Considerations for Phasor Measurement Unit Introduction in Distribution System

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***Abstract*--We consider a distribution network evolution involving highly automated systems with PMUs. We argue that PMU-based grid control operations carried out autonomously would be faster and more cost efficient than current manned operations. Controls that are capable of optimizing the system could significantly improve performance and reliability. PMUs at distribution substations would support many of the applications required for moving towards a smart grid. Viewed from a broader perspective, it is recognized that the functions listed in this paper would have to be considered on a utility by utility basis.**

***Index Terms*—Phasor Measurement Unit, Distribution network automation, smart grid.**

I. Introduction

Phasor Measurement Units (PMUs) do some of the most vital measurements in power transmission networks. It is important to be able to see the status of the grid across the power network during critical events like generation unit loss or power swing oscillations.

Since the first PMU was installed, the main forces for PMU installation and development have been the North American Synchrophasor Initiative (NASPI) [1], American Recovery and Reinvestment Act of 2009 [2] and IEEE [3].

Measurement reporting rates for a PMU are standardized, scaled to the power frequency (typically 25 to 50 reports per second in Europe) but can be higher. (Measurements are based on much higher input sampling rates.) Results from different locations can be combined to get estimated grid operation status over an entire interconnection. [1]

Recent PMU research has investigated PMU technology applications and technological benefits along with challenges in the distribution network. A PMU prototype (called a μPMU) for the distribution system network has been developed by a team led by the University of California, Berkeley. The prototype μPMU device is very compact, and based on 512 input samples per cycle. It is said to measure phase angle at unprecedented accuracy of ~0.010°. [4] [5]

In this paper we consider possible PMU implementation in the distribution system and describe possible benefits and indicate major costs. The work focuses on a European type network.

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II. Possible applications in distribution network

Since the majority of the applications described involve controllable switchgear, the focus of this paper is more on the medium voltage part of the network where remotely controllable devices are usually installed. PMU device costs, their installation costs and communication infrastructure (section IV) will be treated as shared costs between all indicated benefit costs and will not be mentioned separately.

A. Real-time Measurements for Main Power System Parameters

1) Requirements

Compared to the transmission network, distribution system lines are much shorter and more compact. This poses a question whether the parameter changes along the feeder are significant enough to give useful information from possible phasor measurements.

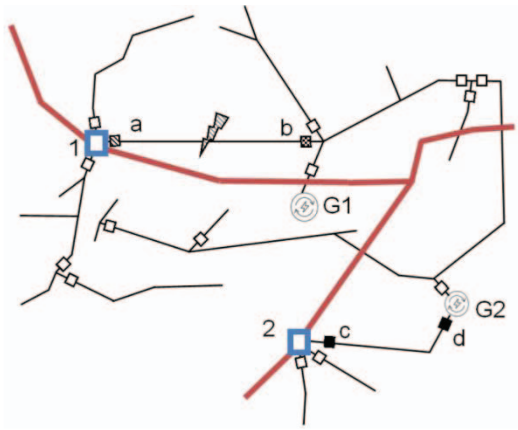

Fig. 1. Eastern European rural distribution network (approximation).

A typical medium voltage distribution grid scheme is given in Figure 1 without distinguishing between circuit breakers, reclosers or sectionalizers. It is mainly a 12 kV network, with bold lines being 25 kV. The longest feeder line starts with circuit breaker “a” and is approximately 1.6 km. The line is 150 mm^2 overhead aluminum (ASCR) line. Conductor resistance is given in the manufacturer’s handbook as 0.191 Ω/km. Reactance at 50 Hz is given as 0.391 Ω/km.

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For such a line the phase angle for voltage is ignored in the majority of available literature on distribution networks. In [6] it is stated that "*the angle between the source voltage and the load voltage (δ) is very small*". Unfortunately it does not indicate numeric values for the "small" angle. By putting in the values of the line described, it became clear that in the worst case scenario (thermally-limited load, power factor close to 0) the voltage angle δ would not exceed 3°.

This supports the resolution of the µPMU. Another possibility would be to relax the need for accurate tiny angle values and instead concentrate on larger values, for example, phase difference between two islanded parts of the network. This might enable industry to manufacture a lower cost PMU and encourage utilities to invest in such solutions.

2) Model Validation

PMUs can provide very accurate and real-time measurements for validating circuit models. Calculation accuracy would be increased by PMU-based techniques of model validation, as is done in transmission. Better modelling scenarios benefit distributed energy resource integration and validation in distribution network while maintaining system stability and reliability. This gives the distribution system operators greater confidence in their performance.

Information about power flow and voltage across the distribution line could increase system reliability by providing frequency ride-through capabilities for Distributed Energy Resources (DER). This could actually help to maintain system stability during critical events instead making it worse (according to rule, in the case of a voltage drop all DERs shut off. That reaction increases power deficit and may lead to system instability).

Recent µPMU projects indicate possible solutions for phase detection where the phase order is unknown or the hardware is poorly labeled. This could greatly aid technician work and safety as well as GIS (Geographical Information System) keeping track of network topology [7].

The cost of installation and communication must be considered, and for a distribution system PMU device, installation and communication infrastructure costs may seem large. Devices and communication network would have to be installed on pretty much all Middle Voltage (MV) line ends and on a majority of long/loaded distribution feeders in order to obtain a full, real-time picture of the distribution network. In the next sections we will look at ways to justify these costs.

B. System Reconfiguration

1) Efficiency

Distribution system reconfiguration is a part of normal operation. It has been routinely done manually since the start of the power industry, sometimes to improve system performance (such as voltage profile), sometimes to restore service.

The idea of reconfiguring just to improve efficiency is at least 30 years old. In 1984 and 1985 Pennsylvania Power and Light, along with Westinghouse, collected 15 minute load data in six feeders. Using these data they modeled a network reconfiguration solution on 26 feeders. The results showed losses reduced by 14% (2 500 MWh annually) [8]. The hypo-thetical efficiency improvement mentioned would have required automation, as it was based on a daily movement of load. It would be a candidate for smart grid functionality.

2) Post-Fault Restoration

Following a fault, PMU data might reveal multiple system reconfiguration options. For the system of Fig 1, one of the scenarios could involve phase-ground fault on the 12-kV line between circuit breaker "a" and "b". The protection system would normally trip the breaker at the substation, thus cutting power to the whole feeder. However there is no reason why so many customers should remain disconnected from the network. An automation system in this case would be able to reconfigure power flow, and reduce the number of customers without electricity supply and reduce repair time for the affected region.

Equipped with PMU devices, system load characteristics, phase angle and other parameters would be obtained real time and the fault could be located and isolated by already existing protection devices (fuses, breakers, reclosers, sectionalizers). If the load can be picked up by a different transformer ("2" in figure 1) connected to this network, the automation system could operate sectionalizers and reclosers to provide power from different source to the feeder that has been cut-off.

The phase angle would have to be negotiated between PMUs installed on "1" and "2." Large difference in phase angle while reconnecting could result in damaging circulating currents [9]. In the reconnection process the faulty line would be disconnected from the network, while the rest of the feeder would be supplied from transformer "2."

A good communication network and very rapid and accurate measurement devices such as PMUs solves the phase angle problem for safe and fast reconnections.

The reconfiguration solution involves relatively few PMU devices, but has additional costs because of the wider communication network and additional remotely controllable switchgear.

C. Islanding Parts of the Distribution Network

When part of a power network remains energized after being disconnected intentionally from the main grid, it is usually known as a *microgrid*. Unintentional disconnection can also occur due to an unplanned sequence of events. For example, when protection switchgear disconnects a faulted feeder some DER generation units could fail to detect disconnection and keep operating for some time. We term this *islanded* operation.

Unintentional islanding is generally avoided in order to prevent damage to network loads and power generators, as well as for safety reasons. The main problem is that DER generators are not usually capable of operating without balancing from the network.

Nonetheless islanding is still possible if the network control system is provided with all necessary information about the load and generation characteristics, and if the generators can manage the control in the part of the system of interest. Distribution PMUs could provide all information needed about network conditions on the borderlines of distribution network segments that can be operated remotely.

Phase angle information provided by PMUs can allow safe island restoration to the main power network by enabling angle synchronization before switchgear operation, therefore avoiding damaging circulating currents or power swings. The number of customers without service as well as outage time can be greatly decreased if network control systems are able to perform all of this automatically.

PMUs differ from conventional measurements in that they can obtain multiple network parameters very rapidly. With a little additional data, that speed could improve:

- Island territory *selection,* based on generation and load data and switchgear availability;
- Very rapid island balancing adjusting load/generation;
- Optimized island reconnection to power network.

Islanding in this way would require a capable communication network together with considerable amount of switching gear for network isolation and possible load shedding. The number of PMUs need not be large: the minimum might be a PMU at each DER connection plus one at substation buses.

D. Integrating DER

There is political pressure to keep DER penetration in the power network constantly increasing. This is partly due to the commitment of developed countries to reduce carbon emissions and dependence on fossil resources.

It is possible that power flow could reverse the direction in the distribution feeder. Protection design would have to change to allow that. Maintaining reliability could therefore become more and more expensive for utilities as they work to predict and accommodate DER and its complex load behavior.

Misleading DER integration models could create a potential for power quality and grid safety violations as well as unnecessary investments in mitigation solutions. Better understanding of the evolving and rapidly changing distribution network could help to address this problem. This would mean that more sophisticated measurements and information about system fundamental features are necessary to calibrate and validate distribution system models.

To fully benefit from DER integration we should also consider islanding costs (or consider DER PMU control costs as part of islanding costs).

III. Requirements for PMUs

Existing PMUs are highly capable devices, but it is generally accepted that the functional requirements that exist in the standards have been generated without reference to any specific application.

In order to achieve the goals discussed above, the PMU devices as well as their infrastructure may need to be compliant with some specific *new* requirements.

Suggested applications that may give rise to new functional requirements (beyond those of the present standards) include:

- Power system performance monitoring and dynamics analysis;
- DER management;
- Voltage control;
- Power flow estimation;
- Power system reconfiguration management;
- Thermal monitoring of devices;
- Relaying coordination;
- Fault detection;
- Islanding operation and management;
- Oscillation detection;
- Model parameter validation;
- Load balancing.

Applications such as these would require PMU systems to deal with harmonics, control in response to input commands and feedback signals, and interaction with the relaying schemes in force. Such functions go beyond just an ordinary PMU.

Requirements beyond functional performance requirements should also be considered in future designs. Examples include:

- Environmental requirements:
    - vibration (for installations in DER objects);
    - immunity to temperature changes;
    - immunity to humidity.
- Compactness (for retrofitting in substations and DER objects);
- EMI/EMC
    - Immunity to voltage surges, dips etc.(to survive the events it must monitor and record);
    - Compatibility with other devices
- Security by design (design with multiple security features and protection levels).

Our preliminary idea and also indications of some other research on this matter shows that PMUs would be needed at each distribution substation and at each interconnection of considerable power DER to avoid deficiency in observability with network reconfiguration and islanding.

IV. Requirements for communication infrastructure

Compared to SCADA, operating at four-second reports, the amount of data being produced by a PMU is considerable (with more than 30 frames per second with multiple parameters). However, by modern communication standards, the data rate is not large. Based on [3] we find that a substation network with six PMUs would require a bandwidth just under 0.2 megabit/s (Mb/s).

This is the rate for inbound data that is sent to data aggregation devices in the system. It may flow in a peer-to-peer fashion, and require consideration of security.

Command data is smaller in volume, but must be reliably and securely communicated. It typically flows in a master-slave hierarchy. Some commands may require low-latency communications with a control center. The large difference between the volumes and the high importance of control signals allow consideration of the telecommunication systems separately. Given the asymmetry, what are the options?

Power Line Communication (PLC) is used in much of Europe for distribution communications. However, it is vulnerable to faults in the power network, and for data communications, it would fail to meet the bandwidth requirements. We can rule out PLC.

Cellular communication can meet the bandwidth criteria but might be too costly for utility companies, and its reliability for network control would have to be assessed carefully.

Two companies in the US (Chattanooga Electric Power Board and Snohomish Public Utilities District) have shown that fiber optics can meet all criteria for bandwidth, security and reliability for grid operations with PMUs. The fiber systems are reported to be cost effective, with financial benefits coming from fault restoration.

However it is uncommon for utility companies to have fiber optics applications such as these. Most utilities in Europe have implemented advanced metering (AMI) first. This is also happening in the US. There is anecdotal evidence of power companies finding that their AMI systems do exactly what they were designed for—but are incapable of expansion after implementation. They are relatively low bandwidth, and may have high latency.

Automation goals for communications are more difficult to reach than monitoring. The solution for a given company should be found via a telecommunications traffic study. It would determine data rate requirements, total volumes, data paths, error rates, latency limitations and other communications characteristics. An optimum communications solution would allow for expansion to support future applications.

Suggested requirements:

- High subnet (local) communication speed (microgrid operations, reconnections);
- Reliability (power network should be able to rely on telecommunications network not to fail when power network does)
- Security (because of critical commands like system stability and vital measurements cyber security must be priority)
- Scalability (adding new devices or parts of the networks – like during islanding)
- Affordability (has to be comparable to benefits from PMUs and communication network)
- Controllability and transparency (ability to supervise large communication network with little effort and make it easy to automate).

V. Conclusions

One of the main challenges is the need for a reliable, high performance, secure and widespread communication backbone to support not only PMU integration but also aid future smart grid applications and devices. We have seen that optical fiber technology would serve perfectly: but it is very costly and not common among utility companies. It is possible that many other incentives should be considered in reference to long term development to outweigh the high costs of strong communication network investments.

It is noted that PMUs would give most benefits when installed in all significant substations, network intercon-nections, DER connections and in meaningful network parameter data gathering points. It is also proposed that planners consider relaxing the need for extremely accurate phase angle measurements and focus on larger angle differences measured between different parts of network and during critical network events. This could result in a more affordable distribution PMU solution.

In order to accommodate the benefits highest costs are expected to be from investments to sufficient communication network. PMUs also are considerable investment, but it is predicted that technology price will become more affordable with developments of distribution PMU device.

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