

Automating the Smart Grid

Substation-based Smart Grid Automation will cut peak demand and reduce outages

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Automation and industrial PCs have improved productivity in every area of industry over the last few decades. The electric power generation, transmission and distribution systems have been integrating automation systems and industrial PCs as well - but now must face the challenges of full conversion to integrated automation and information platforms.

An area of particular focus is the distribution system and its

substations. Many existing substations still have circular recording charts with paper graphs that must be manually replaced every week. Many of the protective devices for line, bus, and transformer protection are electromechanical components with only basic inputs and outputs. Utility line workers must often manually operate switches to re-route the flow of power during routine maintenance or power outages.



Although the present system has worked for decades, fully integrated automation and information platforms based around substations and encompassing the entire utility distribution system will provide significant improvements. These will result in increased safety, more accurate diagnoses of problems, lower customer outage minutes, better utilization of assets and other benefits listed below.

1. Increased capacity.
2. Improves utilization.
3. Automatically pinpoints outages.
4. Automates outage restoration.
5. Simplifies troubleshooting and maintenance.
6. Provides real-time information to improve protection schemes.

7. Provides real-time information for demand response.
8. Provides safer work environment.

Peak Demand Outstrips Capacity

It's been over a century since Thomas Edison, Nicola Tesla and George Westinghouse began the electric utility business in the



U.S. For decades, electric power was considered more of a luxury than a necessity. Outages that lasted an hour or more were tolerated. The price of raw material such as steel, copper, and aluminum were cheap compared to today. Capacity issues due to an increase in demand were resolved by building

larger facilities and replacing smaller conductors with larger ones.



As the usage of electric power increased, utilities upgraded their facilities by buying larger equipment, consuming more raw materials in the process. Utilities and other industries found themselves competing for raw materials and driving up prices for copper over 400% since the year 2000 (reference 1).



Increases in raw material and construction costs made it difficult to justify increased capacity projects, all of which are ultimately funded by increasing the price per kilowatt-hour (kWh) paid by utility customers. Customers and other agencies typically advocate against all rate hikes, often pressuring the Public Utilities Commission (PUC).

The PUC is in a constant balancing act. It must make sure that the utility has enough capacity to serve all of its customers, but at the same time limit requests for rate increases. When rate increases for additional capacity projects are rejected, utilities must find ways to accommodate more loads with existing equipment. Automation is often the best solution.

Coping with Peak Demand

Equipment such as substation transformers, circuit breakers and conductors has a continuous current rating dependant on temperature. Depending on the ambient temperature, the same piece of equipment transfers a certain amount of power during the cool winter months, and then is de-rated during the hot summer months. Unfortunately for utilities, the summer is usually the same time when electric customers increase their demand, primarily by using air conditioning.

Even though summer is a relatively short period compared to the rest of the year, utility equipment must be rated to meet the summer peak. Reviewing data from the California Independent System Operator (ISO) for past years shows that

average demand for the rest of the year is approximately 65% of the summer peak (reference 2). Therefore, for most of the year, there is an excess capacity of 35%.

Before explaining the benefits of automating the electric grid, it's important to understand the nature of the daily peaks. Taking a further look at the ISO data, we find that peak loads for heavily populated areas such as Los Angeles generally occur during the hours between 6 to 9pm. This is usually when everyone gets home from work and begins their daily routine of turning on the TV, using the washer and dryer and cranking up the AC.



Piecing together the data shows that most utilities only use their maximum capacity during the hottest days of the summer months, and for only 3 to 4 hours on those days. Some generation and transmission equipment, which cost millions of dollars to install and maintain, are only used during these times.

To help lower peak demand, utilities create demand response and emergency load curtailment plans. In the first stages, a broadcast is made via radio and TV asking customers to lower their electricity consumption. If there's not enough voluntary load curtailment, utilities turn to customers that have agreed to demand response contracts.

These contracts require the customer to lower their electric usage to a certain level when requested by the utility, and in turn the customers pay a lower rate throughout the year. When the electric utility anticipates a peak day, they speak with customers in advance. One of the main problems with this system is that demand response is often voluntary as most customers can still choose not to curtail load and instead pay a higher rate for that day.

A few customers may be on a mandatory curtailment plan, but typically not enough to cut demand to required levels. If all else fails and not enough customers are willing to curtail load, the utility forces rolling blackouts to maintain frequency and voltage and prevent a transmission level outage. Transmission level outages affect multiple cities at once and can cause system instability, which can ripple through the system causing still more outages.

To forestall outages, utilities attempt to forecast demand up to ten years out, and to increase system capacity as needed. But equipment, labor and other costs associated with new generation plants and transmission lines are foreboding.

In addition, the general public is usually not in favor of having large utility equipment installed close to their homes. Typically, local governments support the public and make it difficult for utilities to acquire permits and rights to install new generators and overhead transmission lines.

Peak demand continues to grow even as capacity additions become ever more difficult and expensive. The lowest cost solution is to make the grid smart, reducing peak demand via automation.

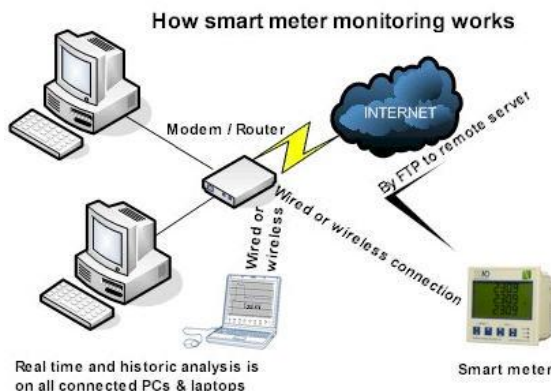
Automation Increases Effective Capacity

If all the appropriate automation systems were in place, utilities could curtail customer loads automatically, and provide control of distributed energy resources (DERs). DERs in particular have skyrocketed in growth over the last few years as governments worldwide have promoted relatively small and localized generation facilities.

Monitoring and controls for DERs will become ever more important as these resources increase in size and quantity. Whether it's a solar panel or a small gas turbine generator, utilities want to be able to increase the generator's output or completely shut it down, all in support of the overall utility generation system.

With the customer's agreement - controls could also be connected to major use points such as air conditioners via electric meters to help shed load. These initiatives, sometimes called Smart Meter programs, have already started with most electric utilities (reference 3).

Before the installation of Smart Meters, all residential customers had electromechanical meters that only kept track of kWh usage. These meters weren't and aren't capable of remotely monitoring and controlling power usage.



With Smart Meters, utilities now have the capability to implement time-of-use billing. This means that utilities can bill at a higher rate for power usage during peak demand. With time-of-use billing, customers become aware of their electric usage and its cost, encouraging load curtailment during peak hours.

Some utilities, such as Southern California Edison, go one step further and offer their customers guaranteed

annual rebates if they agree to let the utility automatically shut off their air conditioners during peak demand periods.

Utilities also offer their industrial customers a variety of load curtailment programs. These programs offer progressively lower rates as customers agree to cede more control of their electricity demand to the utility (see OpenADR sidebar). Ceding this control to utilities will lead to higher utilization factors of existing equipment and drastically reduce the money spent each year for capacity increases.

Finding and Fixing Outages Faster

For maximum reliability, utilities often use spot networks in the distribution system (reference 4). Spot networks use a network of transformers which are connected in parallel on the low voltage side. At any given time, a customer is connected to at least two circuits. There is enough capacity on each circuit such that an outage on one of the two circuits will not interrupt power to the customer.

This type of system provides the highest reliability, but because of high cost it's only implemented in the downtown areas of large cities such as San Francisco and New York. No one will argue the importance of reliable power to major cities, but smaller cities and other customers are usually connected to their local substation by a single radial feeder. Outages to these feeders are called in to the control center, which then dispatches a person to the area to manually restore power to customers.

Most utilities have begun to automate the restoration process by installing supervisory control and data acquisition (SCADA) systems that monitor and control line reclosers, switches and sectionalizers - but the system is still a long ways from being completely automated.

Consequently, the customer average interruption duration index (CAIDI) minutes are over 100 for most utility customers (reference 5). CAIDI is a reliability index that all utilities must report to their regulatory agencies. It is computed by taking the sum of all customer outage durations and dividing this sum by the total number of outages. Essentially, CAIDI measures how long an average customer will be out of power for the year.

There are many factors that affect CAIDI minutes such as whether the area is suburban or rural, known hazards in the area, and limitations on resources and materials during storm conditions. But during a normal outage, most of the restoration time is spent in the initial response.

Most power outages at the distribution level aren't identified by alarms from a circuit breaker, but from actual customer calls and from first responders such as the fire or the police department. This is because most of these outages are first registered by protective devices such as fuses, circuit breakers or line reclosers -

all typically not supplied with alarms. Less commonly, a wire falls down on a high resistive surface and the fault current is not enough to trip ground relays.

Because most radial feeders are supplying power to multiple customers, an electrical fault in one section will affect all customers connected to that feeder. Other protective devices may be put in place to minimize the customers affected, but usually all customers will be out of power if a fault happens close to the substation or in the instantaneous protective zone.

In the event of an outage, a line worker is dispatched to the area, and he or she conducts a visual patrol to find the faulted section. Once the problem is found, the line worker must open nearby switches. If there are none, the line worker must cut jumper wires to isolate the problem area.

Once this field work is complete, the line worker contacts the control center to restore power to the remaining customers by switching load to adjacent circuits. Once the section is isolated, a line crew will arrive to repair and replace equipment as needed and to reconnect jumper wires if they were cut. It's not the most efficient way to restore power, and automation offers a better solution.

Implementation of automated devices such as SCADA enabled switches and line reclosers would cut outages. Distribution circuits could be sectionalized with SCADA operated devices between each section. Open points that connect to other circuits could be replaced with SCADA-enabled switches.

During an outage, each device would determine if the fault location was within its zone, and then communicate the information to the control system. The system would then automatically isolate the problem by opening the adjacent automatic switches. Power would be quickly rerouted to unaffected sections by closing connections to adjacent circuits. This could all be done without the intervention of a line worker.

Another added benefit is that automated devices have computer-based controllers with on-board memory. Files with setting information, historical readings and event files can be stored for several months. This gives engineers the capability to interrogate the automatic devices remotely and download fault information. With this valuable data, engineers can troubleshoot and determine if there are any systemic problems.

Controlling Voltage and Power Factor

Utilities must maintain system power factors close to unity and minimize reactive power to maximize the efficiency of the power transmission system. The more reactive power flowing through the transmission lines, the less real power can be transferred. Utilities spend millions of dollars installing power factor correction

devices such as static VAR compensators to maintain power factor at the transmission level.

Since most customers are connected to the distribution grid, correcting the power factor at the distribution level will reduce the cost of installing expensive equipment at the transmission level. Control of capacitor banks at the distribution level is generally limited. They are either fixed to stay on or controlled by a simple timer or voltage sensor. During the summer peak, all capacitors can be manually turned on to support power factor and voltage.

Some issues can arise due to the large fluctuation of demand. Capacitor banks manually switched to support the power factor in the summer could provide too much reactive power in the winter, using up system capacity or causing high voltage. Vice versa, a capacitor bank could fail and lower customer voltage below acceptable standards.

The process for fixing high/low voltage issues and implementing power factor correction is usually not automated. Customers must instead measure their own voltage periodically and determine if it's outside the standard limits. High voltage will decrease the life of many electrical components, and also increase power usage.

Most electronics and appliances have a maximum voltage limit and can be damaged if limits are exceeded. On the other end of the spectrum, providing low voltage may not be enough to turn on some equipment.

Automatic capacitor controls with communications to the control center can assist in power factor correction and resolve voltage issues. Instead of time-based, voltage-based or manual switching - sensors can measure the power factor, and this information can be used to automatically and remotely control capacitor bank switching.

Steps to Automating a Grid
1. Automate power factor correction.
2. Replace open points in the distribution network with switches.
3. Implement pilot protection schemes.
4. Automate fault isolation systems.
5. Replace electromechanical relays with microprocessor-based relays.
6. Install servers at control centers.
7. Install high-speed two-way data networks.
8. Provide automated control of distributed energy resources.
9. Fully implement the OpenADR initiative.
10. Upgrade substation controllers to industrial PCs.

Through the newly installed automatic controller on each capacitor bank, specific voltage and current readings can also be sent back to the control center. With more real time data points, engineers can be proactive and anticipate voltage and power factor problems.

Coping with Distributed Energy Resources

Voltage issues will become a more common problem as additional and larger DERs are connected to the grid. With government agencies setting aggressive deadlines to incorporate more renewable resources, long term system impacts may be overlooked.

DC to AC inverters are used with DERs such as solar panels, fuel cells and other direct current generating resources. The inherent problem with most inverters is that they must elevate the output voltage to produce power compatible with the grid. Without proper engineering studies, a customer without any history of high voltage problems could have issues when a neighbor installs a photovoltaic system.

DERs present more problems than just high voltage to local customers. When the distribution system was first designed, it was considered to be a radial system with no other positive sequence source aside from the transmission system (reference 6). Hence, all protective relays were simple over-current devices, with no provisions for generator protection.

When a DER is installed downstream, the distribution system is no longer radial and utilities must consider two important safety issues: the ability to isolate the generator so that it does not back feed power into a line where work is being done, and the desensitizing of over-current relays such that they do not trip during a fault condition.

Unlike the previous examples where automation was an added benefit, in this case it is a safety requirement. When a DER is installed, circuit breakers must have voltage monitoring to verify that the generator is not online during a planned shutdown or during line testing. This prevents harm to both line crews performing work, and to DER generation equipment.

If over-current relays are not sufficient to protect the line, relays must be upgraded to the microprocessor type to give the additional functionality of a direct transfer trip scheme. More inputs are required along with a dedicated communication line from the substation to the generator relays, allowing for simultaneous tripping during electrical faults.

Automation Implementation Challenges

Most of the solutions discussed in this paper are already available, but many haven't yet been implemented. Vendors have pushed utilities to adopt new

technologies such as microprocessor-based device's, and in most cases microprocessor-based controls and relays are the only option available from suppliers.

Microprocessor relays save panel space because they combine all the features of several electromechanical relays into one box. They also have more features, and require less maintenance as it's not necessary to clean parts or make mechanical adjustments.

To perform diagnostics, technicians can simply plug into the relay with a laptop. If the system is designed correctly, the relays are redundant and technicians can take them out of service for trip testing.

Microprocessor relays also have a wide variety of communication options. When connected to the control center, typically via an industrial PC, relay setting changes which used to require a person to physically turn dials can be done remotely. Event files that hold fault data can also be uploaded to the control center via the PC for analysis.

Relays in the distribution system can operate circuit breakers and shut down power to several city blocks. Because of this consequence, security of the network will become a big issue for the utility. If a fully automated system were in place, various types of communication would be used to reach field devices including wireless, which would further complicate security measures.

At the same time, security should be balanced with cost and convenience. It would be optimal to access relay data from an employee's desk computer, but doing so via the existing Internet and email network could expose the system to more security threats.

The upfront cost of new automated control and monitoring components and systems along with integration to existing equipment are key hurdles for utilities. For example, new SCADA-enabled switches are much more expensive than non-communicating versions. The cost is escalated because a communication line is needed to connect the switch to the SCADA system.

Since most of the components are installed outdoors - vendors and ultimately their utility customers must spend extra money to deal with elevated temperatures in the summer and electrical interference from lighting strikes. Additional costs are also incurred for testing new components and for replacement of parts such as batteries. Training is another issue, as utility workers must be provided with the knowledge and expertise to effectively utilize automated components and systems.

If the electric utility were able to automate all of its switches, line reclosers, and capacitor banks - substation controllers would be the next bottleneck of the system. Hundreds of new data points would be added, and most of the data would need to be stored. The data is important to compare the demand during different times of the year and to monitor the system conditions in real time.

As data points would increase exponentially, the best solution is an industrial PC with enough capacity to store data for several years. The PC would also need enough communication bandwidth to stream real time data from the field devices to the control center, and it would need enough processing power to handle all data access requests.

Existing communication bandwidth will not be sufficient in most cases. Ethernet is the likely choice for a communications protocol, as it has the ability to transfer data in the Gigabit range and as it's an IP-based protocol not proprietary to any particular vendor. The ideal way to keep this Ethernet network safe and secure is to build it completely separate from the existing email and Internet infrastructure.

The electric power industry as a whole agrees that it's beneficial to automate the existing system. Many initiatives are being implemented, and automated devices are slowly replacing older components. But it will be some time before utilities can completely rely on system automation to manage demand and generation during system peaks.

As more automated components and systems are installed - the industry will need to address new challenges such as increasing bandwidth, ensuring security of communication protocols and establishing standard equipment specifications.

Automation Implementation Challenges
1. Cost of retrofitting existing equipment.
2. Cost of new automation hardware and software.
3. Cost to train employees.
4. Lack of standards.
5. Maintaining security of networks.

It will be important for standards groups, governing bodies and manufacturers to work together with the utility to develop industry standards that address these issues. This will be especially critical for equipment installed by third parties such as DERs. Once a set of specifications and standards are agreed upon, the technical challenges of transitioning to a new Smart Grid will be minimized.

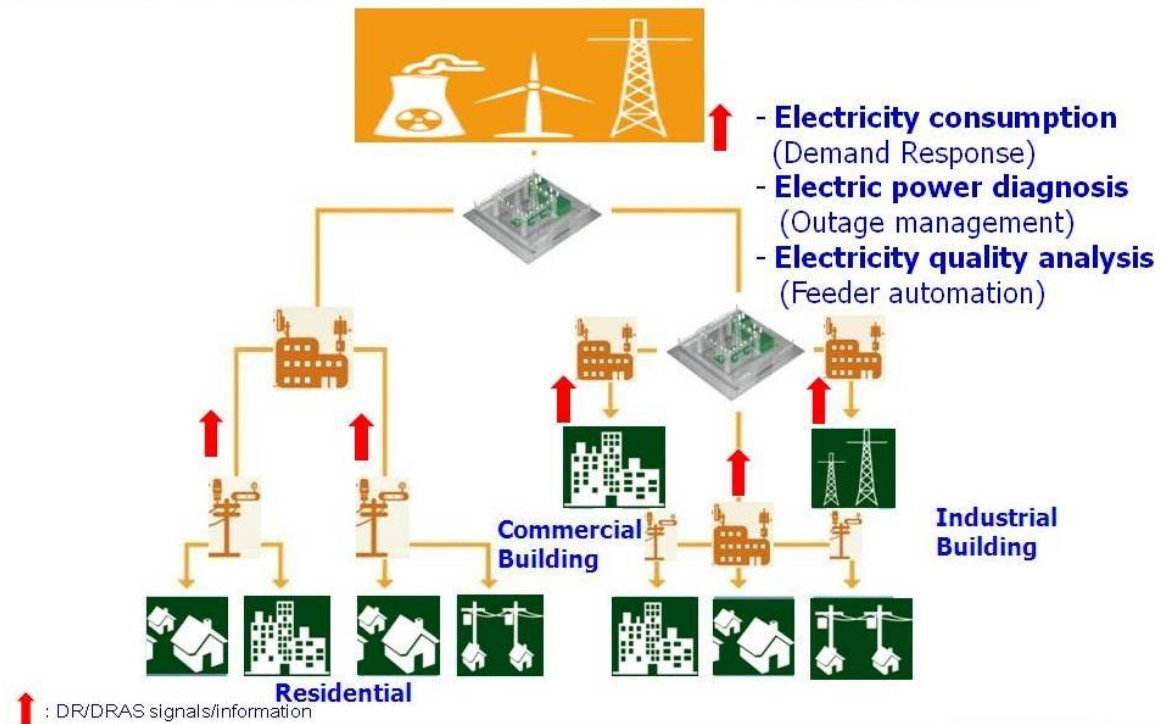
Sidebar: OpenADR

California has taken a major step towards standardization within the Smart Grid initiative. Through funding from the California Energy Commission, automation specifications are being developed for automated control of the electric system's demand response.

The written specification - Open Automated Demand Response (OpenADR) - creates an open communications infrastructure which will provide load shedding for customers, controls for DERs, system monitoring and dynamic pricing information to DER owners. The goal of the specification is full automation.

The heart of OpenADR is a central computer called the Demand Response Automation Server (DRAS). In most cases, the central DRAS will be owned and operated by the electric utility or the Independent System Operator (ISO). The server will send information to the clients such as dynamic pricing and anticipated days and times for load shedding.

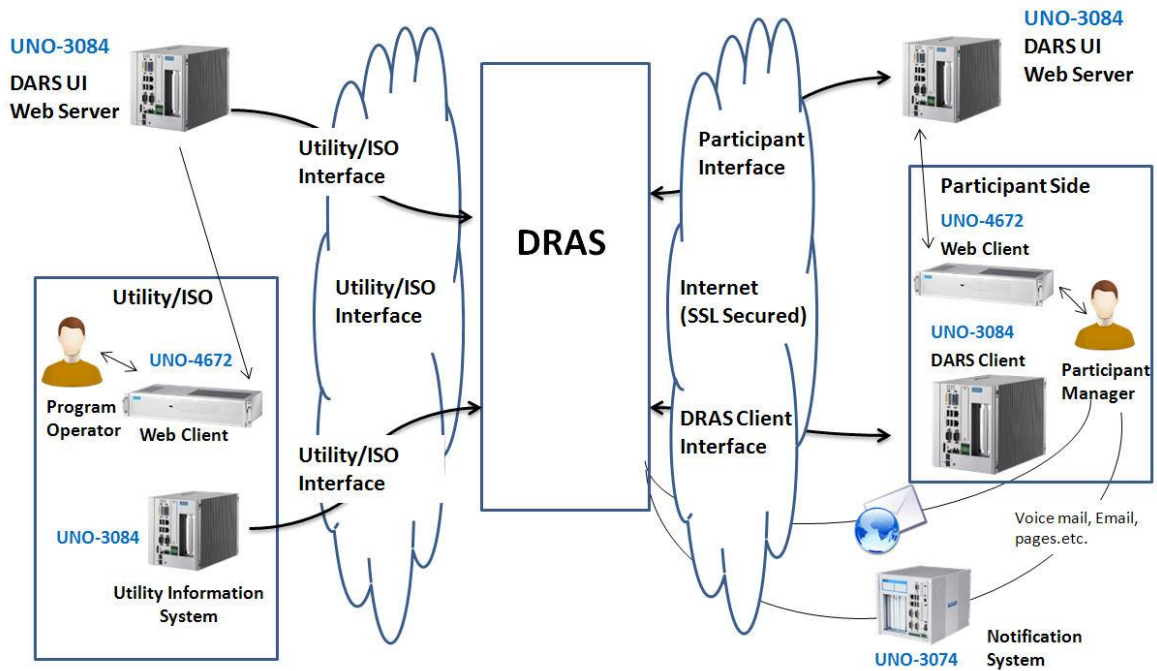
Smart Grid DR/DRAS Signals/Information



Major customers will have one or more DRAS client computers installed at their facility and connected to the central server. Customers can choose to be part of the demand response program and become a “participating client”. Participating clients will have additional controls as compared to a regular client for shedding load or for turning on their generators.

The ISO and utility can predict when electric usage will be at its highest with a high degree of accuracy. With OpenADR, the utility operator will use the Generic Event Based Program to communicate to all DRAS client computers. Operators will send an event that details the upcoming peak demand along with the actions required by all participating clients. If more power is needed, the DRAS will have pre-programmed Generic Bidding Programs which will send another event to customers detailing the system location where there is a shortage along with dynamic pricing for power.

DRAS Client Interfaces



Once the peak demand period subsides, utilities can review information stored at the DRAS regarding the most recent event and the response to it. The DRAS will log all demand response events along with actions taken by participating clients. The DRAS will also review client contracts to compare the expected load curtailment with the actual, and determine if additional actions are needed prior to the next period of peak demand.

OpenADR is still in the developmental phase and faces hurdles before it can be fully implemented. For example, many of the requirements for the computing system noted in section 5.4 of the specification are vague. Requirements such as

“The DRAS should recover gracefully from facility faults with minimum lost data....” (reference 7) don’t address specifics such as backup power requirements.

The standard also doesn’t specify the operating system or the actual communications protocol between the DRAS and the clients. This is a substantial issue that can be complex and costly if the DRAS is required to communicate using multiple protocols and different operating systems. Although the standard is still in the developmental phase, it’s an important first step towards a fully automated system.

Full specification development and implementation is in progress, but some OpenADR initiatives are already in place. Major utilities in California use an OpenADR gateway installed at their customers’ sites. Each gateway has an IP address and an Internet connection. Via this connection, a signal is received from the utility concerning desired customer demand response.



Advantech’s ADAM-4501 Ethernet Communication Controller

Four contact outputs from the OpenADR gateway indicate the level of demand response desired by the utility. Each customer can connect these contact outputs as desired to their building and facility automation systems. For more info on these and other OpenADR programs, go to www.openadrcollaborative.org.

Sidebar: Governments Influence Smart Grid Development

Starting in 2003, the electric industry worked with the U.S. federal government and communicated the major issues regarding the electrical grid. Together they agreed on the need to upgrade the aging infrastructure and integrate new automation technology. That summer, the Northeast Blackout left 10 million people (reference 8) without power and provided proof that the system was in dire need of improvement.

Before that blackout, federal governing bodies had little involvement in the operations and the technical aspects of the electric grid. As governing bodies became more interested, they realized the urgency of the issues brought up by the industry. In July of 2003, the Department of Energy (DOE) published “Grid 2030, A National Vision for Electricity’s Second 100 years”.

The paper envisioned a new power grid using superconductive materials to replace copper and aluminum. The new materials would have much higher capacities and less electrical resistance, allowing more power to flow through existing electric transmission paths. The new electric grid would also have a “fully automated power delivery network that monitors and controls every customer, their appliances, and every electrical node in the system”, more commonly referred to as the Smart Grid.

With the vast array of new technologies and with the different ways that they could be applied to the system, it was important to develop standards and specifications for the Smart Grid. So in 2007, the government passed the Energy Independence and Security Act, which created the Federal Smart Grid Task Force to “coordinate Smart Grid activities across the federal government” (reference 9).

This task force consisted of players from existing government agencies such as the Department of Energy, Federal Energy Regulatory Commission, the Environmental Protection Agency, the Department of Homeland Security and other government groups.

The task force highlighted four areas needing standards: Architecture and Communications, Monitoring and Load Management, Advanced Components & Operating Concepts, and Modeling and Simulation. Partnerships were created with technical groups such as IEEE, the National Renewable Energy Laboratory and the National Institute of Standards and Technology (NIST) to provide standards for the four subject areas.

Funding and support were given to develop existing standards such as IEEE1547, which covers the interconnection of DERs with the electric power system. Support was also given to new standards such as NIST IR 7628 which covers cyber security strategies and requirements (reference 10).

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