Integrating Distributed Energy Resources into Electricity Resource Planning

Current Practices and Emerging Issues

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EPRI Project Manager

A. Diamant

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

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The following organization, under contract to the Electric Power Research Institute (EPRI), prepared this report:

Energy + Environmental Economics Inc. (E3)
101 Montgomery Street, Suite 1600
San Francisco, CA 94104

Principal Investigators
F. Kahrl
N. Ryan

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PRODUCT DESCRIPTION

This report provides an overview of key methodological issues associated with integrating distributed energy resources (DER), such as distributed generation (DG), energy efficiency (EE), demand response (DR), flexible load / advanced DR, and energy storage technologies, into electric company resource planning.

Background

Electric company resource planning is evolving rapidly today in response to dramatic changes occurring in the electric sector, such as increased DER deployment, changes in the cost and performance of power generation technologies, and the advent of the "smart grid" and two-way power flow across electric sector transmission and distribution networks. Today, electric company planners are trying to better understand and account for a variety of key issues associated with incorporating DER into resource planning, including:

- Growing deployment of "behind-the-meter" DG resources, such as rooftop solar photovoltaic (PV) systems;
- Public policies and changes in the market that are incentivizing greater deployment of demand-side management (DSM) programs and strategies, such as EE and DR;
- Emergence of new types of grid-connected and customer-sided electricity storage systems; and,
- Uncertainty about future electricity loads and deployment of distributed generation, energy storage technologies, and energy efficiency programs.

The potential for higher DER penetrations, driven in the near term by distributed PV, has important implications for resource planning. This report examines current practices and emerging issues associated with integrating DER into resource planning in three states that already have, or are anticipating, higher DER penetrations: California, Hawaii, and New York.

Objectives

This study examines four key questions: (1) how will DER affect resource planning; (2) what methodological questions are raised when considering how to incorporate DER into resource planning; (3) how are these questions being addressed in California, Hawaii, and New York; and, (4) what are key existing research gaps?

Approach

The research in this report is based primarily on a literature review focusing on materials available in regulatory proceedings and expert knowledge of the authors.

Results

The study identifies and addresses six key issues related to methodologies that can be used to incorporate DER into resource planning: (1) whether to treat DER as a load modifier or resource; (2) how to forecast DER adoption; (3) how to assess the system reliability value of DER; (4) how to target DER for use as a local or system resource; (5) how to determine how much DER can be integrated into different parts of the electric system; and, (6) how to determine potential operational impacts of DER. The second and fourth questions are relevant for all electric utilities, whereas the other four questions are more relevant to utilities facing higher levels of DER penetration.

These key methodological questions can be answered, and many of the electricity resource planning tools being used to address them today are adapted versions of tools that have been used in the electric industry for decades. However, these tools either were developed with expectations of much lower DER penetrations, where accuracy was not as critical, or they were designed for other purposes. As a result, the approaches, methods, and tools used to incorporate DER into resource planning today are still in flux, even in the three case study states with relatively high DER penetration.

The study results suggest electric utilities should consider being proactive in integrating DER into resource planning. Hawaii's experience with integrating distributed PV illustrates the potentially disruptive nature of DER if it is not considered proactively as part of the resource planning process.

Applications, Value, and Use

The principal audience for this report includes electric utility planners, regulators, and industry analysts.

This report will be useful for electric company planners seeking to understand different approaches that can be used to incorporate DER into resource planning, key DER-related methodological questions, how these questions are being addressed in the three case study regions, and current gaps in analytical tools.

The relevance of different DER planning tools will vary by location, driven by different policies, rate designs, and customer preferences. However, DER adoption forecasting and targeting are relevant for all utilities, regardless of expected DER penetrations. As a next step, the report recommends electric utilities and regulators focus on developing and improving adoption and avoided cost modeling capacity.

Keywords

Distributed energy resources
Electricity resource planning
Distributed resource planning

EXECUTIVE SUMMARY

Although distributed energy resources (DER) have begun to dominate electricity industry headlines in recent years, in reality they have been an ongoing area of investigation for electricity resource planners since the 1970s. Until recently, penetrations of DER — distributed generation (DG), energy efficiency (EE), demand response (DR), flexible loads, and energy storage — were never sufficiently high to influence electric industry resource planning practices. Now, with some jurisdictions anticipating much higher DER penetrations over the next decade, DER has the potential to lead to more fundamental changes in resource planning.

This report provides an overview of current practices and emerging issues associated with integrating DER into resource planning, focusing on three states that are now experiencing, or anticipating, significant growth in DER: California; Hawaii; and, New York. These three states have different policy and economic drivers for, and different levels of, DER adoption. In California, where adoption of a wide range of DER technologies is being driven by state policies and utility programs, DER penetrations remain modest, but are expected to grow considerably in the near term. In Hawaii, rapid growth in distributed solar photovoltaics (DG PV) already is creating operational challenges for utilities, requiring new planning strategies to accommodate continued growth while maintaining system reliability. New York, which has relatively low DER penetrations today, has proposed a radical restructuring of its electricity industry in part to encourage rapid growth in DER through market-based platforms.

Across these different contexts, increased DER penetration is raising a number of methodological questions for resource planners. Six of these key questions are examined in this report:

- *DER Treatment: load modifier or supply resource?* – Should DER be treated as an adjustment to expected electric system load or as an electricity supply resource?
- *Adoption forecasting* – How should resource planners model potential DER adoption?
- *Resource adequacy* – How should regulators and electric load serving entities account for DER in bulk and distribution system resource adequacy planning?
- *DER as a resource* – Can DER be used as a bulk or distribution system resource to meet incremental resource and regulatory compliance needs? If so, how should it be evaluated and targeted?
- *Distribution integration capacity* – How should different parts of the electricity distribution system be evaluated for their ability to integrate DER?
- *Operations* – How should DER operations be treated in resource planning models?

In exploring these questions, the report focuses on current practices and emerging issues, drawing on examples from public proceedings and documents in the three case study areas.

The report distills five key DER implications for resource planning. First, DER blurs the historical divide between high voltage (bulk) system and distribution planning processes. For instance, DER that is connected at a *distribution* level can contribute to bulk system capacity, energy, and ancillary services (AS) needs. However, using DER implemented at a *system* level may mean it is not available to provide value (e.g., capital investment deferral value) at the distribution level. Accurate accounting implies a need for closer coordination between bulk system-level and distribution-level resource planning.

Second, analytical tools used for DER planning are still evolving, even in the three states examined in this study. Key analytical tools include those used to forecast DER adoption, assess DER capacity value, value and target DER, assess DER integration capacity, and determine DER operational impacts. Most tools currently in use in these areas are extensions of ones that have long existed in the electricity industry, but are being adapted to account for the need for greater spatial detail, load and generation uncertainty, integration among different resources, and system complexity.

For instance, effective load carrying capability (ELCC) — an approach developed in the 1960s — provides an alternative to more heuristic approaches for calculating DER capacity value, allowing utilities to capture more accurately the incremental reliability benefits of DER, though at higher computational cost. Utilities in California and New York are adapting existing cost-effectiveness tools to provide a more spatially granular and integrated approach to DER valuation. Utilities in Hawaii are using production simulation models, with probabilistic representations of solar PV, to assess the operational impacts of higher DG PV penetrations. In general, the development and application of DER analytical tools in resource planning is still nascent. Going forward, this is a major area of work for utilities and regulators.

Third, DER changes the role of retail rates in resource planning. Historically, retail rate calculations and rate design considerations were primarily an output of the planning process. Because DER adoption is sensitive to retail rate levels and designs, however, planners may need to give more attention to the endogeneity of rates — rate changes may influence DER adoption, and DER adoption may also influence rates. The potential for more price responsive loads also increases the importance of considering retail rates within the planning process.

Fourth, development of modeling tools at a distribution level implies a large increase in data requirements and computing needs for utilities. For instance, assessing integration capacity — the ability of distribution substations or feeders to accommodate additional DER capacity — requires forecasts of loads, DER adoption, and DER profiles at a substation or feeder level. Data from advanced meters can provide a valuable source of data inputs for DER forecasts and assessments. However, higher data intensity and computational complexity should be balanced against the need for transparency. The use of "public tools" in stakeholder processes, where stakeholders can see and change inputs, provides some measure of transparency. The continued use of screening tools, in tandem with more complex analysis, provides another approach to help improve transparency.

Fifth, treating DER as a supply resource rather than an adjustment to load can help to provide greater transparency and more efficiently allocate risks between DER providers and non-DER customers, reducing some of the uncertainty associated with DER. For instance, allowing third parties to bid DER into wholesale power markets, as proposed in New York, would reward them for the capacity, energy, and AS values they provide. However, transitioning to a market and regulatory environment that supports resource treatment requires addressing a range of issues, including metering requirements, potential conflicts between wholesale and retail pricing, billing system impacts, and jurisdictional issues between system operators and regulators. Ultimately, regulators must decide if the benefits of this transition are worth the costs.

Many of the planning considerations associated with higher penetrations of DER are further on the horizon for many utilities and regulators. Nevertheless, it is valuable for utilities and regulators to think through the kinds of planning questions that DER might pose, and to follow planning developments in “leading adopter” states. Part of the challenge of DER is that utilities and regulators have limited control over adoption. Rapid adoption, if not adequately prepared for, can be disruptive.

The report is organized into four main sections. Section 1 provides a historical overview of electricity resource planning and recent drivers of change in the traditional planning paradigm. Section 2 provides a working definition of DER, enumerates six implications for resource planning, and describes the three case study regions. Section 3 examines each of the six implications, drawing on examples from the case study regions. Section 4 provides a synthesis and distills key conclusions. Section 5 identifies key research gaps and outlines next steps.

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HISTORICAL CONTEXT AND A CHANGING PARADIGM

Planning questions surrounding distributed energy resources (DER) have emerged in the context of an evolving paradigm for electricity resource planning. This section briefly describes the recent history of resource planning in North America, and factors that have been driving changes in resource planning more recently. The section provides context and background for the rest of the report.

Historical Context

Current resource planning practices are rooted in the 1970s. In that era, concerns over rising costs, reliability, the environment, and growing uncertainty led to the development of least-cost planning[1] processes, with a goal of minimizing the total fixed and variable costs of an electric utility's[2] power generation resource portfolio, subject to reliability and emissions constraints [1].

Least-cost resource planning was oriented around physical reliability standards for the high voltage (i.e., "bulk") power system, which drove the need for new resource investments. The dominant standard in North America — a loss-of-load expectation (LOLE) of "1-in-10-years" — came into currency as early as the 1940s and became the centerpiece of resource planning [2].[3] Utilities and regulators translated standards into equivalent planning reserve margins, often expressed in percentage terms (e.g., a 15% reserve margin), which indicated the margin of supply above forecasted peak demand needed to maintain a given LOLE target.

The use of planning reserve margins lent itself to an accounting-based approach to resource planning, often expressed in load and resource balance tables. These tables enabled direct comparison of a resource need, equal to a peak load forecast plus the reserve margin, and resource supply, historically focused on central-scale power generating resources. Utilities constructed or procured new generation resources to ensure total resources were sufficient to meet need.

The emphasis on least-cost planning raised new questions. Most importantly, which portfolio of generation resources would minimize short- and long-run costs, in the face of growing cost and regulatory uncertainty? Significant improvements in computing power in the 1980s and 1990s enabled the development of complementary planning tools to address these questions. These included: (1) *production simulation models* that simulated the detailed operation of the power system and its operating ("production") costs over a discrete time period; and, (2) *capacity*

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[1] "Least-cost planning" refers here broadly to planning processes that are designed to minimize costs subject to some constraint, rather than more narrowly to integrated resource planning.

[2] "Utility" here refers to any entity that acquires electricity resources to serve end-use customers.

[3] The interpretation of "1-in-10 years" varies widely across North America. In some cases it is interpreted as 1 *event* in 10 years (0.1 events per year), and in other cases it is interpreted as 1 *day* in 10 years (2.4 hours per year). A deeper discussion of reliability standards is beyond the scope of this report. For further treatment, see [2].

expansion models that identified least-cost expansion plans over time, based on a simplified representation of system operations [1, 3, 4].

The Electric Generation Expansion Analysis System (EGEAS) software developed by EPRI in the early 1980s is an example of a planning tool that combines production cost modeling with the capability to develop optimal capacity expansion plans.[4]

Growing regulatory, demand, and cost uncertainty also led to the development of integrated resource planning (IRP) in the 1980s [5]. IRP provided a structured approach to integrate supply-side and demand-side investments in a long-term, least-cost planning framework. By the early 1990s, all but nine states had some variant of an IRP process [6] in place.

Resource planning underwent two important structural changes during the 1980s to 2000s. First, the Public Utility Regulatory Policies Act (PURPA), passed in 1978, required utilities to procure generation from qualifying non-utility facilities (QFs) at their avoided cost. QFs included significant amounts of behind-the-meter combined heat and power (CHP) generation and renewable resources, requiring utilities to account for these non-utility, often non-dispatchable resources in their resource plans.

Second, the introduction of organized wholesale markets for power generation in California, the East, the Midwest, and Texas, accompanied by the divestiture of utility-owned generation in these regions, changed the role of utilities. Rather than building, owning, and operating generation, many utilities began to purchase energy and capacity through a combination of bilateral and centralized markets. These changes in resource procurement changed the nature of risk management in resource planning [7].

Despite these and other changes in the electricity industry, the basic principles and practice of resource planning have remained largely unchanged for the past three decades. Resource planning continues to be structured around load and resource balance tables and bulk system reliability, guided by least-cost planning principles. As of the early 2010s, more than half of the states had an IRP process in place, and most of the remainder required utilities to file long-term resource plans [8].

The general approach to resource planning also has not changed markedly over the past three decades, although improvements in computing power have enabled more sophisticated analysis of operations and uncertainty. For utilities, the resource planning process generally consists of a series of interrelated steps [9, 10]:

1) Review regulatory requirements;
2) Review existing generation resources;
3) Forecast future electricity demand;
4) Develop a set of generation resource portfolios to be evaluated that are expected to meet demand and regulatory requirements;

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[4] Additional information about the current version 11.0 of EGEAS is available online at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005317 and http://eea.epri.com/models.html#tab.=3&tab=3.

5) Calculate the present value of the revenue requirement (PVRR) for these different portfolios;
6) Subject portfolios to uncertainty analysis, focusing on key variables, such as capital costs, fuel prices, inflation, demand uncertainty, and more recently in some areas, CO_2 prices;
7) Choose the portfolio has the lowest expected PVRR at an acceptable level of risk; and,
8) Finalize and implement new resource plan.

Drivers of Change

Recent changes in policy and industry trends are driving fundamental changes in the resource planning paradigm. The most important of these drivers include:

- Federal environmental policies, including the Regional Haze rule [11], Mercury and Air Toxics Standards (MATS) [12], Coal Combustion Residuals (CCR) rule [13], Cooling Water Intake Structures (CWIS) rule [14], Carbon Pollution Standards for new, modified and reconstructed fossil-fired power plants[15], and the recently adopted final Clean Power Plan (CPP) to reduce CO_2 emissions from existing fossil-fired power plants [16];
- Renewable portfolio standards (RPS), which the majority of states now have implemented;[5]
- DER policies, including subsidies for DG PV, net energy metering (NEM) policies, storage mandates, electric vehicle (EV) subsidies, and rules to allow direct participation of DER in wholesale markets;
- Changing customer demands, including demands for "green" energy (e.g., renewable power, such as wind, solar and biomass), and new rate structures;
- Cost reductions for renewable energy, particularly PV;
- Improvements in information and communication technologies; and,
- New business models for third-party (non-utility) energy service providers.

These drivers are requiring utilities to plan for new loads (e.g., electric vehicles) and generation resources (e.g., wind and solar) that have very different characteristics than those the electricity industry has grown accustomed to working with over the past century. DER, driven by a combination of policy, technology cost declines, and customer demand, presents a particular challenge for resource planners because it involves a multitude of different technologies, is geographically dispersed, and has location-specific costs and values. Generally, utilities also have less ability to control DER adoption, and DER's eligibility to be used for compliance with environmental and energy mandates often is less straightforward than is the case for central-station resources.

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[5] See U.S. Energy Information Administration (EIA), "Most states have Renewable Portfolio Standards," February 2012, http://www.eia.gov/todayinenergy/detail.cfm?id=4850.

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DER DEFINITIONS, IMPLICATIONS, AND "EARLY ADOPTERS"

DER is not a new issue for utility planners. As early as the late 1970s, and particularly in the 1990s, planners and researchers began to investigate potential impacts of DER on electricity systems and opportunities to use targeted DER as a system resource [17, 18, 19]. What has changed more recently is that, in some areas, DER adoption levels either have, or are anticipated to increase to the point where they become a significant part of electricity systems. Higher DER penetrations are being driven by a number of factors, including policy mandates, direct incentives, rate designs, interconnection policies, capital cost reductions, and technology performance improvements.

This section begins with basic DER definitions. It then explores the questions that higher DER penetrations now are raising related to bulk and distribution system resource planning, providing a framework for several regional case studies. It closes with an examination of DER policies and trends in three case study areas: California, Hawaii, and New York.

DER Definitions

DER is defined differently in different contexts. This report takes a broad definition of DER, focusing on resources that are connected to the distribution system. These include:

- *Distributed generation* (DG) – generation connected directly to the distribution system, including PV, wind, fuel cells, CHP, and gas-fired microturbines;
- *Energy efficiency* (EE) – permanent load reductions due to end-use efficiency improvements, such as through implementation of LED lighting programs;
- *Demand response* (DR) – temporary load reductions under capacity-constrained conditions, such as through interruptible load programs;
- *Flexible load / advanced DR* – temporary load increases or decreases under flexibility-constrained conditions, such as EV charging during times of high PV generation;[6] and,
- *Energy storage* – distribution-level or customer-side energy storage, including batteries and thermal energy storage.

Some DER technologies may extend across these categories. For instance, EVs can be viewed either as a flexible load or as a form of energy storage, depending on their operating characteristics. Although new retail rate designs are necessary to enable many of these resources, particularly flexible loads, rate design is not included as a separate DER in this report.

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[6] The definition of DER as distribution-connected resources excludes flexible loads that are directly connected to the bulk power transmission system.

DER Implications for Resource Planning

Where DER policies or penetrations have reached a critical threshold, they are beginning to raise six broad, interrelated kinds of questions for resource planners.

1. *DER Treatment: load modifier or supply resource?* – Should DER be treated as a power supply resource or as an adjustment to load?
2. *Adoption forecasting* – How should planners model DER adoption?
3. *Resource adequacy* – How should regulators and load serving entities account for DER in bulk and distribution system resource adequacy planning?
4. *DER as a resource* – Can DER be used as a bulk or distribution system resource to meet incremental resource and regulatory compliance needs? If so, how should it be evaluated and targeted?
5. *Distribution integration capacity* – How should different parts of the distribution system be evaluated for their ability to integrate DER?
6. *Operations* – How should DER operations (storage, EVs, other flexible loads, DG, DR) be treated in resource planning models?

Many of these questions are not new, but in regions where DER is expected to become a larger part of electricity systems they require new thinking about planning processes, methods, and tools. Even in jurisdictions where higher DER penetrations are not imminent, addressing two of these questions — DER adoption forecasting and DER targeting — is important to ensure utilities and regulators are prepared for sudden changes in DER deployment, and are maximizing the benefits of DER to all customers.

Although this report often uses the term "DER" generically, different kinds of DER technologies may have different implications for planning on different time horizons. In the nearer term, for instance, DG PV is the primary DER of interest to many utilities, whereas distributed energy storage and EVs may become more important planning considerations over the longer term. Behind-the-meter and wholesale DER — DG and distributed energy storage — can have very different implications for resource planning. The sections below clarify these distinctions, where applicable.

Early Adopters

The three case study regions chosen for this report — California, Hawaii, and New York — either already have, or are anticipating, high DER penetrations, but for different reasons. California has a large number of policies and programs focused around DER that have succeeded in driving higher penetration. Hawaii has very high penetration of DG PV, driven by high retail rates and incentives. New York's approach, under the Reforming the Energy Vision (REV) proceeding, is to create a competitive market platform for DER, although this proceeding is in its early stages and DER penetrations remain relatively low.

Although these states are on the forefront of DER deployment, many of the planning questions they face are useful references for states where DER is a more distant concern. Utilities and regulatory commissions have limited control over DER adoption. If not planned for in advance, rapid DER adoption can be disruptive, as illustrated in Hawaii.

California

California has a large and diverse electricity system that includes three large investor-owned utilities (IOUs), two large and a number of smaller municipal utilities, and a number of smaller utilities and co-ops. The California Independent System Operator (CAISO) operates a wholesale energy and ancillary services market that encompasses most of the state, and runs a state-wide long-term transmission planning process. The California Public Utilities Commission (CPUC) oversees a resource adequacy planning process, as well as utility EE and DR programs. The California Energy Commission (CEC), a policy and planning agency, provides electricity demand forecasts for resource planning and compiles load and resource tables.

The economic framework for DER is set largely through a combination of CPUC and legislative decisions and CAISO initiatives. The most important and relevant of these include:

- ***Distributed generation programs*** implemented through incentive programs (e.g., California Solar Initiative, Self-Generation Incentive Program, New Solar Homes Partnership), rate designs (net energy metering tariff), and interconnection policies.[7]
- ***Zero net energy (ZNE) standards for new buildings*** that require new residential construction to be ZNE by 2020 and new commercial construction to be ZNE by 2030. A ZNE building is defined as "… a building where the net of the amount of energy produced by on-site renewable energy resources is equal to the value of the energy consumed annually by the building" [20].
- ***Demand response initiatives*** aimed to better integrate DR into the CAISO energy markets and the CPUC's resource adequacy planning process.[8]
- ***Utility-sponsored energy efficiency programs*** with annual savings targets set by the CPUC.
- An ***energy storage mandate*** that requires the three IOUs to procure 1,325 MW of storage by 2020, 425 MW (32%) of which must be distribution-level and 200 MW (15%) of which must be customer-side [21].
- A ***distribution resource planning requirement*** that requires the three IOUs to develop Distribution Resources Plans (DRPs) which are intended to be blueprints for integrating DER into distribution operations, planning, and investment.[9]

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[7] CPUC, "Distributed Generation in California," http://www.cpuc.ca.gov/PUC/energy/DistGen/.

[8] For more on the CAISO's Demand Response Initiative, see CAISO, "Demand response," https://www.caiso.com/informed/Pages/StakeholderProcesses/DemandResponseInitiative.aspx. For more on DR in the CPUC's

[9] For more on these plans and the DRP proceeding, see CPUC, "Distribution Resources Plan (R.14-08-013)," http://www.cpuc.ca.gov/PUC/energy/drp/.

- *Aggressive zero emission vehicle (ZEV) goals* requiring 1.5 million EVs and fuel cell electric vehicles (FCEVs) on the road by 2025 [22].

These initiatives are expected to drive DER penetrations much higher over the next decade. For instance, state policymakers set a goal of 12 GW of DG by 2020. Separately, the CPUC and IOUs are targeting 16 terawatt-hours (TWh) of cumulative energy savings through implementation of EE programs between 2012 and 2020 [23], equivalent to 5% of forecasted 2020 demand.[10] Pacific Gas & Electric (PG&E) expects growth in DER will reduce peak demand by around 5-7 GW by 2020, and 7-12 GW by 2025;[11] for reference, the CEC forecasts PG&E's peak demand to be around 27 GW in 2022.[12]

Hawaii

Hawaii's electricity system is comprised of non-interconnected grids on six main islands, with load served by three vertically integrated IOUs — Hawaiian Electric Company (HECO, Oahu), Maui Electric Company (MECO, Maui, Lanai, Molokai), and Hawaii Electric Light Company (HELCO, Hawaii) — and one cooperative — the Kauai Island Utility Cooperative (KIUC, Kauai). The three IOUs are required to procure new and replacement generation competitively through independent power producers. The IOUs' IRP and procurement processes are overseen by the Hawaii Public Utilities Commission (HPUC).

A combination of high retail rates, policy support, and falling costs have led to a dramatic increase in DG ownership, dominated by DG PV, across the three IOU service territories, beginning in about 2010 (Figure 2-1). Oil products (fuel oil, diesel, and naphtha) accounted for 70% of Hawaii's electricity generation in 2014, contributing to retail rates that range from $0.35-$0.46/kWh and are the highest in the nation [26]. As PV prices fell, commercial and residential customers responded quickly to net energy metering (NEM) and state tax incentives by installing DG PV. By the end of 2014, 12% of Hawaii's residential customers had rooftop PV [26]. The three IOUs expect a tripling of DG PV capacity by 2030 [27].

In addition to DG, the utilities and HPUC have a number of other DER initiatives. These include Energy Efficiency Performance Standards (EEPS), which require the IOUs to meet cumulative energy savings targets equivalent to 30% of sales by 2030, and pilots for fast DR and distribution-level storage.

New York

New York has one of the oldest electricity systems in the U.S., combining sparsely populated rural areas with the country's largest and densest city. Five IOUs provide the majority of electricity service. The state also has one large municipal utility, the New York Power Authority (NYPA), and a large number of smaller municipal utilities.

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[10] Based on the CEC's 2013 final mid energy demand forecast of 305 TWh for 2020 [24].

[11] PG&E, 2015, "PG&E's Distribution Resources Plan Webinar," http://www.cpuc.ca.gov/NR/rdonlyres/9855FE35-90F5-4A67-8D35-DA5636FD443E/0/PGE_DRP_Webinar_final.pdf.

[12] Load forecasts are from [24].

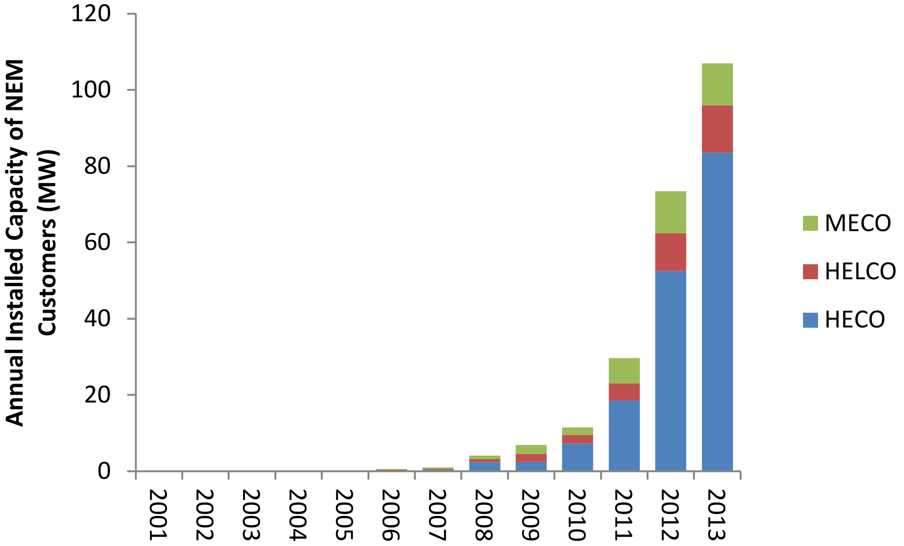

Figure 2-1
Installed Capacity of Customers with NEM Tariff, 2001-2013, HECO, HELCO, and MECO[13]

In 1996, the New York Public Service Commission (NYPSC) ordered the creation of competitive wholesale and retail electricity markets and the New York Independent System Operator (NYISO). NYISO operates energy, ancillary service, and capacity markets, and leads resource planning through its Comprehensive System Planning Process (CSPP).

The NYPSC, within the Department of Public Service (DPS), retains key regulatory functions, including ratemaking and policy initiatives. In April 2014, Governor Andrew Cuomo announced the REV initiative, designed to improve energy system efficiency, reliability, and resiliency by increasing deployment of DER (Figure 2-2). As part of REV, state policymakers are seeking to reshape the traditional roles of utilities and regulators, creating space for third-party DER providers and a market platform for distribution-level electricity service transactions.

More specifically, REV envisions utilities will transition from their traditional role as providers of centrally-generated electricity to distributed system platform providers (DSPP). In this role, utilities still would be responsible for maintaining reliable, affordable service, but they would assume additional responsibilities as operators of a distribution-level market platform, facilitating entry and participation by third-party DER providers. New revenue opportunities — for instance, through providing data analytics, customer acquisition, aggregation, and energy management services — would help to counteract declining volumetric sales.

Markets are seen as central to the achieving the REV goals of innovation and cost-effective solutions. DPS emphasizes that aligning market-based incentives with fair cost recovery for network providers will require significant changes in retail rates and DER compensation, grounded in six principles: (1) align earning opportunities with customer value; (2) maintain implementation flexibility; (3) provide accurate value signals; (4) maintain industry stability

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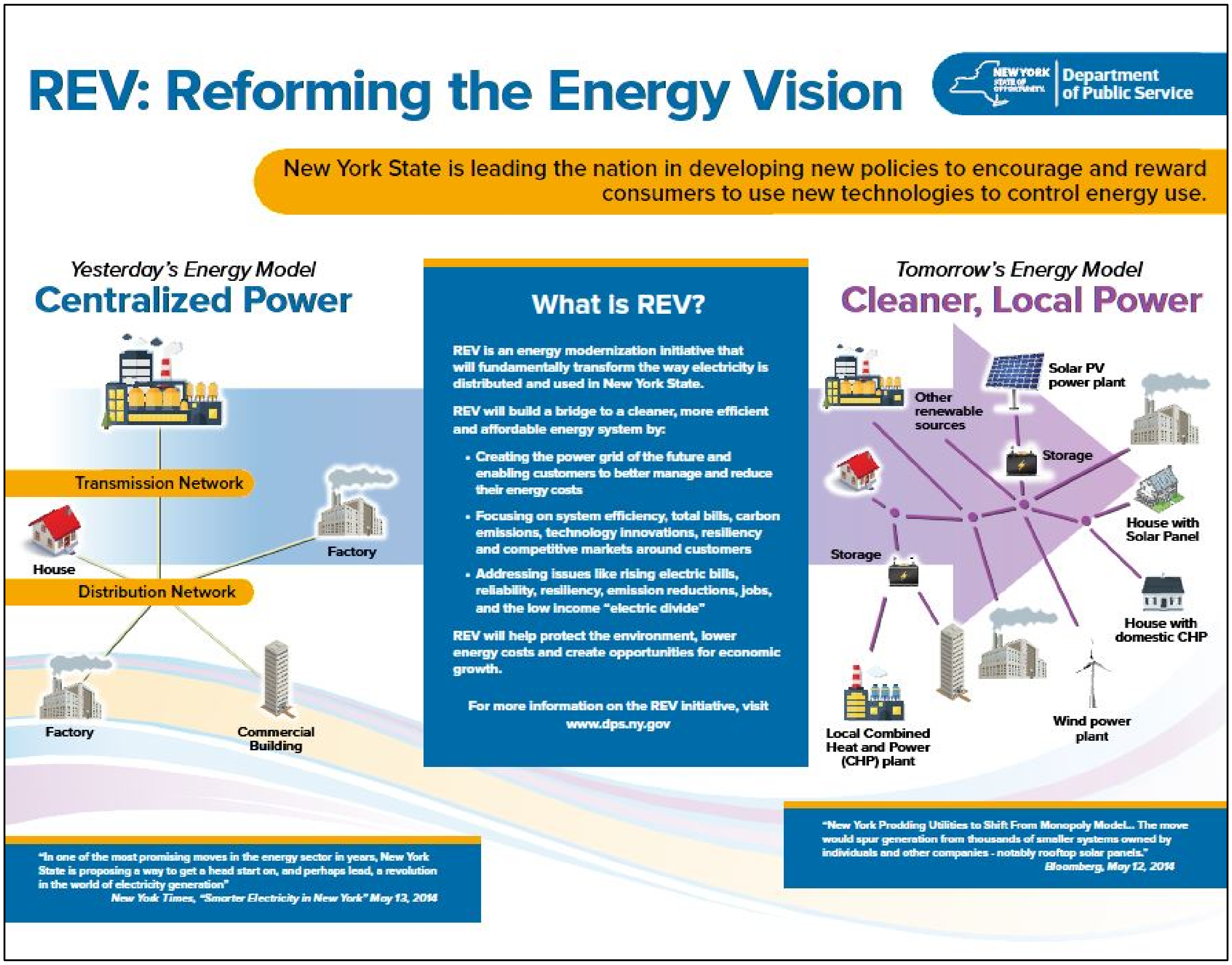
[13] Data are from [25].

through gradual transition; (5) shift from regulatory incentives to market incentives; and, (6) achieve public policy goals [28].



REV: Reforming the Energy Vision

New York State is leading the nation in developing new policies to encourage and reward consumers to use new technologies to control energy use.

What is REV?

REV is an energy modernization initiative that will fundamentally transform the way electricity is distributed and used in New York State.

REV will build a bridge to a cleaner, more efficient and affordable energy system by:

- Creating the power grid of the future and enabling customers to better manage and reduce their energy costs
- Focusing on system efficiency, total bills, carbon emissions, technology innovations, resiliency and competitive markets around customers
- Addressing issues like rising electric bills, reliability, resiliency, emission reductions, jobs, and the low income "electric divide"

REV will help protect the environment, lower energy costs and create opportunities for economic growth.

For more information on the REV initiative, visit www.dps.ny.gov

"In one of the most promising moves in the energy sector in years, New York State is proposing a way to get a head start on, and perhaps lead, a revolution in the world of electricity generation"
New Yok Times, "Smarter Electricity in New York" May 13, 2014

"New York Prodding Utilities to Shift From Monopoly Model... The move would spur generation from thousands of smaller systems owned by individuals and other companies - notably rooftop solar panels."
Bloomberg, May 12, 2014

Figure 2-2
DPS Diagram for REV[14]

New incentives under REV are expected to increase dramatically DER adoption in New York, but so far adoption has been small relative to California and Hawaii. Given its recent inception, many of the details related to rate and compensation reforms, as well as DER provider and utility business models, are still being worked out. By June 2016, utilities are required to submit Distributed System Implementation Plans (DSIPs), which will provide a five-year plan for how utilities plan to develop their roles as DSPPs, and which will be the first major step in the REV transition.

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[14] Diagram is from DPS website, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument.

3

CURRENT PRACTICE AND EMERGING ISSUES

DER policies and programs are, to different degrees, exerting pressure on traditional approaches to resource planning in California, Hawaii, and New York. This section explores current planning practices and emerging issues around the six key resource planning questions associated with DER described in section 2, with an emphasis on planning methods.

The three case study regions have different industry structures, are at different stages of DER deployment, and face different challenges. Thus, the approach here is to use examples selectively from each state to shed light on analytical challenges and adaptations, but not to systematically review how utilities and regulators in each state are responding to each of the key resource planning questions.

DER Treatment: Load Modifier or Supply Resource?

Historically, the most common approach to treating DER in resource planning was as a "load modifier," an exogenous adjustment to forecasted electricity demand. Before the late 2000s, DER consisted primarily of small amounts of EE and DR, and adjustment methods had a relatively minor impact on planning. Even as the diversity and scale of DER has grown, DER continues to be primarily treated as a load modifier in resource planning.

In theory, load modifier and resource treatment could converge on the same planning results and actual outcomes. In practice, however, because of the uncertainties associated with DER's future costs, its value to electricity systems, and operational impacts on those systems, different treatment will lead to different results. For instance, treating DER as a supply resource enables utilities and DER providers to more explicitly address performance risk, though doing so will generally lead to more sophisticated analyses. The sub-sections below describe some of the methodological differences that result from these different treatment approaches.

To some extent, industry structure affects DER treatment. For a pure vertically integrated utility, for instance, there may be greater obstacles to treating DER as a resource than in an organized wholesale market, because the former may lack a regular procurement process. Regardless of industry structure, however, the basic questions are the same: (1) what kinds of DER should be treated more like supply resources; and, (ii) what kinds of DER should be treated more like load modifiers, under what conditions, and on what basis?

This question of how to treat DER influences outcomes across resource planning, through its effect on the following elements:

- Value of DER capacity, or its bulk and distribution system reliability benefits;
- DER valuation and value proposition to different customers, which determine DER customer benefits of services provided to the grid;
- DER adoption, which is influenced by DER's value proposition; and,

- DER operational impacts, which are shaped by the location, speed, and magnitude of DER adoption and operators' ability to "see" and control DER.

For utilities and regulators, the decision to treat DER as a load modifier or as a resource likely will need to be based on which approach provides the most value to customers, weighing different considerations using a set of criteria. Table 3-1 provides an example of some possible criteria and tradeoffs to determine whether to treat a specific type of DER as a load modifier or resource. In general, resource treatment provides more accurate valuation, greater transparency, and flexibility, but comes with transition and transaction costs. These include the costs of setting up market rules for DER providers, additional metering and communications infrastructure, and changes to billing systems.

Table 3-1
Criteria and Tradeoffs for Treating DER as a Load Modifier or a Resource

Criterion	Characterization	
	Load Modifier	Resource
Capacity value and valuation accuracy	Generally less accurate	Generally more accurate
Flexibility to changes in supply and demand, and technology costs	Generally static	Can be dynamic
Transparency	Lower	Higher
Customer acceptance	Higher	Lower
Consistency with current practice	Higher	Lower
Consistency with longer-term policy	Could be lower or higher	Could be lower or higher
Transaction costs	Lower	Higher
Control over policy implementation	Generally more	Generally less

Today, the only DER that is regularly treated as a resource is DR, through its participation in wholesale electricity capacity markets (e.g., NYISO) or other market products (e.g., in CAISO). In both California and New York there has been a push to integrate more DER into wholesale markets through third-party aggregators. In New York, DER market integration has been a central part of discussions under the REV proceeding, but has not yet resulted in actionable proposals. In California, the CAISO is conducting a stakeholder process to develop a framework to allow distributed energy resource providers (DERPs) meeting a 0.5 MW minimum threshold to participate in its wholesale markets.[15]

The CAISO's process has highlighted some of the difficulties associated with treating behind-the-meter DER as a supply resources, including metering requirements, difficulties differentiating wholesale and retail rates, impacts on billing systems, and jurisdictional issues between system operators and regulators.[16] For instance, do all devices that are participating in a wholesale market need to be separately metered or sub-metered, and who should pay for

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[15] CAISO, "Expanding Metering & Telemetry Options – Phase 2 (distributed Energy Resource Provider or "DERP" proposal)," Stakeholder Web Conference, http://www.caiso.com/Documents/AgendaPresentation-DistributedEnergyResourceProvider-DraftFinalProposal.pdf.

[16] See, for instance, PG&E's comments on the CAISO's DERP proposal [29. 30].

additional metering costs? If a storage device is sub-metered behind a retail meter and is participating in a wholesale market, how should its market participation be isolated from retail activity for settlement and billing purposes? To avoid double counting, how should retail rates be designed for DG PV customers who are participating, through third-party aggregators, in wholesale markets? It is likely to be a longer term effort to address these questions and related issues.

DER Adoption Forecasting

Questions surrounding DER adoption cut across all of the themes in this section. For instance, how much DER should utilities count on for bulk system resource adequacy in long-term plans? When and where should they prioritize distribution network upgrades to support customer DER adoption? When should they begin to take measures to mitigate potential DER impacts on system operations?

Historically, DER adoption has not been large enough to warrant concern as a resource planning issue. Aside from their use in bottom-up load forecasting models, adoption models were generally not part of the resource planning toolkit. Where DER penetrations are expected to rise to more meaningful levels, the questions “how much,” “how fast,” and “where” are taking on greater salience, requiring new approaches to forecasting the magnitude, timing, and location of potential DER penetration.

The challenge of forecasting DER adoption is that adoption behavior depends on a diverse array of different factors, including geography (e.g., insolation), demographics (e.g., income), building type (e.g., single-family home), cost, technology performance, incentives, rate designs, and interconnection policies. Rates can be endogenous, in that high DER adoption can lead to changes in rates, which in turn influence adoption. Accurately forecasting location often is critical, particularly for distribution-level analysis. A useful modeling framework must be able to address how changes in technology, cost, income, policies, and rate design influence the magnitude, pace, and location of adoption over time.

Most emerging approaches to address these kinds of questions have used market diffusion adoption models (i.e., “S-curve” models), focused on projecting DG adoption. The “NEM public tool,” used in recent regulatory proceedings in California to evaluate and redesign the state’s NEM tariff for DG, provides an example of the general approach used in these models.[17]

The NEM public tool uses an iterative process with six main steps:

1) *Classify and aggregate customers into bins*. Aggregate customers into bins, based on key characteristics (e.g., utility, customer class, rates, climate zone, voltage level, electricity use, and other locational variables). Aggregating to bins with a single representative

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[17] The CEC uses a similar approach to forecast DG PV, residential solar hot water heater, and commercial CHP adoption [18]. Both this and the NEM public tool draw on methods used in the National Renewable Energy Laboratory’s (NREL’s) Solar Deployment System (SolarDS) model [31]. For a more detailed description of the NEM public tool, see CPUC, “Renewable Customer-Generation Successor Tariff or Contract,” http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm.

customer allows for dealing with data gaps, where DER is not separately metered, and reduces computational requirements.

2) *Develop generation and load profiles*. Use metered data simulation tools, and other existing data to develop location-specific hourly or sub-hourly load and generation profiles for each customer bin, using a range of different DER sizes. Generally, this process begins with hourly or sub-hourly DG output, either metered or simulated where metered data is not available.[18] Monthly gross consumption can be forecasted with existing customer data, and scaled to an hourly load shape using metered data or load research data.

3) *Calculate customer benefit-cost ratio*. Calculate present value benefits and costs for each customer bin and DER size. Customer benefits from the DG system include incremental revenues (e.g., as with a feed-in tariff) or bill savings (e.g., as with a NEM tariff). DG system costs may be unfinanced, financed, leased, or paid through a power purchase agreement (PPA). Use benefit-cost (B/C) ratios to determine the most cost-effective system size for each customer bin, by choosing the system size that results in the highest B/C ratio for that bin.

4) *Calculate market saturation levels*. Convert the benefit-cost ratios into discounted payback periods, by dividing present value costs by annualized present value benefits.[19] Use assumed functional relationship between payback period and market saturation to calculate market saturation levels,[20] which is the highest possible level of adoption (e.g., 50% of households). Adjust the market saturation levels for technical potential.

5) *Calculate annual adoption*. Use an S-curve, scaled by market saturation level, to determine the annual and cumulative share of customers in each bin adopting a given DG technology in each year (Figure 3-1). Multiply this share by the number of customers and DG system size by bin, and sum across bins, to calculate annual installed capacity.[21]

6) *Adjust input parameters and repeat from step 3*. To account for endogenous input changes, such as rate or cost changes, adjust inputs based on results and re-calculate benefit-cost ratios, discounted payback period, market saturation level, and annual adoption for the next year.

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[18] DG output can be simulated using off-the-shelf tools (e.g., the PVWatts Calculator for solar PV) or with renewable resource data (e.g., solar irradiance) and first principles.

[19] The discounted payback period (DPP) is equivalent to one divided by a capital recovery factor (CRF) multiplied by the benefit-cost ratio (BCR), where BCR is the present value of benefits divided by the present value of costs.

$$DPP = \frac{1}{CRF \times BCR}$$

[20] The NEM public tool uses the exponential relationship in [31], where the market saturation level (MSL) increases with decreasing payback time (PT), and payback time is scaled by a sensitivity parameter (PS)

$$MSL = e^{-PS \times PT}$$

[21] There are a number of S-curves commonly used in adoption models. The NEM public tool and CEC use a Bass diffusion model, consistent with [31].

Step 6 in this process is relatively unique among adoption models. This iteration allows the model to incorporate changes in rates and costs that are driven by DG adoption, and will in turn influence adoption in later periods.

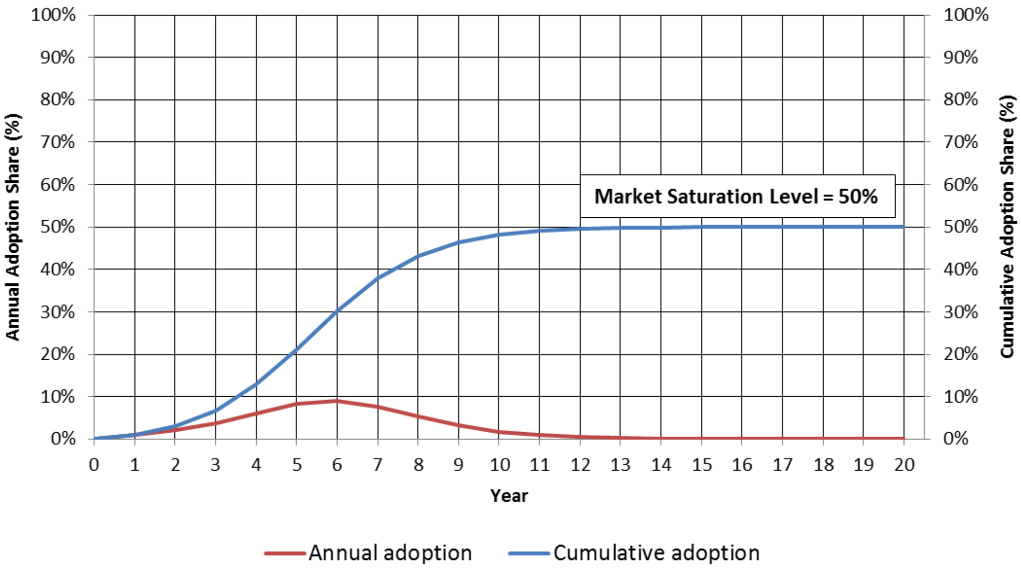

Figure 3-1
Illustrative Example of Annual and Cumulative Adoption Shares using S-Curve with 50% Market Saturation Level

Although the use of market diffusion models of adoption has thus far focused on DG, in principle they can be expanded to a wider range of DER technologies, including energy storage and EVs. The approach described above, however, is subject to significant uncertainty in its input assumptions (e.g., costs, demographics), underlying assumptions (e.g., to what extent does discounted payback drive adoption?), and curve parameterization (e.g., scaling parameters in S-curves). The “public tool” approach to adoption modeling can help to manage some of this uncertainty, by making input assumptions and methods transparent to stakeholders. In addition, validating and bounding uncertainty in these models will be an important area of work going forward.

An alternative approach to forecast DER adoption is to use discrete choice regression models (e.g., logit, probit). In these models, the probability of adoption of a given system (i.e., dependent variable) for a region, customer group, or individual customer is estimated based on a number of potential adoption drivers (i.e., independent variables). The advantage of these models is their greater explanatory power, particularly if factors other than discounted payback are driving adoption. Their disadvantages include: (1) they may require additional data collection and survey work to give them a clearer advantage over diffusion models; and, (2) they are not as capable of capturing endogenous change.

Resource Adequacy

Generally, grid-connected DER can contribute some amount to bulk system resource adequacy. However, typical characteristics of DER — limited dispatchability, output uncertainty, and, in some cases, variability — make its capacity value more difficult to account for than traditional central-station resources. Higher penetrations of DER also raise longer-term questions about the effectiveness of planning bulk system resource adequacy around a small number of peak demand hours, as potential reliability issues no longer will be confined to these hours.

DER Capacity Value

Regardless of whether DER is treated as a resource or load modifier, assessing its impact on bulk system reliability requires methods to determine its capacity value. For both dispatchable and non-dispatchable resources, three main factors affect this value: (1) coincidence with system peak, (2) location; and, (3) technology. Capacity value for *non-dispatchable* DER also is influenced by generation or consumption uncertainty and variability, and the system's existing quantity of variable resources. Capacity value for *dispatchable* DER depends on the number of times a resource can be dispatched, the duration of each dispatch, and its outage rate.

In much of North America, system planners determine system-wide and local DER capacity values by using historical approximations or rules-of-thumb to de-rate nameplate capacity. For instance, NYISO estimates the capacity value of DG PV by using historical capacity factors during peak hours [32]. For energy storage, the CPUC assumes a capacity value de-rate of 50% for distribution-level energy storage and 100% for customer-side energy storage in its long-term procurement plan [33].

While these kinds of heuristic approximations are simple and reasonably accurate at lower DER penetrations, they generally decrease in accuracy as penetrations increase. For variable DG and other dispatch-limited resources, a key issue to be considered is that higher penetrations lead to diminishing capacity values. Figure 3-2 illustrates this concept for DG PV. Higher DG PV penetrations, shown in 6 GW increments, shift the timing of peak demand (the x's), from early afternoon to late evening. Each 6 GW increment of PV reduces peak load by a smaller amount. By 18 GW, additional DG PV has no impact on peak load, and thus has a marginal capacity value of zero.

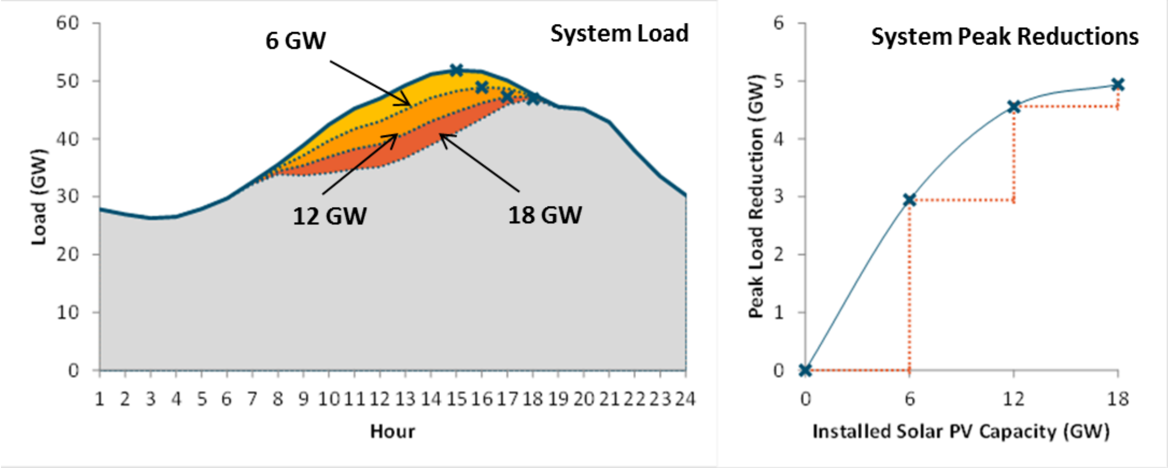

Figure 3-2
Illustration of the Diminishing Marginal Value of DG PV
(Note: Capacity values shown in the figure on the left refer to installed solar PV capacity, and point to corresponding load *net* of solar PV on the Y-axis.)

Location and technology are also critical determinants of DER capacity value. For instance, a dual tracking DG PV system in "Rain City" Seattle will have a much *higher* capacity value than a fixed axis system in sunny Los Angeles, because of its higher correlation with load and tracking ability [34]. Residential lighting efficiency improvements in a congested part of the grid generally will have higher capacity value than residential refrigeration efficiency improvements in an uncongested part of the grid, because of the former's higher correlation with load and value in reducing congestion.

Accurately reflecting DER capacity values becomes more material at higher penetrations. By not including DER as a capacity resource, utilities may over-procure generation capacity and over-spend on transmission and distribution upgrades, leading to higher customer costs. By using heuristic approximations, utilities may under-procure capacity, leading to reliability issues. The capacity value of DER already has become a contentious issue in resource planning processes in California and New England.[22]

A number of reliability-based approaches have emerged to address these kinds of bulk system capacity valuation issues [34, 37, 38]. Of these, the most widely discussed thus far has been effective load carrying capability (ELCC).[23] The ELCC method was developed in the 1960s, but has not been widely used as a metric in resource planning. In 2011, the California legislature ordered the CPUC to begin using ELCC to calculate the capacity value of both utility-scale and distributed solar and wind resources, although state agencies are still refining the methodology for doing so [39].

ELCC consists of three main steps:

1) Calculate the LOLE of the existing generation fleet using the formula shown below, where $LOLE_0$ is a base LOLE, P is the probability function, G_h is available existing generation, adjusted for forced outages, in hour h, and L_h is load in hour h.

$$LOLE_0 = \sum_h P(G_h < L_h)$$

2) Add DG resource, and recalculate LOLE using the formula shown below, where DG_h is DG output in hour h. The addition of the DG resource will reduce LOLE (i.e., $LOLE_1$ will be lower than $LOLE_{0)}$.

$$LOLE_1 = \sum_h P(G_h + DG_h < L_h)$$

3) Add a constant to load in each hour using the formula shown below, until the LOLE is equal to its original value (i.e., $LOLE_1$ is increased to $LOLE_0$ again), where LC_h is the

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[22] See, for instance [35, 36].

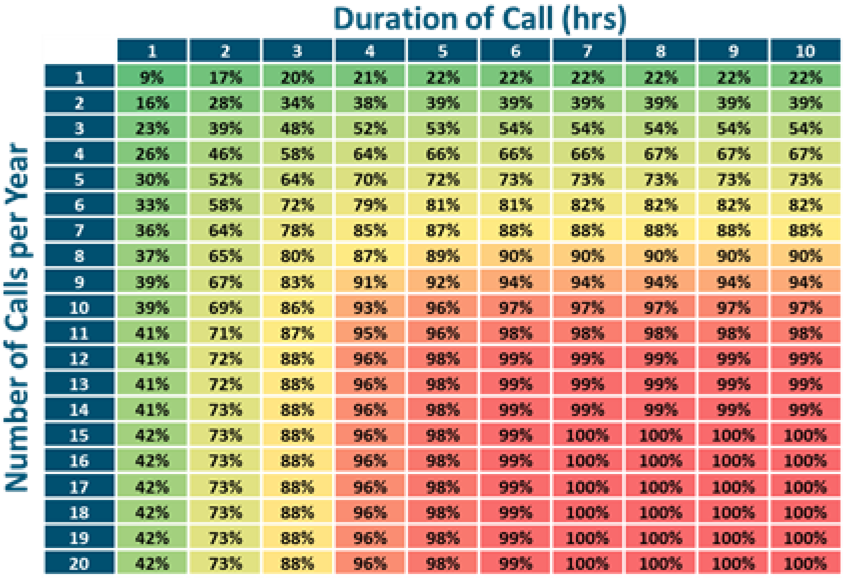
[23] Other, less widely discussed reliability-based approaches include equivalent conventional power (ECP) and equivalent firm capacity (EFC) [34].

load constant added in each hour h. The sum of LC_h is the effective load carrying capacity of the DG resource.[24]

$$LOLE_0 = \sum_h P(G_h + DG_h < L_h + LC_h)$$

The ELCC approach can be applied to other types of DER as well. For DR, for instance, this consists of two steps. First, an hourly load shape for a DR resource is added to the left hand side of the inequality in step two (i.e., instead of DG_h), and a load constant is added in a similar manner to the right hand side. The resulting value is the DR resource's *availability factor*, measuring its availability.

Second, based on the dispatchability of the resource, in terms of maximum frequency (calls) and duration (hours), the availability of the resource is de-rated by a *dispatchability factor*. This factor is calculated using an hourly loss-of-load probability (LOLP) table, with values normalized to 100%. For a DR resource that is limited to one call for a duration of one hour, its dispatchability factor is the highest value in the normalized LOLP table. For one call for a duration of two hours, the dispatchability factor is the sum of the highest LOLP value in the table and the higher of the two LOLP values beside it. For two calls of one hour each, the dispatchability factor is the sum of the two highest values in the table; and so on. Using this algorithm, a dispatchability factor table can be constructed, illustrated in Figure 3-3.



	Duration of Call (hrs)									
Number of Calls per Year	1	2	3	4	5	6	7	8	9	10
1	9%	17%	20%	21%	22%	22%	22%	22%	22%	22%
2	16%	28%	34%	38%	39%	39%	39%	39%	39%	39%
3	23%	39%	48%	52%	53%	54%	54%	54%	54%	54%
4	26%	46%	58%	64%	66%	66%	66%	67%	67%	67%
5	30%	52%	64%	70%	72%	73%	73%	73%	73%	73%
6	33%	58%	72%	79%	81%	81%	82%	82%	82%	82%
7	36%	64%	78%	85%	87%	88%	88%	88%	88%	88%
8	37%	65%	80%	87%	89%	90%	90%	90%	90%	90%
9	39%	67%	83%	91%	92%	94%	94%	94%	94%	94%
10	39%	69%	86%	93%	96%	97%	97%	97%	97%	97%
11	41%	71%	87%	95%	96%	98%	98%	98%	98%	98%
12	41%	72%	88%	96%	98%	99%	99%	99%	99%	99%
13	41%	72%	88%	96%	98%	99%	99%	99%	99%	99%
14	41%	73%	88%	96%	98%	99%	99%	99%	99%	99%
15	42%	73%	88%	96%	98%	99%	100%	100%	100%	100%
16	42%	73%	88%	96%	98%	99%	100%	100%	100%	100%
17	42%	73%	88%	96%	98%	99%	100%	100%	100%	100%
18	42%	73%	88%	96%	98%	99%	100%	100%	100%	100%
19	42%	73%	88%	96%	98%	99%	100%	100%	100%	100%
20	42%	73%	88%	96%	98%	99%	100%	100%	100%	100%

Figure 3-3
DR Dispatchability Factors as a Function of the Number of Calls per Year and Duration of Calls

The value in row 1, column 1 (9%) reflects a DR resource that can be called once per year for one hour, and corresponds to the highest value in the normalized LOLP table. The value in row 2, column 1 (16%) reflects a DR resource that can be called twice per year for one hour per call,

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[24] An equivalent approach is to subtract DG_h from L_h to calculate net load (step 2), and then add the load constant to the right hand side of the less than sign in step 3.

and corresponds to the sum of the two highest values in the normalized LOLP table. The value in row 1, column 2 (17%) reflects a DR resource that can be called once per year for two hours, and corresponds to the sum of the highest value in the normalized LOLP table and the highest value adjacent to it; and so on. As the number and duration of calls increase, the dispatchability factor increases to 100% (i.e., fully dispatchable). The equivalent ELCC of a DR resource is its availability multiplied by its dispatchability factor.

ELCC can be used to evaluate the reliability impacts of a marginal resource, or a portfolio of DER resources. If the portfolio includes non-dispatchable resources, ELCC values for a portfolio generally will be higher than those for the individual resources, due to resource diversity. Currently, there are neither standard nor rigorous ways to allocate portfolio capacity values to individual non-dispatchable resources.

Multiple models have been used to calculate ELCC for variable renewable resources, differing in their level of detail and computational requirements. For example, the CPUC plans to use a stochastic reliability simulation model (SERVM) to calculate ELCC values for renewable energy resources as part of RPS procurement. Other commonly used reliability simulation models include GE-MARS and RECAP/REFLEX. These models incorporate the stochastic nature of weather- and generator performance-related uncertainty either by simulating a large number of weather years, or by drawing loads, generator outages, and solar, wind, and hydro output from a statistical distribution [40].

A unique issue associated with DER is the potential conflict between resources used at a bulk system level and distribution level. For instance, storage resources dispatched to relieve constraints at a distribution level may not be available physically or contractually available to provide capacity or ancillary services at a bulk system level. In this case, system capacity values must be reduced to account for the storage resources' reduced availability at a system level.

Potential Challenges to the Bulk Planning Paradigm

A longer-term issue that already has begun to emerge in California around DER and renewable energy more broadly is the continued effectiveness of planning bulk system reliability around a peak demand forecast and a reserve margin. For instance, the CAISO has argued this approach is no longer sufficient to maintain bulk system reliability [41]. Going one step further, a recent NREL paper argues higher solar PV penetrations will require planning to shift away from a focus on peak demand to a focus on energy demand [42].

At higher levels of DER penetration, resource adequacy planning must ensure the following conditions at a minimum are met: (1) dispatchable resources are sufficient to meet net load (i.e., gross load minus non-dispatchable resources) – in all hours with non-negligible LOLP; (2) dispatchable and non-dispatchable generation are sufficient to meet energy demand over a planning horizon; and, (3) system flexibility is sufficient to economically balance supply and demand.

Traditional planning tools already have the capacity to analyze the first and second of these conditions, though planning would need to shift away from using rules-of-thumb toward a more data rich, computationally-intensive approach embodied in tools like ELCC. The third condition requires development of new frameworks and tools, discussed briefly in the *Operations* subsection below.

DER as a Supply Resource

The notion of using DER as a resource to offset traditional bulk and distribution system investments dates back to the late 1970s. Efficient use of DER, in a manner that provides value for all customers, requires accurate valuation. With local DER valuation that accounts for both bulk and distribution system-level benefits, DER can be targeted to where it has the most system value. More recently, the potential to use DER as a means to comply with state RPS mandates and the federal CPP have become related areas of interest to utilities, regulators and stakeholders.

Valuing and Targeting DER

The system benefits provided by DER, both at bulk and distribution system levels, typically are calculated using an avoided cost framework. Avoided cost approaches to valuing DER in power systems date to the 1980s, and were documented systematically in the CPUC's *Standard Practice Manual* in 1983.[25] Traditionally, avoided costs consisted of six components:

1. Avoided energy;
2. Avoided or deferred generation capacity;
3. Avoided ancillary services;
4. Avoided transmission and distribution (T&D) losses;
5. Avoided or deferred T&D capacity; and,
6. Avoided emissions.

Over time, the number of avoided cost components has grown to include other elements such as energy security, market price mitigation, economic development, avoided RPS expenditures, fuel hedge value, flexible resource adequacy procurement value, voltage and power quality, system resiliency, renewable integration benefits, and public safety. What is included in the calculation of avoided costs varies significantly across jurisdiction and analyses, as illustrated in Figure 3-4, which shows "value of solar" estimates for DG PV by value component and state.

The need for a more systematic and transparent approach to calculate the value of DER benefits and costs has been a key driver for the DRP proceedings in California and the REV proceedings in New York. Although these proceedings are proposing eventually to use very different approaches to DER valuation and compensation, utilities in both California and New York currently use similar avoided cost frameworks to assess DER benefits.

There are a number of general references for avoided cost methodologies. The focus here is on methods for DER targeting. For targeting, the two most important benefits are cost savings from (i) avoiding transmission congestion and line losses, and (ii) deferring or avoiding distribution system investments triggered by load growth. In nodal markets, locational marginal prices (LMPs) can be used to calculate avoided congestion and line losses, or these can be estimated using nodal production simulation models.

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[25] For an updated version, see [43].

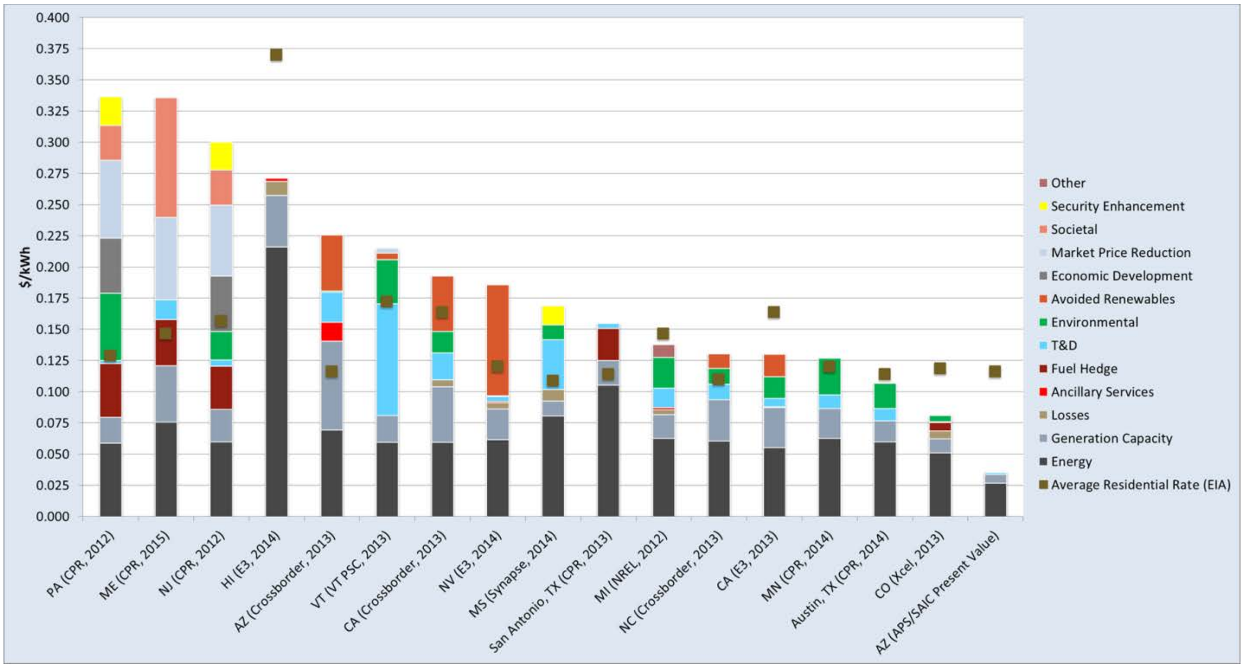

Figure 3-4
Value of Solar Estimates by Avoided Cost Component and Jurisdiction[26]

Utilities in both California and New York use the five-step process described below to calculate the value of DER for deferring or avoiding distribution system investments triggered by load growth.

1) *Calculate deferral and avoided cost values*. Using base load forecasts and a forward-looking investment plan, calculate deferral and avoided cost values at an appropriate level of spatial aggregation. This requires assessment of the kinds of costs that can be deferred or avoided (e.g., deferrable equipment costs versus non-deferrable land costs), and the timing and cost of viable investment deferrals. Typically, distribution deferral values are estimated using the present worth method [44], or the financial savings from delaying an investment. Avoided costs are the levelized cost of avoiding an investment. Deferral and avoided cost values vary significantly across distribution systems and utilities, as illustrated for avoided costs in Figure 3-5.

2) *Determine peak demand reductions from DER*. Bulk system approaches for determining resource adequacy, discussed previously, are not appropriate at the distribution level. Distribution-level capacity values can be calculated by estimating DER coincidence with forecasted distribution system loads, using a peak capacity allocation factor (PCAF) method. With this method, a threshold for high load hours in each year is estimated as distribution peak load minus one standard deviation of distribution load for the year. The area between the load duration curve and the threshold is a proxy for peak energy demand (Figure 3-6).

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[26] Figure based on estimates compiled by Energy and Environmental Economics (E3).

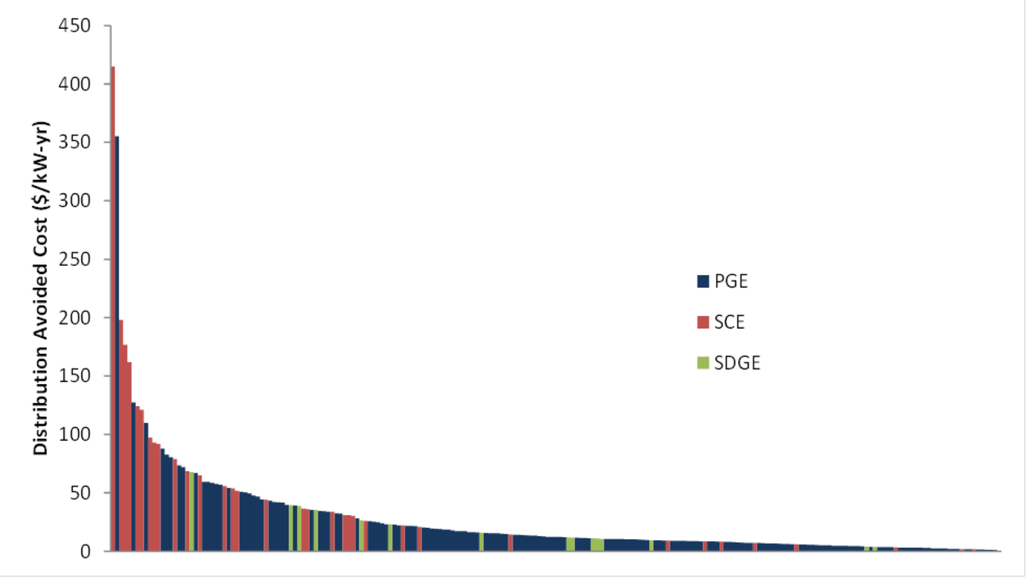

Figure 3-5
Distribution System Avoided Costs by Substation for California IOUs[27]

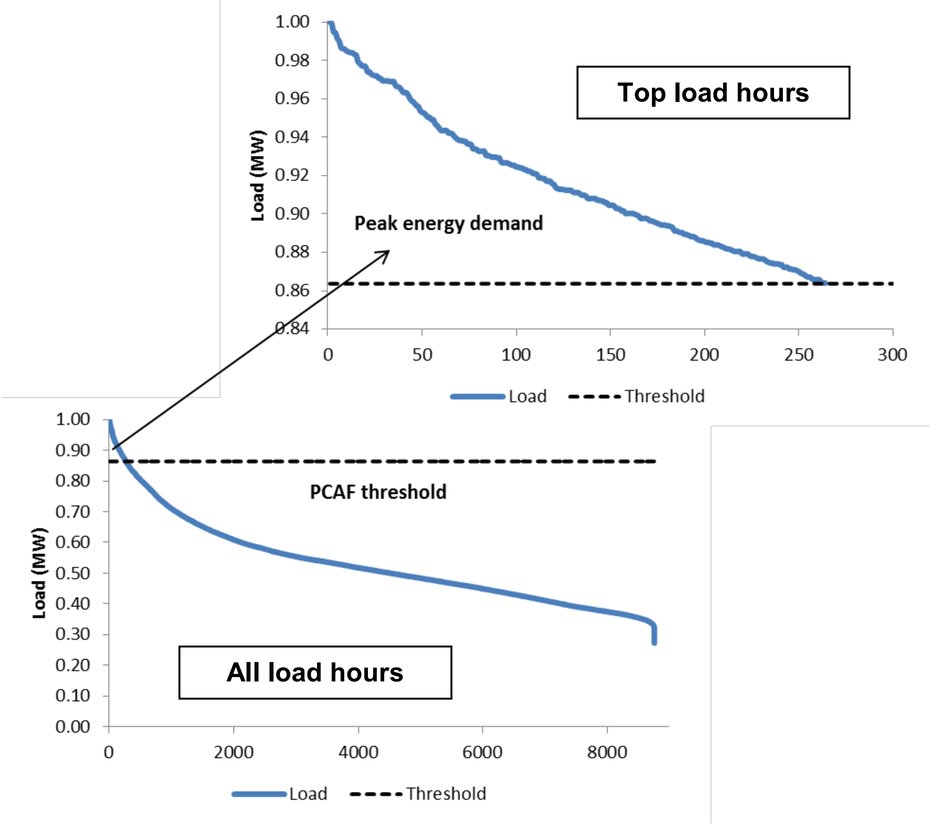

Figure 3-6
Illustrative PCAF Threshold and Peak Energy Demand for 1 MW Peak Load System

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[27] Figure is from [45].

The PCAF in a given year and hour ($PCAF_{y,h}$) is that hour's share of total peak energy demand in that year.

$$PCAF_{y,h} = \frac{Max\left(0, Load_{y,h} - Threshold_y\right)}{\sum_h Max\left(0, Load_{y,h} - Threshold_y\right)}$$

Peak demand reductions from DER in a given year ($PDER_y$) are calculated by multiplying the DER profile ($DER_{h,y}$) by the PCAF

$$PDER_y = \sum_h DER_{h,y} \times PCAF_{h,y}$$

3) *Determine dependable DER output*. "Dependable output," accounting for DER availability, is determined by using a de-rate factor based on the probability of coincidence between the DER resource and distribution load. For non-dispatchable resources, this factor typically is based on a rule that indicates how likely the resource will be available in a given hour. For instance, planners may insist that a resource be fully available 97% of the time in a given hour to be given distribution capacity value in that hour. Based on this rule, new DER profiles and peak demand reduction values can be calculated. For dispatchable resources, de-rate factors are based on the dispatchability of the resource, accounting for limitations on the frequency and duration of dispatch (e.g., number and duration of calls for DR). They must also account for conflicts between dispatching against bulk and distribution system loads (e.g., storage providing bulk system AS may not be available to be dispatched during distribution peaks).

4) *Determine deferrable or avoidable investments*. This determination requires risk assessments and rules to determine the amount and timing of peak load reductions from DER required to defer or avoid an investment. Key questions that need to be addressed in this regard include the following. To what extent do reductions in load need to be demonstrated before deferring or cancelling an investment? What margin is required to be built into DER adoption forecasts associated with a program to ensure it can achieve the full peak reduction needed to defer or avoid an investment? These kinds of rules are still evolving.

5) *Update PCAFs and DER profiles regularly*. Regular updates to the PCAFs incorporate changes in net load over time. This will help to account for the diminishing marginal capacity value of non-dispatchable DG at higher penetration levels, and the higher value of bundled DG and energy storage.

Avoided costs form the basis for valuing the benefits of DER. For addressing the costs and cost-effectiveness of DER, approaches differ for programmatic expenditures (e.g., incentives) and procurement. For the former, utilities typically incorporate DER costs based on internal forecasts and determine cost-effectiveness using one of five main cost test perspectives: (1) participant, (2) utility, (3) ratepayer, (4) total system, and (5) society. The latter involves an evaluation of net market benefits, or an assessment of benefits minus a cost bid, as part of a request for offers. The least-cost best-fit (LCBF) method, designed for RPS procurement in California, also has been used for DER procurement by the state's IOUs.[28]

Within a programmatic context, utilities historically have evaluated EE, DR, DG, and storage resources separately under different programs, although more recently this approach has begun to change. In California in 2009, the CPUC asked the IOUs to explore more integrated approaches to demand-side programs and projects, culminating in the DRP process. In New York, Consolidated Edison Company (Con Edison) has operated a Targeted Demand Side Management (TDSM) program since 2004, focused on targeting energy efficiency investments to reduce distribution peak loads. In 2014, the company supported the development of a tool — the Integrated Demand Side Management (IDSM) Potential Model — to optimize DER investments across resources [47]. This tool selects an optimal DER portfolio over time, based on iterative ranking of DER options based on benefit-cost ratios, which leads to creation of an "optimal" investment plan (Figure 3-7). Iteration allows for the tool to account for changes in load shapes and values with higher DER penetrations.

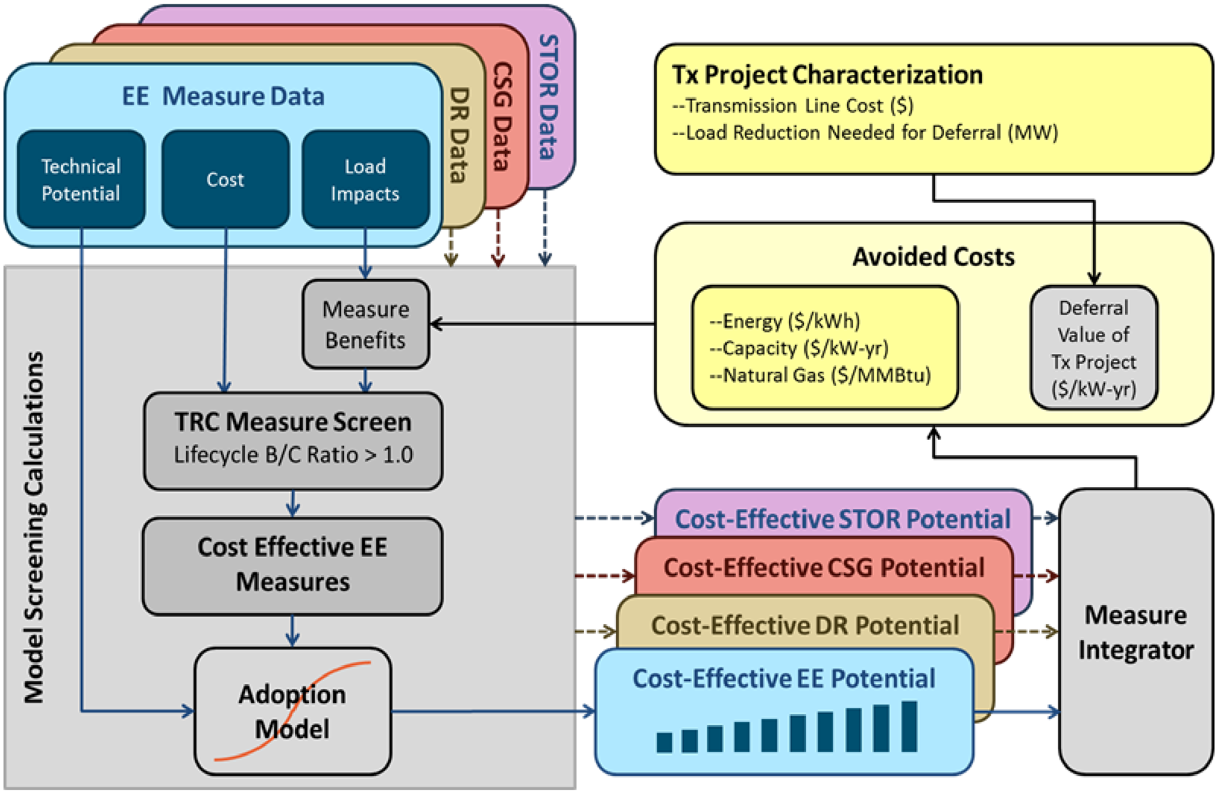

Figure 3-7
High-level Model Process for IDSM Model

How the economic benefits identified through these valuation processes are to be compensated remains an open question in both California and New York. As part of the DRP progress in California, the IOUs were requested to recommend changes to retail rates and compensation mechanisms to support cost-effective DER deployment. In New York, the REV process

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[28] For more on LCBF methods, see [46].

envisions eventually decentralizing both the evaluation of benefits and costs to DER providers through rate designs.

DER for Compliance with RPS and CPP

The two most important areas for which DER can be used for compliance are RPS requirements, involving only renewable DG, and the CPP, involving DG and energy efficiency. Whether renewable DG is allowed to count toward RPS goals varies by state. For instance, in California renewable DG does not count towards RPS compliance, but in New York and Hawaii it does.[29] In the latter cases, utilities use estimates of DG generation for compliance purposes — DG used for RPS compliance does not need to be separately metered.

In October 2015, the U.S. Environmental Protection Agency (EPA) published final regulations to reduce CO_2 emissions from *existing* fossil-fired electric power plants under §111(d) of the 1990 Clean Air Act (CAA). The final CPP creates national uniform emission rate standards for two subcategories of electricity generating units (EGUs): (i) a rate of 1,305 lbs CO_2 per net MWh for steam generating units (i.e., coal-, oil-, and gas-fired boilers); and (ii) 771 lbs CO_2 per net MWh for natural gas-fired combined cycle units (NGCCs).

The EPA derived these emission rates by assessing the emissions reductions achievable using three so-called “building blocks” that comprise the “best system of emissions reduction” (BSER): (i) heat rate improvements at existing coal-fired units; (ii) replacement of higher-emitting steam generation with lower-emitting generation from NGCC units; and (iii) replacement of fossil fuel-fired generation with generation from zero-emitting renewable resources.

On the basis of these emission rate standards, the CPP creates state-specific goals to reduce CO_2 emissions from existing fossil-fired power plants. Each state’s goal is expressed both as an emissions rate (lbs CO_2/MWh), and as an absolute mass (tons CO_2) that is allowed to be emitted from existing EGUs. Each state can choose to comply with the CPP either on a rate or a mass basis. These goals must be achieved by 2030, with initial interim compliance required in phases starting in 2022.

Although the EPA did not use DG and EE to calculate BSER or the state rate or mass goals, both DG and EE can be used for CPP compliance if a states chooses to pursue these approaches in the state-specific CPP compliance plan that must be submitted to, and approved by, the EPA. States are required to present Evaluation, Measurement, and Verification (EM&V) plans and M&V reports to the EPA. The final CPP suggests EM&V designs could build off the existing compliance infrastructure developed around RPS and EE programs [16].

Integration Capacity Limits

Although additional DER may defer the need for distribution investments in some cases, in other cases additional DER — particularly DG and EVs — may require distribution upgrades to be made to accommodate increased penetration. Thus, the DER integration capacity limit of distribution substations and feeders is a useful metric for planning. Knowing these limits can

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[29] In New York, distributed renewable generation is covered under the Customer-Sited Tier, which is has a separate goal under the state’s RPS program.

help utilities to plan for distribution investments, encourage DER where spare capacity exists, update interconnection rules over time, and provide greater transparency to DER providers on interconnection schedules and costs.

Historically, utilities and regulators have determined interconnection capacity limits based on rules-of-thumb. For DG, these limits are intended to prevent overloading and backflow, where power flows from a distribution feeder back into the bulk system and may compromise protection systems. For instance, in California, interconnection rules limit generators that can bypass interconnection study requirements to 15% of peak load on a distribution substation or feeder. In Hawaii, they are based on the DG share of gross daily minimum load on a feeder [48]. These heuristics provide a useful basis for screens.

California's DRP process seeks to improve upon this approach by requiring IOUs to determine explicitly the ability to integrate additional DER on individual distribution substations and feeders based on its impact on thermal loading, system protection components, power quality, and safety. These integration capacity analyses are intended to balance the accuracy of more detailed studies and the speed of fast-track screens. The result of the analysis is a series of local capacity values that indicate the levels for each substation or feeder at which further interconnection studies would be needed.

PG&E's proposed integration capacity analysis (ICA) approach consists of four main steps:

1) *Determine the appropriate level of granularity* — substation, feeder, or line section. PG&E chose line section as the appropriate level in its ICA, to capture the effects of distribution topology.
2) *Develop hourly load and generation profiles for each distribution feeder*. These provide a basis for screens, and for use as inputs to more detailed power flow modeling.
3) *Model system impacts using power flow analysis*. PG&E used commercial distribution system analysis software (CYMDIST), with some customization, to organize data outputs.
4) *Evaluate results against criteria*. Publish results for each specified level of granularity and DER type.

Given the expanse of distribution systems, ICA is a non-trivial exercise. For instance, PG&E has 785 distribution stations, 3,000 distribution feeders, and analyzed roughly 102,000 line sections.[30] PG&E's proposed approach manages this complexity using software. An alternative approach proposed by Southern California Edison (SCE) is to model a sample of part of the distribution system in detail, and then extrapolate the results to other parts of the system [49].

Operations

Increased DER penetrations have the potential to change power system operations significantly, shifting from an operating model in which loads and generator availability are relatively certain,

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[30] PG&E, 2015, "PG&E's Distribution Resources Plan Webinar," http://www.cpuc.ca.gov/NR/rdonlyres/9855FE35-90F5-4A67-8D35-DA5636FD443E/0/PGE_DRP_Webinar_final.pdf.

to one in which both are more variable and uncertain. For resource planning, incorporating these new sources of variability and uncertainty requires new approaches to: (1) screening tools that identify the nature and timing of future operating conflicts and potential solutions; (2) production simulation models that incorporate the stochastic nature of DG PV and wind, the operating limits of distribution-level energy storage, and accurate representations of DER load shape impacts; (3) pilot projects to better understand the potential flexibility of loads like EVs; and (4) interconnection standards to enable DER to be integrated more effectively into long-term planning.

Consistent with the "load modifier" approach described previously, planners typically have assumed DER will have no appreciable impact on bulk system operations. As penetrations increase, this assumption no longer holds true. This fact has been most clearly illustrated in Hawaii, where DG PV already is creating operating challenges, driven in large part by the fact that DG PV was not visible to, or controllable (curtailable) by, local utilities until recently.

To examine the scope and nature of these challenges, a recent study for the HPUC and utilities employed a combination of screening tools and more detailed production simulation analysis.[31] The screening tool sought to provide a clear, intuitive sense of a range of key system drivers, capturing key system constraints without the need for more computationally intensive optimization. The production simulation analysis was used to verify results obtained using the screening tool.

Consistent with a trend in analyzing high renewable penetration electricity systems, both the screening tool and production simulation modeling used probabilistic (i.e., stochastic) resource and load profiles. This approach, in contrast to deterministic profiles, is important to capture weather-driven variability in resources and loads. A larger data set of resources and loads was created by classifying 55 years' worth of solar and load data by season, temperature, weekend, and weekday into bins, and sampling matching solar and load days (Figure 3-8).

The screening study sought to identify at a high level the operational challenges associated with higher penetrations of DG PV, and potential cost-effective solutions. Specifically, it examined the frequency and magnitude of occurrences, if any, where gross load minus utility-scale and DG PV exceeds minimum generation requirements (Pmin levels) plus downward reserves at different levels of DG PV penetration. If the difference is significantly greater than zero in all hours, utilities may still have headroom before PV becomes an operational issue (Figure 3-9). If it is slightly less than zero, utilities may still respond by curtailing utility-scale PV, to the extent permitted by contracts. If load minus curtailable utility-scale and DG PV exceeds Pmin plus downward reserves, utilities no longer will be able to maintain reliable operations and will require additional integration solutions.

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[31] This study is still in progress.

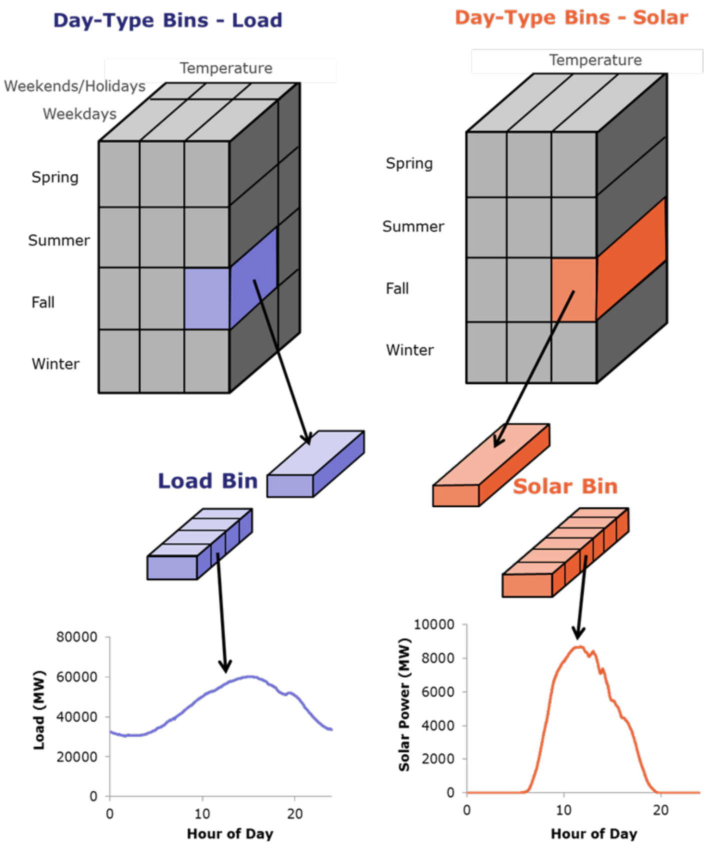

Figure 3-8
Sampling Approach for Load and Solar Availability in Hawaii Study

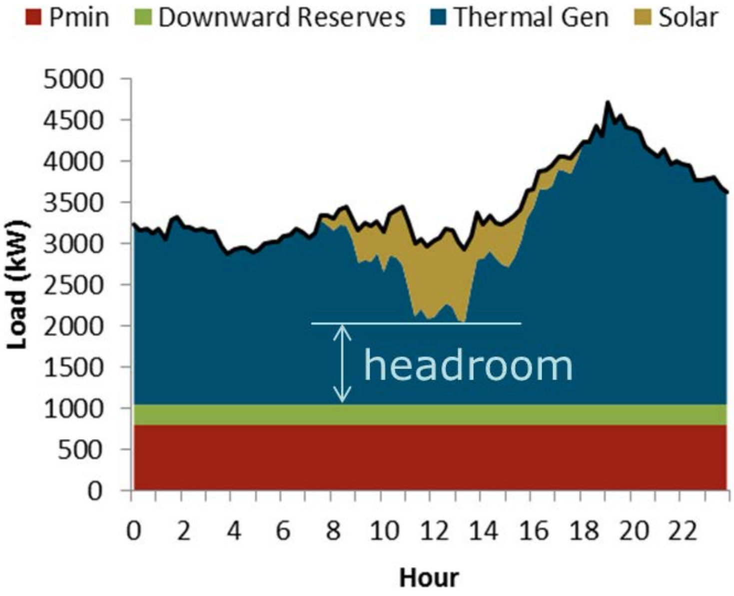

Figure 3-9
Illustration of Screen for DG PV Operational Impacts

The production simulation model used to verify results from the screening study used a similar sampling strategy to generate resource and load data, but also included the full set of generator constraints — i.e., ramp rates, startup and shutdown times. Results produced by this more detailed analysis were similar to those from the screening tool. This example illustrates that screening tools used in tandem, and complemented by, production simulation analysis can provide a useful approach for utilities to identify potential operating issues and integration solutions at different levels of DER penetration.

Although probabilistic modeling is not new to resource planning [4], the use of probabilistic solar and wind profiles in screening tools and production simulation models significantly increases computational requirements. Rationalizing flexibility needs to accommodate non-dispatchable resources, and also requires new logic in these models to evaluate the benefit-cost tradeoffs between renewable energy curtailment and integration solutions [50]. For instance, is it more cost-effective in terms of impacts on total system costs to provide compensation for curtailed DG generation or to invest in battery storage?

In addition to new modeling approaches, there also have been efforts to better understand how flexible loads, such as EVs, might respond to price or other signals through the use of pilot projects. For instance, in 2014 San Diego Gas & Electric Company (SDG&E) applied for a pilot to test the effectiveness of dynamic rates and smart charging equipment for EV charging [51]. In principle, relative to less granular time-of-use (TOU) pricing (left hand side of Figure 3-10), a combination of dynamic (real-time) pricing and price responsive charging equipment could shift charging to periods when marginal costs are low, such as during periods of high solar generation (right side of Figure 3-10). The results from these kinds of pilots can better inform planning analyses.

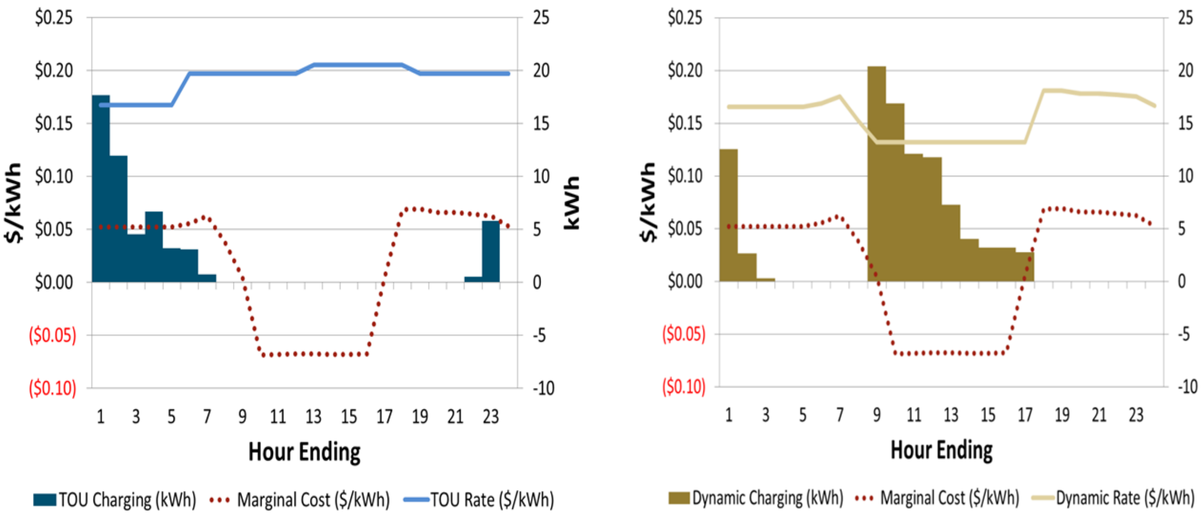

Figure 3-10
Hypothetical EV Charging under TOU and Dynamic Rates

Updating DER interconnection standards also can facilitate improved long-term planning, both by resolving future operational issues and providing planners and system operators with greater ability to see and control DER. For instance, a collaborative study by HECO, NREL, EPRI, and SolarCity found that the use of “smart inverters” for DG PV — inverters with advanced voltage regulation, reactive power control, ride-through, and communications functions — would enable higher penetrations of DG PV by reducing the risk that they destabilize the grid during and after a grid disturbance [52].

Enabling smart inverter functionality allowed HECO to relax a planning constraint on the maximum capacity of DG PV systems on individual circuits. Through enabling communications technology, it will also provide HECO with greater visibility on DG PV performance and distribution system conditions, providing its planners with better and more granular data. In the longer-term, with bi-directional communications, smart inverters also may allow system operators greater control over DER, though this requires first resolving compensation issues.

4

SYNTHESIS AND CONCLUSIONS

How to integrate DER in electricity resource planning has been an ongoing question since the 1970s. What distinguishes current discussions about DER is that in some areas, such as in Hawaii, DER penetrations already have increased dramatically, and in other areas, such as California and New York and perhaps others, DER penetrations are expected to significantly increase over the next decade. Although DG PV has been the main driver of recent interest in DER, a host of other technologies — EVs, LEDs, customer-side batteries, energy management systems — have the potential to be transformative as well over the longer term.

This report examines six planning issues that DER growth raises for resource planning, drawing on examples from California, Hawaii, and New York. These six issues include:

1. *DER Treatment: load modifier or supply resource?* – Should DER be treated as a supply resource or an adjustment to load?
2. *Adoption forecasting* – How should planners model DER adoption?
3. *Resource adequacy* – How should regulators and load serving entities account for DER in bulk and distribution system resource adequacy planning?
4. *DER as a resource* – Can DER be used as a bulk or distribution system resource to meet incremental resource and regulatory compliance needs? If so, how should it be evaluated and targeted?
5. *Distribution integration capacity* – How should different parts of the distribution system be evaluated for their ability to integrate DER?
6. *Operations* – How should DER operations (storage, EVs, other flexible loads, DG, DR) be treated in resource planning models?

In general, expected DER growth has not yet led to fundamental changes in resource planning practices in the three case study regions. Resource planning remains oriented around ensuring sufficient resources to meet a peak demand forecast plus a reserve margin. For planning purposes, DER still is primarily treated as a modification to load. Systematic, integrated assessment of DER as a system resource remains embryonic.

This status quo likely will change over the next decade. In California and New York, change is likely to be driven by a combination of policies, programs, and markets to support a range of different DER. In Hawaii, it is likely to be driven primarily by continued customer adoption of DG PV. The most important implication for resource planning is a blurring of the traditional separation between bulk system and distribution system planning. DER can have important customer benefits at the distribution level, but counting as resources at the distribution level means DER may not necessarily be available at a bulk level, and vice versa. At the very least, addressing this issue requires closer coordination between bulk and distribution system planning.

A second important shift is the trend toward use of reliability-based tools, such as ELCC, to determine DER capacity values and more broadly for resource adequacy accounting. This shift is part of a move away from heuristic rules-of-thumb and toward more data-intensive approaches to resource planning. This is also the case for a range of other assessment tools, including models used for DER adoption forecasting, valuation, integration capacity assessment, and operations impact assessment.

The planning tools currently being used today to address these areas are adaptations of existing tools, rather than completely new tools. Table 4-1 provides an overview of commonly used tools and the questions they address. For instance, DER adoption forecasting typically relies on market diffusion models developed in the 1960s, but these models must be tailored to accurately reflect the influence of geography, demographics, building type, cost, technology performance, incentives, rate designs, and interconnection policies on adoption. DER valuation and targeting relies on avoided cost methods developed in the 1980s and 1990s, but models must now integrate several types of DER and incorporate higher spatial granularity.

Table 4-1
Key DER Questions and Typical Analytical Tools Used to Address Them

Question	Tool
How much DER adoption will occur, when, and where?	Adoption models (e.g., market diffusion, discrete choice)
How can DER be best targeted to provide the most value to all customers?	Avoided cost models
How much should DER count toward reliability needs?	Reliability-based models (e.g., ELCC)
How much DER can be integrated into the distribution system?	Distribution system analysis models
How will DER impact bulk system operations?	Stochastic production simulation models

A key implication is that planners need to collect and develop data with higher spatial and temporal resolution, both for DER and for the electricity system more broadly. Metering and other communications infrastructure, supported by interconnection policies, can help to provide this data. Pilot projects, such as SDG&E’s dynamic pricing pilot for EV charging, provide a means to collect data on customer price responsiveness.

Even as planning becomes more data-intensive, all case study regions highlight the importance of balancing analysis complexity, intuition about what drives the results, and transparency. The “public tool” approach, which has been used successfully in California in stakeholder processes, provides one approach to achieve this balance. Screening tools also remain an important complement to more complex modeling.

California, Hawaii, and New York have taken different approaches to how DER services should be valued and compensated, and how DER-related costs should be allocated. California has taken a more programmatic route, through the DRP process, and the utilities likely will play a more active role in the future in planning for and valuing DER. New York has embarked on a more market-based approach, where the utilities are primarily responsible for providing and maintaining a market platform. Hawaii has yet to articulate a longer-term vision. These differences illustrate there are multiple avenues to integrate DER into resource planning, and the most appropriate approach will vary by context.

5

RESEARCH GAPS AND POTENTIAL NEXT STEPS

The kinds of resource planning questions arising as DER penetrations increase vary across states, in response to differences in policy, retail rates, and customer preferences. In states that are experiencing or anticipating high DER growth, there is a clear need to better integrate DER into the resource planning process. Even in states that are not anticipating such growth, utilities and regulators need to be prepared for the potential for rapid adoption. Hawaii provides a cautionary tale on the potentially disruptive nature of DER.

Across the industry, two areas of planning research stand out as near-term priorities: (i) DER adoption forecasting and (ii) DER targeting. At lower penetrations, these should be areas of interest for all utilities. Adoption forecasting can help utilities to understand when and where DER adoption might occur, and under what conditions. Targeting can help utilities to better structure incentives for DER adoption, including programmatic designs that reward high value applications of DER, performance-based payments linked to the value of DER, and rate design updates that better reflect underlying marginal costs. For utilities that do not currently have DER adoption forecasting or avoided cost tools, an important first step is to develop them. Even simple tools and high-level analyses can help to improve decision-making.

For utilities that are anticipating higher DER growth, there are a number of areas for improving current adoption and avoided cost models. The electricity industry is just beginning to grapple with the challenge of how to forecast accurately the magnitude, timing, and location of DER adoption. Improving the accuracy of market diffusion models requires: (1) refining DG output simulation tools to incorporate real-world performance (e.g., age-related de-rates); (2) developing more spatially diverse load data; and, (3) examining input assumptions used to estimate S-curves and market saturation levels. Discrete choice models may provide an alternative to diffusion models, particularly for EVs, but they will need to be assessed in terms of data requirements and accuracy.

For DER targeting, the most important component of avoided costs often is the distribution capacity expansion deferral value, which many utilities never have estimated. Doing so requires a robust internal process, which may include development of rules to determine the amount, timing, and certainty of peak load reductions required to defer a capital expenditure. In addition, utilities, regulators, and stakeholders must refine the scope and methods to calculate avoided costs, which often vary significantly among different analyses within the same jurisdiction.

Rate and incentive design is an additional near-term research area related to DER adoption and targeting. This can be an important tool to encourage DER adoption in areas where it has higher local and system value, but the effects of different rate and incentive designs on adoption are still poorly understood. Improvements in adoption and avoided cost models, and better understanding customer response to rate and incentive designs, also may enhance existing utility programs in addition to being useful for DER planning.

As DER penetrations rise, utilities and regulators are likely to need to address the other planning questions raised in this report with a greater level of effort (Figure 5-1). While tools and methodologies exist today to address these questions, there remains significant scope for improving these tools. However, in the nearer term these tools are likely to be relevant only to a subset of utilities, or may be relevant for central-scale resources before DER. These tools include:

- Development and integration of reliability-based assessment tools, such as ELCC, into planning processes to assess the reliable capacity contribution of DER;
- Development of tools to assess DER integration capacity, which are still at an early stage even in states that already have higher DER penetrations;
- Development of stochastic production simulation modeling capabilities to address solar and wind uncertainty and variability; and
- Better understanding of price responsive loads (e.g., EVs), and methods to integrate them into resource planning.

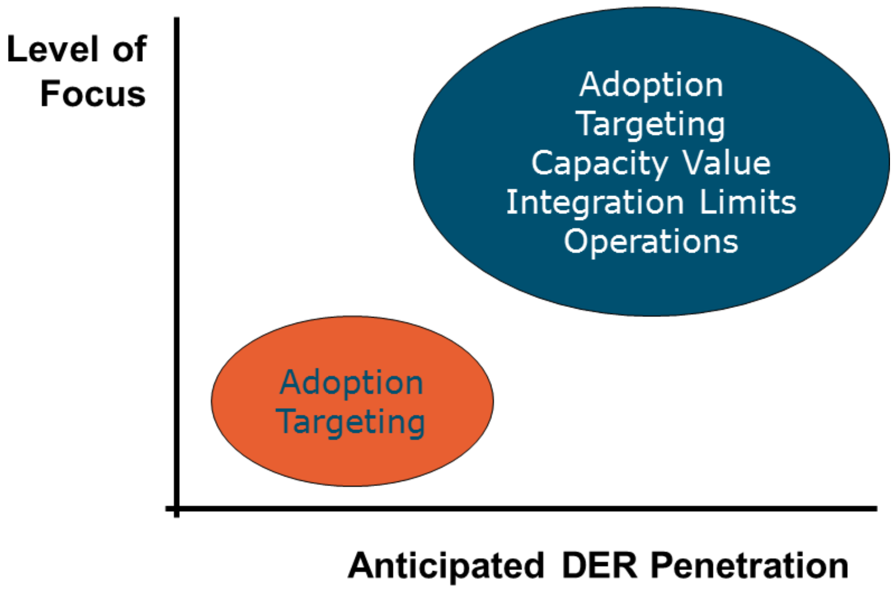

Figure 5-1
Focus Areas for DER Planning, at Different Anticipated Levels of DER Penetration

In summary, this study suggests it may be beneficial for utilities and regulators to take a more proactive approach to DER, by more explicitly integrating DER into resource planning processes. Doing so will help to ensure DER adoption is more beneficial to all customers than otherwise may be the case.

6

GLOSSARY OF TERMS

AS	Ancillary services
BCR	Benefit cost ratio
BSER	Best system of emissions reduction under §111(d) of the Clean Air Act
CAA	Clean Air Act
CAISO	California Independent System Operator
CCR	Coal combustion residuals
CEC	California Energy Commission
CHP	Combined heat and power
CPP	Clean Power Plan under §111(d) of the 1990 federal Clean Air Act
CPUC	California Public Utilities Commissions
CRF	Capital recovery factor
CSPP	Comprehensive System Planning Process
CWIS	Cooling water intake structure
DER	Distributed energy resources
DERP	Distributed energy resource provider
DG	Distributed generation
DG PV	Distributed generation photovoltaic
DPP	Discounted payback period
DPS	New York Department of Public Service
DR	Demand response
DRP	Distribution Resource Plan
DSIP	Distributed System Implementation Plan
DSM	Demand-side management
DSPP	Distributed system platform providers
EIA	United States Energy Information Agency

ECP	Equivalent conventional power
EE	Energy efficiency
EEPS	Energy efficiency performance standard
EFC	Equivalent firm capacity
EGU	Electricity generating unit
ELCC	Effective load carrying capacity
EM&V	Evaluation, measurement, and verification
EPA	United States Environmental Protection Agency
EM&V	Evaluation, measurement, and verification
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
HPUC	Hawaii Public Utilities Commission
IDSM	Integrated Demand Side Management Potential Model
ICA	Integration capacity analysis
IGCC	Integrated gasification combined cycle
IOU	Investor-owned utility
IRP	Integrated resources planning
KIUC	Kauai Island Utility Cooperative
KWh	Kilowatt-hour
LCBF	Least-cost best-fit
LED	Light emitting diode
LMP	Locational marginal price
LOLE	Loss of load expectation
LOLP	Loss of load probability
MATS	Mercury and Air Toxics Standard

MECO	Maui Electric Company
MW	Megawatt
MWh	Megawatt-hour
NEM	Net energy metering
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYPSC	New York Public Service Commission
PCAF	Peak capacity allocation factor
PG&E	Pacific Gas & Electric Company
PPA	Power purchase agreement
PURPA	Public Utility Regulatory Policy Act
PV	Photovoltaic
PVRR	Present value revenue requirement
QF	Qualifying facility
REV	Reforming the Energy Vision
RPS	Renewable portfolio standard
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
TDSM	Targeted demand side management
TOU	Time of use
TWh	Terawatt-hour
ZEV	Zero emissions vehicle
ZNE	Zero net energy

7
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3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com