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Distributed Energy Resources:

Seizing Opportunities While Managing Distribution Grid Impacts

1. Introduction: Challenges and Opportunities of DERs

Distributed energy resources (DERs) are reshaping the operation of the electric power system. How can we coordinate DERs with centralized generation, in economically sustainable ways, to drive savings and enhance efficiency — to the mutual benefit of all entities involved?

Renewable energy is growing fast, currently comprising nearly all new generation capacity being installed in the U.S. In some regions, solar is moving astonishingly fast: for instance, by 2031 solar is expected to comprise 17 percent of all generation capacity in Texas. Still, renewables are unlikely to overtake conventional centralized generation for decades. In 2015, according to the U.S. Energy Information Agency, natural gas, coal, and nuclear power plants still supplied 85 percent of all U.S. generation capacity — and hydropower (mostly utility owned and operated) supplied approximately six percent. Consequently, renewables, DERs, and centralized power stations will continue to need to functionally complement each other for the foreseeable future.

Utility-scale solar photovoltaic (PV) accounted for a mere 0.6 percent of cumulative U.S. generation capacity in 2015. Although this overall penetration level is quite low, some regions have quite high PV penetration. Thus, PV is disproportionately impacting many U.S. distribution grids, as most solar facilities connect to grids at the distribution level, not the transmission level.

There are many market drivers for the growth of utility-scale solar PV. While state renewable portfolio standards remain a strong driver, most solar projects today are being developed primarily due to their strong economics, not mandates. According to the Lawrence Berkeley National Lab, the average price of solar electricity in the U.S. has dropped to five cents per kilowatt-hour, allowing PV to surge beyond expectations. In 2015, solar surpassed natural gas in new capacity additions, spurred by tax credits and other incentives.

Despite this growth, solar farms can be a particularly challenging type of DER to accommodate on grids at high levels of penetration. New solar projects of all sizes are appearing at every point along power systems, often not at the most optimal locations from a grid management perspective. Also, most installed distribution assets were not designed to accommodate solar's fluctuating output and power quality, or bidirectional power flows. This causes problems with voltage and frequency, stresses grid assets, and can result in curtailment of renewable energy output.

Many supporting technologies and strategies can help alleviate the negative grid impacts of renewables — while also extending the useful life of grid assets, preventing outages and curtailments, optimizing renewable output efficiency and increasing overall grid capacity. These measures are not always easy to justify economically, but some states are clarifying their value.

"If you follow the money, DERs offer substantial economic promise. For instance, the state of New York identified potential annual savings of $1.2-$1.7 billion by reducing the state's peak 100 hours of demand," said Gary Rackliffe, vice president, Smart Grids North America, ABB Inc. "DERs can play a strong role in realizing those savings. NY is trying to capture that economic benefit, recognizing that asset owners may need incentives to offset peak demand."

The challenges and opportunities of integrating DERs encompass more than solar PV and battery storage, of course. Wind power, fuel cells and other storage technologies offer many similar considerations. However, solar PV and battery storage — taken separately and together — exemplify most of the broader DER challenges facing utilities and renewable project developers.

The economics and deployment of DERs depends largely on which roles they play in a power system. Solar PV tends to play one role: generation. That said, its characteristics are quite unlike the type of generation that utility systems were designed to accommodate. Renewable power output is not as predictable or reliable as centralized generation, and it can only be controlled through curtailment. So far, curtailments have been a significant problem for renewables. In California, the state's independent system operator has curtailed more than 650 megawatts of solar on certain occasions.

Large centralized generation cannot be ramped up or down quickly enough to respond to solar power's fluctuating output, and spinning reserve represents a significant capital investment. Without additional grid compensation for its variability, solar PV can potentially impair grid stability.

In contrast, battery storage can play several grid roles. It can serve as load by absorbing power, or it can serve as generation by injecting power. It can be connected wherever it might be needed on a power system: at a solar facility, a substation, or along a feeder line.

Furthermore, battery storage can provide grid support services, which vary by duration of operation:

- By operating in bursts of a few milliseconds, storage can help regulate frequency.
- Over the course of a few seconds to a minute (the amount of time it might take for clouds to traverse a solar farm), battery storage can inject or absorb power, providing capacity firming that can compensate for sudden shifts in supply or load, which serves as ramping support for centralized generation.
- In areas where especially high solar penetration has shifted system-wide peak times, batteries can operate for a few hours at a time to level system demand.

Despite all of these possible benefits, battery storage currently suffers from a poor cost model. Typically, adding storage doubles the cost of renewable energy projects — even though it can address exactly the kinds of challenges that renewables can create.

The utility value proposition for DERs is complicated. It will likely be well over a decade before DERs begin to significantly offset utility investments in centralized generation capacity. However, in the coming years, utilities are likely to start seeing significant offsets in T&D system investments by using DERs to expand the capacity of existing grids.

Ben Kellison, Director of grid research for GTM Research, observed, “There’s an increasing focus among utilities for using DERs to offset transmission and distribution grid capacity. That’s being actively tried now. Over time, DERs will start to offset generation investments. But today, the biggest value of DER to regulated utilities is to enhance their ability to take advantage of grid efficiencies.”

When coupled with protection and control technologies (particularly to manage reactive power and optimize voltage), as well as demand response, DERs can enable grids to safely and reliably handle a larger volume of power — reducing the need for new T&D lines and substation equipment. Utilities are keenly interested in such “non-wires” alternatives to T&D expansion.

2. DER Market Considerations:
Utilities and Developers Have Different Agendas

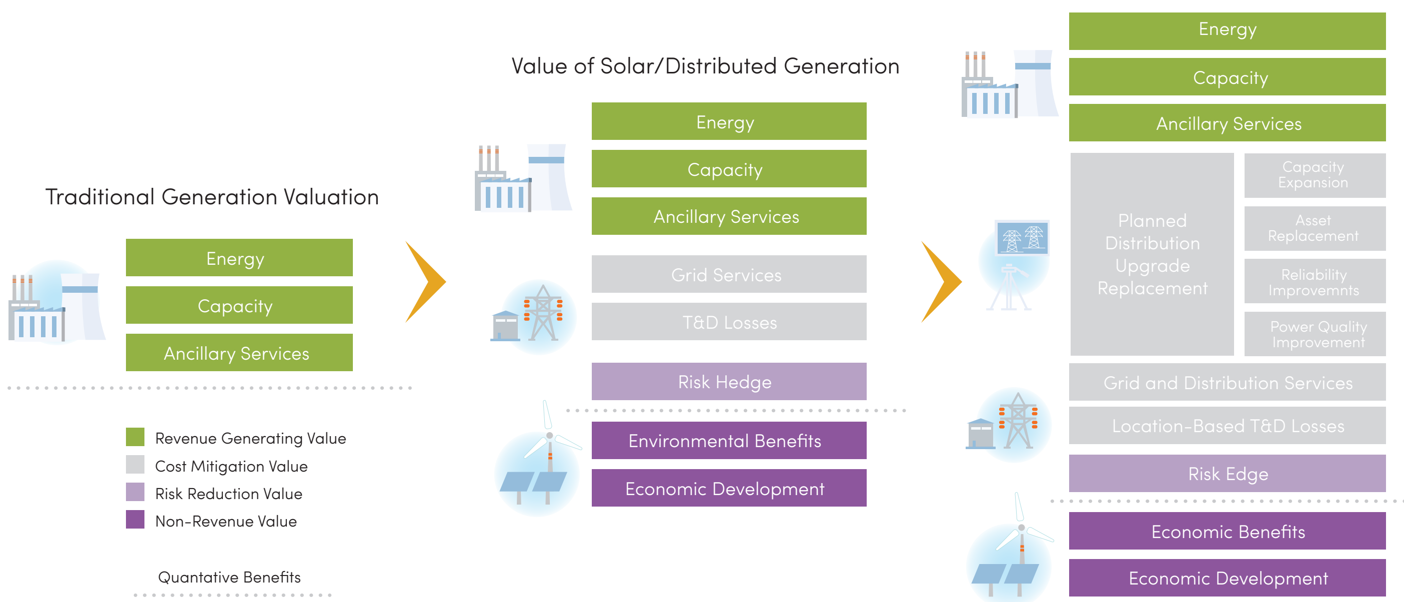
On distribution grids, there is an appetite for more control over the location of DERs for overall system benefit. But often, the effectiveness and efficiency of DERs is hindered by the diverging agendas that utilities and developers typically have for these projects. Such differences can perpetuate negative grid impacts from DER integration. Often, there are missed opportunities to enhance overall operational and economic performance for both developers and utilities.

Part of what's hindering more optimal DER deployment is the complexity of coordinating these resources with centralized generation due to who owns and operates what equipment, and their respective goals. Vertically integrated utilities own and operate most central baseload generation facilities, while developers generally own and operate solar PV facilities.

Ultimately, utilities are tasked with safely providing reliable power to consumers and they are accountable to consumers, regulators and shareholders for efficient use of their resources. This places procedural, operational and economic constraints on how utilities are able to integrate DERs onto their grids.

"Often, developers don't fully understand the process and constraints that utilities

Location is changing the DER value proposition



Source: Pacific Gas & Electric, GTM Research face when adding DERs to a grid," said Gary Rackliffe of ABB. "There are operational issues; the utility always has to back up the DERs for the sake of reliability, and manage voltage on the feeder. Utilities are responsible for protection and control of the feeder, and its safe operation."

When a DER is added to a distribution grid, utilities first must determine whether they have the capacity to absorb its output and impacts. This means assessing the current condition, load, and protection on affected substations and feeders — as well as the likely effects of possible reverse power flows, increased voltage, or frequency variations. DERs can considerably increase the wear and tear on distribution assets, which implies long-term costs that are the utility's responsibility. Also, when located toward the end of a feeder, DERs can create overvoltage that might damage customer appliances or equipment.

Utilities often conduct interconnection studies for proposed DER projects to assess these considerations. These studies can slow down the project approval process and frustrate developers. In states where solar development is moving the quickest, such as North Carolina and California, utilities often have long queues of potential projects awaiting approval, as well as projects in development awaiting interconnection.

Developers almost always cover the cost to upgrade utility assets to accommodate the output from their facility. This might include adding or upgrading switchgear and breakers, installing static synchronous compensators (STATCOMs) or storage, adding new controls and software, or perhaps increasing transformer capacity.

Negotiations over interconnection costs can get tense if a developer questions whether all specified interconnection upgrades are necessary. When compiling interconnection cost estimates, it is important for utilities to include all of the upgrades that they believe a project would warrant. If these costs are underestimated, it can be challenging for a utility to later justify to regulators or shareholders the cost of, say, adding storage to compensate for the effect of renewable resources that the utility did not build and does not operate.

Typically, developers don't have much leverage to negotiate interconnection costs. If they strongly disagree with the utility's estimate, the project does not move forward.

Several negative grid impacts of DERs could be addressed by measures that developers can install at solar facilities, such as on-site storage, STATCOMs, smart inverters, or advanced controls. However, developers are generally averse to

undertaking voluntary measures strictly for the benefit of grids that they do not own and operate, because this could have a significant negative impact on their return on investment.

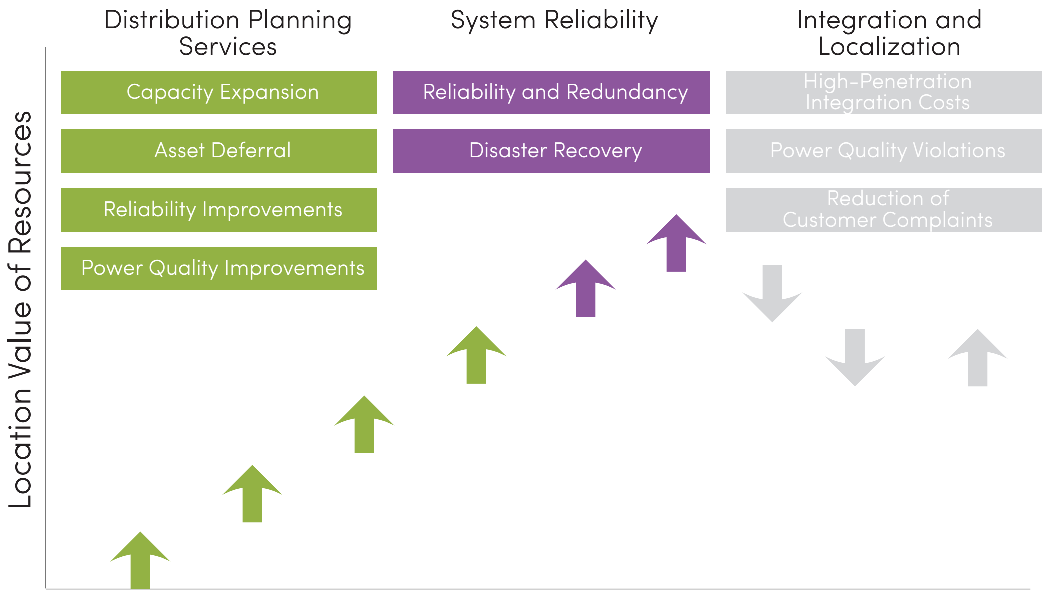
Also, when more than one renewable project seeks to interconnect at the same substation or feeder, it can get contentious. The first developer would probably not want to pay for interconnection upgrades that would allow subsequent competing developers to become free riders.

Renewable project developers almost always sell their power through long-term power purchase agreements, where price is determined solely by electricity output, not power quality or grid services. This is a fast-moving and highly competitive market, so developers are motivated to keep their cost per kilowatt-hour as low as possible.

Hence, key developer considerations are minimizing their costs for land, solar panels, other installed infrastructure and interconnection. This is why many DER projects are located in rural areas where land is cheaper and usually far from significant loads, even though this can increase stress on more utility assets. This is also why it is typically not a top priority for developers to install extra storage, protection and control equipment at solar facilities.

Such cost-cutting choices do have tradeoffs for developers. If the utility grid does not have the capacity to handle re-

Locational Costs and Benefits of DERs



Better data sharing between utilities and renewable facilities could mitigate grid problems from DERS

newable output or its impacts, the developer may have to curtail power production, which could represent a substantial blow to project revenues. Thus, by installing storage and advanced controls, developers may optimize their overall solar PV output and protect the grid.

However, developers are also generally eager to move fast in order to win contracts or obtain time-limited incentives or credits. These pressures sometimes make developers more amenable to measures that might increase their costs.

Utilities are the buyers (offtakers) for up to 60 percent of the output from large-scale solar in the U.S., according to GTM Research. The request for proposal (RFP) solicitation process gives utilities some control in project siting, as well as protection requirements. In their renewable RFPs, some utilities give general guidance about which parts of their grids have available interconnection capacity. This is usually defined in terms of grid assets, rather than geographic location.

Enhancing the amount and type of data shared between utilities and renewable facilities could streamline and optimize long-term coordination on a day-by-day and minute-by-minute basis. Currently, large solar facilities tend to provide substantial data about their power output and quality. Utilities that have advanced distribution management systems can make use of data from renewable facilities and also provide more data about utility systems, thereby supporting a more harmonious operation.

Harmonious operation of DERs and distribution grids can occur at two levels: locally at the point of physical interconnection, and on a system-wide basis.

3. **Operational DER Impacts** at the Feeder Level

DERs don't stand alone; they require many other supporting technologies in order to yield a net benefit to the grid, and to customers. That's because DERs aren't as predictable or conceptually simple as centralized generation and one-way power distribution.

Wind farms and the largest solar facilities (especially concentrating solar thermal plants) tend to connect to grids at the regional transmission level, but the vast majority of solar PV projects connect to distribution grids. Typically, high-voltage transmission assets are equipped with protection, controls and communication technology to support fluctuating, bidirectional power flows. But medium-voltage local distribution grids tend to lack such costly infrastructure.

Most solar PV coupling happens at the distribution feeder level — sometimes at a substation, sometimes elsewhere along a feeder, even at the very end of a line. The larger the solar facility, the more economic it is for developers to include built-in controls and protection equipment. This can help address frequency and other power quality issues at the source, reducing impacts to utility assets.

The management of voltages on distribution feeders is crucial to avoiding over- or undervoltages, especially when DERs are deployed toward the end of a feeder line. This is increasingly common, since land tends to be cheapest at the grid edge. There are two main types of voltage problems associated with DER grid integration:

- Overvoltage. This can happen as a sudden surge, such as when a cloud finishes traversing the solar facility. Excess voltage also can be a more endemic problem — for example, when a 5MW solar farm is sited at the end of a feeder that has typically only carried 2MW. Without proper management, voltage at the end of the line can get consistently high, potentially damaging equipment belonging to customers and the utility.
- Voltage sags. These tend to happen due to cloud cover varying from a few seconds to minutes or more. Larger sags can also occur due to curtailment at the renewable facility. When voltage dips too low, frequency drops as well, causing power quality problems. Customers in the area may also experience outages or brownouts.

Managing reactive power flow allows grid operators to manage voltage, but some of this can happen on the developer's side of the coupling. For instance, smart inverters are a new technology that implement grid-balancing tasks, right at the point where direct current from solar panels is converted to alternating current, guided by data communication with the grid. Historically, utilities handled these tasks with capacitor banks, which worked well for one-way power flows, but DERs present bidirectional power flow issues that capacitors cannot effectively manage.

"Most utilities don't yet have voltage optimization control, where they can leverage smart inverters, in addition to capacitors, line voltage regulators and load tap changers," observed Rackliffe. "The capability now exists in distribution management systems to remotely control the setpoints of smart inverters. This can allow the utility to better manage reactive power flow, which helps control voltage on a distribution feeder."

Smart inverter technologies are currently being rolled out in Hawaii, California and Arizona. In 2014, Hawaii regulators set standards for smart inverters that require low-voltage ride-through capabilities. Numerous pilots have been supported in the state for residential systems. California's interconnection standard, Rule 21, updated the requirements for communications and controllability for PV inverters, basically recommending that several key setpoints and functions should be able to be adjusted in response to signals from the utility.
So far, Rule 21 implementation has been slow. The impact of smart inverters will become clearer over the next several years, as consensus around the value of this technology builds. This and other coalescing rules and standards offer opportunities where utilities and developers might collaborate to proactively address power quality concerns and other grid impacts, and to reduce curtailments.

A more established technology, the distribution STATCOM, injects reactive power at levels that continuously adapt to keep pace with voltage variations. This device can be installed at any suitable point in a grid, or at a DER facility, to enhance power transfer capability by maintaining a smooth voltage profile as network conditions fluctuate. A STATCOM also can provide active filtering for additional power quality support.

Similarly, battery storage can be installed on developer or grid assets to stabilize voltage and enhance power quality, with the added bonus of being able to inject real power into the grid — effectively functioning as spinning reserve. Battery storage can also absorb power to supplement later demands to relieve stress on the grid. A handful of U.S. utilities are currently experimenting with using battery storage for voltage support or with dynamic controls on solar facilities.

Controls, software and communications are crucial to ensure that all of this works. At the feeder level, milliseconds count. Immediate, automated response is essential. Momentary minor fluctuations can eventually cause significant damage to grid assets, and exacerbate grid stress.

Advanced distribution management software offers voltage optimization and communication for managing disparate grid devices. These applications utilize detailed power system models. This type of system can help utilities save money by reducing stress on grid assets, and also potentially avoid T&D wires investment by increasing grid capacity and efficiency.

4. **DER Services** and Impacts to Distribution Grids

Since it will be a long time before renewables comprise the majority of the overall energy supply, the most pivotal role for DERs is in providing grid services, rather than simply supplying energy.

Load shifting and peak shaving seem to be two of the most obvious potential grid benefits of DERs. Here, the key issue is dispatchability. When coupled with sufficient storage, renewables can provide fairly reliable capacity. At a large enough scale, this could potentially offset long-term capital expenditures in conventional centralized generation.

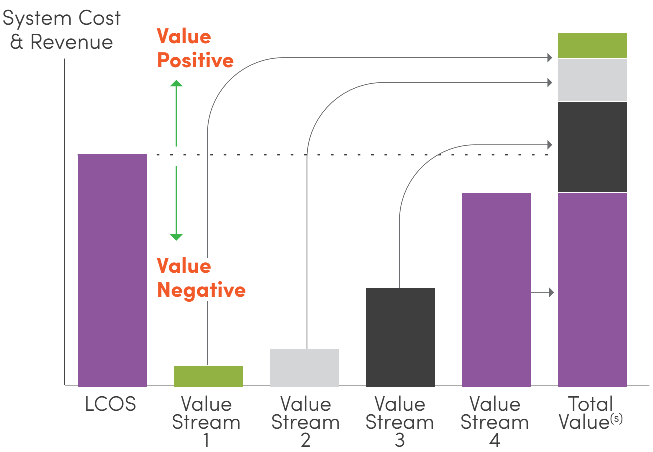
The American Recovery and Reinvestment Act (ARRA) funded nearly 60 MW of utility-scale battery storage demonstration projects, for load shifting, ramping control, and to compensate for the operating patterns of wind farms. There was also a 20 MW ARRA test project to apply flywheels for frequency regulation. And an additional 30 MW of test projects, at various utilities and other entities, explored using various battery storage technologies for ancillary grid support services.

The commercial market for large solar-plus-storage is only just beginning to emerge for capacity firming. In Hawaii, the Kauai Island Utility Cooperative is constructing a 17 MW solar PV array with an adjacent 52 MWh battery system supplied by SolarCity. In May 2016, SolarCity debuted a new set of services: installation, financing, and consulting services for utility-scale solar and energy storage resource development, as well as advanced controls for demand response, distributed energy resources, and aggregated grid services.

In the near term, a more feasible and economical way to shift load and shave system peaks might be for utilities or third parties to deploy storage strategically around a grid and behind the meter, to charge batteries when demand is low and to add effective capacity for offsetting loads or shaving peaks. Also, charging batteries when load is low helps keep the system balanced, allowing more efficient grid operation if certain parts of a grid tend to be overloaded or underloaded, or if solar PV is being added at levels higher than the existing grid can easily accommodate. Thus, storage is a key non-wires alternative for expanding grid capacity.

The hurdle, of course, is that battery storage is still relatively costly. In November 2015, the financial advisory firm, Lazard, published its first analysis of the levelized cost of storage, which predicted that the cost for lithium-ion battery storage would decline by 47 percent over the next five years. It's possible that Tesla's new lithium-ion battery Gigafactory, slated to open in 2017, will have a significant impact on this cost.

Energy Storage Value Proposition



Source: Lazard's Levelized Cost of Storage Analysis 1.0.

Lazard's analysis examined many ways that battery storage can be used in power systems, taking into account that a single battery can provide many services at once. Of all these possible applications, only one — using lithium-ion batteries for frequency regulation of a grid — was found to be cost effective today. However, Lazard predicted that within five years, seven possible uses of battery storage would become cost effective — including replacement of diesel or natural gas-fired peaker plants.

For now, other grid services represent the greatest potential benefits deploying DERs. Capacity firming is a significant opportunity. This can comprise several DER functions, which achieve the goal of holding capacity steady without having to ramp large coal or nuclear power plants.

Pat Hayes, business development manager for energy storage at ABB, explained: "Ramping is a big problem, because it creates inefficiencies. Conventional power plants were built to provide a fixed output. If a power plant needs to ramp up or down, that significantly increases a utility's fuel costs and emissions — and it isn't good for the machinery, either. This is an issue that's hurting utilities today.

"Energy storage has no ramp limits; you could reach nameplate output within milli-seconds. This can effectively fill in the gaps caused by solar intermittence to create firm capacity. Another ramp mitigation strategy is to store the PV power in the battery and then discharge it when the sun is setting — a shifting mode of operation."

In some respects, utility control of large loads behind the meter can also be con-sidered a DER of sorts, if they can be reliably dispatched when warranted by grid conditions. Supply following is when large loads, such as industrial pumps or motors, are switched on to absorb energy from the grid or curtailed to supply available energy to the grid — with a grid balancing effect similar to charging battery storage. Where loads of appropriate size and characteristics exist (with industrial customers, or perhaps water utilities), they might be combined in a demand response program to help com-pensate for the grid impact of renewables.

Paying for everything that a utility needs to prepare the distribution grid for large amounts of renewable power can be a challenge. But the ancillary benefits of mak-ing these upgrades can offer new revenue streams and cost saving measures.

For instance, with the ever-accelerating addition of sensitive electronics behind the meter, additional power quality support might become a value-add feature that utilities could offer. This might help utilities differentiate their service from alternative power suppliers, or become a revenue stream as a premium service for certain customer types, such as data centers. Battery storage can be one way to realize this option.

On a more basic level, reliability of power supply is part of any utility's core man-date. When there are bidirectional power flows, it becomes more complicated to compartmentalize a grid in order to keep localized disturbances from spreading. Protection, communication and control equipment that compensates for the ongoing impact of renewables also en-hances a utility's overall ability to prevent, minimize or respond to outages.

Realizing all of these benefits requires many kinds of devices and software deployed across a grid. Usually, utilities cannot include all of these in the inter-connection cost estimates for renewable energy projects. But through their regula-tory mandate to keep the lights on, utilities may be able to obtain rate relief for some of these extras, in the name of reliability.

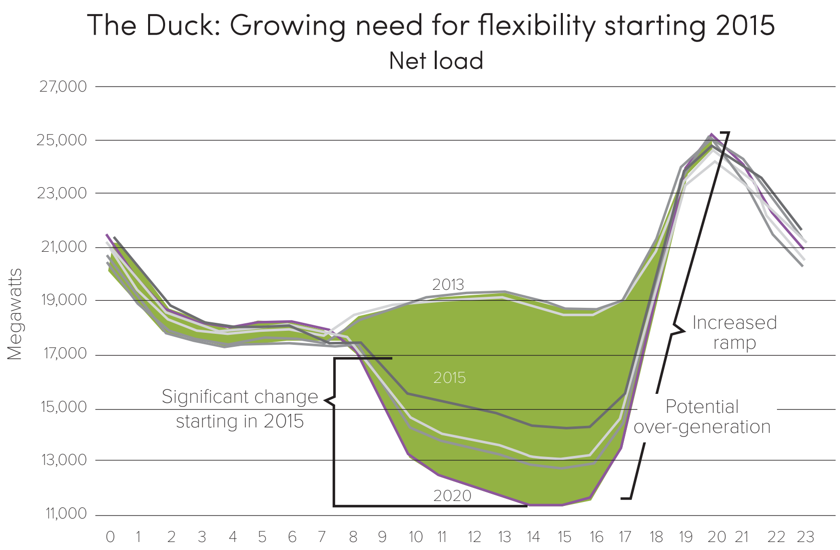
47%

Predicted decline in the levelized cost of battery storage over the next five years.

5. DER's Big Picture: Maximizing Benefits and Minimizing Unintended Consequences

How can utilities and developers avoid unintended consequences when integrating DERs? California and Germany offer clear examples of how a fast, large influx of renewables can inadvertently skew grid operations.

In California, the "Duck Curve" phenomenon is also presenting a challenge to keeping power grids balanced. Since California began adding vast amounts of solar power (both on customer premises and utility-scale projects), it's projected that the peaks and troughs of the state's overall system demand are likely to become dangerously exaggerated. In fact, according to the system operator, this trend is already five years ahead of schedule.



Demand was once mostly level — with a mild peak in the morning, a mild dip in the afternoon, and a larger peak in the evening. But the California Independent System Operator projected that, by 2020, afternoon load could drop dramatically as renewable energy production soars on sunny days. This would be followed by a rapid evening peak, as renewable generation falls and demand increases, yielding three substantial grid risks:

- Steep ramps. Lower base load and relatively unchanged peak demand means that utilities would need to increase or decrease baseload generation capacity (large coal or nuclear power plants), or diesel or natural gas-fired ramping generators. This is one way to firm capacity, but it comes with substantial tradeoffs. Capacity firming with DERs (discussed in the previous section) can mitigate the need to firm capacity on the generation side.

- Oversupply. Renewables may squeeze baseload generation and upset the centralized generation mix. On the distribution level, they might also add more power to the system during the afternoon trough than existing assets can safely manage, causing overvoltages.

- Reduced power quality and increased outage risk. On sunny days during hours with low load, CAISO projected that as much as 60% of California's energy might be supplied by renewable facilities that are not required to have automated frequency response. Frequency instability can make a system more susceptible to blackouts.

The stress on California's power system, plus pressure from that state's ambitious renewable energy goals, has led CAISO to contemplate a controversial move. So far, CAISO has operated fairly independently of grids in surrounding states. But to avoid curtailing renewables during times of peak production, and to maintain system stability, CAISO is contemplating closer interconnections with utilities in Wyoming, Utah, and Oregon. These utilities rely heavily on coal-fired power plants, which is stirring controversy throughout western states.

"The real competition for battery storage is gas-fired generators. Utilities are comparing the cost of installing gas-fired ramping generators to compensate for the impact of solar PV, versus installing battery storage that can discharge power to meet evening peak demand," said Rackliffe. "The catch is that the cost of battery storage isn't yet at the tipping point. California is trying to push the experience curve with mandates to increase battery storage, and progress is occurring."

In 2013, the California Public Utilities Commission passed a controversial mandate requiring the state's three major investor-owned utilities to add a total of 1.3 GW of energy storage to their grids by 2020. While this mandate is increasing the amount of deployed battery storage on California grids, sorting out the most cost-effective and beneficial applications is still a complex, arduous process.

Renewable project developers and investors dislike curtailments and scrapped projects. And utilities dislike grid imbalances and risk. These mounting frustrations may provide motivation for developers and utilities to overcome their divergent DER agendas and adopt a more sustainable and beneficial approach. Collaborating more on siting DERs in optimal locations could lay the groundwork for a smoother future for DERs.

In some states, notably California and New York, regulators are working to merge these cost and benefit factors with other societal goals to create a comprehensive, location-specific DER valuation algorithm. This would allow utilities to compare DER procurement options and choose the optimal combination of low-cost, high-value grid upgrades. A detailed description of these efforts can be found in the recent

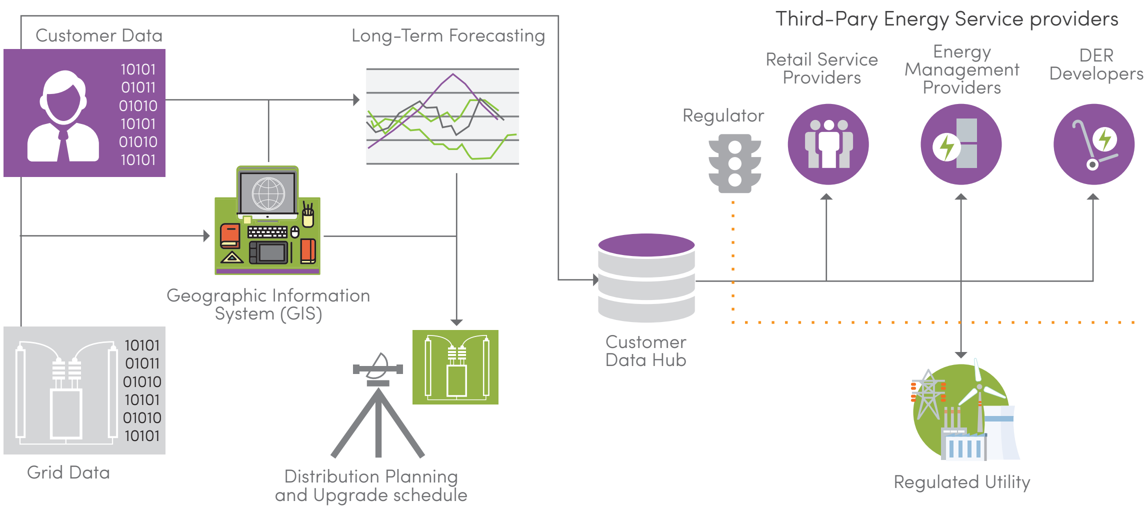
Greentech Media report, Unlocking the Locational Value of DERs 2016.

Such an algorithm, coupled with greater utility transparency about the location of available grid capacity or constraints, and about the queue of interconnections slated for specific substations, would also benefit developers. This information would help developers to more efficiently target project proposals — likely speeding the approval process and reducing the risk of rejection, while also reducing work for utilities in responding to proposals.

So far, investor-owned utilities in California and Vermont have created maps that show, down to specific feeders or substations, grid sections with available capacity for interconnection, or strong congestion. And, in a recent solicitation in Long Island, the utility provided a list of feeders ranked by available capacity and likely required upgrade costs for interconnection. Also, regulators in California, New York and some other states are working to create guidance on available capacity that would be shared between utilities and qualified developers.

More optimal, efficient siting of DERs can help utilities compete for large customers, who are becoming more interested than ever in purchasing renewable power. In June 2016, the World Resources Institute published an interactive map of renewable energy options in the U.S., by state. This tool highlights green tariffs and other utility offerings, comparing each product to the Corporate Renewable Energy Buyers' Principles. Collectively, signatories to these voluntary principles represent nearly 44 million MWh of annual demand by 2020.

Over the next two to five years, utilities in California and New York will be developing software and processes to accurately apply



Source: GTM Research

these valuation algorithms, with models of existing grids and real operational data. In addition, regulators are encouraging utilities and third-parties to develop and test new resource procurement methods that could leverage locational DER valuation.

Another challenge is the existing model for power purchase agreements. Typically, these long-term contracts are energy-only, based primarily on output from the renewable facility, as a set price per kWh delivered. Even though utilities buy most of the power from utility-scale solar PV PPAs, the pricing of these contracts typically still fails to consider the timing or characteristics of power supplied, or grid conditions. But, in California, some utilities are adding new factors into their DER solicitations, such as time-of-use pricing for power delivery.

At the state and national level, larger goals (e.g., resilience to extreme weather or attacks on critical infrastructure, or emissions reductions) are leading to policies that may end up improving how DERs get integrated into grids. For instance, in the wake of Hurricane Sandy, infrastructure resilience in coastal areas has become a high priority for legislators and regulators in New York. This has led to a push on microgrid implementation in that state, an important DER application.

Similarly, some regulators are taking leadership for decreasing grid congestion while managing customers' long-term infrastructure costs. For instance, when Con Ed proposed building a $1B substation to serve growing demand in Brooklyn and Queens, the New York Public Service Commission pushed the utility to instead expand grid capacity through a major demand management program. DERs could easily complement such initiatives.

Utilities can realize many operational and business benefits from DERs: expanded grid capacity, enhanced grid operation, quality of service to customers, reduced operations and maintenance costs, avoided or delayed capital expenditures, and potential revenue streams or competitive advantages for ancillary services. While all of these benefits are potentially substantial, few are straightforward. This can complicate internal utility deliberations about how to proceed with DERs.

It can be particularly challenging for utilities to figure out which of their internal departments should be responsible for the cost of battery storage projects. Gradually, these complex issues are being resolved and the potential for DERs to alleviate grid problems.

The utility and renewable industries are gaining more insight into how DERs and centralized generation can complement each other safely and efficiently, thus allowing power grids to operate more effectively.

Conclusion

DERs offer substantial opportunities to help shift utilities toward a more sustainable and resilient energy system. This can yield significant economic and environmental benefits for utilities and renewable project developers. The challenge, for now, is to deploy DERs in ways that support the evolution of more flexible power grids.

Utilities can work more collaboratively with developers to site third-party DERs more optimally, and also to integrate technology that supports better coordination between renewable power facilities and power grids. The potential economic, operational, and business benefits to all parties from this collaboration might outweigh the added up-front effort and cost.

Meanwhile, utilities can also leverage DERs on their grids to reduce or defer capital expenditures on new T&D infrastructure. In the near term, this benefit is likely to provide the most viable rationale for utility deployment of DERs. In the longer term, utilities and independent system operators may be able to leverage DERs to reduce overall system peak, providing potentially significant peak capacity savings.

Ultimately, customers benefit from increased reliability and quality of power supplied via utility grids. For some customer classes, this could also provide additional revenue streams.

As the energy landscape continues to evolve, utilities will need to adapt to managing more diverse and complex energy resources. Understanding today's DER integration issues and opportunities is key to creating a more robust and reliable energy future.