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Distribution Automation Strategies: Evolution of Technologies and the Business Case

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***Abstract*—With the spotlight on smart grid development around the world, it is critical to recognize the key factors contributing to changing power-system characteristics. This is more apparent in distribution systems with the integration of renewable energy sources, energy storage, and microgrid development. Source and load control at the distribution level is a key requirement of the evolving system. These activities require distribution automation (DA) strategies that take advantage of available technologies, while promoting newer solutions. It is necessary to create a roadmap for holistic DA strategies in a smarter grid. Sustainable and resilient grid development is a paradigm shift requiring a new line of thinking in the engineering, operation, and maintenance of the power system. Distributed control architectures based on dynamic load and source data should be explored as a possible solution. This paper discusses a novel approach that integrates protection, control, and monitoring using high-performance computing at the primary distribution substation level. The business case for infrastructure investment in the distribution systems is also discussed. This paper concludes with a discussion on emerging and future technologies for DA to improve the resiliency of a sustainable grid.**

***Index Terms*—Demand response (DR), distributed control, distributed energy resource (DER), distribution automation (DA), microgrid, smarter grid.**

I. Introduction

MODERN POWER systems continue to evolve, affected by technology innovations, environmental impacts, regulatory policies, energy usage and resources, and aging infrastructure. The power system changes are more apparent in distribution systems due to the changing landscape which offer challenges along with opportunities to strengthen the aging infrastructure [1]–[3].

Historically, distribution systems have operated in a radial mode due to the simplicity of operation, ease of coordinating the protecting devices, and overall economics. The regulatory requirements to improve reliability indices have introduced concepts such as loop systems, where possible, to support the uninterrupted flow of power to the load. With the reduced cost and improved functionality of protection devices due to the adoption of newer technologies and the introduction of communication between different points in a distribution system, cost-effective solutions that support more reliable energy provision to customers have become feasible.

Distribution automation (DA) technologies are already in use and they continue to be improved to meet the needs of modern grids. Initial DA applications involved the protection of assets. It has taken some time to capture the full benefits of DA; however, as the business cases have been based on individual applications. Recent technological improvements, coupled with the lessons learned from pilot installations, have highlighted the DA requirements and business case needs. The DA business case must be based on a holistic approach that takes into account distribution system operations, including volt-var optimization/control (VVO/VVC), conservation voltage reduction (CVR), power quality improvement, system reliability improvements through automated reclosing and restoration, state estimation (SE), and system and outage management. International perspectives on DA, as discussed in [1], reflect that one solution will not fit all circumstances.

As related practices and operational needs have changed, DA technology implementation has also evolved. In the past, restoration of the system following a disturbance would have required a human response based on the operation of protective devices, which is often local. Expectations for quicker restoration times have led, for example, to the development and installation of fault circuit indicators or fault passage indicators to more selectively identify and isolate the faulted part of the system. Another type of system enhancement is the introduction of capacitor banks in distribution feeders to maintain the proper voltage profile. With the introduction of communication technologies in the distribution system, and the installation of automated switches and reclosers, it is now possible to identify and isolate the faulty part, or section very quickly. Rapid isolation of trouble spots also helps in rapid restoration. An automated process for restoration contributes to

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improved reliability indices. Technologies originally designed for transmission systems, such as GPS-synchronized measurements, are now being implemented in distribution systems as well.

II. Evolution of Distribution System

A. Radial and Loop

Radial distribution system design has evolved as the most efficient, inexpensive way to serve many loads from a single source. The need for greater reliability has driven a transition to a "mesh" or "loop" design—actually a hybrid of existing radial lines and new ties between substations and feeders—that can carry out the work of advanced distribution system applications [4]. The hybrid or mesh design provides a means to isolate faults and reroute power around the troubled section, keeping as many customers as possible in service while the faulted section is repaired. For example, a mesh or loop design also allows the linking of substations, so that in the case of a substation with two transformers—one out of service, the other unable to handle the complete load—another substation can be substituted.

Greater complexity is added in the form of distributed energy resources (DERs). For example, demand/supply activities change for a solar PV unit based on normal, predictable patterns such as anticipated seasonal atmospheric behaviors or sudden changes in the weather, which can suddenly reduce the output power of a solar PV as viewed by distribution management system (DMS). Or, consider when solar PV output exceeds a customer's needs and DER is injecting power back into the grid; power then is flowing in two directions. The distribution system needs greater flexibility to satisfy steady-state conditions, let alone fault disturbance conditions. Hybrid topology provides the desired flexibility to maintain reliability, stability, and safety under dynamic conditions.

Because economics is a significant consideration, and it is important to note that moving from a radial design to a hybrid design can be accomplished incrementally. For example, if a specific feeder is experiencing reliability issues—say, a new development along it pushes it beyond its capacity at peak—adding an open tie to another feeder connected to a different substation can provide a level of redundancy.

B. Microgrid Installations and Experiences

The Washington State University (WSU) campus in Pullman, WA, USA, has about a 28 MW peak load (30 MVA peak) and is supplied by a local power company [5]. The city of Pullman (population 30 000) is supplied through several 13.2 kV feeders from multiple 115 kV substations. The university runs its own 4-kV system inside the campus using two 4-kV substations and a 4-kV feeder loop. The campus also has multiple generators (some diesel and some natural gas) connected to the 4-kV loop in addition to several UPS in some of the buildings as needed.

As part of the Pacific Northwest Demonstration Project (the U.S. DOE Grant pilot project), Pullman was made a smart city with the installation of smart meters (SMs) for all customers, a few of whom also have utility controllable thermostats, and DA that is connected to the local utility DMS and outage management system (OMS). The university was automated to operate as a microgrid and can also receive a transactive signal through the local utility from the regional level controller, as in Fig. 1.

The microgrid control automatically starts-up the campus back-up generation in case of an interruption in the university power supply. There is a step-by-step logic to start-up the generators. For example, starting gas units before the diesel unit sequence allows economic factors to be part of the start-up process, and a similar step-by-step logic to switch in the individual buildings, so that load and generation is kept in balance. The buildings with UPS have a logic process to start the UPS on a local power failure so that these buildings are restored much faster than the buildings that are part of the step-by-step logic.

The supervisory signal is used when there is a regional shortage of power and the campus generators can be switched on to help the situation. In addition to starting generation, campus loads can be curtailed by controlling or shedding the building HVAC (heating/cooling) systems. In the case of a fault on the internal campus feeder, the operator in the campus control room can remotely switch breakers to reroute power. The control room operator also operates the building management system that controls the HVAC.

Another pilot installation is at the Illinois Institute of Technology (IIT) in Chicago, IL, USA. Fig. 2 shows the IIT campus microgrid [6]. The system at the IIT campus has been in operation for nearly five years. The project has equipped IIT's microgrid with a high-reliability distribution system, new sustainable energy sources (roof-top solar panels, wind generation units, flow batteries, and charging stations for electric vehicles), and smart building automation technology (building controllers, sensors, controllable loads) for energy efficiency and demand response (DR). The investment is expected to be recovered in five years. The system consists of smart microgrids featuring a loop system and redundant electricity supply. It offers IIT the opportunity to eliminate costly outages, minimize power disturbances, moderate an ever-growing demand, and curb greenhouse gas emissions.

IIT is now working on life cycle support and has established a hierarchical power distribution asset management study criteria. It categorizes the asset management strategies in power distribution sector chronologically, based on short-term, mid-term, and long-term time scales. The integration of IT applications over a robust IT infrastructure has been indispensable in the long-term for the optimal asset management. This denotes the importance of favoring open standards that facilitate data and message exchanges among different utility systems and provide the framework for extensibility, in the context of asset management on all timescales [7]–[9]. Furthermore, the IIT study highlights the importance of the security of the distribution network in the light of increased deployment of distributed generation, which necessitates sophisticated operation and control strategies and enhancement of existing asset management systems.

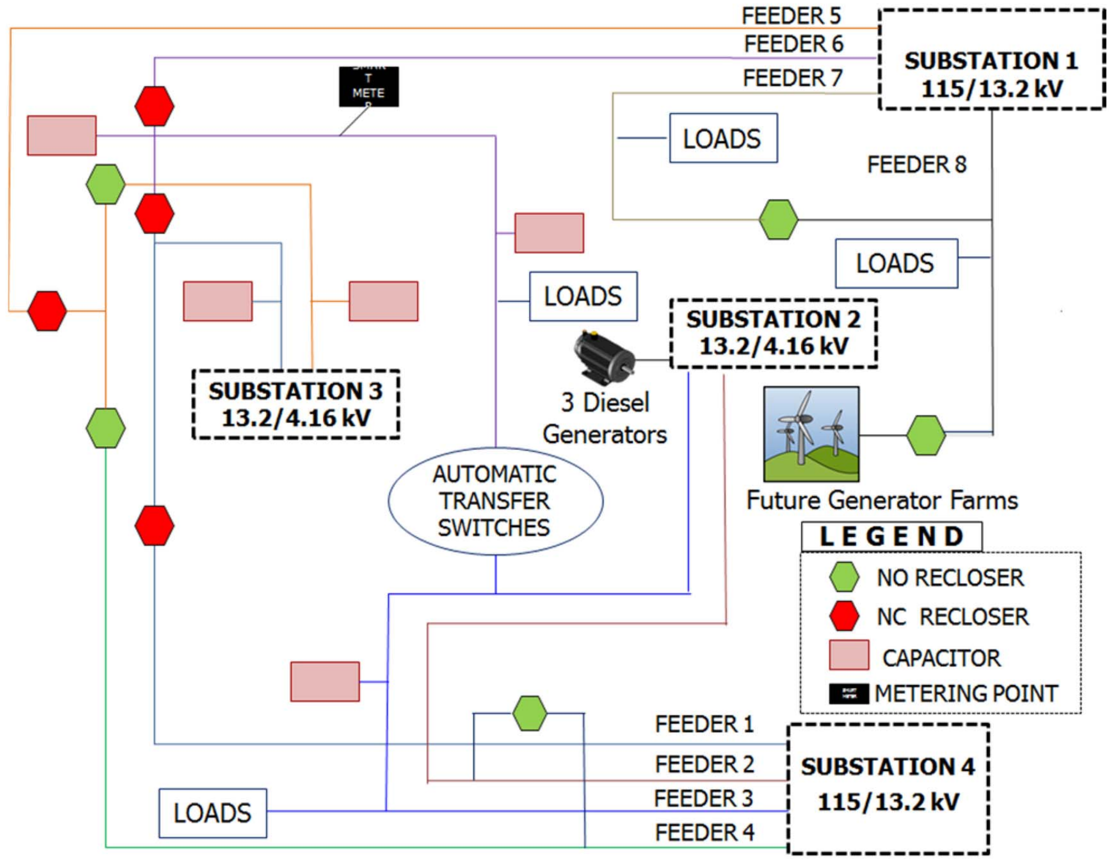

Fig. 1. WSU campus microgrid [5].

C. Restructuring of the Distribution System—Dynamic Microgrid

The evolution of the dynamic microgrid and the integration of DERs and energy storage are changing distribution system characteristics [10]–[12]. However, changes are not happening across the system—newer topologies are expected to co-exist with existing topologies, and the evolution will be gradual. One such scenario is described in Fig. 3, which takes a holistic view of a power grid from the balancing authority to the customer loads at distribution level.

In this scenario, many microgrids co-exist with conventional substations under the control of a DMS as in Fig. 3(b). These microgrids can be dynamic and substations can be used as dynamic control centers of these microgrids in some scenario. This feature complements the dedicated control centers of some microgrids and offers maximum flexibility from the operation perspective. Possibility also exists for asynchronous connection of microgrids with the main ac grid using medium voltage and low voltage dc links [13].

Distribution systems by nature can be treated as a three or four-tier hierarchical entity as shown in Fig. 3. The first tier goes from distribution control center to distribution substations (DSs) as in Fig. 3(b). The second level goes from each DS to distribution transformers (DTRs) and the third tier from each transformer to customers as in Fig. 3(c). Another possible layer (fourth layer) may be from each customers' SM to individual loads if the energy usage of each major appliance needs to be captured. This newer approach makes sense from customers' point of view which is the essence of the smart grid. Applications that typically run today and are expected to run in future at different layers of a power grid are identified in Fig. 3.

III. DA Technologies

This paper is focused on protection, control, and monitoring functions and use communication as a medium for implementing solutions. Detailed discussion of communication technology history could be the subject of an entirely separate paper.

A. Past and Present

In the history of electrical protection, different technologies have been applied to achieve the main functions of a relay: to properly detect a disturbance in the system and to clear the faulted area. In recent decades, microprocessors and digital technology have been used in protective relaying. Most of the relaying fundamentals, however, are inherited from legacy technologies [14].

Multifunction relays, which reached the market in the late 1980s, offered significant advantages by drastically reducing control room space requirements and product and installation cost. Modern protection and control technology is characterized by a few trends: common hardware platforms configurable via software to perform different functions, relays that integrate with the substation control system, and improved supervisory control and data acquisition system (SCADA) and communication capabilities to integrate with DMS are just a

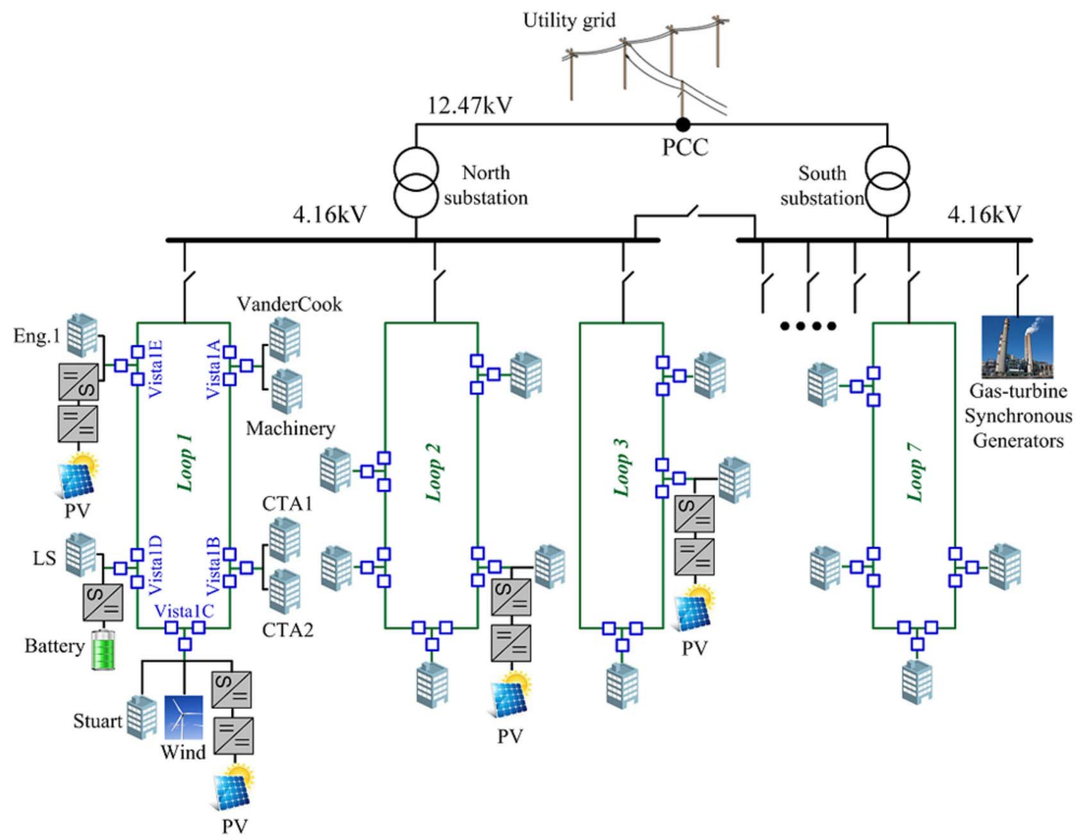

Fig. 2. IIT campus microgrid at Chicago, IL, USA [6].

few examples of the latest technologies. This development has led to intelligent electronic devices (IEDs) that perform metering, logic processing and control functions, and communication functions, in addition to their traditional protection role. Fig. 4 captures the evolution of technologies applied for protection, control, monitoring, and communication over the years.

The nonmicroprocessor (electro-mechanical and solid state) relays are shown in block 1. Block 2 reflects SCADA communications using remote terminal units for integration with DMS either through substation automation system or directly. Block 3 reflects the peer-to-peer communications using protocols like distributed network protocol (DNP), Modbus, and more recently using the GOOSE feature of the IEC61850 standard. Introduction of IEC61850 standard has provided new possibilities of transferring digitized analog values directly to IEDs, as in block 4, from merging units. Applications that typically run today at different layers of a distribution system are also shown in Fig. 4.

B. Evolution of Grid and Microgrid Adaptive Protection

A modern distribution network usually incorporates active sources such as distributed generation, energy storage, and controllable loads; therefore, it needs to be more actively managed for enhancing the operation efficiency and meeting the security of supply standard. In addition, the changing topology of distribution networks from radial to loop implies that conventional protection designed for passive radial networks needs to be revised and improved.

Preliminary investigations clearly show that conventional overcurrent relays will be inadequate for active distribution networks, and computer-based differential relays integrated with proper communication systems will be more suitable to accommodate varying fault current ranges as network topology and power sources change. As a consequence, the proposed advanced protection paradigm involves the selection, utilization, and coordination between the new protective devices, sensors [digital relays, phasor measurement units (PMUs), intelligent reclosers, and line sensors], and advanced communication infrastructure for fast fault interruption and service restoration. The selected IED technology will enable more flexible coordination between the substation and downstream controllable devices, unlike the local protection philosophy that has been adopted in the past. The new protection system will be able to adaptively respond to changing system conditions such as varying distributed generation or storage output and network reconfigurations using the following:

1) remote interrupters and line sensors for fast fault interruption (coordination implemented through communication);
2) PMUs and line sensors for fault location;
3) measurement-capable devices for zone protection, including high impedance fault detection.

To address the challenges encountered during the modernization of distribution networks, there is a need to coordinate control-based on information provided by sensors, energy boxes, and SMs, in order to integrate DERs with the DMS, which will enhance performance of the emerging grid.

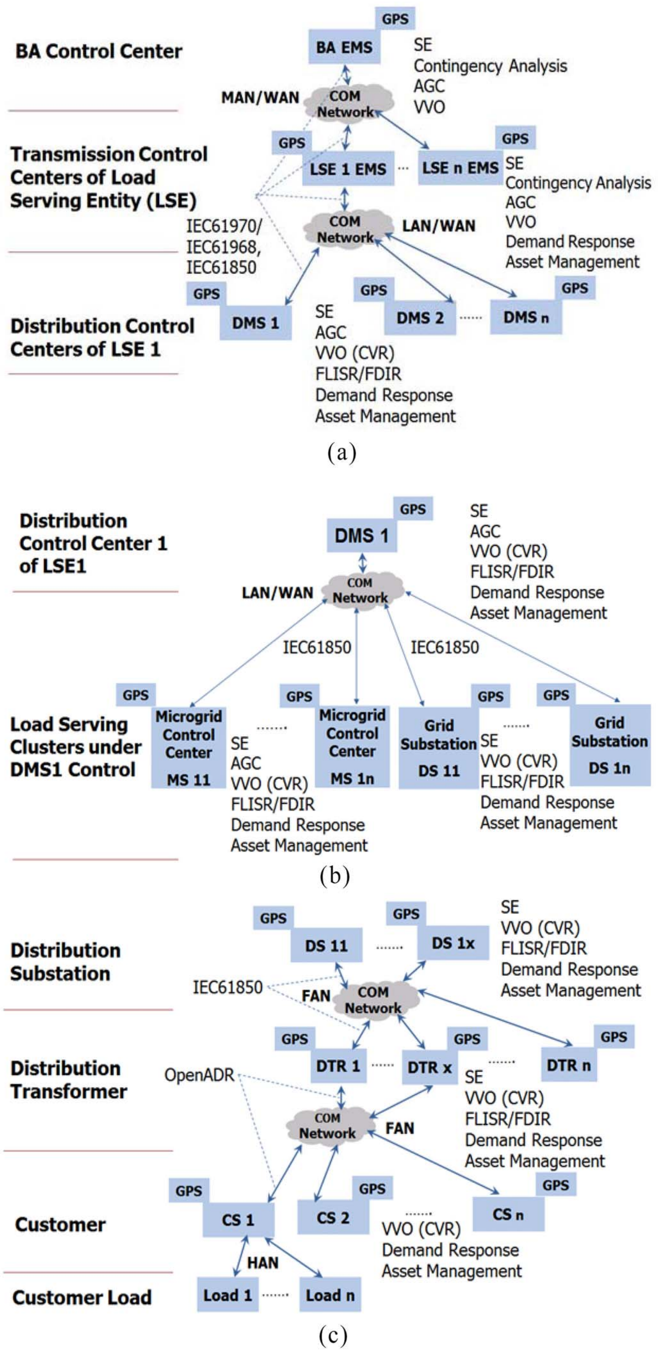

Fig. 3. Possible architecture of a distribution system connected to a larger grid. (a) From transmission system to DMS. (b) From DMS to primary and secondary substations. (c) From substations to customer loads.

This section introduces the concept of adaptive protection for emerging distribution grids, including grid-connected and islanded microgrid scenarios. Microgrids contain loads and sources and can operate either connected to the grid or islanded. Due to the issues in microgrids associated with changing operating conditions from distributed generators, which introduce bi-directional power flow, and islanding, a microgrid must have an advanced and adaptive protection scheme as classical distribution protection is inadequate. A novel approach to a holistic microgrid protection scheme that is, based on the principle of distributed differential zones with the use of digital differential relays is discussed in [15].

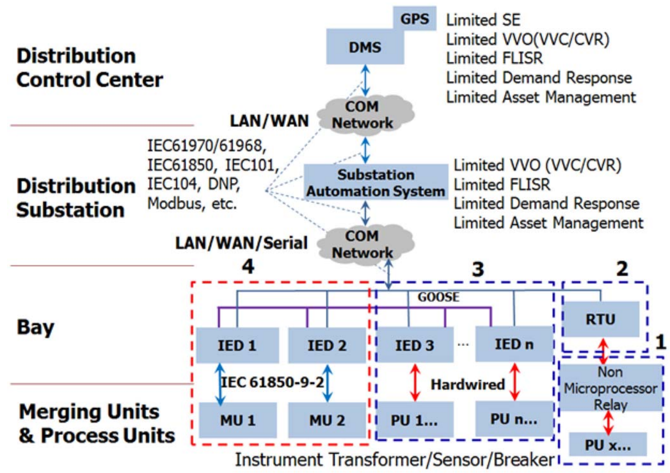

Fig. 4. Evolution of protection, control, monitoring, and communication.

These zones compare current or power measurements from a combination of relays and sensors located on the borders of the zones assisted by suitable communications. This method can effectively detect all types of faults in a microgrid. An accurate fault location approach using voltage and power measurements from the differential zone protection devices is developed that will aid in improving repair and service restoration. The optimal placement of the devices to form the zones is also required. A practical case study demonstrates that the optimal placement of relays and sensors can reduce costs significantly when compared to having all relay at each line segment and that the placements can detect faults and locate close proximity of the fault [15]–[17].

C. FLISR/FDIR and High Impedance Fault Detection System

It is important to determine the location of a fault when it occurs so that the utility may restore electric service to the customers as soon as possible [18]. Fault location, isolation, and service restoration (FLISR) is an important aspect of system operation to improve system reliability indices [19]. In some cases, it is also known as fault detection, isolation, and restoration (FDIR) [20]. Considered as one, FLISR/FDIR is designed to detect a fault on a feeder, isolate the faulted section, and restore service to un-faulted sections, reducing restoration time for the faulted section while maintaining service to unaffected customers. Although FLISR and FDIR are used synonymously, a subtle distinction can be made between the two systems. Precise fault location may not be an integral part of a FDIR system and depends on other external systems like OMS and geographic information system—in some cases, customer information system data may even be used to locate the fault for dispatching the repair crew. It is certain that fault location will always be an important aspect of overall system operation and continuous improvements are likely going forward. FLISR/FDIR logic can be centralized at the operation center or distributed over substation-based or peer-to-peer switches residing in feeders.

High impedance faults usually result when an energized primary conductor comes in contact with a semi-insulated object and they are usually associated with arcing at the point of

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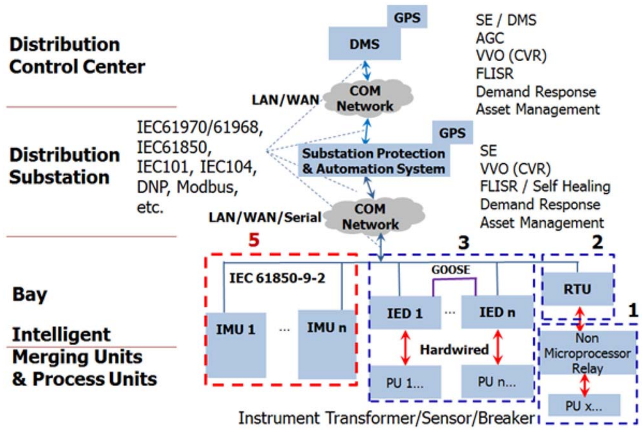

Fig. 5. Integrated substation protection and automation system.

contact. They present serious public safety and fire hazards. High impedance fault detection is very challenging and efforts have been made to ensure its reliability [21]. Due to the impact on public safety and property, high impedance fault detection will remain an active area of research. The next frontier in high impedance fault detection is to locate such a fault swiftly to enable operational decision-making. Voltage-source inverter-connected devices introduce another dimension to high impedance fault detection.

D. Future

1) Protection, Control, Monitoring, and Communication for Primary Distribution System: Future protection, control, monitoring, and communication systems must adapt to the flexible architecture of a distribution system like that shown in Fig. 3. Control of active and reactive power while maintaining the regulation voltage profile and frequency across the network will offer opportunities for greater innovation for the network owners and managers—utilities, distribution agencies, state or governmental agencies, and reliability coordinators. Greater integration of the control system with the network protection devices will assist in addressing these challenges and reduce the overall ownership cost of system protection, control, monitoring, and communication. This approach will also assist in managing assets with performance and retrofit/replacement requirement information for maintaining system reliability.

Fig. 5 illustrates a possible evolution of the protection, control, monitoring, and communication system to address the need of an evolving distribution system [22]. The essential difference between Figs. 4 and 5 is in block 4 in Fig. 4 and in block 5 in Fig. 5. Most protection functions from distributed IEDs within a substation in the former example are integrated to the substation protection and automation system in the latter example. Block 4 in Fig. 4 describes the evolution of present-day IEDs as they receive analog signals from merging units as digitized information using the IEC 61850 standard. The next logical step of this evolution is described in the block 5 in Fig. 5, in which digitized analog signals are transmitted to the substation protection and automation system using fiber optic communication, providing optical isolation between the intelligent merging units (IMUs), and the substation protection and automation system.

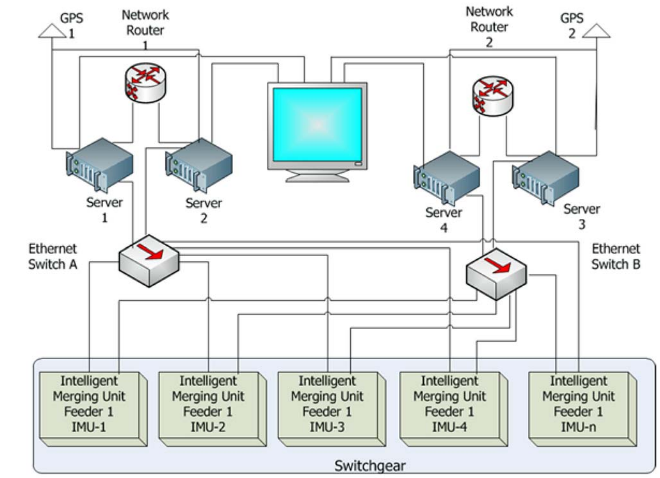

Fig. 6. Architecture of an integrated protection and automation system.

The optical isolation between IMUs and the substation protection and automation system also enables off-the-shelf hardware use, for the substation protection and automation system.

The substation protection and automation system also integrates FLISR/FDIR and high impedance fault detection system, as well as other control/monitoring functions like power quality and VVO/VVC at the substation level. The system also provides asset management data to the DMS center or any other desired location. IMUs, with built-in back-up protections, address the unlikely event of total communication failure and ensure reliability of the overall system.

Fig. 6 shows a possible architecture that could integrate all IEDs within a substation into one protection, control, monitoring, and communication system by bringing high-performance computing (HPC) to the substation level [22], [23]. Time synchronization between the substation protection and automation system (servers) and IMUs are achieved using IEEE-1588 PTP. This architecture enables higher system reliability by providing more redundancy for hardware and software upgrades than normally available with a single IED. The architecture also harmonizes operational technology and information technology requirements and supports the implementation of advanced control and monitoring functions like SE, VVO, CVR, FLISR, and DR as shown in Fig. 5 while also providing asset management information.

2) Distributed Sensing, Control, and Protection Architecture: With the availability of new sensors and IEDs with communication capabilities, the term real-time takes on new meaning. Some utilities have already implemented DA from the control center to each customer in milliseconds to seconds data update rate. This in turn will require gathering and storing large amounts data for monitoring, protection, and control purposes. Such an approach poses a real challenge for operators to monitor, control, and protect the system in a centralized manner. A decentralized approach introduces opportunity for consideration and evaluation or merits for distributed architecture-based on the overall size of the integration and data processing as well as responsiveness and system reliability.

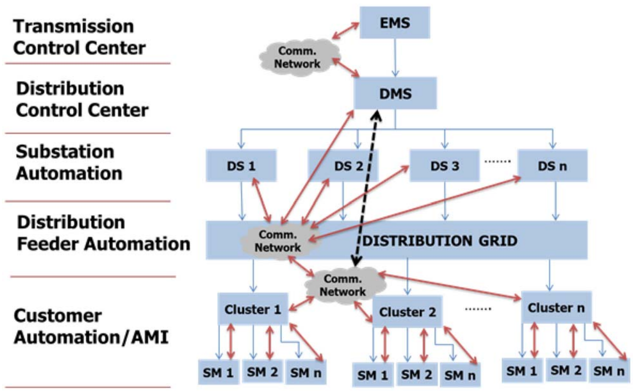

Fig. 7. Typical four-tier distribution system architecture.

Additional information related to smart meters and communication flow has been added to Fig. 3 and is shown in Fig. 7. Distribution feeder automation in Fig. 7 covers from DTRs to SMs.

From an automation perspective, the detailed modeling of each secondary feeder and the associated loads connected to it need to be captured. This could become a very formidable issue. Therefore, each secondary feeder and the associated loads can be treated individually on a sequential basis to avoid the computational burden.

Such a four-tier system also can be mapped based on the communication interface for each tier. For substation automation, a fiber-optic or network-based system may be beneficial. For feeder automation, some form of wireless scheme can facilitate primary and secondary feeder automation. Finally, some form of Advanced Metering Infrastructure (AMI)/wireless scheme is ideally suited to deal with customer automation.

Each tier of the four-tier grid can have its own distributed architecture and intelligence to handle data at each level more effectively and efficiently than in a centralized approach. In this hierarchical structure, each of the automation functions can be handled at each tier with all the data gathered from that tier, as shown in Fig. 7. Only important and critical data will be transferred from a lower level to the next higher level. In this way, system operators have to deal only with data they need to manage system operations in both the normal and emergency modes. This will require that each substation and each DTR have its own intelligence to operate the relevant part of the system. The general consensus among many utilities is that an intelligent combination of both centralized and distributed intelligence is optimal for effective operation of distribution systems. Whether that view holds up over time is another matter.

3) Advanced Applications: A new environment for utilities/grid operators has been described in which load growth, aging infrastructure, and the introduction of DERs and bidirectional power flows have affected distribution system performance, protection, and control. We need to factor in a greater degree of participation by customers, not only in the addition of DERs, but also in DR, dynamic pricing, and someday, transactive energy programs. It is clear that grid modernization has imposed new challenges on the reliability, stability, and safety of the distribution system. Load growth in particular sets up options that include a clear choice between expanding supply/capacity and/or gaining efficiencies through DA [24]. The latter option typically has the virtue of being less expensive and thus, it offers a chance to defer significant capital investment in expanding supply/capacity in favor of distribution efficiencies.

Once a particular utility/grid operator has determined its specific challenges, it can articulate a technological roadmap, timeline, and budget for DA, which will deliver the best return-on-investment (ROI) among grid modernization options. In fact, DA creates a platform for advanced applications that addresses the fundamental drivers of improved reliability, stability, and safety by providing granular visibility into distribution system behavior along with faster and more precise control over outcomes.

Advanced applications are supported by the DMS in coordination with a substation protection and automation system [25]. FLISR/FDIR, VVO/VVC, and distribution power flow are the commonly used advanced applications. VVO reduces network losses, maintains an optimal voltage profile on feeders, and reduces peak load via feeder voltage reduction. Distribution power flow enables the operator to simulate the results of switching strategies, which contributes to energy efficiency by controlling losses and optimizing loading on feeders. This suite of functionalities makes a very strong business case for adding intelligence to the distribution system.

A number of other applications are worth mentioning, in their proper context. Advanced real-time applications include SE and load estimation. Advanced analytical applications include short circuit analysis, optimal capacitor placement/optimal voltage regulation, and relay protection coordination. Advanced ancillary applications include maintenance and outage planning, power quality analysis, retail power marketing, as well as coordination with other systems and distribution simulation.

The addition of IEDs and other data-generating sensors not only provides data for the aforementioned applications, but also increases visibility and provides data for further improvements in reliability, stability, and safety. Recent work with PMUs, for instance, has enabled distributed SE, and has established that many new advanced applications will be developed in addition to fault locations for radial and looped systems with DERs and with high fault impedance using PMUs [17]. Another real-time application is the closed loop VVC with PMUs and micro PMUs. One could easily conceive of more than five other applications for advancing DA during the coming decade.

Advanced applications can be applied in a phased manner. When DA is applied both centrally and in a distributed fashion (i.e., distributed intelligence at the substation and/or feeder level), that is a hybrid arrangement. If a simple fault occurs downstream, logic embedded at the substation or out on the feeder can respond swiftly and automatically and report upstream after the fact. If a fault has more complicated consequences, and operators need to assess conditions on several substations before taking action, then centralized logic can be brought to bear on the issue. Ultimately, as noted previously, a hybrid of centralized and distributed intelligence will provide the most flexibility in responding to a wide range of potential issues on the distribution system. Operators can rely on downstream logic as much as possible for speed and to avoid overburdening data networks and servers, but can select centralized logic when a wider view of the system is needed.

As the proliferation of acronyms and the systems they denote suggests, the new world of DA will rely heavily on integration, standards, interoperability, and open data exchange interfaces.

IV. Business Case

A. Intersection of Technology, Policy, and Standards: Balancing Infrastructure and Application

We might apply the idiomatic expression, biggest bang for the buck, to characterize the costs and benefits of DA, implemented in a holistic fashion. Pursuing the integrated suite of technologies described in this paper that support a general assessment of positive value in this context may be worthwhile to consider.

Similar to other challenges described earlier, case-by-case examination of needs, resources, regulatory environment, and future enterprise strategy to create a specific business plan with positive ROI are warranted. It is difficult to generalize when it comes to seeking a positive cost/benefit ratio in specific circumstances. However, a broad assessment of various drivers and trends provides the basis for a utility/grid operator to pursue hard numbers for its own, unique set of circumstances.

Certainly, a number of socio-economic and environmental factors play a role in the macro-context. Some of these factors make intuitive sense and may be soft benefits, but many can and should be quantified in a business case. Generally, technology costs are dropping. Policies encouraging energy efficiency, system optimization, and the integration of renewable sources are becoming more ubiquitous. Standards are being written and/or amended to address existing gaps or evolving circumstances and global coordination of standards development is increasing.

Customer expectations for service in a digital era are rising and customers are becoming a factor in the operation of the grid through the application of DER and participation in DR, dynamic pricing, and transactive energy markets. As renewable energy options become more affordable to customers and third-party technology offerings present the threat of disintermediation, utilities/grid operators are under pressure to improve service options, accommodate bi-directional power flows, provide transactive energy services, improve service reliability, and lower operational costs through efficiencies.

Coupled with higher customer expectations are similarly increasing regulatory expectations and their corollary, fines for poor reliability performance as measured by reliability indices. These shifts are occurring in an era when power system infrastructure in many parts of the world is reaching the end of its useful life. Investments for delivering enhanced functionality, efficiency, and reliability are needed. This point is underscored by recent, extreme weather events in North America, the U.K., and elsewhere, placing new emphasis on reliability and resiliency for distribution systems. The importance of increased visibility and control down into the distribution system through automation is gaining momentum.

The implementation of IEDs, including PMUs, provides enhanced visibility into and control over the distribution system by providing useful data, driving cost savings, and quality of service improvements throughout the enterprise. Approaching the business case for DA must methodically assess enterprise-wide benefits as well as costs and override traditional silos that constrain a full accounting of quantifiable benefits.

Meanwhile, DA technologies have been dropping in price, and as standards are written or amended and interoperability improves, economies of scale will hasten the drop in costs. The same can be said for the communications networks that handle data traffic in both directions between operators and the field. The cost of running traffic over wireless data networks has reached a tipping point in favor of their use by utilities/grid operators.

To summarize, capital investment deferral, reduced O and M costs, declining technology prices, the cost of maintaining aging infrastructure, coupled with the service and reliability improvements, and pan-enterprise, data-driven insights made available through DA should enable most utilities to justify exploring the DA business case.

The fact that DA can be phased in over time on a schedule set by the utility/grid operator lends flexibility to any business case and allows an incremental approach, with commensurate benefits. That makes the prospect of DA implementation less daunting than in the past. Hard costs are modest in contrast with the most pertinent resource: staff time across the organization that's needed to build a rational business case.

Finally, the business case for DA must be integrated into a utility/grid operator's overall strategy for a more comprehensive view of costs and benefits, in order to present regulators, shareholders, and stakeholders with a holistic, well-vetted business case.

B. Real-Time Calculation of Cost-Benefit of CVR and IVVC of WSU Campus Microgrid

The costs and benefits of CVR and Integrated Volt-Var Control (IVVC) are usually calculated off-line to obtain average expected benefits. But the actual benefits obtained, say for a particular period, are more difficult to calculate because the actual operating cost has to be compared to the cost of operation without CVR and IVVC. This requires knowing the load models, including their voltage sensitivity, during that particular hour or day. Such accurate load models for real time calculations can only be obtained if the load models are continually updated with real time data [5]. This calculation of accurate energy/cost savings is a major portion of the ROI mentioned above needed by the distribution company as well as the regulators who set rates.

The WSU microgrid implementation project has developed a method that uses real time load data to identify the variation in the ratio of constant impedance, constant current, and constant power loads (ZIP parameters) over time. The method can use either the feeder load data from the DMS or load data from the SM database, or a combination of the two. This method has already been tested on historical DMS data from several distribution feeders in the utility system to which WSU is connected, to calculate the load ZIP parameters, which can then be used to calculate the cost savings for CVR and IVVC that run on the DMS. This application for benefit calculations is expected to run in real time on the utility DMS, after further testing is done on feeders serving the campus.

V. Conclusion

The distribution system landscape has been transitioning for some time. Rapid changes in distribution systems require new ways of thinking for infrastructure investments, engineering, and managing operations. The development of a resilient grid to meet public, regulatory, and overall requirements is a paradigm shift which must be met with new strategies. DA is a key ingredient for fulfilling those requirements and developing new strategies.

The transition from legacy protection and control devices to new DA systems is a crucial component of the infrastructure and paradigm shift as the distribution system landscape is transformed. Distribution system operators need to control sources and loads to optimize the active and reactive power balance in the distribution system. They need islanding and paralleling capabilities. They even need automatic generation control to adjust frequency, and other operational considerations similar to transmission systems. The substation-level strategies show some advantages in comparison to enterprise, DMS-level strategies. The HPC brings opportunities to the substation level, though challenges remain.

Integration of technical, business, and policy decisions is necessary to facilitate the development of technologies and standards, as well as the implementation of cost-effective solutions. Technologies and methods from transmission systems are being deployed in the distribution system as the systems are becoming more similar due to the proliferation of DERs and technologies that are becoming more cost-effective for wider deployment in much larger distribution networks. In summary, aspects of emerging and future DA-related technologies to improve grid resiliency described in this paper could serve as a basis for heterogeneous DA roadmaps for a smarter grid.

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