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Planning the Distributed Energy Future

Emerging Electric Utility Distribution Planning Practices for Distributed Energy Resources

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EXECUTIVE SUMMARY

The market landscape for electric utilities in the United States is shifting dramatically toward a future with much higher penetrations of distributed energy resources (DERs), including:

- Solar photovoltaics (PV)
- Energy storage (ES)
- Electric vehicles (EVs) and charging infrastructure
- Demand response (DR)
- Combined heat and power (CHP)
- Other non-solar types of distribution generation (DG)
- Energy efficiency (EE) measures

This shift is driven by changes in customer choices around energy; technological development leading to lower costs and better performance; and new policies and regulatory proceedings requiring utilities and utility customers to embrace DERs in many forms.

The traditional distribution system planning framework is no longer sufficient to ensure grid reliability in an era of increasing DER penetration, and a new framework is emerging among utilities seeking to proactively plan for DER integration.

To understand how utility planning is changing, Black & Veatch and the Solar Electric Power Association (SEPA) interviewed five leading utilities across the United States and identified trends in utility planning practices. Each utility is pursuing a different mix of new methodologies and tools for DER planning, based on its own unique circumstances and concerns, including:

- Methods and tools for assessing the DER hosting capacity of distribution circuits
- Valuing the locational costs and benefits of DERs
- Guiding DER installations to preferred interconnection locations
- Assessing the need for rate restructuring
- Monitoring and control of DER assets

These utilities are also trying new organizational structures that bring together the multi-disciplinary teams needed to effectively plan for all aspects of DER deployment. New modeling software capabilities are emerging to address the needs around grid modeling in an age of increasing DER penetration, and leading utilities are beginning to take advantage of the new analytical tools. However, a number of open questions remain around DER planning processes, modeling approaches, and monitoring/control methods.

To the authors' knowledge, no utility has yet put into practice a comprehensive framework for utility planning that incorporates the far-reaching impacts of DER growth. To assist utilities in addressing this major industry challenge, this whitepaper outlines a proactive DER planning process, which is summarized in Table 1.

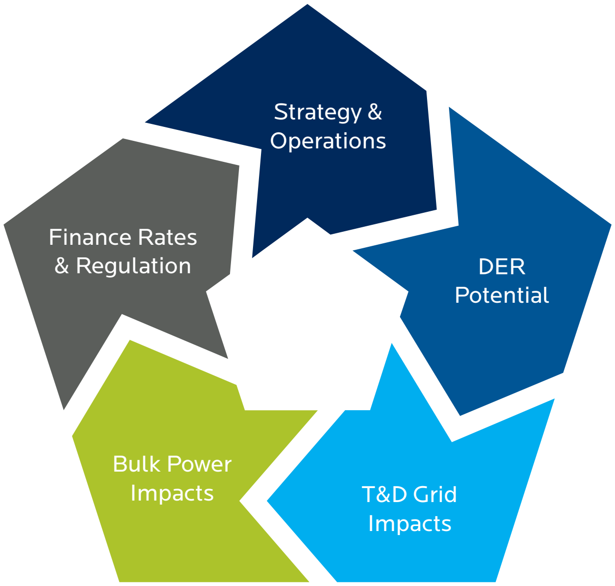
The five processes noted in Table 1 are interconnected, where a change in any one aspect will affect the others. For example, under one set of incentive rates there may be PV and EV penetration that overly stresses a utility's transmission and distribution (T&D) system. Strategically, the utility may seek to change incentives, which will then change customers' adoption of those particular DERs, and will in turn require a re-examination of T&D impacts (though regulatory constraints may limit the ability to modify incentives). The process is thus iterative, with a goal of converging on a utility's optimal portfolio of distributed grid opportunities (please refer to **Section 3** for additional detail).

Utilities can realize numerous benefits from better DER planning, including more efficient interconnection processes, expanded capacity to accommodate DERs, reduced total infrastructure costs, and improved forecasting of DER impacts on load and utility revenues. However, a number of issues must be considered when implementing a proactive DER planning process, including:

- Ownership and control of DER assets
- DER markets and procurement
- Data sharing and confidentiality
- Rate impacts
- Interactions with other utility regulatory proceedings
- IT infrastructure
- Staff resources
- Preferences of local customer and policy-makers.

To summarize, key takeaways include:

- Significant growth in DER penetration is expected across the United States due to multiple market drivers. Among these drivers, is a growing list of states that are providing active policy support and regulatory guidance for utilities
- More sophisticated tools and methods, along with new utility processes and organizational structures, for DER planning are being developed and adopted rapidly
- DER forecasting and valuation will become a standard part of the utility planning process in the near future
- New procurement methods and business models are emerging around DER assets and grid integration, and



DERs may be able to replace some conventional grid investments in the distribution system (with appropriate contract structures and technical specifications)

- Utilities will need to make significant financial investments in new hardware and software, but also investments in human capital (e.g., staff retraining and reorganization, new skill-sets, new processes and new ways of doing business) to enable the DER-rich grid of tomorrow

Table 1. Proactive DER Planning Process Summary

Step	Name	Description
1	Load and DER Adoption Forecast	Develop load forecast, assess technical/economic/achievable potential for DER deployment and estimate customer adoption, and determine net load profile.
2	T&D Grid Impacts	Run dynamic distribution system model to identify and quantify all grid impacts from load/DER growth.
3	Bulk Power Impacts	Run full model of bulk power system (generation and transmission), including impacts from distribution level.
4	Finance, Rates and Regulation	Quantify locational costs and benefits of DERs, determine if/how DERs can defer or avoid traditional utility distribution investments, calculate financial and rate impacts of DER deployment, and develop appropriate policies (e.g., incentives, tariffs, standard contracts, competitive solicitations) to encourage DERs at the right place and right time.
5	Strategy and Operations	Decide on utility's overall DER strategy and any related changes to the business model, as well as modifications to utility operations to support effective DER integration.

Implementation of a proactive DER planning process will prepare utilities for the expanded adoption of DER. Early planning efforts will enable utilities to minimize the risks and realize the benefits of a distributed energy future.

1 UTILITY DER PLANNING CHALLENGES

The purpose of this whitepaper is to educate utilities, regulators, technology vendors and other stakeholders about the issues facing electric utilities as they manage increasing DER deployment and modify their planning processes.

In terms of distribution planning, most electric utilities today operate as they have for decades. This section explains the conventional distribution planning process, why it is no longer sufficient to handle the increasingly complex demands on utility distribution systems, and the three major trends that are driving DER adoption (customer choices, technological development, and policies and regulatory proceedings). It begins with the purpose, scope and definitions for this whitepaper.

1.1. PURPOSE, SCOPE AND DEFINITIONS

The scope is to provide background on DER planning challenges, identify utility planning trends in this space and describe a generic framework for proactive DER planning. It is meant to give general guidance to stakeholders on this topic, but is not a detailed "how to" manual and does not recommend specific software tools or vendors.

DER technologies covered in this whitepaper are solar photovoltaics (PV), non-solar distributed generation (DG), energy storage (ES), electric vehicles (EVs) and charging infrastructure, demand response (DR), combined heat and power (CHP) and energy efficiency (EE). To qualify as DERs, these assets must be connected to the utility distribution system, though they may be located either on the customer-side or the utility-side of the meter. DERs can range from 1 kilowatt (kW) rooftop PV installations, to 20 megawatt (MW) CHP systems, to fleets of EV chargers or thousands of DR customers.

Black & Veatch's 2016 *Strategic Directions: Smart City/ Smart Utility Report* included a survey of 206 predominantly North American electric utility leaders. Figure 1 shows that survey participants ranked solar photovoltaics as the technology with the highest potential impact, with battery storage, demand response and electric vehicles also on their radar. Notably, the impact of these non-solar DER technologies will likely grow in the future as overall DER penetration increases, further emphasizing the need for proactive DER planning that addresses all types of DER technologies.

1.2. CONVENTIONAL DISTRIBUTION PLANNING

Conventional distribution planning works within the premise of delivering electricity to end-use customers after it has been generated in a centralized power plant and often moved over long distances via high-voltage transmission lines. Conventional distribution assumes that power moves in a single direction from generation through transmission and distribution lines to the end user—from "turbines to toasters" as pioneers of the electric grid would say.

The main focus of distribution planning is to ensure safe, reliable and cost-effective delivery of electricity. Three indices are most often used to evaluate the annual reliability of the distribution system:

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Duration Index (SAIDI)
- Customer Average Interruption Duration Index (CAIDI)[1]

Each of the listed indices measures delivery interruptions relative to the customer base. Distribution engineers often use these metrics to decide when their designs have achieved a sufficient level of reliability to satisfy regulatory requirements in a manner that keeps costs reasonable and safety absolute.

Traditionally, distribution system planning incorporates some results from other processes (e.g., transmission planning) and also provides outputs that feed back into capital budgets and rates. Distribution planning engineers

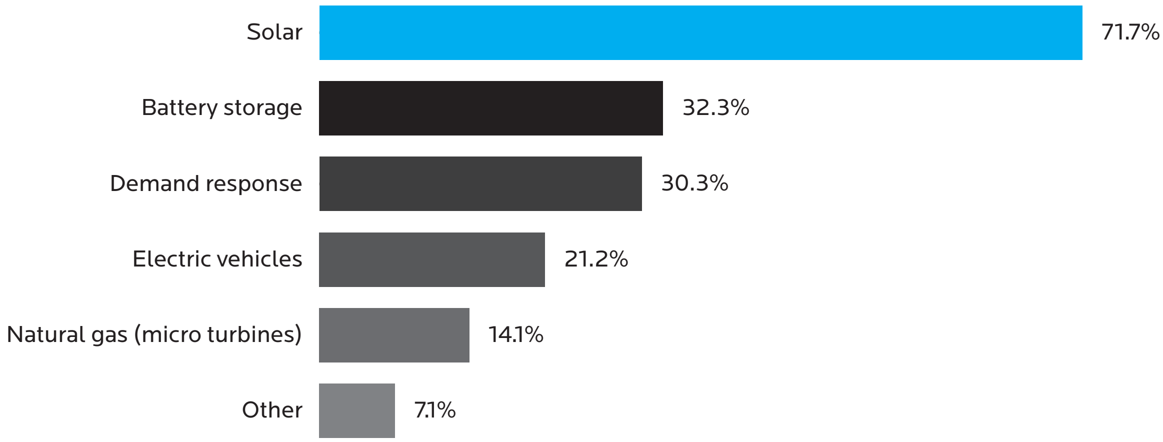


Figure 1. Distributed energy resources that will impact electric utilities the most

typically use static power flow models to test whether the designed circuit configurations and equipment will safely and stably accommodate predicted electric load scenarios. These distribution scenarios are tested at the initial stage of larger projects (involving new loads), prior to any new construction or regular feeder upgrades.

Distribution planning usually focuses on how to serve increasing customer load over time. New load may be added, for example, from development projects resulting in an increase of regional electricity demand, or from customers adopting new technologies that use more electricity. When a change in load is forecasted, engineers use power flow models that test new peak load, zero load, faults, and other conditions to determine whether equipment upgrades are required to ensure the reliability and safety of electricity delivery. Utilities are generally required to build their distribution systems to accommodate the annual peak load of all customers, with no consideration of customer-side energy efficiency or distributed generation. The distribution system is tested within the bounds of defined worst-case scenarios for the forecasted load (e.g., zero-load, peak load, etc.); power flow is unidirectional; customers are assumed to be static loads; and only the distribution system equipment is modeled and tested.

Because of the emphasis on reliability, the "status quo" or central role of distribution planning has been focused on successfully modeling a few extreme scenarios through historically-based heuristics; then within those parameters, engineering a design layout with suitable equipment (namely, feeders) that can withstand those scenarios.

Besides load growth, distribution engineers must also take into account the need to replace aging equipment on the system, or account for changes in the bulk generation and transmission system. A high-level diagram of the distribution planning process is shown in Figure 2[2], where the main components of the distribution system also are noted: The substation, which reduces transmission-level voltages from hundreds of kilovolts to tens of kilovolts; the feeders (or circuits), which originate at the substation, extend "the last mile" and typically each serve approximately 1,000 customers; and ultimately the customer, who is connected to a feeder by a service transformer, usually shared with other customers, and which further reduces voltages from tens of kilovolts to hundreds of volts for final consumption as measured by the electric meter.

[1] Cheryl A. Warren, Senior Member, IEEE. "Overview of 1366-2001 the Full Use Guide on Electric Power Distribution Reliability Indices", July 2002. http://grouper.ieee.org/groups/td/dist/sd/panels/2002-07-warren.pdf.

[2] *Power Distribution Planning* Reference Book Second Edition, Revised and Expanded H. Lee Willis ABB, Inc. Raleigh, North Carolina, U.S.A.MARCEL MARCEL DEKKER, INC. NEW YORK • BASEL loDEKKER

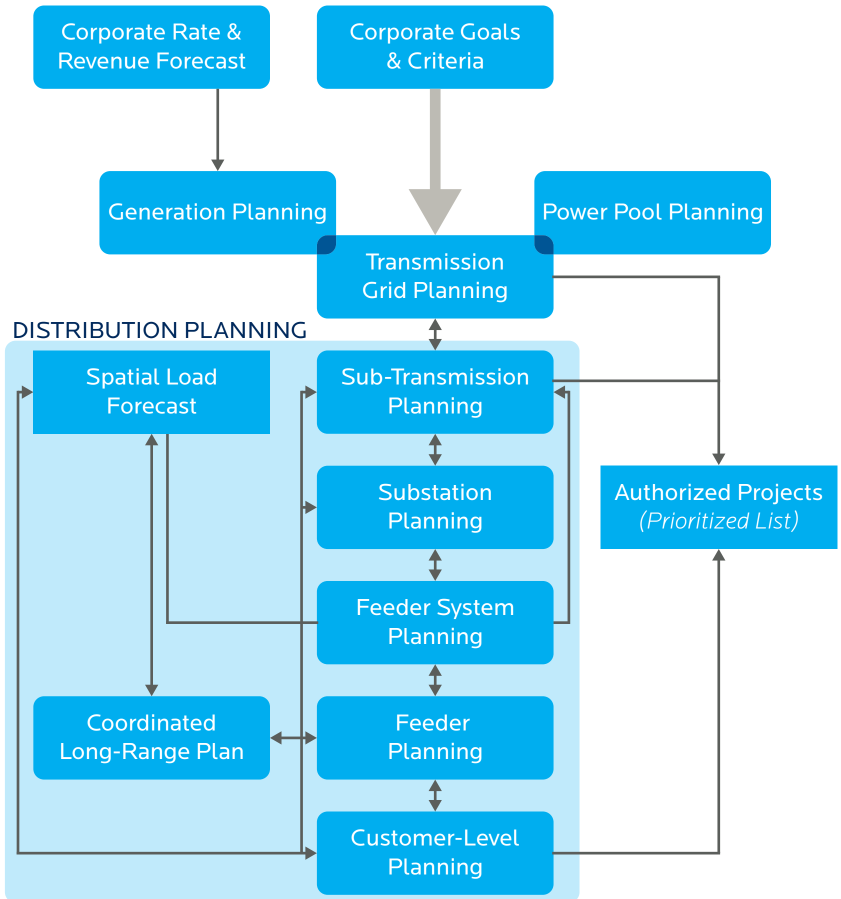


Figure 2. The conventional distribution planning process

1.3. WHY CONVENTIONAL DISTRIBUTION PLANNING IS NO LONGER SUFFICIENT

In many regions, DER penetration is reaching levels at which it has a measurable impact on grid planning and operations. For example, solar PV, in some areas the most prevalent DER technology today, is expected to continue its steep growth trajectory for at least several more years (Figure 3). A significant driver to solar PV growth is the Federal Investment Tax Credit (ITC), which was expected to expire in 2016 but was extended through 2021 by Congress in December 2015. The 2016 peak in the chart is due to a large number of projects trying to meet the previous expiration deadline, and the market is expected to return back to a normal growth trajectory in 2017.

The growth of DERs is challenging many of the assumptions upon which traditional distribution planning relies. DERs are creating two-way power flows on the distribution system that legacy distribution equipment was not designed for. DERs are also confounding conventional load forecast methodologies and complicating the modeling of distribution feeders by introducing new kinds of generation sources or modifying load profiles.

Utilities may find that the traditional distribution planning framework is no longer able to accurately predict net load profiles and guarantee grid reliability once DERs reach a significant level of penetration on their system.

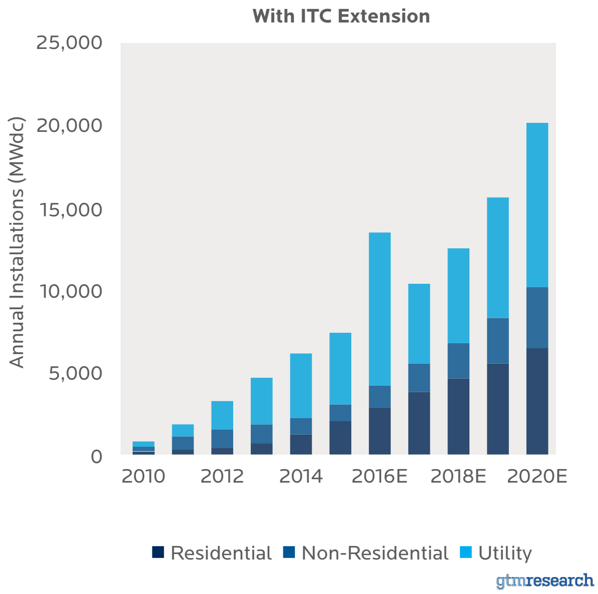


Figure 3. Greentech Media Research Forecast of U.S. Annual Solar Installations, with ITC Extension[3]

High volumes of DER interconnection applications also put administrative strain onto the utility if it lacks efficient methods to handle interconnection studies. Integrated distribution planning that takes load and DER adoption forecasts into account would help speed up the interconnection process. Considering the traditional approach of analyzing the effect of a DER interconnection individually, the inundation of interconnection requests is another factor causing utilities to re-evaluate their current processes.

In short, utilities are facing a new market landscape in which DERs play an ever-increasing role in the electric power system. Figure 4 provides a visual representation of the transition to a distributed energy future and highlights some key features of the new market landscape.

1.4. DRIVERS OF DER ADOPTION

DER adoption is being driven by three major trends: changes in customer choices, technological development, and new policies and regulatory proceedings. These trends are described in more detail below.

1.4.1. Customer Choices

In recent years, many customers have shown an increasing interest in controlling their energy use and energy sources based on multiple motivations:

- Reducing electric bills
- Desire for "energy independence"
- Perceived deficiencies in grid reliability (especially during storms and natural disasters)
- Pursuit of cleaner energy options
- Enthusiasm for new technologies

Customer preferences are also shaped by solar developers, energy efficiency installers, electric vehicle manufacturers, "smart home" equipment and software vendors, environmental groups and other new market entrants that commit significant resources to marketing, policy advocacy, building customer relationships and making various DER technologies the "next big thing" that customers will want.

1.4.2. Technological Development

Until recently, DER technology uptake has been severely hampered by economics and technical capabilities. However, costs are declining rapidly for solar PV, battery storage, electric vehicles, communications/control devices and software, and other DER technologies, making them more attractive to end users. At the same time, DER performance and functionality has been improving, again making it more attractive and increasing

A growing number of utility customers now have options for new products and services related to electricity that they have not had previously, and are making choices that do not necessarily align with utility plans and preferences. Some of these choices also reduce overall electric load, which is a major concern for utilities whose revenue is directly tied to energy sales.

[3] www.greentechmedia.com/articles/read/investment-tax-credit-extension-will-increase-solar-installations-54

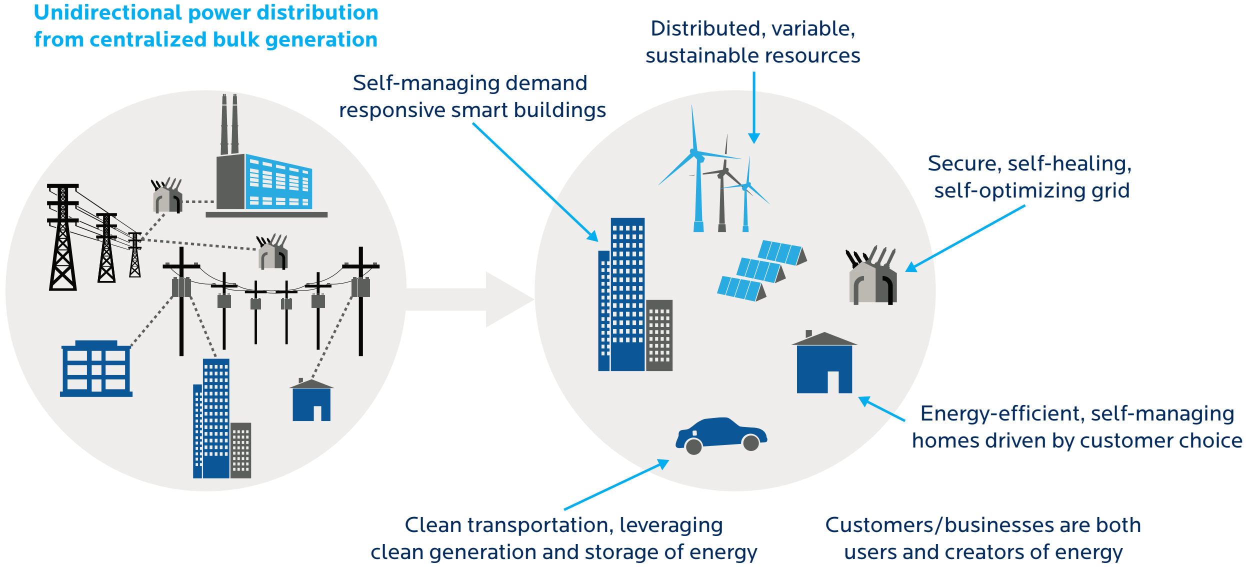


Figure 4. The Transition to a Distributed Energy Future

uptake. For example, solar PV system efficiency continues to increase, as does battery energy density. In addition, the machine learning and computing power of smart thermostats, enabled through a home's Wi-Fi router (rather than the utility's smart meter), is expanding quickly due to intense competition among vendors.

In addition to cost and performance improvements that have made DER technologies more attractive to customers, it now offers capabilities that can provide benefits to utilities. Smart inverters for solar PV systems and other DERs can help support voltage and frequency stability on the distribution system, batteries can offer fast-ramping capabilities when demand spikes, and more sophisticated demand response programs (including EV charging loads) can target load reductions in a much more granular way than before. However, the availability of these new capabilities also means that utilities need to develop standards, electric rate structures and monitoring/control systems to manage and/or influence these DERs, which is a large challenge in itself.

1.4.3. Key DER Policies and Regulatory Proceedings

As utilities are looking for new and innovative ways to perform distribution planning and deal with the challenges of DER growth, legislators and regulators in several states are taking a more "proactive" role by instituting policies and proceedings to engage utilities in DER deployment and planning, as summarized in Table 2.

Table 2. Policy and regulatory proceedings in key states

State	Policies Relevant to Distribution Planning
California	State Renewable Porfolio Standards (RPS) requires electricity retail sales procured from renewable energy resources as 33% by 2020, and 50% by 2030 (75% must come from resources located within, and/or states connected to, California). In July 2015, State Assembly Bill 327 required investor-owned utilities to submit individual Distribution Resources Plans (DRPs) for approval that included: (1) DER integration capacity within current distribution system down to circuit level; (2) Methodology for quantification of DER locational value; and (3) Growth scenarios of 10-year deployment siting at the substation level and impacts on distribution. CAISO will allow aggregated DER portfolios to bid into wholesale markets beginning in late 2016. "Integrated Demand-Side Resources" (IDSR) proceeding is exploring new procurement models, tariffs, and contracts for DERs to meet grid needs. In January 2016, the California Public Utilities Commission voted to retain retail-rate Net Energy Metering (NEM) tariff, while requiring NEM customers to pay more in non-bypassable charges and switch to time-of-use rates (NEM tariff will be reviewed again in 2019).
Hawaii	State RPS requires renewable penetration to ramp up according to the following schedule: ■ 15% by 2015 ■ 25% by 2020 ■ 40% by 2030 ■ 70% by 2040 ■ 100% by 2045 In 2014, the Hawaii Public Utilities Commission directed the Hawaiian Electric Companies (HECO) to develop and implement a fully integrated portfolio for demand response programs (Order No. 320542, Docket No. 2007-0341), along with a comprehensive Distributed Generation Interconnection Plan (DGIP) for accelerating grid integration of DERs. In early 2015, HECO was the first utility to enable advanced PV inverter functionality on a large scale, which allowed it to raise the threshold for detailed interconnection studies from 120 to 250% of minimum daytime load (highest in the nation). In October 2015, the PUC adopted two new NEM programs (Order No. 332583, Docket No. 2014-0192): ■ "Grid supply" program resembles traditional NEM with customers receiving wholesale instead of retail for energy exported to the grid ■ "Self-supply" does not pay for grid exports and encourages customers to align generation with load profile using energy storage and load management ■ Next phase of proceeding will focus on growing competitive markets for DER to maximize the value of grid-supported DER systems
Massachusetts	RPS requires up to 25% renewable generation by 2030; State law requires >25% load satisfied by demand-side resources by 2020. Senate Bill 2214 established solar and net metering task force to focus on planning solutions to reduce effects of outages; optimize demand (reduce system and customer costs); integrate distributed resources; and improve workforce and asset management. The Department of Public Utilities also ordered distribution utilities to develop and execute 10-year Grid Modernization Plan (GMP), including marketing, education and outreach plans, with five-year capital investment plan to achieve advanced metering functionality within five years of GMP approval.

State	Policies Relevant to Distribution Planning
Minnesota	Stakeholders requested the 21st Century Energy System, or e21 Initiative (docket 14-1055), to realign issues at odds between the traditional utility model, technology advancement, and public policy: DER growth identified as main drivers of change in the electricity industry Phase I examined and called for more transparent and integrated system planning process (December 2014) Phase II will map out new regulatory system to develop economically viable utility business model for DER initiatives
New York	Reforming the Energy Vision (REV) initiative changes the role of distribution utility via two tracks: ■ **Track 1:** Utilities are to efficiently integrate behind-the-meter DER into the grid; utilities are distributed system platform provider, or "market enabler" of DERs and third-party services. Utilities are not expected to primarily own DERs (except where market is not responding in cost effective ways). This includes DER participation in the NYISO market. ■ **Track 2:** Financial support of Track 1 via ratemaking to raise capital for infrastructure improvement and upgrades, and aligning utility financial incentives with societal goals (e.g., reducing emissions, improving reliability).
Texas	Distributed Resource Energy and Ancillaries Market Task Force (DREAM TF) approved by Electric Reliability Council of Texas (ERCOT) to allow appropriate DER market participation through: Investigation of current and future DER development opportunities at transmission substation level and up Development and recommendation for regulatory framework, including rules for DERs to bid into wholesale market

While the six states listed in Table 2 are actively guiding DER adoption, they also represent a significant market share of the industry. In 2014, the utilities and electricity providers located within the six states combined to sell 25 percent of total U.S. megawatt-hours (MWh), according to the annual EIA-861 survey. The 48 investor-owned utilities in these states sold 11 percent of U.S. MWh in 2014.

Examples in 2015 of more states pursuing DER policy changes include:

- Colorado House Bill (15-1250) introduced to direct utilities to seek alternative revenue models that take into account of grid resiliency, carbon emissions and customer satisfaction
- New Hampshire's House Bill 614 requests investigation and identification of grid modernization elements

At the forefront of DER adoption, regulated utilities in these key states must follow guidance from their regulatory commissions and explore the best integration methods. But other initiatives have also emerged with the intention to assist utilities in adopting proactive DER planning processes. Examples include:

- Advanced Energy Economy (AEE): "21st Century Electricity System (21-CES)"
- Electric Power Research Institute (EPRI): "Integrated Grid" Initiative
- Energy Innovation: "America's Power Plan"
- GridWise Alliance: "Future of the Grid" Initiative
- Solar Electric Power Association: "51st State" Initiative
- Department of Energy: "Grid Modernization Initiative (GMI)"

NOTE: Most of the proceedings and initiatives listed are still underway as of February 2016. This report captures information that was available as of the time of publication. However, given how rapidly industry practices are changing with increasing DER penetration, readers are encouraged to seek updated information.

While 75 percent of MWh sales are in states with relatively "passive" DER policies, more states are following the leaders and DER policies are expected to converge between states over the next decade.

2 UTILITY DER PLANNING TRENDS

This section describes emerging trends among utilities in the area of DER planning.

2.1. UTILITY INTERVIEWS

Black & Veatch and SEPA held discussions with key leaders at five different large utilities. Combined, these organizations represent nearly 9 percent of total U.S. electricity sales. Each is working to integrate proactive DER planning methodologies into its distribution planning process. These leaders shared insights on the approaches they are developing, their external and internal motivations, and the challenges they are facing in embracing DER planning.

For purposes of this whitepaper, participating utilities are represented anonymously by numbers 1 through 5. Represented organizations are geographically dispersed from the West Coast to the East Coast, and operate under differing policy environments with varying customer mixes. They include investor-owned as well as publicly-owned utilities.

The knowledge shared by these utilities enabled Black & Veatch and SEPA to identify common themes and how advanced each utility is in each area. These findings, including key drivers, methodology and tools, are summarized in Table 3.

NOTE: The “heat map” color coding in Table 3 is meant to provide a quick visual aid, with green denoting activities that are most advanced and red denoting the least advanced in each area by utility. It is also important to note that the term “advanced” does not necessarily imply better. It simply means that the utility is taking actions further from the current distribution planning norm in response to development of DER within its service territory. Utilities that are not actively planning for DER may not need to, if DER growth and policy support are not significant.

Sections 2.2 through **Section 2.7** describe key drivers and methodologies/tools in more detail, and also cover trends in organizational structure, industry gaps and critical software tools.

2.2. KEY DRIVERS

Interviews revealed that regulatory compliance and operational necessity are the two most important factors in driving utilities toward proactive distribution planning for DER.

Regulatory Compliance: Three out of five utilities responded that they face regulatory mandates to conduct DER planning. Although one utility is pushing to implement changes ahead of regulatory mandates, others have been working to meet regulatory deadlines for DER plans in 2015 and 2016. In addition, two utilities face potential financial penalties for not meeting distribution system reliability metrics (e.g., SAIDI/SAIFI targets), which is driving them to plan proactively for DER integration in order to avoid the penalties associated with outages or service deterioration, which may potentially be caused by DERs.

Operational Necessity: All five utilities cited a growing volume of DER interconnection requests (in queue and projected) as another key driver for proactive DER planning, in addition to the potential impact of DERs on distribution system operations and safety. Some utilities are now reaching penetration levels at which the need to address these “operational necessity” issues has become critical to maintain reliability. One specific reason is that DER developers often site their projects based on factors (e.g., land prices, rooftop space, or customer interest) that may conflict with where the grid is best able to handle these interconnections.

Table 3. Summary of Interview Findings (Green>Yellow>Red = *most* to *least* advanced activities)

		Utility 1	Utility 2	Utility 3	Utility 4	Utility 5
Key Drivers	**Regulatory Compliance**	Regulatory DER mandates	PUC DER mandates	PUC DER & reliability mandates	Reliability mandates	None
Key Drivers	**Operational Necessity**	Interconnections	Interconnections	Reliability; Interconnections	Reliability; Interconnections	Interconnections
Methodology	**Timeline for DER Planning**	Short-term Early 2016	Short-term By July 1, 2015	Short-term Will submit DER plan under PUC proceeding in the near future	Mixed Jurisdictions have different planning requirements, some include DERs	Not set No specific timeline
Methodology	**Incentivizing Preferred Interconnection Locations**	Somewhat Interconnection studies differentiate costs by location (indirect guidance for customers)	Somewhat Provides maps of preferred interconnection locations	Yes Strategic Solar Locations come with extra incentives	Somewhat Currently provides maps of "restricted" circuits; may provide more detailed guidance in the future	No Does not provide any specific guidance on interconnection locations
Methodology	**Cost Recovery/ Rate Restructuring**	Under consideration Conscious of DER rate impacts and considering future rate design options	Yes NEM 2.0 proceeding underway	Under consideration Rate restructuring likely under PUC proceeding	No specific plans NEM tariff is only rate structure currently for behind-the-meter DERs	Under consideration Assessing current rate structure and design
Tools	**Maps of Preferred Interconnection Locations**	Somewhat recent RFO identifies optimal solar interconnection locations	Yes Preferred interconnection location maps publicly available	No Third-party provides solar installation mapping for public view; but contains no interconnection info	Somewhat Public Can view distribution Mapping of restricted circuits; working on further guidance	No
Tools	**Advanced DER Modeling Tools**	Most developed System-wide distribution model; tools for measuring and forecasting solar output	Some development Does T&D modeling, but no system-wide distribution model; uses static distribution modeling tools	Some development No DER forecasting; sophisticated internal modeling tools but no system-wide distribution model and tools need to be integrated better	Most developed System-wide distribution model and DER forecasting tools; DOE grant for modeling advanced voltage reg. strategies and upgraded control schemes	Some development Runs offline GIS/DMS for interconnection studies in some cases; conducting high solar penetration impact studies on bulk generation and T&D system wide
Tools	**Active DER Management**	Demo-stage Multiple storage demos; establishing EV plans; testing IT systems to better integrate DER data	Most Advanced Smart inverter standards; substation-level energy storage; EV and demand response integration; DERMS	Demo-stage Microgrid projects; AMI pilot	Most Advanced Planning autosectionalizing/ restoration schemes with all customer DER mapped; testing smart inverter functions	Demo-stage Developing DER interoperability standards; adapting DMS to handle DER

2.3. METHODOLOGY

The following three factors were identified as being important components of the DER planning approach at a utility.

Timeline for DER Planning: Three out of five utilities have established timelines for completing DER plans in the near term, which are mostly determined by regulatory mandates. Utility 5, because it does not have regulatory mandates around DERs, has not established a specific timeline.

Incentivizing Locational Deployment: One indication of utilities implementing proactive DER planning is providing (dis)incentives for locational deployment (e.g., to drive interconnections to more suitable locations on the distribution system). Utility approaches include:

- Applying additional cost to unfavorable interconnection locations
- Fast-tracking requests in favorable locations
- Identifying "solar strategic locations" for extra DER project incentives
- Identifying restricted circuits with little or no ability to handle further DER interconnections

Use of incentives for this purpose may not be allowed by regulators, and it is not yet clear what level of incentives is required to drive developers to favorable locations. Some grid operators, like PJM, have taken a stance against providing location guidance to developers because it could be perceived as providing an unfair advantage to certain applicants.[4]

Cost Recovery / Rate Restructuring: All five utilities are concerned about their ability to recover their fixed infrastructure costs in the future if DER penetration continues to increase. Rate restructuring is an obvious method for dealing with this cost recovery concern. Therefore, implementation of proactive DER planning will likely include some level of rate restructuring. Only one utility out of the five interviewed has a specific rate proceeding underway to date that could significantly restructure the tariff for DERs. Three of the other utilities note they are investigating changes to their rate structures for DER customers as a result of growing levels of DER penetration.

2.4. TOOLS

"Tools" in this case refer to software packages and other analytical aids that facilitate distribution planning assessment and communication with DER developers and customers.

Maps of Preferred Interconnection Locations: Similar to "Incentivizing Locational Deployment" above, the use of this tool demonstrates that the utility has begun attempting to direct DER projects to more optimal locations, utilities are working to direct DERs to more optional locations to avoid interconnection applications in locations where they will not be approved (and thereby saving time for the utility and developer), or because of a regulator mandate. Although only one utility indicated that its preferred interconnection location maps are complete and publicly available, two other utilities also provided more limited maps of optimal or unsuitable interconnection locations. More utilities are expected to pursue this type of map in the future to track DER installations and guide project siting.

Advanced DER Modeling Tools: This includes system-wide asset models (including bulk generation and/or T&D), forecasting of DER output and dynamic distribution modeling capabilities. Two of the five utilities have integrated some of the most advanced models/tools, while the other three will likely be adopting similar tools in the future.

[4] SEPA and EPRI, 2014. "Utility Strategies for Influencing the Locational Deployment of Distributed Solar." The Executive Summary is available for download at http://www.solarelectricpower.org/media/224388/Locational-Deployment-Executive-Summary-Final-10-3-14.pdf

Active DER Management: All five utilities are exploring active management with demonstration-stage DERs (inclusive of solar, energy storage and demand response resources). Three of these utilities have established plans and begun implementation, beyond demonstration, of remote control systems to manage DERs. As an example, one utility has mapped all customer-sited DER installations and is currently testing feeder auto-sectionalized protection plans to increase reliability under a variety of load/DER scenarios.

2.5. ORGANIZATIONAL STRUCTURE

Changes in the distribution planning process are also beginning to affect utility organizational structure.[5] Traditional utility distribution planning departments may not be ready to take on the new responsibilities associated with a more proactive and holistic DER planning process. Among the interviewed utilities, two approaches appear common:

1. The utility has moved or is moving toward a dedicated DER group that incorporates multi-disciplinary personnel.
2. The utility has a lead department supported by a cross-functional set of other departments involved in DER deployment.

For the latter option, the main department may bear various labels, e.g., the "distribution planning" or "DER/customer strategy" group. Support groups can include technical departments (e.g., distribution engineering, protection, construction and maintenance, IT) and non-technical departments (e.g., rates, billing, customer service, key accounts, incentive program operations, interconnection processing), and correlates to the DER planning strategies and support needs identified by the utility.

In general, utilities adopting organizational structure #2 tend to utilize a wider array of methodologies and tools in the DER planning process, whereas utilities adopting organizational structure #1 tend to develop DER strategies through implementation of specialized technical tools.

2.6. INDUSTRY GAPS

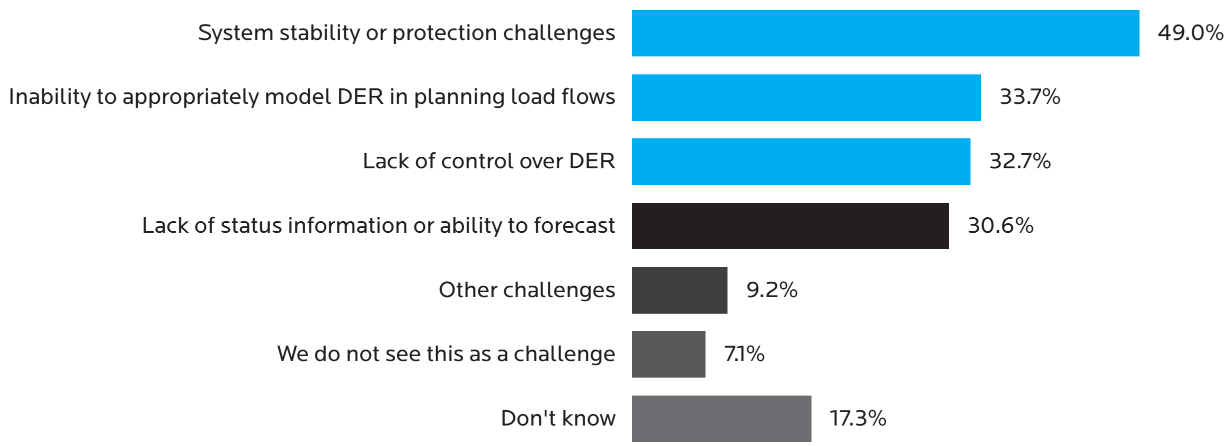
In Table 3, the yellow and red boxes for the five utilities interviewed could be viewed as areas where utilities have gaps in developing distribution planning methodologies and tools that incorporate DER impacts. Utilities 1, 2 and 3 are located in one or more of the states listed in Table 2 where regulators are actively setting guidelines for DER adoption (CA, HI, MA, MN, NY, TX). As one might expect there are fewer planning gaps within these utilities (one red area but most are green) compared to the two utilities in DER "passive" states (several red areas with just a couple in green). Yellow areas can be viewed as those where the utility is transitioning to DER-focused methods, typically faster in active states and slower in passive states.

There is reason to believe that utilities 4 and 5 are representative of the broader U.S. utility industry (as previously noted, passive-state utilities represent 75 percent of 2014 electricity sales). Utilities in passive states are studying, and in a number of cases adopting, techniques like those being developed at utilities 1, 2 and 3 because utilities in active DER states are pioneering tools and methodologies for DER planning.

Black & Veatch's 2016 *Strategic Directions: Smart Cities/Smart Utilities Report* supports the hypothesis that planning gaps in these five utilities are, in fact, representative of the broader U.S. electric utility industry. As previously noted, the Black & Veatch report included survey responses from 206 predominantly North American electric utilities. Their view on the challenges of supporting a high penetration of DERs is illustrated in Figure 5.

Operationally-focused system stability and protection concerns top the list of challenges, which is consistent with Black & Veatch's findings in its long-running *Strategic Directions: U.S. Electric Industry* report series, where reliability consistently tops the list of top utility concerns. With regards to interview findings, it is "inability to appropriately model DERs in load flows" that is the top gap in DER planning (please refer to **Section 2.7** for more details on modeling tools.).

[5] For information on how renewable energy is changing utility organizational development, see the executive summary of "Benchmarking Utility Organizational Structures: How Renewable Energy Is Reshaping the Utility Hierarchy". Available at: http://www.solarelectricpower.org/media/215253/SEPA-Benchmarking-Report-Executive-Summary-9-15-14-rev.pdf



Other key gaps utilities are working to address include:

- The lack of a standard approach and best practices for taking DERs into account within the distribution planning process
- The lack of proven hardware and software solutions for widespread DER monitoring and control, e.g., a Distributed Energy Resource Management System (DERMS)
- Uncertainty about what level of DER control/aggregation is appropriate, and whether DERs should be managed by utilities, third-party aggregators, or a combination of the two
- The lack of device-level DER models that allow distribution engineers to accurately predict the behavior of smart PV inverters and other new technologies when interconnected
- The lack of a direct link between financial/rate models and distribution/DER planning models

Another key industry gap is the differing perspective of the utility and customers regarding DER adoption. Utilities tend to have preferred areas for customers to interconnect DERs, with "preferred" meaning what is best for the utility in terms of grid reliability, safety and economics—which of course eventually benefit customers, but through the lens of a utility's way of doing business.

As part of California's Distribution Resource Plan filings, the state's investor-owned utilities (IOUs) developed methodologies to assess their distribution circuits and identify those that have the best capacity and economics to accommodate DERs. Some utilities refer to these studies as "breakpoint" or "hosting capacity" analyses—or how much a circuit can handle before problems occur like voltage violations (which can appear with PV) and service transformer overloads (which can appear with EVs).

While utilities may offer rates or programs to motivate customers to add DERs in utility-preferred locations, such incentives are just one part of what drives people to adopt solar PV or EVs. There are market, demographic and cultural forces beyond the utility's sphere of influence that will very likely lead to DER installations in locations that are not advantageous for the utility. People will acquire EVs for a variety of reasons—tax rebates, carpool lane access, lower operating costs, environmental concerns, etc. Thus, utilities should accept a broader perspective of DER adoption and dispersion (as described in **Section 3.1**), in addition to the perspective of what is best for the grid. Distribution planners may be surprised at the difference between what is best for the grid and what is desired by their customers.

2.7. KEY SOFTWARE TOOLS

Interviewees at the five leading utilities, and participants in the Black & Veatch survey all highlighted the particular need to have more effective power flow system modeling that can better assess DERs as compared to legacy tools. This is the one key area of utility-specific software that is new compared to widely adopted, existing planning tools. Figure 6 lists the features of legacy modeling tools, and compares them to the features of the latest generation of modeling tools.

Legacy Modeling	Vs.	Latest Modeling
T *or* D	→	T *and* D
Engineering	→	Planning
Design	→	Operations
Low Resolution	→	Time Series
Static	→	Dynamic
Snapshots	→	Forecasts
Heuristic	→	Optimization
Feeders	→	Full System
Balanced 3Ø	→	Unbalanced 3Ø
Slow	→	Fast
Some DER	→	DER Scenarios
Cumbersome	→	Usable

Figure 6. Legacy vs. Latest Features of Grid Modeling Software

System power flow modeling has three primary components:

- T&D asset model
- Power flow state estimation algorithms
- Analytics/optimization capabilities.

Figure 7 shows data sources for the parts on the left and notable vendors on the right (**Section 3.2** discusses the power flow modeling process, and places it in the larger, proactive DER planning context).

Notable software and service providers are listed. Most are well-established and widely-deployed, like SynerGi (formerly known as SynerGEE) and CYME, and have been updating their offerings to move from legacy to latest capabilities. EPRI's OpenDSS and PNNL's GridLabD are open-source software (though many add-ons are not freely available); the others are proprietary. A new entrant, Qado, offers both planning and operational capabilities aimed at facilitating customers' and developers' PV interconnection requests through online portals linked into the host utility's existing software.

Electric utilities are also adopting distribution management systems (DMS) software that assists distribution grid operators with real-time information and control, as opposed to just static modeling. A core DMS component is a very detailed and up-to-date distribution system asset model that is capable of simulating power flows and estimating electrical state variables quickly and accurately enough to help operators with a number of challenges such as Volt/VAR control. Utility 5 claimed that it has taken 10 person-years to develop, test and validate its DMS model to the point where it can be used by system operators. This is the "heavy-lifting" part of building system models. Interestingly though, neither the DMS at utility 5 or at utility 2 is being used regularly in an off-line, "study mode" to assess the impacts of projected DER penetration.

Vendors listed in Figure 7 offer separate, off-the-shelf planning-focused distribution models, while some utilities are building internal, operationally-focused DMS models. For those utilities, a logical next step could be to leverage those hard-won DMS asset models and incorporate the "what-if" analytics and optimization capabilities of distribution planning software. Several large DMS vendors like GE, Oracle and Schneider are pursuing this opportunity and working to incorporate planning functionality into their DMS packages. Utility 2 is also developing a custom DERMS to allow real-time monitoring and control of DER assets within its territory. This capability is not available in existing DMS software and the utility sees it as critical to maintaining grid reliability in a future with high DER penetration.

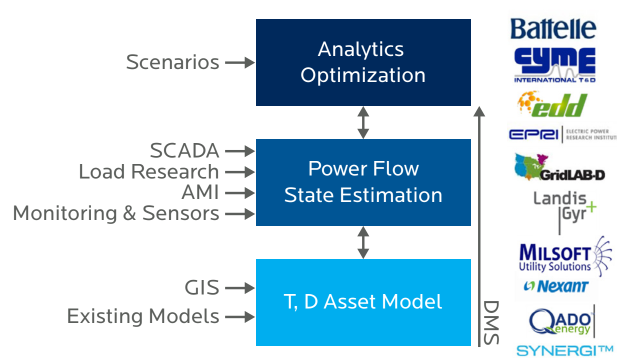


Figure 7. Diagram of Power Flow Modeling Components and Key Software Vendors

3 PROACTIVE PLANNING FOR DER DEPLOYMENT

Section 2 showed a number of leading utilities are beginning to develop various components of a new comprehensive planning process for DERs. However, none have implemented a complete solution yet. This section describes the key features of the emerging DER planning paradigm that will enable utilities to fully incorporate DERs into their normal planning processes. In essence, this new planning process is an expansion of the traditional utility Integrated Resource Plan (IRP) process.

Figure 8 provides an illustration of what this process may look like. Each step in this process is described in **Section 3.1** through **Section 3.5**. **Section 3.6** examines the benefits of a proactive DER planning process, and **Section 3.7** discusses other issues that require consideration during the implementation of such a process. **Section 3.8** provides a summary of the proactive planning process.

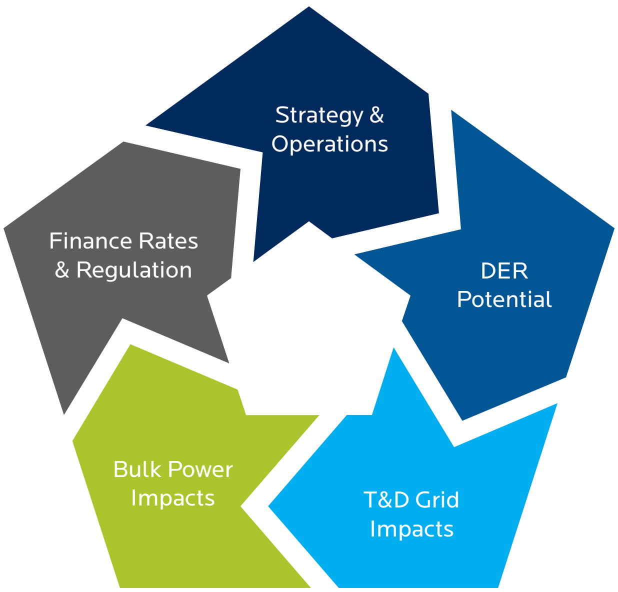


Figure 8. Illustration of a complete, proactive DER planning process

3.1. DER POTENTIAL: LOAD AND DER ADOPTION FORECAST

The first step in traditional distribution planning is forecasting load growth in the various sub-regions of a utility's service territory. With increasing penetration of DER technologies utilities also need to forecast growth in the penetration of DERs. While utilities have been developing load forecasts for many decades and have well-established methodologies for such studies, the methodologies for DER adoption forecasting are in their infancy today and the necessary techniques and software tools are still under development by various consultants and software vendors. However, there are a few key elements of an effective DER adoption forecast. These steps are summarized in Table 4. This forecasting process should be completed for each DER technology of concern. In addition, for the most precise results, utilities should model DER adoption at the individual customer or site level.

Various vendors have commercialized methodologies and software tools for completing steps 1 and 2 listed in Table 4. However, those tools are usually designed to assess one site at a time for individual customers. Tools for certain technologies, like solar PV, are more advanced than tools for other technologies, like EVs.

In short, there has been rapid progress in refining and automating this DER adoption forecasting process over the last few years at the utility service territory level, but methodologies have not been standardized across the industry yet, and this is an area for future study.

Table 4. Key DER adoption forecast steps

Step #	Name	Description
1	Technical Potential	Estimate the amount of DER capacity that can fit within the physical constraints of each customer site. (For solar PV, the constraint is the amount of unshaded, properly oriented space on the rooftop or the ground available at the site. For other technologies, the constraint may be the electrical panel capacity, natural gas line capacity, customer peak demand, or best available technologies,)
2	Economic Potential	Model the economics of DER assets for each customer site to determine the amount of DER capacity that is cost-effective according to a specified financial metric. (Metrics may include levelized cost of energy, payback period, net present value, etc.) This is a subset of the technical potential.
3	Achievable Potential	Even if a DER technology is technically feasible and cost-effective, not all customers will adopt it due to other non-technical/non-economic barriers. This step applies an "adoption curve" to estimate what proportion of customers is likely to implement DER technologies (e.g., with a ten-year payback 50 percent of customers will adopt, and with a one-year payback 90 percent of customers will adopt). This is a subset of the economic potential.
4	Customer-Level Adoption Probability (or "Dispersion Analysis")	The end result of the DER adoption forecasting process is an adoption probability for each DER technology at each individual customer site, based on the technical/economic/achievable potential calculated in the previous steps. It can also be taken a step further to project how adoption probability will change over time as technical/economic/achievable potential changes (e.g., as technical performance improves or costs decrease). This customer-level adoption probability can be aggregated to calculate the amount of likely DER adoption across an entire distribution circuit, or utility service territory, for distribution planning purposes; or it can be used to select which customers should be targeted for more detailed modeling or for marketing of DER-related programs and services.

Commercial tools for steps 3 and 4 are not available at this time, based on the authors' knowledge, and more research is needed to accurately estimate the "adoption curve" for each DER technology in step 3. However, Black & Veatch has developed proprietary analytics tools for completing steps 1-4 for large groups of customers simultaneously over an entire utility service territory. This requires significant computing power to process the very large volumes of data involved, as well as methods for quickly visualizing the results of the analysis.

Once the load and DER adoption forecasts are created they can be combined for a complete picture of how the net load profile on the distribution system is likely to change in the future. Ideally, the load and DER profiles will be on an hourly basis, or even sub-hourly if necessary for the dynamic grid modeling in the next step.

It should be noted that, in addition to the new tools for DER adoption modeling, new tools are emerging for more robust and granular load forecasting than was possible in the past, and it will be necessary to ensure proper alignment between distribution-level and transmission-level system forecasts.

3.2. T&D GRID IMPACTS: DYNAMIC GRID MODELING

Most utilities have historically performed distribution grid modeling by examining static "snapshots" in time corresponding to peak load periods to identify where system limits were being violated and where upgrades were required to accommodate load growth. However, increasing DER deployment means the net load profile will become much more variable than before. As a result, dynamic modeling of load and DER technologies on an hourly or sub-hourly basis is required to capture all potential impacts on the distribution system. In addition to modeling peak load periods, periods of minimum load and peak solar PV generation may also need to be investigated.

The new breed of distribution modeling tools described in **Section 2.7** are currently being developed and implemented to serve this need. The first step, which is often laborious, is to assemble all transmission and distribution system data (e.g., substation and circuit characteristics) and populate all relevant details about the utility grid within the modeling platform. Once the model is complete, new modeling tools have the capability to simulate individual distribution circuits or the entire transmission and distribution system—including all customer loads and DERs down to the level of the secondary side of the service transformer—in order to comprehensively quantify all positive impacts (e.g., reduction in peak load) and negative impacts (e.g., increased voltage fluctuations) on the grid.

In particular, the modeling should identify at what time, or at what level of DER penetration, a violation of thermal/voltage/power quality/protection/safety limits occurs on the system. This analysis also determines the DER "hosting capacity" of the existing distribution system (e.g., what the system can handle without decreasing reliability). Ideally, this information would be compared with the utility's aggregated load and DER adoption forecast to determine where customers are most likely to install an amount of DERs that could cause violations. This "top-down" hosting capacity analysis and "bottom-up" DER adoption forecast can inform the utility's future planning for the distribution system.

Once the grid impacts of load/DER growth are known, utility planners must list possible mitigation solutions to address the violation(s), and select the most cost-effective option. Mitigation solutions traditionally included options such as:

- Re-conductoring
- Transformer upgrade/replacement
- Installation of voltage regulators and capacitor banks
- Reconfiguration of protection scheme settings

In addition to traditional methods, some DER technologies, like advanced solar PV inverters, battery storage, demand response, and EV charging infrastructure, may now be feasible alternatives to address certain types of violations—assuming the utility is, though some are not yet fully, convinced that DERs are sufficiently reliable to defer or avoid the need for traditional options. As a result, utility planners must now compare traditional and DER options on a common basis, and select the optimal mix of mitigation solutions to cost-effectively address the violation(s).

For example, growth in rooftop solar PV on a particular circuit might lead to voltage violations, which could be addressed by a new capacitor bank and/or by installing battery storage and advanced PV inverters to better manage voltage. This new paradigm can also be extended in an iterative process to determine the costs and equipment investments required to achieve a certain level of DER penetration on a circuit. For example, utilities may want to answer the question, "what equipment upgrades or DER-based solutions are needed and what will the total cost be to reach 100 percent PV penetration on this circuit?" The new planning paradigm allows utilities to answer this question for a single circuit, or for the entire distribution system.

3.3. BULK POWER IMPACTS

The bulk power system consists of the transmission grid and the fleet of large-scale generators connected to the transmission grid. At low DER penetration levels, there are few, if any, impacts on the bulk power system because any excess generation from DERs on various circuits is consumed by other customers connected to the same distribution substation.

> Traditional distribution planning involved forecasting load growth, identifying violations using static models, and selecting a traditional utility equipment solution to address violations at the lowest cost. The new planning paradigm involves forecasting load and DER adoption, identifying violations using dynamic tools, and selecting an optimal mix of traditional and DER-based mitigation solutions to address violations.

However, in areas with rapidly increasing DER penetration, some utilities are beginning to see noticeable bulk system impacts. This occurs when excess DER generation begins to back-feed onto the transmission grid. In these areas, utilities are working to develop methodologies for assessing these impacts.

The first step is to run a base case simulation of the bulk power system using a production cost modeling software tool (there are many mature commercial software packages available for this purpose). Once the base case is complete, a change case simulation can be run with modified assumptions—including a net load profile that takes DER adoption forecasts into account—to determine the differences in generation fleet dispatch, transmission system impacts and overall production costs.

Such analysis can help answer many questions at the bulk power and distribution levels, including:

- Given a particular set of DER installations on the distribution system, what is an optimal fleet of bulk generation resources?
- Given a particular fleet of bulk generation resources, what is an optimal overall mix of DER installations on the distribution system?
- What system-level capacity value can an aggregated portfolio of DERs provide?
- What impacts will increasing DER penetration have on existing bulk generation assets in terms of operations, maintenance, fuel purchases, imports, exports, ramp rates, need for ancillary services, etc.?

Any number of scenarios can be run with varying mixes of large-scale generation and DERs to fully understand the impact of increasing DER penetration on the bulk power system. Running numerous scenarios can be part of a grid investment optimization process that is generally conducted in the context of a utility's Integrated Resource Plan. Any number of scenarios can be run with varying mixes of large-scale generation and DERs to fully understand the impact of increasing DER penetration on the bulk power system. Running numerous scenarios can be part of a grid investment optimization process that is generally conducted in the context of a utility's Integrated Resource Plan.

3.4. FINANCE, RATES, AND REGULATION

In addition to the technical modeling in the preceding steps, it is critical to incorporate economic/financial/rate analysis into the DER planning process. Traditionally, utilities have estimated the costs of necessary investments in distribution upgrades/transmission system upgrades/bulk generation, determined the total revenue requirement, allocated the revenue requirement across customer classes, designed rates for each class and calculated the impact on corporate-level financial metrics.

Utilities with high DER penetration are developing methodologies for quantifying the locational value of DERs on the distribution system. Ideally, this analysis should be based on a full accounting of all costs (e.g., integration and interconnection costs) and benefits (e.g., avoided energy, capacity, losses, emissions, etc.) associated with DER installations on the grid. Many utilities have undertaken cost-benefit studies of net metering tariffs, or "value of solar" studies, which are examples of such DER value analysis. The most sophisticated studies are now beginning to incorporate location-specific costs and benefits into the valuation methodology.

If the utility seeks to encourage DER installations, this locational value methodology can be extended to develop specific tariffs to encourage customers to install particular DER technologies in specific locations on the distribution system, or to develop procurement processes and contracts for DER projects to meet very specific reliability needs (e.g., battery storage providing local capacity when demand peaks on a certain circuit/substation). Such tariffs or contracts should include a time-varying rate to ensure that DER assets actually help meet grid needs at the proper times.

This whitepaper does not focus on policies to support DER deployment at the right time and place (that topic was covered in detail in a separate SEPA report on locational deployment[6]). However, it is important to note that maximizing the value of DERs on the distribution system will likely require some corresponding modifications to existing policies, or introduction of new policies to ensure that each DER asset's performance provides adequate benefits to the utility as well as the customer. DER tariffs or compensation schemes can vary along three primary dimensions:

- **Location:** Utilities could provide upfront or performance-based incentives to DER installations in preferred locations to support distribution system reliability needs. These incentives could be incorporated into tariff design for large groups of customers, or they could be incorporated into standardized contracts for DER customers with specific performance requirements and penalties. A variation on this concept would be to increase or decrease interconnection costs for DER customers depending on location.
- **Time:** Utilities could use time-varying rates to encourage DER customers to generate or modify consumption of electricity at times that benefit the local distribution system and/or the bulk power system. In most cases, rates would be higher at times of peak demand, lower at off-peak times, or configured to vary in real-time on an hourly or sub-hourly basis with wholesale market or localized distribution market prices.
- **Services:** DER tariffs and compensation schemes can vary based on the services the utility provides to DER customers and the services DER customers provide to the utility; one version of this is "unbundled rates." In general, the DER customer would pay the utility for any energy, capacity (generation and T&D), interconnection, metering, billing, or other services delivered by the utility and would receive compensation from the utility for any energy, firm capacity or other ancillary services delivered to the utility.

Given the complexity of establishing tariffs or compensation schemes that are fully differentiated along all three of these dimensions and applicable to all DER technologies, policies in the near future will likely be targeted at particular DER technologies and encompass only one or two of these dimensions.

3.5. STRATEGY AND OPERATIONS

A key portion of the proactive planning process is not only determining specific grid needs, but also formulating a high-level strategy toward DER integration—including any changes to utility operations to enable more effective DER integration. Utility strategy and operations in the future will be influenced by forecasts of DER growth, and alterations in utility strategy and operations will in turn affect how utilities do or do not accommodate DERs on the grid. The frequency of planning (in terms of Integrated Resource Planning and DER planning) may also need to increase to capture the fast-changing market dynamics of DER adoption.

3.5.1. DER Strategy

In the utility industry today, the question is rapidly shifting from *"should DERs be allowed to expand across the grid?"* to *"how can the growth of DERs be enabled in a manner that supports customer demands, maintains grid reliability and ensures reasonable costs?"* This shift is creating new business opportunities, and many utilities are considering whether to offer new services, such as:

- Community shared solar
- Invest in customer- or third-party-owned DER portfolios
- On-bill financing for customer-owned DERs
- Online tools to support customer decisions about DER adoption

[6] "Utility Strategies for Influencing the Locational Deployment of Distributed Solar." The Executive Summary of this SEPA report is available for download at http://www.solarelectricpower.org/media/224388/Locational-Deployment-Executive-Summary-Final-10-3-14.pdf

- Operations and maintenance services for customer-owned DERs
- Utility ownership of customer-sited DERs
- Utility-owned DER assets to meet grid needs (e.g., utility control of advanced inverters, or microgrids where high reliability is needed)
- Rate structures that allow utilities to recover costs while equitably sharing those costs among ratepayers, and fairly compensating DER customers for the services they provide to the utility

Formulating a coherent strategy around enabling DERs will involve utility management asking fundamental questions about their business model. At one end of the spectrum, a vertically integrated utility could maintain ownership and control of generation, transmission and distribution assets and simply add on new services—many utilities are doing so today.

At the other end, a deregulated utility could relinquish ownership over many grid assets and become solely a distribution system operator that manages supply and demand from customer load and DERs through a "transactive energy" platform. A few utilities are beginning this process voluntarily, including RWE in Germany. Other organizations are heading in this direction due to regulatory mandates, such as IOUs in New York under the state's "Reforming the Energy Vision" proceeding. In the short-term, it is likely that most utility strategies will involve peripheral changes to existing business models. Over the longer-term, a transactive energy model may become the standard.

3.5.2. Utility DER Operations

Once the overall utility DER strategy is created, changes in operations will likely be necessary. Each utility's approach will be unique, based on its own circumstances and culture. Operational changes could include, but are not limited to:

- Internal reorganization (e.g., formation of a dedicated DER operations/planning department)
- Rollout of new DER interconnection processes
- Adoption of new software tools for managing DERs in real-time
- Updates to design standards and construction procedures
- Workforce training and hiring of new skill-sets
- Alterations in how customer service is handled for DER owners

3.6. BENEFITS OF A PROACTIVE DER PLANNING PROCESS

The increasing penetration of DER technologies on utility distribution systems creates challenges for utility planning and operations, but the implementation of a proactive DER planning process as outlined above can address many of these challenges. An initial list of benefits includes:

- Better forecasting of DER growth and resulting impacts on net load profile
- Better forecasting of revenue and rate impacts from DERs
- Decreased DER interconnection timeframes
- Increased DER hosting capacity
- Minimization of distribution system infrastructure costs

3.7. OTHER ISSUES

The following issues should be considered by any utility, regulator, or other stakeholder involved in the implementation of a proactive DER planning process.

3.7.1. Utility Control and Ownership of DER Assets

There are concerns that utility ownership of DER asset portfolios may be less cost-effective than competitive procurement of services from third-party DER developers and may lead to undue burdens on ratepayers. The benefit of utility-owned DERs is the higher probability that DERs would be available when needed to provide necessary grid services when compared to the use of contracts or tariffs with third-party owners involving probabilistic models of DER aggregate portfolio performance rather than "firm capacity". In addition, if third-party developers or customers own and operate DER assets, there is a question about how much monitoring and control by the utility is necessary to maintain distribution grid reliability without significantly diminishing the ability of DER assets to provide benefits at the customer sites where they are installed. It will be critical to ensure regulator-approved tariffs and/or contracts are in place to clearly delineate how much utility control is appropriate.

3.7.2. DER Markets and Procurement

Jurisdictions like New York are pursuing a strategy in which utilities will eventually transition into distribution system operators that maintain an open market allowing customer-owned DERs to serve grid needs. This is a major structural change in the industry and will take time to be implemented. In addition, it will not be implemented by all utilities or all jurisdictions. An alternative approach is for utilities to release specific solicitations for DERs to participate in standardized contracts and tariffs to provide specific grid services in specific locations. Other procurement or market mechanisms for DER will likely emerge in the future as well.

3.7.3. Data Sharing, Confidentiality and Stakeholder Participation

Utilities are caught between competing demands to increase transparency by sharing more data with interested grid/DER stakeholders and mandates to ensure high levels of physical security and cyber security for grid assets. Clearly, DER customers and developers can benefit from greater grid data, but utilities can also benefit from data on DER performance and costs, and requirements for data sharing in both directions will need to be negotiated. This is still an area of very active debate. Each jurisdiction will have to determine what data is appropriate to share and what should be kept confidential. One potential compromise is allowing greater grid data access to a limited stakeholder group that can review utility assessment and provide objective, outside feedback. Perhaps the most robust example to-date of public grid data sharing is California IOUs' Distribution Resources Plan filings in July 2015 that include online maps showing estimated DER hosting capacity by circuit.[7]

3.7.4. Responsibility for DER Interconnection Costs

In the past, utilities and their regulatory commissions have developed policies to determine who is responsible for the costs to interconnect DERs to the utility's distribution system. For example, in California, DERs on the net energy metering tariff under 1 MW do not have to pay any interconnection costs, while DER installations on the utility side of the meter (e.g., those on a feed-in tariff) do have to pay for interconnection costs. Other states have different policies. However, this type of framework assumes that the utility is simply reacting to each interconnection request individually, without any proactive planning. But if utilities adopt more proactive DER planning approaches, they may identify the need for distribution upgrades to accommodate DER interconnections before the actual DER installations occur. This complicates the process of assigning responsibility for interconnection costs. Thus, in adopting a proactive DER planning process, utilities and their regulatory commissions will need to consider how to fairly allocate interconnection costs between the utility and the customers or developers who install DERs.

3.7.5. Integration of DER Planning into Utility Regulatory Process

Once appropriate tools and methodologies are in place for DER planning (as described in **Section 3.1** through **Section 3.5**), it will be crucial to align the DER planning process with other regulatory processes (e.g., distribution planning, transmission planning, generation resource planning and procurement, rate cases, etc.). In particular, assumptions and timelines should be harmonized between distribution-level and bulk system-level planning.

3.7.6. Utility Organization and Staff Resources

Traditional utility organizational silos may hinder effective DER planning. To address this barrier, some utilities have already begun establishing dedicated cross-functional departments focused on DER issues. In addition, growing DER penetration usually means increasing volumes of interconnection requests, and many utilities report that inadequate staffing and complicated processes are a challenge. These should be considered in a utility's overall DER strategy.

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[7] Online maps are available at: http://morethansmart.org/july-1st-california-distribution-resource-plans-released/

3.7.7. Utility Modeling Tools and IT Infrastructure

As discussed in **Section 2**, a number of new modeling tools and other new software platforms are emerging and becoming commercially available to help utilities address DER planning. Identifying tool/IT gaps and seeking cost-effective solutions should also be key considerations in a utility's DER strategy.

3.8. SUMMARY

Table 5 summarizes the steps in a proactive DER planning process. As this DER process matures, and DER penetration begins having a significant impact on grid operations, it will be important to have an overarching DER strategy in place to enable the utility to capture the benefits of a proactive approach.

Table 5. Proactive DER planning process summary

Step #	Name	Description
1	Load and DER Adoption Forecast	Develop load forecast, assess technical/economic/achievable potential for DER deployment and estimate customer adoption, and determine net load profile.
2	T&D Grid Impacts	Run dynamic distribution system model to identify and quantify all grid impacts from load/DER growth.
3	Bulk Power Impacts	Run full model of bulk power system (generation and transmission), including impacts from distribution level.
4	Finance, Rates and Regulation	Quantify locational costs and benefits of DERs, determine if/how DERs can defer or avoid traditional utility distribution investments, calculate financial/rate impacts of DER deployment, and develop appropriate policies (e.g., incentives, tariffs, standard contracts, competitive solicitations) to encourage DERs at the right place and right time.
5	Strategy and Operations	Decide on utility's overall DER strategy and any related changes to the business model, as well as modifications to utility operations to support effective DER integration.

4 CONCLUSION

DER growth is challenging the status quo of distribution planning as a result of changing customer choices, technological development and new policies and regulatory proceedings. Higher DER penetration is pushing a number of leading utilities to confront industry gaps in this area by developing new methodologies and tools, adopting new software with more sophisticated modeling capabilities, and reorganizing internal departments to bring together the multi-disciplinary teams needed to streamline DER deployment. However, a number of open questions remain around DER planning processes, modeling approaches, and monitoring/control solutions.

No single utility has yet put into practice a comprehensive framework for distribution planning in this new high-DER environment. This whitepaper provides a framework as a starting point for utility leaders. This framework emphasizes the need for an iterative planning process that is repeated frequently to capture rapidly changing market conditions in the electric utility industry. Traditional integrated resource planning frequency (usually every 2-5 years) will likely not be able to keep pace with the expected rapid growth in DER penetration and its associated impacts.

The benefits of a more holistic and proactive DER process could include:

- Better forecasting of DER growth and resulting impacts on net load profile
- Better forecasting of revenue and rate impacts from DERs
- Decreased DER interconnection timeframes
- Increased DER hosting capacity
- Minimization of distribution system infrastructure costs.

Utilities can no longer avoid the advance of DER technology adoption. The sooner utilities begin to implement a proactive DER planning process, the better prepared they will be to achieve the potential benefits and minimize the risks of the distributed energy future.

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Andy Colman leads the Analytics and Business Performance offering for Black & Veatch Management Consulting, LLC, a wholly owned subsidiary of Black & Veatch Holding Company. He works with clients to develop new approaches to analyze, plan and execute grid modernization in an era of distributed energy resources. Prior to joining Black & Veatch in early 2014, Andy was CEO of GRIDiant Corporation, a provider of grid optimization software that was acquired by Landis+Gyr. He has over 25 years of experience in energy management software and hardware for both the commercial real estate and electric utility industries. Andy has assisted office buildings and chain stores in energy efficiency initiatives including Energy Star and LEED certifications, and with solar PV deployment. He was CEO of EnFlex, a pioneer in building energy management and solar monitoring that was acquired by SunEdison. Earlier he was a consultant with Booz, Allen & Hamilton focusing on utility organization and strategy. Andy is based in San Francisco.

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Dan Wilson is a Renewable Energy Consultant in Black & Veatch's power business, focusing on the intersection of the electric utility sector with renewable and distributed energy resources. Over the past five years, he has led numerous studies for utilities and other clients related to grid integration of renewable and distributed resources, quantifying the value of solar, Integrated Resource Plans, distributed solar PV potential across large geographic areas, solar policy design, customer-facing solar program management, implementation of new software to streamline solar incentives and interconnection, solar PV and battery storage feasibility analysis, and distributed energy planning for smart cities.

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Daisy Chung joined SEPA's research team in 2014 to lead specialized solar research ranging from nationwide policy to utility incentives and customer offerings. Her research focus includes asset management and operations and maintenance, grid transformation, utility business models, and energy portfolio diversification. She re-launched and had since led the management of the Utility Solar Database, a SEPA members-only research tool guided toward electric service providers, solar integrators, developers, and manufacturers, supporting service providers, and policy makers. She has years of process implementation experience as a thin-films engineer at Samsung Austin Semiconductor, with specialization in process start-ups and qualification, production standardization, and root cause analysis through Six Sigma data monitoring and analytics strategies.