kind initiative in Con Edison's territory that illustrates certain principles underlying the new regulatory paradigm. Under this program, instead of building a new substation at an estimated cost exceeding $1 billion, Con Edison will be deploying local clean energy resources such as energy efficiency, renewables, and storage to meet system constraints, at a substantially lower total projected cost. This Brooklyn/Queens Demand Management Program serves as a tangible example of how new approaches can create 'win-wins.' Managing electrical demand (by shifting and reducing consumption) can reduce GHG emissions while improving the efficiency of the overall system and lowering the cost of maintaining the grid for all ratepayers." New York State, "Energy to Lead: 2015 New York State Energy Plan," page 58. See also: Con Edison, "Request for Information: Innovative Solutions to Provide Demand Side Management to Provide Transmission and Distribution System Load Relief and Reduce Generation Capacity Requirements," issued July 15, 2014, which describes (on pages 2-3) the intention to solicit responses from qualified parties

stating their interest and qualifications to supply Con Edison with new Demand Side Management (DSM) measures within the targeted load areas served by the Brownsville No. 1 and Brownsville No. 2 substations. These

substations support the Richmond Hill, Crown Heights, and Ridgewood networks. Brownsville No. 1 and Brownsville No. 2 area substations are forecasted to be overloaded under normal conditions. The targeted network map can be found in Appendix A. Operational measures will be employed by the Company to address overloads in years 2014 and 2015. However, due to the inherent temporary nature of the operational measures, a permanent solution is required to address the forecasted summer overloads and defer the need to build traditional utility infrastructure, namely a new area sub-station. Customer and utility side "alternative" solutions are planned to delay the need for the traditional infrastructure solutions. These solutions are needed to address forecasted summer overloads in 2016 (18 MW overload), 2017 (49 MW overload), and 2018 (58 MW overload). This RFI is the first step in identifying and pre-qualifying contractors for receipt of future RFPs and/or other purchasing actions for specific MW reduction needs, associated targeted geographic areas, and need dates. As the sub-transmission constraint is currently subject to potential overload, solutions that can be deployed rapidly, and with operational confidence, will be given greater consideration. This RFI is seeking information from innovative solutions providers for potential DSM multiyear "firm contracts" for pre-determined MW needs and delivery.
Targeted areas and characteristics of the Brownsville substations load pockets, where relief is needed, are included in Appendix B. Timing and duration of load reduction needs have been identified as the summer peak load occurring over the months of June through September, Monday to Friday, during the hours of 12pm to 12 am. A graph of the time of day in which the summer peak overload would occur is included in Appendix C.

[45] State of Maine Office of Public Advocate and Strategm, "A Ratepayer Focused Strategy for Distributed Solar in Maine," 2016. http://www.maine.gov/meopa/news/Maine%20VOS%20White%20Paper%20V2%202.pdf.

[46] This diagram results from conversations with Eric Takayesu from SCE on the value for DERs for D.

[47] e-Lab 2013 Solar Study.

[48] Many observers have pointed out the expectation that as the penetration of DER (especially solar) increases, each additional increment of DER will have diminishing value to the system. See, for example: Andrew Mills and Ryan Wiser, "Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels," LBNL, March 2014.

[49] EPRI, "Integrated Grid: A Benefit/Cost Framework," Final Report, February 2015, page 2-3.

[50] More than 80 percent of distribution-feeder-level investments planned and deployed on 1-2 year cycles, and "Substation and system-wide technology deployment planning horizon [is] between 5-7 years." Greentech Leadership Group and CalTech Resnick Institute, "More Than Smart: Overview of Discussions Q3 2014 thru Q1 2015," Volume 2 of 2, March 31, 2015.

[51] See, for example: Paul Denholm, Robert Margolis, Bryan Palmintier, Clayton Barrows, Eduardo Ibanez, Lori Bird, and Jarett Zuboy, "Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System," Prepared by the *National Renewable Energy Laboratory* under Task No. SS13.1040. Chapter 8.

[52] "Customers and services firms should know what types of services and benefits they can provide to the grid through access to relevant information, as compensation for these services may comprise a necessary element of the DER providers' business plans to obtain project financing. This also includes rules for the physical interconnection of new resources, whether principles of "open access" should apply and, if so, how they are specified and enforced. Boundary questions need to be addressed, such as whether DERs can participate in the wholesale transmission-level market directly, or must go through a distribution operator or load serving entity (LSE)42 that would provide the wholesale market interface." Paul De Martini, Lorenzo Kristov and Lisa Schwartz, "Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight," LBNL, Report No. 2, October 2015, pages 24-26.

[53] Paul De Martini, Lorenzo Kristov and Lisa Schwartz, "Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight," LBNL, Report No. 2, October 2015, page 52.

[54] There are lessons from academic research suggesting that disclosure of such costs works to the disadvantage of the utility and can result in higher retail electricity prices. See, for example: Timothy Cason and Charles Plott, "Forced Information Disclosure and the Fallacy of Transparency in Markets," *Economic Inquiry*, Vol. 43, No. 4, October 2005, 699-714.

[55] See, for example, Susan Tierney and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for NARUC and funded by the U.S. Department of Energy, 2008.

[56] As the market for DERs transitions to more competitive pricing in the future, the goal should be to design markets so as to produce efficient prices. This tendency is similar to what can occur in "pay as bid" versus clearing-price auctions in wholesale power market, with the former leading to bidders raising their offer prices and the latter leading to offer prices that are as low as possible. Efficient prices tend to flow from the latter, relative to the former. See Susan Tierney, Todd Schatzki, and Rana Mukerji, "Uniform-Pricing versus Pay-as-Bid in Wholesale Electricity Markets: Does it Make a Difference?" March 2008.

[57] See the informative discussion of distribution operational markets in the recent paper by Paul De Martini, Lorenzo Kristov and Lisa Schwartz, "Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight," LBNL, Report No. 2, October 2015, pages 24-26 (on markets and market services).

[58] One of the elements of the Maine proposal is an aggregator that can treat DERs as a fleet. See the presentation by Tim Schneider, Lisa Smith, and Lon Huber, "A Ratepayer Focused Strategy for Distributed Solar in Maine," NASEO Policy Outlook Conference, February 11, 2016http://energyoutlook.naseo.org/Data/Sites/8/media/presentations/Smith-NASEO-Solar-Policy-Framework-Maine.pdf. The white paper explaining the proposal in greater detail indicates that "this framework uses market forces to maximize value to all ratepayers, while fairly compensating solar adopters….The policy presented here is based on the premise that there are now better ways than net metering to encourage solar adoption that send the right signals to developers and consumers, drive technological innovation, and allow utilities to more easily manage the increase in intermittent generation. This paper presents policy concepts for two important distributed solar market segments in Maine: Customer-sited (systems installed for residential and small commercial/industrial customers); and Wholesale (systems installed on the utility side of the meter within the distribution system). An aggregation entity, or "Solar Standard Buyer" (SSB) would interface with the customer sited market segment. Under the existing net metering construct, this role is currently assumed by the Standard Offer Provider or a customer's competitive electricity provider. Centralizing procurement with the SSB would allow for a more efficient aggregation and sale of the different attributes solar energy can provide. The SSB would aggregate the energy, RECs, capacity value, and ancillary services potential and monetize these in the applicable markets. As stated previously, the underlying goal of the policy structure is to allow Maine ratepayers to capture the benefits of distributed solar energy while minimizing the costs and inequities experienced in other states. … While many details would need to be defined, it is our hope that all parties can agree on the general goal of maximizing benefits while mitigating costs, and that this common guiding principle can foster further dialogue on strategic and sustainable solar deployment in Maine." State of Maine Office of the Public Advocate and Strategen, "A Ratepayer Focused Strategy for Distributed Solar in Maine," 2016, pages 1, 6-7, 16.
http://www.maine.gov/meopa/news/Maine%20VOS%20White%20Paper%20V2%202.pdf

[59] I have previously written about these conditions for successful markets. Susan Tierney, "ERCOT Texas's Competitive Power Experience: A View from the Outside Looking In," October, 2008, pages 15-16.

[60] A recent white paper prepared by SolarCity, suggested that in jurisdictions where the utility has the role of distribution system owner and operator, it would be constructive to allow a "new utility sourcing model, which we call infrastructure-as-a-Service,' that allows utility shareholders to drive income, or a rate of return, from competitively sources third-party services." SolarCity Grid Engineering, "A Pathway to the Distributed Grid," February 2016, page 2.

[61] Con Edison Corporate Profile, http://investor.coned.com/phoenix.zhtml?c=61493&p=irol-homeprofile.

[62] Con Edison Newsroom electric system, http://www.coned.com/newsroom/energysystems_electric.asp.

[63] Con Edison's service territory in square miles comes from Con Edison Newsroom electric system, http://www.Con Edison.com/newsroom/energysystems_electric.asp. New York State's land area covers 47,214 miles. U.S. Geological Survey data, http://www.theus50.com/fastfacts/area.php.

[64] State population data for New York State: https://www.census.gov/newsroom/press-releases/2015/cb15-215.html.

[65] NYISO, "2015 Load & Capacity Data (Gold Book), Table I-2a: Baseline Forecast of Annual Energy & Coincident Peak Demand, combining the data for zones I and J.

[66] Con Edison provided this information on March 25, 2016,   The figures for grid-interconnected DER reflect the MW of installed (nameplate) capacity tracked through Con Edison's distribution-system interconnection process, and includes solar PV (94.1 MW), wind (0.1 MW), fuel cell (7.8 MW), gas turbine (40.1 MW), internal combustion engine (102.9 MW), micro-turbines (9.8 MW), steam turbines (3 MW), and battery (0.9 MW),

[67] Con Edison provided this information on March 25, 2016. The figures reflect: 186 MW of net-peak-reduction due to energy efficiency; 260 MW of DR participating in the NYISO DR program, and another 45 MW of Con Edison DR (with the latter two DR program amounts reflecting enrolled capacity derated to expected performance levels.

[68] SCE, Our Service Territory, https://www.sce.com/wps/portal/home/about-us/who-we-are/leadership/our-service-territory/!ut/p/b1/hdBNDoIwEAXgs3gBZqAFZVnEQDVR-TFgNwYNVhSpASLXFxI2LsTZveR7izcgIAVRZe9CZm2hqqwcsrBO-sJjPo-Q70LiIg-N2GZ0g3Sp9-DYA_xxDP_1ExDfxIupidwx5sRzOAltYxrEK3MauJSOwPZw5a93AwgIchLgNmKMIFojmFixBiFLde4_krgg9lQ_NHLYzqozWUgQdX7N67zWbqppIe26TpNKyTLXLuoJr2eKBb-bj4TNPjgYPjk!/dl4/d5/L2dBISEvZ0FBIS9nQSEh/.

[69] California's land area covers 155,959 miles. U.S. Geological Survey, http://www.theus50.com/fastfacts/area.php.

[70] SCE Distribution Resources Plan, July 1, 2015, page 26, which provides detail for the basis on which SCE has estimated these amounts of DER.

[71] The California Energy Commission has forecast a 2016 coincident peak load of 23,537 MW for SCE's planning area (based on the 2014 mid-energy demand estimate). Table 10 of CEC, "California Energy Demand Updated Forecast, 2015-2025, February 2015, Table 10.

[72] AB 327 text: Section **769.**   "(a) For purposes of this section, "distributed resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. (b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

> (1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.
> (2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
> (3) 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.
> (4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.
> (5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.
> (c) The commission shall review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.
> (d) Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable. The commission may also adopt criteria, benchmarks, and accountability mechanisms to evaluate the success of any investment authorized pursuant to a distribution resources plan."

[73] SCE's DRP can be found accessed at:
http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/BF42F886AA3F6EF088257E750069F7B7/$FILE/A.15-07-XXX_DRP%20Application-%20SCE%20Application%20and%20Distribution%20Resources%20Plan%20.pdf.

[74] See E3's website: https://ethree.com/public_projects/cpuc5.php.

[75] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

[76] Finding of Fact #12, CPUC, Decision Adopting Successor to Net Energy Metering Tariff, Rulemaking Docket 14-07-002. Finding of Law #25 found that "In order to ensure that the NEM successor tariff is consistent with Commission policy on distributed energy resources, makes use of relevant information about locational benefits and optimal DG resources, and is appropriately aligned with changes to retail rates for residential customers, the successor tariff adopted in this decision should be reviewed in 2019."

[77] CPUC, "Joint Assigned Commissioner and Administrative Law Judge Ruling and Amended Scope Memo," Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evaluation of Integrated Distributed Energy Resources, Rulemaking 14-10-003 ("CPUC IDER Rulemaking Memo"), page 5.

[78] CPUC IDER Rulemaking Memo, page 3. This proceeding will address four issues (paraphrased from the original document on pages 6-7):

1. Development of a competitive solicitation framework targeting the reliability needs within particular areas: …including defining the services to be bought and sold within those areas, as well as development of rules and oversight requirements related to those solicitations.
2. Further development of technology-neutral valuation or cost-effectiveness methods and protocols, including incorporating location-specific considerations;
3. Leveraging the work being performed through the Distribution Resource Plans Demonstration Projects where practical for the purpose of advancing the development of a competitive solicitation framework for distributed energy resources."
4. Utility role, business models, and financial interests with respect to distributed energy resources deployment.

[79] See the REV website: https://www.ny.gov/programs/reforming-energy-vision-rev.

[80] Audrey Zibelman, Chair, NY PSC, "Reforming the Energy Vision," presentation to the New England Electric Restructuring Roundtable, June 27, 2014. Also, the New York State Energy Plan describes the REV regulatory docket:

> In April 2014, the PSC commenced the REV regulatory proceeding to reform New York State's electric industry and utility regulatory practices. The REV Regulatory Docket considers an overhaul of New York's utility regulations to give customers greater value from and choice over their energy use, facilitate the rapid expansion and integration of DERs into the State's energy system, and transition clean energy from the periphery to the core of investor-owned utilities' business models. By redesigning price signals, revising utility compensation structures, and opening up access to previously undisclosed data (bearing in mind privacy concerns), the REV Regulatory Docket aims to maximize utilization of all behind-the-meter resources such as demand management, energy efficiency, clean distributed generation, and storage to reduce the need for costly new infrastructure.
>
> Building upon the success of the State's recent regulatory reforms, REV will also aim to further the establishment of robust retail energy markets that recognize and account for the environmental and economic values of energy efficiency and load management. As a result, REV will increase opportunities for existing and new market participants to develop both central and distributed generation resources, which will create value for New York's consumers, more energy sector jobs, and a cleaner energy generation mix."

"Energy to Lead: 2015 New York State Energy Plan," pages 47-48.

[81] NY PSC, Case 15-E-0082, Proceeding on a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings, July 17, 2015, page 24.

[82] NY PSC, Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework, January 21, 2016. The NY PSC has stated that the benefit/cost analysis

> will be applied to four categories of utility expenditures: investments in Distributed System Platform (DSP) capabilities; procurement of Distributed Energy Resources (DER) through competitive selection; procurement of DER through tariffs; and, energy efficiency programs. The BCA Framework enables the careful comparison of the value of the benefits obtained through a potential project or action against the costs incurred in effectuating that project or action, generally considered through the systematic quantification of the net present value of the project or action under consideration…..
>
> In the BCA Whitepaper, the proposed BCA Framework is premised upon a number of foundational principles. The BCA analysis should: 1) be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular; 2) avoid combining or conflating different benefits and

costs; 3) assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures); 4) address the full lifetime of the investment while reflecting sensitivities on key assumptions; and, 5) compare benefits and costs to traditional alternatives instead of valuing them in isolation. The BCA Framework will rest upon the selection of methodological approaches, which include the Societal Cost Test (SCT), Utility Cost Test (UCT), and the Rate Impact Measure (RIM).

Those benefits and costs that should not or cannot be reflected in the Framework will be clearly delineated. The outcomes of the BCA analysis should allow for judgment and where appropriate a qualitative assessment of non-quantified benefits. The interests in sustaining a stable investment environment to support the DER market would be balanced with remaining flexible and adaptive so that the valuation process does not become outdated or inaccurate. Over time, developing more dynamic and granular methods will require a continuous process, rather than a single decision. Therefore, the matters addressed here are only the first initial step in forming a robust and long-lasting BCA Framework.

That Framework will stand within the broader scope of REV implementation. Under REV, utilities will file Distribution System Implementation Plans (DSIP) by June 30, 2016 that identify opportunities to avoid traditional utility distribution and investments by calling upon the DER marketplace.3 The BCA Whitepaper identifies means for evaluating DER alternatives as substitutions for traditional utility solutions, and against each other. Alongside cost avoidance and system efficiency benefits, the BCA Framework as proposed would reflect consideration of social values, also known as externalities, quantifiably when feasible and qualitatively when not. A full evaluation of alternatives over their expected lives, it is suggested, would be accomplished by stacking resources of different characteristics into a portfolio that results in meeting system needs in the aggregate.

Besides evaluation of electric system alternatives, the BCA Framework should support the developments of tariffs that place a value on DER. The evaluation of tariffs, however, differs from the evaluation of utility system alternatives, because tariffs are more dynamic measures of near term benefits and costs. Dynamic tariffs may be self-adjusting or embed other mechanisms to address the concern of variation over time. The tariffs can serve as an incentive mechanism to promote the development of a more competitive behind-the-meter market, including the installation of the DER facilities currently promoted through the device of net metering tariffs. Through these processes, the BCA Framework will work in coordination with the DSIPs, upon the identification of processes for assuring fair, open and value-based decision making.

When utilities present their DSIPs, each utility will identify its system needs, proposed projects for meeting those needs, potential capital budgets, particular needs that could be met through DER or other alternatives, and plans for soliciting those alternatives in the marketplace….(pages 1-3)

The Commission adopts SCT as the primary measure of cost effectiveness under the BCA Framework. The SCT recognizes the impacts of a DER or other measure on society as a whole, which is the proper valuation. New York's clean energy goals are set in recognition of the effects of pollutants and climate change on society as a whole, and only the SCT would both properly reflect those policies and create a framework for meeting those goals.

The UCT and RIM tests would be conducted, but would serve in a subsidiary role to the SCT test and would be performed only for the purpose of arriving at a preliminary assessment of the impact on utility costs and ratepayer bills of measures that pass the SCT analysis. (page 12)

[83] NY PSC, Case 15-E-0407, Orange and Rockland Utilities, Inc. – Petition For Relief Regarding Its Obligation to Purchase Net Metered Generation Under Public Service Law §66-j, Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation, October 16, 2015.

[84] NY PSC, Case 15-E-0751 - In the Matter of the Value of Distributed Energy Resources, Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference, December 23, 2015, Attachment A (Questions on the Value of Distributed Energy Resources and Options Related to Establishing an Interim Methodology), pages 3-4.

[85] K. Anderson, M. Coddington, K. Burman, S. Hayter, B. Kroposki, and A. Watson, "Interconnecting PV on New York City's Secondary Network Distribution System," NREL, November 2009.

[86] Con Edison, "BQDM Quarterly Expenditures & Program Report," Q3-2015, page 22.

[87] See: EPRI, "The Integrated Grid: A Benefit-Cost Framework," 2014, and 'The Integrated Grid: Phase II: Development of a Benefit-Cost Framework," 2014. The latter report explains on page 3 that

EPRI launched its Integrated Grid initiative with a concept paper [1] and the goal of aligning power system stakeholders on key issues. With widespread adoption of distributed energy resources (DER), potentially fundamental changes in the grid will require careful assessment of the benefits, costs, and opportunities of different technological or policy pathways. Four main areas requiring global collaboration were identified: Interconnection rules and standards; Grid modernization; Strategies and tools for grid planning and operations; Enabling policy and regulation.
Work on the three-phase Integrated Grid initiative is intended to provide stakeholders with information and tools that are integral to these four areas. Phase I – Stakeholder alignment, including the production of a concept paper, supporting documents, and related knowledge transfer efforts. Phase II – Development of a benefit-cost framework, interconnection technical guidelines, and recommendations for grid operations and planning with DER. Phase III – Global demonstrations and modeling to provide comprehensive data that stakeholders will need for transitioning to an integrated grid.

88 EPRI, “The Integrated Grid: A Benefit-Cost Framework,” 2014, pages xvii-xviii.

89 EPRI, “The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources,” 2014.