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AUTOMATED SOLUTIONS for Distribution Feeders

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As computers and other electronic equipment become the mainstay of today's businesses, customer awareness and intolerance for power system outages continues to heighten. For these customers, it is important that utilities be able to offer complete solutions to meet their needs. Depending on the customer load requirements, standby generation, uninterruptible power supply, or automatic restoration are possible solutions to improve the system reliability. In addition, utilities are becoming increasingly automated to keep up with the demands of the new business environments. As newly reregulated distribution companies emerge, it is likely that reliability indexes will be one of the key factors for regulators to examine to determine the overall performance of the distribution company. Thus, drivers for distribution automation include:

- Remote control and restoration
- Targeted regions or customers for improved reliability and operation
- Performance based rates (PBR)
- Safety issues for circuit isolation.

Whatever the driver for feeder automation, several key issues must be addressed:

- What automation scheme is required?
- How are communications implemented?

This article addresses these issues with example solutions for overhead feeder automation.

What Automation Scheme is Required?

Presently, utilities employ a variety of techniques to improve the reliability of the delivery of electric power. Traditional feeder practices include reclosers, sectionalizers, and load break switches. Reclosers, switches, and feeder restoration are key components to improving the operation of the distribution grid. For

To be able to calculate the exact performance of an individual MV distribution network requires considerable engineering skill and sophisticated software analysis



The 15 kV VR3S poletop recloser is an example of a new generation of automation-ready devices

* ABB

Table 1. Feeder without Automation

	Outage Minutes due to Fault 1	Total Outage Minutes
Customer 1	360	360
Customer 2	360	360

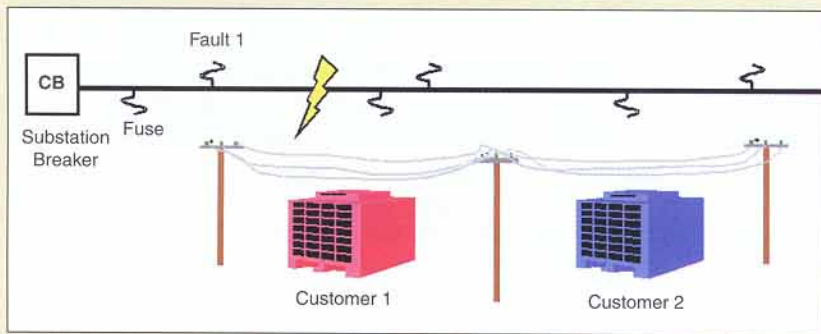


Figure 1. Example system with no feeder automation

Table 2. Feeder with Recloser

	Outage Minutes due to Fault 1	Outage Minutes due to Fault 2	Total Outage Minutes
Customer 1	180	0	180
Customer 2	180	180	360

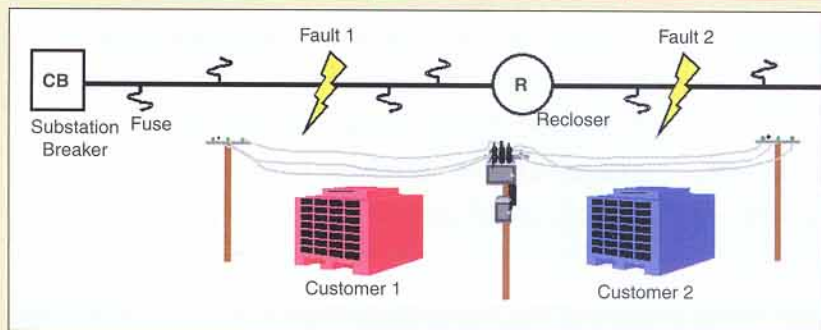


Figure 2. Example system with recloser

Table 3. Feeder with Recloser and Sectionalizer

	Outage Minutes due to Fault 1	Outage Minutes due to Fault 2	Outage Minutes due to Fault 3	Total Outage Minutes
Customer 1	120	0	0	120
Customer 2	120	120	0	240

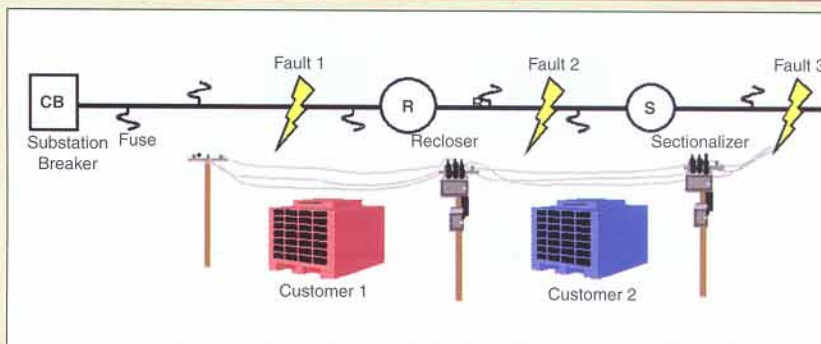


Figure 3. Example system with recloser and sectionalizer

feeder automation, it is important that the equipment be able to operate numerous times without maintenance to minimize maintenance support. Other key factors include standard communications protocols for SCADA integration, sufficient temperature operating range, and standby power to allow for operation while the system is de-energized. By use of several examples, different feeder automation solutions are highlighted. The example system is illustrated in Figure 1. For the examples, we will assume that it is important to minimize outages to customer 1 and customer 2.

For the examples, we will assume that faults occur evenly distributed on the feeder. We will also assume that it takes 1 hour to restore the power following a permanent fault and that the feeder experiences six permanent faults per year. Using this information, we can calculate the outage minutes due to fault 1 and the total outage minutes (Table 1).

Reclosers and the Impact on Outage Minutes

Historically, reclosers have been used as an economic method to improve distribution feeder reliability. Reclosers provide fault-interrupting capability to isolate the faulted line where needed. Reclosers are compact, easily installed, and can be applied in substations as well as on poletops. Reclosers must be coordinated with the upstream device such as the substation circuit breaker and the downstream devices such as line fuses. For line fuses, two schemes are possible.

- **Fuse Saving:** The fuse-saving scheme allows several operations of the recloser and, thus, allows temporary faults caused by animals or tree limbs to clear before the fuse operates. A successful clearing of a temporary fault prevents a sustained outage and

saves money by avoiding unnecessary dispatch of line personnel to refuse the cutout. For permanent faults, the recloser operates more slowly, allowing the fuse to operate and isolate the permanent fault.

- **Fuse Clearing:** For some feeders, it is important to isolate the fault as quickly as possible, even if a lateral fuse must clear the fault. This minimizes the outage for all customers on the feeder. For example, the fuse-clearing scheme is used when a momentary outage is less desirable than dispatching a line crew to refuse a cutout serving a small branch line.

Both schemes are frequently deployed. In choosing which one to use, several economic and operational factors must be considered. For example, the costs of dispatching line personnel vis-à-vis the power quality of the affected customers.

In terms of improvements in system operation, consider the example above. A recloser is now installed on the example distribution feeder, as shown in Figure 2.

Again, assuming six permanent faults evenly distributed results in three faults at fault 1 and three faults at fault 2. Improvements by adding a recloser are illustrated in Table 2.

Note that while permanent faults still result in customer 2 having the same outage minutes, customer 1 sees a 50% reduction in outage minutes per year.

Sectionalizers and the Impact on Outage Minutes

Sectionalizers are used on distribution feeders as a cost-effective means to further reduce the customer impact due to permanent faults. Typically, sectionalizers are used on a line downstream from a recloser or a reclosing relay in the substation. Sectionalizers are not fault-interrupting devices, but operate in a coordinated manner with the reclosing operation. For typical operation, consider Figure 3. In this example, the sectionalizer has a counter setting of 2. For a fault at fault 3 at the end of the feeder, a the sequence of events is:

- Fault 3 is sensed by poletop recloser
- Poletop recloser trips
- Sectionalizer detects fault interruption and increments counter to 1
- Recloser recloses
- Since fault is permanent, recloser trips again
- Sectionalizer increments counter to 2
- While recloser is open, sectionalizer opens

- Recloser recloses and power is restored to customer 2.

Note that, for a fault at fault 1, the sectionalizer would not have detected the fault interruption and would not have incremented the counter.

For the example system shown, the sectionalizer is added to the circuit to further improve the circuit reliability. Again, for our discussion, we will assume that the faults are evenly distributed on the circuit and that the recloser and sectionalizer are equally spaced on the feeder, resulting in two faults at each location. Again, we assume that it takes 1 hour to restore the power following a permanent fault. Using this information, we can calculate the results in Table 3.

Thus, with a recloser and sectionalizer installed on the line, there is a 66.6% improvement for the outage time of customer 1 and a 33.3% improvement in the outage time for customer 2, as compared to Table 1. (33.3% improvement in the outage times for customer 1 and customer 2, as compared to Table 2).

Switches at Normal Open Points and the Impact on Outage Minutes

When increased reliability is required and dual feeders are available, it is possible to place a switch at the nor-

Components are integrated into functional devices and assembled into a system to solve the complete control or automation needs of each distribution network

Table 4. Feeder with Alternate Feeder and Automation

	Outage Minutes due to Fault 1	Outage Minutes due to Fault 2	Outage Minutes due to Fault 3-6	Total Outage Minutes
Customer 1	60	0	0	60
Customer 2	0	60	0	60

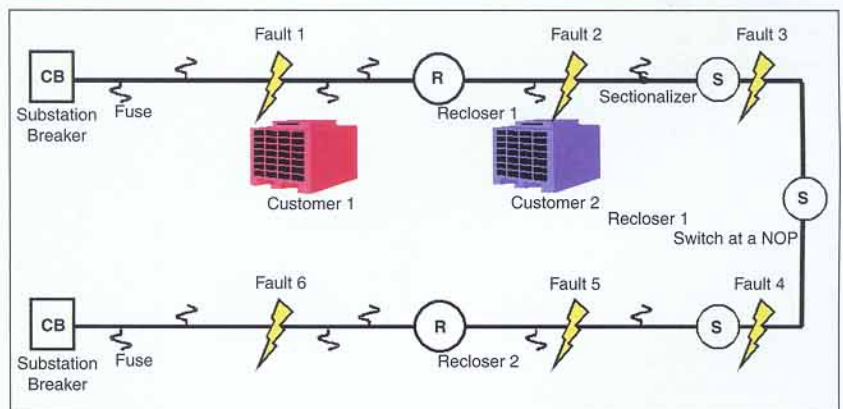


Figure 4. Example system with an alternate feeder

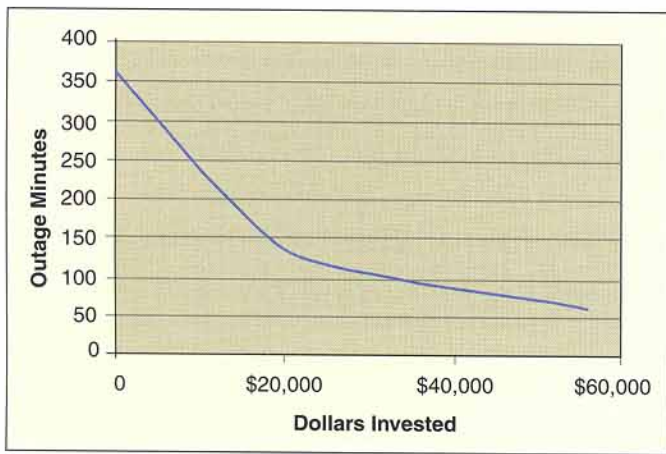


Figure 5. Expenditures vs. outage minutes for customer 1

mal open point (NOP) and restore power following a permanent fault. Typically, feeders serve customers from different substations such that a station outage does not eliminate the possibility of restoring power. Two typical implementations are:

- **Remote Transfer:** Following a permanent fault, the SCADA/DMS system reports the outage and the operator examines the recloser operation or sectionalizer fault indication to initiate the proper equipment operation to isolate the fault and restore power.
- **Local Automatic Transfer:** Following a permanent fault, the line equipment clears the fault and isolates the faulted section. Following a time delay, the NOP switch will close, restoring power.

For typical operation, consider Figure 4. In this example, the switch is placed at the NOP as shown and is normally open. For a fault at fault 1, a sequence of events is:

- Fault 1 is sensed and cleared by the station circuit breaker
- Either via system operator or local logic, recloser 1 is opened
- The switch at the NOP is closed, restoring power via the alternate feeder.

Note that, for a fault at fault 1, customer 1 is without power, since it is located on that segment.

For the example system shown, the addition of an alternate distribution feeder and fault isolation equipment on the feeders will provide the highest reliability. Again, for our discussion, we will assume that the faults are evenly distributed on the circuit, resulting in one fault at each location. Again, we assume that it takes 1 hour to restore the power following a permanent fault. Using this information, we can calculate the results in Table 4.

With a recloser and sectionalizer installed on the line, the customer is only impacted by faults on the connected segment. Thus, there is a 83.3% improvement in the outage times for customer 1 and customer

2, as compared to Table 1.

Selection of the proper feeder automation solution requires an engineering evaluation of the proper scheme versus the capital costs. For the example system, the expenditure and improvement in reliability for customer 1 is illustrated in Figure 5. This would have to be evaluated in terms of customer requirements to determine an optimal automation strategy.

For evaluation of complex systems, intelligent network modeling and optimization are required. Many factors (such as which feeders to yield optimal improvements, equipment selection, equipment placement on the feeder, and other factors) must be considered. Determining the optimal method for feeder automation involves several factors: how critical is the load, equipment placement, equipment costs, etc.? All of these factors must be carefully weighed in order to optimize the parameter of interest. To be able to calculate the exact performance of an individual MV distribution network requires both considerable engineering skill and sophisticated software analysis. This type of analysis requires intelligent analysis tools, such as the ABB Performance Advantage. These tools predict items such as outage frequency and duration together with frequency and level of voltage sags at selected points in the distribution network for a given configuration to determine an optimal automation strategy.

How are Communications Implemented?

The decision to communicate with feeder equipment often depends on the utility practices. For example, some utilities want the recloser operation/status as an input to the utility SCADA/DMS. In the system illustrated in Figure 4, some utilities will allow local automation, while others want the operator to control the feeder equipment. Further, some local automation schemes involve peer-to-peer communications. Integration of automated feeder equipment such as reclosers, switches, or sectionalizers into the DMS system depends on several factors.

- **Protocol Selected:** The unit must be capable of communicating with a standard protocol for immediate or future integration.
- **Automation Strategy:** This is for a particular problem feeder or general system deployment.
- **Communications Medium Available:** Is cellular, POTs, radio, available? If so, at a local position or system wide?

Communications Protocol

For the protocol, DNP 3.0, IEC 870, or Modbus are commonly used for utility automation. Modbus was developed by Modicon for industrial programmable logic control and is a widely used protocol due to its simple structure. Modbus can be implemented in an ASCII or RTU (binary) mode. It is very often implemented in

RTU mode and interfaced to SCADA RTUs in the field. DNP 3.0 is a more complex protocol but with some nice features, such as report by exception and allowing multiple masters. This protocol was developed by Harris and is now widely used in the power industry. Certification of DNP is now available from multiple sources. There is also a great deal of interest in IEC 61850, which promises to be a future standard. IEC 870 is widely used in Europe and is similar to DNP 3.0.

Automation Strategy and Communications Medium

The automation strategy determines which type of communications system is to be utilized. Two typical implementations are shown in Figure 6. The left side of the figure depicts a wide-area network such as a dedicated wireless network or cellular technology. The right side of the figure depicts a local wireless network with a local hub, which may be located in the substation connected to the automated feeders.

For a communications medium, it is important to understand the utility goal for feeder automation. Depending on requirements, two options illustrated in Figure 6 are available. For the first option, a communications system, usually wireless, is available throughout the service territory. These systems are used to interface to all feeder equipment and retrieve the field information for central processing. In the second example, feeder automation is applied to a select region. In this case, it may be most economical to deploy feeder equipment and communicate via local radios, such as the MDS 9810 unlicensed spread-spectrum radio. A gateway can provide a link to the feeder equipment. The gateway could be connected to a dial-up phone line or a dedicated link and is typically placed in the substation. This type of system is very economical for small system applications.

As newly reregulated distribution companies emerge, reliability indexes will be a key factor for regulators to examine to determine a company's overall performance

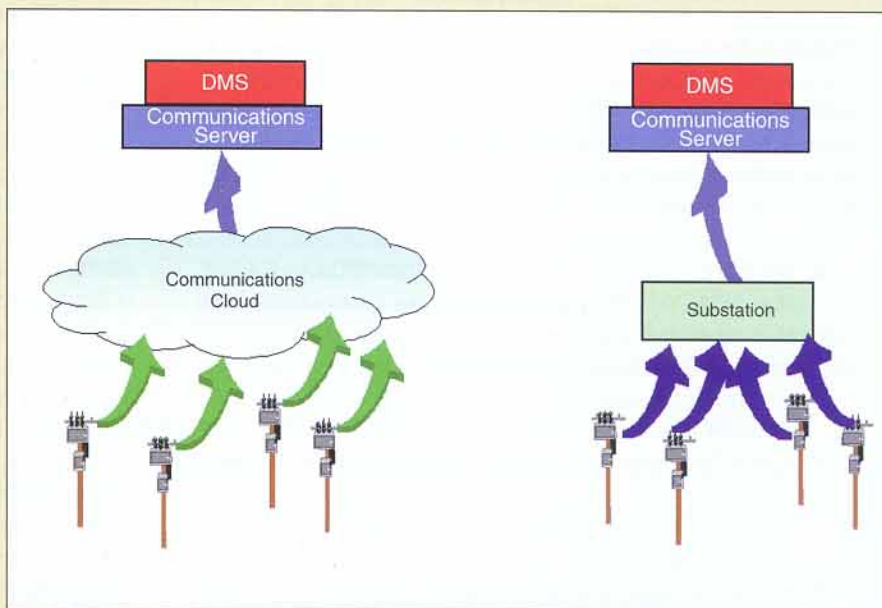


Figure 6. Wide area vs. local communications deployment

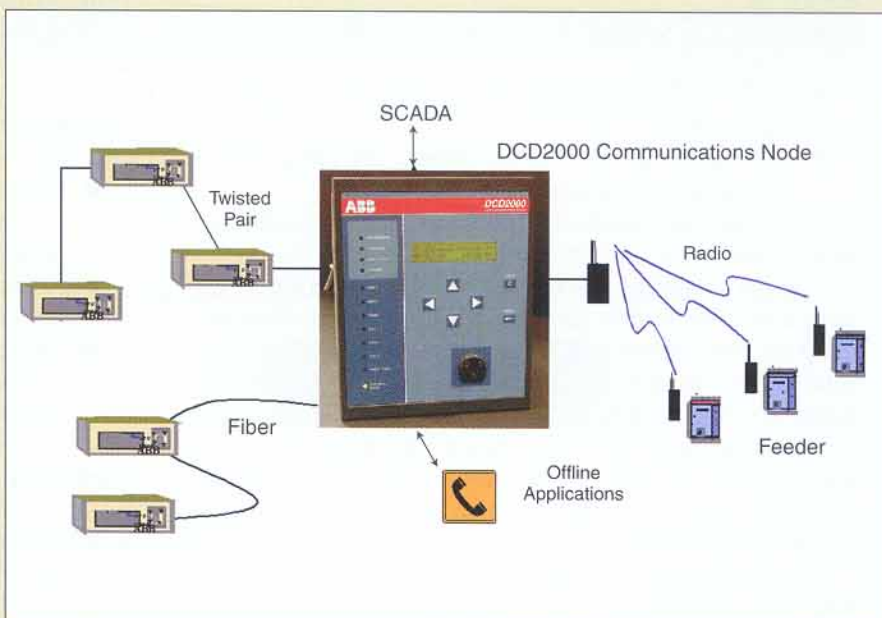


Figure 7. Integration of substation and feeder equipment communications

The type of communications systems selected for feeder automation depends on many factors, e.g., protocols and media availability

Selection of the communications approach depends on the number of units to be automated, polling rate, amount of bytes to transmit, and data transport fees, if applicable.

An example of a local deployment from a substation is illustrated in Figure 7. In this example, the DCD2000 data control device is a microprocessor-based networking device that enables you to support multiple masters with the Modbus or DNP 3.0 protocols. It has up to four RS-232 communications ports (two of these ports can be configured as RS-485), and one fiberoptic port. The DCD2000 also includes a hardened modem for use in the substation. The hardened modem is resistant to lockup or other problems typically experienced in the substation environment.

Future Issues for Feeder Automation

One of the major drivers for feeder automation in the future will be the continued global expansion of low-cost communication technologies. It is estimated that over 70% of utilities have implemented wireless devices into their present infrastructure. However, for large-scale deployments, communications continues to be a major issue. New technologies such as GSM, CDPD, and satellite are becoming available and will allow for new low-cost automation solutions. However, report by exception and slow data throughput will have to be carefully examined.

For some utilities, dedicated communications are not a viable option. Another option is to have a local device monitor the substation or feeder equipment for a particular condition, such as lockout, and initiate a page if the event occurs. Using standard protocols, this type of functionality can easily be implemented and configured. This provides the utility a report-by-exception capability, leveraging dial-up phone lines or other on demand types of communications.

In addition to automation, microprocessor devices gather a wide range of information available to utility personnel. In a typical application, it is possible to retrieve information such as power quality monitoring (sags, swells, outages), metering, load profiles, fault records, fault location, fault indication, fault records, oscillographic data, and other information from the devices. Integration of this information into utility operations will become increasingly important in the future.

Building-Block Approach

To match the utility/customer needs, a suite of automated solutions comprising automation-ready building

blocks is required. In general these products are a synthesis of state-of-the-art individual components (distribution switchgear, fault passage indication, RTU, local power supplies, and communications interface), integrated to form complete functional devices. These devices are assembled into a system to solve the complete control or automation needs of each distribution network. The building block devices must be preengineered and prepackaged to give the lowest possible costs for deployment.

Determining if, where, and how much automation to deploy is a complex issue. Detailed analysis is required to select the optimal strategy to fit the utility's and its customer's needs.

For Further Reading

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Biographies

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