NEW CONTROL AND MANAGEMENT ARCHITECTURES FOR ACTIVE DISTRIBUTION NETWORKS

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1. Abstract

Active networks will create new challenges which will dramatically change the electrical network operation and its interaction with the consumer, driven by factors like environmental sustainability, consumer empowerment, security and quality of supply, and finally the European energy market.

New innovative and integrated solutions are crucial for the improvement of end-use energy efficiency, demand side participation, support for life-cycle remote contractual operations, new services exploitation, renewable and microgeneration integration, and others.

This paper points the way to how the configuration at the upper SCADA/DMS levels is built automatically based on the lower level models, following the network architecture, providing a natural consistency between the models, reducing the overall cost.

The paper also proposes how SCADA/DMS systems should evolve to tackle new challenges, including new functionalities such as optimal network operation, voltage control and reconfiguration strategies, outage management, protection and fault detection, system stability and validation of maintenance schemes in order to minimise operational costs and increase reliability.

2. Introduction

The expected growth in Distributed Generation (DG) will significantly affect the operation and control of today's distribution system. In the near future, SmartGrids will pave the way towards a less passive and more active and efficient electrical network. To ensure a proper interface between DGs and the electric utility system, clever new controls will be essential if DG is to be used efficiently and safely.

More than a large technical challenge, it is also an excellent opportunity to progress towards the SmartGrid concept, integrating all new smart metering and commercial processes and at the same time, allowing operation flexibility at all distribution levels, efficiency improvement, network reinforcement cost deferment, and increase in quality of service while decreasing investment and operational costs [1].

3. System Architecture

As the system complexity increases and many actors produce power, traditional Supervisory Control And Data Acquisition (SCADA) is inadequate to manage and optimize all possible combinations of power production/consumption. Loads will become more responsive to requests from system operators and their controllability should be properly represented.

DG units connected at the MV level, microgeneration in LV and responsive loads will greatly impact distribution automation through the expected explosion in numbers and sophistication of intelligent control devices and Remote Terminal Units (RTU).

SCADA/DMS and other utility systems should act as one and extend over the whole network, from generation to client. Control and automation functions are no longer limited to control centres and appear throughout the network.

The large scale deployment of communications and automation is changing the passive distribution network into an active SmartGrid where all manoeuvres can be monitored and remotely operated. Distribution Transformer Controllers (DTC) and RTUs with "smart" onboard controls will be required to enable local network optimal operation based on constantly updated distribution system parameters [2][3].

The system should be seen as a whole with all parts inter-connected through a utility-wide and two-way data communications network, connecting customers, distributed resources and field devices with the enterprise systems.

On the consumer/producer level smart meters enable accurate recording of load/generation profiles in real time, reducing billing costs, detecting fraud, providing energy balance opportunities and allowing the customer to actively manage his energy behaviour and controlling microgeneration, allowing also for third-party related services implementation.

At the Distribution Substation the DTC additionally clusters the attached meters, manage Public Lighting, monitors local components and automate their operation. It enables local network optimal operation based on constantly updated distribution system parameters optimising energy flows, network topology and offer self-healing algorithms in collaboration with primary substation automation. Such controls will need to communicate with the utility to provide the information needed to operate the network in an optimal way resulting in new control capabilities accessible to the Distribution Network Operator (DNO) to improve reliability, quality of supply and in order to optimise network operation with distributed generation.

The primary substation will be complemented with Substation Automation Systems (SAS) able to optimise energy flows, network topology and self-healing algorithms [4].

Central system level aggregates capabilities of commercial and energy management, while accurately processes billing and load profiles. It also provides a global view over all these devices, operating over the active distribution network. The bridge between SCADA components, Energy Data Management (EDM) applications and other enterprise systems is made at all levels, from control centre through to lower levels. Effectively the SCADA will manage a collection of intelligent semi-autonomous subnetworks. The result is an optimal network management, enhanced reliability and quality of supply, opportunities for Demand Side Management.

Central management, energy data and SCADA/DMS systems will guarantee the dispatching orders and data collection activities – measurements, notifications and alarms from devices,

network monitoring and potential fraud detection, etc. Subsequently, integration with existing and new Meter Data Management (MDM) and EDM applications will provide services improvement for market activities, energy balance for network losses characterization, optimal network operation and reconfiguration strategies, outage management, DG management and planning, protection and coordination, fault detection and analysis, system stability, optimal maintenance strategies (validation of day-ahead schedules) so that operational costs are minimised and reliability and system stability is increased.

4. Local Control – DTC

The DTC concept performs an important management role at the electric power grid serving end consumers, namely those fed by the LV network. It can also manage independent micro-production players, which, together with the consumers, constitute what are known today as *Prosumers*. These are the new pro-active agents that may perform simultaneously the role of an intelligent consumer or independent micro-producer.

This intelligent module is targeted to be used in MV/LV Distribution Substations and aims to supervise and control local equipment, as well as collecting remote metering data coming from smart metering devices, concerning downstream LV network branches belonging to that specific Distribution Substation.

It has an integrated Digital Signal Processor (DSP) technology giving support to specific functionality such as Fault Detection and Power Quality Analysis.

At the Distribution Substation the DTC additionally clusters the attached meters, manages Public Lighting and can monitor and control local components. It will be responsible for collecting information from the Prosumer devices, process some of that and send it upward. It will also receive information from central systems and distribute it amongst Prosumer devices. It enables optimal local network operation based on constantly updated distribution system parameters optimising energy flows. The local network topology is thus controlled locally, including the adoption of self-healing algorithms. These autonomous functions will need to communicate with the centre to provide the information needed to operate the network in an optimal way, offering in new control capabilities to the DNO that improve reliability, quality of supply and optimise network operation while supporting distributed generation.

The DTC manages dynamically the 2-way communication systems with those smart meters, detecting their insertion into the system, recognizing and integrating them in its own internal database. The inclusion of those smart meters, as well as the related incoming metering data, is reported upwards into the Central Systems.

Being a flexible solution, capable of managing multiple input data, for multiple applications, the DTC allows the system to identify, at the distribution transformer substation level, the demand shifts, the independent production, and the power resources present in the network. Additionally, the DTC sends that data to the upstream systems, either to the respective distribution network control centre, or to the utility's corporative information system. Besides this standpoint, the DTC also offers electrical interface mechanisms, providing not only alarm or metering, but also voltage, current, power and power factor values. Moreover it executes remote controls, coming from the control centre or the Information System, as well as local controls, when applicable, over the MV or LV circuit breakers.

The DTC manages dynamically the communications with those metering devices, detecting their own insertion into the system, recognizing and integrating them automatically in its internal database. The inclusion of those devices, as well as the metering data arising from them, is reported to the central systems.

It is able to control the public lighting, executing previously scheduled orders, received from the network control centre. Furthermore it is able to perform public lighting metering.

The processing power permits the implementation of algorithms for MicroGrids management. Corresponding to the MicroGrid Central Controller, to be housed in MV/LV distribution substations, the DTC will be responsible for managing the MicroGrid, including the control of the microsources and responsive loads as well as managing storage systems [4].

Besides these functions, the DTC allows detecting upstream MV network faults, as well as managing a set of alarms concerning the internal operating environment, namely those related to the state of the equipment, ambient temperature, MV/LV transformer oil temperature, intrusion, among others.

5. Network Operation Challenges

The present electricity grid is designed based on a vertically integrated supply model using dispatchable centralized generation and distributed consumption with little or no dispersed generation resources. SmartGrids will need to accommodate more intermittent and decentralised generation and support bi-directional power flows, continuing to guarantee the energy supply from other sources when local microgeneration or DG fails.

The consumers role will be strengthened as well, not only from the microgeneration perspective, where they shall contribute may expect benefits from their investment, but also by taking an active role in the management of their own energy consumption in the home [5]. This role fits in a Demand Side management (DSM) perspective, promoting cost reductions as a result of the implementation of a new model, aiming for higher energy efficiency. Other consumer benefits are also foreseen, resulting from the availability of new services, new tariffs and price plans, in line with the goal to reduce the end user energy costs.

The synergy between the SmartGrid and deregulation will bring further benefits, all the actors in the energy chain, producers through to end users, will be offered a more active role, looking together for improvements in energy quality. This active distribution grid will require a high degree of monitoring and automation to secure these aims, using coordinated voltage and VAr control, automated switching responsive loads, load transfer and relay coordination.

The information network will bring together the diverse data needed to manage generating and demand resources present on the distribution network while maintaining power quality and respecting commercial agreements with the customer.

6. Modes of Operation

Two operating modes can be envisaged for the operation of the MV grid: normal mode and emergency mode. In normal operating mode, several functionalities can be implemented which include local state estimation, voltage and reactive power control and self-healing

capabilities for reducing interruption times such as fault location and isolation, network reconfiguration and service restoration.

One of the most important functionalities in normal operating mode will be voltage and reactive power control that, due to the specific characteristics of distribution systems, will require a new management approach able to deal with simultaneous large-scale integration of DG directly connected to the MV network and microgeneration at the LV level.

On the other hand, an emergency mode can be considered by assuming the possibility of exploiting the MV grid in islanded mode, where DG is used for this purpose. Under this emergency mode, black start can also take place involving islanded operation and synchronization steps.

In the islanded operating mode the substation and its associated MV and LV networks (including MV loads and generators, LV loads and generators at the MicroGrid or Virtual Power Plant level) will operate isolated from the main power grid. The interest in such capability also requires the development of an extended set of control functionalities to be implemented at the substation level. In this case, frequency control stands as the most important functionality that is expected to be installed at the substation level (namely when adopting a type of secondary control approach) to deal with local islanded scenarios and system synchronization [6].

7. Fault Location and Isolation, Network Reconfiguration and Service Restoration

Using the information of fault indicators located along the feeders, the primary substation controller is able to identify the feeder section where the fault occurred and, by operating both upstream and downstream switches, isolate that feeder section. After fault isolation, the feeder circuit breaker located at the HV/MV substation can again be closed, restoring the service to part of the loads.

Using pre-fault information about load levels, the primary substation controller is also able to identify alternative paths, using other feeders of the same substation, and reconfigure the network in order to restore the service to loads that were left without supply after the fault isolation process.

Where service restoration can not be completed using the original substation, a centrally coordinated action, at the central SCADA/DMS level, will be needed to complete restoration by involving other substations.

8. Voltage and Reactive Power control

Given the characteristics of the LV networks (in particular a low X/R index), traditional control strategies using only reactive power control may not be sufficient to perform efficient voltage control since active / reactive power decoupling is not valid [4]. Therefore, in scenarios with high microgeneration penetration, generation shedding can also be employed.

The control algorithms to be adopted for the MV network should use all traditional control approaches for voltage and reactive power control namely managing On-Load Tap Changing transformers, reactive power provided by DG sources and capacitor banks together with

active power control at the MicroGrid/Virtual Power Plant level in extreme scenarios (using microgeneration shedding mechanisms) [6].

9. Negotiations

When well designed, the electrical distribution network is stable within statutory limits, and one of the main tasks of the DMS is to maintain it within the designed operating limits, maintaining that stability. The addition of distributed generation and managed load under distributed control must not spoil this situation.

In normal operating mode, at the central DMS a dynamic model should be optimizing the use of distributed generation to minimize the costs of distribution and reduce the generation required from centralised sources. Whenever the situation is less than ideal, for example the stability of the network is reaching undesirable limits, then the centre will look for help to the lower level nodes, to reduce/shift load and to reduce/increase generation to achieve energy balance and system stability [7].

However, it is not supposed that the processing will remain completely centralised, the centre is relying on at least two lower levels of management, at the primary substation and at the DTC. These levels will act as partners with there own specific models and capabilities. The DTC in particular can be expected to have a more detailed view of the LV side, whereas the dynamic model at the centre can be expected to terminate at the MV/LV transformers with their DTC's. The MV substation model will run from the HV or MV infeeds through to the distribution transformers, again it seems unlikely then this model will go beyond into the LV network.

This means that the DTC models will offer 'aggregate' views of their capabilities to the upper node models. These dynamic models should include both short term and long term factors, for example the short term and long term prices for buying any LV energy. The many LV clients behind a DTC may be making demands not only for immediate power, but also planning short term needs. The obvious challenge introduced here is to develop a dynamic *negotiating* structure, the upper level can dictate operating envelopes to the lower levels, and lower levels can indicate to upper levels their capacity to generate energy and their expected load demands. As in any negotiation, one side can not be expected to do *exactly* what the other wants, relieving the upper level of the decision as to *exactly* what the lower level should do.

The development of the negotiating parameters will come from the research being done into load-frequency control as a service between economic dispatch and system interconnection, including the environmental cost into the optimisation goals [8].

As with all negotiations, the requests made by the upper node levels may not be well fulfilled or able to be satisfied by the lower levels, at such times an adequate alarm and maybe automatic disconnecting of autonomous processing will be necessary. The failure conditions in which this may occur include failures in communications and failures in energy delivery, that is a substation or feeder may find itself 'islanded' but in communication with the centre or with communications to the centre cut-off but still connected to the main energy distribution. Though such occasions may be rare, it is in these situations that a good robust algorithm will really pay for the investment made.

10. Static Data Models

The large number of DTC's expected implies that single data entry for the additional equipment is not only desirable, it is essential. There is a certain tradition of trying to load this data first into a central Geographic Information System (GIS) or DMS database, normally however excluding the SCADA model from this information. With the advent of models for distributed control we can see a situation where the DTC will use a complete local model of the equipment covering electrical characteristics, circuit naming and SCADA model. The in-factory installation of an equipment is unlikely to cover all of this, but the on-site installation should result in a complete working model. The interchange of models as standard XML documents will permit flexibility here, will allow the central systems to acquire this model and load it into the central models specific to each system and will allow model updates to be downloaded from the central systems. These models, including the necessary contractual aspects, will be required and used at every level.

11. Other Challenges

With the implementation of market structures, new market players will emerge that require significant communication infrastructure improvements for data exchanges, as well as technical support services, in order to ensure system security, controllability and optimize network operation.

A large scale SmartGrid initiative will have an impact on many utility systems and processes spanning over customer services, system operations, planning, engineering and field operations, and even power supply functional unit of a utility business.

In order to achieve overall optimization, a full integration of central systems such as SCADA/DMS, Energy Management Systems (EMS), Distribution Automation, Outage Management System (OMS), GIS, MDM, Asset Management System (AMS), Customer Information System (CIS) should be maintained.

Implementation of a SmartGrid will require integration of processes and information across a multitude of systems and applications within utility system operations, planning and engineering and customer services. The technical integration activities will include integration of data and messages associated with real-time events, alarms and other notifications that require immediate attention, and integration of data associated with assets and networks, their configuration, condition and other operational and business data that can be accesses across the company.

The best mix for DG / Load over the next 'hour' or day forecasts for all the elements, from pricing through to weather, will need to be brought into system. Future energy market activity will have many more active participants than today's market. Not only DG and responsive loads will react to price signals sent by the central systems but they will also participate in the spot price market. Their role in energy balance will be very important and, therefore, rewards and compensation for these services needs to be defined [9].

However, for the DNO to be able to know what to account with in terms of generation, accurate forecasts will be necessary such as weather forecast, load forecast, price forecast and generation forecast.

Another challenge to tackle in the near future will be the large scale deployment of electric plugged in vehicles. At the same these new advanced control infrastructures will allow the

management of the charging of the batteries of the electric vehicles and the development of a more ambitious concept - the Vehicle to Grid, where the electric vehicles batteries may help in delivering ancillary services to system.

12. Final Notes

Future distribution networks require new planning for novel, decentralized network architectures able to incorporate all these new grid elements, including the need for new design and planning tools that rely on heuristics, probabilistic approaches, multi-scenario analyses, a more loosely defined normal switching state, amongst other features.

Complementarily, it is necessary to develop new active network technologies that enable a massive deployment and control of industrial and residential generation in combination with demand side participation. Tools here to link to the energy market as well manage and optimise the grid operation while maintaining network stability.

Systems interoperability, information management and data integration are among the key requirements for achieving the benefits of active networks. Automation and intelligent operations will require timely and accurate data, and the need for operational efficiencies demand coordination, orchestration and synchronisation of information used by various elements of the utility operation.

The SmartGrid strategy calls for enterprise-level integration of these islands of information to improve information flow and work throughout the organisation. Only in this way can the DNO predict and control the SmartGrid.

None of this changes the basic requirement for a distribution system, to give to the clients the energy they want, at the times they want it, at the lowest cost, maintaining system conditions such that the unpredictable accidents will not unnecessarily disrupt the energy supply. The change is in the way it will be done and the emphasis on reducing the environmental impacts, since large scale of renewable power sources integration is a main goal to achieve.

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