The evolving energy landscape
Different geographies, different priorities

Trends toward decarbonization, digitization and decentralization are playing out differently for distribution utilities around the globe.

While distribution utilities around the globe are facing the challenge of moving to a smarter grid, their motivations and requirements can differ widely, thanks to broad national and regional variations in load and generation profiles, as well as in their respective market structures. Consider how renewables profiles affect distribution utilities in these three different markets:

**Germany** — A strong regulatory drive to renewables means solar and wind now comprise approximately 40% of total grid-connected generation capacity (and 53% of installed net power). Most of the nation’s solar capacity is produced by photovoltaic (PV) installations smaller than 1 MW in capacity. By 2030, continued renewables growth could change how German distribution utilities acquire their electricity, with conventional generation dropping out entirely during portions of the day in both summer and winter.¹

Germany also now allows distribution utilities to implement non-firm distributed energy resource (DER) connections. For example, the German utility E.ON has launched a new residential storage product (called Aura) for easy pairing with rooftop PV arrays. By using the Aura storage system and an associated app, consumers can optimize their own usage and sell excess electricity back to the grid, essentially using the distribution system as virtual energy storage. According to a press release on Aura’s market launch, “The system can increase a home’s energy self-sufficiency rate — that is, the proportion of self-produced electricity the home consumes — from about one third to around 70 percent.”²
California — Home to more distributed solar than any other U.S. state, California is at the forefront of efforts to understand how DERs can add value to the distribution grid. In 2015, the California Public Utility Commission and the state’s three investor-owned utilities began demonstration programs to test a tool designed to help identify the best grid locations for new DERs, recognizing the economic value of deferred distribution investments. As of spring 2017, this tool remained a work in progress.

South Australia — This Australian state has embarked on a rapid decarbonization plan that has shuttered coal plants in favor of renewables. Between June 2016 and May 2017, South Australia counted on renewables — primarily wind — for 53% of its supply. Their remaining supply needs are supported by natural gas and an interconnection with the neighboring state of Victoria. As the result of a series of severe weather events and a lack of fast-responding peaking support, the state’s electrical networks have suffered from a series of blackouts and load-shedding events over the course of the last year. This has prompted calls for de-privatizing the investor-owned power system.

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Recent history has proven the need for large organizations to plan for the unexpected. In this time of rapid change for electricity markets, risk mitigation strategies specific to electric utilities are highly recommended.

Utilities seeking to better understand how unexpected events could impact their financial stability should consider the following possible scenarios.

**Energy for free** — With tech companies finding new ways to monetize data, a leader in that field — Amazon, for example — could find opportunity in offering “energy for free” in exchange for personal data. In this scenario, utilities could lose the customer relationship and become pure commodity power suppliers.

**Decentralized energy landscape** — New direct-to-consumer DER suppliers are beginning to bundle rooftop PV systems with batteries, electric vehicles and power-to-heat technologies. Such an integrated approach, paired with a compelling brand, could mean reduced demand for traditional grid-based power. In this scenario utilities again lose the customer relationship, and generation assets quickly lose value.

**Emissions fraud** — This scenario considers the impact of an information leak that discloses a cover-up (in this case of a utility’s emissions data). Energy companies and their executives could find themselves under public and political scrutiny, with a loss of trust.

**Cyberattack on critical infrastructure** — With the growing impact of Internet of Things (IoT) modernizations reaching deep into utility operations, an increased risk of cyberattack could take critical infrastructure offline, with the potential of shutting down national systems. This scenario also could provoke a loss of public trust and spur new operational regulations.

**Radical price transparency** — European retail power, gas and other markets have seen a rise in price-comparison websites. Taken to an extreme scenario, such portals could encourage frequent switching of energy suppliers that quickly erode profit margins.4
The European Union is currently working actively on issues critical to distribution utilities and the distributed energy resources (DER) they support. In November 2016, the European Commission announced a package of measures designed to promote what it called a “clean energy transition.” This “Clean Energy Package for all Europeans” focuses on ways to empower consumers as central players in the energy markets of the future. The goal is to aid the EU in its quest to reduce region-wide greenhouse gas emissions 40% by 2030, over 2005 levels. Set to take effect in 2021, the 1,000-page package, at this point, is a proposal still under debate. The introduction of a new market design across 28 national markets (27 if the UK does not participate) is an ambitious and complex enterprise which will ensure that energy policy issues are shared across all EU member states.5

The package has four main axes. One axis addresses renewable generation, and the remaining three relate to distribution utilities. Of those, the first proposes new energy efficiency targets for 2030 and defines energy supplier obligation schemes and metering functionalities, as well as standards for the active management of energy efficiency in buildings. The second concerns energy flexibility, in the
context of decentralization support, freedom for end-users to access demand response, self-generation dynamic pricing, and more empowerment for distribution utilities to enable more flexibility in their century-old business model. The third axis addresses governance, so that the organization of energy markets can be strengthened at the European level.

Among the document’s more contentious elements are provisions encouraging energy self-consumption via on-site resources, such as solar, combined heat and power (CHP), storage and demand-side management.

Distribution utilities in EU member states haven’t held back, waiting for this new package of legislation to be finalized, however. Their varied paths are reflective of the political and economic gaps EU politicians will likely address during their negotiations.

**Germany** — One word — “Energiewende” — defines the reason for the massive realignment now underway in Germany. Energiewende (“energy transition” in English) is the national program to move from fossil fuels to renewable resources. Renewables are targeted to meet 50% of demand by 2030, 65% by 2040 and at least 80% by 2050. As the German energy think tank Agora Energiewende puts it: “Decentralization will become a permanent characteristic of the power market, because the Energiewende core technologies — wind, solar, storage, e-mobility, heat pumps — all imply a more distributed structure.”

To help address the variability caused by the rapid acceleration of rooftop PV and wind installations encouraged by Energiewende policies, the German government is dialing back generous feed-in tariffs and, instead, encouraging self-consumption. The country’s KfW 275 incentive program has created one of the world’s largest energy storage markets. The German solar energy association BSW-Solar estimates some 52,000 storage systems now serve solar installations in the country, with 20,000 installed in 2016 alone. The association anticipates this number will double by the end of 2018. Load defection — the loss of customers now capable of supplying 100% of their own electricity — is real for German distribution utilities.

One important driver for the expected rapid growth in storage adoption will be the fact that the first solar systems are aging out of the old incentive program. Under these agreements, solar owners have been compensated for self-generated power at up to ~ 0,5€ per kWh. In future, this payment will drop to almost nothing, but with rates around 0,3€ per kWh for energy they use from the utility. This policy change could well encourage customers to disconnect from grid-connected supplies entirely.

**France** — France is unique in Europe as its power sector is still dominated by nuclear, which accounted for three quarters of total electricity production in 2015, along with hydropower. France’s landmark energy sector reform program was initiated in July 2015. The country is currently focused on implementing and meeting ambitious targets for renewables, energy efficiency and the advanced transport sector. Among the main changes are a transition toward auctions and feed-in premiums for renewables, the launch of a net metering policy, and a cap on nuclear capacity. In 2012, 13.4% of France’s final energy consumption came from renewable sources (including large hydro). This figure is short of the country’s 2012 interim target of 14% and must rise to 23% by 2020 under the European Renewable Energy Directive (2009 / 28 / EC).

The French government aims to meet more than half of the target through renewable heat, which
is the sector where progress has been the slowest (16.9% vs 19% 2012 target). Renewables are also progressing slowly, with 6.6% of electricity generated by solar, wind and bioenergy combined in 2015. However, France is closing its high-emissions power plants (-1.5GW of coal in 2015) further reducing the carbon intensity of the power system.

France’s renewable energy policy support is transitioning toward more competitive mechanisms. The solar sector (more than 6GW installed in 2015) was granted considerable visibility, with the government announcing a quarterly auction schedule up to 2019 targeting 9GW of new projects larger than 100kW. The onshore wind sector (more than 10GW installed in 2015) is still in transition and is adding around a 1GW a year under the current feed-tariff. From 2017 the government will introduce an auction covering three years with annual bidding windows for the sector.

Overall, the power market in France will be affected by two other important policy changes. First, the introduction of a capacity market in the winter 2016-17, which the government hopes will help address the country’s increasingly peaky consumption. Second, the decision to bring the share of nuclear in the energy mix down from around 75% to 50% by 2025. France also has an ambitious energy efficiency and electrified transport deployment strategy combining preferential loans and large direct subsidies.8

For example, the rapid uptick of DER has UK Power Networks, with 18 million electricity customers in London, as well as the country’s East and South-East regions, rethinking their role in the larger grid. In July 2017, the company announced its intention to redefine its responsibilities from network operator to system operator. “We are on the verge of a change as significant for electricity as the advent of broadband was for telecommunications,” is how the company’s chief executive, Basil Scarsella, framed the shift to distribution-level generation.9 To jumpstart their transition, the company installed a £18.4 million grid-scale battery system for distribution system support.

United Kingdom — National Grid, the nation’s transmission-system operator, reported in its 2017 Future Energy Scenarios (FES) document that, by the end of 2016, 27% of the nation’s installed generation capacity was connected at the distribution level. Under the most ambitious FES forecast, this figure could rise to 50%, which would be 93GW, by 2050.9
United States

Several states have “deregulated” their markets, meaning their distribution utilities are no longer allowed to own generation assets.

In the U.S., net energy metering (NEM) programs pose a special challenge for deregulated utilities, whose revenues are based on a regulated rate of return on their distribution system assets, represented as a per-kWh service charge on a retail customer’s monthly bill. In most states with NEM programs, customers are reimbursed for generation in excess of their own consumption at the full retail rate — the combination of energy and delivery charges — not simply for the cost of avoided energy purchases. As DER penetration grows, such arrangements could force customers without their own on-site generation to pick up a bigger share of distribution system maintenance costs.

Transmission and distribution utilities in the U.S. are even more varied than their European counterparts, because electric utilities are often managed at a state or federal level. Until the early 1990s, all states had implemented a vertical, regulated monopoly model, in which utilities owned their own generation, transmission and distribution assets. Today, however, several states have “deregulated” their markets, meaning their distribution utilities are no longer allowed to own generation assets. Instead, they now serve as delivery service providers connecting independent power producers to commercial, industrial and residential customers.
Three states now are looking at new ways to encourage utilities to rethink their roles in the electricity marketplace:

**New York** — The state’s “Reforming the Energy Vision” (REV) initiative sets a goal to rebuild, strengthen and modernize New York’s energy system. The guiding New York State Energy Plan sets year 2030 targets that include a 40% reduction in energy-sector greenhouse gas emissions (versus 1990 levels), an increase in generation from renewables to 50%, and a reduction of building energy consumption by 23% (versus 2012 levels). Under the plan, New York utilities will be transformed into distribution system platform (DSP) providers responsible for facilitating third-party DER integration into the network. In fact, this task becomes the primary concern for utilities, which will be motivated through incentives to look to DERs as viable traditional grid investment alternatives.

**California** — The California Public Utilities Commission (CPUC) is also reconsidering the state’s regulator and business models. It sees traditional models as contradictory to the state’s energy-conservation goals. As new technologies and financial innovation blur the boundaries that have, up until now, defined the limits of a natural monopoly, the CPUC has directed the state’s three investor-owned utilities to draft distribution resource plans. These roadmaps will define how DERs will be integrated into grid operations, investments and planning regimes.

**Texas** — Texas leads the country in market deregulation, with most residents choosing from a statewide roster of energy providers, rather than a default local utility. This arrangement gives those providers more freedom to innovate — such as TXU Energy’s Free Nights and Solar Days residential plan. Thanks to the state’s significant wind-energy resources — always more plentiful (and less expensive) at night — customers actually pay nothing for electricity used between 9 p.m. and 6 a.m. During the day, TXU buys electricity from solar producers, along with sufficient renewable energy credits to meet participants’ demand.

The solar portion of the plan is new, but the free nights offering has been available since 2015. The company claims participating customers received nearly 40% of their electricity for free in 2016.

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Australia

Perhaps no place better illustrates the challenges today’s more digitized, decarbonized and decentralized market poses for distribution utilities than the Australian state of South Australia (SA). Between 2014 and 2016, generation capacity available to SA’s sole distribution operator, South Australia Power Network (SAPN) dropped by more than a third, thanks to the retirement of several coal and natural gas generating stations. Substantial incentives have encouraged expansive wind-energy development which, in turn, has driven down wholesale electricity prices and reduced the utilization and profitability of thermal power plants. The decline in firm, thermal-power capacity has led to a heavy dependence on variable renewables. Large-scale wind, residential rooftop PV systems, along with a small degree of hydro, now account for 46% of SA’s generating capacity, according to GTM Research. When those resources fall short, SAPN now must rely on its two interconnection points to the country’s National Energy Market (NEM), which can be inadequate to meeting actual demand.

Two recent severe-weather events have illustrated the precariousness of this situation:
• In September 2016, two tornadoes tore through SA, initiating a series of events that resulted in a significant quantity of wind generation dropping offline. The increased dependence on one of the two power interconnections then triggered protection devices that tripped the interconnection out of service. When generation then available within the now-islanded SAPN network proved insufficient to support network frequency, the entire state was plunged into darkness.

• In February 2017, at the height of the Australian summer, an extended heatwave drove up demand just as wind resources began falling short of forecasts. The remaining gas and coal plant capacity proved insufficient to meet climbing demand, leading to load shedding of 90,000 customers.

While Australia has moved to address some equipment issues specific to these two events, the lack of sufficient backup capacity remains a long-term issue.
India and Africa

While Europe and the U.S. are spearheading the energy transition, other global giants like India and Africa are also preparing for the same magnitude of energy distribution changes. These two geographical regions, however, are approaching the energy transition from two different sets of circumstances.

India currently has a power surplus. Electricity consumption is meeting, at best, only 60% of the installed capacity of 360GW, including periods of peak demand. Despite the power surplus, though, the country’s distribution sector is challenged with chronic issues, including unhealthy distribution companies, power outages, and commercial losses, including theft and unmetered connections. These factors are limiting social and industrial growth and, as a whole, the country is unable to sustain the pace for economic growth. According to the World Bank, “...many factors that constrain performance are under the control of the utilities themselves — underpricing, physical losses, and inefficiencies in bill collection — underlining the importance of limiting the government’s role, strengthening regulatory governance, and bolstering competition so that utilities are both pushed to be efficient and permitted to run on commercial lines.”

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In view of this, the reduction of techno-commercial losses (<15%), the improvement of the System Average Interruption Duration Index (SAIDI), the enhancement of economic and financial viability, and the improvement of operational efficiency of more than fifty state-owned distribution utilities are the key growth drivers of India’s Ministry of Power. Additionally, the government has set a target of 100+ GW of renewables by 2022.

The African continent, on the other hand, generally has little to no strong electric grid infrastructure. Africa ultimately needs a continental transmission grid that supports renewable integration, but the first step toward that will also focus on local energy systems. Much in the same fashion as cellular telephony developed on the African continent, modern distribution networks can avoid many of the complex problems associated with overhauling any existing models. This leap-frogging offers unique opportunities and benefits for modern electrical distribution systems to take shape.

“… many factors that constrain performance are under the control of the utilities themselves.”

— Philippe H. Le Houerou
Vice President, South Asia Region
The World Bank
Definition of terms

**DSO** — “Distributed System Operators” or DSOs are grid network operators who manage multiple points of variable power supply and consumption.

**DER** — “Distributed Energy Resources” or DERs refer to a wide array of distributed energy-related technologies and services. Examples include distributed energy storage, distributed generation, and assorted demand flexibility and energy efficiency improvement tools. The precise definition of which technologies and programs are considered DERs varies by geography.

**Feed-in tariff** — A governmental policy mechanism that rewards the generation of electricity from renewable energy sources, such as solar panels and wind turbines.

**Prosumers** — Companies, buildings, and people that both consume and produce energy. “Prosumers” can be city districts, university campuses, military bases, hospitals, commercial buildings, factories, and even residential home owners.

**Digitization** — The process of converting information into a digital (i.e., computer-readable) format, in which the information is organized into bits.

**Digitalization** — The use of digital technologies to change a business model and provide new revenue and value-producing opportunities; it is the process of moving to a digital business.

**Transactive energy** — The utilization of economic or market-based constructs that factor in grid reliability constraints when managing the generation, consumption or flow of electric power within an electric power system.
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