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Emergency control of catastrophic disturbances in a power system

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Department of Electrical, Computer and Telecommunication Engineering

Emergency Control of Catastrophic Disturbances in a Power System

Sk Razibul Islam

"This thesis is presented as part of the requirements for the award of the Degree of Master of Philosophy of the University of Wollongong"

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ABSTRACT

Most of the transmission networks in modern interconnected power systems are more heavily loaded than ever before to meet the growing demand. The continuing interconnection of bulk power systems due to economic and environmental pressures has led to an increasingly complex system that must operate closer to the stability limit. This is particularly worst during the peak demand of the year. Under such a stressed system, when catastrophic events due to unplanned multiple contingencies occur; the transmission grid cannot maintain its integrity to maintain the resilience of the network. As a result, power systems become vulnerable to various instability problems such as voltage instability, transient instability, dynamic instability etc. It is important to detect the causes of system breakdown and to actuate fast countermeasures to mitigate the impact of contingencies so that the power system, even under such catastrophic disturbance, can operate with sufficient security and reliability.

One type of system instabilities, which is usually experienced when the system is heavily loaded, is the voltage instability. This event is characterized by a slow variation in the voltage magnitudes followed by a rapid sharp disruptive change resulting in voltage collapse. Analysis of several voltage collapse incidents in the past few decades has revealed that the first impact of any critical disturbance occurs in a limited region of the transmission grid, gradually encompassing the entire grid if timely countermeasures are not taken. In this project, a novel approach based on the multi-agent technique is proposed to counteract the voltage instability and the resulting voltage collapse issues that arise from an unplanned multiple contingency. At first, the transmission network is divided into some local areas to take the benefit of the initial limited geographical effect of voltage instability. Several criteria such as bus effectiveness factor based on the reactive power injection capability and the electrical distance among the buses are considered to find the local zones. To determine the severity of the disturbance that can lead to voltage instability, performance indices have been formulated based on the local variations of load voltage magnitudes and generator reactive power outputs. Each area is assigned a team of intelligent agents to detect the occurrence of the instability and to initiate the appropriate and timely countermeasures to stabilize the system. A
decentralized architecture of the multi-agent system is used so that the agents can take quick decision without any intervention from the central controller. For this purpose, various negotiation protocols among the agents have been researched to determine the proposed solution using Java Agent Development Framework (JADE). To determine the optimal amount of countermeasures, a sensitivity approach based on the linearized power flow equations has been proposed. Simulation results based on the IEEE benchmark systems have been used to validate the proposed methodology.

A typical scenario of long term voltage instability ranges from tens of seconds to several minutes. Studies of voltage instability incidents have shown that the dynamics of on-load tap changer, operation of over-excitation limiters in the generators and the load restoration contribute to the final voltage collapse. It is, therefore, necessary to consider the future evolution of the system states. An approach based on multi step receding horizon control using multi agent system is proposed to counteract the long term voltage instability. In this approach, an online optimization problem is solved at each sampling instance to bring the load voltages and generator reactive power in the admissible limits within a specific time period. This method can successfully deal with the dynamic evolution of the system after any disturbance. On top of that, a distributed architecture of multi agent system is used where each agent preserves its local information and communicates only with its immediate neighbours to find an optimal solution. The optimality condition decomposition (OCD) is used to decompose the overall problem into several sub-problems, each to be solved by an intelligent agent. The method exhibits good convergence over traditional Lagrangian relaxation approach. The CIGRE Nordic32 test system is used to validate the proposed approach.
ACKNOWLEDGEMENTS

This work was supported by the Australian Research Council (ARC) linkage grant under Grant LP0991428 and TransGrid, a Transmission Utility in New South Wales. We gratefully acknowledge the financial support received from Transgrid for the successful completion of the work in this thesis.
DECLARATION ON PUBLICATIONS

This thesis includes chapters that have been written as the following journal articles.


As the principal supervisor I, Prof. Danny Sutanto, declare that the candidate, Sk. Razibul Islam, has contributed greater part of the work in each article listed above. In each of the above listed manuscripts, the contribution of the candidate is in the development of the main idea/concept, which has been extended, refined and tuned for improvement with advice from myself, and his co-supervisor A/Prof. Kashem Muttaqi, contributing as co-author. The candidate has prepared the first draft of each of the manuscripts and revised those according to the suggestions provided by the supervisors. The candidate has been responsible for submitting each of the manuscripts for publication to the relevant journals, and he has been in charge of responding to the reviewers’ comments, with assistance from his co-authors.

Prof. Danny Sutanto  
Principal Supervisor
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CHAPTER 1
INTRODUCTION

1.1 Motivation

Large scale interconnection in modern electric power grid has increased the complexity of the system in terms operation and control. Moreover, the deregulation of electric power systems with its associated competitive electricity market has created additional difficulties for power system security. Economical, environmental and political pressure on the power utilities have caused many power systems to operate close to the stability limit during the peak period. As a result, the danger posed by extreme contingencies and the risk of wide-spread blackout have now intensified. Various incidents of system collapse in the form of voltage instability have occurred in the last few decades [1], [2] which have highlighted the vulnerability of transmission grid against unpredictable disturbances. The July 2, 1996 blackout [2] incident was a result of multiple contingencies that occurred when a flashover tripped a 345 kV line between Wyoming and Idaho, followed by another parallel line outage due to protection malfunction. This led to system voltage instability causing 11 power stations to shutdown and 2 million consumers were lost.

Planning criteria only assess credible contingencies, however studies on recent system voltage collapses, have found that extensive blackouts are usually caused by multiple contingencies more severe than that considered by planning criteria [3]. Since multiple contingencies can occur anywhere in the system, the disturbance identification is only possible after the event. After its identification, timely and appropriate countermeasures must be triggered if the grid integrity is to be sustained. This objective cannot be achieved with a preventive control since preventive actions are taken in a normal operating state before the occurrence of any disturbance. The cost involved in maintaining an acceptable post-disturbance equilibrium in case of all potential disturbances is also another discouraging factor for preventive control. Therefore, the system is usually left unprotected for thousands of low-probability incidents. For these types of incidents, emergency control actions are more preferable than preventive control [4]. Emergency control aims at implementing corrective actions after a disturbance has actually occurred in the system. The control system has to actuate countermeasures based on the post disturbance system evolution by
tracking identifying parameters associated with such disturbance. Because of the relatively short time frame for countermeasures to be activated before a system collapse occurs after the disturbance, one has to rely on automatic control to successfully implement effective control actions.

According to the stability definition of IEEE/CIGRE task force [5], voltage stability refers to the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition. It is also known as ‘load stability’ as it is related to the inability of combined generation-transmission system to provide the power requested by the loads [6]. Voltage instability may occur in the event of a large disturbance, which usually consists of loss of transmission lines, generators or loads or may be caused by a small perturbation that produces increasing instability around an operating point. In the event of voltage instability due to a large disturbance, the maximum power deliverable to the loads is reduced because of the increased reactance (thus reduced load voltage) in the transmission lines and the operation of field-current limitations on some generators. On the other hand, the on load tap changers (OLTCs) attempt to restore the load voltages to their pre-disturbance values causing further increase in the active and reactive powers of the loads. These two opposite effects gradually cause the power system to deviate from the equilibrium and instability occurs when a post-disturbance acceptable equilibrium is lost. Voltage instability may evolve in the time frame of tens of seconds to several minutes depending on the severity of the disturbance.

Typically, large disturbance voltage instability exhibits two phases; an initial stable calm phase followed by a disruptive unstable phase [7]. When a critical disturbance strikes the transmission grid, the voltage profile may initially look stable just after the disturbance when the electromechanical oscillations have died out. This initial calm and stable phase is mainly caused by the load reduction due to reduced load voltages and the short term ability of the synchronous generators and condensers to increase their field currents to produce extra reactive powers beyond the normal sustainable capacity of the generators. However, the system voltages are usually controlled by OLTCs. The OLTC adjusts the tap ratio of the transformer to keep the secondary voltage within the dead band. Since the load power is dependent on the load voltage, the increase in load voltage due to adjustment in tap ratio of
OLTC restores the load to the pre-disturbance value (assuming that the OLTC does not hit the tap ratio limit). The synchronous generators and condensers need to produce more reactive powers because of the load restoration causing them to increase the field currents even further. When the short-term over-excitation capability of the most over-excited generator is exhausted, the over-excitation limiter (OEL) on this generator operates causing the generator reactive power to be limited to its rated capacity and the generator terminal voltage to be unregulated since the reactive power is now fixed. The difference in the generated reactive power must now be supplied by the nearby generating units causing them to become more over-excited. All the generators running above the admissible reactive power limits are sequentially restricted by the OELs forcing the generators to reduce the terminal voltages. This chain reaction of generators’ OEL activations creates the disruptive phase of sharp voltage decline which results in a voltage collapse. Therefore, the voltage level alone is not a good indicator of impending voltage instability. To identify the onset of voltage instability, both the load voltage magnitudes and the reactive power outputs of the generators has to be considered.

From reported incidents of voltage collapse, the initial impact of the disturbance has been restricted to a limited region in the system. The affected area caused by the disturbance gradually increases and finally encompasses the entire grid if timely control actions are not applied in the initial affected area [8]. The grid integrity can be sustained if proper countermeasures are applied only to the area affected by the disturbance. Therefore, intuitively the power system can be divided into several areas or zones, each with its own intelligence to quickly locate the area or zone which is most affected by the disturbance and to initiate timely and appropriate countermeasures to that area only in order to prevent the system breakdown. The characteristic variations of the disturbance identifying parameters such as the load voltages and generator reactive powers can be monitored to identify the area undergoing instability. As the initial slowly varying stable phase offers sufficient time for interposing control actions with the available fast communication technology, each area can be equipped with intelligent controllers (or agents) to take autonomous decision. Thus, the entire system can work co-operatively in a multi-agent environment to necessitate quick identification and control of voltage instability.
1.2 Research Objectives

The prime objective of the work presented in this thesis is to develop strategies for dealing with voltage instability in a power system. The aims of the thesis are achieved through:

- The development of a decentralized approach for voltage control by dividing the power network into some local areas based on electrical distances among the generators and the loads.
- The formulation of a novel performance index based on the characteristic variations of load voltages and generator reactive powers to identify the severity of a disturbance and to locate the disturbance affected zone.
- The development of a strategy to co-ordinate different countermeasures in order to prevent the disruption resulting from any disturbance.
- The development of multi-agent system to effectively control the system in the post disturbance period through negotiation and/or taking autonomous decision.
- The development of multi-area quasi-steady state model to achieve globally optimal solution to facilitate multi time step predictive control for real time voltage stabilization.

1.3 Solution Approaches

An algorithm has been developed based on multi-agent system to segregate the system into several areas. The electrical distances among the loads and the generators are selected as the criteria for designing each area. Since any disturbance, such as transmission line or generator outage will create topological changes in the system, an approach has been developed to adaptively determine the boundary of each zone.

Novel performance index has been formulated based on the deviation of the load voltages and generator reactive powers to estimate the severity of any disturbance. The integral of the performance index has been used to trigger fast countermeasures to the adversely affected zone(s).

A co-operative negotiation scheme among the agents has been designed to determine the most appropriate actions in order to maintain a steady acceptable voltage profile in the system after any disturbance. The amounts of countermeasures are determined by network steady state voltage and reactive power sensitivities to the variations of generator voltages and load power consumptions.
A multi-time step optimization problem in a receding horizon time scale has been formulated to correct the unstable and non-viable network voltages in a multi-area architecture. The system has been modelled with linearized quasi steady state power flow equations to capture the long term evolution of transmission voltages and load powers. A relaxation scheme based on first order optimality condition decomposition has been developed to determine the globally optimal solution without any interaction from a central co-ordinator. The solution has been achieved through only neighbour to neighbour communication and by exchanging only the boundary variables, thus preserving the internal information within each area.

1.4 Outline of the Thesis

The contents of the remaining chapters are briefly described as follows:

Chapter 2 proposes a decentralized architecture of intelligent agents to identify the affected region and to activate timely countermeasures to achieve a fast and reliable response. The network is divided into several areas to localize the voltage instability problem and to facilitate quick decision making in the system by the authorized local agents. Each area is equipped with agents associated with the generator and load buses capable of monitoring the local parameters of voltages, active and reactive powers. A manager agent is assigned in each area to co-ordinate the actions of the local agents and to negotiate with the neighbouring area manager agents. The simulation results obtained using the proposed method is presented and found to be very effective in countering multiple contingencies that can lead to voltage instability, particularly in terms of its simplicity and reliability.

The content of Chapter 2 is prepared to be submitted for publication in IEEE Transactions on Power Systems (2014).

Chapter 3 presents the co-ordination among the different emergency voltage control devices in a decentralized environment. The severity of any contingency in an area or zone is estimated by monitoring the violation of load voltages and generator reactive powers from the admissible limits within that area. A performance index for each area has been formulated based on the deviation of load voltages and generator reactive powers. The value of the performance index indicates the vulnerability of an area to voltage instability. Each area initiates the countermeasures when the integral of the performance index exceeds a pre-defined threshold value. Thus the timing of the countermeasures is adaptively determined where the most
affected area makes the fastest response. The simulation results from the proposed method show a good performance particularly in its ability to successfully stabilize load voltages under various voltage instability scenarios including multiple contingencies.

The content of Chapter 3 has been accepted for publication in IEEE Transactions on Power Systems (2014).

Chapter 4 proposes a multi-agent based voltage and reactive power control in the case of a multiple contingency. Incorporating the agent based autonomous feature into the intelligence of the Remote Terminal Units (RTUs), the present power system control structure can be used to help in preventing system voltage collapse during catastrophic disturbances. An adaptive determination of the local zones undergoing voltage collapse has been developed based on the electrical distances among the generators and loads. Once assigned, the elements of the Jacobian matrix can be used to determine the optimum actions that need to be carried out at each power system element (such as increasing the voltages of generators and load shedding) within the assigned local zone. The contract-net-protocol (CNP) is used for agent interactions. Simulation result validates the effectiveness of the proposed approach in case of system emergency involving multiple contingencies.

The content of Chapter 4 has been accepted for publication in IEEE Transactions on Industry Applications (2014)

Chapter 5 proposes a multi-agent receding horizon approach for emergency control of long-term voltage instability in a multi-area power system. The proposed approach is based on a distributed control of intelligent agents in a multi-agent environment where each agent preserves its local information and communicates with its neighbours to find an optimal solution. Optimality condition decomposition (OCD) is used to decompose the overall problem into several sub-problems, each to be solved by an individual agent. The agents can find an optimal solution without the interaction of any central controller and by communicating with only its immediate neighbours through neighbour-to-neighbour communication. The proposed approach has been compared with the traditional Lagrangian decomposition method and is found to be better in terms of fast convergence and real-time application.

The content of Chapter 5 has been published in IET Generation, Transmission and Distribution vol.8, no.9, pp.1604,1615, Sept. 2014
CHAPTER 2

A DISTRIBUTED MULTI-AGENT BASED EMERGENCY CONTROL APPROACH FOLLOWING CATASTROPHIC DISTURBANCES IN INTERCONNECTED POWER SYSTEM

Abstract
This chapter presents a decentralized emergency control approach for preventing long-term voltage instability by controlling the reactive power and voltage of the system. The proposed control algorithm is based on a decentralized architecture of intelligent agents to identify the affected region and to activate timely countermeasures to achieve a fast and accurate response. By dividing the network into several areas, the voltage instability problem can be localized and countermeasures can be directed to the most affected area by the authorized local agent. This facilitates quick decision making within the system. To achieve effective voltage and reactive power support, a sensitivity based zone formation is proposed. The Nordic32 74-bus test system has been used for testing the proposed multi-agent emergency control (MAEC). The results from the case studies demonstrate the effectiveness of the proposed MAEC approach.

Keywords: Multi-Agent System, Voltage Collapse, Voltage Stability, Emergency Control, Inter-connected Power System.

2.1 Introduction
Most of the transmission networks in modern interconnected power systems are more heavily loaded than ever before to meet the growing demand. The continuing interconnection of bulk power systems due to economic and environmental pressures has led to an increasingly complex system that must operate closer to the stability limit. This is particularly worst during the peak demand of the year. When catastrophic events due to unplanned multiple contingencies occur in such a stressed system, the transmission grid cannot maintain its integrity to maintain the resilience of the network [1] that can lead to voltage instability.

This event is characterized by a slow variation of the voltage magnitudes followed a rapid sharp disruptive change resulting in voltage collapse [2]. According to the
stability definition of IEEE/CIGRE task force [3], voltage stability refers to the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition. Voltage collapse refers to the process by which the sequence of events accompanying voltage instability leads to a blackout or abnormally low voltages in a significant part of the power system.

A disturbance at first impinges on a limited area in the network, spreading slowly to a larger area [4]. Voltage instability is therefore, first and foremost, a local issue. Voltage instability and voltage collapse can be avoided, if appropriate countermeasures can be applied to the most affected area in a timely manner. In this way, the difficult task of performing system wide sequential actions in a very limited time, which include communications, analysis, prediction and decision making, can be minimized. This suggests the need for devising a decentralized control system, which can be applied in real time to counteract voltage instability.

Current trends in power system operation and control are towards an automated self-healing intelligent system with the advent of smart grid technologies. The multi-agent system (MAS) technology has emerged as an advanced intelligent control system which can model complex control system with the help of simple interaction among the agents. In the last few years, multi-agent system (MAS) technology has been employed in many areas of power system including fault diagnosis, power system restoration, market simulation, network control and automation [5]. Several research works based on MAS to eliminate voltage instability have been proposed in the literature. A multi-agent collaboration protocol of secondary voltage controllers such as SVC and STATCOM to eliminate voltage violations in the pilot nodes has been proposed in [6]. Voltage stabilization based on multi-agent technique considering load modelling effect has been proposed in [7]. A request-interaction protocol is used among the agents to achieve the admissible voltage magnitudes following any disturbance. A multi-agent system for emergency control against voltage collapse is proposed in [8]. The agents have been used to coordinate different control device to prevent voltage collapse during the post emergency period. A multi-agent approach for power system restoration after a disturbance in the system has been proposed in [9]. All these approaches are based on the centralized architecture of the agents. To capture the localized nature of voltage instability, the
agents can be designed to have a decentralized architecture to act only on a local area of the system, thereby facilitating a quick decision making capability on controlling strategic system parameters for emergency control of the post-disturbance period. Moreover, distributed control enhances the reliability of the control system, where failure in one component can be compensated for, by control actions by other controllers. As a result, distributed control of voltage instability has been reported in recent years [10] [11].

In this chapter, a multi-agent emergency control (MAEC) of voltage instability using a decentralized coordination strategy of intelligent agents is proposed. The distributed intelligence has been used to monitor the voltage and reactive power output changes in the local area and to actuate timely countermeasures during system emergency. The control variables selected in this paper are the generator terminal voltage and load shedding. At first, the voltages in some selected generators are increased to provide more reactive power to the system, followed by a predetermined time when the on-load tap changing transformers are allowed to vary according to their normal operating time in accordance with the utility operating procedure. If this is not sufficient to restore the load voltages within the allowable limits, load shedding is performed after a pre-selected deadline to avoid the operation of the over-excitation protection to limit the generator excitation to its rated value that can lead to voltage collapse.

2.2 Problem Formulation

The aim of emergency secondary voltage control (ESVC) is to maintain voltage stability by timely utilizing the available generators’ reactive power reserves and by applying load shedding in some selected buses as a last resort [12]. This control is activated when there is a violation in the load voltages and/or generator reactive powers from the operational limits. For a centralized wide-area monitoring and control system (WAMCS), the procedure consists of collecting measurements from remote locations and executing the countermeasures at regular time intervals (say every 10 seconds). At each step, the following online linear optimization problem has to be solved.

$$\min z = w_G \Delta V_G + w_p \Delta L_{sh,p} + w_q \Delta L_{sh,q}$$  \hspace{1cm} (2.1)

subject to

$$V_{L,\min} \leq V_L + S_{LG} \Delta V_G + S_{LF} \Delta L_{sh,p} + S_{LQ} \Delta L_{sh,q} \leq V_{L,\max}$$  \hspace{1cm} (2.2)
\[ Q_{G,\text{min}} \leq Q_G + S_{QG} \Delta V_G + S_{QF} \Delta L_{\text{sh,p}} + S_{QQ} \Delta L_{\text{sh,q}} \leq Q_{G,\text{max}} \]  
\[ V_{G,\text{min}} \leq V_G \leq V_{G,\text{max}} \]  
\[ 0 \leq L_{\text{sh,p}} \leq L_{\text{sh,p}}^{\text{max}} \]  
\[ 0 \leq L_{\text{sh,q}} \leq L_{\text{sh,q}}^{\text{max}} \]

In these relations, \( \Delta V_G \), \( \Delta L_{\text{sh,p}} \) and \( \Delta L_{\text{sh,q}} \) are the vectors of changes in generator voltages, active and reactive power load shedding, respectively. The vectors of weighting factors \( w_G, w_P \) and \( w_Q \) are used to provide relative importance to each of the control actions. Normally, higher values are used for \( w_P \) and \( w_Q \) to discourage any load curtailments and to give more preference to generator voltage. \( V_L \) and \( Q_G \) are the vectors of load voltages and generator reactive powers, respectively. \( V_{L,\text{min}} \) (respectively \( Q_{G,\text{min}} \)) and \( V_{L,\text{max}} \) (respectively \( Q_{G,\text{max}} \)) are the corresponding admissible limits. The sensitivity matrices \( S_{LG}, S_{LP} \) and \( S_{LQ} \) denote the sensitivities of load voltages with respect to generators voltages, active and reactive power load shedding, respectively. Similarly, the sensitivity matrices \( S_{QG}, S_{QP} \) and \( S_{QQ} \) denote the sensitivities of generator reactive powers with respect to generators voltages, active and reactive power load shedding, respectively. \( V_{G,\text{min}} \) and \( V_{G,\text{max}} \) are the minimum and maximum limits of generator voltages. \( L_{\text{sh,p}}^{\text{max}} \) and \( L_{\text{sh,q}}^{\text{max}} \) are the maximum limits of active and reactive power load shedding, respectively.

In the context of real-time control, the above ESVC suffers from following difficulties:

- It does not take into account the effect of load tap changers (LTC) controlling the distribution voltages. Since the load power restorations produced by LTCs also affect the transmission voltages, it becomes difficult to decide the optimal control actions needed to maintain the transmission voltages within the operational limits.
- The on-line computation of the sensitivities is highly dependent on the exact model of the system. Any model inaccuracy would result into unexpected load voltages and generator reactive powers.
- In case of severe load voltage/generator reactive power violations, the amount of countermeasures would be large which may produce unacceptable transient and oscillatory behaviour in the response.

To deal with these inconsistencies, a decentralized model-free emergency voltage control scheme using multi-agent technique is proposed in this study.
2.3 Zone Identification

The initial impact of any voltage related disturbance is found to be in the area where the disturbance occurs. At first, the voltage instability occurs mainly in this area. If immediate countermeasures are not taken, the other areas gradually become voltage unstable. Therefore, the power system can be divided into some local areas. The design of each area must address a number of issues discussed below:

- As the first countermeasure is the generator voltage increase, each area should have sufficient number of generators which are electrically close to each other so that at time of emergency, they can help each other by providing reactive power to the area.

- The interaction among the areas can be allowed but not to be relied upon so that in case of communication failure the area undergoing instability can act alone to mitigate the instability.

- The area should have sufficient number of loads so that load shedding can improve the voltages. On top of that, these loads should be electrically close to the area generators.

Considering the above mentioned criteria, a strategy has been developed based on the concept of sensitivity to divide the entire system into several local zones or areas. Sensitivities of generator reactive powers and load voltages with respect to generator voltages are used in this paper for this purpose. The sensitivities can be obtained from a set of network equilibrium equations that describes the power system at steady state condition. The power system, at steady state equilibrium, can be described as:

\[
g(x, u) = 0
\]

where \(x\) is the vector of state variables, \(u\) is the vector of control variables and \(g\) consists of long-term equilibrium equations. Let \(\eta\) be a quantity of interest which is a function of both \(x\) and \(u\). Then the sensitivity of \(\eta\) with respect to \(u\) can be expressed as [12]:

\[
S_{\eta u} = \nabla_u \eta - g_u^T \left( g_x^T \right)^{-1} \nabla_x \eta
\]

where \(\nabla_u \eta\) and \(\nabla_x \eta\) are the gradient of \(\eta\) with respect to the control variable vector \(u\) and state variable vector \(x\), respectively, \(g_u(g_x)\) is the Jacobian of \(g\) with respect to
From (2), the sensitivity matrix of generator reactive powers with respect to generator voltages, $S_{QG}$ and the sensitivity matrix of load voltages with respect to generator voltages $S_{LG}$ can be obtained.

Once the sensitivities are derived, the network can be divided into some zones; each having a number of generators and loads. In this paper, first the generators are selected to form the zones in such a way that the reactive power sensitivities with respect to the generator voltages are maximized in each zone. This would employ maximum reactive power supports among the area generators when any emergency situation occurs. To this purpose, the sensitivities from $S_{QG}$ matrix are used to express this inter-relationship among the generators.

Once the generators that have to be included in each zone have been found, the load voltage sensitivities from $S_{LG}$ are utilized to form the zones with the load buses. The proposed zone formation strategy is described step-by-step as follows and the flow chart is shown in Fig. 1.

**Step 1)** Usually, the off-diagonal elements of $S_{QG}$ matrix are not same. To have equal values of sensitivities between two generators, the $S_{QG}$ matrix is modified as:

$$S'_{QG}(i,j) = \frac{(S_{QG}(i,j) + S_{QG}(j,i))}{2}$$

for $i,j = 1, 2, \ldots, N_G$

where $S'_{QG}$ is the modified $S_{QG}$ matrix and $N_G$ is the number of generators in the system.

**Step 2)** Assign each generator to its own cluster so that we have $N_G$ clusters, each containing only one generator. We call it ‘initial clusters’ of the system.

**Step 3)** Find the pair of most similar clusters ‘$ms_1$’ and ‘$ms_2$’ as:

$$ms_1, ms_2 = \arg \max_{m,n} \frac{1}{n_{G,mm} \cdot n_{G,nn}} \sum_{i \in IG_m} \sum_{j \in IG_n} S'_{QG}(i,j)$$

for $m,n = 1, 2, \ldots, \text{no. of clusters}$

where $n_{G,mm}$ is the number of generators in cluster ‘$m$’ and ‘$n$’, $IG_m$ and $IG_n$ are the indexes of generators in cluster ‘$m$’ and ‘$n$’, respectively. From (2.10), the pair of clusters having the highest sensitivity can be found.

**Step 4)** If the number of generators in clusters ‘$ms_1$’ and ‘$ms_2$’ is less than the maximum allowable generators in a zone, $n_{GC,max}$, these clusters are merged to one single cluster. Otherwise, the next pair of most similar clusters from step 3 is selected until the number of generators in these clusters is less or equal $n_{GC,max}$.
Fig. 2.1. Zone formation algorithm

**Step 5** If all the clusters are having at least the minimum number of generators, $n_{GC,min}$, the remaining clusters give the zones of the generators. Otherwise, steps 3 and 4 are repeated until all the clusters have at least $n_{GC,min}$ generators.

**Step 6** In this step, the loads are systematically grouped into the zones found in step 5. To this purpose, the load voltage sensitivity with respect to generator voltage from $S_{LG}$ is used to find the average sensitivity of each load with respect to all the zones as follows:

$$S_{avg}(i,k) = \frac{1}{n_{G,k}} \sum_{j=I_G} S_{LG}(i,j)$$

(2.11)

for $i=1,2,...,N_L$

$k=1,2,...,N_{zone}$
Here, $N_L$ is the number of loads in the system, $N_{zone}$ is the number of zones found in step 5, $S_{avg}$ is a $N_L \times N_{zone}$ matrix which provide the average sensitivity of each load with the zones and $n_{G,k}$ is the number of generators in zone $k$.

**Step 7** Each load, $i$ is merged into the zone, $ik$ where the maximum average sensitivity occurs, which is found as:

$$ik = \arg \max_k S_{avg}(i,k) \quad \text{for } k=1,2,\ldots,N_{zone}$$  

(2.12)

### 2.4 Multi-agent System Architecture

A decentralized architecture of the multi-agent system is proposed for the emergency voltage and reactive power control. A team of intelligent agents will be assigned in each identified local area. The agents will capture local information on the vulnerability parameters and form a negotiation scheme to achieve the system goal. The architecture of the proposed multi-agent system (MAS) is shown in Fig. 2.2.

![Multi-agent system architecture](image)

Fig. 2.2. Multi-agent system architecture

A two level hierarchical model using master/slave combination of the agents is employed here. The proposed MAS contains two layers i.e. Proactive Layer and Reactive Layer and three types of agents i.e. Generator Agent (GA), Load Agent (LA) and Manager Agent (MA). Generator agents and load agents are in the bottom level of the hierarchy and manager agents are in the upper level. The agent networks can communicate directly with the neighbouring agents.

The Proactive Layer is the lowest layer and is in charge of monitoring the changes in voltages and reactive power outputs. When a violation in the voltage and the generator reactive power is identified, the Reactive Layer is activated and the
agents will work co-operatively in this layer to determine the best strategy of the timely countermeasures.

During the voltage and reactive power control process, each agent can be in one of three states: IDLE, WAITING and ACTION. An agent remains in an IDLE state if it is not assigned any task or any violation in voltage/reactive power has not occurred. An agent in the WAITING state has been committed to perform a task but it has to wait for a specific time period to perform any action. An agent in the ACTION state actually performs the action.

The manager agent (MA) assigned to each area is the master controller and in charge of gathering information from the agents and assigning tasks to the agents of the group in order to achieve the goal. The agents communicate with each other through forwarding messages. In this chapter, the request-interaction-protocol of agent interaction [13] is used to coordinate the actions of the agents. In this protocol, an agent sends a REQUEST message to other agents to perform some actions. The participant processes the request and makes whether to accept the request or not based on its operating condition. If it agrees, then it sends an AGREE message, otherwise, it sends a REFUSE message. The major characteristics of each agent are described below.

2.4.1 Manager Agent (MA)

Each area has a MA that works as the monitoring agent in its area. The MA is not physically connected to a bus and continuously monitors the load voltages and reactive powers of the generators through RTUs. If any violation occurs, it sends REQUEST message to the area GAs and LAs to start their actions. It also sends REQUEST messages to the neighbouring MAs to participate in the control process. Once it finds all the load voltages and generator reactive powers within the operating limits, it stops the control process by sending INFORM messages to the area LAs and GAs and to the neighbouring MAs.

MA that receives REQUEST message from neighbouring MA interacts similarly with the agents in its area. But in this case, the neighbouring MA only communicates with area GAs to take actions since no load voltage violation occurs in its area. The neighbouring MA stops the control action once it receives INFORM message from the initiator MA or the load voltages tend to rise above the maximum limit because
of the GA actions. Note that a MA can work simultaneously as initiator and responder. Fig. 2.3 shows the flow diagram of the above mentioned control interaction process of MA.

![Control flow diagram of MA](image)

**Fig. 2.3. Control flow diagram of MA**

### 2.4.2 Generator Agent (GA)

A GA represents a physical generator in the network. A GA has the ability to monitor the terminal voltage and reactive power output of the generator and to adjust the terminal voltage by changing the AVR reference value of the generator. At normal operating condition, there is no REQUEST message from the MA and the GA remains in IDLE state. When a REQUEST message comes from the MA, the GA checks its terminal voltage and reactive power. If the terminal voltage $V_g$ is less than the maximum voltage $V_{g,\text{max}}$ and the reactive power $Q_g$ is less than pre-specified value of the maximum reactive power $Q_{\text{max}}$, it moves into the ACTION state. The
maximum reactive power $Q_{max}$ is calculated based on the rotor capability limit given by [3]:

$$Q_{g,max} = \frac{V_g^* F_{E5s}}{X_d} \cos(\delta - \theta) - V_g^2 \left( \frac{\sin^2(\delta - \theta)}{X_q} + \frac{\cos^2(\delta - \theta)}{X_d} \right) \quad (2.13)$$

where $V_g$ is the terminal voltage of the generator, $F_{E5s}$ is the maximum excitation voltage, $X_d$ and $X_q$ are the direct and quadrature axis reactances, respectively, $\delta$ is the rotor angle and $\theta$ is the phase angle of terminal voltage ($V_g$) to a synchronously rotating reference frame.

In this study, the reactive power of the generator is expected to be less than 90 percent of the maximum limit before it can take an action, so that any increase in generator voltage does not cause the generator to exceed the reactive power limit. In the ACTION state, the voltage of the generator is increased by $\Delta V_g$. Then the GA moves to the WAITING state and waits for a certain time period of $\tau_{delay}$ before it can again increase the voltage. As the agents are taking actions concurrently, small values of $\Delta V_g$ and $\tau_{delay}$ are chosen, which would provide smooth transition and prevent the generators from exceeding their reactive power limits. However, the values should not be so small that the system cannot be stabilized in a timely manner. The GA again moves to ACTION state from WAITING state if the waiting time $\tau_{delay}$ has elapsed, $V_g$ is less than $V_{g,max} - \Delta V_g$ and $Q_g$ is less than 90 percent of $Q_{g,max}$. However, if $V_g$ is equal to $V_{g,max}$ and/or $Q_g$ is not less than 90 percent of $Q_{g,max}$, the GA cannot take any action and remains in the WAITING state. Once GA receives INFORM message from MA, it returns to IDLE state and stops performing any action. Fig. 2.4 shows the state flow diagram of GA.

![State flow diagram of GA](image.png)
2.4.3 Load Agent (LA)

An LA is installed at every load bus in the network where it has access to the interruptible loads. The LA observes the voltage $V_L$ at its local sub-station. As long as the voltage $V_L$ is above the minimum operating limit $V_{L,min}$ or there is no REQUEST message from the MA of the area, it does not take any action and remains in the IDLE state. When there is a REQUEST message from the MA or the load voltage falls below $V_{L,min}$, it moves into the WAITING state. Initially, it waits for a time period of $\tau_{i,delay}$ before it can take any action. This time period is required to allow the GAs to perform their action to correct the voltages. At $t = \tau_{i,delay}$, if $V_L$ remains below $V_{L,min}$ and load can be shed, the LA can move to ACTION state and shed load. Two more criteria have to be satisfied before the LA can move to ACTION state.

1) It is recommended that more load shedding takes place where pronounced voltage drop occurs. This can be done by either shedding large amount of load at once or shedding a fixed amount of load at a time but with quick succession. The former can lead to a sharp change in the voltage and oscillatory response as mentioned in section II. The latter has the advantage of smooth voltage recovery and reduced amount of load shedding. The time delay between successive load shedding can be adjusted based on the amount of voltage drop from the minimum limit. This can be evaluated using the integral of voltage deviation ($IVD$) of the load voltage magnitude which can be computed on-line as:

$$ IVD = \int_{t_w}^{t_v} (V_{L,min} - V_L(t)) dt $$(2.14)

Here, $V_L(t)$ is the magnitude of the voltage of the load, whose values are outside the operating limits, $V_{L,min}$ is the minimum operating voltage limit, $t_w$ is the time when $IVD$ is computed and $t_v$ is the time when the last load shedding took place or the time when voltage violation (value outside normal operating limits) started if no load shedding occurred before $t_w$.

The LA can only shed load when the $IVD$ becomes greater than a pre-specified threshold limit, $C$. In this way, the LA experiencing a larger voltage drop will shed loads more frequently than the one having smaller voltage drop. There will be cases where no load shedding will be required by the LAs having smaller voltage drop
since load shedding at other buses having larger drops will be sufficient to remove all the voltage violations.

2) Since load shedding is less preferable than generator voltage increases, because of the resulting customer service interruption, load shedding will only be carried out when it is anticipated that the voltage cannot be corrected by generator voltage increases or by other controllers (i.e. OLTC) present in the system. One way to comprehend the voltage correction on-line is to observe the difference of the voltage measurements \((DVM)\) at successive time intervals, \(T_c\) given by:

\[
DVM(t) = V(t) - V(t - T_c)
\]  

A positive value of \(DVM\) indicates that the voltage is improving and hence, no load shedding is applied. The time interval, \(T_c\) should be sufficiently large so that generator voltage and OLTC can operate in each interval which will ascertain if the voltage is improving or decreasing. However, it should be small enough not to cause too much delay in shedding loads.

Another problem is that voltage measurements are affected by measurement noises and system transients. Rapid fluctuations may be encountered when frequent operations of generator voltages take place. A filtering scheme is, therefore, implemented using the moving average of the voltage magnitude instead of its actual measurement collected at specific time instants. The moving average at time \(t\) is given by:

\[
\overline{V}(t) = \frac{1}{n_m} \sum_{k=0}^{n_m-1} V(t - k\Delta t)
\]

where \(\Delta t\) is the sampling period of measurement and \(n_m\) is the number of samples over which the moving average is computed. In this study, the averaging period is taken equal to \(T_c\) so that it gives the actual indication of \(DVM\). Thus the second criterion to trigger load shedding is the non-positive value of \(DVM\) given by:

\[
DVM(t) = \overline{V}(t) - \overline{V}(t - T_c) <= 0
\]  

Summarizing the above discussion, LA will only curtail load by opening the distribution circuit breaker at \(t = t_{i,delay}\), if

a) the load voltage is below \(V_{L,min}\),
b) \(IVD\) exceeds threshold \(C\),
c) \(DVM\) is not positive,
d) load can be shed.
At any instance, a fixed amount of load will be shed by opening distribution feeder and $\text{IVD}$ will be reset to zero. The next load shedding will occur when the above four conditions are again fulfilled. Thus, load shedding will continue as long as conditions (a), (b), (c) and (d) are simultaneously satisfied. Fig. 2.5 shows the state flow diagram of LA.

![State flow diagram of LA](image)

**Fig. 2.5. State flow diagram of LA**

### 2.5 Simulation Results

#### 2.5.1 Test System

The proposed multi-agent controller is applied to study the Nordic32 20 machines test system. This system is a CIGRE model of the Swedish national power system, developed for comparing transient stability and voltage collapse performance for different simulators [14]. This model represents a realistic network topology with more detailed component models.

The system has three different transmission voltage levels, 130 kV, 220 kV and 400 kV. The nineteen 400 kV transmission system buses (shown in Fig. 5) are given four digit node numbers starting with 4. Similarly, the two 220 kV buses and the eleven 130 kV buses of the sub-transmission system have numbers starting with 2 and 1, respectively. There are 22 OLTC-controlled load buses which represent the combined sub-transmission and distribution systems with loads. A continuous time model is considered for OLTC with inverse time delay characteristics. The static data for the power flow analysis as well as the dynamic data of the generator and the exciters can be found in [14]. To capture the long voltage instability scenario, each of the generators was modelled using a sixth-order dynamic model equipped with...
automatic voltage regulator (AVR) and over-excitation limiters (OEL) [15]. The OEL follows the inverse time characteristics. The simulation is performed in MATLAB environment using PSAT [15].

The allowable range of the voltages is 0.95 to 1.1 pu. The loads were modelled as constant currents for active power and constant impedances for reactive power. The system is divided into 7 zones based on the zone formation algorithm as shown in Fig. 2.6. $N_{GC,max}$ was set to five so that at least four zones can be formed to illustrate the multi-agent system performance involving neighbour-to-neighbour communication. $N_{GC,min}$ is selected to be two since less than two generators in a zone seems unrealistic.

![Fig.2.6. Nordic32 test system divided into seven zones](image)
Fig. 2.7 shows the step-by-step merging of the generators into the zones. The zone numbers from Fig. 2.6 are also indicated in this figure. In the first step, generator 17 and 18 are merged which are not further merged with any other generator. Thus, these two generators form a zone (zone 7). The later stages of merging generators are shown with larger heights. Note that the formation of zones also complies with the geographical proximities and electrical distances in the system.

Fig. 2.7. Step-by-step merging of the generators into the zones.

2.5.2 Design Parameters

The GAs are designed to have $\tau_{delay} = 3$ seconds and $\Delta V_g = 0.01$ pu. Therefore, the GAs will adjust the voltages of the generators at every three seconds after receiving the REQUEST message from the MA. $\Delta V_g$ is very small so that any increase in terminal voltage does not exceed the maximum reactive power limit. The initial time delay $\tau_{i, delay}$ is 30 seconds for the LA. This 30 seconds waiting time will allow the GAs to increase the generator voltages before any load shedding occurs. Based on numerous simulations carried out on the system, an appropriate threshold value $C$ to initiate load shedding is selected as 0.5 and the time interval $T_c$ as 10 seconds. At any instance, 10 MW loads can be shed by LA. With these settings, the proposed MAEC has been applied to the system.
2.5.3 Case 1: Outage of Generator 8 in Zone 4

This case involves the outage of generator 8 in zone 4. At $t = 5$ seconds after the simulation starts, generator 8 trips and circuit breaker is opened without any fault (see Fig. 2.8). The evolution of two 220 kV bus voltages in zone 4 are shown in Fig. 2.8.

![Fig.2.8. Unstable transmission voltage evolution in case 1](image)

The voltages decline in an attempt to restore the distribution voltages by the OLTCs as well as the field current limitations of the OELs. Collapse occurs at $t = 111.78$ seconds rightly after the field current of generator 10 becomes limited.

The solid curve in Fig. 2.9 shows the voltage at bus 2032, which is stabilized by the proposed MAEC.

![Fig.2.9. Voltage at bus 2032 stabilized by the proposed MAEC in case 1](image)

The dashed line represents the moving average of the voltage. We assume that the agent actions start after 10 seconds of the disturbance so that the controller does not react to any normally cleared fault and electromechanical transients. Initially, the disturbance only affects zone 4. So, MA4 sends REQUEST message to GAs in zone
4 and to neighbouring MA3, MA5 and MA7. Hence, the generator voltages in zone 3, 4, 5 and 7 are increased. At \( t = 35 \) seconds, voltage at bus 2032 is below 0.95 pu, \( IVD \) is 0.5651 and \( DVM \) is -0.0168. So, LA2032 sheds 10 MW load with the corresponding decrease in reactive power load to maintain a constant reactive power. Although the voltage remained below 0.95 pu until \( t = 120 \) seconds, no load shedding occurred since DVM was always positive. This shows the effectiveness of the proposed MAEC in terms of reducing the amount of load shedding.

The response of some of the generator voltages by the proposed MAEC can be seen in Fig. 2.10, which is implemented by changing the AVR reference voltage. Initial pronounced changes are observed in generator 4 and 13. Latter, generator 14 and 15 also increase the voltages since the voltage increments by other generators reduce the reactive power outputs of generator 14 and 15.

![Fig.2.10. Adjustments of generator voltages by the proposed MAEC in case 1.](image)

### 2.5.4 Case 2: Outage of Lines 4032-4044 and 4042-4044 in Zone 5

This case illustrates the performance of the proposed MAEC in case of double transmission line outage in zone 5 (outage of lines 4032-4044 and 4042-4044). This is a severe contingency which makes the system unstable earlier than the previous case and collapse occurs at \( t = 94.625 \) seconds. Fig. 2.11 shows the 400 kV transmission voltage evolution in zone 5. The sharp decay of voltage is owing to the inverse time effect of the OLTCs.
The MAEC performance to control the transmission voltage in zone 5 is shown in Fig. 2.12. In this case, violation in load voltage and/or generator reactive power is first detected by MA4 and MA5. So, generator voltages are increased in zone 3, 4, 5 and 7 by the REQUEST messages of MA4 and in zone 2, 5, 6 and 7 by the REQUEST messages of MA5. Note that MA4 and MA5 are acting both as initiator and responder in this case. Fig. 2.12 shows the successful stabilization of the voltage at bus 4043. Load shedding occurs three times at this bus (at \( t = 85.37, 107.87 \) and 127.57 seconds). More load shedding occurs at some other buses in zone 5 and zone 6 (see Table 2.1).

2.5.5 Comparison with conventional ESVC

In this section, the performance of the proposed MAEC is compared with the conventional ESVC approach described in section II. The contingency in case 2 is considered for this simulation. It was assumed that the time interval for implementing the ESVC is 10 seconds i.e. the online optimization is computed every 10 seconds after the disturbance. This also complies with the SVC currently practiced in France [16]. The solid curve in Fig. 2.13 shows the voltage controlled by
ESVC. For comparison, the same voltage controlled by proposed MAEC is shown with dotted line. It is observed that the ESVC approach is able to save the system but more oscillation occurs due to large step adjustments of generator voltages and load shedding at $t = 15$ seconds. After this time, no further violation in load voltage/generator reactive power occurred and hence, no control was applied. Although ESVC approach stabilizes the voltage earlier than the proposed MAEC approach, this comes with a larger amount of load shedding as can be seen in Table 2.1.

![Fig.2.13. Voltage at bus 4043 in case 2 for both MAEC and ESVC](image)

<table>
<thead>
<tr>
<th>Bus No.</th>
<th>Load shedding in MAEC (MW)</th>
<th>Load shedding in ESVC (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1041</td>
<td>20</td>
<td>29.96</td>
</tr>
<tr>
<td>1042</td>
<td>0</td>
<td>25.44</td>
</tr>
<tr>
<td>1043</td>
<td>30</td>
<td>31.89</td>
</tr>
<tr>
<td>1044</td>
<td>20</td>
<td>36.13</td>
</tr>
<tr>
<td>1045</td>
<td>10</td>
<td>29.96</td>
</tr>
<tr>
<td>2031</td>
<td>0</td>
<td>8.2</td>
</tr>
<tr>
<td>2032</td>
<td>0</td>
<td>3.74</td>
</tr>
<tr>
<td>4042</td>
<td>20</td>
<td>17.98</td>
</tr>
<tr>
<td>4043</td>
<td>30</td>
<td>24.06</td>
</tr>
<tr>
<td>4046</td>
<td>20</td>
<td>22.7</td>
</tr>
<tr>
<td>Total</td>
<td><strong>150</strong></td>
<td><strong>230.06</strong></td>
</tr>
</tbody>
</table>

Table 2.1. The comparison of the amount of load shedding (in MW) by the proposed MAEC and the ESVC approach

### 2.6 Conclusion

A decentralized multi-agent control scheme against long term voltage instability in a power system has been proposed in this paper. The underlying concept is to design an automatic and reliable control strategy to initiate timely countermeasures to prevent voltage collapse and resulting black-out. Simulation results have been shown using Nordic32 test system to demonstrate the effectiveness of the approach. The robustness of the proposed approach has been validated through the
demonstration of various scenarios. The method is simple, computationally less expensive and easily implementable. Effort has been made to minimize the load shedding by simply allowing the GAs to participate more frequently than the LAs and not to shed any load when the voltage tends to stabilize. The proposed method has been compared with the conventional secondary voltage control approach and found to perform better in terms of the amount of load shedding.

References:


CHAPTER 3

COORDINATED DECENTRALIZED EMERGENCY VOLTAGE AND REACTIVE POWER CONTROL TO PREVENT LONG TERM VOLTAGE INSTABILITY IN A POWER SYSTEM

Abstract
This chapter proposes a decentralized adaptive emergency control scheme against power system voltage instability. Decentralized control architecture is proposed by segregating the system into several local areas or zones based on the concept of electrical distance. Intelligent agents are assigned in each area to monitor the bus voltages and generator reactive powers to detect any threat of voltage collapse and to actuate countermeasures. A novel performance index has been formulated based on the load voltage and generator reactive power violations to identify the severity of disturbance and the risk of system emergency in each area. The coordination of the timing of the countermeasures among the agents is achieved through the formulation the integral of the performance index. The simplicity and the adaptive nature of the proposed control scheme to provide countermeasures against any disturbance make it useful for real time application. The robustness of the proposed approach has been validated through several case studies using the New England 39 bus test system and a more realistic Nordic32 test system.

Keywords— Emergency control, Intelligent Agents, Power Systems, Voltage Collapse and Voltage Stability.

3.1 Introduction
Modern power systems are being operated close to the stability limit due to the increasing size and complexity of electric power industries and a high rate of growth of electric power demand. Further, the existing power infrastructure is continuously facing unpredictable catastrophic events such as natural calamities, human factors, unplanned loss of multiple transmission lines or generators etc. Facing these challenges, the power system therefore becomes vulnerable to various instability problems such as voltage instability when load increases or any contingency happens
during the peak load [1] leading to voltage collapse that often causes widespread blackouts [2] [3].

According to the stability definition of IEEE/CIGRE task force [4], voltage stability refers to the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition. Instability occurs in the form of a progressive fall or rise of voltages of some buses. Voltage collapse refers to the process by which the sequence of events accompanying voltage instability leads to a blackout or abnormally low voltages in a significant part of the power system.

The incidents of the system blackout due to voltage instability leading to voltage collapse have been reported in the last few decades [2-3] when thousands of consumers lose power supply costing millions of dollars loss. These massive power outages underscored the vulnerability of the electricity infrastructure and highlighted the deficiency in the existing protection system. Therefore, it has become a growing concern for the power industries to deal with the problems associated with voltage instability.

The phenomenon of voltage collapse during a catastrophic disturbance is often caused by an initial low voltage profile due to the significant increase of reactive power losses in the transmission lines, when they are overloaded, coupled with insufficient reactive power resources. The voltage instability is a dynamic phenomenon characterized by a first deceptive stable phase, lasting up to one or two minutes and then a sharp gradual reduction in the transmission voltage resulting in a voltage collapse [1]. The first deceptive calm phase is due to the field forcing of the rotating units to produce extra reactive power to maintain reactive power balance in the power system until the field current is reduced by the over excitation limiter protection (OEL) of the generator. Furthermore, the voltage reduction caused by the disturbance initiates automatic tap changing in the load substation and the uncoordinated actions of the tap changing transformers exacerbate the problem, and they are the main reasons of the system dynamic changes in the first stable phase. After the field current is reduced by the OEL protection of the generator, part of its reactive power support is transferred to the nearby units [5]. The remaining units become heavily overloaded causing their OEL protection to start functioning. At this moment, the generating units are no longer capable of maintaining their terminal
voltages due to their reactive power being limited, and therefore this will lead to the second and disruptive phase of sharp voltage reduction causing voltage collapse in the system.

A critical disturbance initially affects a limited region within the system, expanding gradually to a wide area. Voltage instability is thus, primarily, a local problem. If proper countermeasures can be effectively applied to the most affected area in a well-timed manner, system breakdown can be avoided [6]. In this way, the difficult task of system wide sequential actions, which include communications, analysis, prediction and decision making within a very short time can be minimized. Planning criteria against system disturbances normally only assess credible contingencies. These are the single (N-1) and a few harmful multiple (N- k) contingencies that can occur in the system. It is not economically possible to provide reinforcement for all possible contingencies. The disturbances with a reasonable probability of occurrence are assessed while the unforeseeable and rare severe disturbances are alleviated through corrective control actions. This is performed by the system protection scheme (SPS) through automatic emergency control [6]. SPS initiates automatic countermeasures when abnormal system condition is detected to sustain grid integrity and to regain an acceptable post-disturbance equilibrium.

The SPS based emergency control approach can be classified into centralized and decentralized schemes [7]. The centralized scheme relies on wide area measurements (WAMS) and control devices located at remote areas in the system. The decentralized scheme uses only local measurements and acts on local devices. The decentralized approach is more reliable since it does not rely on the wide area communication system. However, in such a scheme, the coordination of different emergency control devices poses a challenge due to the lack of system knowledge [8].

In recent years, several types of emergency control strategies against voltage instability have been reported. One category belongs to the multi-step optimization of voltage and reactive power objectives, called Model Predictive Control (MPC). MPC, based on system wide measurements, has been proposed for emergency voltage control to co-ordinate the actions of shunt capacitors and load shedding in a cost effective manner [9-12]. An emergency voltage control based on MPC has been proposed in [9] to control the generator voltage and load shedding. This approach is
based on the system wide steady state power flow equations and WAMS. In [10], a coordinated voltage control framework is developed based on nonlinear system equations using Euler state prediction and pseudo gradient evolutionary programming. In [11], a control switching strategy of shunt capacitors is presented by means of MPC to prevent voltage collapse and maintain a desired stability margin after a contingency. A tree search optimization technique is presented in [12] for coordination of generator voltages, tap changers and load shedding. Although the MPC methods for voltage instability control exhibit robustness against measurement uncertainty and system dynamic evolution, the computational complexity and communication requirement are prohibitive for real time implementation.

Computational intelligence has been applied for emergency control to prevent voltage collapse. An artificial neural network (ANN) based online long term voltage stability margin monitoring has been proposed in [13]. ANN can provide satisfactory results for trained scenarios but may fail to converge in unknown cases. A fuzzy-logic (FL) based load shedding approach has been proposed in [14] to identify the most appropriate location and amount of load shedding for avoiding voltage collapse. The membership functions of FL are usually based on heuristic and/or prior system knowledge which may provide undesirable result in case of system parameter changes. In [15], a fuzzy adaptive particle swarm optimization method has been applied to minimize the active power loss, voltage deviation and the voltage stability index to control voltage and reactive power in the system. Owing to its longer time period to convergence, this method is not compatible for real time application.

Recently, multi-agent system (MAS) technology has been employed in power system for a range of application including fault diagnosis, power system restoration, market simulation, network control and automation. Reference [16] proposed a multi-agent system for emergency control against voltage collapse. The agents have been used to coordinate different control device to prevent voltage collapse during the post emergency period. A multi-agent based secondary voltage control during power system emergency has been proposed in [17]. The individual agents are assigned to the secondary voltage control device (i.e. STATCOM) to control voltage in power system. A multi-agent approach for power system restoration after a disturbance in the system has been proposed in [18].
All these approaches are based on the centralized architecture of the agents. However, the centralized control system is highly sensitive to system failure because the control system depends on a central controller in the decision making and coordination. Moreover, to cater for catastrophic situations, it is necessary to design an emergency control system with quick decision making capability to correctly initiate countermeasures during the post-disturbance period in the first phase of the system voltage instability.

In this chapter, a decentralized method for emergency control of voltage collapse in a power system is proposed. The proposed method uses local online measurements, to identify the severity of the disturbance, and once the emergency state is identified, to initiate the countermeasure actions of shunt capacitors and load shedding. A performance index has been formulated to quantify the severity of disturbance and risk of emergency. The system is divided into several voltage control areas and the control actions in each area are coordinated using multi-agents without any communication among the different areas.

The chapter is organized as follows. Section 2 briefly describes the long term voltage instability mechanism in a power system, Section 3 elaborates the proposed approach for preventing voltage collapse, and Section 4 shows the effectiveness of the proposed method based on the simulation of the New England 39 bus test system and the Nordic32 74 bus test system.

3.2 Long Term Voltage Instability Mechanism and Problem Statement

Consider the example power system in Fig. 3.1

![Fig. 3.1. An example power system](image)

The load is assumed to have voltage dependency i.e. the load power (active and reactive) consumption varies with the variation of load voltage. Fig. 3.2 shows the variation of voltage $V_2$ with respect to the load power $P$, and is often referred to as the ‘PV curve’ or the ‘nose curve’.
For each load power, there are two voltages, one is higher and the other is lower. One is higher and the other is lower. The upper part of the curve is called the stable region and the lower part is called unstable region. Point $B$ on the curve is called the critical point related to the maximum load power that can be supplied by the system.

The process of voltage instability can be illustrated using the PV curve. Suppose the system is operating at point $A$ with a load power $P_0$ (as shown in Fig. 3.3), when one of the lines between bus 1 and 2 is removed from service.

This disturbance increases the transmission line reactance, resulting in the decrease in the maximum deliverable power to the load for which the operating point jumps from point $A$ to point $A_1$ following the transient load characteristic (shown as dashed line). The LTC will try to restore the distribution side voltage $V_3$ by adjusting the LTC tap ratio. This will also restore the load power to the pre-disturbance value $P_0$. The system will gradually move from $A_1$ to the new operating point $A_2$. Now, suppose that the remote generator was operating over its maximum rotor current limit because of the disturbance and now has its rotor current restricted to the rated
value due to the over-excitation limiter (OEL) action. Since the action of OEL reduces the generator terminal voltage, the maximum deliverable power will also get reduced. The operating point will now move to point $A_3$ following a new PV curve (shown as red line in Fig. 3.3). This curve has no intersection with the steady state load characteristic. Hence, the system will fail to reach equilibrium and gradually will proceed to instability due to the unsuccessful attempt of the LTC trying to restore load. The system will follow the trajectory $A, A_1, A_2, A_3,$ and $A_4$.

The evolution of the transmission voltage $V_2$ in time domain is shown in Fig. 3.4.

![Fig. 3.4. Time evolution of the transmission voltage](image)

A similar behaviour is obtained when initially the voltage decays slowly due to the LTC action followed by a sharp decrease at point $A_3$ when the OEL comes into action.

It can be concluded from the above discussion that the driving force to long term voltage instability is the system inability to meet the load demand due to the action of the LTC to restore the load power and/or the sudden reactive power reduction due to the action of the OEL. The latter is responsible for the sharp voltage decay that results into collapse.

### 3.3 Proposed Approach

#### 3.3.1 Area Wise Analysis

The initial impact of any voltage related disturbance is usually observed in the area where the disturbance occurs. At first, the voltage instability occurs mainly in this area, and if immediate countermeasures are not taken, it spreads system-wide and more and more areas gradually become voltage unstable. Therefore, it seems logical that the power system can be divided into several local areas. In this chapter, a strategy has been developed based on the concept of electrical distance to divide
the entire system into local areas. Electrical distance can be simply obtained from the absolute value of the inverse of the system admittance matrix, although several other definitions exist in the literature [19].

\[
[D] = [Y_{bus}]^{-1}
\]  

(3.1)

Each element \(D_{ij}\) in the distance matrix \(D\) gives the electrical distance between bus \(i\) and bus \(j\) and provides a measure of electrical closeness (distance) among the buses i.e. the higher the impedance between two buses, the less will be the impact of the change of the reactive power in one bus on the change of the voltage in the other bus and vice versa. Initially, the generators that are electrically close are merged together to form a zone. For a generator \(G_i\) to form a group with generator \(G_j\), it must satisfy:

\[
D_{ij} = \min(D_{ik}) \quad k=1, 2, 3, \ldots, N_G
\]

(3.2)

where \(N_G\) is the number of generators.

Fig. 3.5(a) shows the flow chart for the zone formation process among the generators. The groups so formed by the generators are analysed and the zones are formed in such a way that the electrically closest generators are in the same zone. For instance, if generator ‘a’ is grouped with generator ‘b’ and generator ‘b’ is grouped with generator ‘c’, then generator ‘a’, ‘b’ and ‘c’ should be in the same zone. After finding the generators that have to be included in an area, the electrical distances between the generators and the loads are calculated. For each load \(load_i, i=\{1, 2, 3, \ldots, N_L\}\) where \(N_L\) is the number of load buses, the electrically closest generator is searched and \(load_i\) is allocated into the zone having this generator. Fig. 3.5(b) shows the flow chart for the allocation of loads into the zones.

### 3.3.2 Indicator of Vulnerability

As can be observed from the discussion in section 3.2, the voltage level alone is not a strong indicator for voltage instability. The voltage levels might be normal, in certain cases, when the rotating units are operating close to the limits of their capacities. The identifying parameters for a potential system voltage instability and voltage collapse are the significant reductions of transmission voltage levels and the significant increase of reactive power outputs on the rotating units beyond their reactive power limits. Any dangerous disturbance can be identified by analysing the measurements of these parameters changes.
For this purpose, a performance index \((PI)\) has been formulated in this chapter to objectively articulate the severity of a disturbance based on the load voltage deviation from the admissible limit and the generator reactive power production over the reactive power limits.

The \(PI\) is the summation of the differences between the minimum voltage limit, \(V_{L,\text{min}}\), and the actual voltage value in pu at the load buses (when the voltages are below the lowest voltage limit, \(V_{L,\text{min}}\)) and the summation of the differences between the actual generator reactive power and the maximum reactive power limit, \(Q_{G,\text{max}}\), in pu at the generator buses (when the reactive power are above the maximum reactive power limit \(Q_{G,\text{max}}\)), each summation is multiplied by some weighting factors as expressed in (3).

\[
PI = w_i \sum_{i=1}^{N_{LD}} (V_{L,\text{min}} - V_{L,i}) + w_g \sum_{i=1}^{N_{GD}} (Q_{G,\text{max}} - Q_{G,i})
\]

(3.3)

where \(V_{L,\text{min}}\) is the minimum limit of the load voltage, \(Q_{G,\text{max}}\) is the maximum reactive power capacity of the generator, \(V_{L,i}\) is the voltage at the load bus whose voltage is below \(V_{L,\text{min}}\), and \(Q_{G,i}\) is reactive power output of the generator whose reactive power is above \(Q_{G,\text{max}}\), \(N_{LD}\) and \(N_{GD}\) are the number of load and generator buses whose voltages and reactive powers are outside their normal limits.
respectively, \( w_v \) and \( w_g \) are the weighting factors associated with the load and generator buses, respectively.

The generator maximum reactive power capacity is derived from the reactive capability curve which can be analytically expressed based on the maximum rotor current as [20]:

\[
Q_{g,\text{max}} = \frac{V E_{FD}^\text{max}}{X_d} \cos(\delta - \theta) - V^2 \left( \frac{\sin^2(\delta - \theta)}{X_q} + \frac{\cos^2(\delta - \theta)}{X_d} \right)
\]

(3.4)

where \( V \) is the terminal voltage of the generator, \( E_{FD}^\text{max} \) is the maximum field voltage, \( X_d \) and \( X_q \) are the direct and quadrature axis reactances, respectively, \( \delta \) is the rotor angle and \( \theta \) is the phase angle of terminal voltage to a synchronously rotating reference frame. The weighting factor reflects the relative importance of any load bus and/or generator in the formulation of \( PI \). Since the generator field current limitation contributes a lot to the rapid voltage collapse, a higher weight to the generator reactive power deviation is adopted than the weight to the load voltage deviation.

### 3.3.3 Countermeasures

Two types of countermeasure have been considered in this chapter to counteract voltage instability. These are the shunt capacitor switching and load shedding. When capacitor is switched on in a low voltage situation at a load sub-station, the load voltage improves because of the reactive power injection. Thus the maximum deliverable power also increases and the post-contingency PV curve shifts to the right in Fig. 3.3. If there is sufficient installation of shunt capacitors at the load sub-station, the post-contingency PV curve will intersect with the steady state load characteristic. Hence, a new equilibrium can be achieved. However, in case of inadequate shunt reactive power injection, the voltage can be improved to some extent but a new equilibrium may not be achieved. In that case, a strategic load shedding is required to stabilize the system.

Load shedding is a very effective countermeasure against voltage instability [21]. When the drop in the load voltages, due to a critical disturbance, cannot be corrected with the available shunt compensation, load shedding is required to prevent the voltage collapse. When load shedding is performed, the steady-state load characteristic moves to the left and a new intersection with the network PV curve can be achieved. Load shedding should be performed at a proper location, with a proper
amount and at an appropriate time [22]. It should act as a last resort after other countermeasures (shunt capacitor in this chapter) have been exhausted since it is more intrusive to the customers.

3.3.4 Control Strategy

The objective of this chapter is to design a control system that can act in a decentralized manner without any interaction from the central controller and other areas. Each area has a local controller agent (LCA) that monitors the generator reactive power outputs and the load voltage magnitudes in the area. The architecture of the multi-area control system is shown in Fig. 3.5.

![Fig. 3.6. Control algorithm of a LCA](image)

The LCA receives the measurements of the local area load voltages and reactive power and activates the countermeasures based on the logic shown in Fig. 3.6 and Fig. 3.7. At first, the measurements are compared with the reference values and the deviation is passed to block 1. The dashed box in the figure explains the behaviour of block 1. When the input $x$ is greater than zero, it passes the input to the output, otherwise, it blocks the signal. For example, if the load voltage becomes less than 0.95 pu ($V_{L,min}$), the input to block 1 is greater than zero. As a result, the output of block 1 will be deviation of the load voltage from the minimum limit. If the load voltage is above 0.95 pu, the input to block 1 is less than zero, so the output of block 1 will be zero. Thus, only the differences of the deviated values of voltage and reactive power are passed from block 1. These values, multiplied by the weighting
factors, are added to give the performance index. Next, the value of $PI$ is integrated and compared with a pre-defined threshold $C$. The integral of $PI$ ($IPI$) plays a vital role in co-ordinating the actions among the areas. The area undergoing disturbance will have comparatively larger values of $PI$ than the other areas. This will produce a rapid change in the $IPI$ value in that area. As can be observed from Fig. 3.6, when $IPI$ becomes greater than $C$, countermeasures are activated in the area. Thus, the area undergoing disturbance will first initiate the countermeasures.

Since control actions in one area will also affect the other areas (particularly the neighbouring areas), the voltages and generator reactive powers of other areas will also improve to some extent. In that case, the other areas will have to take fewer countermeasures than if the countermeasures are initiated at the same time in all areas.
In this way, a coordination of the countermeasure initiating times is achieved among the areas through the value of $IPI$. Once initiated, the countermeasures persist until the value of $PI$ becomes zero.

Thus, an $LCA$ monitoring the measured local area voltages and generator reactive powers is operating in a ‘closed loop’ manner with variable initiating time of countermeasures depending on the $IPI$ value. Moreover, the various $LCAs$ are implicitly coordinated by the $IPI$ value without any communication network which makes the control system simple and reliable.

The logic inside the dotted box ensures that the countermeasures continue until a time $t_{stop}$ has elapsed after the $PI$ becomes zero. This waiting time $t_{stop}$ provides an additional reliability by checking that the system is really stabilized and by providing some extra margin to load voltages and generator reactive powers above or below the admissible limits. After this waiting time is over and $PI$ remains zero, the $LCA$ stops the countermeasures. The integrator block will be reset to zero after the system is stabilized.

### 3.4 Test Result

#### 3.4.1 Test System

The performance of the proposed controller is illustrated using the New England 39 bus, 10 generator test system. The system is first divided into some areas (see Fig. 3.8) according to the zone formation principle as described in section 3.3.1. The electrical distances among the generators can be seen in Table 3.1.

Starting with generator 30, it has the lowest electrical distance with generator 37, so generator 30 forms a group with generator 37. Also, generator 38 has the lowest electrical distance with generator 37, so generator 30, 37 and 38 are in one group. Generator 39 has the lowest distance with generator 30. So, generator 30, 37, 38 and 39 are in the same group. Generator 31 has the lowest electrical distance with generator 32 and they form a group. Similarly, generators 33 and 34; and generators 35 and 36 form separate groups.

So, we have four areas with the generators: zone1 with generators 30, 37, 38 and 39; zone 2 with generators 31 and 32; zone 3 with generators 33 and 34; zone 4 with generators 35 and 36.
For the loads, a search is made for each load that has the lowest electrical distance with the generators. For example, bus 14 has the lowest electrical distance with gen 32. So, bus 14 is included in zone 2. Following the above approach, the zones are finally determined as shown in Fig. 3.8.

As can be seen from Fig. 3.8, zones 3 and zone 4 are very small. It will be not realistic to keep them as separate zones. So, they are merged into one zone and finally three zones are obtained as shown in Fig. 3.9.
The static data for the power flow analysis as well as the dynamic data of the generator and the exciters can be found in [23]. To capture the long voltage instability scenario, each of the generators was modelled using a sixth-order dynamic model equipped with automatic voltage regulator (AVR) and over-excitation limiters (OEL). The OEL follows the inverse time characteristics. The generator transformers were modelled to have fixed transformation ratio and the transformers between bus 11-12, bus 13-12 and bus 20-19 were modelled to have on-load tap changing capability (OLTC). The OLTCs have a continuous time model and inverse time characteristic [24]. In order to capture the effect of the distribution side OLTCs, the loads are designed to have exponential recovery characteristics in trying to restore the loads to the pre-disturbance values [25]. All necessary power flow and time domain simulations were carried out in Power System Analysis Toolbox (PSAT) [26] in MATLAB environment. The per unit values of voltage and power (active and reactive) are computed using base values of 345 kV and 100 MVA, respectively.

The system is provided with six shunt capacitors banks at buses 3, 4, 8, 12, 15 and 20. The capacitors can be switched in a step of 0.1 pu from 0 to 0.5 pu at 5 seconds interval. Initially, all the capacitor values are set to zero to match the actual base case condition. Each controller starts the action when the activation signal is sent from the LCA and terminates when it receives stop signal from LCA. The load shedding controllers were distributed over the buses 3, 4, 7, 8, 12, 15, 16, 18, 21 and 26. The

*Fig. 3.9. New England 39 bus test system divided into three zones*
load shedding controller sheds load in steps of 5 MW (with a corresponding decrease of reactive power to maintain the power factor of the load constant) and with a delay of 10 seconds between two successive load curtailments.

3.4.2 Case 1: Outage of the Generator at bus 32

This case illustrates the effect of the outage of a generator. The disturbance of concern is the outage of the generator at bus 32 without any other fault in the system at \( t = 5 \) seconds of the simulation. This critical disturbance makes the system long term voltage unstable. Zone 2 and Zone 3 are affected by the disturbance. Fig. 3.10 shows the evolution of three most affected bus voltages after the disturbance with respect to time. The system evolves under the effect of OLTCs and load restoration after the disturbance. The load voltages slowly decay until the activation of OEL at generator 33 at \( t = 124.3 \) seconds. As a result, the voltage support at generator 33 is lost and the load voltages decay more rapidly. At \( t = 208.3 \) seconds, generator 35 also has its rotor current limited due to excessive over-excitation. The system could not survive further and a sharp reduction in the load voltages takes place. Finally, at \( t = 236.9 \) seconds, generator 33 losses synchronism and the voltages become completely unstable. Fig. 3.11 shows the field current of generator 33 and 35 after the disturbance.

![Fig. 3.10. Evolution of bus voltages in case 1 without control](image)
The performance of the proposed controller is then tested on the above described case. Based on numerous simulations carried out on the system, the most appropriate threshold value of $IPI$ to initiate countermeasures has been selected as 1 and the stop time $t_{stop}$ is set at 10 seconds. The weighting factor $w_{vl}$ is selected as 1 for all the deviated load bus voltages and $w_{gl}$ is selected as 2 for all the deviated generator reactive powers. With these settings, the countermeasures are applied to the system following the proposed logic as described in section 3.3.4. The successful stabilization of the load voltages by the proposed controller can be seen in Fig. 3.12. All the capacitors have been switched on in Zone 2 and Zone 3 where load shedding occurs once in Zone 2 and five times in Zone 3. The total amount of load shedding is 20 MW in Zone 2 and 75 MW in Zone 3.

The evolution of $PI$ in Zone 2 and Zone 3 is shown in Fig. 3.13. The $IPI$ of these two regions can be seen from Fig. 3.14.
The IPI of Zone 3 first exceeds the threshold limit (1 in this case) at $t = 24$ seconds. So, LCA in Zone 3 first starts the countermeasures. After a short time, IPI of Zone 2 also exceeds the limit at $t = 26$ seconds. Thereafter, these two zones concurrently take the countermeasures. At $t = 45.25$ seconds, the PI in Zone 2 becomes zero and remains on that value. Therefore, the countermeasures in Zone 2 are stopped at $t = 55.25$ seconds. Since the PI in Zone 3 is relatively larger than the PI in Zone 2, the voltages and reactive powers in Zone 3 take longer time to return to the values within the limit. Finally, at $t = 84$ seconds, the PI in Zone 3 becomes zero and the countermeasures are stopped at $t = 94$ seconds.

The static analysis of the system on the load power-voltage space is shown in Fig. 3.15. Fig. 3.15 shows the P-V operating trajectories both for stable and unstable cases at bus 4. The system operates initially at point ‘a’. The outage of the generator at bus 32 decreases the load voltage and load power consumption accordingly (because of the voltage dependency). The new operating point just after the disturbance is point ‘b’. Now, because of the effect of load restoration, the load voltage slowly decays and the load power is increased.

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At point ‘c’, the OEL at generator 33 is activated. As a result, the operating point jumps from point ‘c’ to point ‘d’ because of the terminal voltage reduction at generator 33. Now, the voltage decays more rapidly from ‘d’ to ‘e’. The OEL at generator 35 is activated at point ‘e’. The system becomes unstable after this event and sharply moves to point ‘f’ resulting in voltage collapse. Therefore, the unstable system evolution follows the trajectory ‘a-b-c-d-e-f’ which is shown as broken line in Fig. 3.15.

The stable evolution of the operating point is shown as bold line in Fig. 3.15. At point ‘b’, the $IPI$ in Zone 2 becomes greater than 1 and capacitors are switched on successively. The voltage gradually improves and the load power increases. The system moves to point ‘h’ when all the capacitors have been switched on. However, still the PI in Zone 2 is greater than zero. So, some loads are shed which shifts the operating point from ‘h’ to ‘i’. The new stable equilibrium point of the system is at ‘i’. The stable evolution of the operating point at bus 4 is ‘a-b-g-h-i’.

### 3.4.3 Case 2: Outage of Lines 5-6 and 6-7

This case involves the study of multiple transmission line outages. The selected lines are line 5-6 and line 6-7 in Zone 2. The evolution of bus voltages by this contingency is shown in Fig. 3.16.

A severe decline in the load bus voltages in Zone 2 is observed in this case. At around $t = 180$ seconds, the OELs on the generators at buses 32, 32 and 39 are activated in quick succession. The load voltages sharply drop and finally voltage collapse occurs at $t = 246$ seconds.
Fig. 3.16. The evolution of bus voltages without control in case 2.

Fig. 3.17 shows the successful stabilization of load voltages by the proposed controller. The evolution of $PI$ and $IPI$ can be observed from Fig. 3.18 and Fig. 3.19.

Fig. 3.17. Stabilization of bus voltages with proposed control in case 2.

Fig. 3.18. Evolution of $PI$ in case 2.

Fig. 3.19. Evolution of integral of $PI$ in case 2.
It can be observed from Fig. 3.18 that all the zones are affected by this disturbance, the most pronounced changes being occurred in Zone 2 where the disturbance took place. The countermeasures are first initiated in Zone 2 at $t = 8$ seconds, when $IPI$ in Zone 2 exceeds the threshold limit (see Fig. 3.19). At $t = 96$ seconds, $IPI$ in Zone 3 becomes slightly greater than one, which invokes the $LCA$ in Zone 3 to switch on the capacitor. As a result, the $PI$ in Zone 3 becomes zero at $t=98$ seconds and the countermeasures in Zone 3 is stopped at $t = 108$ seconds. The countermeasures in Zone 2 continue with successive load shedding at every 10 seconds interval. At $t = 173.25$ seconds, the $PI$ becomes zero and the countermeasures are stopped at $t = 183.25$ seconds. Load shedding occurs 16 times in Zone 2 with a total amount of 320 MW.

Note that no control is applied in Zone 1 although $PI$ in Zone 1 is greater than zero after the disturbance. This happens because the $IPI$ never reaches the threshold value in Zone 1, since the control actions in Zone 2 have also removed the deviations in Zone 1. The $PI$ in Zone 1 is returned to zero at $t = 83$ seconds. Thus some savings in terms of capacitor switching and/or load shedding in Zone 1 can be achieved. This demonstrates the benefit of a co-ordination of activation time of countermeasures among the areas by the proposed controller.

Fig. 3.20 shows the P-V operating point trajectories at bus 7.

![P-V operating point trajectories at bus 7 in case 2.](image)

A similar behaviour is obtained for the unstable trajectory that follows the points ‘a-b-c-d-e’. The operating point moves from point ‘b’ to point ‘f’ by capacitor switching by the proposed controller. As this point is not inside the admissible operating limits, the proposed controller starts to curtail the loads. The successive load curtailments move the operating point from ‘f’ to inside the allowable boundary at point ‘g’. The stable P-V trajectory follows the points ‘a-b-f-g’.
3.4.4 Case 3: Sudden load change

To illustrate the robustness of the proposed controller in case of sudden load changes in the system, the loads in Zone 2 were linearly increased by 25% of the base case load, together with the outage of line 5 - 6. The evolution of load voltages in Zone 2 is shown in Fig. 3.21. The voltage collapse occurs at $t = 180$ seconds.

Fig. 3.21. Evolution of load voltages in Zone 2 without control in case 3.

Fig. 3.22 shows the performance of the proposed controller in this case. A successful stabilization is obtained by the control actions in Zone 2 and Zone 3, since the $IPI$ in these zone crossed the threshold value (see Fig. 3.23) at $t = 23$ seconds and $t = 39$ seconds, respectively. The control actions are stopped at $t = 188.37$ seconds in Zone 2 and at $t = 124.25$ seconds in Zone 3 after the $PI$ values in these zones become zero (see Fig. 3.24).

Fig. 3.22. Evolution of load voltages in Zone 2 with control in case 3.

Fig. 3.23. Evolution of $IPI$ in Zone 2 and Zone 3 in case 3.
Fig. 3.24. Evolution of PI in Zone 2 and Zone 3 in case 3.

Fig. 3.25 shows the P-V operating points in this case. The system moves from ‘a’ to ‘b’ by the line outage, from ‘b’ to ‘c’ by the load increments, from ‘c’ to ‘d’ due to load restoration, from ‘d’ to ‘e’ due to OEL activation and finally collapses at point ‘f’ without any control action. With the proposed controller in operation, the operating point moves from ‘c’ to ‘g’ due to capacitor switching and from ‘g’ to ‘h’ due to load shedding. Point ‘h’ is the final stable operating point.

3.5 Validation using Nordic32 Test System

To validate the performance of the proposed controller on a large scale power system, the Nordic32 test system (with 20 machines and 74 buses) is investigated.

3.5.1 Nordic32 Test System

This system is a CIGRE model of the Swedish national power system, developed for comparing transient stability and voltage collapse performance for different simulators [26]. This model represents a realistic network topology with more detailed component models.

The system is geographically divided into three Swedish areas denoted Southwest, Central, North and a foreign part named External. The external and
northern regions are characterized by a large amount of hydro power generation, while the other two having thermal power plants. The system has three different transmission voltage levels, 130 kV, 220 kV and 400 kV. The nineteen 400 kV transmission system buses in Fig. 26 are given four digit node numbers starting with 4. Similarly, the two 220 kV buses and the eleven 130 kV buses of the sub-transmission system have numbers starting with 2 and 1, respectively. There are 22 LTC-controlled load buses which represent the combined sub-transmission and distribution systems with loads.

The “North” and the “Central” regions are comparatively larger than the other areas. These two areas were further divided into two parts based on the electrical distance property. Finally, six areas are formed, namely “Equivalent”, “North-1”, “North-2”, “Central-1”, “Central-2” and “South”.

Fig. 3.26. Nordic32 test system.
3.5.2 Removal of one 400kV transmission line

The disturbance is created by removing the 400 kV transmission line between bus 4032 and bus 4044 at $t = 5$ seconds. The evolution of the bus voltages after this contingency is shown in Fig. 3.27. The system is long term voltage unstable and collapse occurs when the generator at bus 6 losses synchronism at $t = 183.87$ seconds.

Fig. 3.27. Unstable evolution of transmission voltages after the disturbance

Fig. 3.28 shows the successful stabilization of the transmission voltages by the proposed controller. Fig. 3.28 shows the voltages initially decay but gradually increase by the action of 12 switchable shunt capacitors/reactors and 13 interruptible loads distributed over the system. The system reached the equilibrium just before 200 seconds. For this system, the shunt capacitors/ reactors can be switched on/off in step of 0.3 pu and loads can be curtailed in step of 10 MW. The other settings such as the weighting factors, stop time etc. are similar to the New England test system.

Fig. 3.28. Transmission voltages stabilized by the proposed controller.
Fig. 3.29 shows the IPI in North-2, Central-1 and Central-2 regions, since the disturbance only affects these three zones. The countermeasure is first initiated in Central-1 zone at \( t = 12.9 \) seconds when the IPI in this zone exceeds the threshold limit of 1. A short time later at \( t = 19.6 \) seconds, the LCA in North-2 also initiates the countermeasures. Finally, at \( t = 62.3 \) seconds, the countermeasures are triggered in Central-2 zone; the least affected region by the disturbance.

The evolution of PI in these three zones is shown in Fig. 3.30. The countermeasures stop at \( t = 110.6 \) seconds in Central-2, at \( t = 125.9 \) seconds in North-2 and at \( t = 126.3 \) seconds in Central-1 regions.

3.5.3 Comparison with the conventional control system

Several voltage control methods using the conventional centralized multi-agent systems [16], [17], [18] have been reported in literature.
In reference [17], a secondary voltage control scheme involving an AVR, an SVC and a STATCOM installed in the system is presented using a multi-agent system. Since load shedding is not considered in this study, it is not suitable to compare this method with the proposed approach. Moreover, the method in [17] has been illustrated using a simple single machine infinite bus system. How the method in [17] would perform in a large transmission multi-machine system, as considered in this paper, is not clear.

Reference [18] demonstrates an approach of power system restoration after any contingency using the conventional centralized multi-agent system. This study deals with switching the sub-station circuit breakers to find a sub-optimal configuration with minimized load shedding after a large area power outage (blackout) has occurred due to fault. However, the proposed approach works during the emergency period before the occurrence of the blackout. Thus, the scope and methodology of reference [18] is different from the proposed approach and hence the results are not comparable.

Therefore, the performance of the proposed control system is compared with that of a conventional voltage control of a power system [16]. Instead of generator voltage adjustment actually used in [16], shunt capacitors have been incorporated in the method described in [16] for similar comparison with the proposed approach. The shunt capacitors are gradually switched on when the sub-station voltage drops below the limit for a predefined time period (say 5 seconds) until the voltage recovers. If the voltage cannot restore within the specified limit after all the capacitor banks are switched on, the load shedding is applied by sequentially opening the distribution feeder circuit breaker according to the load shedding schedule.

Fig. 3.31 shows the response of the voltage at bus 4044 by the proposed method and the conventional method. We assume that the conventional method also switches on/off shunt capacitors/reactors in step of 0.3 pu and sheds load in step of 10 MW. The proposed method reacts faster to the disturbance because it takes into account the reactive power violation of the generators. The conventional method reacts slowly and takes more time to stabilize and acts only based on the voltage violations. Table 3.2 shows that the conventional method requires more load shedding because of delayed response to the disturbance.
3.5.4. Comparison of performance using different formulation of PI

The formulation of PI considering both the voltage violations and reactive power deviations gives better performance than considering only the voltage violation (PIV) or the reactive power deviation (PIQ).

Fig. 3.32 shows the voltage response at bus 4032 for the cases considering PI, PIV and PIQ separately. The figure shows the response of the voltage is slower when using PIV than when PI is used. Also, the voltage cannot be restored within the operational limits in case of PIQ, because it does not take into account the voltage violations that occur after the field currents are restricted by the OELs on the over-

<table>
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<tr>
<th>Bus no.</th>
<th>Proposed method</th>
<th>Conventional method</th>
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<tbody>
<tr>
<td>1041</td>
<td>10</td>
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<tr>
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</tr>
<tr>
<td>1043</td>
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</tr>
<tr>
<td>1044</td>
<td>10</td>
<td>130</td>
</tr>
<tr>
<td>1045</td>
<td>10</td>
<td>60</td>
</tr>
<tr>
<td>1022</td>
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<td>2031</td>
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<tr>
<td>Total</td>
<td>310</td>
<td>380</td>
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</tbody>
</table>

Table 3.2. The Comparison of the Amount of Load Shedding (in MW) by the Proposed Method and the Conventional Method

56
excited generators. A smooth and successful stabilization is achieved when considering the proposed formulation based on $PI$.

Table 3.3 shows the amount of load shedding in MW for different formulation of the performance index. Load shedding required for the case in $PI_V$ is more than the load shedding in case of $PI$. Since the voltages deviate much for the former causing more time to stabilize, the controller has to shed more loads. Although load shedding is less in case of $PI_Q$, the voltages are not finally within the limits.

![Voltage response at bus 4032 for various performance index.](image)

### Table 3.3

<table>
<thead>
<tr>
<th>Bus no.</th>
<th>$PI$</th>
<th>$PI_V$</th>
<th>$PI_Q$</th>
</tr>
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<tbody>
<tr>
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<tr>
<td><strong>Total</strong></td>
<td><strong>310</strong></td>
<td><strong>670</strong></td>
<td><strong>370</strong></td>
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</table>

**3.5.5. Comparison of performance using different weighting factors**

Table 3.4 illustrates the performance of the control system in terms of required load shedding for different values of weighting factors. More load shedding is required when $w_{vi}$ is higher than $w_{qi}$ as shown in the first column of Table 3.4. On the other hand, the load shedding is lower for the cases where $w_{qi}$ is greater than $w_{vi}$ as shown in the last three columns in Table 3.4. This demonstrates the efficiency of
the proposed control system that suggests using a higher value of weighting factor for the generator reactive power violations.

<table>
<thead>
<tr>
<th>Bus no.</th>
<th>( w_{c_i} = 2 )</th>
<th>( w_{q_i} = 1 ), ( w_{g} = 3 )</th>
<th>( w_{c_i} = 1 ), ( w_{q_i} = 4 )</th>
<th>( w_{c_i} = 1 ), ( w_{q_i} = 5 )</th>
</tr>
</thead>
<tbody>
<tr>
<td>1041</td>
<td>20</td>
<td>10</td>
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<tr>
<td>1042</td>
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<td>10</td>
<td>10</td>
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<tr>
<td>1045</td>
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<td>0</td>
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<tr>
<td>1022</td>
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<td>50</td>
<td>40</td>
<td>60</td>
</tr>
<tr>
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</tr>
<tr>
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</tr>
<tr>
<td>Total</td>
<td>380</td>
<td>320</td>
<td>290</td>
<td>320</td>
</tr>
</tbody>
</table>

Table 3.4. Load Shedding (in MW) for Different Values of Weighting Factors

3.6 Conclusion

A decentralized emergency control scheme against voltage instability has been proposed in this chapter. The proposed controller relies on a team of intelligent agents, each agent being assigned to monitor the transmission voltages and generator reactive powers and to actuate control actions when these values are out of the admissible limits for some specific time periods. A performance index has been formulated based on the violated load voltages and generator reactive powers to articulate the severity of any disturbance and to determine the timing of countermeasures. The main advantages of the proposed control system are (i) the simple architecture independent of system wide measurements, (ii) the co-ordination of the countermeasure activation time among the agents without any dedicated communication network among them and (iii) the better performance in terms of appropriate levels of countermeasures needed to stabilize the system. The proposed controller is validated using the New England 39 bus, 10 generator test system as well as a larger Nordic32 test system with 20 generators and 74 buses. Simulation results demonstrate the effectiveness of the proposed controller. The performance of the system has been compared with the conventional emergency voltage control system and has been found to be better in terms of the required load shedding.

References


CHAPTER 4

A DECENTRALIZED MULTI-AGENT BASED VOLTAGE CONTROL FOR CATASTROPHIC DISTURBANCES IN A POWER SYSTEM

ABSTRACT

In this chapter, a multi-agent based voltage and reactive power control in the case of a multiple contingency is presented. Incorporating the agent based autonomous feature to the intelligence of the Remote Terminal Units (RTUs), the present power system control structure can be used to help in preventing system voltage collapse during catastrophic disturbances. The control algorithm is based on a decentralized architecture of intelligent agents and the determination of a local zone that can carry out quick countermeasures in a decentralized manner as a multi-agent system (MAS) during an emergency situation. An adaptive determination of the local zones undergoing voltage collapse has been developed based on the electrical distances among the generators and loads. Once assigned, the elements of the Jacobian matrix can be used to determine the optimum actions that need to be carried out at each power system element (such as increasing the voltages of generators and load shedding) within the assigned local zone. The contract-net-protocol (CNP) is used for agent interactions. Simulation results using IEEE-57 bus system show that the proposed method can act quickly to respond to emergency conditions to ensure that voltage collapse can be avoided. The contribution of the chapter is the novel adaptive determination of the local zone where the disturbances occur using electrical distances and the development of a multi-agent decentralized control algorithm to determine the most optimum operation in the local zone to avoid voltage collapse.

Keywords — Contract Net Protocol, Multi-Agent System, Reactive Power Control, Emergency Control

4.1 Introduction

Power systems are normally designed to meet the forecasted annual peak demand and to provide secure operation in case of credible contingencies. This is provided by system reinforcement and protection systems to ensure that the power system operation is safe, stable, reliable and economical. Because of the low probability of
multiple contingencies in a system, no automatic system protection is generally provided to safeguard the system against multiple contingencies [1]. However, many incidents of multiple contingencies have occurred in the past few decades throughout the world which had led to voltage collapse and widespread blackouts such as the events of July 2, 1996, August 10, 1996 [2], August 14, 2003 in Canada and North America [3], and November 4, 2006 in European Power System [4]. More recently, some blackout events have occurred on 16th January, 2007 in Victoria, Australia [5] and 30th July, 2012 in Northern India [6] which were caused by cascaded line failures that segregated the system into several islands. Therefore, it has become a growing concern for the power utilities to develop a system-wide protection scheme to maintain the integrity of the transmission grid against such unpredictable multiple contingencies [7].

The phenomenon of voltage collapse is characterized by an initial slow stable phase lasting from several seconds to minutes after any disturbance followed by a sharp disruptive phase of voltage decline in the system [8]. The dynamic changes in the initial stages are predominantly due to the automatic on-load tap changers (OLTC) and switching of static reactive plant. The second disruptive phase starts when the most over-excited generator’s field current is reduced by the rotor over-excitation limiter and part of its reactive power is transferred to the nearby units. These units also become over-excited and their rotor over-current limiters start functioning one by one. The generator terminal voltage is no longer controlled by the automatic voltage regulator (AVR). As a result, the voltages in the surrounding regions drastically reduce resulting in voltage collapse. The important findings from reported incidents of voltage collapse are [9]:

- The initial impact of a critical disturbance is in a limited region of the system.
- The short-term rotor over-excitation capacity offers a certain time period before abruptly collapsing.
- The affected region by the disturbance can be identified by the increase of excitation and reduction of voltage.
- The existing control system that provides safety of the individual equipment is not sufficient to provide control for the transmission grid.
- An automatic control strategy must be developed to mitigate the contingencies.
This chapter describes a decentralized multi-agent based voltage and reactive power control in the case of multiple contingencies to help in preventing system voltage instability characterized by a sudden decline in bus voltages and an increased amount of reactive generation in the surrounding area. In recent years, the multi-agent system (MAS) has been applied in many fields of power engineering including fault diagnosis, network control, power system restoration, automation and market simulation [10]. Besides these applications, MAS has also been applied in demand response and distributed storage management in microgrid [11], wide area current differential protection system [12], generation scheduling and demand side management for real-time operation of microgrid [13] and combined preventive and corrective power system emergency control [14]. MAS can facilitate self-organizations, self-steering and control paradigms with complex behavior even when the individual strategies of all their agents are simple.

Both centralized and decentralized coordination strategies have been reported in the literature to control the agents in MAS [15]. However, when a system faces a catastrophic situation due to multiple contingencies, it is necessary to provide a fast emergency reactive power support to the affected region. This can be achieved using a decentralized coordination strategy of intelligent agents to avoid the delay in transferring information to the central controller from the affected areas, performing calculation and receiving commands from the central controller. In this paper, a decentralized coordination strategy of the local zones is proposed, where each local zone can make a quick autonomous decision to find the best solution for the power system following multiple contingencies to prevent voltage instability.

Many recent works have been reported in the literature for voltage control following system contingencies using MAS. A multi-agent collaboration protocol of secondary voltage controllers such as SVC and STATCOM to eliminate voltage violations in the pilot nodes has been proposed in [16]. The voltage controllers are treated as agents and a fuzzy logic learning algorithm has been used to train the agents. A similar approach using a different learning algorithm has also been proposed in [17] where the agents were trained by distributed reinforcement learning algorithm. Reference [18] used the contract net protocol to control the reactive power and voltage violation in case of a large disturbance. All these methods can provide voltage support to a certain extent depending on the reactive power capacity of the
reactive power sources; however, these papers have not taken into account the effect of not having enough reactive power capabilities and the need for load shedding. Reference [19] proposed a multi-agent technique for both the voltage and reactive power control to prevent voltage instability. In this method, the primary bus voltage is controlled by ‘reactive power control’ and the secondary bus voltage is controlled by ‘voltage control’. While the proposed method can maintain the voltages in the substations between the allowable ranges, the method does not take into account the generators’ over-excitation and the subsequent exciter current limiter protection which can drive the system towards voltage instability. A multi-agent approach including emergency reactive power dispatch and load shedding has been proposed in [20]. The authors proposed a request-interaction protocol for VAR dispatch and contract-net-protocol for load shedding to control both the system voltage and generators’ over-excitation in case of multiple contingencies. However, the author did not mention any strategy to optimize the VAR rescheduling and load shedding. A multi-agent based distribution system voltage control using contract-net-protocol has been proposed in [21]. An iterative negotiation between the agents has been suggested to correct the voltage in the distribution feeder. The iterative negotiation will lead to more time in finding an optimum solution. It is not suitable for the application during system emergency, where time is of essence.

In this chapter, a novel design of MAS using the existing SCADA based control structure is proposed. The remote terminal units (RTU), that can measure the electrical parameters such as voltage, current, power, frequency in the associated substations, will be used as intelligent agents. At first, the network will be divided into local zones, where the generators and the loads have maximum voltage/reactive power coupling. An adaptive determination of the local zones has been developed based on the electrical distances among the generators and loads. Then the agents in each zone will work cooperatively to find the optimum control action to achieve an acceptable post-disturbance equilibrium condition. The multi-agent cooperative control protocol can coordinate a group of agents and achieve their group goals in real-time. The controls considered in this paper are varying the generator voltage reference setting and, as a last resort, load shedding. Reactive power sensitivity factors and voltage sensitivity factors to active and reactive power load have been
formulated to determine the optimum amount of reactive power dispatch and load shedding.

4.2 Zone Identification and Zone Formation

Since the effect of transmission line outages on the system is initially limited in a small zone, close to the point where contingency occurs, the power system, therefore, can be divided into local zones to utilize the limited geographical effect of the outage. These are the areas where the loads and the generators have sufficient electrical proximity so that when the system undergoes any critical disturbance, the actions of the controller in the affected zone can interpose prompt maneuver of the system towards the acceptable operating states and can have more impact on the voltage improvement.

The concept of electrical distance developed in [22] provides a good measure to identify different zones in the power system. Electrical distance is the impedance path between different nodes of the system and measures the relative voltage coupling. The concept of electrical distance is used in this chapter to identify the different zones of voltage and reactive power control within the power system.

4.2.1 Measures of Electrical Distance

Electrical distance has been used in a number of power system problems [22]-[26]. There are a number of variant measures of electrical distance for a power network.

4.2.1.1 Sensitivity based method

It can be quantified by the sensitivity matrix $\frac{\partial V}{\partial Q}$ which is the inverse of the matrix $\frac{\partial Q}{\partial V}$. $\frac{\partial Q}{\partial V}$ is part of the Jacobian matrix which appears during a load-flow computation following the Newton-Raphson method [22], [24]. In this approach, the electrical distance is calculated as the attenuation of voltage variations between two nodes $i$ and $j$ given by

$$
\alpha_{ij} = \frac{\partial V_i}{\partial Q_j} / \frac{\partial V_j}{\partial Q_j}
$$

(4.1)

4.2.1.2 Travelling wave based method

The electrical distance has been calculated based on the time of energy transfer between two nodes in the system [25]. The difference between the phase angles of
the travelling electromagnetic waves at these nodes is considered as the electrical distance.

**4.2.1.3 Input impedance based method**

The electrical distance has also been defined as the input impedance between two buses as:

\[ Z_{ij,\text{in}} = Z_{ii} + Z_{jj} - 2Z_{ij} \]  

(4.2)

where \( Z_{ii} \), \( Z_{jj} \) and \( Z_{ij} \) are the elements of the bus impedance matrix.

**4.2.1.4 Bus admittance matrix based method**

One of the simplest methods is to use the absolute value of the inverse of the system admittance matrix [26]:

\[
[D] = \left| Y_{\text{bus}} \right|^{-1}
\]

(4.3)

This distance matrix \([D]\) with elements \( d_{ij} \) gives the active and reactive power sensitivity with voltage changes between bus \( i \) and \( j \). The smaller the electrical distance, the higher the impact on the voltage change by the change in active and reactive power (for example due to a load shedding).

The elements of the bus admittance matrix are usually readily available, prior to the disturbances, from the control center, and as will be shown in the following section, the elements can be easily modified in case of contingency by the agents incorporating the system topology change into the bus admittance. In this way, the proposed multi agent system can respond quickly from an earlier known admittance matrix. During the emergency condition, no global knowledge of the system is required. This method has been adopted in this chapter for real time local zone identification.

**4.2.2 Defining Zones by Electrical Distance**

The performance of the local voltage control will depend on how the zones are determined. The zones can be determined by a bottom-up or agglomerate hierarchical clustering algorithm starting from the individual generator nodes and gradually encompassing the entire grid [24]. Another method is the K-means clustering that uses a top-down, or divisive approach which begins with a complete network, and then divides the network into clusters and finally adjusts those clusters based upon some criteria. The aim of the K-means algorithm is to divide the \( n \) nodes
in the network into K clusters so that the cluster distances are minimized [27].

Reactive power cannot be transmitted over long electrical distance [28],[29]. Therefore, it is necessary to form the cluster in such a way that any load in the cluster gets sufficient reactive power support from the system.

This requires that every local zone should include buses that can generate reactive power such as buses with generator, synchronous condenser, Static VAR compensator (SVC), and on load tap changers that can regulate voltage.

Hence, a zone is first defined such that the load buses are grouped with the reactive power generating units, which are closest to the load buses in terms of their electrical distances. This resembles the typical method of K-means clustering with the cluster centers fixed at the generator buses [27].

Initially, the zones will be identified for the base case system without any contingency. Let, $x_i$ represents a load bus at node $i$ in the system and $N_G$ is the number of generators/synchronous condensers. $S_j$ represents a zone where $j = \{1,2,\ldots,N_G\}$, then $x_i$ is chosen to be in zone $S_j$ if the following criterion holds:

$$S_j = \{ x_i : d_{ij} \leq d_{ik} \forall 1 \leq k \leq N_G \}$$

(4.4)

where $d_{ij}$ and $d_{ik}$ are the distances between the load $i$ and generators $j$ and $k$, respectively.

In this way, each load bus is grouped with its nearest generator and there will be $N_G$ zones in the system with one generator in each zone. After forming all the zones, if some generators have very few load buses or no load bus, and then it is not realistic to keep them as separate zones. In this study, an strategy has been made that if a zone has less than or equal to one load bus, we call it an ineffective zone. The electrical distance between the generator in the ineffective zone and the generators in the neighbouring zones are compared. The lowest electrical distance is sought and the ineffective zone is merged into the neighbouring zone corresponding to the lowest electrical distance. Thus, the zones are automatically formed for the pre-disturbance base case system.

4.2.3 Zone Adaptation after Contingency

Initially, the zones will be identified for the base case system without any contingency. Since the system topology will change after a contingency, such as due
to transmission line outages, the electrical distances need to be recalculated using the modified bus admittance matrix \([Y']\). If there are \(N\) buses in the system and \(M\) transmission line outages, the modified matrix \([Y']\) can be calculated as:

\[
[Y'] = [Y] - [M][\delta y][M]^T
\]  

(4.5)

where \([Y]\) is the original \(N \times N\) admittance matrix, \([M]\) is a \(N \times M\) connection matrix and \([\delta y]\) is a diagonal matrix containing the admittance of the outaged lines in the diagonal. Each column in \([M]\) corresponds to each line outage and contains +1 and -1 at the positions of the sending and receiving end, respectively. The rest of the values of \([M]\) are zero.

According to the Inverse Matrix Modification Lemma (IMML) [13], the inverse of \([Y']\) can be calculated as

\[
[Y']^{-1} = [Y]^{-1} - [Y]^{-1}[M][c][M]^T [Y]^{-1}
\]  

(4.6)

where

\[
[c] = \ell([\delta y]^{-1} + [z])^{-1}
\]  

(4.7)

\[
[z] = [M]^T [Y]^{-1}[M]
\]  

(4.8)

In this way, the electrical distance can be obtained quickly from the absolute value of the inverse of the modified system admittance matrix as given in (4.6) from the base case bus admittance matrix \([Y]\), which is usually available in advance, prior to the disturbance. No global knowledge of the system is required during the disturbance when applying this zone adaptation.

4.3. Determining Optimal Countermeasures using Voltage Sensitivity Approach

In order to develop a real time control of voltage instability, the voltage sensitivity method could be used to calculate the appropriate amount of countermeasures such as the increase in the generator voltage reference setting and the amount of load shedding [30]. The control algorithm should be able to determine the optimum value of the countermeasures to restore the load voltage magnitudes to a safe level within a reasonable time span and by a minimal amount of control actions.

In this study, an attempt has been made to utilize the concept that the voltage increase in some selected generators/synchronous condensers would increase the load voltage magnitudes as well as relieve some of the generators whose reactive
power have exceeded their reactive power limits. In some cases, the reactive power outputs of these generators would be brought back below the maximum limit allowing them to participate in the control of the terminal voltages. The other control variable is load shedding which will come into action if the load voltages are not corrected by the action of generators’ terminal voltage increment and the operation of the automatic OLTC within a pre-specified time limit.

4.3.1. Varying the Generator Voltage Reference Setting

Assuming that each zone does not have the voltage information of the global network, the voltage sensitivities with respect to the generators’ reactive power outputs can be obtained from the decoupled load flow $Q-V$ equation [31] which can be written in matrix form as:

$$[\Delta Q/V] = [B][\Delta V]$$

(4.9)

where $B$ is the imaginary part of the bus admittance matrix.

The matrix given by (4.9) does not include the equations related to the generator buses in the traditional decoupled load flow formulation, because the voltages are specified for these buses. However in our proposed approach, the voltages of the generator buses will be varied to produce the necessary reactive power to reduce the reactive power deficit during post-contingency period. For this reason, the equations of the generator buses need to be included in (4.9). The generator buses and load buses can be separated where the matrix $B$ can be partitioned into four sub matrices as follows:

$$\begin{bmatrix}
\Delta Q_G \\
\Delta Q_L
\end{bmatrix} =
\begin{bmatrix}
B_{GG} & B_{GL} \\
B_{LG} & B_{LL}
\end{bmatrix}
\begin{bmatrix}
\Delta V_G \\
\Delta V_L
\end{bmatrix}$$

(4.10)

where, $\Delta Q_G$ (in MVAR) and $\Delta V_G$ (in pu) correspond to the reactive power and voltage changes in the generator buses, and $\Delta Q_L$ (in MVAR) and $\Delta V_L$ (in pu) correspond to reactive power and voltage changes in the load buses, respectively. In the case of varying the generator voltage reference setting, the load is unchanged, i.e. $\Delta Q_L = 0$, and equation (4.10) can be rewritten as:

$$\begin{bmatrix}
\Delta Q_G \\
0
\end{bmatrix} =
\begin{bmatrix}
B_{GG} & B_{GL} \\
B_{LG} & B_{LL}
\end{bmatrix}
\begin{bmatrix}
\Delta V_G \\
\Delta V_L
\end{bmatrix}$$

(4.11)

The incremental relationship between the change in the load voltage and the change in the generator voltage can be obtained from (4.11) assuming $B_{LL}$ is non-singular:
\[ \Delta V_L = -B_{ll}^{-1}B_{lg}\Delta V_G \] (4.12)

from which:

\[ \Delta Q_{V} / V_G = [B_{gg} - B_{gl}B_{ll}^{-1}B_{lg}]\Delta V_G \] (4.13)

Thus the load voltage sensitivity to the generator voltage change, denoted by \( S_{LV} \), is given by:

\[ S_{LV} = -B_{ll}^{-1}B_{lg} \] (4.14)

And the generator reactive power sensitivity to the generator voltage change, denoted by \( S_{QV} \), is given by:

\[ S_{QV} = (\text{diag}[V_G])[B_{gg} - B_{gl}B_{ll}^{-1}B_{lg}] \] (4.15)

After catastrophic disturbances, the load bus with the largest voltage drop will be selected as the target bus for the countermeasures. The load voltage sensitivity in (4.12) corresponding to the target bus will be used to find the generator bus that is most sensitive to the voltage change in the target bus. In this way, the voltage in the target bus can be improved by changing the voltage setting in the obtained generator bus. Once the most effective generator bus is found, and knowing the reactive power reserve (the reactive power limit minus the current reactive power output of the selected generator), the amount of voltage setting increase in the generator bus can be determined from (4.13), which should result in the increase of the target load bus voltage. As extra reactive power is injected into the system, all the other nodal voltages in the zone will also be improved. It is to be noted that only the voltage information in the zone is required.

### 4.3.2. Load Shedding

After the preliminary countermeasures of raising the terminal voltage of selected generators and synchronous condensers, the on-load tap changers are allowed to change automatically to try to improve the load voltages for a fixed period of time. This period of time is chosen in such a way that a margin of time is given prior to the operation of the over-current limiter in the rotor field circuit to limit the reactive power output of one of the generators which have exceeded their reactive power limit that can lead to the onset of voltage instability. If some load voltages are still below the lower limit at the end of the fixed period of time above, a strategic load shedding needs to be performed and the amount of load shedding can be calculated using the voltage sensitivity to active and reactive power load. Load shedding is a very
effective mean of emergency voltage control if performed at right location, at the right time and at the right amount.

The decoupled load flow equations do not directly give the relationship between the voltage and the real power. Hence, to derive the load voltage sensitivity to active and reactive power load changes, the load flow equations are written in a rectangular form assuming a ‘flat start’ condition (all the load voltages are 1 pu. and angles are zero) as given in (4.16):

\[
\begin{bmatrix}
\Delta P \\
\Delta Q
\end{bmatrix} =
\begin{bmatrix}
G & B \\
B & -G
\end{bmatrix}
\begin{bmatrix}
\Delta e \\
\Delta f
\end{bmatrix}
\]  

(4.16)

where \(\Delta e\) (in pu) and \(\Delta f\) (in pu) are the real and imaginary parts of the voltage difference, \(G\) and \(B\) are the real and imaginary parts of the bus admittance matrix, and \(\Delta P\) (in MW) and \(\Delta Q\) (in MVAR) are the changes in active and reactive power load, respectively.

From equation (4.16), the voltage difference can be expressed in terms of real and reactive power as:

\[
\begin{bmatrix}
\Delta e \\
\Delta f
\end{bmatrix} =
\begin{bmatrix}
S_{eP} & S_{eQ} \\
S_{fP} & S_{fQ}
\end{bmatrix}
\begin{bmatrix}
\Delta P \\
\Delta Q
\end{bmatrix}
\]  

(4.17)

where \(S_{eP}\), \(S_{eQ}\), \(S_{fP}\) and \(S_{fQ}\) are the sub-matrices that provide the sensitivities between voltage and power. \(S_{eP}\) is the partial sensitivity of the real part of the voltage difference with respect to real power load, and similarly others. In the case of a load shedding at bus \(k\), all the \(\Delta P\) and \(\Delta Q\) values at other nodes can be set to zero except for \(\Delta P_k\) and \(\Delta Q_k\). The change in \(i\)-th bus voltage magnitude due to load shedding at \(k\)-th bus can be obtained as:

\[
\Delta V_i = \sqrt{(\Delta e_i^2 + \Delta f_i^2)}
\]  

(4.18)

Using (4.17), equation (4.18) can be rewritten as

\[
\Delta V_i = \sqrt{(S_{eP}(i,k) \Delta P_k + S_{eQ}(i,k) \Delta Q_k)^2 + (S_{fP}(i,k) \Delta P_k + S_{fQ}(i,k) \Delta Q_k)^2)}
\]  

(4.19)

In the case of load shedding, the load power factor is assumed to be constant, and eqn. (4.19) can be rewritten as:

\[
\Delta V_i = \sqrt{(S_{eP}(i,k) + S_{eQ}(i,k) \sqrt{1 - \Psi_k^2 / \Psi_i^2})^2 + (S_{fP}(i,k) + S_{fQ}(i,k) \sqrt{1 - \Psi_k^2 / \Psi_i^2})^2} \Delta P_k
\]  

(4.20)
where, the power factor at node \( k \) is,

\[
\Psi_k = \frac{P_k}{\sqrt{P_k^2 + Q_k^2}}
\]  

(4.21)

Equation (4.20) can be re-written in the following form:

\[
\Delta V_i = S_{V_L}(i, k) \Delta P_k
\]

(4.22)

where, the voltage sensitivity at bus \( i \) to the active power (and implicitly voltage sensitivity to the reactive power) load shedding at bus \( k \) is given by:

\[
S_{V_L}(i, k) = \sqrt{((S_{\rho}(i, k) + S_{\sigma}(i, k)\sqrt{1 - \Psi_k^2 / \Psi_i^2})^2 + (S_{\rho}(i, k) + S_{\sigma}(i, k)\sqrt{1 - \Psi_k^2 / \Psi_i^2})^2)}
\]

(4.23)

The load bus with the largest voltage drop after the fixed period of time specified is chosen as the target bus for load shedding. The load voltage sensitivity in (23) corresponding to the target bus will be used to find the load bus where the load shedding in that bus is most sensitive to the voltage change in the target bus. In this way, the voltage in the target bus can be best improved by shedding a minimal amount of load in the selected load bus. The amount of the desired voltage increase in the target bus can be determined from the difference between the lower limit of the target voltage bus and the current voltage value. Once the most effective load bus for the load shedding is found, the amount of load shedding in that bus can be determined from (4.20). The maximum amount of load available for load shedding in the selected load bus is the current load that can be interruptible in that bus. If the amount of load shedding calculated from (4.20) is less than the available interruptible load, then the desired voltage in the target bus can be obtained by applying the load shedding in the selected bus. Otherwise, the above procedure will be repeated until the desired voltage at the target bus is achieved by successively applying load shedding in the next sensitive buses.

4.4 MAS based Reactive Power and Voltage Control

Modern power system is equipped with SCADA (Supervisory Control and Data Acquisition) that monitors and controls the entire system over a large area. The SCADA consists of a number of different devices communicating with each other, such as HMI (Human Machine Interface), MTU (Master Terminal Unit) and RTU.
A central MTU is located in the control center which communicates with the RTUs. The RTU is a composite device that collects signal from a sensor and converts the sensor signal to digital data and sends them to MTU. It is also responsible for executing instructions coming from the MTU. The accessibility of information among the RTUs has been made possible by direct communication between RTUs. A typical SCADA system architecture is shown in Fig. 4.1.

![SCADA system architecture](image)

**Fig. 4.1.** SCADA system architecture

The main constraint in the SCADA based control system is that the RTUs are located far from the control center and in emergency the response from the control center may be too slow to direct necessary countermeasures in time to avoid potential voltage instability. Further, there is always a threat to the communication security resulting from network damages by cyber attacks. For this reason, many of the modern RTUs are powerful enough to act as intelligent agents to autonomously monitor network parameters, communicate to other RTUs and make decisions without involving the host computers of the SCADA system.

The term ‘intelligent agent’ means an entity embedded with computer program that can automatically carry out some assigned tasks and can take autonomous decisions based on negotiation and any decision-making algorithm. An intelligent agent is an agent which exhibits proactivity (goal-directed behaviour), social ability (ability to interact with other agents) and reactivity [34].

### 4.4.1. Proposed MAS Architecture

The architecture of the multi-agent system proposed for emergency voltage and reactive power control is shown in Fig. 4.2. Two types of agent have been considered for the proposed voltage/reactive power emergency control: Generator Agent (GA)
and Load Agent (LA). The proposed architecture has two layers: Reactive Layer and Deliberative Layer and follows a vertical layered architecture [34]. The LAs work in the reactive layer and are modelled as simple reflex agents [35]. The agent function is based on some pre-defined condition-action rules i.e. if load voltage below minimum limit then send REQUEST message to GA etc. When a critical contingency that produces violations in the load voltage magnitudes occurs in the system, the deliberative layer becomes active. Both GAs and LAs work in this layer to systematically remove the load voltage violations through negotiation and based on the sensitivity model of the system. The GAs exhibit model-based goal-oriented behaviour [35]. The goal is to improve the load voltages above the minimum admissible limit with minimal amount of load shedding.

![Layered architecture of the proposed MAS](image)

Fig. 4.2. Layered architecture of the proposed MAS

Fig. 4.3 shows the functional diagram of the agent-based RTU in the MAS environment. The agents within the RTU perceive the environment through sensors and act upon it through the actuators. The inputs to the sensor are the local electrical parameters such as voltage, current, tap position, breaker status, etc. A two-way communication link among the RTUs provides the message transfer capability for the agent interaction. Decision is made based on the local measurement as well as the information received from other agents.

GA takes the measurements of voltage and reactive power from the system and sends it to the control processing unit. The control processing unit also gets the messages from other agents through the communication interface. GA takes the necessary decision on the adjustment of the generator’s terminal voltage based on the control algorithm and implements it through the actuator by changing the AVR.
reference voltage. The decision of load shedding is implemented by LA which also works in a similar fashion. It applies load shedding to the associated bus by opening the circuit breaker in the feeder through the interposing relay operation.

4.4.2. MAS Control Strategy and Agent Co-ordination

One of the important factors in designing a multi-agent system is the agent interaction to achieve a global objective. The Foundation of Intelligent Physical Agent (FIPA) has developed certain interaction protocols using a standard set of communicative act with a well-defined semantics [36]. A widely accepted task sharing protocol in multi-agent system is the Contract Net Interaction Protocol (CNP) [37].

---

Fig. 4.3. Agent based RTU structure
In this protocol, each agent is represented as a manager or a contractor. When an agent realises that it cannot solve the present task by itself, it announces the task to other agents in the system and act as a manager of that task. An agent that receives the announcement will decide whether it is capable of carrying out the task and if so submits a bid for the task as a contractor. The manager agent then receives the bids from the potential contractors and decides who should be awarded the contracts in order to achieve an optimal solution of the task. The contract awards are then communicated to the agents that have submitted the bids. The winning contractors then take the initiative to fulfil the assigned task. An agent can be simultaneously a manager and a contractor for different tasks. The negotiation process during the CNP is shown in Fig. 4.4.

![Negotiation Process Diagram](image)

**Fig. 4.4.** Negotiation process during the CNP

In the proposed multi-agent based emergency control system, the contract-net-protocol will be used for agent interaction. The GA can act both as a manager and a contractor, whereas the LA will act as a contractor only. The step by step procedure of the negotiation strategy is given as follows:

**Step 1:** After a contingency has been identified in the system, the LA at each of the terminals of the outaged line broadcasts a message informing the event to all the neighbouring agents. The agents that receive the message update their electrical distances and subscribe to their nearest generator as described in section II. In this way, GAs obtain the information of the modified zone.

**Algorithm:** Zone Forming Algorithm

**Input:** Load Agents (LA), Generator Agents (GA)
**Output:** Zones

for each LA $\alpha$ do

for each GA $\beta$ do

Calculate $d_{\alpha\beta}$;

end

$\beta_{\min} = \arg \min \beta d_{\alpha\beta}$;

$\text{Zone}_{\beta_{\min}} = \text{Zone}_{\beta_{\min}} \cup \{ \alpha \}$;

end

The LAs that find their load voltages lower than the specified limit inform the GA the magnitude of the voltages and request for voltage support. The GA, after knowing the load voltage magnitudes in the zone, selects the load bus with maximum voltage deviation from the reference value as the target bus for the control actions.

**Step 2:** The GA in the violated voltage zone specifies a task of reactive power support issuing a call for proposal (CFP) to other GAs in the system and acts as a manager GA. The GAs that receive the message inform the manager GA of their available reactive power reserves and the terminal voltages. The manager GA after receiving all the bids from the GAs, or after the deadline, will calculate the amount of reactive support for the potential contractors. This will be assigned as follows:

The generator $i$ with the highest voltage sensitivity factor, $S_{LV}(tg,i)$ to the target bus voltage and with a positive reactive power reserve will be chosen first to dispatch. The amount of reactive power increase $\Delta Q_{Gi}$ can be calculated as:

$$\Delta Q_{Gi} = \min \left\{ \frac{S_{QV}(i,i)}{S_{LV}(tg,i)} \times (V_{tg}^{\text{min}} - V_{tg}), \Delta Q_{Ri} \right\}$$

where $V_{tg}$ and $V_{tg}^{\text{min}}$ are the current voltage and minimum operating voltage of the target bus respectively, $\Delta Q_{Ri}$ is the reactive power reserve of the $i$-th generator, and $V_{Gi}$ and $V_{Gi}^{\text{max}}$ are the current terminal voltage and maximum terminal voltage of the $i$-th generator respectively. If the amount of reactive power is not sufficient to raise the target bus voltage to the desired value, the reactive power reserves of the generators are updated as:

$$\Delta Q_{Rj}(\text{new}) = \Delta Q_{Rj}(\text{old}) + S_{GV}(i,j) \times \Delta V_{Gi}, \quad j \in N_{G}$$

where $\Delta Q_{Rj}(\text{old})$ is the previous reactive power reserve and $\Delta Q_{Rj}(\text{new})$ is the updated reactive power reserve. The generator with the highest value of the sensitivity factor
and with a positive reactive power reserve is selected again as the next candidate to increase the reactive generation. The process is repeated until the desired voltage support at the target bus is achieved or the limit constraints are met. The manager GA then sends an accept-proposal act to the contractor GAs to increase the terminal voltage of the generator by the specified amount. The process of the optimal reactive power dispatch is shown in the flow diagram in Fig. 4.5.

**Step 3:** After completing the reactive power scheduling task, the manager GA waits for a fixed period of times to allow other normal voltage control actions to operate, such as switched capacitors, OLTC, etc. If the target bus voltage does not come within the limit by the end of the fixed period, the GA initiates the load shedding procedure. The GA sends a call for proposal (CFP) to the LAs in the zone. The LAs reply with their load voltages and load active and reactive powers. The

**Fig. 4.5.** Flow diagram of the control strategy
amount of load shedding is calculated following the same procedure described in step 2.

First, the load bus \(i\) with the highest value of sensitivity \(S_{VL}(tg,i)\) is selected to shed the load. The load shedding amount \(\Delta P_L\) is calculated as:

\[
\Delta P_L = \min(P_{Li}, \frac{V_{REF}^{tg} - V_{tg}^{tg}}{S_{VL}(tg,i)})
\]  
(4.26)

where \(P_{Li}\) is the current load of bus \(i\). If the specified load shed at bus \(i\) does not bring the target voltage over the minimum limit, the load bus with the second highest value of sensitivity is selected for further load shedding. This continues until the target bus voltage come within the limit.

The amount of load shedding so calculated will be sent to the respective LAs. These LAs, after receiving this information, will curtail the loads by successively opening the distribution feeder until the loads are shed by the desired amount.

The proposed multi-agent system is different to that described in [21], as the communications between the generator and load agents are assigned in a single time step rather than iteratively as suggested in [21]. This reduces the communication overhead between the agents. After the target bus voltage has been controlled to be within the limit, the GA checks whether there is any other voltage violation in the zone or not. The process is repeated until all the voltages come within allowable limits as shown in Fig. 4.5.

4.4.3. Design and Implementation of the Proposed MAS

The proposed MAS has been implemented using Java Agent Development Framework (JADE) [34]. JADE is a FIPA compliant open source agent simulation software with well-specified semantics for agent communication. It is implemented in Java programming language and works as a middleware for the development and run-time execution of peer-to-peer applications that use agents. The negotiation among the agents in JADE is performed through interchanging messages which use FIPA-specified Agent Communication Language (ACL). The ACL messages passed among the agents are characterized by (i) performative (ii) conversation ID (iii) sender (iv) intended receiver and (v) content.

In order to fulfil the task of decentralized emergency voltage control, the agents need to communicate with each other to exchange information of bus voltages and
generator reactive powers. This information is shared among the agents through transmission of messages with pre-defined templates. Table 1 shows the required information of the agents both in normal and emergency states in order to take part in the control mechanism and negotiation. This work is done within the agent behaviours. In this paper, we have defined five user-specified agent behaviours; each of them is the extension of agent’s cyclic behaviour. Table 4.1 shows the performative, conversation ID, content and sender/receivers of messages associated with the behaviours of the agents.

<table>
<thead>
<tr>
<th></th>
<th>Normal State</th>
<th>Emergency State</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator Agent</td>
<td>Bus admittance matrix</td>
<td>Load voltages</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Generator voltages</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Generator reactive powers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Load power consumption (active and reactive)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ID of the outaged line(s)</td>
</tr>
<tr>
<td>Load Agent</td>
<td>Load voltage</td>
<td>Load voltage</td>
</tr>
<tr>
<td></td>
<td>Breaker status</td>
<td>Load power consumption (active and reactive)</td>
</tr>
</tbody>
</table>

Table 4.1. Required Information of the Agents

4.4.3.1. Update Electrical Distance

This behaviour is implemented in step 1 of section 4.4.2. On the event of a line outage, the LA/GA nearest to the outaged line sends an INFORM message with conversation ID “Elec_Dis” to all other agents. The content of this message is “type, name, outaged bus number”. Type indicates whether it is from load agent or generator agent, name is the local name of the sending agent and outaged bus number is the sending/receiving end bus number of the outaged line. With this information, the agents can update the electrical distance as described in section 4.2.3.

4.4.3.2. Update Zone

This behaviour also corresponds to step 1 of section 4.4.2. After updating the electrical distance, the LAs send an INFORM message with conversation ID “Zone” to a GA to register with this agent. This GA has the lowest electrical distance with the sending LAs among all other GAs.
When a LA detects a violation in voltage, it sends a message to the GA with performative “REQUEST”, conversation ID “Voltage Support” and content as “type, name, bus voltage”, as described in step 1 of section 4.4.2.

4.4.3.4. Increase Reactive Power

The CNP for generator reactive power increase is implemented in this behaviour. Four types of messages are associated with this behaviour. The explanations of the messages are given in step 2 of section 4.4.2.

4.4.3.5 Load Shedding

The CNP for load shedding is implemented in this behaviour. Four types of messages are associated with this behaviour. The explanations of the messages are given in step 3 of section 4.4.2.
4.5. Test Results and Discussion

In order to evaluate the effectiveness of the proposed MAS based emergency control scheme, the IEEE-57 test system [38] shown in Fig. 4.6 has been simulated using PSAT [39] to carry out the proposed emergency reactive power and voltage control.

Fig. 4.6. IEEE 57 bus test system: (a) Initial zones of the system without adjustment (b) Initial zones of the system after adjustment.
The IEEE-57 test system has seven synchronous machines, each of which is modeled by a six order machine model including the type II Automatic Voltage Regulator (AVR) and over-excitation limiter (OXL) model. Initially, the electrical distances of all the buses prior to the contingency are calculated using (4.7) and the zones are defined using the clustering approach given by (4.11). Each load bus is grouped with its closest generator in terms of electrical distance as shown in Fig. 4.6(a). However, the generators at bus 1, 2 and 6 have very small areas. Therefore, they are merged into the neighbouring zones and finally four zones have been chosen for the pre-disturbance base case system as shown in Fig. 4.6(b).

The agents in JADE can read/write the power system data via Transmission Control Protocol (TCP/IP) communication through MATLAB Instrument Control Toolbox [40]. As shown in Fig. 4.7, the TCP_Agent in JADE collects the snapshot of the load voltages and generator reactive powers from PSAT at each control instance and transmits the data to the relevant agents. The required sensitivities for optimal control actions are computed by calling MATLAB from JAVA. The control actions resulted from the negotiation among the agents are then passed back to the TCP_Agent; which transfers these data again to PSAT.

4.5.1 Case 1: Line Outage of 36-37 and 37-38

The loss of lines 36-37 and 37-38 is simulated to test the proposed emergency reactive power and voltage controller. This has resulted in changes to electrical distances and required the re-zoning of some of the buses as shown in Fig. 4.8. The voltage profile of all buses prior and after the disturbances is shown in Fig. 4.9. Fig. 4.9 shows that the lowest voltage after the disturbance is at node 34.
4.5.1.1 Reactive Power Dispatch under Emergency

When any of the load voltage drops below a pre-specified limit, the emergency reactive power dispatch is activated. It is recommended to wait until transients have settled down and the line auto-reclosure time is exceeded. To allow this, the agents will start the negotiation process after 10 sec, if the voltage violation still occurs. During the 10 sec period, the LAs update the electrical distances and subscribe to the nearest generator to set up the zones, each of which can act like a MAS. In this case, only the generator at bus 9 (GA 9) has exceeded the maximum reactive power and the load voltages that have gone below 0.9 pu are also in zone 3. As a result, the...
countermeasures will be initiated only in zone 3. The load agents having bus voltages below 0.9 pu send request message to GA 9 in zone 3 for voltage support. The GA 9 in zone 3 finds the maximum voltage deviation at bus 34 and sets this bus as the target bus for the control actions. At first, GA 9 initiates the CNP for reactive power dispatch and sends a CFP to other generators.

It is anticipated that the deadline for sending the proposals is short enough to ensure quick responses from the generators. As a result, not all the generators in the system will be able to respond due to communication delay. But that does not hamper the control strategy because only the generators in the surrounding regions will have significant impact on the voltage improvement of the affected buses. Let us assume that only generators 8 and 12 have been able to respond to the CFP within the deadline. Therefore, only generators 8, 9 and 12 will be considered for the reactive power dispatch. GA 8 and GA 12 respond with their bids given below:

\[
\begin{align*}
\text{GA 8: } & (1.005, 64.096, 200) \\
\text{GA 12: } & (1.015, 129.71, 155)
\end{align*}
\]

The figures in the bids correspond to each generator’s terminal voltage (in pu), current reactive power generation and maximum Q limit (in MVAR), respectively. GA 9 knows its own generator’s terminal voltage, the Q-output and the Q-limit which are 0.97981 pu, 13.43 MVAR and 9 MVAR, respectively. Once GA 9 gets these values, it calculates the amount of voltage increase for the candidate generators and sends these dispatch awards to the agents which are:

\[
\begin{align*}
\text{GA 8: } & 0.0815 \text{ pu, } \\
\text{GA 9: } & 0.0578 \text{ pu, } \\
\text{GA 12: } & 0.0398 \text{ pu. }
\end{align*}
\]

Notice that GA 9 also increases its terminal voltage although initially its Q output was over the maximum limit. This is because the other two generators have increased the reactive power generation resulting in GA 9 reactive power to go below its reactive power limit and hence the terminal voltage of GA 9 is allowed to be increased. Once the GAs receive their contracts, they increase their voltages accordingly by increasing the AVR reference voltages.

\subsection{Load Shedding Under Emergency}

In this case, the deadline for load shedding is considered to be 30 seconds i.e. after 30 seconds of the disturbance, if the voltages and reactive powers are not within limits, the GA will start the load shedding procedure. After 30 seconds, the lowest bus voltage is found to be 0.78759 pu at bus 34. As a result, GA 9 selects this bus as a target bus and starts the load shedding procedure. GA sends another CFP to the
LAs in the zone. The LAs reply with the current voltage and power. Then GA 9 starts the process of load shedding. The solution converges with 6 MW load shedding at bus 35 and 2.97 MW load shedding at bus 33. After applying the specified amount of load shedding, the target bus voltage is found to be 0.90982 pu, which is within the limit and no other voltage violation exists. So, a solution has been obtained and therefore MAS stops the control process. The improvement in the load bus voltages and the generator reactive powers are shown in Fig. 4.10 and the voltage profile at different stages are shown in Fig 4.11.

![Graph](image-url)

*a* Fig. 4.10. The bus voltages (a) and reactive power (b) change for contingency in case 1.
4.5.2 Case 2: Line Outage of 31-32 and 32-34

Before applying this contingency, the system load was increased by 20 percent except for those buses where load increase causes voltage violation. This case has been selected to show the effectiveness and performance of the proposed MAS based control strategy in the case of more than one zone is affected. After applying the contingency, the zones are modified according to the electrical distance which is shown in Fig. 4.12.

Fig. 4.11. Voltage profile at different stages for contingency in case 1.

Fig. 4.12. Modified zones for the contingency in case 2.
In this case, both zones 1 and 4 are affected and the target buses for these zones are bus 31 (0.83792 pu) and bus 32 (0.8594 pu), respectively. So, GA 8 and GA 12 start the control procedure and send CFP for generator reactive power scheduling. Assuming that GA 6 responds to GA 8, and GA 1 responds to GA 12, the submitted bids for these generators are:

GA 1: (1.04, 141.26, 200)       GA 6: (0.98, 14.98, 25)

The similar values of terminal voltages and reactive powers of GA 8 and GA 12 are:

GA 8: (1.005, 86.5, 200)       GA 12: (1.0093, 155.6, 155)

The calculated voltage increases for these generators are:

GA 1: 0.0129 pu.,     GA 6: 0.0322 pu.
GA 8: 0.0509 pu.,     GA 12: 0.0104 pu.

At 30 sec, the target bus voltages are still below 0.9 pu (0.86224 pu at bus 31 and 0.87273 pu at bus 32). As a result, GA 8 and GA 12 start the load shedding procedure in their zones, namely zone 4 and zone 1, respectively. In this case, the amount of load shedding as calculated by the manager agents are 2.6 MW at bus 31 in zone 4 and 2 MW at bus 32 in zone 1. When the LA 31 and LA 32 shed the specified amount of load, the voltages at these buses rise to 0.9006 pu and 0.8998 pu, respectively. Since these values are within the tolerance limit of 0.001pu, the solution is accepted. All the load bus voltages are within the acceptable limits (0.9-1.1 pu) as shown in Fig. 4.13 and the agents stop the control procedure. Fig. 4.13 shows the voltage profiles at different stages of the control process for the above contingency.

![Fig. 4.13. Voltage profile at different contingency in case 2.](image-url)
Fig. 4.14 shows the load bus voltage magnitudes and the changes in the reactive power outputs of the generators. It can be observed that the reactive power outputs of all the generators involved have been increased to their maximum limits and the load shedding at 30 sec has resulted in the voltages at the target bus voltage (bus 31 and 32) magnitudes to be within the tolerance of the limits specified.

![Graph of reactive generation and voltage change](image1)

Fig. 4.14. Change in reactive power outputs of the generators (a) and load voltage (b) for contingency in case 2.

4.5.3. Case 3: Effect of Communication and Implementation Delay

The proposed MAS based emergency voltage control scheme might introduce a delay in implementing the actions because of the communication among the agents. In particular, the load shedding will be performed by direct tripping the load from the utility transmission sub-station through under-voltage relay installed at the primary of the distribution sub-station located close to key transmission sub-stations [41]. This would also cause additional delay in actually shedding the loads. Fig. 4.15 shows the delay between the detection of voltage violation and the actual
implementation of the countermeasures on a time scale. The total delay $T_{\text{delay}}$ can be expressed as

$$T_{\text{delay}} = t_{\text{neg}} + t_{\text{com}} + t_{\text{imp}}$$

(4.27)

where $t_{\text{neg}}$ is the time required by the agents for negotiation which includes the communication delay among the agents, $t_{\text{com}}$ is the time for computation of the sensitivities and algorithm and $t_{\text{imp}}$ is the time to implement the actions after decision making.

Fig. 4.15. Delay time between the occurrence of voltage violation

Long term voltage instability scenario is typically monotonic [8] i.e. the voltage decays slowly over a period of minute or more before abruptly collapsing. Based on this assumption, one can expect that the countermeasures can be successfully implemented with the above mentioned delays without causing any significant deviation in the response. To illustrate this, we have considered 10 seconds delay between detection and implementation by the proposed MAS for the scenario described in case 1. Fig. 4.16 shows the voltage at bus 34 in case 1. For comparison, the response without delay is shown in dotted line. It can be seen that the countermeasures can successfully stabilize the system.

Fig. 4.16. Voltage at bus 34 in case 1 with and without considering delay.
The actual delay in the response of the proposed MAS will depend on the communication facility in the transmission system and between the RTU and IED (Intelligent Electronic Device) relay that will trip the distribution feeder. The wide-area network based on high speed optical fibre network with 155.52 Mbps can facilitate to communicate over 180 km distance with 1.3 ms delay time [42]. With the extensive deployment of substation automation, Ethernet based local area network can be applied for communication between RTU and IED relay. According to IEEE standard 802.3, for an Ethernet with a maximum of 2.5 km in length and four repeaters, the maximum transmit delay should not exceed 25.6 µs [43]. Thus, it is quite feasible to successfully implement the proposed MAS with the above mentioned delays considering modern communication facility of the system.

4.6 Conclusion

Within the structure of modern power system control, a multi-agent based emergency control scheme under multiple contingencies has been proposed in this chapter. The simulation results show the effectiveness of the proposed control strategy to maintain acceptable voltage profile under emergency conditions. This method can provide quick and effective voltage support in system contingencies when the disturbances in the affected zone can be identified. However, it is necessary to facilitate interaction among the neighbouring zones when more than one zone is taking countermeasures to account for the effect of the overall control action. The main contribution of the chapter is the novel adaptive determination of the local zones and the development of a multi-agent decentralized control algorithm to determine the most optimum countermeasures at zones near the disturbances to maintain the load voltages and reactive power outputs of the generators in the allowable operating limits.

References


CHAPTER 5

A MULTI-AGENT RECEDED HORIZON CONTROL WITH NEIGHBOUR TO NEIGHBOUR COMMUNICATION FOR PREVENTION OF VOLTAGE COLLAPSE IN A MULTI-AREA POWER SYSTEM

ABSTRACT

In this chapter, a multi-agent receding horizon control is proposed for emergency control of long-term voltage instability in a multi-area power system. The proposed approach is based on a distributed control of intelligent agents in a multi-agent environment where each agent preserves its local information and communicates with its neighbours to find an optimal solution. In this chapter, optimality condition decomposition (OCD) is used to decompose the overall problem into several sub-problems, each to be solved by an individual agent. The main advantage of the proposed approach is that the agents can find an optimal solution without the interaction of any central controller and by communicating with only its immediate neighbours through neighbour-to-neighbour communication. The proposed control approach is tested using the Nordic-32 test system and simulation results show its effectiveness, particularly in terms of its ability to provide solution in distributed control environment and reduce the control complexity of the problem that may be experienced in a centralized environment. The proposed approach has been compared with the traditional Lagrangian decomposition method and is found to be better in terms of fast convergence and real-time application.

Keywords —Multi-agent System, Optimality Condition Decomposition
Receding Horizon Control, Voltage Instability.
5.2 Introduction

Emergency voltage control has become an important task to be implemented by the power system control centre and has gained much attention among the research community, especially after several wide-spread black out events throughout the world in the last few decades [1, 2]. An added concern is the complicated situation to fulfill this task by the transmission system operator (TSO) arising from the large scale inter-connection of electric power system. Furthermore, reported incidents on voltage collapse has shown that the time-span between an initiating disturbance and system breakdown is too limited and too complex for the TSO to take manual control action to prevent the system from undergoing voltage instability [3]. According to the stability definition of IEEE/CIGRE task force [3], voltage stability refers to the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition. Instability that may result occurs in the form of a progressive fall or rise of voltages of some buses. Voltage collapse refers to the process by which the sequence of events accompanying voltage instability leads to a blackout or abnormally low voltages in a significant part of the power system. As a result, many automatic voltage control schemes have been proposed in the literature that deal with the real time assessment of the control system to avoid voltage collapse during emergency condition involving several coincident disturbances [4] [5] [6].

Recently, many emergency voltage control strategies have been developed using the concept of Receding Horizon Control (RHC) (also known as Model Predictive Control (MPC)) [7 - 15]. RHC is a special class of online control strategies in which the control actions and closed-loop feedback of the system are computed at each moving window of time rather than at a single time instance. In the context of voltage control, this strategy helps to take advantage of the dynamic system evolution and to provide a feasible transition to stable system equilibrium. A pioneering work using RHC technique is the co-ordinated secondary voltage control addressed in [6]. In this study, the original predictive control scheme is separated into two sub-problems, namely the static and dynamic sub-problems taking into account the transmission delays and asynchronous measurement. A tree search method has been employed in [8] to co-ordinate the generator voltages, tap-changers and load shedding in the RHC approach and an Euler State predictor (ESP) has been used to
predict the output state trajectories. Reference [9] also used ESP based on non-linear system equations and the optimization problem was solved using pseudo-gradient evolutionary programming (PGEP). A RHC based real time system protection scheme against voltage instability by means of capacitor switching is proposed in [10]. A receding horizon multi step optimization has been used in [11] based on the steady state power-flow equations to alleviate unacceptable voltage profile. The evolution of the load power restoration due to On Load Tap Changing Transformers (OLTCs) and the activation of the over-excitation limiter (OEL) were formulated explicitly to capture the dynamic behaviour of the system. In [12], a sensitivity approach based on linearized power flow equations was presented using MPC (or RHC) to control transmission voltages. Reference [13] also used the sensitivity based approach and a variable reference trajectory to adaptively determine the amount of load shedding for voltage control.

All the aforementioned methods are of the centralized architecture in which the control actions are implemented by a central controller. However, due to large scale interconnections among transmission networks spanning over a wide geographic regions, the centralized formulation of the RHC strategy may have some difficulties because of the huge computational cost and communication facility, requirement of the global knowledge of the system and a single point of failure. Moreover, with the introduction of deregulation and market liberalization in the power utilities, many of them are reluctant to disclose their local information. These facts have led to the distributed approach of RHC technique by many researchers [14 -15]. A non-cooperative distributed RHC with neighbour-to-neighbour communication has been put forward in [14] to co-ordinate the LTC actions to prevent voltage collapse. The approach is based on the Nash equilibrium of different coordination areas; however this will not provide a globally optimal solution. A Lagrangian decomposition based optimal control scheme has been proposed in [15] in an iterative fashion to find the global optimal solution. The key idea behind this approach is to solve a local problem which is a sub-problem of the original global problem and update some parameters by a central controller until a convergence is achieved. This approach still needs a central controller to co-ordinate the sub problems to find the optimal solution. In [16-18], evolutionary algorithms are used to determine or improve voltage collapse margin for system planning purposes; however these are not
generally suitable for dynamic type of optimisation in the receding horizon control, as system conditions and operating points change continuously during an emergency.

This chapter proposes a novel emergency voltage and reactive power control approach based on the multi-agent structure of RHC scheme using optimality condition decomposition (OCD) to decompose the overall problem into several sub-problems, each to be solved by an individual agent. An on-line distributed optimization technique is employed based on the linearized steady state model of the system. The optimization problem is formulated as a quadratic programming problem and an algorithm for global co-ordination is presented to get the optimum operating point. The agents only require communication with the neighbours, and no central co-ordinator is necessary for the convergence of the algorithm.

5.3 Multi-agent Receding Horizon Control

Receding Horizon Control (RHC) is one of the most widely used advanced control strategies which has been successfully applied in the process industries [19]. One of the most useful features of this framework is the ability to handle input and output constraints efficiently by formulating a discrete-time control model of the system. The conceptual structure of the RHC approach is shown in Fig. 5.1. The main idea is to formulate an on-line optimization problem subject to input and output constraints which results in a sequence of future control actions over a control horizon \((N_C)\) given a system model in hand. The output is predicted over a prediction horizon \((N_P)\) which is usually different from \(N_C\). The first sequence of the so-computed actions is actually implemented and the process is repeated at the next sampling time when new measurements are available.

According to Fig. 5.1, a set of admissible control sequence \(u = \{u_k, u_{k+1}, \ldots\}\)
$u_{k+Nc-1}$ is computed at a given discrete time instance $k$ to minimize the output trajectory deviation from the desired reference set point over the prediction horizon with minimum control efforts. In the single agent architecture, this optimization is performed by a central controller. The central agent thus requires the knowledge of the complete model of the system and the system-wide measurement should be available to the agent.

In a multi-agent receding horizon control (MARHC), multiple control agents use RHC where each agent is assigned to control a sub-system which is a part of overall system [20]. The agents first evaluate the sub-system states, compute the best control actions for the predicted sub-system state and input evolution and then implement actions. The actions that an agent takes in a MARHC structure influence both the evolution of its own sub-system and the evolution of the sub-system connected to it. Since the agents usually have no global overview and can access only a limited portion of the overall network, the future sub-system state prediction becomes uncertain without any interactions among the agents. Therefore, a communication network must be established among the agents (see Fig. 5.2). The challenge in implementing such a multi-agent RHC strategy is thus to ensure that the combined actions selected by all the agents should approach a similar result obtained from the actions selected by a single agent which has a complete knowledge of the system.

![Fig. 5.2. Multi-agent receding horizon control](image)
5.4 System Modelling

Provided that the short term dynamics are stable, the dynamics of the RHC-based voltage control are predominantly associated with the long-term dynamics. In this context, one can resort to the Quasi-Steady State (QSS) model of the system in which the short term dynamics of the system are replaced by their equilibrium conditions. The QSS model for long term equilibrium can be written in a compact form as shown in (5.1) [21, 22]:

\[ f(x, u) = 0 \] (5.1)

where \( u \) is the vector of control variables (generator voltages and real and reactive power loads) and \( x \) is the vector of the algebraic state variables. Equation (5.1) can be linearized at a known operating point to obtain the incremental relationship between the control and state variables which can be presented as:

\[ f_x \Delta x + f_u \Delta u = 0 \] (5.2)

where \( f_x \) and \( f_u \) are the Jacobian matrices of \( f \) with respect to \( x \) and \( u \). If \( f_x \) is non-singular, one can obtain the change in the state variables due to the change in the control variables as:

\[ \Delta x = -f_x^{-1} f_u \Delta u \] (5.3)

Let \( \varphi(x,u) \) be a quantity of interest which is a function of both the state variables and the control variables. Therefore, the change in \( \varphi \) due to a change in \( u \) can be obtained as:

\[
\begin{align*}
\Delta \varphi &= \nabla_x \varphi \Delta x + \nabla_u \varphi \Delta u \\
&= -\nabla_x \varphi f_x^{-1} f_u \Delta u + \nabla_u \varphi \Delta u \\
&= \left( \nabla_u \varphi - \nabla_x \varphi f_x^{-1} f_u \right) \Delta u 
\end{align*}
\] (5.4)

where \( \nabla_u \varphi \) and \( \nabla_x \varphi \) are the gradients of \( \varphi \) with respect to \( u \) and \( x \), respectively. Hence, the sensitivity of \( \varphi \) to \( u \) is given by:

\[
\frac{\partial \varphi}{\partial u} = \nabla_u \varphi - \nabla_x \varphi f_x^{-1} f_u
\] (5.5)

Equation (5.5) can be used to obtain the sensitivity of load voltages and generator reactive powers to the control variables and a linear model of equation (5.1) can be derived.
5.4.1 Objective function in a centralized scheme

The overall objective is to minimize the changes in the control variables over the control horizon while satisfying the voltage and generator reactive power limits based on the measurements received at a specific time instance \( k \). From a centralized point of view, this can be expressed as a quadratic programming problem [23] and can be defined as:

\[
\min_{i=1}^{N_c} \left\| \Delta u(k+i) \right\|^2_R \tag{5.6a}
\]

subject to

\[
u^\text{min} \leq u(k+i) \leq u^\text{max} \tag{5.6b}
\]

\[
\Delta u^\text{min} \leq \Delta u(k+i) \leq \Delta u^\text{max} \tag{5.6c}
\]

\[
V_L(k+i) = V_L(k+i-1) + \frac{\partial V_L}{\partial u} \Delta u(k+i) \tag{5.6d}
\]

\[
Q_G(k+i) = Q_G(k+i-1) + \frac{\partial Q_G}{\partial u} \Delta u(k+i) \tag{5.6e}
\]

\[
V_L^\text{min} \leq V_L(k+i) \leq V_L^\text{max} \tag{5.6f}
\]

\[
Q_G^\text{min} \leq Q_G(k+i) \leq Q_G^\text{max} \tag{5.6g}
\]

for \( i=1, \ldots, N_c \)

The objective (5.6a) minimizes the future deviation of the control variables over the control horizon \( N_c \). As far as the long-term voltage instability scenarios are concerned, there is no clear advantage to take the prediction horizon \( N_p \) different than \( N_c \) [10]. Hence, the prediction horizon is considered equal to the control horizon. \( R \) is a diagonal weight matrix that penalizes expensive control variables with higher weights. Equations (5.6b) and (5.6c) impose the limits on the control variables. Equation (5.6d) and (5.6e) are the sequence of load voltage vector \( V_L \) and the vector of generator reactive power \( Q_G \) over the control horizon \( N_c \), respectively. \( \frac{\partial V_L}{\partial u} \) and \( \frac{\partial Q_G}{\partial u} \) are the sensitivity matrix of load voltages and generator reactive powers to the control variables, respectively. The constraints (5.6f) and (5.6g) aim at limiting the load voltages and generators reactive power within their admissible limits.
5.4.2 MARHC problem formulation

We consider a multi-area power system which has $M$ sub-systems (i.e. areas), where each sub-system consists of a set of generators and loads. The interactions among the sub-systems are established by the tie lines. The nodes that are connected to the tie lines are denoted as the boundary nodes for each sub-system.

An agent is assigned for each sub-system in MARHC framework (see Fig. 5.2) to control reactive power and load voltages in its associated sub-system by manipulating the generator terminal voltages and applying load shedding. It is assumed that the agent does not have an access to the information of the other sub-systems. Therefore, it uses RHC to obtain the best control sequence in the control horizon based on the model of its own sub-system and tries to improve its solution via communication with the neighbouring sub-systems. The agents work in a cooperative manner [24], i.e. they help each other to improve the overall cost function. Each agent is required to solve a RHC problem as conveyed by (5.6). However, the agent cannot independently solve the problem because of the following reasons:

1. The sensitivities of load voltages and generator reactive powers with respect to the control variables in each area will depend on the state variables of the whole system i.e. these sensitivities are global quantities.

2. Each agent will try to optimize its local decision variables. The control action in one sub-system may affect another sub-system’s state due to the relative coupling between them. Therefore, the optimal decision for one agent may not be the optimal decision for the overall problem.

Owing to the facts mentioned above, a decomposition scheme to decompose the overall problem into sub-problems is proposed in this chapter which can be solved in a coordinated way to find the global optimal solution. This also complies with the proposed MARHC scheme that the task of the emergency voltage control problem is shared by multiple agents; each is in-charge of its associated sub-system.

5.4 Multi area system modelling

Fig. 5.3 illustrates the equivalent systems for a two area power system. The sub-systems/areas are connected by tie-lines. In the equivalent model, each area preserves the actual model of its sub-system and replaces the neighbouring sub-systems by the voltage and angle of the neighbouring boundary node(s). For the sake of simplicity, only one boundary node per area is shown but the concept can be extended without
any loss of generality to any number of boundary nodes and any number of neighbouring areas.

The decomposed equivalent steady-state model of the above system can be expressed as:

\[ f_1 \left( x_1, u_1, V'_{b2}, \theta'_{b2} \right) = 0 \]  \hspace{1cm} (5.7a)

\[ V'_{b2} = V_{b2} \]  \hspace{1cm} (5.7b)

\[ \theta'_{b2} = \theta_{b2} \]  \hspace{1cm} (5.7c)

\[ f_2 \left( x_2, u_2, V'_{b1}, \theta'_{b1} \right) = 0 \]  \hspace{1cm} (5.8a)

\[ V'_{b1} = V_{b1} \]  \hspace{1cm} (5.8b)

\[ \theta'_{b1} = \theta_{b1} \]  \hspace{1cm} (5.8c)

Equation (5.7a) indicates the steady state model for sub-system 1, \( x_1 \) refers to the state variables and \( u_1 \) refers to the control variables of sub-system 1. Note that the boundary voltage \( V'_{b2} \) and angle \( \theta'_{b2} \) are appended in (5.7a) because the power flow equations of the boundary buses of sub-system 1 depend on these variables. These two variables are constrained through equations (5.7b-5.7c) which are the coupling equations for the model of sub-system 1. These equations imply that the variables \( V'_{b2} \) and \( \theta'_{b2} \) must be equal to the actual variables \( V_{b2} \) and \( \theta_{b2} \) respectively. This ensures that
for a given system state and input set, the same solution will be obtained using the model (7) and (8) as would have been obtained from the model (1) [15].

The equivalent MARHC problem of the problem in (5.6) for the decomposed model of (5.7)-(5.8) can be stated as:

\[
\min \sum_{i=1}^{N_c} \left( \| \Delta u_1 (k+i) \|_{R_i}^2 + \| \Delta u_2 (k+i) \|_{R_2}^2 \right) \tag{5.9a}
\]

subject to

\[
u_1^{\text{min}} \leq u_1 (k+i) \leq u_1^{\text{max}} \tag{5.9b}
\]
\[
u_2^{\text{min}} \leq u_2 (k+i) \leq u_2^{\text{max}} \tag{5.9c}
\]
\[
\Delta u_1^{\text{min}} \leq \Delta u_1 (k+i) \leq \Delta u_1^{\text{max}} \tag{5.9d}
\]
\[
\Delta u_2^{\text{min}} \leq \Delta u_2 (k+i) \leq \Delta u_2^{\text{max}} \tag{5.9e}
\]

\[
V_{L_1} (k+i) = V_{L_1} (k+i-1) + \frac{\partial V_{L_1}}{\partial u_1} \Delta u_1 (k+i) + \frac{\partial V_{L_1}}{\partial V_{b_2}} \Delta V_{b_2} (k+i) + \frac{\partial V_{L_1}}{\partial \theta_{b_2}} \Delta \theta_{b_2} (k+i) \tag{5.9f}
\]
\[
Q_{G_1} (k+i) = Q_{G_1} (k+i-1) + \frac{\partial Q_{G_1}}{\partial u_1} \Delta u_1 (k+i) + \frac{\partial Q_{G_1}}{\partial V_{b_2}} \Delta V_{b_2} (k+i) + \frac{\partial Q_{G_1}}{\partial \theta_{b_2}} \Delta \theta_{b_2} (k+i) \tag{5.9g}
\]
\[
V_{L_2} (k+i) = V_{L_2} (k+i-1) + \frac{\partial V_{L_2}}{\partial u_2} \Delta u_2 (k+i) + \frac{\partial V_{L_2}}{\partial V_{b_1}} \Delta V_{b_1} (k+i) + \frac{\partial V_{L_2}}{\partial \theta_{b_1}} \Delta \theta_{b_1} (k+i) \tag{5.9h}
\]
\[
Q_{G_2} (k+i) = Q_{G_2} (k+i-1) + \frac{\partial Q_{G_2}}{\partial u_2} \Delta u_2 (k+i) + \frac{\partial Q_{G_2}}{\partial V_{b_1}} \Delta V_{b_1} (k+i) + \frac{\partial Q_{G_2}}{\partial \theta_{b_1}} \Delta \theta_{b_1} (k+i) \tag{5.9i}
\]
\[
V_{L_1}^{\text{min}} \leq V_{L_1} (k+i) \leq V_{L_1}^{\text{max}} \tag{5.9j}
\]
\[
Q_{G_1}^{\text{min}} \leq Q_{G_1} (k+i) \leq Q_{G_1}^{\text{max}} \tag{5.9k}
\]
\[
V_{L_2}^{\text{min}} \leq V_{L_2} (k+i) \leq V_{L_2}^{\text{max}} \tag{5.9l}
\]
\[
Q_{G_2}^{\text{min}} \leq Q_{G_2} (k+i) \leq Q_{G_2}^{\text{max}} \tag{5.9m}
\]
\[
V'_{b_2} (k+i) = V_{b_2} (k+i) \quad \theta'_{b_2} (k+i) = \theta_{b_2} (k+i) \tag{5.9n}
\]
\[
V'_{b_1} (k+i) = V_{b_1} (k+i) \quad \theta'_{b_1} (k+i) = \theta_{b_1} (k+i) \tag{5.9o}
\]

for \( i = 1, \ldots, N_c \)

In (5.9a), the centralized objective function is split into two parts, where the first part belongs to sub-system 1 and the second part belongs to sub-system 2. All the variables in equation (5.9) relate to the variables in (5.6) while the sub-scripts 1 or 2 indicate that the variables belong to sub-system 1 or 2, respectively. The sensitivities
in (5.9f-5.9g) and (5.9h-5.9i) are derived using the sensitivity formula (5.5) based on the linearized model of (5.7a) and (5.8a), respectively. Note that the boundary voltage and angle of the neighbouring sub-system are considered as inputs to the sub-system under consideration because they reflect the impact of the neighbouring sub-system. Thus, these variables are considered as decision variables in the optimization routine which are constrained through equation (5.9n-5.9o) to ensure that the solution stemming from optimization problem (5.9) is identical to the solution of the problem (5.6).

The constraints (5.9n-5.9o) are called complicating constraints because they involve variables from different sub-systems. The complicating constraints prevent the sub-systems to solve the optimization problem independently. Therefore, a mathematical decomposition technique is required to separate the problem (5.9) into a set of sub-problems so that each sub-problem can be solved independently by the associated agent.

Various decomposition techniques of the optimization problem having complicating constraints have been proposed in the literature; mostly using the Lagrangian and the augmented Lagrangian theory [25]. In a Lagrangian decomposition approach, the complicating constraints are relaxed and a Lagrange multiplier or dual variable is associated with each relaxed constraint. Then the sub-problems are solved independently with the relaxed constraints added to the objective function. A master co-ordinator is used to update the dual variables. The sub-problems are repeated with the updated dual variables until some convergence criteria are met [26]. A modified Lagrangian decomposition technique based on the decomposition of the first order optimality condition is proposed in [27]. This method has an excellent performance over the traditional Lagrangian decomposition approach and has been applied to many multi-area optimal power flow and state estimation problems in recent years [28], [29], [30] and [31].

5.4.1 Proposed Optimality Condition Decomposition

The optimality condition decomposition (OCD) is a modified Lagrangian decomposition approach in which the global optimization problem is decomposed into several sub-problems in such a way that if the first-order Karush-Kuhn-Tucker (KKT) optimality conditions of every sub-problem are joined together, they are
identical to the first-order optimality conditions of the global problem [30]. The area sub-problem is obtained by relaxing all the complicating constraints of other areas through adding them to the objective function of the area sub-problem and maintaining its own complicating constraints. The sub-problem is then solved iteratively by fixing the optimization variables of other sub-systems that are known from previous iteration. Based on the aforementioned idea, the global MARHC problem (5.9) can be decomposed into area sub-problems as follows.

**Sub-problem 1:**

\[
\min \sum_{i=1}^{N_c} \left( \left\| \Delta \mathbf{u}_1 (k+i) \right\|_{R_1}^2 + \lambda_{v1} (k+i) \left( V_{b1} ' (k+i) - V_{b1} (k+i) \right) + \lambda_{\theta1} (k+i) \left( \theta_{b1} (k+i) - \theta_{b1} (k+i) \right) \right) \\
\text{subject to constraints (5.9b, 5.9d, 5.9f, 5.9g, 5.9j, 5.9k)}
\]

(5.10a)

\[
V_{b1} ' (k+i) = V_{b1} (k+i) : \lambda_{v1} (k+i) \quad (5.10b)
\]

\[
\theta_{b1} (k+i) = \theta_{b1} (k+i) : \lambda_{\theta1} (k+i) \quad (5.10c)
\]

for \( i = 1 \ldots N_c \)

**Sub-problem 2:**

\[
\min \sum_{i=1}^{N_c} \left( \left\| \Delta \mathbf{u}_2 (k+i) \right\|_{R_2}^2 + \lambda_{v2} (k+i) \left( V_{b2} ' (k+i) - V_{b2} (k+i) \right) + \lambda_{\theta2} (k+i) \left( \theta_{b2} (k+i) - \theta_{b2} (k+i) \right) \right) \\
\text{subject to constraints (5.9c, 5.9e, 5.9h, 5.9i, 5.9l, 5.9m)}
\]

(5.11a)

\[
V_{b1} ' (k+i) = V_{b1} (k+i) : \lambda_{v1} (k+i) \quad (5.11b)
\]

\[
\theta_{b1} (k+i) = \theta_{b1} (k+i) : \lambda_{\theta1} (k+i) \quad (5.11c)
\]

for \( i = 1 \ldots N_c \)

The objective functions (5.10a) and (5.11a) now include the complicating constraints for the adjacent sub-system which are multiplied by the Lagrange multipliers associated with these constraints. The lines over the variables indicate the known value of the variables from previous iteration or trial values for the first iteration. Thus, each sub-problem aims to minimize the cost of its own sub-system together with the cost of the contribution from the neighbouring sub-systems as conveyed by the relaxed complicating constraints. In the above procedure, the Lagrange multipliers are updated by maintaining the sub-problem’s own complicating
constraints (constraints (5.10b) and (5.10c) for sub-problem 1 and constraints (5.11b) and (5.11c) for sub-problem 2).

5.4.2 Proposed Co-ordination Algorithm

The main advantage of the above described procedure for MARHC is that it does not require a central co-ordinator to update the Lagrange multiplier as in the case of common Lagrangian decomposition algorithm. Further, the convergence of the algorithm is relatively faster and the computational efficiency is improved (see [30] for the proof of the convergence). The control is initiated when an agent finds any violation of load voltage and/or generator reactive power in its sub-system, mostly after any contingency event. The only information that the agent needs to share with the neighbouring agents are the boundary voltages and angles and Lagrange multipliers associated with the complicating constraints. The step by step procedure for the proposed MARHC algorithm is described as follows (for sub-system 1):

1) At a given time instant \( k \), collect measurement and derive the sensitivity based model of the sub-system.

2) Perform the optimization problem in (5.10) over a control horizon \( N_c \). For this purpose,
   a) Initialize the boundary variables \( V_{bi}^{k+i} \), \( \theta_{bi}^{k+i} \), \( V_{b2}^{k+i} \) and \( \theta_{b2}^{k+i} \) and the Lagrange multipliers \( \lambda_{c2}^{k+i} \) and \( \lambda_{q2}^{k+i} \) for \( i=1,\ldots,N_c \). This is Iter = 0;
   b) Solve (5.10a) subject to the constraints (5.10b) and (5.10c).
   c) Transmit the updated values of the boundary variables \( V_{bi}^{k+i} \), \( \theta_{bi}^{k+i} \), \( V_{b2}^{k+i} \) and \( \theta_{b2}^{k+i} \) and Lagrange multipliers \( \lambda_{c1}^{k+i} \) and \( \lambda_{q1}^{k+i} \) for \( k=1,\ldots,N_c \) to sub-system 2.
   d) Receive the updated values of the boundary variables \( V_{bi}^{k+i} \), \( \theta_{bi}^{k+i} \), \( V_{b2}^{k+i} \) and \( \theta_{b2}^{k+i} \) and the Lagrange multipliers \( \lambda_{c2}^{k+i} \) and \( \lambda_{q2}^{k+i} \) for \( i=1,\ldots,N_c \) from sub-system 2.
   e) If they don’t change significantly, stop, go to step (3) else Iter = Iter + 1. Repeat step (b) to (d).

3) Apply the first sequence of the so computed actions to the practical system.
4) \( k = k + 1 \), repeat step 1 to 3 until all the load voltages and reactive power outputs are within the admissible limits.

The above algorithm is carried out in sub-system 2 in the similar manner and therefore, is not described here. Note that the algorithm is not initiated by all the agents at the same time; rather it is initiated by the agent that has found any constraint violation in its sub-system. The other agents will participate in the algorithm by receiving the boundary variables and Lagrange multipliers from the neighbouring agent. In this way, the proposed procedure will traverse from one sub-system to another sub-system.

5.4.3 Issues for Real time implementation of the proposed MARHC

The proposed MARHC algorithm can be implemented to find the optimal solution of the global problem in a distributed way without disclosing the internal information of the sub-systems. However, this comes with a price of an iterative process among the agents which will increase with the number of boundary variables and Lagrange multipliers. To apply the proposed algorithm for real time voltage control in a receding horizon concept, several issues should be taken under consideration:

1) As has been stated earlier, the long term voltage collapse scenario is typically monotonic lasting from tens of seconds to several minutes. This indicates that the RHC scheme can be implemented with longer sampling time and shorter control horizon. This will allow relatively longer amount of time for the agents in the MARHC scheme to perform the iterative algorithm as well as reduction in the number of iterations to converge because of the reduced number of boundary variables.

2) It can be observed that the sensitivities are updated from one time instant to another. However, the sensitivity matrices do not vary significantly because of the “linear” nature of the voltage decay problem and thus can be computed only at the beginning of the prediction horizon which will reduce the computation time. This assumption can be compensated for by the feedback nature of the algorithm at the next sampling instant when the sensitivities will be updated with new collected measurements.

3) Depending on the communication facility of the system, a maximum limit can be imposed on the iteration number of the algorithm or the solution can be obtained with a certain degree of accuracy. Moreover, it should be noted that the agents
communicate only with the neighbours. As the voltage instability is typically a local phenomenon and local countermeasures are the most effective, the algorithm can be restricted within a limited region of the system where disturbance occurs.

5.4.4 Tuning of constraints in the control horizon

The advantage of the receding horizon strategy lies in the ability to gradually correct the voltages and generator reactive powers along the control horizon instead of doing that in a single step. This can be implemented by enforcing the limits on the constraints (5.9j) to (5.9m) only at the end of the control horizon [11]. But this may lead to slow voltage recovery and generator reactive power correction. Moreover, some voltages and reactive powers which were within the limits before the control action starts may violate the limits in the intermediate steps which is not desirable. Therefore, a time varying limit on the voltage and reactive power constraint along the control horizon has been considered in this chapter. If the voltage or reactive power is out of the admissible limit at the start of the control horizon, that limit varies linearly along the control horizon. This means that the limit is not considered as a hard limit along the control horizon. Rather it gradually becomes satisfied at the end of the horizon which is the inherent benefit of the receding horizon control. For example, if a load voltage is 0.9 pu at the beginning of the horizon and the control horizon consists of 2 time steps, then at first time step the limit will be 0.925 pu and at the second time step the limit would be 0.95 pu which is the admissible steady state limit of the load voltage. Equations 5.12(a) – 5.13(c) show the steady-state minimum and maximum limits of the load voltages and reactive powers in the generator buses.

\[
\begin{align*}
V_{L}^{\text{min}}(k+i) &= V_{L}(k) + \frac{V_{L}^{\text{min}} - V_{L}(k)}{N - i + 1} & \text{if } V_{L}(k) < V_{L}^{\text{min}} \quad (5.12a) \\
V_{L}^{\text{max}}(k+i) &= V_{L}(k) + \frac{V_{L}^{\text{max}} - V_{L}(k)}{N - i + 1} & \text{if } V_{L}(k) > V_{L}^{\text{max}} \quad (5.12b) \\
V_{L}^{\text{min}}(k+i) &= V_{L}^{\text{min}} & \text{otherwise} \quad (5.12c) \\
Q_{G}^{\text{min}}(k+i) &= Q_{G}(k) + \frac{Q_{G}^{\text{min}} - Q_{G}(k)}{N - i + 1} & \text{if } Q_{G}(k) < Q_{G}^{\text{min}} \quad (5.13a) \\
Q_{G}^{\text{max}}(k+i) &= Q_{G}(k) + \frac{Q_{G}^{\text{max}} - Q_{G}(k)}{N - i + 1} & \text{if } Q_{G}(k) > Q_{G}^{\text{max}} \quad (5.13b)
\end{align*}
\]
\[ Q_{G}^{\text{min}}(k+i) = Q_{G}^{\text{min}} \quad \text{for } i = 1, \ldots, N_c \]
\[ Q_{G}^{\text{max}}(k+i) = Q_{G}^{\text{max}} \quad \text{otherwise} \quad (5.13c) \]

where \( V_{L}^{\text{min}} \) (\( V_{L}^{\text{max}} \)) is the steady-state minimum (maximum) limit of the load voltage and \( Q_{G}^{\text{min}} \) (\( Q_{G}^{\text{max}} \)) the reactive power limit of the synchronous generator. The generator reactive power limit should be compatible with the reactive capability curve. Hence, the reactive power limit is calculated based on the received snapshot of terminal voltage and real power generation (see [21], equations (3.32a), (3.32b) and (3.49)), where the effect of saturation is neglected for the sake of simplicity.

**5.4.5 Generator voltage set-point and reactive power**

As the terminal voltage of the generator is considered as a control variable, it should be noted that this control is implemented by changing the AVR reference voltage which is usually different from the actual terminal voltage. Based on the fact that a change in AVR reference voltage results in almost equal change in the terminal voltage [11], the controller changes the AVR reference voltage by the amount equal to the desired terminal voltage correction.

The generator reactive power under over excitation (OXL) control of the excitation system (i.e. constant field current) is given by

\[ Q_g = \frac{V_{FD}^{\text{max}}}{X_d} \cos(\delta-\theta) - V^2 \left( \frac{\sin^2(\delta-\theta)}{X_q} + \frac{\cos^2(\delta-\theta)}{X_d} \right) \quad (5.14) \]

This clearly shows that the reactive power is dependent on the generator terminal voltage. As the OXL tends to lower the AVR reference voltage to control the excitation current, the terminal voltage of the generator also gradually falls. As a result, the reactive power also gradually falls under OXL control.

Generator bus voltage is used as control variable since the generator excitation control is able to control the voltage directly and can adjust the bus voltage. Load shedding is another control variable that is used in the proposed method, when the countermeasures are not sufficient. In the proposed method, the on-load tap changers (LTC) are also allowed to vary automatically within the time frame before load shedding is activated.
5.5 Validation of the proposed method using Case Studies

The proposed MARHC is implemented on Nordic-32 test system [32, 33] shown in Fig. 5.4. The system consists of 52 buses, 20 synchronous machines and 22 loads. This system composes of four areas: “North” with hydro generation and some load, “Central” with much load and thermal power generation, “Equiv” connected to the “North” which includes a very simple equivalent of an external system, and “South” with thermal generation, rather loosely connected to the rest of the system. The system has rather long transmission lines of 400-kV nominal voltage. Five lines are equipped with series compensation. The model also includes a representation of some regional systems operating at 220 and 130 kV, respectively [33]. Simulations have been carried out using PSAT and MATLAB.

![Fig. 5.4. Single-line diagram of Nordic32 test system.](image)

To capture the realistic scenario of long term voltage instability, a detailed dynamic model of the generators with automatic voltage regulator (AVR) and over-
excitation limiter (OEL) is considered. The OEL was modelled to follow either inverse time or fixed time characteristics. All the loads are supplied through distribution transformers having automatic load tap changer (LTC). A delay of 30 seconds is considered for the first tap movement. The subsequent tap changes have shorter delays but vary from each other ranging from 9 to 12 seconds to prevent the unrealistic tap synchronization. An exponential model for the load is used with exponent 1 (constant current) for active power and exponent 2 (constant impedance) for reactive power.

As shown in Fig. 5.4, the system is composed of four areas, namely North, Central, Equivalent, and South. North area is generation reach-area with hydro generation and some loads and Central area is load-reach area with thermal power generation. For the purpose of illustration of the proposed MARHC, each of these areas was considered as a sub-system and was assigned an agent to solve the optimization sub-problem as given in (5.10).

Each agent is able to change the generator voltages in the range of 0.95-1.1 p.u. and curtails a maximum of 30 percent of the load at each bus in its area. The associated weights for the controls in the optimization are 1 for generator voltages and 100 for load shedding. The proposed MARHC was implemented with a sampling time of 20 seconds and control horizon of 40 seconds.

5.5.1 Case 1: Single contingency: Outage of line 4032-4044

This case involves the outage of a tie line 4032-4044 between North and Central area without any fault, after 5 seconds of the start of the simulation. The evolution of three transmission voltages without the proposed MARHC is shown in Fig. 5.5. The system settles to a short-term equilibrium after the electromechanical oscillations have died out. The LTCs start acting at 35 seconds. Subsequently, the voltages evolve under the effect of LTCs trying to restore distribution voltages and OELs limiting the field currents of the generators. The voltage instability of the power system eventually leads to voltage collapse in less than three minutes after the initiating the disturbance.
Fig. 5.5. Transmission voltages without MARHC

Fig. 5.6 shows the evolution of the field currents for some of the field limited generators in the central area. After settling to the post disturbance values, they start increasing from $t = 35s$, when the OLTCs start acting. The actions of OEL subsequently limit the field currents of generator 14 (Gen 14), generator 15 (Gen 15) and generator 16 (Gen 16), causing the generators to produce constant field current leading to the release of constant voltage constraint.

Fig. 5.6. Field currents of limited generators in central area without MARHC

The control action is initiated by the agents in Central area as it detects the maximum reactive power violation in generator 14. It is assumed that the agents wait for a short period to take into account the line auto-reclosure time and to allow the transients to
die out to find the steady-state measurement. In this case, the first control action is implemented at 30 seconds followed by consecutive actions at a 20 seconds interval. The termination condition for the algorithm is set by a tolerance of .0001 for the boundary variables and Lagrange multipliers. The evolution of the transmission voltages stabilized by the proposed MARHC is shown in Fig. 5.7.

![Fig. 5.7. Transmission voltages in case 1 with proposed MARHC](image)

Fig. 5.7. Transmission voltages in case 1 with proposed MARHC

Fig. 5.8 shows the change in AVR reference voltages in some generators as requested by the proposed MARHC. No load shedding occurs in this case because the generator voltage set-point adjustment is sufficient to eventually stabilize the voltages. The system is stabilized before 230 seconds and no control actions are further issued after this time.

![Fig. 5.8. Change in AVR reference voltage by the proposed MARHC in case 1](image)

Fig. 5.8. Change in AVR reference voltage by the proposed MARHC in case 1

Using the convergence criteria as described earlier, the algorithm converges between 26 to 34 iterations at each sampling instant. Simulation was carried out with a tolerance of 0.001 and the number of iterations required is from 16 to 20. The
The number of iterations is quite small compared to the Lagrangian decomposition approach as shown in [20]. Moreover, the agents do not need to communicate with a central controller; they only need to communicate with their immediate neighbours which will reduce the time for communication in the proposed MARHC algorithm. Fig. 5.9 shows the evolution of some of the Lagrange multipliers at the first sampling step.

![Fig. 5.9. Evolution of the Lagrange multiplier in case 1](image)

### 5.5.2 Case 2: Multiple Contingency- Outage of parallel lines 4044-4045

This case represents a double line outage scenario. The contingency involves the outage of one of the parallel lines between bus 4044 and 4045 at 5 seconds after the simulation starts. At 20 seconds, the other line between bus 4044 and 4045 also goes out of service. Fig. 5.10 shows the voltage evolution in this case without any countermeasures. The voltages decay more rapidly in this case than in case 1 and undergo long-term instability by collapsing at 153 seconds.

![Fig. 5.10. Evolution of transmission voltages in case 2](image)

Fig. 5.11 shows the voltage evolution under the operation of the proposed MARHC. The control action is initiated by the central area agent and the first control is applied...
at 30 seconds. The MARHC manipulates the generator voltages at first few steps (see Fig. 5.12) to control the voltages and reactive powers. Owing to the severity of the contingency, this countermeasure is not sufficient to stabilize the system. Therefore, load shedding occurs at $t = 70$ seconds (to shed 21.386 MW) and at $t = 110$ seconds (to shed 8.9 MW further).

5.5.3 Case 3: Load increase scenario

This case demonstrates a load increase scenario together with a single line outage between bus 4041 and 4061 which is tie line between Central and South area. The loads in the Central area are linearly increased from 20 seconds to 120 seconds by a total amount of 100 MW. The voltage collapse occurs at $t = 213.3$ seconds in this case (see Fig. 5.13).
Fig. 5.13. Evolution of transmission voltages in case 3

Fig. 5.14 shows the system response with the MARHC controller in action. The proposed MARHC smoothly stabilizes the system mainly with the control of the generator terminal voltages (see Fig. 5.15) and the system settles to a post-disturbance equilibrium at $t = 250$ seconds. A very little amount of load shedding (5.6 MW) occurred at $t = 210$ seconds.

Fig. 5.14. Voltage stabilization by proposed MARHC in case 3

Fig. 5.15. Change in AVR reference voltage by the proposed MARHC in case 3
The optimization routine directly gives the amount of load (active and reactive power) that needs to be shed. A constant power factor is preserved from the original load in the load shedding algorithm, such that if 10MW is shed at any bus, a proportional amount of reactive power is also shed to ensure that the power factor remains constant. This practice is also adopted in [11,12]. We also follow the practice described in [11], where a load less than 0.1 MW is assumed to be so small that no shedding will be carried out on this type of load.

Table 5.1 The optimal values of the generator bus voltage in per unit

<table>
<thead>
<tr>
<th>Bus Number</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.1000</td>
<td>1.0975</td>
<td>1.0960</td>
</tr>
<tr>
<td>2</td>
<td>1.0375</td>
<td>1.0416</td>
<td>1.0709</td>
</tr>
<tr>
<td>3</td>
<td>1.0610</td>
<td>1.0931</td>
<td>1.0720</td>
</tr>
<tr>
<td>4</td>
<td>1.1000</td>
<td>1.0564</td>
<td>1.0548</td>
</tr>
<tr>
<td>5</td>
<td>1.0876</td>
<td>1.0844</td>
<td>1.0505</td>
</tr>
<tr>
<td>6</td>
<td>1.0421</td>
<td>0.9838</td>
<td>1.0174</td>
</tr>
<tr>
<td>7</td>
<td>1.0306</td>
<td>0.9530</td>
<td>1.0008</td>
</tr>
<tr>
<td>8</td>
<td>1.0855</td>
<td>1.0732</td>
<td>1.0646</td>
</tr>
<tr>
<td>9</td>
<td>1.0682</td>
<td>1.0602</td>
<td>1.0517</td>
</tr>
<tr>
<td>10</td>
<td>1.0625</td>
<td>1.0558</td>
<td>1.0448</td>
</tr>
<tr>
<td>11</td>
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</tr>
<tr>
<td>12</td>
<td>1.0326</td>
<td>1.0484</td>
<td>1.0110</td>
</tr>
<tr>
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<td>1.0490</td>
</tr>
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<td>14</td>
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<td>1.0195</td>
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<td>15</td>
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</tr>
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<td>16</td>
<td>1.0940</td>
<td>1.0960</td>
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</tr>
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<td>1.0356</td>
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</tr>
<tr>
<td>18</td>
<td>0.9879</td>
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<td>1.0565</td>
</tr>
<tr>
<td>19</td>
<td>1.0807</td>
<td>1.0338</td>
<td>1.0556</td>
</tr>
<tr>
<td>20</td>
<td>1.0414</td>
<td>0.9545</td>
<td>1.0319</td>
</tr>
</tbody>
</table>

Table 5.2 The optimal values of load shedding in MW in the subsystems under control – CENTRAL and SOUTH areas (The Power factor of the original load is preserved)

<table>
<thead>
<tr>
<th>Bus Number</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>1041</td>
<td>0</td>
<td>9.989</td>
<td>0.7</td>
</tr>
<tr>
<td>1042</td>
<td>0</td>
<td>0.919</td>
<td>0.33</td>
</tr>
<tr>
<td>1043</td>
<td>0</td>
<td>4.652</td>
<td>0.59</td>
</tr>
<tr>
<td>1044</td>
<td>0</td>
<td>0.84</td>
<td>0.49</td>
</tr>
<tr>
<td>1045</td>
<td>0</td>
<td>6.552</td>
<td>0.5</td>
</tr>
<tr>
<td>4041</td>
<td>0</td>
<td>0</td>
<td>0.18</td>
</tr>
<tr>
<td>4042</td>
<td>0</td>
<td>0</td>
<td>0.29</td>
</tr>
<tr>
<td>4043</td>
<td>0</td>
<td>0.202</td>
<td>0.47</td>
</tr>
<tr>
<td>4046</td>
<td>0</td>
<td>0.136</td>
<td>0.61</td>
</tr>
<tr>
<td>4047</td>
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<td>0</td>
<td>0.33</td>
</tr>
<tr>
<td>4051</td>
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<td>5.384</td>
<td>0.4</td>
</tr>
<tr>
<td>4051</td>
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<td>0.561</td>
<td>0.26</td>
</tr>
<tr>
<td>4062</td>
<td>0</td>
<td>0.646</td>
<td>0.25</td>
</tr>
<tr>
<td>4063</td>
<td>0</td>
<td>0.405</td>
<td>0.21</td>
</tr>
</tbody>
</table>
Table 5.1 shows the final optimal values of generator voltages after the system is stabilized in per unit. Table 5.2 shows the bus number and the amount of load shedding in MW. A constant power factor has been preserved for the load shedding as adopted in [11,12].

5.5.4 Case 4: Testing the Effectiveness of the Proposed Approach

To demonstrate the effectiveness of the proposed approach, a comparative study is carried out in this section. The proposed approach is compared with a traditional approach. Also computational time is estimated to indicate the suitability for real-time application of the proposed method.

5.5.4.1 Comparison with Traditional Lagrangian Relaxation Approach

In this case study, the performance of the proposed MARHC is compared with the traditional Lagrangian relaxation (LR) approach. All of the above described scenarios have been tested using the LR approach. A sub-gradient method has been used to update the Lagrange multipliers associated with the complicating constraints [34]. As can be seen from Table 5.3, the maximum number of iterations to converge to the optimal solution is greater for the LR approach compared to the OCD approach used in the proposed MARHC.

<table>
<thead>
<tr>
<th>Case</th>
<th>Maximum no. of iteration OCD</th>
<th>Maximum no. of iteration LR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1</td>
<td>34</td>
<td>178</td>
</tr>
<tr>
<td>Case 2</td>
<td>39</td>
<td>201</td>
</tr>
<tr>
<td>Case 3</td>
<td>28</td>
<td>144</td>
</tr>
</tbody>
</table>

Fig. 5.16 shows the evolution of the Lagrange multiplier in both the approaches. The value of the Lagrange multiplier in proposed MARHC approach converges quickly within 34 iterations while an oscillatory behaviour can be observed for the LR approach. The LR approach took 178 iterations to converge to the desired tolerance.
5.5.4.2 Computational time and communication delay

The total number of iterations required to converge to an optimal solution by the proposed MARHC for the cases 1 to 3 was in the range of 19 to 38. The algorithm was implemented in MATLAB running in a Windows XP machine with Core i7 CPU and 3.55 GB of RAM. The computation time considered in this chapter is the time to solve the optimization sub-problem based on the information received at each sampling instance. The total number of iterations required to converge to an optimal solution for each sub-problem for cases 1 to 3 was in the range of 19 to 38. The maximum time taken by an iteration was 9.7 msec and therefore the maximum time taken to solve each sub-problem for the convergence would be 368.6 msec. With regards to the communication speed among the agents, it will depend upon the bandwidth of the communication channel and the delay in collecting data through local measurements. With the advent of synchronized phasor measurement techniques in power systems [35], the data through local measurements can be collected in real-time. As the proposed MARHC is based on only neighbour to neighbour communication, the communication delay among the agents will also be less. As indicated in [36], the wide-area network based on high speed optical fibre network with 155.52 Mbps can facilitate to communicate over 180 km distance with a delay time of 1.3 msec. Assuming that the radius of each area or sub-system does not surpass more than 100 km, a total maximum delay of 548.8 msec may incur in
the cases described above. Thus, in a worst-case scenario, an overall delay of 917.49 msec may occur that includes computational time as well as communication delay.

5.6 Conclusion

A multi-agent based receding horizon control to prevent voltage collapse during an emergency is illustrated in this chapter. The proposed control scheme is developed based on the optimality condition decomposition of the global optimization problem with neighbour-to-neighbour communication among the agents. A distributed control in a multi-agent environment is used as a cooperative framework in which each agent can preserve its local information and communicate with neighbouring agents to mutually agree and provide a best solution. Various scenarios were created to validate the robustness of the proposed method and results presented. The main advantages of the proposed method are that no central controller is required to make a decision and the convergence of the proposed method is faster compared to the traditional Lagrangian decomposition method. The overall computation and communication requirement are relatively small and within the reach of the modern communication facility of a power system.

References:


6. CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORKS

This thesis has developed comprehensive and realistic emergency control approaches of voltage instability arising from catastrophic disturbances in a power system. General conclusions of the thesis and directions for future works are provided below.

6.1 Concluding Remarks

The summarized conclusion of the thesis are-

1. In case of unplanned multiple contingencies in a power system; the voltage instability problem can be alleviated by an emergency corrective control. The control actions must work in real time based on the post disturbance system evolution and measurements. A closed loop control system is emphasized where the amount of countermeasures is not pre-determined and may vary depending on the severity of any disturbance.

2. The system can be divided into several voltage control regions to consider the localized effect of voltage instability and to improve the local reactive power support in case of system emergency. Since voltage instability originates from the inadequacy of local reactive power generation and reactive power cannot effectively be transferred over a long distance, the electrical distances among the loads and the generators can be good criteria to form the voltage control areas.

3. The vulnerability of the system to voltage instability can actually be detected based on the variations of load voltages and generator reactive power outputs. Voltage level alone is not a good indicator of voltage instability since initially the transmission voltages may be fairly normal just after the disturbance. A performance index has been formulated based on the deviation of load voltages and generator reactive power outputs to discover areas that are close to the onset of voltage instability.

4. Efficient control can be achieved in terms of real time monitoring and fast and reliable control response by using distributed intelligent agents. The agents will work in a co-operative environment through negotiation and take autonomous decisions at times of system emergency. A decentralized co-
ordination of the agent network is proposed to enhance the robustness and reliability of the control system.

5. The co-ordination among the emergency control devices plays an important role in the successful stabilization of the system. The generator terminal voltage adjustment and shunt capacitor switching are the preferred countermeasures at the beginning of the post-contingency period because of their fast response compared to those of the slowly acting OLTC control. Moreover, these control actions are less intrusive to the consumers than from load shedding. A strategic load shedding is suggested for more severe contingency when other countermeasures are not sufficient to stabilize the system.

6. The algorithm based on receding horizon (RHC) multi-step optimization has a potential benefit in terms of smooth control, handling model and measurement uncertainty and a feasible transition to a stable equilibrium for long term voltage instability control. In the context of multi-area power system, the global optimal solution can be achieved by first order optimality condition decomposition (OCD). A combination of these two approaches will lead to satisfactory decentralized control of transmission voltages in real time by preserving the local information by the TSO and by exchanging some boundary variables with only the neighbouring TSO without any interaction from the central controller. This approach enhances the reliability of the control system and reduces the computational burden and communication requirement by each TSO.

7. The long term voltage instability evolution of a power system can be effectively modelled with the quasi steady state (QSS) approximation of the long term dynamics. The QSS model can be linearized to achieve easily tractable solution without sacrificing the accuracy and acceptability of the result because of the monotonic variation at the initial post-disturbance period. By incorporating the linearized system model into the RHC and OCD routines, the computation time is greatly reduced improving the performance of the proposed approach for real time application.
6.2 Recommendations for future work

Some areas for future works are listed below:

1. The design parameters of the multi-agent protection scheme described in Chapter 2 can be optimized over a large set of scenarios to achieve better performance. Algorithm based on evolutionary programming could be used to determine the best combination.

2. Since load shedding affects both the voltage and frequency of the system, a more accurate dynamic model of the system can be developed incorporating the evolution of both frequency and voltage. A unified approach to counteract both frequency and voltage instability may be developed to assess the impact of emergency actions.

3. In case of extremely severe contingencies that splits the network into islands, the performance of proposed approaches can be evaluated for the restoration of normal operation in the islanded networks. For this purpose, the amount and timing of load shedding can be adaptively determined to ensure the stable operation of the islands.

4. The severity measure by performance index in Chapter 3 can be modified to include the effect of line over-loading, the change in tie-line power flow and the available reactive power reserve within the area.

5. The load behaviour uncertainty can be included in the proposed approaches by incorporating the statistical aspects of load behaviour modelling. A large set of reliable statistical data of hourly and daily load profile is required to obtain realistic result.

6. The adaptive determination of voltage control areas after any contingency in Chapter 4 can be extended to include the failure of an agent and loss of communication among the agents. The load agents could be authorized to take independent decision in case of communication failure.

7. The receding horizon control in Chapter 5 can be modified to include the shunt capacitor and tap changer control in the optimization routine. An appropriate dynamic modelling of the tap changer is required to produce a realistic result.

8. Short-term voltage instability resulting from induction motor stalling is another issue of concern. A completely distributed control approach with fast
and immediate countermeasures is required in order not to rely on the communication among the controllers.

9. Load shedding has been considered as a continuous variable although practically it is performed on a feeder basis and thus it is a discrete process. A combinatorial optimization problem can be formulated to include the discrete characteristic of load shedding.