

National Conference on 'Innovative Research on Robotics, Circuits and Technology' (IRCT 2018) Organized By : CIrcuit Branches of SCSVMV, (EEE, ECE, EIE & Mechatronics) , Kanchipuram, Tamil Nadu, India In Assotiation with International Journal of Scientific Research in Science, Engineering and Technology © 2018 IJSRSET | Volume 5 | Issue 1 | | Print ISSN: 2395-1990 | Online ISSN : 2394-4099

Advanced Distribution Automation for a Smart Grid Environment

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ABSTRACT

Everyone is looking to "the Smart Grid" to provide electric utilities with information age technologies that will significantly improve distribution system protection, reliability, operating efficiencies, power quality, safety, and customer satisfaction. These technologies are now readily available in mature and sophisticated products that make it easier than ever for an electric utility to implement elegant protection coordination schemes at the distribution level complete with advanced Distribution Automation (DA). This white paper discusses some of the most useful of these technologies, including pulse reclosing, and describes how they can be used effectively to install an advanced Distribution Automation System based on practical experiences and successful implementations. The benefits of such a system are enormous and will directly improve an electric utility's reliability figures (SAIDI, SAIFI and CAIDI) and reduce momentary operations (MAIFI).

EXECUTIVE SUMMARY

Many proven and effective Distribution Automation (DA) technologies are now available to help an electric utility significantly improve reliability, operating efficiency, power quality, and public and worker safety. These technologies are already built into products that are readily available from established and trusted manufacturers. Many of the products "plug and play" together very nicely under the right infrastructure which is ideal from any utility's viewpoint. The key to unlocking the full benefits in these technologies and products is for a utility to develop a comprehensive DA design plan up-front that meets its specific requirements and its short and long-term objectives.

Since many utilities have already successfully implemented some form of Distribution Automation with excellent results, there is no longer any question of DA's potential overall benefits. However, when evaluating cost-benefits of the various types of DA functionality now available, each utility may find a different set of functions that provide the best overall cost-to-benefit ratio. This is the functionality they should focus on for their DA implementation.

The concept of implementing a Distribution Automation System closely aligns with the U.S. Department of Energy's (DOE) vision to implement Smart Grid across the United States in each of its 3,100+ electric utilities¹ by the year 2030.

Grid 2030 Vision calls for the construction of a 21st century electric system that connects everyone to abundant, affordable, clean, efficient, and reliable electric power anytime, anywhere. We can achieve this through a smart grid, which would integrate advanced functions into the nation's electric grid to enhance reliability, efficiency, and security. It would also contribute to the climate change strategic goal of reducing carbon emissions. These advancements will be achieved by modernizing the electric grid with information-age technologies, such as microprocessors, communications, advanced computing, and information technologies.²

The Smart Grid that DOE envisions will actually be built as a series of inter-related projects of which Distribution Automation will only be a part. However, DA will be a critical component in terms of the Smart Grid's ability to provide safe, reliable and secure electric power of high quality to the nation's 131 million³ electric customers. In fact, the main objective of a Distribution Automation System is to improve electric service reliability by 1) avoiding potential outages, 2) localizing outages quickly when they do occur, 3) shortening restoration time to customers that have outages, and 4) minimizing momentary interruptions and voltage fluctuations.

Once a utility develops a design plan for its overall Distribution Automation System, it can be implemented incrementally rather than all at once. This allows each utility to develop its DA System at a rate that fits its resource capabilities and its financial constraints.

- ¹ Estimate from the DOE's "Grid 2030"- A National Vision for Electricity's Second 100 Years, page 3.
- ² See http://www.oe.energy.gov/smartgrid.htm
- ³ Same as Footnote 1.

DISTRIBUTION AUTOMATION

Defining Distribution Automation is somewhat like defining Smart Grid because if you ask ten different utilities you will likely get at least ten definitions. For this paper, it's important to start by defining what the distribution system includes and what is being automated when describing Distribution Automation.

The distribution system is the collection of primary radial circuits that a utility uses to deliver power from a substation to the end customers. The substation breaker is the source device for a distribution circuit and it forms the boundary between substation and distribution. The substation itself is not considered part of the distribution system. The circuit feeder is the backbone of a distribution circuit that can carry the circuit many miles from the substation. The feeder often reaches a fork where it splits and goes in two or more directions. A feeder can have multiple forks as it spreads out from the substation. The feeder "feeds" many smaller lateral branches all along its length that carry power out from the feeder to the customers.

With this basic configuration, a fault anywhere on a circuit would lockout the station breaker and all of its customers would experience an outage until the fault was located and repaired. Sixty years ago when circuits were small and had few customers, a couple of well place fuses on the distribution circuit would have improved reliability enough to be acceptable. However, this would not be acceptable today, and distribution circuits now have very complex protection schemes utilizing sophisticated protection devices that attempt to minimize the number of customers affected by a circuit fault.

The most common protection devices used on distribution circuits today are fuses, sectionalizers and reclosers ⁴. All three of these devices will automatically operate for a fault according to programmed settings or fuse size and type. Reclosers and sectionalizers are used on the main feeder of a circuit and fuses are generally only used on lateral branches. Reclosers are designed to operate like a station breaker. They interrupt fault current and reclose a preset number of times before going to lockout. Sectionalizers count breaker and recloser operations during a fault sequence and lockout ⁵ when they reach their preset shots-to-lockout count while the breaker or

recloser is still open. Sectionalizers can interrupt normal load current but not fault current. Fuses blow when they see fault current above their rating according to a specific time-current curve (TCC). It is fairly easy to set these devices up on each circuit so they coordinate correctly with each other and provide the desired protection over a wide range of fault conditions. This is very important and is the reason these devices are widely used.

Sectionalizers and reclosers can be remotely monitored and controlled, but they still always operate for a fault using their own local programming and control logic. Fault protection requires much faster analysis and decision making than existing remote monitoring and control technologies can provide from a remote location.

⁴ Because sectionalizers and reclosers operate automatically for a fault according to their programmed settings, they are sometimes referred to as "Automatic Sectionalizers" and "Automatic Reclosers".

⁵ Sectionalizers cannot interrupt fault current and they do not reclose. They open and lockout once when their programmed shots-to-lockout count is reached while the circuit is deenergized, i.e., the breaker or an upstream recloser is open.

A typical distribution circuit of the type being described would have the configuration shown in Figure 1. This circuit has a station breaker, 7 normally closed sectionalizers, and 2 normally closed reclosers for its protection. No fuses are shown because they are not used on the feeder. The circuit also has 5 normally open tie sectionalizers to other distribution circuits that are used as alternate feeds when needed.



Figure 1. Protection Configuration for a Typical Large Radial Distribution Circuit

The protection devices on this circuit are set so that, for a fault in any load block, the closest upstream device locks out. See the example in Figure 2 below.



Figure 2. Circuit with 2-Shot Sectionalizer Locked Out for Downstream Fault

The 2-Shot sectionalizer in Figure 2 has correctly locked out for a fault in the adjacent downstream load block⁶. With the fault removed from the circuit, the upstream station breaker and 3-Shot sectionalizer stay closed and all customers in the 3 upstream load blocks retain power. However, all load blocks downstream of the 2-Shot sectionalizer have now lost power since this is a radial circuit with only one upstream source, the substation breaker. Approximately 70% of the customers are experiencing an outage for a fault in a load block that only has 10% of the customers.

This outcome could be significantly improved if the substation breaker and all sectionalizers and reclosers on the distribution system were remotely monitored and controllable through a Distribution SCADA System and either 1) distribution operators were given special tools needed to quickly analyze outage and fault conditions and safely reroute power around problems using remote control, or 2) have an application that performs automatic restoration for the distribution operator. Figure 3 shows the results of such a system.



Figure 3. Circuit Restoration through two N.O. Tie Sectionalizers after Fault Isolation

Figure 3 now shows 90% of the circuit restored with only the load block containing the actual fault still out of power. A repair crew would be quickly dispatched to this load block to locate and repair the actual fault.

Collectively, Figures 1, 2 & 3 show the essence of what Distribution Automation is, and it doesn't matter whether distribution operators do the remote switching using SCADA remote controls or an Auto-Restoration Application⁷ does it automatically.

⁶ Each line section between protection devices is called a load block. Utilities usually have a design standard they follow for the number of customers or KVA assigned to each load block. ⁷ Experience has shown that distribution operators can do a better job than Auto-Restoration Applications because of the complexity of most distribution systems. However, new approaches to automation that are limited to small groups or teams of devices are proving to be very effective. With small group automation, a distribution operator still oversees the big picture.

The sectionalizer/recloser circuit configuration described above has proven itself to be both effective and reliable since the late 1960's, but it does have shortcomings. In order for a sectionalizer to open and lockout to isolate a fault beyond, an upstream device⁸ has to trip and reclose multiple times. This causes unwanted momentary outages for customers upstream of the fault. It also requires multiple reclosings of an upstream device under fault conditions to enable a downstream sectionalizer to reach full count. This stresses the distribution system and can cause additional circuit damage. Attempts to use all-recloser configurations in the past to avoid these problems have resulted in a lot of miscoordination because reclosers have not had the time-current curve accuracy needed to reliably open and lockout the correct device⁹. Therefore, the sectionalizer has had a dominant role in distribution automation systems since the 1970's because there hasn't been anything better.

THE PULSE RECLOSER

Today, a totally new type of device is available that significantly improves the whole distribution protection/automation landscape. This new device is the Pulse-Recloser and it is designed to eliminate the weaknesses that sectionalizers and reclosers have had. It also brings a whole new set of advanced features to the distribution system that truly embodies the Smart Grid vision.

The Pulse-Recloser represents a totally new class of distribution device. It is more like a 3-Phase recloser than a sectionalizer because it can interrupt fault current It provideseasily selectable TCC curves of every type a utility could want which enables it to coordinate extremely well with all the standard protection devices on a distribution circuit from the substation breaker down to single-phase fuses without coordination problems. In addition, Pulse-Reclosers can be installed on a circuit as close together as needed to meet load block (*connected-KVA*) design guidelines and the correct one will lockout for a fault. To enable all this amazing functionality, a Pulse-Recloser provides a number of sophisticated features.

1. Its TCC curves are extremely accurate, i.e., much more accurate than anything previously available for use on a distribution feeder. This makes device coordination much easier and a lot more flexible.

- 2. It has a Pulse-Close / Pulse-Reclose feature that pulses and tests the line one phase at a time so it does not hard-close directly into a solid fault. *(This is why it is called a Pulse-Recloser.)*
- 3. It takes both its preferred and its alternate AC Power directly from the primary lines so no secondary power sources are needed.
- 4. It synchronizes time¹⁰ and location through a built-in GPS Radio.
- 5. It is a totally self-contained unit/package that mounts near the top of a pole (*i.e.*, *it has no control box, no control cables and no power cables to deal with.*)
- 6. It can be configured to operate in single phase mode where applicable to only open faulted phases keeping unfaulted phases energized.
- 7. It has a fuse-saving feature that enables one fast trip and reclose to save a downstream fuse from blowing for a momentary fault such as a lightning arrestor flashover or a tree branch brushing past a conductor in a wind storm. (*This could save hours of outage time to customers in a storm when no one may be available to replace a blown fuse for hours because of other more critical problems.*)
- 8. It provides a feature called Pulse-Finding¹¹ for improved coordination at the ends of a circuit where minimum trip settings are constrained by load and fuse sizes or on circuits that have a standard recloser downstream with less accurate timecurrent curves.
- 9. It maintains a very accurate and detailed sequence of events log that can be easily downloaded remotely to analyze circuit operations. (*The detail and accuracy of these logs easily rivals anything available from a substation.*)
- 10. It also provides very accurate waveform captures that can be easily downloaded remotely to analyze circuit operations. (Again, the detail and accuracy of the waveform captures easily rival anything available from a substation.)

⁸ Since a sectionalizer cannot interrupt fault current, an upstream breaker or recloser has to operate.

⁹ Protection devices on a distribution circuit are generally spaced too close together for all-recloser deployments to accurately open the correct device for a fault. A 2 to 1 mix of sectionalizers to reclosers generally works best as shown in figures 1 through 3.

¹¹ Pulse-Finding allows Pulse-Reclosers near the end of the circuit to use the same TCC Curves. They will all trip simultaneously for a fault beyond and the most upstream device will reclose first because it has AC source voltage. If it recloses successfully, it momentarily raises its minimum trip setting. Now the next downstream device has source voltage and it recloses. If it closes successfully without seeing the fault return, it momentarily raises its minimum trip setting. If the fault returns at any point in the sequence, then that Pulse-Recloser opens and locks out and the upstream devices stay closed.

Pulse-Reclosers are deployed on a circuit the same way sectionalizers and reclosers are used. Figure 4 below shows all Pulse-Reclosers installed on the same circuit we examined in Figures 1, 2 and 3 above.

¹⁰ It's wonderful to analyze a fault across multiple distribution devices and have the time be exactly the same in all of them.

Note that most of the devices are now set for 2 Shots-to-Lockout which provides 1 Pulse-Reclose after an initial trip on fault.



Figure 4. Protection on a Radial Distribution Circuit using all Pulse-Reclosers

Pulse-Recloser coordination relies mainly on TCC Curves and minimum trip settings and not on Shots-to-Lockout settings to clear a downstream fault. Figure 5 below shows how the Pulse-Reclosers operate for the same fault analyzed in Figure 2 above.



Figure 5. Circuit with Pulse-Recloser 2 Locked Out for a Fault just Downstream

With all Pulse-Reclosers installed on our sample distribution circuit, the fault sequence for a fault just downstream of Pulse-Recloser 2 is quite different than what we saw for the Sectionalizer/Recloser

configuration shown in Figure 2. Only Pulse-Recloser 2 operates for the fault now and the breaker does not operate at all. What are the benefits?

- 1. Upstream customers between the substation and Pulse-Recloser 2 (PR 2) do not see any momentary outages because the breaker does not operate.
- 2. PR2 trips faster for a fault than the breaker since it uses a faster TCC curve, so less energy is delivered to the fault putting less stress and potential damage on the circuit. (See See Figure 7 which shows the TCC Curves for each of the devices.)
- 3. Only one reclose is needed to verify that the fault is not temporary because shotsto- lockout is not used for coordination as with sectionalizers.
- 4. The reclose performed by PR 2 is a Pulse-Reclose which tests each phase for fault before actually closing. If the fault is still present during the Pulse-Test, then the device locks out without actually reclosing into the fault. Pulse-Reclose Testing is quite effective in detecting both phase and ground faults with only a small current pulse injected into the downstream line. In this example, PR 2 was only configured to perform 1 Pulse-Reclose, but up to 4 recloses can be configured. Each reclose can be individually configured for either a Pulse or a Hard¹² reclose.

¹² Downstream sectionalizers cannot reliably see and count a Pulse-Reclose so sometimes one Hard-Reclose is needed to allow a 2-Shot downstream sectionalizer to coordinate with a Pulse-Recloser.

Figure 6 below shows 90% of the circuit restored with only the load block containing the actual fault still out of power. This load pickup would normally be completed via remote controls issued by Distribution Operators in less than 5 minutes¹³ from the start of the fault. The Operators would first verify the location of the fault by checking to see that PR 1 and PR 2 both had fault indicators active. They would then check to verify that downstream devices PR 3 and PR 4 did not have active fault indicators. This would confirm that the fault was in the load block just downstream of PR 2. They would then isolate the fault by opening downstream devices PR 3 and PR 4 via remote control. Next the Operators would determine if adjacent circuits could pick up the deenergized load blocks by checking those circuits to see what their available capacity was. Generally, circuits are designed to allow load pickup through N.O. Tie devices WR 12 and PR 14.



Figure 6. Circuit Restoration through N.O. Ties, PR 12 and PR 14, after Fault Isolation.

Later when a distribution operator is ready to remotely close Pulse-Recloser 2, believing the fault has been cleared, a Pulse-Close will be issued which again tests each phase first to verify that no other faults are still present before actually closing. If a fault is still present, the Pulse-Recloser will report which phase(s) appear faulted, what the estimated fault magnitude is and it will lockout without closing. Operators always have the option to send a hard close to the device which might help crews spot the fault

location.

Figure 7 shows the TCC curves used by the Pulse-Reclosers in the example circuit.

¹³ The target for First Pickup of customers downstream of the actual fault through Normally Open Tie devices is generally 5 Minutes because any outages 5 minutes or less are considered momentary operations and not outages. However, with modern SCADA tools, Distribution Operators routinely analyze and isolate a fault and then pickup downstream customers within two minutes.



Figure 7a. U4 Extreme Inverse Curves for the Breaker, PR 1, PR 2 & PR 4.



Figure 7b. U4 Extreme Inverse Curves for PR 4, PR 6 & PR 7, a 100K Fuse & a 65K Fuse.

In Figure 7, there are portions of the curves that overlap. This is not a problem because the overlaps occur at higher current levels that are above available fault currents at the point on the circuit where they would apply.

In the preceding Pulse-Recloser example, PR 6 and PR 7 both use the same TCC Curve. This means that if a fault occurs just beyond PR 7, both PR 6 and PR 7 will trip at the same time. This was done to insure that 100K fuses downstream of PR 7 will operate (blow) for a fault beyond before PR 7 trips. Pulse-Reclosers have a lower curve limit that is defined by the type fuses used beyond. This is only a concern near the end of a feeder. Since PR 6 and PR 7 do use the same TCC Curve, PR 6 is configured for 3

Shots-to-Lockout and PR 7 is configured for 2 Shots-to-Lockout. When PR 7 locks out for a fault beyond on 2-Shots, PR 6 will have one additional reclose remaining. It will close and stay closed because PR 7 is open and locked out.

This is somewhat similar to the sectionalizer coordination scheme described earlier. The difference is that the Pulse-Reclosers are still tripping on fault overcurrent and not waiting for an upstream device

to operate. Also, since Pulse-Recloses are used rather than Hard-Recloses, the circuit is not being stressed with full fault current on each Pulse- Reclose.

The Pulse-Recloser also provides a Pulse-Finding Mode which allows devices to use the same initial TCC Curve and the same Shot-to-Lockout setting and still coordinate correctly.

Additional Pulse-Recloser Notes:

- When Pulse-Reclosers are used on a circuit, station breaker ground trip settings may need to be tuned. Because a Pulse-Recloser closes one phase at a time after each successful phase pulse test, there is a very short period of time when just one phase is closed and then two phases closed. If ground fault settings are set too low at the breaker, it could start timing on ground fault overcurrent. This would not cause the station breaker to trip because Pulse-Closing is so fast, but if a delayed fault returns just after the Pulse-Recloser fully closes, the station breaker might already be timing on ground overcurrent and trip before the Pulse-Recloser. Tree faults sometimes come back slow enough to cause this problem. If this occurs, setting breaker ground trip levels slightly higher will correct the problem.
- When pulse-reclosing after tripping on a fault, a Pulse-Recloser always tests the phase that had the highest fault current first, then the phase that had the second highest fault current, etc.
- Pulse-Recloser settings can be easily installed, changed, verified, copied, saved or reapplied remotely. A snapshot downloaded from an installed device can be used to build a setting sheet or run in a simulator program to test and verify settings.
- On circuits that use both Pulse-Reclosers and Sectionalizers, the Pulse-Reclosers might need to have at least one Hard-Reclose configured in order for downstream sectionalizers to count correctly. Sectionalizers generally can't see or count an upstream Pulse-Reclose.

COMMUNICATIONS FOR DISTRIBUTION AUTOMATION

The biggest obstacle to implementing Distribution Automation over the last 30 years has been the lack of good communication options. A utility's distribution assets are spread-out across its service territory, they move¹⁴ frequently and a lot are in locations that until recently were cost-prohibitive to reach with reliable two-way communications. This lack of good communication alternatives in the past is the major reason why DA is not more widely utilized today.

However, this has now changed significantly and a wide range of cost-effective communication technologies and good products are readily available to use for Distribution Automation. Even older technologies now work much better because of greatly improved equipment. Examples:

Technology	Qualities / Features	Configurations	Owner
UHF Radio Wide Range of Technologies Available	Line of Sight Basic Coverage, Repeaters Extend its Reach, Some Support Routable Hopping Networks & Some are Self-Configuring, Speed Varies – Slow to Very Fast	Point-to-Point, Spread Spectrum, Fixed NW-Packet Hopping, Peer-to-Peer Meshed Networks 800 & 900Mhz	Utility or 3rd Party
VHF Radio 30-300Mhz	Licensed, Spread Spectrum Long Dist., Penetrates Hills and Valleys	Wireless Conduit, Some Limited Address Routing	Utility or 3rd Party
Cellular	Excellent coverage in urban areas and along major highways, Low Implementation Costs	Public Cell Phone Network, Dial-up and Limited Direct Access over Control Channels	Cell Phone Company
CDMA/GSM (Keeps Improving)	Good coverage in urban areas, Low Implementation Costs, Low Monthly Operating Costs	Public Wireless Data Network, Supports Routable IP Protocols, Technology is Changing Fast	Cell Phone Company
Fiber	High Speed, High Bandwidth, Non-Metallic, Resistant to Fault Surges	Supports Routable IP Protocols	Utility or 3rd Party
Wire-Pair (Twisted- Pair)	Standard from the Past, Limited Bandwidth & Speed, Still Works Well with the Right Modems	Point-to-Point, Party-Line Leased Line	Utility or 3rd Party

Most utilities will need to use a mix of the communication technologies listed above to achieve the best performance and cost-benefit ratio from their Distribution Automation System. It is extremely critical for a utility to plan their communication strategy up-front, pick the technologies that will work with each of their DA end-points and establish standards¹⁵ that the entire company adheres to. Then, for example, when a new distribution device is needed on a circuit, the design engineer will automatically include

the required DA communications equipment needed to automate the device according to the standard.

¹⁴ As distribution load grows, circuits are changed and distribution protection devices get moved to new locations. DA communication needs to follow the device.

¹⁵ Make the communication standards practical. For example, poletop devices (sectionalizers and reclosers) that could move due to future circuit load growth should use wireless technology. Then if they are moved, they will continue to communicate in their new location as soon as they are reinstalled without having to redesign the communications network. For a distribution substation where high speed and large throughput are important, it might be best to have the standard require a communications engineer to determine the best technology that can be supported at this location.

DA Functional Components

There are seven major functional components in a Distribution Automation System as envisioned by Smart Grid. Five of these are associated with automating major components of the distribution feeder and include: 1) the Distribution SCADA System, 2) Distribution Breakers, 3) Sectionalizers, Reclosers & Pulse-Reclosers,

4) Fault Locators, and 5) Capacitor Banks. The remaining two components are associated with the end points on the distribution feeder, 6) Distribution Transformers and 7) the Customer- DA and Outage Management.

1. DISTRIBUTION SCADA

The heart of a Distribution Automation System is its real-time, computer-based Supervisory Control and Data Acquisition (SCADA) System that continuously monitors distribution field equipment and enables remote control. For most companies, this will be a separate system from the one that is used for Transmission, however the Transmission SCADA System may already be collecting a lot of the data that the DA System needs, such as substation breaker information. Likewise, there may be additional data that the Distribution SCADA will be collecting that the Transmission Operators would like to have access to. Rather than bringing duplicate data back from the field, the DA SCADA System should have a real-time, two-way data link¹⁶ with the Transmission SCADA System so the two systems can continuously share information. However, for security and safety reasons, distribution operators should not be able to control transmission points and transmission operators should not be able to control distribution points.

There is a wide range of good SCADA Systems available for use in Distribution Automation today and most of these have their roots in Transmission SCADA, so they are mature and reliable products. One Northeastern utility, that has a fully deployed DA System, now uses a single combined Transmission/Distribution SCADA System¹⁷, which has helped them to reduce maintenance and support costs, improve information access across the traditional Distribution/Transmission boundaries and improve SAIFI and SAIDI reliability. However, recent CIP security standards by NERC now discourage this.

a. Dynamic (Real-Time) Circuit / Feeder One-line Displays

These are full-graphic circuit maps that are viewed on a computer screen¹⁸ and show actual real-time feeder device "open/close" statuses and feeder section flows as continuously reported from the field. Devices and analog values that are in an alarm condition generally flash or have a special predefined color to make them easy to spot. Operators can perform remote controls to field devices directly from these displays. Some SCADA Systems support an underlying distribution network model that shows the live/dead condition of every line section on the circuit.

Circuit one-line displays are the most important and most critical screens in a DA System and should be designed very carefully with a lot of operator input. Don't rely on the SCADA Vendor to design¹⁹ these displays even though they have the technical skill. They just don't have the right operating experience.

b. Real-Time Digital Alarm Point & Detail Displays

These are live, real-time displays that show lower priority detail information for circuits and field equipment. This is data that's not really suitable or needed on the one-line displays and can include both digital and analog information as required. They can have a standardized tabular layout or be made to mimic a device or relay's front panel or its diagnostic screen. Some points on these displays will allow operator input or control, such as group alarm resets.

Displays of this type can be categorized into the following groups:

- General Circuit Alarm Point Displays
- General Device Alarm Point Displays
- Device or Relay Setting Displays
- Communication Performance & Statistic Displays

c. Real-Time Analog and Rating Displays

These are live, spreadsheet-like displays that are viewed on a computer screen and show actual real-time analog values (e.g., Amps, MW, MVAR, Volts, Temp) reported from the field. Usually, analog Amp values are shown along with their corresponding seasonal limit ratings (2 Hour, 24 Hour, etc) and Tie Amps²⁰ Available. Analog values that are in an alarm state flash and/or have a special predefined color and an accompanying tag to indicate which limit value they have exceeded. Monitored values can be easily compared against all the displayed seasonal limit values. These displays are critical during peak load periods because they help operators to manage circuit overload conditions, prevent lockouts and avoid over stressing distribution equipment.

d. Alarm Displays & Historical Event Logs

Alarm displays are live, sorted, filtered, scrollable lists that show the active alarms in the DA System (similar in appearance to an email in-box) with one alarm per line²¹. The alarm lines are often color-coded by a priority/category scheme to make it easy to distinguish them from one another and to find the high priority alarms quickly. New alarms can generally be configured to come in on the top (newest to oldest) or the bottom (oldest to newest) as desired and new alarm lines usually flash until an operator views and acknowledges them. Some alarm systems can be configured to only allow a point to be shown in the active alarm list once, so a new occurrence automatically deletes or overwrites a previous occurrence. This guarantees that every point in the alarm list always shows its current state in the field. Operators usually try to

keep the number of alarms in the active alarm list to a minimum by deleting alarms that have been corrected or otherwise addressed. This makes it easier to manage the next group of alarms that come in.

It's important that the filter and sort, acknowledge and delete, alarm print function, and the priority/category settings for the Alarm Displays all work the way operators need. The vendor's standard setup may not be best here. Address this early in a project because some of this configuration needs to be done when the database is being set up. Also, make sure that operators can get to their most used alarm display filter settings with predefined one-click points so they don't have to go through a multi-step selectable menu each time.

Historical Event Logs are scrollable, filtered lists that show a chorological sequence of the events captured by the DA System (similar in appearance to the alarm display). The event lines can be color-coded by a priority/category scheme to help distinguish them from one another. Some events are not considered to be alarms, so they may never have been in the alarm list. Events in the Historical Event log cannot be deleted by an operator, so a typical Event Log will contain many thousands of events. Good filtering capabilities in the Historical Event Log are important to make it easy to deal with all these events.

As with the Alarm Display, it's important that the filter & sort, event print function and the priority/category settings for the Event Displays work the way operators need. Again, the vendor's standard setup may not be best.

¹⁹ This is not suggesting that each utility will need special customized screen functions that the vendor has to build. This is more about logical screen layout, design consistency, making sure the right information is shown in the right place and in the right size, and eliminating data that's not needed.

²⁰ Tie Amps Available are values calculated by the DA System indicating the reserve capacity in amps that a circuit or tie device can support without exceeding its current seasonal limits. They are used when determining if a tie device can be safely closed to pickup load on an adjacent circuit without causing an overload.

²¹ Some systems allot more than one line per alarm to provide extra information to the operator.

²² Distribution devices that are monitored and controlled through the DA/SCADA System will be referred to as "Automated" throughout the rest of the document.

²³Or the Auto-restoration Program if it's turned on.

2. DISTRIBUTION BREAKER AUTOMATION

Ideally, every distribution breaker should be monitored and controlled²² by the DA System because the distribution operator²³ has to know what the breaker did during a fault sequence to

accurately determine 1) where the fault is and 2) if the rest of the protection on the circuit worked correctly. During restoration, it's also important to know what the breaker load was just prior to the fault in order to determine how much load needs to be picked up. Because the breaker is the source device for a circuit, it's actually one of the most important devices on a circuit to monitor and control remotely, and it can have a huge effect on customer outage time and overall circuit reliability. The DA System should continuously monitor every distribution breaker for overloads, fault operations and lockouts.

When a breaker operation or lockout occurs, the responsible distribution operator is immediately notified via a SCADA alarm. The distribution operator will then:

- analyze and locate the faulted line section^{24 & 25}
- isolate the faulted line section from the rest of the circuit by remotely opening the closest normally closed (N.C.) downstream device
- restore power to downstream line sections by remotely closing a normally open (N.O.) tie device to an adjacent circuit²⁶
- dispatch field resources to fix the problem

In most cases, the distribution operator will have the un-faulted line sections of the circuit back in power in less than 5 minutes from the time of the first operation²⁷ and often before customer outage complaints start coming in. The restored customers only see a momentary interruption in power rather than a sustained outage²⁸ which improves SAIFI and SAIDI reliability figures for the circuit.

Of course, if there are no downstream automated devices or ties on the circuit, then the distribution operator will have to rely on dispatched field resources to do the fault isolation and restoration switching. However, there is still some benefit because the operator is able to mobilize the field resources more quickly thanks to the initial SCADA alarm for the breaker.

a. Remote Monitoring & Control of Distribution Feeder Breakers

Many utilities already have remote monitoring and supervisory control of distribution breakers through their Transmission SCADA. The T&D Data Link between the Transmission and Distribution SCADA Systems would then provide the DA System with the desired breaker automation.

There are 3 options for automating breakers not already supervised by the Transmission SCADA:

- Add the breaker to an existing Transmission RTU if there is one already installed at the substation and get this data through the T&D Data Link.
- Install a Transmission SCADA RTU in the SS and get the data through the T&D Data Link.
- Install a small DA SCADA RTU at the SS and get the data directly. This option is only available for distribution substations that do not have Transmission (BES) Assets because of new CIP requirements.

²⁴ Finding the faulted line section is generally fairly simple as will be described in section 3c below.
²⁵ This and the following two steps can be performed automatically by an auto-restoration application, however such software has not yet been very effective, it's difficult to maintain the underlying databases, and operators have demonstrated that they can do the restoration better and faster.
²⁶ Before actually closing the tie device, the operator would estimate the load in amps that needs to be picked up and then check it against the Tie Amps Available for the tie device as described in 3d.
²⁷ It can take up to 90 seconds from the initial fault operation for a station breaker to reach lockout.
²⁸ Many Regulatory Agencies only consider outages over 5 minutes to be sustained outages that are reported in SAIFI and SAIDI reliability figures. This allows a complicated fault sequence followed by DA restoration activities to run to completion before customer outage counting starts.

b. Automatic Limit Alarming for Overloads

The DA System will continuously monitor breaker load amps and generate an overload alarm for any circuit that goes above its current seasonal limit setting.



Figure 8. Circuit has Exceeded its 2 Hour Load Rating by 30 Amps

A distribution operator would then take corrective action to relieve the overload condition by transferring parts of the overloaded circuit to more lightly loaded circuits. If N.C. feeder devices and N.O. tie devices are automated by the DA System, then the distribution operator can quickly and easily perform a circuit load transfer using remote controls.



Figure 9. Circuit Loading Returned-to-Normal due to Partial Load Transfer

The operator would close the N.O. tie before opening the N.C. device so that customers do not experience a momentary outage. When the overload is removed, a Return-to-Normal alarm is generated and a Return-to-Normal event is placed into the historical log.

²⁹ Protection Engineers can access information stored in the devices remotely through the DA System.

³⁰ Lower voltage hydraulic reclosers and sectionalizers generally do not support SCADA functionality. For DA operation, motor operated sectionalizers & reclosers are required.

³¹ The opening and reclosing of the station breaker or a downstream recloser during a fault sequence is the mechanism that allows Sectionalizers to coordinate correctly for a fault. However, each time a breaker or recloser closes back into a fault, it stresses and can damage components of the distribution circuit. The new Pulse-Recloser technology is able to determine where a fault is located without requiring a breaker or recloser to reclose repeatedly into the full fault. Pulse-Reclosers pulse the line for very short and precise reclose periods to determine where the fault is located without needing to fully reclose into the fault.

³² All the information required by the operator to make this decision should be right on the circuit oneline display if it has been designed properly, so it normally take less than 30 seconds. If a crew is working on the circuit, the one-line display will show a tag near the work location and the operator will not take any action until the crew is contacted.

c. Automatic Feeder Load Monitoring and Storage

The DA System should provide functionality to selectively monitor distribution analogs (Amps, MW, MVAR, Volts, etc.) for any circuit or other point and produce 15-minute average integrated values that are automatically stored for use by distribution planners and engineers.

d. Improved Verification of Feeder Protection Coordination after each Fault

Distribution circuit fault protection requires feeder devices to coordinate correctly during a fault sequence or the wrong device will lockout affecting more customers than necessary. The DA System allows distribution operators to verify that device coordination worked correctly after every fault sequence. When a problem is found, protection engineers analyze information stored in the System and in the devices²⁹ to find the cause of the coordination problem.

3. SECTIONALIZERS, RECLOSERS & PULSE-RECLOSERS

Sectionalizers and (Pulse-) Reclosers are distribution circuit protection devices that provide more accurate and more flexible coordination for faults than can be obtained from fuses. Generally, these devices³⁰ are motor or solenoid operated smart devices that support SCADA remote control and data acquisition. Reclosers are designed to operate like a station breaker and can interrupt fault current and reclose a preset number of times before going to lockout. Sectionalizers count breaker and recloser operations during a fault sequence and open when they reach their preset count while the breaker or recloser is still open. Sectionalizers cannot interrupt fault current.

a. Enhanced Protection on Radial Circuits using Normally Closed

Sectionalizers & (Pulse-) Reclosers Improves Reliability As a means of improving circuit reliability, most electric utilities utilize sectionalizers and reclosers in the design of their distribution circuits to divide the main feeder into a series of load blocks. The sectionalizers and (Pulse-) reclosers are

programmed to coordinate with each other and with the substation breaker so that when a fault occurs, only the closest upstream device to the fault locks out, not the entire circuit. This limits the resulting outage to the faulted load block and all downstream load blocks. Customers upstream of the device that locked out do not have an outage. This protection scheme improves the average reliability of each circuit but this improvement is not equal for all customers on the circuit. Upstream load blocks will generally have much better reliability than downstream load blocks and the last load block will have little improvement.

b. Remote Monitoring & Control of the Feeder Devices

The protection function provided by sectionalizers and reclosers are selfcontained and do not require any communication between the devices for the protection³¹ to work properly. The fault current itself followed by loss of voltage when an upstream breaker or recloser opens provides all the information that each device needs to perform its role correctly during a fault sequence. The device just upstream of the actual fault will be the one that locks out. If the substation breaker is monitored by the DA/SCADA System, distribution operators will know that the circuit has operated but will not know which downstream device actually locked out. By adding SCADA monitoring and control to sectionalizers and reclosers, distribution operators will immediately know which device locked

out for the fault plus the status of all the other devices on the circuit.

c. Faster Fault Location & Fault Isolation between Feeder Devices

The fault sequence has completed and the distribution operator is notified by the DA/SCADA System of the problem. The operator then quickly analyzes all the circuit device operations to verify if the protection worked correctly by answering the following:

- How many breaker operations occurred?
- Did any reclosers operate?
- How many "Shots-to-Lockout" is the device that locked out?
- Did the total number of breaker + recloser operations equal this?
- Did any other devices also lock out on the circuit?
- Did the circuit load drop consistently with the lockout?
- Are any line crews working on this circuit?

If the protection worked correctly³² and no line crews are working on the circuit, the operator will then open the downstream sectionalizer(s), recloser(s) or Pulse- Recloser(s) for the faulted load block using remote control. This will isolate the fault form the rest of the circuit.

d. Faster Restoration of Non-Faulted Line-Sections using N.O. Tie Devices

Once the fault has been isolated from the rest of the circuit, the operator looks for a normally open tie device to an adjacent circuit for use as a temporary feed to restore power to the non-faulted line sections. A quick check of the Tie Amps Available for each tie device will indicate

which ties can be used to pickup the load. Usually the operator calls the chosen tie circuit oneline up on the second

SCADA screen so both circuits can be seen and then closes the tie device remotely. This restores the customers downstream of the faulted line section. Operators can generally restore these customers in less than five minutes from the time the first fault operation occurred on the circuit. If no single tie device can supply the total load that needs to be restored, operators will sectionalize the non-faulted load blocks into two or more sections and attempt to pick up each section through a different tie device. Figure 6 shows a circuit that has been restored through 3 tie devices.



Figure 10. Restoration through three N.O. Tie Sectionalizers after Fault Isolation.

e. Automatic Restoration via Centralized or Field Localized Intelligence

It is possible to have the DA System include software that will automatically perform all the functions that an operator does to isolate a faulted line section and restore power to non-faulted downstream load blocks. One advantage of this is that when more than one circuit has a fault at the same time, the DA System can manage both circuits simultaneously where an operator would have to manage them one at a time.

However, during storms, this auto-restoration functionality should be completely turned off because of the high number of momentary operations and temporary faults that can occur. In

storm conditions, it's generally best to let the storm pass though and then determine where the permanent faults are.

Also, for safety reasons, when line crews are working³³ on a circuit, autorestoration functionality should be turned off for the circuits they are working on. Other circuits can still have auto-restoration functionality enabled. This can be done automatically using the DA/SCADA tagging interface.

Some sectionalizer and recloser manufacturers now offer special in-device software that provides automatic restoration functionality locally within the devices. These devices communicate automatically with other devices in a predefined family and can decide how to restore power within their small group. The DA System could still communicate with and have remote control of these

devices but the auto-restoration would be managed by the devices themselves. The DA System would need to have the ability to turn this auto-restoration function on and off remotely.

Note: Some operations people feel that auto-restoration functionality is not yet as good, as safe or as reliable as having a distribution operator perform the same DA functions. There is evidence to back this up, but it depends greatly on how complex a utility's protection scheme is, how many devices they use on a circuit, and how experienced the operators are. When watching an experienced operator

in action, it's obvious that automated restoration can't be any faster and can't deal with the rare unexpected event the way an operator can. Still, sub-transmission circuits which are not usually as complex as a typical distribution circuit have been using auto-restoration schemes for many years with very good success.

f. Reduced Customer Outage Time & Improved Customer Satisfaction

Section 3a demonstrated how the use of non-automated sectionalizers and reclosers on a distribution circuit can improve average circuit reliability³⁴, but it also revealed that this improvement is not equal for all customers on the circuit. Upstream customers in load blocks near the substation will see a lot fewer

outages than customers in load blocks near the end of the circuit. Customers in the last load block will continue to experience an outage³⁵ for every upstream fault. This is not the ideal reliability scenario.

With remote monitoring and control of feeder devices through the DA System, this reliability picture changes significantly. Distribution operators can generally perform fault location, fault isolation and downstream restoration within two to five minutes. Therefore, only customers in the faulted load block will experience a sustained outage.³⁶ This improves the average reliability for all customers on a circuit equally which certainly advances customer satisfaction.

This analysis demonstrates that the only real way to fully utilize all the potential value that sectionalizers and reclosers offer in terms of improved reliability and customer satisfaction is to automate them with a Distribution Automation System. Otherwise, a lot of their inherent value is lost.

³³ Line crews generally work lines hot and if they have a problem it's safest not to perform any restoration or switching until it has been verified that all crew members are in the clear and safe.

³⁴ Assuming that every load block on a circuit is equally likely to experience a fault, the average number of outages that a customer midpoint on the circuit sees will be reduced by about 50%.

³⁵ Even though customers in the last load block will not see a reduction in the number of outages, these outages will be shorter in duration because field resources can be dispatched to perform fault isolation and downstream restoration using the sectionalizers and reclosers.

³⁶ The Pennsylvania PUC only considers outages over 5 minutes to be sustained outages. Outages of 5 minute duration or less are considered to be momentary operations that are part of a modern protection and automated restoration scheme.

g. More Precise Monitoring of Line Section Loads, Phase Balancing & Overloads

One of the important objectives of Smart Grid is for utilities to use information age technologies to avoid potential outages and improve power quality. The DA System accomplishes this by monitoring not only feeder loads at the substation but also downstream line section 3 phase loads, 3 phase voltages and power

factor at each sectionalizer recloser and Pulse-Recloser. The DA System can integrate 15minute averages for this data and store it for distribution planners to utilize in monitoring:

- 3-Phase Load Balancing
- Load Growth
- Potential Overloads requiring load relief
- Downstream Voltage Levels

h. Smart Devices Provide New Improved Functionality

An important benefit of utilizing smart devices (sectionalizers, reclosers and Pulse-Reclosers) on distribution feeders is that they not only provide traditional real-time SCADA information, but they also allow 1) historical event data to be downloaded to enable better analysis of fault operations, 2) device diagnostic information to be accessed and 3) configuration data to be viewed. Additionally, they allow configuration changes to be made remotely without having to travel to the device in the field. This is useful for:

- Abnormal Circuit Configuration Setups
- Improving Safety during Line Maintenance Work
- Permanent Circuit Configuration Changes

4. FAULT LOCATORS

The DA System and its automated distribution devices enable faulted load blocks to be quickly identified, isolated and power rerouted to downstream load blocks. However the actual fault still has to be found and repaired by field crews before all customers can be restored. It can sometimes be very difficult to find the actual fault, especially in certain areas³⁷. Utilities sometimes install permanent fault locators between automated devices in these problem areas to help narrow the location where crews need to look. Some fault locators support remote monitoring by the DA SCADA System enabling distribution operators to narrow the search area for field crews. These fault locators provide the following benefits:

- More Effective Dispatching of Repair Crews to the Fault Location
- Faster Restoration because the Fault is Found more Quickly
- Reduced Customer Outage Time

5. CAPACITOR BANKS

The Distribution Automation System can be used to monitor and control distribution capacitors that are installed out on the distribution feeders where they can be more effective in controlling voltage and power factor than in the substation.

a. Remote Control & Monitoring of Capacitors

Some capacitor banks that are installed on distribution feeders operate from their own local controllers and they turn on and off automatically without any centralized control. These

capacitors can be monitored by the DA System to verify that they are working correctly and to track voltage levels and power factor.

They can also have their local control settings adjusted remotely for things like change of season. It's also possible to perform a mass request to turn all the capacitors on for special conditions like a peak load day in the summer. However, an individual capacitor's local controller may block this remote close request if voltage is already too high at the capacitor.

b. Automatic Voltage & VAR Control at the Circuit Level

Most SCADA manufacturers offer a Capacitor Control Application that can be used to control distribution capacitors on a circuit-by-circuit basis. The application will automatically turn capacitors on and off based on Voltage and VAR levels monitored over the entire circuit. This can provide more optimized results than local cap controllers and it prevents capacitors from cycling on and off due to

interaction between the local controllers. Also, with a centralized application running, the individual capacitors can utilize a simpler controller.

³⁷ Certain areas can have a history of being difficult for first responders and crews to find a fault. In these areas it can be very beneficial to install permanent fault locators.

c. Centralized Automatic Voltage & VAR Control (Network-Based)

The Capacitor Control application can also be used to control distribution capacitors on a systemwide basis. The application will automatically turn capacitors on and off based on Voltage and VAR level requirements for the system. This can be especially useful for utilities that don't have their own generation and they need VAR control.

6. DISTRIBUTION TRANSFORMER MONITORING

Direct distribution transformer monitoring is not a traditional function that has been supported by Distribution SCADA Systems. Electric utilities generally have tens of thousands of distribution transformers and SCADA monitoring has not tried to deal with this many individual end points directly in real-time yet. However, the Smart Grid 2030 Vision sees distribution transformers as an important link between the distribution feeder and the customer that needs to be monitored. Therefore, it is inevitable that the technology and functionality needed to accomplish this will soon emerge.

The realm of the distribution transformer actually falls in between three different technologies that are part of the Smart Grid, i.e., Distribution Automation (DA), Advanced Metering Infrastructure (AMI) and Outage Management System (OMS). All three systems have an interest in the distribution transformer but to different degrees.



To the DA System, the distribution transformer is an end point on the distribution feeder. To the AMI System, the distribution transformer is the source of the customer/meter's power. And, to the OMS System, the distribution transformer is an essential and critical component in the customer's network model.

Of the three systems, OMS is the System that really needs distribution transformer information, but it has no mechanism to retrieve it from the field. The DA System has a mechanism to retrieve data from a distribution transformer but no link to it. The AMI System has a direct link to the distribution transformer and a mechanism to retrieve its data through the meter.

Therefore, the AMI System is probably where Smart Grid will focus for retrieving distribution transformer information. The technology is pointing it in this direction because it's a natural fit and 10,000 transformers is not that significant to a system that is already monitoring 500,000+ meters. The AMI System can then pass the transformer information on to the OMS System.

Of course, to make this work efficiently, the distribution transformer manufacturers will need to start building smart-transformers that can communicate with the meter over the secondary service wires. The smart-transformers should provide the following data:

- Secondary Voltage (Analog)
- Secondary Current (Analog)
- Secondary Power (Analog)
- Transformer Temperature (Analog)
- High Temperature Alarm (Status)
- Critical Temperature Alarm (Status)
- Secondary Breaker Open/Close (Status)

It is generally very difficult to identify distribution transformers that are being overloaded due to normal load growth until they either fail or their secondary breaker operates causing an outage. This is especially problem some during summer heat waves when hundreds of distribution transformers can start failing, causing storm like problems for a utility. Distribution transformer load monitoring would help to prevent

this by identifying overload conditions more gradually as they first occur, rather than during the next hot spell.

One additional benefits that distribution transformer load monitoring could provide is "Theft of Power" detection. Transformer real time loads should closely match the sum of the meter loads connected to that transformer³⁸. When this is not the case, it could indicate that a meter bypass has been installed at a business or residence, an illegal secondary tap has been connected or there is a problem with the network

model/customer-to-network links for this transformer.

³⁸ Un-metered services like street lighting would need to be factored into the calculation.

7. THE CUSTOMER - DA & OUTAGE MANAGEMENT

The distribution operator in the forthcoming "Smart Grid Age" will be able to focus more on the end customer because of two highly effective tools that will be very closely integrated with each other, namely, Distribution Automation and Outage Management (OMS). With the DA tool, the operator

will efficiently operate the distribution system and with the OMS tool he will manage customer outages and

customer restoration work.

These two systems will utilize a common distribution network model with an accurate customer-tonetwork link for every customer. Any action on the DA System will immediately translate to the customers affected on the OMS side. For example, if a sectionalizer is opened on the DA-side causing a forced outage, the operator can immediately look at the OMS-side to see which customers just lost power. The integration will work the other way too. If the OMS indicates that a distribution transformer has lost power, the operator can look at the DA System to examine the distribution feeder powering the failed transformer. The transformer may have lost power because of a blown primary fuse on the distribution circuit.

Existing OMS Systems already utilize some form of a distribution network model that includes a customer-to-network link. However, not all DA Systems have a distribution network model. The challenge will be to have both the DA and OMS Systems use the same network model so that only one model needs to be maintained. The block diagram below shows this configuration.



Envisioned DA and OMS Configuration Model for Smart Grid

The real benefit gained from the envisioned DA and OMS configuration model for Smart Grid is that the Customer Service Department will automatically have near real-time access to outage and restoration information from the operations side to provide to customers. When a customer calls to report an outage, the correct³⁹ outage trouble ticket will automatically pop-up on the Customer Service Rep's screen so they can provide the customer with accurate and up-to-date information about their outage, e.g., cause of outage, location of problem, what's currently being done, estimated time of restoration and number of customers affected. For example, if a sectionalizer locks out, the very first customer that calls to report the outage could be told...

³⁹ Customer is identified automatically by their phone number as the Service Rep answers the call.

"We just had a feeder device lockout on 42nd St & Main due to a circuit fault. We are currently rerouting power around the problem area. Estimated time of restoration is 9:00 PM (2 Hours from now). There are currently 750 customers affected."

Remember, the distribution operator hasn't had time to enter any of this outage information. The DA System provided it automatically to the OMS System. The estimated time of restoration (ETR) for this situation would be a standard default for a sectionalizer lockout which would be used until more is found out about the problem.

This same information can also be made available on the Utility's web site where customers will be able get restoration updates as they occur.

Surveys indicate that customers who have outages are less dissatisfied and rate their electric company higher if they can receive timely and accurate outage/ restoration information when they call⁴⁰.

SUMMARY OF THE BENEFITS PROVIDED BY DISTRIBUTION AUTOMATION

The main benefits provided by Distribution Automation have already been covered in the previous sections as various aspects of DA were described. However a more consolidated list of these and some of the additional ancillary benefits that a utility can receive are worth summarizing.

- Improved SAIFI Reliability Figures (20% to 30% Improvement⁴¹)
- Improved SAIDI Reliability Figures (10% to 20% Improvement⁴²)
- Improved Customer Satisfaction
- More Efficient and Flexible Distribution System Operation
 - ✓ Improved monitoring of circuit loads, voltages & power factor.
 - ✓ During peak load periods, circuits can be remotely reconfigured to avoid overloads and potential outages.

- ✓ This can extend equipment life and reduce maintenance costs.
- Improved Voltage and VAR Control on the Distribution System
 - ✓ Centralized distribution capacitor control can be optimized by analyzing and coordinating with tap-changer controls.
 - ✓ Distribution voltages are better able to stay within targeted levels over the length of the circuit.
 - ✓ Capacitor maintenance can be reduced by preventing capacitors from cycling on and off due to interaction between local controllers.

⁴⁰ Customers indicate that they are better able to plan their activities during an outage if they receive timely and accurate information about the outage from their electric company.

⁴¹ SAIFI improvements from DA result mainly from the ability to rapidly reroute power to load blocks downstream of a fault so that these customers never see an outage, only a momentary interruption.
 ⁴² SAIDI improvements from DA result mainly from the ability to shorten outages by deploying field crews to outage repairs more quickly & efficiently due to 1) knowing where the problem is, 2) not needing these resources to restore power to downstream load blocks first via manual switching, and 3) faster restoration of the faulted load block after repairs are completed using remote switching.

- More Flexible and Cost-Efficient Circuit Designs Possible
 - ✓ Distribution circuits can be longer and have more connected customers without degrading reliability below targeted levels.
 - ✓ Longer circuit design can avoid the need to build new substations or add additional circuits.
- Improved Distribution System Planning
 - ✓ Better planning information is available concerning load growth.
 - ✓ Planners are more effective in meeting load growth requirements without over-building.
- More Effective Distribution System Maintenance
 - ✓ Circuit protection coordination can be analyzed after every fault and problems can be identified and corrected before they impact reliability.
 - ✓ Device setting changes can be made remotely. This is especially efficient for implementing temporary changes

CONCLUSION

This white paper has taken a close look at Distribution Automation implementation in terms of the new technologies that are part of the "Smart Grid Vision". Many of these information age technologies are already developed, tested & proven and built into products that are readily available from established and trusted manufacturers. Of special importance are the wide range of cost-effective communication options that are now available for DA and the "plug-and-play" compatibility of much of the DA equipment.

The benefits of effective Distribution Automation were also explored with detailed discussions on how DA can help an electric utility significantly improve reliability, operating efficiency, power quality, customer satisfaction and safety. All of these discussions have been based on practical DA experiences and successful implementations.

The final topics of this paper looks to the future when Distribution Automation will be closely integrated with Outage Management and utilize a shared distribution network model and customerto-network link that will tie the end customer to every action, planned or unplanned, that occurs in the DA System.