Advanced Distribution Management Systems Necessary With Increased DERs

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Over the last century, the electricity industry has been continuously increasing operational efficiency; improving reliability; and reducing generation, transmission, and distribution costs.

More recently, additional attention has been focused on reducing carbon emissions and improving energy efficiency. These relatively new objectives have resulted in the widespread use of decentralized generation and renewable energy sources. The industry has also changed the economics of delivering electricity with the creation of new pricing structures and, in a few regions, the likelihood of distribution energy markets emerging in the next few years.

These new objectives are placing increased demands on the electric distribution system. These demands include the ability to support two-way flow of power, rapidly rising and falling loads, increased flicker and voltage swings, and new safety risks for line workers. As a result, there is now a need for a management platform to support an electrical control system and electrical health information so that operators can make informed decisions that will assist in maintaining efficiency, reliability, and safety. In fact, these systems are rapidly becoming a necessity to prevent the failure of the distribution system due to increased wear and tear on distribution assets or the failure of the system due to the inability to maintain constant balance between supply and demand. What was once a relatively passive electrical distribution system with little active management now needs to be continuously monitored and controlled.

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Today, the industry calls the management systems that actively control the distribution system Advanced Distribution Management Systems (ADMSs). While Distribution Management Systems (DMSs) have been around for several decades, their use was not widespread and was often considered a luxury only the most advanced utilities used to squeeze out a few extra percentage points of efficiency and reduce energy delivery costs. New DMS platforms that include an integrated solution for proactive distribution management, reactive outage management, and real-time two way monitoring and control have been renamed "Advanced Distribution Management Systems." This article discusses why an ADMS is no longer something nice to have to improve power quality or lower costs, but something that will be required to keep the system running once distributed generation and renewable energy sources become prevalent.

In fact, in some regions of North America and the world, this has already become the case.

WHAT IS HAPPENING TO THE GRID?

Historically, electric power systems were designed so that the flow of energy goes from generation to customers through the transmission and distribution systems.

The traditional business model is that utilities are vertically integrated, where a single utility owns all generation, transmission, and distribution assets in a geographic region. As part of this business model, utilities trade energy at a bulk transmission level directly between themselves to reduce costs and improve reliability.

Since the 1950s, the transmission system has been actively monitored and controlled with large Supervisory Control and Data Acquisition systems and more advanced Energy Management Systems (EMSs). These systems enabled

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electric utilities to constantly balance generation with electricity demand while dispatching the energy produced by a large fleet of generators in the most efficient and economical way using sophisticated optimization algorithms.

Distribution Systems

At the distribution level, system design is mostly radial, with a single direction of flow from the bulk generation supply to the customer. For the average customer, the cost of distribution is the second-highest component after fuel costs. Furthermore, the majority of the interruptions experienced by a customer are due to distribution faults. Customers pay for energy at a flat rate based upon consumption over a long period of time.

In the last decade, there has been a widespread use of the phrase "Smart Grid" as a label for improving the electrical grid. Because the generation and transmission side of the business has been automated and can already be considered smart, the advent of the Smart Grid has been mostly the process of adding automation to the distribution system. And, in particular, a large percentage of the Smart Grid projects that were implemented in the last decade involved adding smart meters.

Foundations for Distribution Management

Smart meters are able to measure energy consumption in small time increments, often every 15 minutes or less, and communicate the energy consumption for that interval back to a centralized data collection system. The smart meters not only eliminate the need for manual meter reading, but also provide the ability to implement time-of-use rates and peak demand–based rates.

Smart meters communicate with a centralized meter management system using one of a variety of different communications approaches such as utility-owned private radio, internet-like mesh radios, public cellar radios, or the power lines themselves. Smart meters can often provide additional information, such as voltage levels, flicker, tampering detection, theft detection, and outage detection.

Outside of providing the ability to implement new rate structures and enable engineers to analyze historical data and identify problems caused by distributed generation and renewable energy sources on the distribution system, smart meters themselves do not provide a means for active management of the distribution system.

If sufficient foresight and planning was made in a smart meter program, the communications infrastructure for the metering system could have been designed to handle additional capacity suitable to support the needs of an ADMS. Otherwise, either a new, separate communications system is required or the smart metering communications infrastructure will need to be upgraded to support an ADMS.

ALTERNATIVES TO CENTRALIZED DISTRIBUTION MANAGEMENT

Engineers have designed systems often called "Distribution Automation Systems" that support functions that can isolate a faulted segment of a distribution circuit and operate switches to restore customers not in the faulted segment. This ability is sometimes referred to as self-healing, although in reality nothing is really automatically repaired—just the impacted area of a failure is automatically reduced.

Another distribution automation program that is often deployed is to automatically manage energy flows to reduce losses or reduce energy consumption using voltage management. This feature is called Volt/VAR Optimization (VVO), and if it is being done specifically to reduce demand, it is called Conservation through Voltage Reduction.

Many of these distribution automation schemes have used local control and monitoring methods that optimize the response for a small region served by one or two electrical circuits. One big advantage of this approach is that the distribution automation can be tested in small trial projects to prove they work as designed. This procedure is frequently done as part of the measurement and verification phase of the project that alternates the operation of the system on and off to measure the differences between the on and off periods during different times of day, days of the week, and seasons of the year. The measured results are then used to model and project the savings over multiple years and, if fully deployed, across the entire service territory.

When proven successful and the investment makes economic sense, with sufficient returns to justify the costs, the automation scheme can be rolled out a few circuits at a time, allowing the costs to be spread out over multiple years.

DISTRIBUTED ENERGY RESOURCES

The term "distributed energy resources" (DERs) is often used to refer to electric-power-

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generating sources that are typically smaller than the historical utility-scale generators and are positioned closer to demand centers. Frequently they are colocated at customer sites. Renewables such as rooftop solar panels and small-scale wind turbines are principal examples of DER technologies.

DER operation must comply with applicable engineering standards such as IEEE 1547 and the applicable Interconnection Agreement with a local utility. Most Interconnection Agreements require compliance with applicable engineering standards such as IEEE 1547 and additional, locally established requirements, and are intended to ensure that the DER interconnection is safe, does not adversely affect power quality for other customers, and is compliant with the regulatory rules.

Loads Are Changing

Certain types of DERs are especially demanding on the power system due to the highly variable nature of their energy source, such as wind- and solar-powered generation. Sufficient concentration of solar and wind sources on a single circuit can produce unacceptable voltage and power flow changes on the distribution circuits that exceed normally accepted standards, resulting in brownouts or even failure of consumer and industrial electronic and electrical devices. Furthermore, the changes can be much more rapid than the normal changes in load over the course of the day, sometimes changing by a large percentage in just seconds or even subseconds, causing flickers, voltage surges, and sags.

For the last few years, load growth has been less than 2 percent annually in North America. This is much lower compared to previous eras, such as in the 1950s and 1960s, when growth was 6–7 percent; in the early years of electrification, growth was over 10 percent. Historically, load growth has also tracked closely with GDP, but more energy-efficient technology and new mandates for efficiency programs are creating recent trends where GDP growth is not coupled to energy demand growth. Other factors that influence load growth have been population growth and decreasing energy costs relative to inflation and average income.

Many forecasts into the next couple decades show load growth decreasing even further to nearly zero even as population and GDP rise. However, there are some potential disruptive factors that could cause big variation in those projections due to uncertainties of electric vehicle adoption, federal and local energy efficiency policies, and the amount of local generation produced by consumers themselves.

For many decades, electrical operators could safely plan on loads gradually rising during the day; experiencing a peak in the early evening, when residents returned to their home and turned up air conditioning, began cooking, and turned on televisions and lights; and then gradually declining until the early hours of the morning. This predictable daily pattern is called a load profile curve. In areas such as California and Hawaii, where there are already large amounts of solar generation installed at customer residences, these load profiles are no longer rising during the day, instead rising in the early morning but declining by mid-morning as solar generation rapidly rises, offsetting the demand increase. Then in the early evening, load rapidly rises again as the solar production decreases coincidentally with the early-evening demand peak.

This profile creates two peaks each day, one in the morning and one in the evening, with the evening one rising much faster than the historical midday peak.

Policy Trends

Structural changes in the distribution business model are now being driven by regulatory initiatives such as California Assembly Bill 327 and New York Reforming the Energy Vision (REV).

California Assembly Bill 327 requires California investor-owned utilities to proactively plan for DERs by identifying the optimal locations for the deployment of distributed resources and requiring them to propose programs to achieve DER deployment based upon the optimal plan. Furthermore, the utilities are required to spend money on grid enhancements that are required to support the additional DERs as planned.

California Assembly Bill 327 is designed to help ensure that ratepayer investments are being made intelligently. Shifting the state's grid planning paradigm requires that Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric proactively plan their grids for DERs. Each utility must take the following three actions:

- Submit plans to the California Public Utilities Commission that identify optimal locations for the deployment of distributed resources.

- Propose policies and programs to achieve this deployment.
- Include any necessary distribution grid spending to accomplish their plans in their next general rate case.

New York REV's stated goals are even broader and extend into the creation of energy markets at the distribution level. The markets are intended to increase customer engagement, improve distribution system efficiency, increase fuel and generation diversity, improve system reliability and resiliency, and reduce carbon emissions.

In New York, the creation of a function called Distribution Service Platform provider will be mandated over the next few years. It will require the following services to be provided:

- A distribution system design process that integrates DERs into the system
- Expansion of distribution grid operations to optimize load and supply at the distribution level and to enable two direction power flows resulting from increased DERs
- Implementation of markets for distribution products and services including the facilitation and processing of market transactions, and measuring and verifying participant performance
- Providing platform technologies to support grid operations and market operations

The identified platform technologies include models of the distribution system, monitoring and control systems needed to maintain a stable and reliable grid, and optimization tools that consider the generation output of existing and new DERs in the grid. Including a secure and scalable communications network including smart metering functionality.

New York REV mandates an ADMS that parallels the sophistication of the EMS technology that has been deployed at the transmission level. In particular, the mandates require real-time load monitoring, network monitoring, fault detection, automatic feeder switching, and VVO functions.

Distribution Grid Devices

Another area where there is rapid change occurring is in the underlying technology used to monitor and control the distribution system.

First, monitoring devices are rapidly becoming cheaper, driven by advances in consumer and industrial electronics. In the past, distribution monitoring devices were considered highly specialized and relatively expensive. The costs of the monitoring devices were often the most challenging to justify this aspect of an ADMS project, because the devices need to be deployed in relatively large numbers to fully monitor an entire distribution system.

Due to the multitudes of applications of remote monitoring technologies in other industries, vendors are now able to leverage advances made in other, much-larger-scale applications to drive down the costs of distribution monitoring devices. Examples of relatively new devices in the market include line voltage and current measurement devices that fit on top of a distribution pole as part of the line support structure, called "line post sensors."

An even more innovative type of device are line voltage and current monitors that also include the radio communications device that harvests the energy directly from the power line, removing the need for separate boxes for monitoring and communication. Significant installation and maintenance cost savings are possible because some of these devices can be "clamped on" by the line person without requiring any interruption or complex installation procedures.

Other advanced monitoring devices include a device called a Phasor Measurement Unit (PMU), also called a syncrophasor. It measures voltage amplitude thousands of time per second and, combined with precise GPS-based time logging, can detect the shift of the voltage oscillations between two different locations. While sounding very complex, the measurements from a couple PMUs can take the place of a large number of individual voltage measurement devices and provide additional insight into the operation of the system that the voltage measurement devices could not provide.

WHAT IS AN ADMS?

An ADMS is a software system that manages the monitoring and control of the distribution system to ensure optimal operation of the system while improving the reliability and safety of the system.

Key to the operation of an ADMS is a simulation model of the entire electrical system that is used to simulate the operational behavior of the system. Computer simulations of various possible control actions and the expected responses are made to determine what the best option for control action is at any given time.

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Integral to the ability to perform these simulations is the ability to collect and measure the current state of the distribution system through sensors that are dispersed throughout the entire distribution grid.

SOME KEY ADMS FUNCTIONS

Short-Term Load Forecasting

The short-term load forecast module of an ADMS is used to predict the expected load on all of the feeders in the distribution system at any given time in the near future. This function must account for the presence of DERs because they change the net load at every location of a DER. The higher degree of variability of DERs due to weather and other external factors makes the load forecast function more complex than ever before.

Voltage Profile Management

A fundamental principle of distribution system operations is to maintain voltage within acceptable high- and low-voltage limits for all customers being served. Electric distribution operations use capacitors, voltage regulators, and adjustable substation transformers as means to maintain voltage under all anticipated loading conditions.

Traditionally, distribution feeders would be operated with a voltage level that decreases the farther the distance from the substation source. The presence of DERs on distribution feeders makes voltage management considerably more difficult. Reverse power flow caused by high DER outputs during light load conditions can produce voltage levels that actually increase with the distance from the substation. This property will cause traditional local voltage regulators to improperly operate, causing voltages that exceed the normally accepted voltage ranges.

A properly operating DMS can monitor the voltage along the entire circuit and detect the rising voltage and instruct the capacitors, voltage regulators, and adjustable substation transformer settings to compensate for the DER contribution.

Volt VAR Optimization

Volt VAR optimization is an ADMS function that serves multiple purposes; it can be used to reduce demand, decrease operational losses, and improve power quality. VVO determines the necessary control actions for capacitor banks and voltage regulators to reduce losses and/or lower demand. Furthermore, as policies change and DERs become more sophisticated, DERs can be actively controlled as part of meeting the desired objective.

Fault Location, Isolation, and Restoration

Faults occur on a distribution system as the result of equipment failure, damage inflicted by the public, or adverse weather.

Opening up switches around the damaged segment can isolate the faulted segment of the distribution circuit. Once the segment is isolated, closing in normally open tie switches that re-energize the unaffected segments can restore customers downstream of the isolated area. However, this restoration is only possible if the adjacent feeder has sufficient capacity and if the resulting larger circuit can maintain adequate voltage profiles. Often there are multiple tie switches that could be chosen.

It is the objective of a Fault Location, Isolation, and Restoration function in an ADMS to determine where the fault is, determine the best tie switch to close, and determine if any additional actions are required to maintain acceptable voltage levels.

Switching Management

A switching management function is used to assist the operator to prepare switching plans that are used for routine construction, maintenance, and operation of the distribution system.

It is the role of the switching management function to assist the operator in preparing a plan that is safe for the crews working in the field. The presence of DERs on the distribution system results in the increased potential for DERs to inadvertently feed into a section where a crew is working, creating a safety risk. A new function in the switching management function is to keep track of all of the locations of DERs and ensure that there is adequate safety protection performed in all switching plans.

SUMMARY AND CONCLUSION

The role of an ADMS is to provide an integrated solution for proactive distribution management, reactive outage management, and real-time two-way monitoring and control. As a result of the proliferation of DERs, an ADMS is no longer something nice to have to improve power quality or lower costs, but something that is required to keep the system running once distributed generation and renewable energy sources become prevalent.