Renewables Integration:
More Data, More Capacity

The Situation Today

As of January 2019, the U.S. Energy Information Administration forecasts that non-hydroelectric renewable energy resources such as solar and wind will be the fastest growing source of U.S. electricity generation for at least the next two years. According to EIA's Short-Term Energy Outlook, wind generation will grow by 12 percent in 2019 and surpass hydropower generation, then grow another 14 percent in 2020. Solar power is on the rise, too. At grid scale, EIA sees its operational capacity growing 32 percent and making up 2 percent of total utility-scale generation in 2020. Small-scale solar generation, such as that at customer premises, will grow by almost 9 GW during the next two years, an increase of 44 percent.[1]

THE CHALLENGE OF VARIABILITY

The ever-changing nature of intermittent renewable energy creates challenges for grid operations and system planning. Among the challenges are:

Voltage Excursions: Low voltage conditions can result when cloud cover or variable wind speed impacts renewable generation. High voltage also can occur on distribution circuits during low-load conditions with high levels of photovoltaic (PV) systems. When voltage strays from permissible high-low thresholds, it can reduce the life of electrical equipment, potentially cause damage to customer equipment, and introduce both public and utility safety risks.[2] Consequently, system balance now means matching the load with generation while planning for contingencies at both a macro and a circuit/station level. Increased visibility into the distribution system to ensure safety, optimal performance and effective system planning requires granular meter data at both the utility interconnect and gross output of the renewable source.

Premature Equipment Failure: PV on a feeder can cause load tap changers (LTCs), a voltage regulation device usually situated at a substation, to operate more often than centralized generation causes these devices to operate. As mechanical devices, LTCs are rated for a specific number of operations, so PV can shorten the device's useful life. "Modern wind turbines and solar photovoltaic systems introduce much faster power dynamics and potentially stress voltage control devices to the point of premature failure," Murali Baggu, manager of NREL's Power Systems Operations and Control Group, told POWER magazine.[3] Utilities without AMI lack visibility into voltage conditions throughout the distribution system, and they can't accommodate localized voltage fluctuations with in-line regulation equipment. Because LTC's and regulators respond in seconds and voltage fluctuations caused by renewables can occur in subseconds, advanced power electronics-based voltage regulation is often required to prevent damage to utility and customer equipment from high or low voltage.

Limited Hosting Capacity: Hosting capacity equals the amount of distributed generation an electric system can accommodate. Many utilities in the U.S. view 15 percent of peak annual load as a rule-of-thumb measure for how much distributed generation can be added without impact studies and potential upgrades.[4] Researchers at Sandia Labs have found that hosting capacity is more closely linked to the primary operating voltage of the circuit than peak annual load. AMI provides data useful for planning and validating infrastructure requirements to support distributed generation.[5]

THE TECHNOLOGY

Advanced metering infrastructure includes three elements: smart meters that have computing and communications capabilities, networking infrastructure and software to manage the system. Advanced meters are also grid-edge sensors capable of giving grid operators readings on key power quality measurements such as voltage, frequency and volt amperes reactive (VARs) or reactive power.

The AMI's system's network infrastructure serves as the backbone for continuous, around-the-clock, two-way communication paths that supports data collection, monitoring and control functions. AMI can support renewables integration with:

ACCURATE ENERGY MEASUREMENT	Many utilities use AMI on the premise and also with rooftop PV systems to accurately measure power delivered to and received from customer premises. These measurements support utility compensation for customer-produced power as well as measurements that help utilities forecast how distributed solar installations perform over varying conditions.
DISTRIBUTION SYSTEM MANAGEMENT	The network provides for robust, low-latency communications with devices that enable a variety of use cases, including volt/VAR monitoring and control, transformer monitoring, capacitor bank control and transformer or line monitoring.
REMOTE CONTROL OF DISTRIBUTED RESOURCES	The two-way AMI network can be used for demand-side management programs and smart inverter control, which may increase hosting capacity of distribution feeders because it allows for voltage management.
DISTRIBUTION SYSTEM VISIBILITY	Utilities use AMI to understand the impacts of customer-owned systems and determine DER capacity on individual feeders.

VOLTAGE MONITORING

Holy Cross Energy (HCE), a Colorado cooperative with some 56,000 meters, overlays AMI voltage data into their GIS to see all of the AMI voltages along the circuit in the context of the broader, overall system. This enables the utility to identify and correct voltage proactively, improve system efficiencies and avoid potential equipment failures. Among the problems HCE has uncovered are tap changer settings that were too low following circuit reconfigurations, an incorrect transformer setting and issues with voltage regulators. Insights like these can help utilities mitigate the voltage fluctuations renewables bring.

DEVICE CONTROL

AMI meters are essentially small computers, just like smartphones, which means their functionality can be expanded with apps. Arizona Public Service used such an app in 2014 to enable its Solar Partners Program, which started with some 1,500 residential customers who received their own PV systems ranging in size from 4 kilowatts to 8 kilowatts. The utility purchased and owns the rooftop generation equipment, giving consumers $30 each month in credit on their electric bills for 20 years. Each PV system has a smart inverter, which APS connected to its SCADA system to facilitate utility control of the generation resources enabling equipment deferment, voltage management and more. Because those inverters communicated via the Modbus protocol, while APS' SCADA system speaks Distributed Network Protocol, or DNP3, a small application in each inverter's meter handled the translation that allows the inverters to talk to the utility SCADA system.

DEMAND MANAGEMENT

In 2018, research from the Smart Electric Power Alliance found that 2.4 percent of utilities now use demand response to mitigate power fluctuation in areas with high penetration levels of renewable energy, but 24 percent of utilities said they had plans for future implementation, and another 54 percent had this approach to managing DER integration under consideration.[6]

National Grid has launched a distribution system platform to manage DER and accommodate distributed generation on the Buffalo Niagara Medical Campus (BNMC), a sprawling alliance of 13 institutions engaged in health care, medical education and life sciences research.[7] BNMC's annual electricity demand was 153 gigawatt-hours, and its peak demand was 30 megawatts in 2015. Each facility on campus has its own set of DERs. National Grid is using a local, small-scale, but centralized distribution system platform to communicate with network-connected points of control that are associated with BNMC's DERs. The platform leverages those DERs for grid support via energy supply, volt/VAR management, peak load management through generation and storage as well as dynamic load management through demand response.[8]

INNOVATIVE RATES TO MAXIMIZE RENEWABLES VALUE

The 2018 demand management plan that Arizona Public Service submitted to regulators included a "reverse demand response" pilot that would give customers no-cost power during negative pricing hours and reduce the need to curtail solar generation. APS participates in California ISO's Energy Imbalance Market that sends 5- and 15-minute price signals, which occasionally include negative pricing. That is, there's so much renewable generation, customers are paid to use it in order to avoid curtailments.[9]

According to the filing, negative prices are most prevalent between 10 a.m. and 3 p.m. "The opportunity for APS to take advantage of negative pricing is real today. The ability for customers to benefit from this is real today," the filing document said. "Also, from a regional perspective, given renewable targets in both California and Arizona (or, the region) and the likely continued deployment of solar resources, this opportunity is likely to increase." [10] This rate requires advanced meters for validation of time-based consumption.

POTENTIAL REVENUE STREAMS

Tucson Electric Power (TEP) owns some 700 solar PV systems sited on customer rooftops. The utility essentially leases the systems and gives the customers a set rate for their electricity over a 20-year period. Meters on these solar systems bring back readings for watts and VARs both delivered and received at 15-minute intervals. TEP analyzes the data to ensure each system is operating within proven thresholds. When a system falls below normalized rates for three days in a row, utility managers know it needs to be serviced. They can see the system just beginning to fail. Although the utility doesn't offer this as a service on customer-owned systems, this is one example of a potential monitoring service utilities could provide.

CAPACITY FORECASTING

Data from AMI also gives utilities more detailed information on circuit power quality, loading and peaks. This allows for more precise capacity planning and asset sizing. Prior to having AMI, most utilities used load profiles that were often based on a sampling of research meters to inform their capacity plans. Along with granular data, AMI data is time-stamped and can be correlated with weather information to help utilities understand how usage changes from day-to-day. AMI also helps utilities quickly spot issues that could impact investment planning. Here's an example from a recent Department of Energy publication: "If there are ten customers for every transformer, and three customers buy a Tesla, the transformer load has just tripled, but it will not be in any planning forecasts because customers generally do not inform the utility of an EV purchase; however, AMI would very quickly show the load change. Some utilities have developed algorithms to track service transformers that might fail due to increased usage."[11]

1 https://www.eia.gov/todayinenergy/detail.php?id=38053
2 https://www.nrel.gov/docs/fy16osti/63114.pdf
3 https://www.powermag.com/distributed-energy-resources-bring-benefits-challenges-and-new-opportunities/?printmode=1
4 https://www.seia.org/sites/default/files/2017-09/SEIA-GridMod-Series-3_2017-Sep-FINAL.pdf
5 https://energy.sandia.gov/wp-content/uploads/dlm_uploads/2016/06/SAND2015-9712C_PES_GM-HostingCapacities.pdf
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7 https://www.nationalgridus.com/news/2018/06/national-grid-launches-distributed-system-platform-with-buffalo-niagara-medical-campus-members/
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