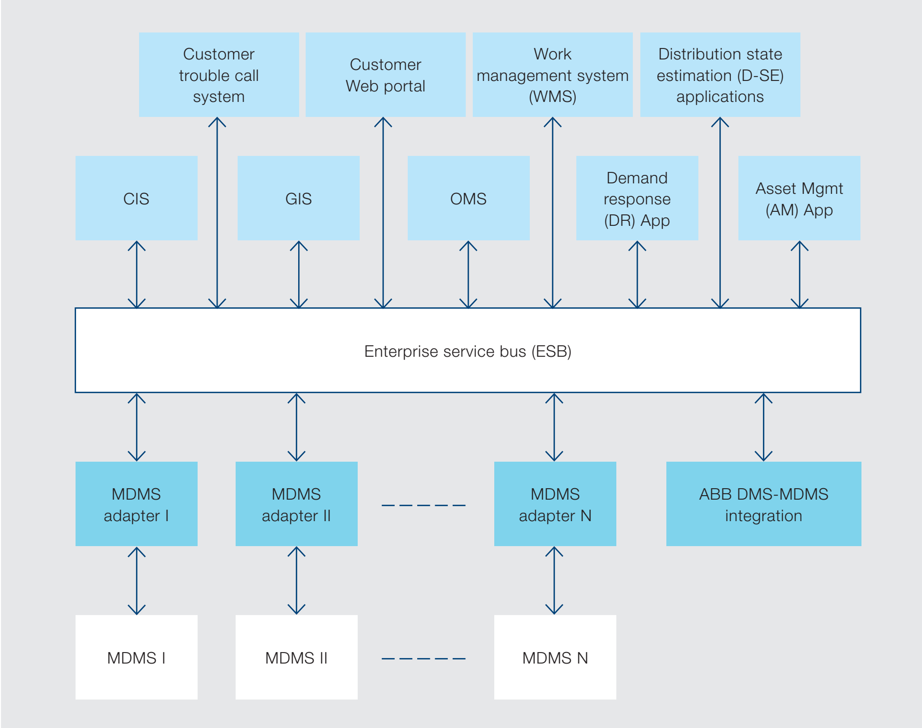
Closing the loop

Smart distribution management systems are helping to provide more efficient and reliable services

WILLIAM PETERSON, XIAOMING FENG, ZHENYUAN WANG, SALMAN MOHAGHEGHI, ELIZABETH KIELCZEWSKI – Utilities are always looking for ways of improving customer service while optimizing overall performance and reducing operating costs. At the distribution control center level, smart distribution management system (DMS) applications have the potential to help utilities achieve this by providing fast, accurate and detailed information about a distribution system so that strategic decisions can be made. Historically, the main DMS application data sources were SCADA telemetry, end-customer calls and maintenance/repair crew reports. With the industry drive toward smart grids, these sources are being augmented by a multitude of sensors with communication capabilities that are deployed for substation automation, distribution automation, and advanced metering infrastructure. Integrating these sensor data into DMS-advanced applications is essential to reaping the potential investment benefits as well as justifying the cost of creating the sensing and communication infrastructure. Through advanced applications, the distribution system provides more efficient and reliable services to customers and, at the same time, helps reduce the ecological footprint of energy production. The availability of real-time and near real-time system information not only enhances the capabilities of existing applications like outage analysis, but also enables advanced smart grid applications that were not possible before.

1 ABB's AMI-enabled smart distribution management system vision



An advanced metering infrastructure (AMI) refers to the information technology and infrastructure that collects, communicates, aggregates and disseminates the power usage, quality and status information from so-called smart meters.[1] A smart meter is not simply a point of instrumentation, but also a point of interaction (POI), or in other words, an intelligent node in the smart grid.

With the rapid deployment of AMI in many utilities, distribution management system (DMS) applications are undergoing significant renovation so that they can make faster and smarter decisions, and achieve network control objectives quicker with less cost and greater reliability. DMS/AMI integration is not without its challenges but smart grid applications, such as outage management systems (OMS), distribution state estimation (D-SE) and demand response (DR) among others, set to benefit from this integration, the utilities will have more efficient operation and customers will have more reliable power.

The benefits of energy-consumption monitoring and control

Advanced DMS applications require real-time or near real-time network information, including network connectivity (switching device on/off status), loading levels (current) at service points (load transformers at end-customer premises) and feeder sources (distribution substation transformers), as well as feeder voltage profiles (voltages along the feeder main and laterals). Conventional supervisory control and data acquisition (SCADA) telemetry can provide information about substation and feeder equipment, but the cost of the infrastructure needed to gather information at the load transformer level and beyond is simply too prohibitive. This can be overcome by using an existing AMI, which not only provides load transformer information at a much lower cost – only the DMS/AMI integration cost is incurred – but is also capable of reaching individual households.

System architecture

The integration of smart meter data into a DMS will enable a whole new breed of smart grid applications at the control center level. However, the standardization of this integration is not easy because of the many types of AMI technologies that exist and the varying requirements for each smart grid application. ABB is pursuing a vision that the meter data management system (MDMS) from any AMI vendor can be easily integrated with ABB Network Manager DMS products. The core of this vision is shown in → 1 where the MDMS adapters enable the transfer of AMI data from any vendor's MDMS via ABB's smart DMS enterprise service bus (ESB).

Advanced outage management

An outage is a sustained interruption of power and occurs when a fuse, recloser or circuit breaker has cleared a fault and, as a result, customers located downstream of the protective device lose power. During such a power outage and without direct communication between the customer's meter and the DMS, the most sensible and perhaps only approach is for the customer to call the local utility company to report the outage and then wait until power is restored. With AMI, this action is totally unnecessary because the outage event will be automatically reported to the DMS within a matter of seconds. An outage analysis (OA) program will then continuously process the incoming outage event messages to determine exactly where power has been lost and infer the most likely location of the fault(s) before informing customers of the estimated time to restoration. AMI literally reduces the time needed for fault analysis from hours to minutes, and most importantly, it shortens the outage duration for customers.

When an outage occurs in the distribution network, an OMS, which typically has two key components: outage notifi-

Footnote

1 A smart meter can be described as a digital incarnation of the traditional electro-mechanical electric meter.

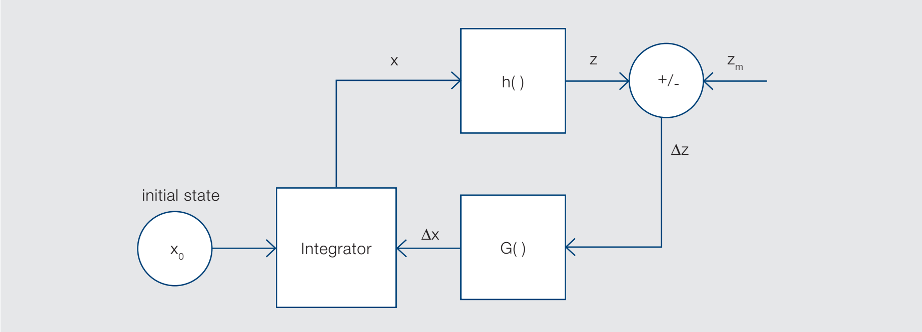
cation and restoration notification [2] – has to quickly and accurately identify the location of the outage so that crews can be dispatched to repair the damage and customers informed about the expected repair time. Two mechanisms normally used are SCADA telemetry or an outage inference engine. Historically, SCADA telemetry has been the fastest and most accurate method of identifying or verifying the location of an outage. However, due to the high cost of the communication and telemetry infrastructure, it is used as little as possible. Instead, an outage inference engine is the most applicable mechanism.

An outage inference engine automatically collects and analyzes outage calls to determine their spatial and temporal pattern, and uses the location of customer transformers and protection devices, and network connectivity to infer which protection device may have reacted. The effectiveness of this process depends on the availability and speed at which customers call to report an outage. For whatever reason, many customers either do not call or delay calling, and this in turn limits the information available to the engine and reduces the quality and confidence of the inference results.

To compensate for this, the outage inference engine introduces tunable parameters that determine the number of calls required to infer the cause of an outage event and the speed at which the system rolls up the outage to the next electrically connected protective device, ie, the system automatically groups several calls into an outage at a higher level of the electrical network. One such parameter is called the outage freeze time, which is defined as the time an outage must stay at a device before it is allowed to roll up. While a small freeze time is naturally desirable in order to identify multiple faults, the variations in call behavior often mean this parameter may be as large as 6 to 10 minutes to allow for the accumulation of the appropriate number of calls.

This is where AMI comes to the rescue – by treating AMI data as customer calls or in other words by creating an automated call system, the freeze time can be significantly reduced, thereby enabling the outage inference engine to quickly resolve multiple outages in a circuit.

2 State estimation block diagram



In addition, utilizing and incorporating the data available from smart meters can also help with the following OMS functions:
– Verification of outages
– Identification of multiple outages in the same circuit
– Identification of broken conductors
– Restoration confirmation

One of the most straightforward applications of AMI would be the verification of outages using metering data in a manner similar to SCADA data. In this case, an outage could be traced to a device if the customers downstream of the device are out of service while those immediately upstream are in service. Another application is in cases where the outage is caused by a broken conductor. The area in or around the broken conductor can be narrowed to one bounded by the customers who are out of service and those who are in service.

> Functions such as distribution state estimation will benefit from the integration of smart meter and sensor data into DMS.

Finally, the DMS system can communicate with the meter to confirm power restoration. Typically, this is accomplished using automated telephone callbacks to customers. Confirmation of service by the metering network would eliminate the need to call back to confirm service.

Another function that benefits from the integration of smart meter and sensor data into DMS is distribution state estimation (D-SE).

Distribution state estimation (D-SE)

A state is defined as a set of information that uniquely characterizes a system's operating condition, and all the major functions of system operation (ie, protection, control, and optimization) require knowledge of the state of the system. D-SE uses statistical analysis and optimization techniques to derive the best estimate of the state of the system from all available measurements (observations). From this estimate, D-SE produces a real-time model that best represents the operating state of the system, which then allows engineers to see if any circuits in the system are overloaded.

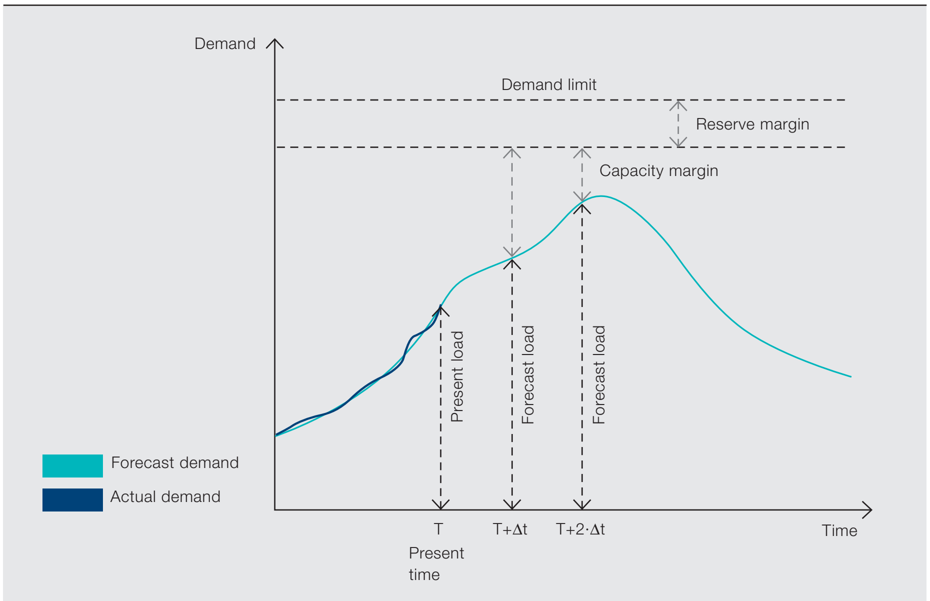
Multiple choices of an information set are possible. For example, if only the static behavior of an electric power system is of interest, a set composed of complex voltages at every node in the system uniquely determines the operating state of the system under consideration. Knowing the complex voltages at every node as well as the component model for transformers and distribution lines allows the current and power flows between any two adjacent nodes in the system to be calculated. However, for many engineering systems, directly measuring the state of the system is not possible (or practical) because only indirect measurements [3] are available. These measurements are used in state

Footnotes

2 Both these functions require distributed measurement points at customer sites.

3 Indirect measurements are functionally dependent on the state variables and therefore provide indirect information about the state of the system.

3 Estimation of the capacity margin



AMI data is valuable in helping grid operators improve the reliability and efficiency of the grid.

estimation to infer, as accurately as possible, the state of the system.

In theory, the estimation of a system state consisting of N variables needs only N independent measurements. In practice, however, a certain degree of redundancy is required to counteract the inevitable random errors in the measurements. The measurement redundancy is the ratio of the number of independent measurements to the number of state variables. Of course, the higher the measurement redundancy, the better the quality of state estimation; a redundancy value of one indicates that there are just about enough measurements to estimate the state.

Typically, state estimation is formulated as an optimization problem in which the decision variables are the state variables, and the objective function to be minimized is a measure of the deviation of the measurement function from the actual measurement. This process is illustrated in ➔ 2. In the diagram:

- x represents the state estimate
- $h(\,)$ is the measurement function
- The discrepancy, Δz, between the measurement function at the estimated state, z, and the actual measurement, z_m is used to generate a correction, Δx, using a gain function $G(\,)$.

Traditionally, state estimation has not been a viable technology for distribution networks for two reasons:

- Very few real-time measurements are available. For a distribution circuit with several thousand nodes, only a couple of measurements, usually near the head of the feeder, are available.
- Complex modeling of multiphase unbalanced distribution networks poses a big challenge to the development of efficient and robust estimation algorithms that can use different types of measurements.

The integration of meter data helps overcome these drawbacks mainly because it is capable of providing a huge amount of near real-time measurements (including power, voltage and current) at every service connection point. The availability of such information drastically improves the quality of state estimation. With a more accurate real-time system model, other DMS functions, such as voltage and var optimization, service restoration, load balancing and system configuration optimization can be performed more reliably.

Demand response (DR)

Electrical demand response (DR) refers to the short-term changes in electrical consumption by end customers in response to changes in the price of electricity over time or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized [1]. From a utility perspective, peak shaving [4] is the main objective of DR although peripheral objectives, such as managing the ancillary services and improving the reliability of the overall system, can also be defined. In addition to the environmental impact of reducing electricity consumption, implementing DR:

- Helps utilities save money by postponing the expansion of the distribution system
- Provides financial benefits to customers
- Makes the overall electricity market less volatile in spot prices (ie, prices for immediate payment and delivery)

DR is often initiated at the utility where data, based on a forecasted demand, is used to estimate the capacity margin for future time intervals ➔ 3. A decrease in this capacity margin or a negative margin would cause the utility to trigger a DR event. Various DR programs offered by utilities can be customized to fit varying needs. These programs can be broadly classified into three categories:

- Rate-based (also referred to as price-responsive) programs where customers reduce their demands

Footnotes

4 Peak shaving describes the slow shedding of loads during traditional peak energy-consumption periods in case of overload.

according to the price signals they receive in advance. Prices can be updated monthly, daily or in real time. Examples of such programs are real-time pricing (RTP), critical peak pricing (CPP) and time-of-use (TOU).
– Reliability-based (also referred to as incentive-based) programs in which customers, having enrolled in any of these programs, agree to curtail demand when notified by the utility. In exchange for compliance, the customer is rewarded by receiving incentive payments, bill credits or preferred rates. On the other hand a failure to comply might lead to penalties. Example programs are direct load control (DLC), interruptible load and emergency demand response.
– Bidding programs come into play when the utility predicts a supply shortage. The utility issues a DR event and opens a bidding window, allowing customers to place bids to either curtail their demand or sell energy back to the utility in exchange for payment.

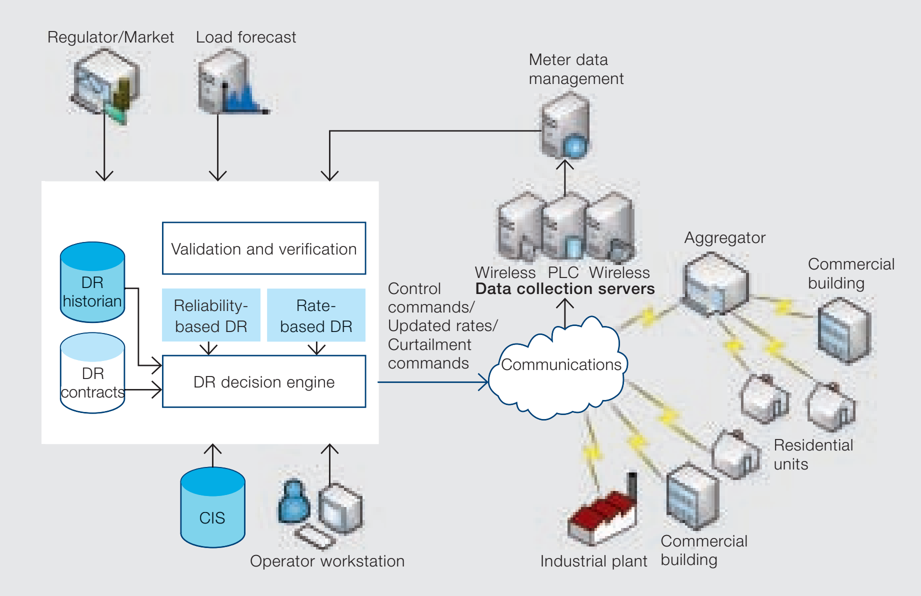
DR infrastructure

DR infrastructure combines a system-level decision-making engine located at the utility with automated and semi-automated solutions available at customer sites. The utility may communicate directly with residential/commercial/industrial end-users or indirectly through DR service providers (ie, aggregators), who assume the responsibility of regulating groups of end-customers and transmitting their aggregate impact as one load point to the utility → 4.

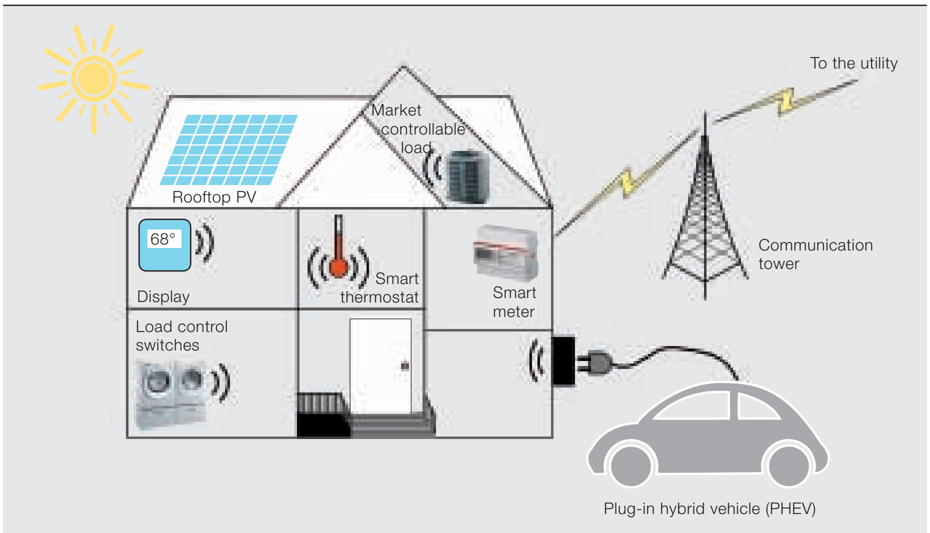
The DR engine communicates with the customer information system (CIS) in order to obtain the details of customer contracts and other related data. The terms and conditions of these contracts detail the constraints of each customer or group of customers regarding participation in a DR event. Constraints, such as the minimum notification time required; the maximum allowable number of interruptions in a day, week or season; the maximum allowable reduction; and the maximum allowable event duration determine which customers can be contacted during a certain DR event.

The DR engine also receives metering data from the meter MDMS. When applicable, it may also receive data from the SCADA system.

4 A demand response (DR) infrastructure



5 Example of a residential customer network



DR Efficiency

The efficiency of a DR program depends on the accuracy of the telemetry system used to measure and validate customer responses to a DR event. In the absence of accurate two-way metering systems, the utility relies heavily on a combination of bulk measurements available from the main substations in the network and stochastic methods, such as load allocation and statistical estimation. However, with the introduction of AMI, the prospect of accurate two-way metering is becoming more realistic. Precise real-time DR events (also known as precision-dispatched demand response PDDR) [2] allow for refined granularity down to individual customers, faster response times and higher visibility to the system operator.

AMI provides real-time two-way communication beyond the smart meter and into the intelligent devices in the house through a home area network (HAN) → 5. This way, HAN-based devices, such as smart thermostats, displays, market controllable loads and load-control switches, are linked to the smart meters and thereby to the utility and can receive data (eg, updated prices for intelligent processors) and commands, such as curtailment signals for intelligent actuators.

The integration of meter data with DR enables the adoption of real-time and near real-time programs, which in turn leads to faster response times, more accurate control, and hence improved reliability benefits for customers and the grid.

In the absence of real-time or near real-time communication between the utility and the customers, the responses of the customers to a DR event cannot be verified immediately. In such cases, the operator has to wait until the next data-collection cycle, which can occur anytime between a few hours and a few days, to process the financial calculations. For the utility, the added value of real-time or near real-time communication is the ability to verify and validate customer responses to a DR event and the DR signals generated, and take remedial action, such as contacting a second group of customers or issuing an emergency DR event, if necessary.

Smart energy management applications

Distribution systems servicing millions of commercial and residential buildings equipped with smart meters mean the volume of data to be processed will drastically increase. The challenge of managing large volumes of real-time data is amply illustrated by the August 2003 power blackout in North America in which, as Congressional hearings uncovered, no manager had a global view of that event-driven situation.

To effectively manage increased volumes of data received from meters and sensors, data management applications must be able to unify data from disparate sources, and synchronize and aggregate it into actionable information. For these purposes, AMI deployment may benefit from complex event processing (CEP) technology. CEP systems process multiple events on a continuous basis in order to identify unique events, such as an impending overload or destabilization of the grid. Data are evaluated locally and propagation is carried out only if network-wide usage is necessary.

Information visualization tools also take advantage of AMI data. These tools leverage spatial information from geographic information systems (GIS) and apply numerous modern techniques, such as color contouring, information dashboards and animation. These techniques, together with the capabilities of the outage inference engine, provide control room operators with effective tools to visually analyze the outage situation.

The graphical representation of meter readings and the ability to ping selected meters may be integrated with GIS-enabled crew management systems to make the dispatchers work more efficiently. Moreover, the operators can replay any changes of meter data throughout a time interval that facilities the detection of trends in temporal and spatial dynamics. By adding weather and temperature data to the graphical analysis, causal factors become evident and scenarios can be studied to assess any future impact.

Aggregating tools, which roll up meter data to the transformer level, are useful for highlighting areas where transformers are at risk of being overloaded and areas with a high density of under-utilized transformers (contour maps). These features may also help during emergency load shedding events to prevent an overload of the system. Generally, in most emergency situations the availability of AMI and sensor data creates opportunities for quicker damage assessment. However, additional possibilities emerge when these data are combined with terrain mapping, video and light detection and ranging (LIDAR) technologies. These technologies are already used in pole/line asset surveys and vegetation control, but still need to be integrated into the infrastructure and global data analysis.

Advancing the future

Until about 20 years ago, distribution system automation was not an urgent priority. However, continuously increasing demands for electrical energy combined with concerns over sustainability and environmental issues have lead to a global drive toward the increased instrumentation and control of distribution systems. Substation automation, feeder automation and AMI systems are being deployed at an accelerating rate throughout the world and make a wealth of data available to control systems. Even though integrating a vast amount of real-time measurements is challenging, it provides opportunities to implement new applications that help reduce service interruption duration (outage management), optimize energy efficiency (voltage and var optimization), increase situational awareness (state estimation) and engage consumer participation (demand response). ABB's research and development laboratories are taking advantage of these new opportunities to create applications enabling better grid efficiency and reliability, and better utility asset usage.

> Integrating a vast amount of real-time measurements is challenging but it provides opportunities to implement new applications that improve grid efficiency and reliability.

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