

CHAPTER FOUR:

Distribution Feeder Automation (DFA):

4.1. INTRODUCTION:

Fault Detection, Isolation and Restoration (FDIR) refers to the ability of an electricity network to discover the occurrence of a fault, detect the location of that fault, isolate the equipment responsible for that fault and then deploying redundant resources in a manner that will restore power to as much of the affected area as possible.

Broadly, two technology components are required to provide FDIR capabilities. These are field devices and algorithms:

- Field devices consist of sensors and switches - Sensors detect issues on the network, while switches are used to control the power flow in the network.
- Algorithms are the mathematical logic that guides the switching activities when isolating equipment on the network. Switching actions proposed by software algorithms could be applied by a system and/or human operator.

For the electrical network the technologies consists of smart relays, smart sectionalisers / reclosers, fiber-optic distribution feeder monitors, low voltage distributor monitors and smart meters. For the control aspect, a combination of communications technologies and SCADA control back-office systems is being used. The process would perform the same functions as today, but with the assistance of software driven analysis in a more real-time fashion to improve efficiency of switching activities [8].

4.1.1. Fault detection:

Complaints reports historically relied on a combination of customer calls to their Call Centre, and faults detected at a zone substation level through its SCADA system, to identify outages on the network. Complaints reports have increasingly been deploying technology on its network to remotely monitor the high and low voltage networks and report status and events back to central Control Rooms.

4.1.2. Fault location:

Fault locator uses earth- and line fault indicators on the underground and overhead lines respectively to detect faults, in addition to the measurement available from the new switching devices themselves. In the past the indicators required manual inspection for an indication of the section of feeder where the fault occurred. In the absence of line fault indicators, visual inspections of the lines were required.

4.1.3. Fault isolation:

Mid-circuit reclosers, sectionalisers and remote-controlled switches are all mature FDIR devices deployed on the electricity network. The devices deployed vary depending on the network type. In urban areas, where the network is largely underground, remote-control switches at and near normally open points is an effective way of being able to shift load quickly between feeders. In rural areas, where the network is predominately overhead and there may be few interconnections, mid-circuit reclosers are used to sectionalise the feeder during outages and to address transient faults.

4.1.4. Fault restoration:

Once the faulty equipment has been isolated, power can be restored to parts of the network by back feeding power to undamaged equipment and feeders, thus restoring power to some customers. This is done by closing normally open

switches, connecting the de-energized equipment to unaffected parts of the network that have sufficient spare capacity available.

The FDIR trial aims to prove the technical viability and financial benefits of these technologies as part of a “Smart”-grid.

4.2. The Smart Grid:

The Smart Grid consists of a number of technological improvements that can be made in transmission and distribution systems. These improvements have been evolving over several decades in the electric utility. In general, these technologies are designed to improve the performance of transmission and distribution systems by:

- Installing sensors that can detect system conditions that indicate failures either have occurred or will occur in the near future.
- Incorporating fast-acting microprocessors that can quickly detect fault conditions and take action to anticipate failures and reconfigure circuit supply routes or restore service as quickly as possible to customers that can be served by alternative supply lines.
- Reconfiguring radial circuits adding normally open points with automatic switches that can be closed to restore service to customers surrounding isolated faults automatically.
- Adding voltage regulation and capacitance down-stream of substation transformers to reduce line losses – thus improving energy efficiency.
- Installing AMI meters that provide a wide range of benefits including:
 - I. Reduced cost of meter reading.
 - II. Improved ability to detect outages and restore service quickly after outages.
 - III. Improved theft detection.

- IV. Improved access for customers to information about the timing and magnitude of electricity consumption.

In the context of debates about the cost effectiveness of Smart Grid reliability investments it is necessary for utilities and regulators to have a common framework for cost-benefit analysis that properly accounts for the societal benefits that arise from utility investments in reliability. This will become increasingly important as society becomes reliant on electricity to supply critical energy requirements in buildings and transportation. The key challenge in developing this framework lies in adopting practical rules for assessing the economic value of service reliability [9].

4.2.1. The Benefits of Smart Grid:

A wide range of benefits arise from Smart Grid investments .They fall into four basic categories:

- Economic benefits: improvements in the efficiency in the use of capital, fuel and labor in the generation, transmission and distribution of electricity.
- Reliability benefits: reduced costs to utilities and customers resulting from service interruptions and power quality disturbances.
- Environmental benefits: reduced emissions associated with electricity generation (i.e., CO₂, NO_X, SO_X and PM-10).
- Security benefits: reduced reliance on oil and reduced likelihood of widespread blackouts [9].

4.3. Distribution Automation:

Defining Distribution Automation is somewhat like defining Smart Grid, it's important to start by defining what the distribution system includes and what is being automated when describing Distribution Automation.

Distribution circuits 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. 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 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.

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 [10].

4.3.1. Distribution Feeder Automation (DFA):

DFA is a remote monitoring and control system of breakers and switches on distribution network in real-time covering the distribution substations & Support

the optimal network operation such as fault processing and load balancing as seen in figure 4.1.

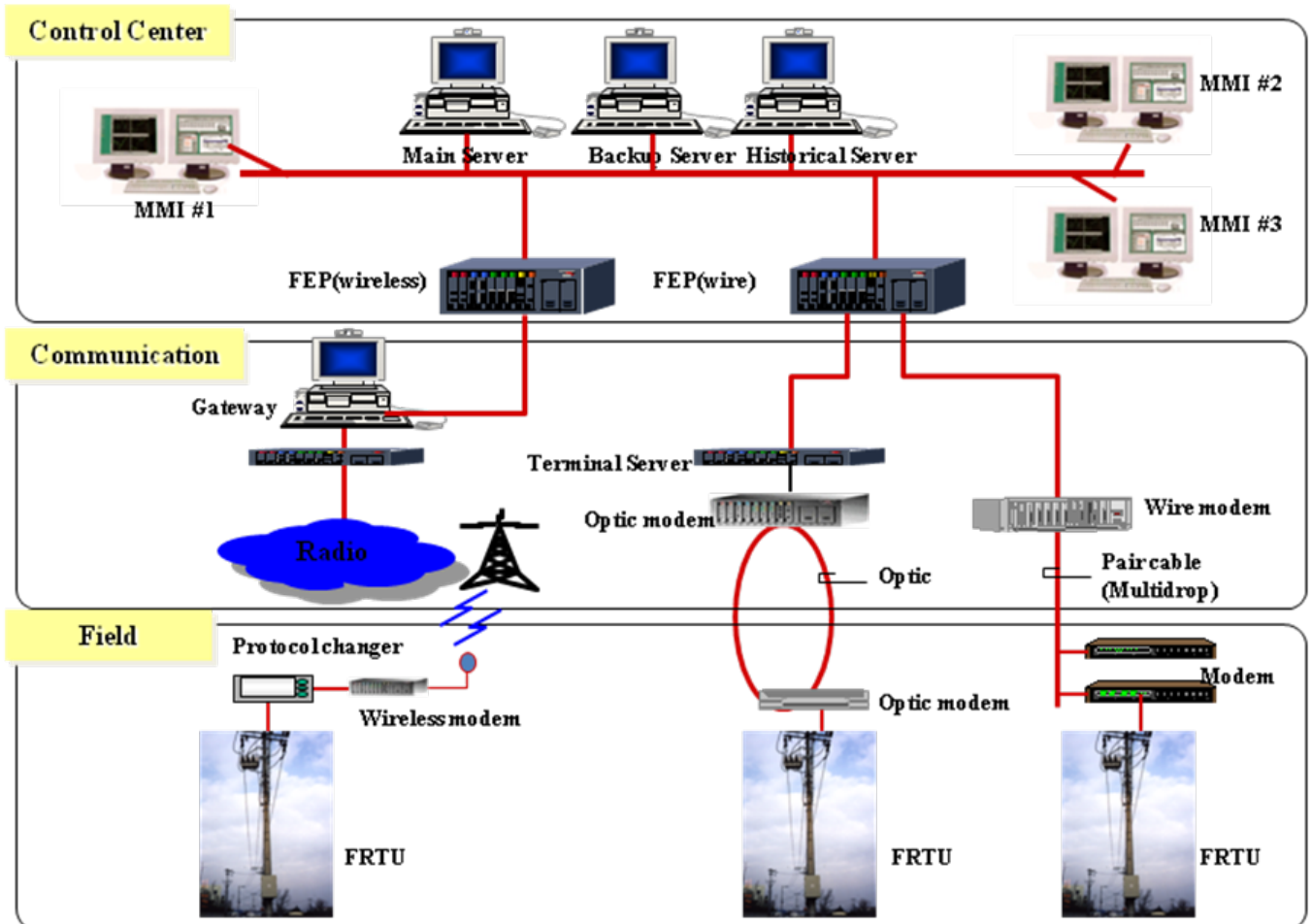


Figure 4.1: automation stages.

❖ *Features and Applications of DFA:*

The distribution feeder automation consist the following features:

- Peer-to-peer logic and control (no centralized controller).
- Differential measurement technique over comm link.
- Automatic Transfer Scheme (ATS) for critical loads.
- Fault Location, Isolation and Service Restoration (FLISR).
- Load Management and Load Balancing.
- Volt / VAR Control and Voltage Reduction [11].

❖ ***Benefits of Distribution Feeder Automation:***

- Keep the lights on! Reduce truck rolls and crew size.
- ATS & FLISR at a lower cost than alternative solutions.
- FLISR minimizes outage time (Address SAIDI, SAIFI).
- Scalable from small to large projects (ATS to FLISR).
- Compatible with existing SCADA, CBs, reclosers & SWs.
- Will supply as turnkey solution [11].

❖ ***Typical Network Architecture:***

The distribution one line diagram in Figure 4.2 represents a simple loop system that will be used for analysis of FDIR which is concerned with the detection of faults on the feeder line, determining the location of the fault, isolation of the faulty feeder section, and automated restoration of power to the feeder sections located outside the fault boundary. The system should consist the following industry practice:

- Point-to-Multipoint Communications.
- DNP or Proprietary Protocol.
- Slow Operation.
- Complex Over current Protection.

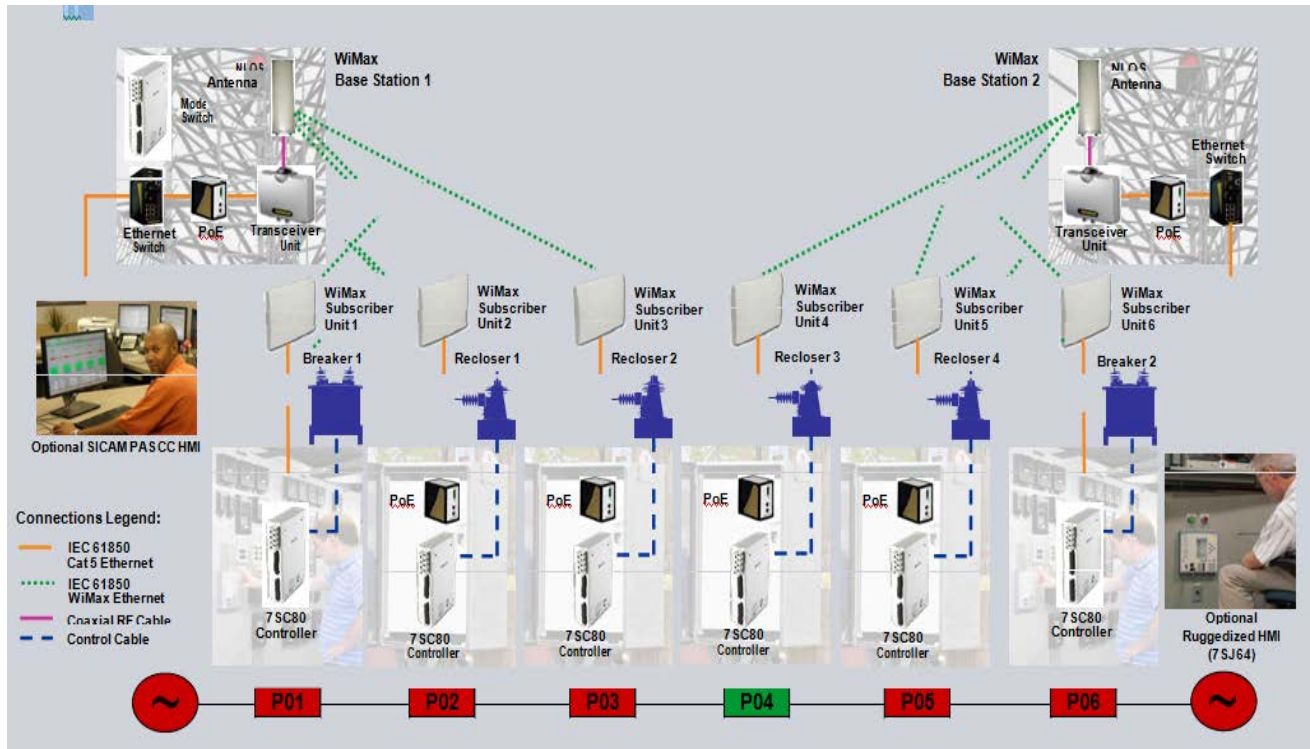


Figure 4.2: Typical Network Architecture.

❖ *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:

- The Distribution SCADA System.
- Distribution Breakers.
- Sectionalizers & Reclosers.
- Fault Locators.
- Capacitor Banks.
- Distribution Transformers.
- The Customer- DA and Outage Management.

4.4. Distribution Management System (DMS):

Distribution Management System (DMS) applications & other supporting applications that are required for SCADA/DMS System. The DMS applications shall utilize the data acquired by the SCADA application. Distribution management System Software shall include the following applications. Utilities shall select /all or certain applications according to the need & characteristic / profile of the electrical network & future part of SMART GRID in the project area [12].

4.4.1. DMS functions:

The Distribution Management System functions are:

- Network Connectivity Analysis (NCA).
- State Estimation (SE).
- Load Flow Application (LFA).
- Voltage VAR control (VVC).
- Load Shed Application (LSA).
- Fault Management and System Restoration (FMSR).
- Loss Minimization via Feeder Reconfiguration (LMFR).
- Load Balancing via Feeder Reconfiguration (LBFR).
- Operation Monitor (OM).
- Distribution Load forecasting (DLF).
- Dispatcher training Simulator (DTS).

4.4.2. Graphical & Tabular display requirements for DMS functions:

A network overview display of the distribution system with substations, feeders colour coded by voltage shall be provided. This display shall present the distribution system in a graphic format. Telemetered and calculated values like active and reactive power flows etc shall be displayed with direction arrow. Lines, Loads,

transformers etc that have exceeded their loading limits shall be highlighted. Stations shall be depicted by suitable symbols which reflect the presence of alarms. Cursor selection of a station symbol shall result in display of the associated Single line diagram for that station. “What if “analysis shall be included to visualize network & verify the impact before an action is taken by dispatcher. For all switching actions which dispatcher have to execute annually/step by step shall have the option to simulate switching operations in order to visualize the effect on the distribution network using what if analysis.

All DMS result tabular displays shall have capability for sorting by name and calculated parameters [12].

4.4.3. Network Model:

The DMS applications shall have a common model for the project area comprising of primary substation feeders, distribution network and devices with minimum 10 possible islands, which may be formed dynamically. All DMS applications shall be able to run successfully for the total distribution system with future expandability as envisaged under the specification. The following devices shall be represented in the model as a minimum:

- Power Injection points.
- Transformers.
- Feeders.
- Load (balanced as well as unbalanced).
- Circuit Breakers.
- Sectionizers.
- Isolators.
- Fuses.
- Capacitor banks.

- Reactors.
- Generators.
- Bus bars.
- Temporary Jumper, Cut and Ground.
- Meshed & radial network configuration.
- Line segments.
- Conductors.
- Grounding devices.
- Fault detectors.
- IEDs.
- Operational limits for components such as lines, transformers, and switching devices [12].

All DMS applications shall be accessed from graphic user interface through Operator consoles as defined in this specification. Reports, results and displays of all DMS application shall be available for printing at user request. Population and maintenance of the distribution network model should be possible by using the database maintenance tools to build the database from scratch. In case the required data already exists within the Employer's corporate Geographic Information System (GIS) as a part of the scheme or otherwise, the DMS database functions should leverage this effort by providing an interface/adaptor to extract GIS data using the CIM international standard IEC 61970/61968 and automatically generate the complete Network Operations Model. The data extracted should include network device information, connectivity, topology, nominal status and nonelectrical data such as cable, land base data etc. Further Land base data can be sourced from GIS in Shape files or DXF [12].

Any GIS model should be extractable to build the network model regardless of the supplier or internal schema. The extraction should also allow incremental updates & global transfer with no need to bring the system down or even fail over. The model should support extraction on a per-station basis and must be fully scalable from a single zone substation to the largest distribution networks. SCADA/ DMS should be able to present geospatial data even when the link to the source GIS at the data center/DR is not available. The user interface supporting the database will provide updated data directly to display geographic and/or schematic views of the network.

The model should support multiple geographic coordinate sets for each device so that, if available, the network can be displayed in custom geoschematic formats.

An interface with the already existing Geographical Information Systems shall be developed using interoperability features between the DMS and the installed GIS.

Each of the two systems shall keep its own specificity, and shall be used for what it has been designed: the SCADA for the real-time data acquisition, control and processing, the GIS for the maintenance of the network construction and geographic data.

The interface shall be developed in order to obtain a maximum benefit of the two systems use. It shall be implemented while maintaining the SCADA/DMS and GIS integrity as individual systems. The required functionalities for this interface shall cover the two following aspects:

1. The transfer of specific real-time data from the DMS into the GIS data-base.
2. The possibility to navigate easily from one system to the other through the user's interface[12].

4.4.4. Fault Management & System Restoration (FMSR) Application:

The Fault Management & System Restoration application software shall provide assistance to the dispatcher for detection, localization, isolation and restoration of distribution system after a fault in the system. The FMSR function shall be initiated by any change in the network connectivity due to any fault. It shall generate automatic report on switching sequence depicting analysis of fault, location of fault & recommendations for isolation of faulty sections & restoration of supply.

❖ Functional Requirement of (FMSR) Application:

The FMSR function shall include the following characteristics:

1. FMSR shall be capable of handling phase-to-ground and phase to phase faults and shall not be restricted by their time of occurrence on one or more feeders.
2. FMSR shall be capable of allowing the substitution of an auxiliary circuit breaker or line recloser that may temporarily function in place of a circuit breaker or line recloser that is undergoing maintenance.
3. The Operator shall be able to suspend FMSR restoration capabilities by activating a single control point.
4. FMSR shall be capable of isolating faulty sections of network by opening any available line Circuit Breaker that may be necessary, however operating limitations on device such as control inhibit flag shall be respected.
5. FMSR application shall utilize the results of LF for recommendations of switching steps for restoration where in it should guide the operator for amount of overloading in lines, bus voltage violations and amount of load that can be restored for various options of restorations, the operator shall have the privilege of selecting the best restoration option suggested by FMSR before it starts restoration.
6. FMSR shall be capable of using data derived from substation RTUs/FRTUs /FPIs to recognize faults in substation transformer banks, any fault on the primary side of

these banks that cause loss of outgoing feeder voltage and current or any fault occurred on 11KV network.

7. FMSR shall be capable to make Restoration plans with identification name and respective merit orders & its execution of Restoration plan using network Display and single line diagram of substation.
8. FMSR shall be capable to find delay in the restoration of network beyond specified time (Dispatcher configurable) and shall be able to report separately in the form of pending restoration actions [12].

❖ *Detection of fault:*

FMSR function shall detect the faulty condition of the network causing CB tripping due to protection operation or FPI indication. The Circuit breakers having auto-reclose feature, the FMSR application shall wait for programmer specified duration before declaring the network as faulty. On detection of fault in the network, an alarm shall be generated to draw attention of the dispatcher.

To avoid potential difficulties during severe storm conditions, the Operator shall be able to suspend FMSR switching sequence of restoration capabilities by activating a single control point. Otherwise, FMSR shall continue to operate for fault detection and isolation purposes. The Operator shall be able to resume FMSR's normal operation by deactivating the storm-mode control point. When this occurs, FMSR shall be ready to restore power as well as detect and isolate faults following the next outage event. The same shall be recorded as an event [12].

❖ *Localization of Fault:*

Wherever protection signal or FPI indication is not available, FMSR function shall determine the faulty section by logically analyzing the telemetered data (status of CBs, analog values etc) as acquired through SCADA system.

For the sections where protection signal or FPI indication is available, the same shall be derived through these telemetered signals. Network diagram identifying the faulty sections/components shall be displayed identifying the relevant section [12].

❖ *System isolation & restoration:*

Once faulty section is identified, the FMSR function shall determine the switching plan to isolate healthy area from unhealthy area. FMSR function shall suggest switching plans for restoration of power to the de-energized healthy sections of the network. The FMSR function shall have following modes of restoration process:

- a) Auto mode of restoration.
- b) Manual mode of restoration.

The dispatcher shall be able to select one of the above modes. These modes are described below:

(a) Auto mode of restoration:

In auto mode, the FMSR shall determine switching plans automatically upon experiencing fault & proper isolation of unhealthy network from healthy part of the network and perform restoration actions upon dispatcher validation automatically.

(b) Manual mode of restoration:

In manual mode, the FMSR shall determine switching plans upon experiencing faulty state & proper isolation of unhealthy network from healthy part of the network. The switching plans shall be presented to dispatcher for step by step restoration. Dispatcher shall be allowed to introduce new steps.

A filter for remote operable & manual switches shall be provided with switching plan [12].

4.5. Geographical Information System (GIS)

A Geographical Information System (GIS) is a system of hardware and software designed for capture, storage, retrieval, mapping and analysis of geographically referenced data and associated attributes.

For an Electric Distribution Utility, GIS is a system of mapping the complete electrical distribution network including the low voltage system and customer supply points with latitude and longitude overlaid on maps. These map representations contain layers of information. The first layer could correspond to the distribution network coverage. The second layer could correspond to the land background containing roads, landmarks, buildings, rivers, railway crossings etc. The next layer(s) could contain information about the equipment, poles, conductors, transformers etc.

Information processing is a key to improving productivity and cutting costs. Converting information to a computerized format in GIS is useful for an electric utility. A well designed GIS user interface will allow utility employees to search and retrieve information stored on a server simply by pointing and clicking through user-friendly menus[13].

In distribution utilities GIS could be used for:

1. Customer management.
2. Asset management.
3. Outage management.
4. Planning routine maintenance.
5. Network planning: up gradation and extension.
6. Network reconfiguration and optimization.
7. Load flow and short circuit analysis.
8. Load growth forecast and trend analysis.
9. Energy accounting and audit.