WHITE PAPER

On the Grid's Bleeding Edge: The California, Hawaii, and New York Power Market Revolution

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Key Findings

1. California, Hawaii, and New York power market reforms will enable dramatically increased solar and distributed energy penetration, improved reliability, lower costs, and reduced greenhouse gas (GHG) emissions.
2. Realizing this vision takes integrated process reform in two fundamental areas: distribution planning and portfolio development to understand how to optimize pricing, programs, and procurement for utility systems.
3. These integration initiatives will lead to fundamental changes for utilities and are the harbinger of similar transitions likely to occur across many states. Early engagement by stakeholders is key to determining if these transitions are friend or foe.

Executive Summary

California, Hawaii, and New York are in the midst of radically reforming their state regulatory processes and eventually markets to accelerate the integration of distributed energy resources (DER) into the grid. Each state process fundamentally envisions the future regulated utility as an enabler of customer choice to manage energy costs through advanced distribution planning, modern integrated grids, and opportunities for DER to provide market-based grid services.

Increasingly, ICF International sees the three state reform initiatives converging toward a common set of goals, mechanisms, and shared elements. In this white paper, we take an initial look at two of these shared elements—the need for a new distribution planning process and the emerging components of market design and portfolio development.

The new planning process for each utility envisioned in all three states must support the development of DER alternatives that meet current and future system requirements. The first step for utilities in establishing such an integrated process will be the development of a standardized planning framework that will require enhanced use of probabilistic-based engineering analysis, scenario-based distribution planning, hosting capacity analysis, and locational net value of DER. These are challenging but achievable steps.

The development of a portfolio of new services enabled by DER using various pricing, programs, and procurements to competitively source them requires several new processes and analytical methods. The potential types of services may include distribution capacity deferral, voltage management, power quality, reliability, and distribution line loss reduction. These services would be sourced through a combination of time-varying rate designs, energy efficiency and demand response programs, and utility procurements. ICF has worked with stakeholders to develop a framework for considering these issues.

Several other critical shared themes cross the three states, including the role of distribution system operators and distribution platforms, and understanding of customer decisions. We expect to focus on these additional themes in future analyses.

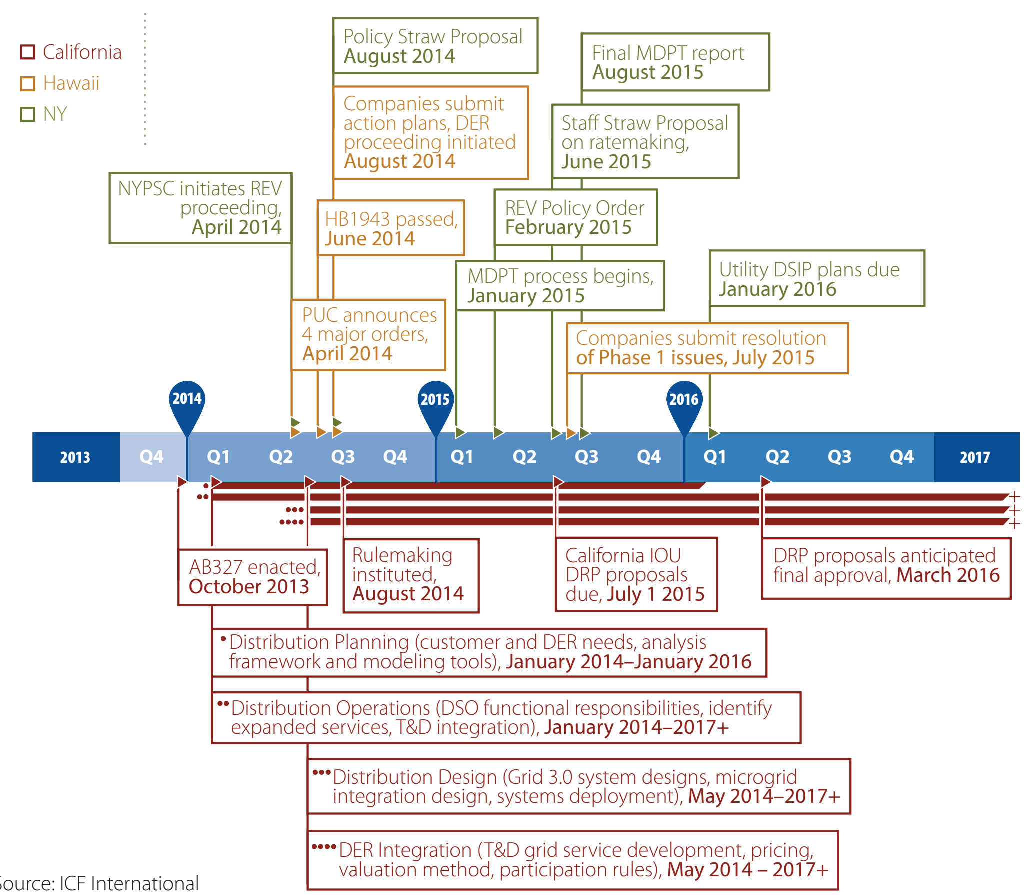
Overall, integrating and enabling DER will require an evolution in how utilities, states, and stakeholders plan, design, and implement systems and markets. The state initiatives highlighted here offer a blueprint for stakeholders preparing to tackle these issues.

The DER Promise: Lower Rates, Better Reliability, Consumer Choice, Resiliency, and Environmental Salvation

The increasing role and cost-competitiveness of DER in the power sector has raised hopes that these technologies can deliver a host of benefits: reduced system costs through avoided/deferred capital expenditures; increased resiliency enabled by storage; distributed generation; microgrids; lower costs for customers through better demand-side management and low marginal cost generation; and faster attainment of environmental targets by enabling low-emitting generation sources and electric vehicles. The rise of DER, however, also will impose costs, unintended consequences, and complexities.

In an effort to quantify and realize these benefits and mitigate costs and risks, California, Hawaii, and New York have each launched initiatives aimed at integrating current or anticipated DER penetration and at addressing the resulting changes to utility planning and business models. Despite some variations in emphasis and timing, in the most fundamental ways the three state processes are converging toward a common set of goals, mechanisms, and shared elements. Broadly speaking, each state is pursuing three goals: reducing customers' energy costs, improving service reliability, and reaching environmental targets. Each state has tended to emphasize those goals in a somewhat different order based on state issues. However, they have ended up considering the same set of questions and mechanisms that are driven by the shared fundamental physics and power market economics.

Figure 1: Timelines for Study, Planning, and Implementation of Three State DER and Market Initiatives



Source: ICF International

California

California has largest amount of DER in absolute terms, and DER penetration is growing exponentially. Although the state is certainly focused on making systemic changes to create an integrated grid, a clear set of state policy objectives related to the environment and the role of DER drive the state's efforts. Put another way, California is looking to turn the near-term challenge posed by DER growth into a long-term opportunity for customers and for policy goals. This emphasis has led to the enactment of state law AB 327 creating Public Utilities Code §769. The law mandates that California investor-owned utilities (IOUs) file distribution resource plans (DRP) to integrate distributed, customer-owned resources into grid investment and operational plans. In addition, parallel proceedings are occurring on energy storage, integrated demand-side management (IDSM), energy efficiency (EE), and net energy metering (NEM)—all within the backdrop of increasingly aggressive renewable targets and GHG reduction goals. Alongside these proceedings, the California stakeholder-driven More Than Smart initiative has provided recommendations for distribution planning, operations, and design of California's future grid.

Hawaii

Hawaii is similarly introducing policy innovation in response to market trends. Unprecedented rapid rooftop solar adoption has caused distribution circuits to back-feed during times of high utilization. One out of every eight homes in Hawaii now has solar, which is leading to overvoltage and utility restrictions to photovoltaic (PV) additions. In response, Hawaii's Public Utility Commission (PUC) issued four orders, including Order No. 32052 that requires utilities to file distributed generation interconnection plans (DGIPs) to upgrade distribution and integrate more PV. Hawaii also has enacted state legislation (HB1943) that will maximize the interconnection of solar PV and require changes to distribution planning, modernization of the grid, and compensation for DER provided services.[1] Hawaii's regulators have responded with a sense of urgency to adapt to market changes as part of its proceeding investigating DER policies. On March 31, 2015, the Hawaii PUC established a requirement for utilities to submit a plan within 90 days for "a) proposed revisions to applicable interconnection-related tariffs to mitigate near-term DER technical integration challenges, expedite interconnection process, and standardize technical specifications for fast-track approval of customer self-supply systems; b) new tariff systems; and for customer self-supply c) proposed DER 2.0 transition plan, including tariff for grid-supply systems."[2]

New York

By contrast, New York has very little current DER adoption, low growth rates, and no state policy targets linked to DER development. Therefore, the state's "Reforming the Energy Vision" (REV) initiative is intended to create an overarching regulatory framework that creates market opportunities for DER to provide system and customer benefits as well as improve resilience to hurricanes like Superstorm Sandy. New York's policy innovation intends to align utility business practices and incentives with the value of DER in an integrated grid through the animation of a distribution market. The REV process is split into two tracks: Track 1 examines the evolution of the distribution system to an open platform to integrated DER through market designs and defines new operational functions for utilities, including new grid and market facilitation services. Track 2 examines changes in regulatory, tariff, and incentive structures. Currently, the Market Design and Platform Technology working group is developing recommendations for commission guidance on planning, operations, market mechanisms, and technology to create a DER-enabling platform within the context of track 1.

[1] The Hawaii legislature also recently passed a bill moving the state's renewable portfolio standard up to 100 percent by 2045.

[2] The current d ORDER NO. 32737 GRANTING MOTIONS TO INTERVENE, CONSOLIDATING AND INCORPORATING RELATED DOCKETS, AND ESTABLISHING STATEMENT OF ISSUES AND PROCEDURAL SCHEDULE; Hawaii Public Utilities Commission. raft "Bases of the Market" contemplates a 10-year tenor for CEL contracts.

Despite the differences in emphasis and approach, California, New York, and Hawaii share a focus on two major reform areas: distribution planning process and portfolio development. Other states looking at enabling DER must address these areas as well.

Integrated Process Reforms

A New Distribution Planning Process…

As distribution systems experience increasing levels of DER interconnection, the three state processes all envision, if not require (California and Hawaii), an evolution in the integrated grid planning process. This integrated planning approach involves a wider and more complex range of engineering and economic valuation issues in an integrated and multidisciplinary fashion, with the participation of relevant stakeholders.

In all three states, the utility will continue to have responsibility for distribution system planning and construction. However, the new planning process must support the development of DER alternatives that meet current and future system requirements. The process must meet and balance a variety of policy objectives, including system reliability and resiliency, customer empowerment, emission reduction, consumer protection, system efficiencies, cost-effectiveness, competitive markets, energy efficiency, power quality, and fuel diversity. This is undoubtedly a tall order.

The first step for utilities in establishing an integrated process is the development of a standardized planning framework that could involve significant changes to traditional distribution planning, as outlined in Table 1. This framework has effectively been adopted in all three states and provides the basic elements of a standardized approach that can be used by others.

Table 1—Elements of a Standardized Planning Framework

Probabilistic-based engineering analysis	As customer DER adoption grows, the distribution system will increasingly exhibit variability of loading, voltage, and other aspects that affect the reliability and quality of power delivery. Traditional distribution engineering analysis based on deterministic methods must evolve to include probabilistic methods.
Scenario-based distribution planning	The uncertainty of the types, amount, and pace of DER makes singular forecasts ineffective. A better approach is the use of at least three scenarios to assess current system capabilities, identify incremental infrastructure requirements, and enable analysis of the locational value of DER.
Hosting capacity	Hosting capacity is the maximum DER penetration for which a distribution grid can operate safely and reliably. Specific methods are used to quantify the engineering factors that increasing DER introduces on the grid within three principal constraints: thermal, voltage and power quality, and relay protection limits.
Locational value of DER	Incremental infrastructure or operational requirements may be met by sourcing services from DER and better locational adoption of DER. The value this approach creates may be associated with a distribution substation, individual feeder, and section of a feeder. Net values may include avoided distribution utility capital and operational expenses as well as external environmental and customer benefits based on a specific location, but are not always a net positive.
Integrated transmission and distribution (T&D) planning	At high DER adoption, net load characteristics have material impacts on transmission system and bulk power system operation. These impacts create a need for analysis of T&D interaction through an iterative approach, because tools to perform a truly integrated engineering analysis do not exist yet. An important consideration is relative cost-effectiveness of managing DER-related variability locally within the local distribution area versus exporting it to the transmission grid.

…is Not an Easy Lift

Each of the elements of this new planning framework is achievable, but will require the development of new methods and an integrated set of processes that individual utilities may not employ today. The Electric Power Research Institute's (EPRI's) Integrated Grid Benefit-Cost Framework[3] is an effective starting point for development of a standardized methodology for distribution planning. However, this framework is not sufficient in practice to address the specifics of each utility's system and state regulatory rules, based on ICF's experience working with utilities to implement these new methods.

Utilities must test these methods and models within their own systems as they develop their distribution plans, not after. As EPRI says about its own framework, "Creating a robust grid modeling framework is essential, but it is not enough—it's just the first step. The technologies developed and operating procedures formulated must be subjected to rigorous, in situ field testing to ensure that they perform as intended." We agree, based on ICF's experience in helping utilities implement these upgraded planning elements across the United States.

In short, for utilities to understand the opportunities and risks in an accelerated DER adoption environment, they must reconsider their planning framework and perform analyses, at least on a pilot basis, well in advance of any required DER integration-focused distribution plan.

Portfolio Development, and Eventually Market Design

Today, distributed resources have a number of opportunities to provide wholesale services, including energy, generation capacity, transmission capacity deferral, and ancillary services necessary to operate the power system.[4] Additionally, changes under way in California, Hawaii, and New York will create new distribution level opportunities for DER to be considered as alternatives to utility capital investment or operational expense. The New York Public Service Commission has stated explicitly, "REV will establish markets so that customers and third parties can be active participants...and distributed energy resources will become integral tools in the planning, management and operation of the electric system." California's DRP order also requires the creation of new services and the use of various pricing, programs, and procurements to competitively source DER services (what New York calls "animating markets"). Likewise, Hawaii recognizes the value of distributed resources requiring compensation for "…electric grid services and other benefits provided by distributed generation customers and other non-utility service providers."[5]

The potential types of services may include distribution capacity deferral, voltage management, power quality, reliability, and distribution line-loss reduction. These services would be sourced through a combination of time-varying rate designs, energy efficiency and demand response programs, and utility procurements.

As these state processes proceed and converge toward similar opportunities for DER to provide distribution grid services, recognition is growing that a mix of time-varying rates, demand-side programs, and procurements will be needed. Such a portfolio requires several new processes and analytical methods.

First, existing demand-side management (DSM) valuation techniques are not well suited for distribution grid services and require re-evaluation to address specific locational value for DSM resources. Second, a portfolio of distributed resources will must be developed. However, unlike an

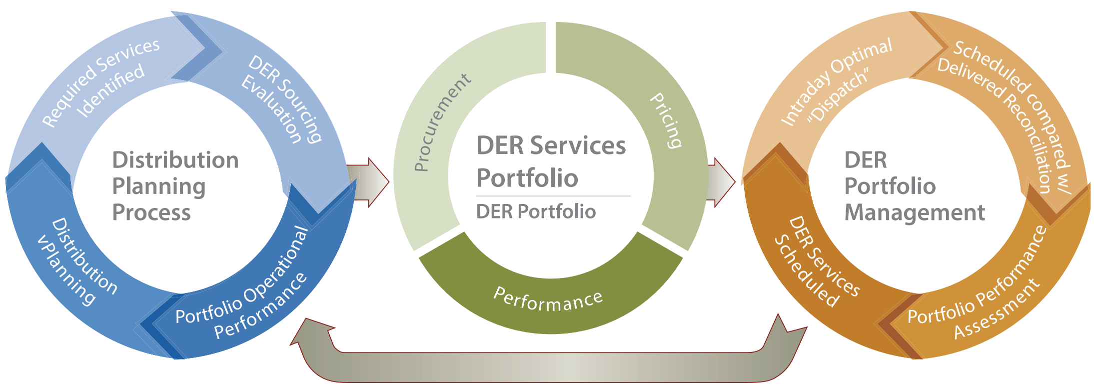
[3] Electric Power Research Institute, "The Integrated Grid: A Benefit-Cost Analysis Framework," 2015; available from http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004878.

[4] Jurisdictional challenges to Federal Energy Regulatory Commission Order 745 are noted.

[5] HB1943, p.5, section 2b.4; available at http://www.capitol.hawaii.gov/session2014/bills/HB1943_CD1_.pdf.

integrated resource plan, this portfolio will potentially need to address a nested set of locational needs across individual feeders, substations and related local distribution area rather than systemic needs. Development of such a portfolio, including the allocation of the sources of services, must address the operational firmness of the various resources as well as the timing of when the distribution upgrade is needed. Because this DER services portfolio must be dispatched in real time, a dispatch priority protocol will need to be developed.

Figure 2: Conceptual Process for Development and Implementation of DER Services and Portfolio



Source: De Martini

…Requires New Approaches

Policy makers across the three states are increasingly considering how to leverage the value of DER to reduce costs across the power system. The focus is increasingly on potential utility avoided costs that are identified in the new distribution planning process. These locational values linked to specific operational services will require a portfolio of distributed resources sourced through a variety of means to realize net benefits and reliable operations. Determining the portfolio and sourcing process as well as dispatch is far from easy. Existing methods are deficient, and new approaches are required to ensure that plans and DER service portfolios actually deliver value in operation.

ICF has been working with utilities, drawing on its expertise in DSM programs and grid planning and operations to develop new valuation methods to address some of these gaps. We have developed an integrated framework for considering these issues from planning through portfolio development and operational implementation as conceptually illustrated above. In initiating an upgraded distribution planning process to enable greater DER penetration, ICF has worked with regulators, utilities, and stakeholders in the initial states. We have learned the importance of getting ahead of the curve in developing methods tailored to the specific needs of a particular locale. The creation of pricing, programs, and procurement processes has been iterative and involves heavy stakeholder engagement. Thus, understanding elements of operational performance and locational needs and value can help stakeholders and especially utilities to work with regulators on designs that work both financially and from a reliability standpoint.

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Conclusion

implementation of a new distribution planning process and the consideration of market design and portfolio development each require new thinking and new types of analysis on their own. One of the greatest challenges we have seen across the three states is the impact of this integrated process on several previously disparate utility and regulatory processes. For example, the analytical inputs to the distribution planning process very much determine a utility's desired DER portfolio development. Success demands a synthesis of people and activities across departments—a level of internal integration that utilities and regulators were not previously required to achieve.

This essential synthesis is one of the many reasons that the California, Hawaii, and New York initiatives and the others to follow must undertake a systemic change in the way that utilities, and perhaps all stakeholders, do business. A central aspect will be the role of customer decisions regarding adoption of DER and potential for leveraging these resources for the benefit of all customers. Customer insights and engagement are becoming a critical success factor in a more distributed electric system — a topic worth in-depth discussion in a future analysis.

We recommend that utilities with increasing DER adoption, or states considering initiatives in this area, get as early a jump as possible in developing customer insights, adapting new distribution planning and related processes, identifying new enabling system capabilities, and considering what outcomes will best position them for the future.

About the Author

Steve Fine – Steve is an expert on environmental markets and has led numerous multistakeholder engagements, including the Edison Electric Institute, U.S. Climate Action Partnership, Regional Greenhouse Gas Initiative (RGGI), and Clean Energy Group. His work has concentrated on evaluating the economics of conventional and renewable energy resources within the context of developing environmental regulations. He was an invited panelist to a U.S. Senate roundtable discussion on the future of 3P and 4P legislation conducted by Senators Carper and Alexander.Mr. Fine has an M.A. in Economics from the Johns Hopkins School of Advanced International Studies and a B.A. from the University of California, Santa Cruz.

Paul De Martini – Paul is an expert on customer-centric business models, integration of distributed energy resources and grid modernization. He is experienced in transforming utility operations, building successful energy services firms, and growing technology ventures globally. His work has consistently been recognized by industry including several awards for innovation and industry leadership. He holds an M.B.A. from the University of Southern California and a B.S. from the University of San Francisco. He is an emeritus member of the U.S. Department of Energy's Gridwise Architecture Council, a senior member of Institute of Electrical and Electronics Engineers and a State of California certified electric system operator.

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