Emergency Control for Catastrophic Disturbance in Future Power Grids

Hadi Lomei
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Emergency Control for Catastrophic Disturbance in Future Power Grids

Hadi Lomei

Supervisors:
Kashem Muttaqi, Danny Soetanto

This thesis is presented as part of the requirement for the conferral of the degree:
Doctor of Philosophy

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The University of Wollongong
School of Electrical, Computer and Telecommunications Engineering

August 2019
This doctoral thesis is dedicated to my wife.
Abstract

The emergency control for catastrophic disturbance in future power grids includes innovative approaches and methods proposed to improve the power system response to the emergency condition caused by catastrophic disturbances and countermeasures to prevent widespread power outage throughout the grid.

In this research work, novel, efficient, practical, and economical solutions have been proposed and developed to address the various instability issues of a power system, such as the voltage, transient and dynamic instability under post-contingency operation. The proposed methods in each chapter of this thesis have been incorporated on typical control systems of the existing network without any additional capital expenditure requirement. The proposed methods can be implemented locally on the generating unit and provide improved characteristics for the power system in dealing with an emergency condition. The focus of this work is to avoid proposing wide-area supplementary control systems that require developed communication infrastructure and significant capital expenditure.

The voltage stability improvement has been achieved through equipping the excitation system with a novel thermal-based over-excitation limiter, the dynamic stability improvement has been achieved through a novel optimal robust excitation system control, the transient instability improvement has been achieved through the continuous on-line detection of the propagated accelerating energy in the grid and through the reduction of the nonlinear interaction between the grid control systems.

This research work aims to provide emergency control for catastrophic disturbance in future power grids without needing extensive capital expenditure or installing new devices. The objective has always been the improvement of the existing power system control systems considering all the challenges that the network system provides dealing with, concerning the grid expansion.

A novel framework has been developed to design an optimal robust excitation system controller considering the uncertainties in the parameters of the model of the excitation system. The uncertainties may cause the parameter values to vary from their nominal values within the specified upper and lower limits. These uncertainties can have a significant influence on the dynamic characteristics of the power system, that is, the variations in the parameters of the excitation controller model, due to the uncertainties in the parameters, can cause the system to be unstable. It is therefore important to design a robust excitation system controller that can ensure that irrespective of the values of the parameters, within the boundary of the uncertainties, the power system will be robust against any voltage instability. The proposed framework decomposes the uncertainties in the parameters of the excitation system model into matched and unmatched components. To eliminate the uncertainties from both components, a linear quadratic regulator is formulated to deal with the matched component, while an augmented control is used to deal with the unmatched component. The robustness of the resulting controller is verified using the PowerFactory time-domain dynamic stability simulations of a single-machine to infinite bus test system and the IEEE 39-bus New England system.

Voltage stability requires the continuing control of the total system's supply of reactive power during an emergency. The supply of reactive power, however, can be curtailed by the action of rotor over-current
Protection or over-excitation limiter in reducing the rotating unit reactive power output. Practical heat run tests show that the timing of the activation of the over-excitation limiter can be very conservative, resulting in an earlier than necessary operation that can lead to a system voltage collapse. A significant benefit can be obtained if the timing of the over-excitation limiter activation can be delayed while ensuring enough margin is provided to avoid harming the rotor of the synchronous generator. To improve the post-contingency characteristic of the voltage, a new thermal-based method has been developed to determine the timing of the over-excitation limiter activation that is based on the thermal capacity of the rotor as the main indicator for limiting the excitation level of the synchronous generator. A new over-excitation limiter has been designed and incorporated in the synchronous generator excitation controller model in the PowerFactory simulation software to supply its full potential of reactive power, with extended time, to the grid under an emergency condition by constantly monitoring the rotor thermal capability to ensure a safe operating condition. The proposed thermal-based method is validated using the extensive PowerFactory simulations of a single-machine infinite bus and, the Nordic power system. Simulation studies show that the system voltage collapse can be delayed significantly by delaying the over-excitation limiter activation without compromising the thermal capacity of the rotor if the proposed over-excitation limiter setting is used.

An innovative approach to detect transient instability has been developed. A disturbance near the synchronous generator terminal has the potential to create a huge difference between the mechanical output of the turbine and the electrical output of the generator. This difference in power is stored in the rotor of the generator in the form of kinetic energy during the existence of the disturbance and is released into the grid as a wave of energy after the disturbance is cleared. The presence of the extra energy influences the operation of the grid elements and if it is not damped in time, it can create transient instability. This proposed approach uses a direct method to accurately calculate the injected excess energy and detect the risk of transient instability in a power grid from the generating unit terminals. The proposed method constantly monitors the energy injected from each generating unit and detects the critical energy level in which transient instability is imminent. The performance of the proposed method was assessed through comprehensive studies on the Nordic power system and results were found to be promising.

Finally, a new approach is presented to reduce the nonlinear characteristics of a stressed power system and improve the transient stability of the system by reducing its second-order modal interaction through retuning some parameters of the generator excitation system. To determine the second-order modal interaction of the system, a new index of nonlinearity is developed using the normal form theory. Using the proposed index of nonlinearity, a sensitivity function is formed to indicate the most effective excitation system parameters in the nonlinear behaviour of the system. These dominant parameters are tuned to reduce the second-order modal interaction of the system and to reduce the index on nonlinearity. The efficiency of the proposed method is initially validated using a four-machine two-area test system. The IEEE 39-Bus New England test system is then used to investigate the performance of the proposed method for a more realistic system. Simulation results show that a proper tuning of the excitation controller can reduce the second-order modal interaction of the system and can even improve the transient stability margin of the network.
Acknowledgments

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Last but not the least, I would like to thank my wife, Elahe, for her patience during my Ph.D. studies, and my parents for supporting me spiritually throughout my life.
List of Publications

The papers that have been published as a result of the effort being done to complete this thesis are as follows:


# List of Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
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<tbody>
<tr>
<td>PSS</td>
<td>Power System Stabilisers</td>
</tr>
<tr>
<td>PMU</td>
<td>Phase Measurement Units</td>
</tr>
<tr>
<td>OEL</td>
<td>Over Excitation Limiter</td>
</tr>
<tr>
<td>IMEF</td>
<td>Individual Machine Energy Function</td>
</tr>
<tr>
<td>SPS</td>
<td>Special Protection Scheme</td>
</tr>
<tr>
<td>SCADA</td>
<td>Supervisory Control and Data Acquisition</td>
</tr>
<tr>
<td>SMIB</td>
<td>Single Machine Infinite Bus</td>
</tr>
<tr>
<td>PEF</td>
<td>Partial Energy Function</td>
</tr>
<tr>
<td>LQR</td>
<td>Linear Quadratic Regulator</td>
</tr>
<tr>
<td>SMEC</td>
<td>Sliding Mode Excitation Controllers</td>
</tr>
<tr>
<td>DFL</td>
<td>Direct Feedback Linearization</td>
</tr>
<tr>
<td>SVC</td>
<td>Static VAR Compensators</td>
</tr>
<tr>
<td>CUEP</td>
<td>Controlling Unstable Equilibrium Point</td>
</tr>
<tr>
<td>EEAC</td>
<td>Extended Equal Area Criterion</td>
</tr>
<tr>
<td>NF</td>
<td>Normal Form</td>
</tr>
<tr>
<td>CCT</td>
<td>Critical Clearing Time</td>
</tr>
<tr>
<td>MS</td>
<td>Modal Series</td>
</tr>
<tr>
<td>MNF</td>
<td>Methods of Normal Form</td>
</tr>
<tr>
<td>DAE</td>
<td>Differential-Algebraic Equation</td>
</tr>
<tr>
<td>SEP</td>
<td>Stable Equilibrium Point</td>
</tr>
<tr>
<td>NSP</td>
<td>Network Service Provider</td>
</tr>
<tr>
<td>ICT</td>
<td>Information and Communication Technology</td>
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</table>
## List of Symbols

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$V_t$</td>
<td>Synchronous machine terminal voltage</td>
</tr>
<tr>
<td>$V_c$</td>
<td>Output of terminal voltage transducer</td>
</tr>
<tr>
<td>$V_{\text{Ref}}$</td>
<td>Generator reference voltage</td>
</tr>
<tr>
<td>$V_e$</td>
<td>Voltage error signal</td>
</tr>
<tr>
<td>$V_I$</td>
<td>Regulated internal voltage</td>
</tr>
<tr>
<td>$V_2$</td>
<td>Excitation system stabilizer output</td>
</tr>
<tr>
<td>$V_A$</td>
<td>Amplified regulated internal voltage</td>
</tr>
<tr>
<td>$E_{\text{fd}}$</td>
<td>Exciter output voltage</td>
</tr>
<tr>
<td>$A$</td>
<td>System state matrix</td>
</tr>
<tr>
<td>$B$</td>
<td>Input state matrix</td>
</tr>
<tr>
<td>$C$</td>
<td>Output state matrix</td>
</tr>
<tr>
<td>$D$</td>
<td>Feedforward matrix</td>
</tr>
<tr>
<td>$P$</td>
<td>Set of values for the uncertain parameter</td>
</tr>
<tr>
<td>$p$</td>
<td>Variable representing uncertain parameter</td>
</tr>
<tr>
<td>$A(p)$</td>
<td>Uncertain state matrix</td>
</tr>
<tr>
<td>$p_0$</td>
<td>Uncertain parameter nominal value</td>
</tr>
<tr>
<td>$A(p_0)$</td>
<td>Uncertain state matrix nominal value</td>
</tr>
<tr>
<td>$p_{\text{max}}$</td>
<td>Uncertain parameter maximum value</td>
</tr>
<tr>
<td>$U_p$</td>
<td>Variable representing uncertainty matrix</td>
</tr>
<tr>
<td>$U_p^{\text{max}}$</td>
<td>Uncertainty maximum value matrix</td>
</tr>
<tr>
<td>$U_p^{\text{unmatched}}$</td>
<td>Uncertainty unmatched component matrix</td>
</tr>
<tr>
<td>$U_p^{\text{matched}}$</td>
<td>Uncertainty matched component matrix</td>
</tr>
<tr>
<td>$B^*$</td>
<td>Pseudo-inverse of input state matrix</td>
</tr>
<tr>
<td>$I$</td>
<td>Identity matrix</td>
</tr>
<tr>
<td>$F, H$</td>
<td>Uncertainty upper bound matrices</td>
</tr>
<tr>
<td>$\alpha, \beta, \rho$</td>
<td>Controller design parameters</td>
</tr>
<tr>
<td>$u$</td>
<td>System input matrix</td>
</tr>
<tr>
<td>$K$</td>
<td>Feedback controller matrix</td>
</tr>
<tr>
<td>$v$</td>
<td>Augmented input</td>
</tr>
<tr>
<td>$L$</td>
<td>Augmented controller matrix</td>
</tr>
<tr>
<td>$S$</td>
<td>LQR unique positive definite solution</td>
</tr>
<tr>
<td>$Q, R$</td>
<td>Semidefinite positive matrices</td>
</tr>
<tr>
<td>$V$</td>
<td>Lyapunov function</td>
</tr>
<tr>
<td>$V_I$</td>
<td>Gradient of Lyapunov function</td>
</tr>
<tr>
<td>$\Delta E$</td>
<td>Changes in the location of eigenvalue</td>
</tr>
<tr>
<td>$E^{\text{Nom}}$</td>
<td>Eigenvalue location for nominal parameter</td>
</tr>
<tr>
<td>$E^{\text{Unc}}$</td>
<td>Eigenvalue location for uncertain parameter</td>
</tr>
<tr>
<td>$\Delta K_A$</td>
<td>Changes in the value of $K_A$</td>
</tr>
</tbody>
</table>
$K_A^{Nom}$  Nominal value of $K_A$

$K_A^{Unc}$  Uncertain value of $K_A$

$V_t$  Synchronous machine terminal voltage

$V_e$  Output of terminal voltage transducer

$V_{Ref}$  Generator reference voltage

$V_e$  Voltage error signal

$V_l$  Regulated internal voltage

$V_2$  Excitation system stabilizer output

$V_A$  Amplified regulated internal voltage

$E_{fd}$  Exciter output voltage

$A$  System state matrix

$B$  Input state matrix

$C$  Output state matrix

$D$  Feedforward matrix

$P$  Set of values for the uncertain parameter

$p$  Variable representing uncertain parameter

$A(p)$  Uncertain state matrix

$p_0$  Uncertain parameter nominal value

$A(p_0)$  Uncertain state matrix nominal value

$p^{max}$  Uncertain parameter maximum value

$U_p$  Variable representing uncertainty matrix

$P_e$  Generator output electrical power

$P_{max}$  Maximum generator active power transfer capacity

$\delta$  Rotor angle

$H$  System inertia constant

$\omega_{sys}$  System speed

$D$  Rotor damping constant

$P_{mo}$  Turbine output mechanical power

$P_{acc}$  Accelerating power

$PAE$  Primary accelerating energy

$SAE$  Secondary accelerating energy

$P_G$  Generated power

$P_L$  Load power

$x$  Vector of system states

$f$  Real valued vector field

$A$  System state matrix

$F_2(x)$  Second order term of the Taylor series expansion

$F_3(x)$  Third order term of the Taylor series expansion

$H_i$  Hessian matrix

$U$  Matrix of right eigenvectors
\( Y \) System output matrix
\( y \) System output (time-domain)
\( \lambda \) Eigenvalue
\( C \) Second order output coefficient
\( z \) New Normal Form coordinate system
\( h_2 \) Vector field of polynomial terms of degree 2
\( I_f \) Index of nonlinearity
\( T_R \) Voltage regulator time constant
\( T_B, T_C \) Compensator time constants
\( K_A \) Amplifier gain
\( T_A \) Amplifier time constant
\( V_{PSS} \) Power system stabilizer signal
\( V_{error} \) Error signal
\( V_{OEL} \) Overexcitation limiter signal
\( V_{ref} \) Reference voltage signal
\( V_T \) Terminal voltage signal
\( V_{Rmax} \) Maximum amplifier output limit
\( V_{Rmin} \) Minimum amplifier output limit
\( S \) Sensitivity function
# Table of Contents

Abstract .................................................................................................................. ii
Acknowledgments ................................................................................................... iv
Certification ........................................................................................................... v
List of Publications ............................................................................................... vi
List of Abbreviations .............................................................................................. vii
List of Symbols ....................................................................................................... viii
Table of Contents .................................................................................................. xi
List of Tables .......................................................................................................... xiii
List of Figures .......................................................................................................... xiv

Chapter 1  Introduction ............................................................................................. 1
  1.1  General Background ...................................................................................... 1
  1.2  Motivation ..................................................................................................... 2
  1.3  Research Objectives and Contributions ...................................................... 3
  1.4  Thesis Outline .............................................................................................. 4

Chapter 2  Literature Review ................................................................................... 6
  2.1  Foreword ....................................................................................................... 6
  2.2  Excitation System Impact on the System Stability ........................................ 6
  2.3  Long-term Voltage Stability Improvement ................................................... 9
  2.4  Transient Stability Assessment ................................................................... 11
  2.5  Nonlinear Power System Dynamic Stability Improvement ......................... 12

Chapter 3  Optimal Robust Excitation Controller Design ..................................... 15
  3.1  Foreword ....................................................................................................... 15
  3.2  Background ................................................................................................... 15
  3.3  Optimal Robust Controller Design Framework ........................................... 16
  3.4  Design of an Optimal Robust Excitation System ......................................... 22
  3.5  Case Study .................................................................................................... 27
  3.6  Summary ....................................................................................................... 33

Chapter 4  Long-term Voltage Stability Improvement ............................................ 35
  4.1  Foreword ....................................................................................................... 35
  4.2  Background ................................................................................................... 35
  4.3  Automatic Voltage Regulators and Over-Excitation Limiter ......................... 36
    4.3.1  Excitation System Perspective ............................................................... 36
    4.3.2  Rotor Thermal Capacity ....................................................................... 37
    4.3.3  Over-excitation Limiter ......................................................................... 39
  4.4  Thermal Based OEL ..................................................................................... 39
  4.5  The Proposed OEL Model Evaluation ......................................................... 43
List of Tables

Table 3-1: IEEE ST1A excitation system model parameters .......................................................... 23
Table 3-2: The real part of the eigenvalues for different values of $K_a$ without the optimal robust modification .................................................. 23
Table 3-3: The real part of the eigenvalues for different values of $K_a$ with the optimal robust modification ....... 26
Table 3-4: Sensitivity analysis of the location of the eigenvalues to the value of excitation system parameter $K_a$ ........................................................................................................................................... 26
Table 3-5: Eigenvalue analysis of the optimal robust excitation system for different values of $K_a$, $T_C$, and $T_B$.......................................................... 26
Table 3-6: Comparison between the excitation control system performance with and without the robust improvement for IEEE 39 bus network .................................................................................. 26
Table 3-7: Different loading conditions considered in the second case study ........................................ 32
Table 4-1: Thermal-based OEL system parameters ........................................................................ 44
Table 4-2: OEL systems activation time for case 1 ........................................................................ 49
Table 4-3: OEL systems functioning time for case 2 ...................................................................... 52
Table 6-1: The participation of each generator in electromechanical modes of the test system ................. 85
Table 6-2: The index of nonlinearity for the selected electromechanical modes .................................. 85
Table 6-3: Exciter system parameter along with their sensitivity and index of nonlinearity in four excitation system model parameters setting .................................................................................................................... 86
Table 6-4: Generator output power (MW) at the selected operating scenarios ........................................ 89
Table A-1: Excitation system parameters values used in Nordic power system modelling .................... 109
Table A-2: Speed governing steam turbine system parameters values used in Nordic power system modelling ................................................................................................................................. 109
Table A-3: Steam turbine system parameters values used in Nordic power system modelling ............. 110
Table A-4: Thermal capability of the generator OEL system .............................................................. 110
Table A-5: Generator data (all four generators) ................................................................................ 111
Table A-6: Generator damping (on machine base) ............................................................................ 111
Table A-7: Line data (on system base 100 MVA) .............................................................................. 111
Table A-8: Load data ....................................................................................................................... 111
Table A-9: Exciter system data ....................................................................................................... 111
List of Figures

Figure 3-1: IEEE Type ST1A simplified excitation system model .......................................................... 22
Figure 3-2: Single line diagram of the single-machine test system .......................................................... 27
Figure 3-3: The influence of uncertainty in the value of $K_a$ without a robust excitation system controller ......... 28
Figure 3-4: The influence of uncertainty in the values of $K_a$ considering a robust excitation system controller ... 29
Figure 3-5: The voltage at bus 5 using the proposed robust excitation system for different generator reference voltages, with the uncertainty in the values of $K_a$ ....................................................... 30
Figure 3-6: Single line diagram of the IEEE 39-buses New England test system ........................................ 30
Figure 3-7: The influences of uncertainty in the values of $K_a$, $T_R$, and $T_C$ without a robust excitation system controller at high loading level ................................................................. 31
Figure 3-8: The influences of uncertainty in the values of $K_a$, $T_R$, and $T_C$ considering a robust excitation system controller at high loading level ................................................................. 32
Figure 3-9: The influences of uncertainty in the values of $K_a$, $T_R$, and $T_C$ considering robust excitation system controller – A comparison for high, medium, and low loading levels ........................................... 33
Figure 4-1: The excitation system model block diagram ......................................................................... 37
Figure 4-2: Different OEL approaches to reduce the excitation current: (a) increase of $V_{OEL}$ which leads to (b) reduction of excitation current ................................................................. 37
Figure 4-3: Rotor windings short circuit current capacity ........................................................................... 38
Figure 4-4: Actual heat test run results [165] ......................................................................................... 41
Figure 4-5: Flowchart of the proposed OEL timing method .................................................................. 42
Figure 4-6: The desired characteristics for the OEL system output signal ............................................... 42
Figure 4-7: The model of the OEL system with the proposed timing method .............................................. 43
Figure 4-8: Single line diagram of the single-machine test system ........................................................... 44
Figure 4-9: Performance comparison between the IEEE and the thermal-based OEL systems for both British and Japanese units ................................................................. 45
Figure 4-10: Single line diagram of the Nordic power system [173] ....................................................... 46
Figure 4-11: Changes in the excitation level of the overexcited generator in the Nordic power system for case 1 considering the IEEE OEL system ................................................................. 47
Figure 4-12: Voltage profile of selected transmission bus-bars near the location of the disturbance for case 1 considering the IEEE OEL system ................................................................. 48
Figure 4-13: Changes in the excitation level of the overexcited generator in the Nordic power system for case 1 considering the thermal-based OEL system ............................................. 48
Figure 4-14: Voltage profile of selected transmission bus-bars near the location of the disturbance for case 1 considering thermal-based OEL system ................................................................. 49
Figure 4-15: Operation of LTCs for case 1 with the thermal-based OEL system ........................................ 50
Figure 4-16: The value of $EAH$ for the limited generators in case 1 ......................................................... 50
Figure 4-17: Changes in the excitation level of the overexcited generator in the Nordic power system for case 2 considering the IEEE OEL system ................................................................. 51
Figure 4-18: Voltage profile of selected transmission bus-bars near the location of the disturbance for case 2 considering the IEEE OEL system ................................................................. 52
Figure 4-19: Changes in the excitation level of the overexcited generator in the Nordic power system for case 2 considering the proposed thermal-based OEL system ................................................................. 53
Figure 4-20: Voltage profile of selected thermal-based OEL system ................................................................. 53
Figure 5-1: Mechanical, electrical and load power, and load voltage subjected to a 3Ph-G fault where load power is assumed to be independent of load voltage ................................................................. 59
Figure 5-2: Mechanical, electrical and load power, and load voltage subjected to a 3Ph-G fault considering the dependency of load power to voltage magnitude ................................................................. 61
Figure 5-3: Flowchart of the proposed transient instability detection approach ........................................ 62
Figure 5-4: A single machine test system connected to an infinite bus through load substation and transmission lines.
Chapter 1     Introduction

1.1 General Background

Emergency condition in a power system is an unplanned operating condition that cannot be avoided or predicted [1], but can only be controlled and managed. Any operation that can be planned for, is a planned outage and is not an emergency condition. During an emergency condition, all system elements will automatically try to adapt themselves to this new condition by running, if necessary, under overloading condition, however, all these elements are protected from harmful overloading by their protection systems. This trade-off between operating with overloading during the emergency condition and being protected from the overloading makes the emergency condition control and management a challenging task.

Typically, the emergency condition happens after a severe disturbance in the power system. The severity of the disturbance determines the intensity of the emergency condition. Power systems are developed to meet the annual peak demand and are usually planned to withstand the most severe single and double contingencies in the grid [2]. However, in some cases, a catastrophic disturbance in a stressed power system can lead to multiple cascading contingencies (beyond the planned contingencies or emergency conditions) and can result in a system breakdown (collapse).

Catastrophic events occur in a large-scale power system because of disturbances from both external and internal sources. Disturbances from the external sources include human factors and natural calamities (earthquake, flood, and fire) and disturbances from internal sources include failures in the power system components, the communication systems, the protection devices, and human errors. These catastrophic events are usually worse than the standard disturbances considered in contingency planning [3], [4]. In the contingency planning, the system will be planned to withstand some selected probable contingencies. The massive power outages in 2003 in North America [5], and Europe, and Moscow blackout in 2005 [6], and 2006 in the European grid [7] and the more recent ones, such as 2007 in Victoria, Australia, 2012 in Northern India, and 2016 in South Australia, Australia, underscored the vulnerabilities of the electricity infrastructure to these catastrophic events. Therefore, an advanced emergency control scheme is needed to identify the post-disturbances emergency condition and to carry out fast countermeasures before the onset of system instability.

Emergency control is usually performed by the actions of the voltage, the frequency, and the power automatic control systems, the automatic protection systems of power system elements, such as the relay protection and the automatic line control system [8]. An automatic emergency control system is responsible to maintain the integrity of the power system under two main conditions [6], [9]:

I. Pre-emergency: After a significant disturbance by maintaining the necessary transfer capability of the inter-area tie-lines through efficiently controlling them using the power system stabilisers (PSS), any available fast-acting reactive power sources, energy storage, etc.

II. Emergency: to maintain voltage levels and damp oscillations using tools such as automatic controllers and control systems, automatic under-frequency and under-voltage load shedding, automatic voltage deviation control, automatic isolation of power plants with auxiliary power supply maintained, etc.
Advanced smart devices, communication infrastructures, and technologies, such as the phase measurement units (PMU) and artificial intelligence, offer new possibilities of solving the complicated and comprehensive problem of automatic emergency control through monitoring, pattern recognition, and control of electric power system operating condition [8].

A practical emergency control scheme follows three key stages:

I. Continuous monitoring of selected parameters such as voltage and frequency.
II. Identification of the type of abnormality.
III. Implementing countermeasure on time.

All these stages are necessary to form an efficient emergency control scheme. Time plays a key role in all these stages and providing extra time, while still ensuring safety, for the emergency control scheme to operate, directly improves the efficiency of the control scheme. Ideally, by increasing the capability of a power system to be over-rated for a longer period and giving the emergency control scheme more time to operate, but still within the margin of safety, an efficient outcome can be achieved.

1.2 Motivation

The motivation behind this research work can be addressed in the three aspects described below:

First, preventing a power system from breakdown is the most critical task of the power system operating and planning authorities. It is evident that virtually, every crucial economic and social function depends on the secure and reliable operation of electrical power infrastructures. All infrastructures such as transportation, telecommunications, oil and gas, banking, and finance, depending on the power grid to energize and control their operations. An unreliable power system will directly impact the economic capabilities of a country. Protecting critical infrastructure such as electric power infrastructure has been identified as one of the national research priorities, which is important to national security and the social and economic well-being of the people.

Second, despite the research effort that has been committed insofar to emergency control of the power system and continues to be devoted to power system breakdown and collapse, a practical, economically efficient, and easily applicable resolution hasn’t been gained yet. The existing approaches have divided the protection task into separate compartments to achieve simplicity in the implementation, modification, maintenance, and operation of the emergency control schemes, but the approach to distributing the emergency control scheme in different sections failed to gain a perspective on the overall power system issues. Moreover, the proposed approaches to deal with the emergency condition use assumptions embedded as “accepted wisdom” which have impeded efforts to resolve each task. Instead, it has been assessed as a total system problem with all assumptions being critically questioned. Just as important is the clear formulation of the objectives, to resolve the issues.

Finally, a discussion about an emergency control scheme is typically followed by the concept of load-shedding or by the need to spend a significant capital expenditure on upgrading the transmission system or installation of new elements to increase the capability of the power grid to withstand multiple contingencies. In
other words, there has always been an effort to plan the system for every plausible contingency that may lead to an emergency condition. Consequently, these approaches lead to significant capital expenditure and an over-designed network. The approach in this work is to optimise the existing capability of the system, in such a way that the system can safely operate at its limits, letting some elements of the network to operate in the overloading condition for a longer period without causing damage to the element. The extended over-rating capability of the grid will give the emergency control scheme and the planner the opportunity to activate the most efficient, practical, and cost-friendly countermeasures.

1.3 Research Objectives and Contributions

The main objective of this thesis is to propose new control strategies on the critical elements of the system that can efficiently and economically address these causes of breakdown in the power system as outlined below:

I. Mismatch in reactive power.
II. Mismatch in active power.
III. Steady-state stability instability
IV. Transient stability instability.

To satisfy the main objective of this thesis, the following contributions have been made:

I. An optimal robust excitation controller design considering the uncertainties in the exciter parameters: A novel optimal robust excitation system has been proposed that improves the steady-state and transient stability of the system in dealing with the contingencies. The presented approach is practical, simple to implement, and can adapt to any linear IEEE standard excitation system type. The proposed robust excitation system eliminates the uncertainty in the excitation system parameters and will make the excitation system characteristic independent of its design parameters, which improves the performance of the excitation system when over-rated or operating close to its operational limits. In addition to the improvement in the stability of the system, the proposed control is robust to changes in the parameters and is obtained through optimization.

II. A new method to determine the activation time of the over-excitation limiter based on available generator rotor thermal capacity to improve long-term voltage instability: A new over-excitation limiter (OEL) for the generator excitation system has been developed that allows the generator to use its full reactive power capability in dealing with the voltage related abnormalities. The developed OEL is capable to monitor the rotor thermally and let the rotor to remain in the over-rated operating condition for a longer period without damaging the rotor. The extended time, within a safety margin, is critical in dealing with the reactive power mismatch phenomena. The proposed method uses the rotor winding current and calculates the rotor winding temperature to avoid overheating in the winding.

III. A direct method to accurately detect the risk of transient instability using the propagated accelerating wave of energy in a power grid: A direct method is proposed in this chapter to assess the transient stability capabilities of the system by constantly monitoring the excess energy level generated by each generating
unit. In the proposed method, the wave of energy flowing throughout the grid in the post-contingency situation is measured continuously by calculating the excess energy caused by the gap between the supply and demand in each generating unit terminal. The proposed method only uses the measured active power through the terminal of the generator to calculate the excess energy. The proposed method can provide a practical, efficient, and fast indication of any risks to the transient stability of the system. In the proposed method, the calculated primary accelerating energy in the power system can be used as an indicator to detect a transient stability abnormality. This method can be used to indicate the gap between a stable and unstable operating condition following a contingency.

IV. **A new approach to reduce the non-linear characteristics of a stressed power system by using the normal form technique in the control design of the excitation system:** This chapter introduces a new method to reduce the second-order modal interaction of a power system by retuning the excitation system parameters. In the proposed method, the Normal Form (NF) theory is applied to extract the Taylor series expansion second-order terms from a power system, since these second-order terms represent the second-order modal interaction in the nonlinear system. To determine the nonlinear characteristics of the system, a new index of nonlinearity is developed using the NF technique. The index is then used to determine the most effective excitation system parameters, in addition to the direction of their influence in the second-order modal interaction using a sensitivity function. This investigation leads to identifying the significant impact of excitation system parameters on the second-order modal interaction of the power system, which leads to a novel proposal to modify these parameters to reduce the identified magnitude of these second-order interactions. The proposed method can be implemented in any type of excitation systems.

As evident from the contributions, in this thesis the efforts have been made to develop, retune and design the traditional controllers of the power system in a way to achieve efficient emergency reaction in the case of single or multiple contingencies. The economical aspect of the emergency control of the system after a disturbance has been always considered and the engineering solutions have been developed most efficiently.

1.4 **Thesis Outline**

After this brief introduction, the thesis structure has been outlined as follows:

Chapter 2 is a comprehensive literature review, investigating different aspects of an efficient emergency control scheme. The literature review discusses the research work related to each chapter of the thesis individually. In this review, the corresponding technical challenges and the main objective of each chapter have been presented and discussed.

Chapter 3 presents a new optimal robust IEEE ST1A excitation system controller that is robust to the uncertainty in one or more of its parameters. Despite the complex mathematics behind the method, it can be implemented simply and straightforwardly, even though uncertainties in the model parameters exist. This optimal approach has transferred the robust controller problem to an optimal control problem while it has preserved the robustness of the excitation system.
In Chapter 4, a new method is proposed for the determination of the timing for OEL activation, which is developed based on available generator rotor thermal capacity. It is shown that the proposed OEL method can efficiently utilize the thermal capacity of the rotor and inject more reactive power into the system in comparison with that from a conventional OEL equipped generators. The generator owners may be able to be persuaded to allow more use of available reactive power contribution of the generators to improve power system performance and voltage stability if incentives are provided through the provision of ancillary and emergency control services in the electric power market. A system protection scheme (SPS) using the operational data from a Supervisory Control and Data Acquisition (SCADA) system can be used to identify the location and timing of the impending voltage instability by observing a sudden increase in the generator reactive power outputs and the reduction of voltages in the area of disturbance. The benefit of the proposed thermal-based OEL system is to increase the time for such an SPS to function, by increasing the time to allow reactive power to be continued to be supplied into the grid to maintain the voltage stability. This will provide the SPS more time to determine the best countermeasure that can be effective to mitigate the emergency condition.

In Chapter 5, a new algorithm to detect transient instability is presented. A disturbance near the synchronous generator terminal creates a huge gap between the mechanical output of the turbine and the electrical output of the generator. This difference is stored in the rotor of the generator during the duration of the disturbance and is released into the grid as a wave of energy after the disturbance is cleared. The presence of the extra energy influences the operation of the grid elements and if it is not controlled, it can create transient stability risks. This chapter presents a new method that constantly monitors the released energy into the grid from the generating unit terminals and detects the critical energy levels in which transient instability is imminent.

In Chapter 6, a new method is presented to reduce the second-order modal interaction of the system. A new index of nonlinearity is developed, which can indicate the nonlinear characteristics of the system due to the interaction between two pairs of modes. It is shown that by retuning the adjustable parameters of the excitation system, this index can be reduced significantly resulting in moving the behaviour of the system closer toward more linear characteristics.

In Chapter 7, the conclusion and discussions of the thesis are presented and some recommendations for possible future research work as a result of the research work are discussed.
Chapter 2  

Literature Review

2.1  

Foreword

The literature review includes a brief analysis of the related research material that is directly or indirectly related to the work carried out in the thesis. In this chapter, the aim is to cover the various available approaches and methods in the field that are affiliated with each chapter of the thesis. Additionally, this chapter emphasizes the gaps that are identified during the research in the same field.

2.2  

Excitation System Impact on the System Stability

Excitation systems are the primary systems that control the generator voltage, which makes them one of the most important elements in large scale power systems; consequently, they have a significant influence on the stability of the network [10]–[12]. The significant impact of the excitation systems on network stability has been carefully investigated for a Single Machine Infinite Bus (SMIB) test system in [13]. Moreover, the excitation system controllers can tackle minor transients such as sudden short circuit faults and major load demand changes effectively. The capability of the excitation system controller to tackle minor transients heavily relies on how the synchronous generator has been dynamically modelled. The synchronous generator dynamic modelling always faces limitations such as parameter variation for different operating conditions, different types of external disturbances, and the load demand variations [14]. All these limitations need to be included in the dynamic modelling of the synchronous generator and the design of the excitation system controller to improve the network stability margins [15]. The excitation system controllers should have the ability to improve system stability by increasing the damping so that the stability margins are not affected by operational constraints [16].

PSSs are used in the excitation controllers in power systems to provide additional damping into the system and to improve the stability of the system [17]. PSSs are mainly designed based on the linearized models of power systems and are used to eliminate low-frequency oscillations due to small disturbances and improve the small-signal stability of the system. PSSs cannot maintain the stability of the system when the network is subjected to larger disturbances since they cannot provide enough damping. To overcome the limitation of the existing PSS systems, in [18], [19] major developments have been presented in the field of linear control techniques, specifically on the H∞ controller-based linear matrix inequality (LMI) and well-developed linear quadratic regulator (LQR); however, the performance of these controllers are highly dependent on the operating condition of the network and the improvement in the stability can be achieved only for limited operating set points.

Increasing the damping of the system and suppressing the low-frequency oscillations is currently being achieved by widely using a linear excitation control system, moreover, these control systems can improve transient stability of the system, even when designed considering linear control theory [20]–[24]. To design a linear excitation control system, the power system dynamic model is linearized in the close vicinity of a probable and stable operating condition, and the controller parameters are then identified based on the linear control theory. This approach is very similar to the design process of the PSSs, where a range of operating conditions are considered to assess the performance of the linear control system, these operating conditions are usually selected.
based on power system characteristics in dealing with small disturbances such as slight changes in load demands [25], [26]. The linear control system performance decreases dramatically when power systems are subjected to large disturbances such as three-phase short circuit solid faults at a critical location in the network [27]–[29].

To overcome the dependency of the linear excitation system controllers to the operating condition of the network, nonlinear excitation system controllers are developed. These control systems are typically capable of preserving system stable operating conditions in a very wide range of operating scenarios [30]–[33]. Among different approaches to design a nonlinear control system, the feedback linearization technique is being widely used to design a nonlinear control scheme for excitation system controllers. Feedback linearization techniques are very popular in dealing with the design of the nonlinear control systems for the excitation system in power systems [34]–[36]. In [34], [37], the exact feedback linearization technique, a significant improvement to the feedback linearization technique that uses the rotor angle of the synchronous generator is considered as the output function, is proposed. The idea of using the rotor angle as an output function is also used with a direct feedback linearization approach to design a nonlinear excitation system controller [36], [38], [39]. The partial feedback linearization technique resolves the difficulties of rotor angle measurement by considering directly measurable speed deviation as an output function. This method is used to design nonlinear excitation system controllers for multi-machine power systems [40], [41]. However, to implement the feedback linearizing excitation system controllers efficiently, power systems’ parameters with a high degree of precision are required [42]. To design a nonlinear excitation system controller for a SMIB system, a passivity-based nonlinear excitation controller is proposed by choosing interconnection and damping matrices [43]. However, this method cannot be used for large-scale power systems since it is very difficult [44] to select these matrices for multiple generators. The method in [44] uses inverse filtering to design a nonlinear control system and enhance the transient stability of the grid. The sliding mode excitation controllers (SMECs) are specifically developed to expand transient stability boundaries in a power system [45], [46]. In the SMECs approach, the chattering effect will push some of the nonlinear modes of the synchronous generator into the unstable area and cause vibration in some of the generator mechanical elements and reduce the efficiency of the controller specifically for the unplanned operating condition [47], [48].

In the modelling of power systems, there exist unavoidable uncertainties due to the nonlinear characteristics of the elements, uncategorized dynamics, significant environmental elements, noises, and parameters that are varying with time. These types of uncertainties impact the precision in power system modelling. Moreover, the uncertainty in the model and parameters of the excitation system happens mainly due to the combination of inaccurate data and restricted access to the information of these elements and it cannot be neglected. As these mismatches negatively impact the performance of the controller, the stability of the system may not be preserved. To achieve reliable and safe operation of the power systems, it is necessary to deal with the uncertainties by designing and implementing a robust excitation system controller that covers the uncertainties in model and parameter. Hence, a robust excitation system model needs to be designed to ensure confidence in the excitation system operation during a disturbance, which should be robust to the uncertainties in the model parameters of the excitation system.

The transient stability of the power system can be improved using robust linear and nonlinear control
techniques for the excitation system controller design. Robust control design approaches based on LMI are using a linearized power system model and reduce the capability of the controller to be efficient in a wide range of operating conditions [49], [50]. To reduce the dependency of the robust controller design to the power system modelling, adaptive control theory is used to eliminate the nonlinear terms in the power system model and derive an exact feedback linearization method to obtain an enhanced robust design [51], [52]. To deal with the nonlinear behaviour of the power system and uncertainty in the parameters, robust adaptive approaches are considered along with direct feedback linearization [39], [53] [54].

Adaptive control approaches are unable to perform efficiently in an uncertain environment when a power system is subjected to a major fault, specifically, a fault at the generator terminal when significant variations are observed in the transmission line reactance and the configuration of the grid and the controller cannot adapt the power system parameters and maintain system transient stability [39], [55]. To overcome this issue, direct feedback linearization technique, Riccati equation and fuzzy logic methods are used to design the controller by considering uncertainty in parameters, topological variation in the network and interaction between the controllers [36], [56]–[61]. However, in these approaches, the interaction between controllers is bounded within the linear first-order interaction which may reduce the efficiency and performance of the design in comparison with including nonlinear interactions.

The bounds on the interaction of the adaptive robust controllers can be eliminated using adaptive back-stepping controllers based on the direct feedback linearization when the algebraic Riccati equations solution can be ignored. These controllers can efficiently ensure the stability of generator active power, speed, and rotor angle under severe disturbances [62], [63]. In these approaches, the error can be bounded and converge to an unknown constant since they are based on traditional adaptive control theory methods [64], [65]. These methods may lead to transient in the closed-loop system causing unacceptable dynamic characteristics [66].

In some cases, the uncertainties cannot be bounded within a specific structure and reasonable dynamic behaviour cannot be obtained, so, the nonlinear terms are eliminated in many steps using a back-stepping controller design approach to target a one-dimensional problem at a time. The focus of these adaptive controller design methods is usually to target uncertainty in the parameters [62]–[67].

An efficient control strategy to design a robust excitation system, which requires only local relative rotor angle and velocity, is proposed in [54]; this controller is robust to load and parameter variations. Additionally, in [68], a robust excitation system is presented for non-linear power systems. In [69], an LMI method is proposed for the design of a robust local excitation control, which allows for the inclusion of a wider class of nonlinearities.

The LMI technique has been proposed for the design of a robust PSS, by placing system poles in an acceptable region, which is then suitable for a major set of system operating setpoints [70]. This method provides the desired closed-loop characteristic for the system in some predetermined operating conditions. In [71], two PSSs are designed and used to stabilize a power system, and the paper compares the results from several methods, such as the classical phase compensation approach, the $\mu$-synthesis, and the LMI technique. In [72], a genetic algorithm is proposed for the design of optimal multi-objective robust PSSs in multi-machine systems. The multi-objective design in [72] is formulated to optimize a set of functions comprising the damping factor
and damping ratio. In [73], genetic algorithm and standard Prony analysis are proposed to extract the critical dynamic characteristics of a system to develop a robust controller for PSSs. The controller parameters can be changed online based on different operating setpoints; however, it requires a comprehensive search and therefore can result in a high order controller. Robustness is also considered for the turbine governor control systems [74]. In [74], the LMI method is used to design a robust turbine/governor control in multi-machine power systems. This control scheme can simply incorporate additional designs, such as gain matrices. In some related works, the robustness of the static VAR compensators (SVC) is also considered to damp power system oscillations [75–79]. In [75], a robust SVC is proposed to increase the damping of a power system, while a fast and stable SVC is presented in [76], using the structured singular value optimization. In [76], different operating conditions are considered using unstructured uncertainty. In [79], a robust supplementary damping controller is suggested for SVC where the $\mu$-synthesis is used to evaluate its robust performance.

2.3 Long-term Voltage Stability Improvement

The ability of the power system to maintain the voltage on each node of the network stable and within the planning criteria in normal and emergency operating conditions is called voltage stability. A gradual reduction in the voltage magnitude can threaten the voltage stability of the network since it is usually followed by a significant sharp reduction and can lead to voltage collapse [2]. Voltage collapse is an emergency operating condition in which a voltage abnormality leads to very low and unacceptable voltage magnitudes in parts of the power system close to the fault. After a voltage related disturbance, the reactive power demand of the system usually increases significantly, the increase in the demand is usually met by the fast-acting reactive power suppliers such as generators and compensators. If sufficient reactive power is supplied to the network and the reactive power mismatch is eliminated, the risk of voltage instability is reduced, and the voltage will reach a stable and acceptable level. However, if the power system is being operated in a stressed condition, the reactive power reserve in the grid is minimal and the reactive power mismatch in post-contingency will not be eliminated and the risk of voltage instability increases.

Generally, in synchronous machines, voltage is controlled by the excitation systems and they are responsible to support the field current of the generator for the normal operating condition, i.e. steady state, including 5 to 10 percent deviation from the nominal condition. In other words, the reactive power output of a generator is controlled by the excitation system [17]. In the case of an emergency, most of the excitation systems can produce higher than rated excitation current (3 times of the rated value) which improves emergency voltage profile. Nowadays, power systems are heavily loaded and operating near their operational boundaries. In such a stressed condition, excitation systems are forced to exceed their capability in the case of emergency voltage conditions for a limited time and, supply the additional required reactive power by increasing their excitation level. However, this capability must be monitored to ensure that both the machine and excitation systems are protected from overheating. This type of protection is provided by OEL. If this higher than rated excitation current persists for a limited time, it will supply an increased reactive power into the system, while at the same time the rotor winding temperature will continually increase. Although a rotor is designed for a continuous level of rated current, a higher than rated current can only be sustained by the rotor for a limited time. If the higher than rated excitation current persists longer, the rotor temperature would rise to a level that can cause insulation failure, if
unmonitored. If the temperature limit is exceeded, the insulation could be damaged permanently, and extensive repair will be required, which would take the generator out of service for months. The significant role of the generator rotor thermal capability to system voltage stability needs to be considered when attempting to improve the voltage stability in a power system. The impact of efficient use of this capability to maintain voltage stability has been widely mentioned in the literature [17], [80]–[83].

Usually, voltage instability creates areas with depressed voltages which not only persist but continue to decrease over time. This situation results in the over-excitation of nearby rotating units and increases their rotor currents above their nominal rating. In this case, the OEL would function, based on its current-time characteristic, to restrict this excessive level of the current [84]. The overheating capability of the generator winding is mostly indicated by the generator rotor winding temperature. But measuring the exact value of the rotor temperature is not a simple task; consequently, most of the manufacturers prefer to use rotor winding voltage and current instead of directly using the temperature. So, generally, a current-time curve is used to indicate the rotor windings overheating capability. The objective of the manufactures is to develop the OEL systems performance to allow the generator to inject as much as possible reactive power into the grid while it protects the rotor winding from destructive overheating. Increasing the reactive power capability of the generator increases the capability of the generator to be responsive to emergency conditions and improves the voltage stability of the grid [85]. To avoid voltage collapse, the generators are required to operate in an overexcited condition for a limited time which may also push the generator beyond overexcited condition until the OEL operates [86]. The impact of an efficient OEL system in which the generator can stay in the over-rated operating condition for a long time has been assessed in [87].

The reactive power margin analysis is necessary to be performed as a part of power system planning to ensure sufficient installed reactive power capacity is available in the power system during the emergency condition, and to avoid steady-state voltage instability. The reactive margin indicates the gap between the peak reactive power demand across the network in each zone substation and the system normal planning reactive power demand. Optimization approaches with the main objective function of the reactive power total demand and constraints such as the generating plant reactive power capabilities and load flow equations can be used to estimate the available reactive power margin [88]. The reactive power management is a critical part of the reactive power margin analysis that is critical in the case of interconnected multi-area power systems. Centralized and decentralised approaches are adapted to maximize the effective reserve of reactive power [89]. In [90], various methods are introduced to control the voltage and the reactive power in the power system, and also the importance of classifying different operating conditions using indices is indicated to help develop the robustness of a zone substation in dealing with the voltage stability. However, a proper supply and control of the reactive power to preserve the stability of the voltage are necessary. This supply is usually managed by the OEL through the reduction of the current flowing in rotor winding and reduction in the reactive power injection. The operational characteristics of the OEL are formed based on physical heat test runs by the manufacturers and are usually very conservative due to warranty concerns. By delaying the activation of the OEL, significant benefits can be achieved as long as a sufficient margin is provided to avoid overheating of the rotor windings of the synchronous generator [91].
2.4 Transient Stability Assessment

The ability of a power system to maintain the synchronism among its generating plants when subjected to a severe disturbance, such as a three-phase short circuit, is referred to as the transient stability. The energy market deregulation, the load demand increase and the high penetration of distributed inverter-based sources in addition to the economic and environmental challenges in the expansion of the transmission grid and installing new power plants have increased the stress in the power system by causing the existing transmission systems to be operated close to their critical conditions. Operating in a stressed environment, when the transmission system may need to be overloaded, increases the risk of transient instability in today’s heavy-loaded and interconnected power systems [92].

Transient instability is considered to be a severe event that a power system may face in daily operation since the probability of transient stability is generally low. However, an uncontrolled severe disturbance may cause the generating systems to lose their synchronism with other power system machines and lead to cascading outages, unplanned islanding operation, and finally widespread blackouts. To avoid the transient instability in the network, transient stability analysis needs to be carried out and a safe margin needs to be preserved for each operating condition. To provide a safe margin against transients stability, a significant capital investment might be needed, however, transient stability can be predicted in real-time using advanced approaches, which can in turn help to place the system into a safe operating condition with a lower required transient margin [93].

In the last several decades, transients stability assessment in the power system has been a major part of the power system analysis [94]. The transient stability of a power system can be assessed through energy methods or time-domain simulations. The development in parallel computing techniques and high-speed computation capabilities has improved the efficiency of the time domain simulation-based methods to be able to handle large-scale power system transient stability assessment [95], [96]. These developments in computation power have also directly impacted the use of pattern recognition methods to predict transient stability issues based on the information provided through PMUs [97].

The energy-based transient stability assessment methods or direct methods describe the ability of the network in absorbing the post-contingency excess kinetic energy flowing throughout the grid and, in comparison with the time-domain simulation, direct methods are very attractive to power system planners. Initially, the Lyapunov method, a well-known direct transient stability assessment method has been popularly used. Afterward, other direct methods such as sustained fault method, Controlling the Unstable Equilibrium Point (CUEP) method, and the Extended Equal Area Criterion (EEAC) method have been proposed to increase the efficiency of the solution methods [98]. Considering the increasing penetration of the inverter-based generating plants and electric vehicles, a global and innovative method has been proposed that integrates the global transient energy function and re-closer probability distribution functions to provide a quantitative measure of the probability of stability [99].

An effective wide-area supplementary control system has been proposed in [100] that uses the information
provided by the PMUs to capture angle and velocity between the wide-area machines and then using a nonlinear Kalman filter estimates the area equivalent states of the system by combining the PMU measurement from each area and substantially reducing the response to local modes in the estimated angles and frequencies. The controller then uses a controllable series compensator to control the local modes. This approach has been further developed in [101] by allocating PMUs to be more sensitive to the desired inter-area modes and less sensitive to local modes. The same nonlinear proposed Kalman filter which is used to design a controller to reject local modes as the measurement noise in the estimated states by combining multiple PMUs in each area of the system using SVCs. An inverse filtering approach has been used in [102] that provides a supplementary signal for the excitation system using a wide-area measurement to determine the generator flux that would maximize the reduction rate of the kinetic energy of any disturbance in the power system and improve transient stability.

The described centralised direct methods have proven to be efficient in transient stability analysis. The transient stability of a multi-machine power system can also be investigated from the individual machine perspective since the synchronism can be lost if more than one machine is affected by the unstable operation of critical machines [103], [104]. The Individual Machine Energy Function (IMEF) method was derived by considering the individual-machine perspective, where the stability of the system is determined by individual machine energy functions [105], [106].

In [107]–[109], a detailed transient stability analysis of multi-machine power systems is performed for each individual machine, and the required energy of the selected local countermeasures was calculated using the Partial Energy Function (PEF). In [110], the transient stability margin of the system is identified using a combination of EAC of the critical machine and PEF. To efficiently determine the transient stability of a power system in the multi-machine environment, a synchronous referred IMEF has also been used [111]. The individual machine method has been used to develop a computational approach to determine the system's critical clearing time (CCT) during the transients [112]. Potential energy in the grid has also been used to detect transient instability in a single machine case [113].

In the individual machine-based transient stability assessment direct methods, the IMEF and the PEF have been very well developed, since they are based on theories with a valuable underlying hypothesis and can be used to explain the fundamental structures. The research on some critical concepts of individual machine-based transient stability assessment direct methods has not been well reported recently, although they were proven to be very efficient in transient stability investigations in multi-machine power systems.

### 2.5 Nonlinear Power System Dynamic Stability Improvement

These days, the level of stress in large-scale multi-machine power systems has increased significantly. Specifically, if the load centre in these large-scale systems is distant from the high generation density areas, any oscillation in these highly stressed well-interconnected networks is considered to be a significant issue since a high number of inverter-based generating plants with changing generating patterns can change the power flow in the transmission system quickly. These changes can produce some oscillatory modes and cause dynamic instability. In some cases, with high penetration of residential solar generation, a significant reduction in the demand is observed and a large amount of power flows through the transmission system where the low-
frequency oscillations, called in classical power system studies the electromechanical oscillations, show nonlinear characteristic. The low-frequency oscillation in power systems is caused by the interactions between various power system elements and control system modes when subjected to small or large disturbances. These modal interactions are usually modelled by linear modal analysis methods based on linearized power system models however, they are mainly nonlinear modal oscillations and are observed in higher-order nonlinear terms of the system equation [114].

To investigate modal interaction, small signal stability analysis has been used predominantly for linearized models of interconnected power systems. In this method, the first-order Taylor’s series expansion of the power system linearized equation is used. The power system equation is linearized around a specific operating setpoint, which makes the small signal stability analysis dependent on the operating condition of the network. In the small-signal stability assessment, modal analysis is used to indicate the interaction among power system elements. The modal analysis uses the eigenvector to express the modal structure of the power system. Moreover, to achieve an analytical expression of the dynamic performance of the system, the eigenvalue analysis which is based on the Lyapunov method can be used. The modal and eigenvalue analysis are the key tools to tune and locate the optimal location of the PSS systems to improve the small-signal stability of the network [17]. It is clear now, that due to the dependency of the modal eigenvalue analysis on the linearized model of the power system, these techniques may not be able to provide accurate insight on the modes, when the system is nonlinear, especially under higher stress levels.

In the late eighties, attempts to consider the nonlinear characteristics and modal interaction of the system were initiated. In [115], [116], the envelope equation, which governs the aspect of the resonance between two modes, is presented. In [117], the inter-area mode phenomenon in stressed power systems following large disturbances is studied. The importance of adding the second-order terms in the time domain simulation is presented in [118]. In the same year, the NF theory is used as a tool to identify the nonlinear aspects of the modal interaction phenomenon [119].

To investigate the nonlinear characteristic of the power system in dynamic stability assessments, the NF theory is proven to be an efficient and powerful tool analytically. Over the past few years, the impact of the modal interaction on the efficiency of the control systems has been investigated widely using the NF theory [120]–[122]. The NF theory has been adapted to reduce the inter-area oscillations in the power system through the design of power system control systems [123]. Moreover, the interactions between system participation factors, machine states, and eigenvectors impact are assessed using NF theory [78], [124], [125]. The nonlinear modal interactions between the power system elements and their impact on the performance of the control system in a power system with a high-stress level have also been investigated using NF theory [126], [127]. The impact of the higher than 2nd order modal interactions on the small-signal stability results has also been investigated recently using NF [128]. Additionally, the closed-loop nonlinear solution of the torques and their interactions with the nonlinear torsional dynamics is derived using NF [129], [130].

A significant research effort has been focused on the analysis of the nonlinear characteristic of the power system recently [117], [120], [131]. The NF method and the Modal Series (MS) approaches have been very popular for the investigation of the power system nonlinear behaviour [128], [132]–[134]. Using the NF and the
MS, the problem of nonlinear dynamics in the network can be simply formulated and a physical insight can be gained to be able to assess the issue more efficiently. In the close vicinity of the resonance condition, the NF method cannot provide effective analysis approaches [135], [136]. The classical NF theory, in particular, cannot handle the resonance condition properly [137]. Consequently, ignoring the resonance terms was critical to achieve an efficient analysis of the power system higher-order modal interactions [124]. An innovative formulation to calculate the real normal forms of resonant vector fields have been proposed in [138], [139] to address the problem of resonance condition in the NF analysis of the modal interaction in power systems. The capability of the MS method to find the solution to the nonlinear problem under resonance condition is one of the main advantages of the MS approach [133], [140]–[142]. The nonlinear modal interactions are necessary to be considered during the control system design process since the control system performance is highly impacted by the nonlinear interactions between modes [123], [143], [144]. The control systems must be able to preserve their performance when subjected to modal interaction in the vicinity of a resonance condition. Providing a simple closed-form solution to the control system problem under resonance condition will help the assessment of the dynamic performance of the control system efficiently [145].

In [132], the IEEE Task Force committee has indicated the great potential of the NF theory with the inclusion of the 2nd order terms in the controller design and the transient stability analysis of the power systems. By including the 2nd order terms, significant improvements are obtained in the assessment of the power system dynamic performance and control design in comparison with those from the conventional eigenvalue analysis. By including the 2nd order terms, some of the nonlinear characteristics of the power system are preserved in the model, however, it fails to represent the whole nonlinear behaviour spectrum. To improve the accuracy of the transient stability assessment, in addition to keeping the 2nd order terms, the 3rd order terms are also included [146]. The application of including the 3rd order terms in the NF theory has been developed in [128], [147], [148], however, its advantages over the linear model and 2nd order terms based methods are not discussed. The NF method with the inclusion of 3rd order terms has been widely used in nonlinear mechanical systems to increase the damping of the system and internal resonances [149]. It has also been used to build reduced-order models and define nonlinear modes of vibration [150]–[152].

To model the nonlinear dynamics in a nonlinear system, Poincaré [153] developed the NF theory initially. To eliminate the resonance condition, the transformation function is selected with specific specifications. The developed process contains eight stages [154], [155]:

1) Differential-Algebraic Equations (DAEs) should be formed.
2) The post-contingency Stable Equilibrium Point (SEP) should be determined.
3) The DAE should be expanded into Taylor’s series around the SEP.
4) The linear part should be linearized.
5) The non-resonant terms of higher-order terms should be transformed.
6) The resonating terms should be eliminated to simplify NF dynamics.
7) The NF transformation should be selected based on the required accuracy in the assessment.
8) The NF should be finally approximated for stability assessment.
Chapter 3 Optimal Robust Excitation Controller Design

3.1 Foreword

In a post-contingency operating condition, when most of the power system elements are overloaded and operated near their operational limits, proper modelling of the critical power system elements is crucial. By determining the precise models of the elements, the actual capability of the power system element can be simulated, however, if the design is based on poor models of the power system elements, the power system may experience failure and devastating consequences. In this chapter, the excitation system, which is one of the most important elements of the power system, has been modelled to be robust to the uncertainty in the parameters of its model, allowing the excitation system to improve the transient and steady-state stability performance of the power grid.

In this chapter, the linear excitation system control unit has been modelled and developed to be an optimal robust excitation system. The proposed optimal robust controller design framework is applied to the IEEE ST1A excitation system controller with the given nominal values of its parameters. These parameters can have uncertainties in their values that can vary between −20% and +20% of their nominal values. Once the most important excitation system parameters that will have the most influence on the dynamics of the power system are determined, the proposed framework to design the optimal controller will be utilized and the optimal robust excitation controller will be designed. The designed optimal robust excitation system is robust to the changes in the most critical excitation system parameter values (within its lower and upper limit outlined by the excitation system manufacturer). The robustness of the designed controller is validated by carrying out a dynamic stability assessment on a pilot power system.

3.2 Background

In today’s fast-growing electric power systems, when most of the systems are operated near their thermal and stability limits, correct models of power system controllers and the correct values for the parameters of the model become more and more important. In a complex power system, extensive studies need to be carried out by the system operators to determine the power system operational limits from both technical and economical points of view. However, power system studies accuracy is always questioned due to the unavoidable uncertainties in the parameters of the models of the power system controllers. These uncertainties can in turn significantly influence the values obtained for the operational limits of the grid. It is, therefore, necessary to make the system more robust to these uncertainties.

In the last two decades, a lot of research work has been reported in the design of robust power system controllers such as turbine governors [74], [156], power system stabilizers [70]–[73] and static VAr compensators [75]–[78]; however, very few works have been reported in the literature on the design of the robust excitation system controllers. Excitation system controllers are one of the most important elements in the large-scale interconnected power systems, because, they directly control the voltages of the generators and they
have a relatively short time constant in their control loop, so they can impact the power system dynamics faster than most of other power system controllers. The major influences of the synchronous generator excitation system on the stability of one machine infinite bus test system have been thoroughly assessed in [79].

The uncertainties in the model and parameters of the excitation system occur mainly due to a combination of factors such as inaccurate data from the manufacturers, restricted access to the information, and aging of these controllers. Hence, it is required to design a robust excitation system to ensure confidence in its operation during normal and specifically emergency condition when the system is under stressed and nonlinear system characteristics are observed. In [68], a robust excitation system was designed to improve the stability of a nonlinear power system. A combination of Lyapunov direct method and partial linearization was studied in [157] to design a robust decentralized excitation system and improve the transient stability margin. In [27], a recursive approach was used to design a robust nonlinear excitation system. A new nonlinear excitation system controller based on inverse filtering has been proposed in [44]; the proposed controller can be simply implemented on the excitation system and, it can improve the transient stability of the power system. In [69], the Linear Matrix Inequality (LMI) method was adopted for designing a robust local excitation system. Having these facts in mind, it is vital to develop an optimal control approach for designing a linear robust excitation system controller with uncertainties in critical parameters. The uncertainties are considered to be bounded and can cause the values of the parameters to vary within a specified upper and lower limits. The uncertainties of the parameters are considered in terms of the uncertainties that can have the most significant influence on the dynamic characteristics of the power system. These can be determined by examining the sensitivity of power system eigenvalues in eigenvalue analysis to the magnitude of uncertainty in the excitation system parameters. Once these parameters are determined, the proposed framework can be applied to design the optimal robust excitation system, which will result in the reduction of the influence of the uncertainties in the identified parameters of the system excitation controller, on the system stability. The designed optimal robust controller is robust to changes in one or more of its parameters, that is, if the parameters of the excitation controller vary (within a specified upper and lower limit) from the given nominal values, the system does not change from being stable to unstable.

The proposed method in this chapter solves a linear system problem and does not cover the nonlinear aspect of a multi-machine power system. In a multi-machine power system, considering various types of generating plant and excitation systems, there are higher-order modal interactions between machine and excitations system and between different types of excitation systems in the network which in turn increases the complexity of the problem and involves different types of uncertainty. In this work, only uncertainties in the excitation system parameters are considered.

### 3.3 Optimal Robust Controller Design Framework

In the proposed framework, the state equations of the model of the excitation system controllers with uncertainties in their parameters are decomposed into the matched and the unmatched uncertainty components. The proposed method only considers the linear characteristics of a single excitation system and assumes no higher-order interactions between different excitation system in a power system. To design the optimal robust controller, the matched uncertainty component leads to solving a Linear Quadratic Regulator (LQR) problem,
while an augmented control is used to deal with the unmatched uncertainty component. The resulting controllers are linear, and the controllers gain can be directly obtained without using any tuning of the controller’s parameters or using trial and error procedures.

The optimal robust controller design [158]-[160] starts with the state equation of the model of the excitation system controller and its uncertain parameters as given in (3-1),

$$\dot{x} = A(p)x + Bu$$  \hspace{1cm} (3-1)

where $x \in \mathbb{R}^n$ is state vector, $u \in \mathbb{R}^n$ is control vector, $A$ is the state matrix, $B$ is the input matrix, and $p \in P$ is the variable representing the uncertain parameter.

The variable representing uncertainty matrix, $U_p$, can be evaluated using (3-2) where $A(p)$ and $A(p_0)$ are the uncertain state matrix and the nominal state matrix, respectively. Here, $p$ is the variable represents the uncertain parameter and, $p_0$ represents the nominal values of the uncertain parameter.

$$U_p = A(p) - A(p_0)$$  \hspace{1cm} (3-2)

To design a robust controller for the IEEE ST1A excitation system, the uncertainty expressed in (3-2) should be decomposed into the sum of a matched component and an unmatched component by projecting it into the range of $B$. This can be performed by using pseudo-inverse $B^+$ of $B$. If $B$ is an $m \times n$ matrix and is a tall matrix ($m > n$) of full rank, then $B^+ = (B^TB)^{-1}B^T$. Let

$$U_p = U_p^{\text{Matched}} + U_p^{\text{Unmatched}} = \left[BB^+(U_p)\right] + \left[(I - BB^+)U_p\right]$$  \hspace{1cm} (3-3)

Since the robust control problem cannot be solved directly as its solution may not be straightforward; it is translated into an optimal control problem and therefore solved indirectly. For the linear time-invariant system given in (3-1), the optimal control problem is the LQR problem, and, the solution to an LQR problem exists if the system is stabilizable [160].

The following assumptions are considered:

1) There exists a nominal value of $p_0 \in P$ exists such that $(A(p_0), B)$ is stabilizable, and
2) $A(p)$ is bounded.

With the above assumptions, the objective is to solve the following robust control problem to stabilize the system with uncertainties in the parameters of the excitation system controller.

**Robust control problem:**

Find a feedback control law $u = Kx$, such that the closed-loop system in (3-4) is globally asymptotically stable for all $p \in P$. 

17
\[ \dot{x} = A(p)x + Bu = A(p)x + BKx \]  \hspace{1cm} (3-4)

Define, \( F \) and \( H \), as the upper bound of the uncertainty for all \( p \in P \).

\[ (U_p^\text{max})^T (B^*)^T B^*(U_p^\text{max}) \leq F \]  \hspace{1cm} (3-5)

\[ \alpha^{-2} (U_p^\text{max})^T (U_p^\text{max}) \leq H \]  \hspace{1cm} (3-6)

where \( \alpha \geq 0 \) is a design parameter and \( U_p^\text{max} \) is the maximum possible uncertainty, which can be easily calculated using (3-7), in which \( p^\text{max} \) is the maximum possible value for the uncertain parameter.

\[ U_p^\text{max} = A(p^\text{max}) - A(p_0) \]  \hspace{1cm} (3-7)

The approach here is to solve the robust control problem indirectly by translating it into an optimal control problem, which is an LQR problem, as discussed below.

**Optimal control problem:**

For the following auxiliary system,

\[ \dot{x} = A(p_0)x + Bu + (I - BB^*)v \]  \hspace{1cm} (3-8)

find a feedback control law of \( u = Kx \) and \( v = Lx \) that minimize the following cost function,

\[ \int \left( x^T (F + \rho^2 H + \beta^2 I)x + u^T u + \rho^2 v^T v \right) dt \]  \hspace{1cm} (3-9)

where \( \alpha \geq 0, \beta \geq 0, \) and \( \rho \geq 0 \) are the appropriate design parameters.

In this LQR problem, \( v \) is an augmented control that is used to deal with the unmatched uncertainty component. The designed parameters should be selected so that the enough condition in the following theorem is satisfied:

The solution to this LQR problem is obtained as,

\[ \begin{bmatrix} u \\ v \end{bmatrix} = -\tilde{R}^{-1}\tilde{B}^TSx \]  \hspace{1cm} (3-10)

where \( S \) is the unique positive definite solution to the following algebraic Riccati equation.

\[ S\tilde{A} + \tilde{A}^T S + \tilde{Q} - S\tilde{B}\tilde{R}^{-1}\tilde{B}^T S = 0 \]  \hspace{1cm} (3-11)

in which
\[\tilde{A} = A(p_0)\]  \hspace{1cm} (3-12)
\[\tilde{Q} = F + \rho^2 H + \beta^2 I\]  \hspace{1cm} (3-13)
\[\tilde{B} = \begin{bmatrix} B & \alpha(I - BB') \end{bmatrix}\]  \hspace{1cm} (3-14)
\[\tilde{R} = \begin{bmatrix} I & 0 \\ 0 & \rho^2 I \end{bmatrix}\]  \hspace{1cm} (3-15)

Since
\[\tilde{B}\tilde{R}^{-1}\tilde{B}^T = \begin{bmatrix} B & \alpha(1-BB') \end{bmatrix} \begin{bmatrix} I & 0 \\ 0 & \rho^2 I \end{bmatrix} \begin{bmatrix} B^T \\ \alpha(1-BB') \end{bmatrix} = BB^T + \alpha^2 \rho^2 (1-BB')^2\]  \hspace{1cm} (3-16)

the Riccati equation in (3-11) becomes;
\[SA(p_0) + A(p_0)^T S + F + \rho^2 H + \beta^2 I - SBB^T + \alpha^2 \rho^2 (1-BB')^2)S = 0\]  \hspace{1cm} (3-17)

The control variables are also determined as,
\[
\begin{bmatrix} u \\ v \end{bmatrix} = \begin{bmatrix} -B^T S \\ -\alpha \rho^2 (1-BB') S \end{bmatrix} x = \begin{bmatrix} K \\ L \end{bmatrix} x
\]  \hspace{1cm} (3-18)

The following theorem states the relation between the robust control problem and the LQR Problem and the condition for choosing the designed parameters.

**Theorem:** If one can choose \(\alpha, \beta\) and \(\rho\) such that the solution to LQR Problem to \(u = Kx\) and \(v = Lx\) satisfies
\[\beta^2 I - 2\rho^2 L^T L > 0\]  \hspace{1cm} (3-19)

then \(u = Kx\) is a solution to a robust control problem [160].

This theorem states the relation between the robust control problem and the LQR Problem and the condition for choosing the designed parameters.

**Proof:** Since \((A(p_0), B)\) is stabilizable, \(F \geq 0\) and \(H \geq 0\), the solution to the LQR problem exists. Denote the desired solution by \(u = Kx\) and \(v = Lx\). The objective is to prove that they are also the solution to the robust control problem; that is,
\[\dot{x} = A(p)x + BKx\]  \hspace{1cm} (3-20)

is globally asymptotically stable for all \(p \in P\).

To prove this, the following is defined,
\[ V = \min_{u \in U} \int_{0}^{T} (x^T(F + \rho^2H + \beta^2I)x + u^T u + \rho^2 v^T v) \, dt \]  

(3.21)

to be the minimum cost of the optimal control of the auxiliary system from an initial state \( x_0 \) to the origin.

It should be shown that \( V \) is a Lyapunov function for the system given in (3.20). By definition, \( V \) must satisfy the Hamilton-Jacobi-Bellman equation which reduces to

\[ \min_{u,v} \left\{ x^T \left( F + \rho^2 H + \beta^2 I \right) x + u^T u + \rho^2 v^T v + V^T \left( A(p_0)x + Bu + \left( I - BB^* \right)v \right) \right\} = 0 \]  

(3.22)

Since \( u = Kx \) and \( v = Lx \) are the optimal control, the follow identities must be satisfied;

\[ x^T F x + \rho^2 x^T H x + \beta^2 x^T K x x^T L x + V^T \left( A(p_0)x + B K x + \left( I - BB^* \right) L x \right) = 0 \]  

(3.23)

\[ 2x^T K^T + V^T B = 0 \]  

(3.24)

\[ 2\rho^2 x^T L^T + V^T \alpha \left( I - BB^* \right) = 0 \]  

(3.25)

By considering (3.23) minus (3.24), it can be inferred that \( V(x) \) is a Lyapunov function for (3.20). It is obvious that

\[ V^T > 0 \quad x \neq 0 \]  

(3.26)

\[ V^T = 0 \quad x = 0 \]  

(3.27)

to show \( dV/dt < 0 \) for all \( x \neq 0 \), from (3.21), it yields,

\[ \dot{V}(x) = V^T \dot{x} = V^T \left( A(p)x + B K x \right) \]  

(3.28)

\[ \dot{V}(x) = V^T \left( A(p_0)x + BKx + \alpha \left( I - BB^* \right) L x \right) + V^T \left( \left( U_p \right)x - \alpha \left( I - BB^* \right) L x \right) \]  

(3.29)

\[ \dot{V}(x) = V^T \left( A(p_0)x + BKx + \left( I - BB^* \right) L x \right) + V^T \left( U_p \right)x - V^T \alpha \left( I - BB^* \right) L x \]  

(3.30)

\[ \dot{V}(x) = V^T \left( A(p_0)x + BKx + \left( I - BB^* \right) L x \right) + V^T \left( B B^* \left( U_p \right)x + V^T \left( I - BB^* \right) \left( U_p \right)x - V^T \alpha \left( I - BB^* \right) L x \]  

(3.31)

from (3.23), the first term of (3.31) can be expressed as (3.32),

\[ V^T \left( A(p_0)x + BKx + \alpha \left( I - BB^* \right) L x \right) = -x^T \left( F + \rho^2 H + \beta^2 I \right) x - x^T K^T K x - \rho^2 x^T L^T L x \]  

(3.32)

and from (3.24), the second term of (3.31) can be expressed as (3.33),

\[ V^T B B^* \left( U_p \right)x = -2x^T K^T B^* \left( U_p \right)x \]  

(3.33)

and from (3.25), the third and fourth terms of (3.31) can be expressed as (3.34) and (3.35),
\[
V_i^T \alpha \left(I - BB^T\right)Lx = -2\rho^2 x^T L^T Lx \quad (3-34)
\]
\[
V_i^T \left(I - BB^T\right)(U_p)x = -2\alpha^{-1} \rho^2 x^T L^T (U_p)x \quad (3-35)
\]

Substituting (3-32) - (3-35) in (3-31), it yields,

\[
\dot{V}(x) = V_i^T \left( A \left(p_i\right)x + BKx + \alpha \left(I - BB^T\right)Lx\right) + V_i^T \left( I - BB^T\right)(U_p)x + V_i^T \left(I - BB^T\right)(U_p)x - V_i^T \left(I - BB^T\right)Lx 
\]
\[
\dot{V}(x) = -x^T \left( F + \rho^2 H + \beta^2 I \right)x - x^T K^T Kx - \rho^2 x^T L^T Lx - 2x^T K^T B^T \left( U_p \right)x + 2\rho^2 x^T L^T Lx - 2\alpha^{-1} \rho^2 x^T L^T (U_p)x \quad (3-36)
\]
\[
\dot{V}(x) = -x^T \left( F + \rho^2 H + \beta^2 I \right)x - x^T K^T Kx - \rho^2 x^T L^T Lx - 2x^T K^T B^T \left( U_p \right)x + 2\rho^2 x^T L^T Lx - 2\alpha^{-1} \rho^2 x^T L^T (U_p)x 
\]
\[
\dot{V}(x) \leq -x^T \left( F + \rho^2 H + \beta^2 I \right)x - x^T K^T Kx - \rho^2 x^T L^T Lx + \rho^2 \alpha^{-1} x^T \left( B^T U_p \right) x \leq x^T \left( B^T U_p \right)^T \left( B^T U_p \right)x \quad (3-37)
\]

The second and fourth terms of (3-37) can be expressed as (3-38),

\[
-x^T \left( K - B^T U_p \right)^T \left( K - B^T U_p \right)x + x^T \left( B^T U_p \right)^T \left( B^T U_p \right)x \leq x^T \left( B^T U_p \right)^T \left( B^T U_p \right)x \leq x^T Fx 
\]

Considering (3-5) and (3-39) yields;

\[
-x^T \left( K - B^T U_p \right)^T \left( K - B^T U_p \right)x + x^T \left( B^T U_p \right)^T \left( B^T U_p \right)x \leq x^T \left( B^T U_p \right)^T \left( B^T U_p \right)x \quad (3-39)
\]

Considering (3-6) and the fifth term of (3-37)

\[
-2\alpha^{-1} \rho^2 x^T L^T (U_p)x \leq \rho^2 x^T L^T Lx + \rho^2 \alpha^{-1} x^T U_p^T U_p^T x \leq \rho^2 x^T L^T Lx + \rho^2 x^T Hx 
\]

Substituting (3-39) and (3-40) in (3-37), it yields

\[
\dot{V}(x) = -x^T \left( F + \rho^2 H + \beta^2 I \right)x - x^T K^T Kx - \rho^2 x^T L^T Lx - 2x^T K^T B^T \left( U_p \right)x + 2\rho^2 x^T L^T Lx
\]
\[
\dot{V}(x) \leq -x^T \left( F + \rho^2 H + \beta^2 I \right)x - x^T K^T Kx - \rho^2 x^T L^T Lx - 2x^T K^T B^T \left( U_p \right)x + 2\rho^2 x^T L^T Lx
\]
\[
\dot{V}(x) = x^T \left( \beta^2 I - 2\rho^2 U_p L \right)x
\]

Consequently, if \( \beta 2I - 2\rho 2LTL > 0 \) condition is satisfied, then, \( dV/dt \) will be negative for all \( x \neq 0 \), and the optimality necessary condition is met.

Accordingly, by the Lyapunov stability theorem, the system given in (3-4) is stable for all \( p \in P \). In other words, \( u = Kx \) is a solution to the Robust Control Problem.

Although the proposed optimal control approach for robust control of the excitation system has assumed no nonlinear characteristic, however, the same approach can be applied to nonlinear systems. The nonlinear optimal controls are usually obtained by solving the Hamilton–Jacobi–Bellman equations. Sometimes it is quite complicated and time-consuming to obtain the solutions. An alternative approach to solve the nonlinear optimal control problem is the State-Dependent Riccati Equation. This approach factorizes nonlinear state equations as
linear-like state equations having state-dependent coefficients, so the equations are written like the formulation of the LQR. Thus, LQR optimal control can be solved to obtain optimal solutions [160].

### 3.4 Design of an Optimal Robust Excitation System

In this section, the aim is to implement the optimal robust control design strategy developed in the previous section on the IEEE ST1A excitation system controller. In the IEEE ST1A excitation system, the excitation power is provided through a transformer from the terminals of the generator (or the auxiliary bus) and is regulated by a controlled rectifier; so, the maximum possible excitation voltage is directly related to the generator terminal voltage [161]. In this model, alternative protection systems such as under excitation and overexcitation limiters are ignored. Figure 3-1 shows the IEEE type ST1A simplified model.

![IEEE Type ST1A simplified excitation system model](image)

From Figure 3-1, the state space representation of the IEEE ST1A excitation system can be formulated as

\[
\dot{x} = Ax + Bu \tag{3-42}
\]

where the output is given by

\[
y = Cx + Du \tag{3-43}
\]

in which \(y\) is the output vector, \(C\) is the output matrix and \(D\) is the feedforward matrix.

By considering the state vector, \(x = [V_1, V_2, V_c, V_A]^T\), the input vector, \(u = [V, V_{ref}]^T\) and the output vector, \(y = [E_{FD}]\), the state space representation matrices are expressed as,

\[
A = \begin{bmatrix}
-1 & \frac{T_c K_c}{T_b T_a T_F} & -1 & \frac{T_c K_c}{T_b T_a T_F} & \frac{T_c K_c}{T_b T_a T_F} \\
\end{bmatrix}
\]

\[
= \begin{bmatrix}
\frac{K_a K_c}{T_a T_F} & -1 & 0 & -\frac{K_a K_c}{T_a T_F} \\
0 & 0 & -1 & 0 \\
\frac{K_a}{T_a} & 0 & 0 & -1 \\
\end{bmatrix}
\]
\[
B' = \begin{bmatrix}
-\frac{T_c}{T_R} & 0 & \frac{1}{T_R} & 0 \\
\frac{1}{T_R} & 0 & 0 & 0 \\
\frac{1}{T_R} & 0 & 0 & 0
\end{bmatrix}
\]

(3-45)

\[
C = [0 \ 0 \ 0 \ 1]
\]

(3-46)

\[
D = [0 \ 0]
\]

(3-47)

Considering the state space representation of the IEEE ST1A excitation system model, the proposed optimal robust control design strategy given in section 3.3 can be applied. The reported nominal values in Table 3-1 for the parameters of the IEEE ST1A excitation system model is adapted from [161].

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Parameter description</th>
<th>Nominal value</th>
</tr>
</thead>
<tbody>
<tr>
<td>(T_R)</td>
<td>Regulator input filter time constant</td>
<td>0.02</td>
</tr>
<tr>
<td>(K_R)</td>
<td>Regulator filter gain</td>
<td>1</td>
</tr>
<tr>
<td>(T_C)</td>
<td>Regulator time constant</td>
<td>1</td>
</tr>
<tr>
<td>(T_B)</td>
<td>Regulator time constant</td>
<td>5</td>
</tr>
<tr>
<td>(K_A)</td>
<td>Amplifier gain</td>
<td>210</td>
</tr>
<tr>
<td>(T_A)</td>
<td>Amplifier time constant</td>
<td>0.02</td>
</tr>
<tr>
<td>(K_F)</td>
<td>stabilizer gain</td>
<td>0.02</td>
</tr>
<tr>
<td>(T_F)</td>
<td>stabilizer time constant</td>
<td>0.7</td>
</tr>
</tbody>
</table>

| Table 3-1: IEEE ST1A excitation system model parameters |

In the IEEE ST1A excitation system controller, the parameter directly impacts the closed-loop feedback controller as the amplification gain. It is expected that \(K_A\) significantly impact the dynamic behaviour of the IEEE ST1A excitation system controller. To assess the impact of \(K_A\) on the performance of the excitation system controller, six different values of \(K_A\) are selected; and for each of these values, the real parts of the eigenvalues are evaluated. To demonstrate this, the value of \(K_A\) can vary between ±20% of their nominal values. Table 3-2 has presented the results of eigenvalue analysis for each value of \(K_A\) in the IEEE ST1A excitation system model.

| Table 3-2: The real part of the eigenvalues for different values of \(K_A\) without the optimal robust modification |
|---|---|---|---|
| Eigenvalue | 1 | 2 | 3 | 4 |
| \(K_A - 0.2K_A\) | -1.68x10^3 | -48.57 | -1.42 | -50 |
| \(K_A - 0.1K_A\) | -1.89x10^3 | -48.57 | -1.42 | -50 |
| \(K_A - 0.05K_A\) | -1.99x10^3 | -48.57 | -1.42 | -50 |
| \(K_A\) | -2.10x10^3 | -48.57 | -1.42 | -50 |
| \(K_A + 0.05K_A\) | -2.20x10^3 | -48.57 | -1.42 | -50 |
| \(K_A + 0.1K_A\) | -2.31x10^3 | -48.57 | -1.42 | -50 |
| \(K_A + 0.2K_A\) | -2.52x10^3 | -48.57 | -1.42 | -50 |
Referring to Table 3-2, it can be concluded that as the value of $K_A$ is varied, the position of the real part of eigenvalue 1 changes noticeably while the positions of the real parts of the other eigenvalues (2, 3, and 4) are unchanged. This confirms that the uncertainty in the $K_A$ parameter has a significant influence on the dynamic characteristic of the excitation system. By substituting the nominal values of the parameters from Table 3-1 in (3-46), the system input matrix is given by,

$$\begin{bmatrix}
-10 & 0 & 50 & 0 \\
0.2 & 0 & 0 & 0
\end{bmatrix}$$

The variable, $U_p$, representing the uncertainty matrix, can be evaluated using (3-2), where $K_A$ represents the uncertain parameter and, $K_{A0}$ represents the nominal value of the uncertain parameter, $K_A$. In Table 3-1, the value of $K_{A0}$ is reported to be 210, so, the uncertainty in parameter $K_A$ is given by

$$
\begin{bmatrix}
2100.2 - 10.2K_A & 0 & 0 & 0 \\
1.43K_A - 300 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 \\
50K_A - 10500 & 0 & 0 & 0
\end{bmatrix}
$$

The uncertainty can be divided into the matched and the unmatched components using the Moore-Penrose pseudo-inverse of $B$ denoted by $B^+$ as follows:

$$B^+ = \begin{bmatrix}
-8.67 \times 10^{-19} & 0 & 0.02 & 0 \\
5 & 0 & 1 & 0
\end{bmatrix}
$$

Using (3-3), the corresponding matched and unmatched components are computed as,

$$U_p^{\text{Matched}} = \begin{bmatrix}
2100.2 - 10.2K_A & 0 & 0 & 0 \\
0 & 0 & 0 & 0 \\
4.4 \times 10^{-16}K_A - 9.11 \times 10^{-14} & 0 & 0 & 0 \\
0 & 0 & 0 & 0
\end{bmatrix}
$$

$$U_p^{\text{Unmatched}} = \begin{bmatrix}
2.33 \times 10^{-13} - 1.13 \times 10^{-14}K_A & 0 & 0 & 0 \\
1.43K_A - 300 & 0 & 0 & 0 \\
9.11 \times 10^{-14} - 4.42 \times 10^{-16}K_A & 0 & 0 & 0 \\
50K_A - 10500 & 0 & 0 & 0
\end{bmatrix}
$$

Now, the upper bound of the uncertainty for all $p \in P$ should be calculated. To do so, the maximum uncertainty, $U_p^{\text{max}}$ by considering $K_A^{\text{max}} = 310$ is obtained as,

$$U_p^{\text{max}} = \begin{bmatrix}
-1000 & 0 & 0 & 0 \\
142.9 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 \\
5000 & 0 & 0 & 0
\end{bmatrix}
$$
Finally, from (3-5) and (3-6) the value of $F$ and $H$ are determined, by considering $\alpha = 1$, as below.

$$
F = \begin{bmatrix}
2.5 \times 10^6 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0
\end{bmatrix}
$$  \hspace{1cm} (3-54)

$$
H = \begin{bmatrix}
2.602 \times 10^6 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0
\end{bmatrix}
$$  \hspace{1cm} (3-55)

The algebraic Riccati equation in (3-11) can be formed by considering the design parameters as $\beta = 10$ and $\rho = 1$. The solution to the algebraic Riccati equation denoted by $S$ is given as follows,

$$
S = \begin{bmatrix}
823.09 & -0.84 & 26.68 & 1.5 \\
-0.84 & 8.68 & -0.17 & -0.216 \\
26.68 & -0.17 & 5.47 & 0.28 \\
1.5 & -0.216 & 0.28 & 0.99
\end{bmatrix}
$$  \hspace{1cm} (3-56)

Using $S$, the closed-loop controller, and the augmented controller are computed using (3-18) as below.

$$
K = \begin{bmatrix}
6896.9 & 0.29 & -6.86 & 1.06 \\
-164.6 & 0.17 & -5.33 & -0.3
\end{bmatrix}
$$  \hspace{1cm} (3-57)

and

$$
L = \begin{bmatrix}
-9.2 \times 10^{-14} & -1 \times 10^{-16} & 3.2 \times 10^{-15} & 1.8 \times 10^{-16} \\
-0.84 & 8.68 & -0.17 & -0.216 \\
4.5 \times 10^{-14} & -4.7 \times 10^{-17} & 1.4 \times 10^{-15} & 8.3 \times 10^{-17} \\
1.5 & -0.216 & 0.28 & 0.99
\end{bmatrix}
$$  \hspace{1cm} (3-58)

and then the new system matrix, $A_{\text{new}}$, is expressed as,

$$
A_{\text{new}} = A + BK = \begin{bmatrix}
-7.1 \times 10^4 & -3.05 & 77.31 & -10.36 \\
300 & -1.42 & 0 & -1.42 \\
3.4 \times 10^5 & 14.47 & -392.9 & 52.97 \\
10500 & 0 & 0 & -50
\end{bmatrix}
$$  \hspace{1cm} (3-59)

To evaluate the robustness of the developed strategy, the eigenvalue analysis is performed. Using the same six different values of $K_A$ in Table 3-2 ($\pm 20\%$ variation in $K_A$ from its nominal value), the positions of the real parts of the system eigenvalues for different $K_A$ values are evaluated. Table 3-3 shows the results of eigenvalue analysis for the IEEE ST1A excitation system model with the proposed optimal robust controller parameters.

Table 3-3 reveals that as $K_A$ is varied, the changes in the positions of the real parts of all eigenvalues are unchanged. This confirms that the designed robust IEEE ST1A excitation controller model is robust for $\pm 20\%$.
variation in $K_A$. To investigate the robustness of the resulted optimal robust excitation system further, the following sensitivity function is defined.

$$\frac{\Delta E}{\Delta K_A} = \frac{(E_{\text{Nom}} - E_{\text{Unc}})}{(K_{A,\text{Nom}} - K_{A,\text{Unc}})/K_{A,\text{Nom}}}$$

(3-60)

where, $E_{\text{Nom}}$ is the real part of the eigenvalue of the system using the nominal value of the parameter $K_{A,\text{Nom}}$, and $E_{\text{Unc}}$ is the real part of the eigenvalue of the system using uncertain parameter $K_{A,\text{Unc}}$.

Table 3-4 shows the results of the sensitivity analysis. It concludes that in the case of eigenvalue 1, the designed optimal robust excitation system reduces the influence of 20% uncertainty in $K_A$ from 22% (20%×1.1) to 0.6% (20%×0.03) variation in the positions of the real parts of the eigenvalues.

<table>
<thead>
<tr>
<th>Eigenvalue</th>
<th>$K_A - 0.2K_A$</th>
<th>$K_A - 0.1K_A$</th>
<th>$K_A - 0.05K_A$</th>
<th>$K_A$</th>
<th>$K_A + 0.05K_A$</th>
<th>$K_A + 0.1K_A$</th>
<th>$K_A + 0.2K_A$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-7.10×10^4</td>
<td>-7.12×10^4</td>
<td>-7.13×10^4</td>
<td>-7.14×10^4</td>
<td>-7.15×10^4</td>
<td>-7.16×10^4</td>
<td>-7.18×10^4</td>
</tr>
<tr>
<td>2</td>
<td>-51.83</td>
<td>-52.11</td>
<td>-52.26</td>
<td>-52.41</td>
<td>-52.56</td>
<td>-52.72</td>
<td>-53.04</td>
</tr>
<tr>
<td>3</td>
<td>-15.72</td>
<td>-16.30</td>
<td>-16.68</td>
<td>-16.96</td>
<td>-17.23</td>
<td>-17.50</td>
<td>-18.21</td>
</tr>
<tr>
<td>4</td>
<td>-1.42</td>
<td>-1.42</td>
<td>-1.42</td>
<td>-1.42</td>
<td>-1.42</td>
<td>-1.42</td>
<td>-1.42</td>
</tr>
</tbody>
</table>

Table 3-5: The real part of the eigenvalues for different values of $K_A$ with the optimal robust modification

<table>
<thead>
<tr>
<th>Eigenvalue</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td>$K_A - 0.2K_A$</td>
<td>-7.10×10^4</td>
<td>-51.83</td>
<td>-15.72</td>
<td>-1.42</td>
</tr>
<tr>
<td>$K_A - 0.1K_A$</td>
<td>-7.12×10^4</td>
<td>-52.11</td>
<td>-16.30</td>
<td>-1.42</td>
</tr>
<tr>
<td>$K_A - 0.05K_A$</td>
<td>-7.13×10^4</td>
<td>-52.26</td>
<td>-16.68</td>
<td>-1.42</td>
</tr>
<tr>
<td>$K_A$</td>
<td>-7.14×10^4</td>
<td>-52.41</td>
<td>-16.96</td>
<td>-1.42</td>
</tr>
<tr>
<td>$K_A + 0.05K_A$</td>
<td>-7.15×10^4</td>
<td>-52.56</td>
<td>-17.23</td>
<td>-1.42</td>
</tr>
<tr>
<td>$K_A + 0.1K_A$</td>
<td>-7.16×10^4</td>
<td>-52.72</td>
<td>-17.50</td>
<td>-1.42</td>
</tr>
<tr>
<td>$K_A + 0.2K_A$</td>
<td>-7.18×10^4</td>
<td>-53.04</td>
<td>-18.21</td>
<td>-1.42</td>
</tr>
</tbody>
</table>

The designed optimal robust excitation system controller is robust for changes in the value of $K_A$; so, any variation in the value of $K_A$ will not influence the excitation system behaviour, but the variation of the other parameters in addition to $K_A$ must also be investigated. Table 3-5 shows the eigenvalues of the optimal robust controlled system when parameters $K_A$, $T_B$, and $T_C$ are uncertain. The results from Table 3-5 confirm that in addition to the robustness of the optimal robust IEEE ST1A excitation system to uncertainty in $K_A$, the designed optimal robust excitation system is also robust to the uncertainty in $T_C$ and $T_B$.

Table 3-5: Eigenvalue analysis of the optimal robust excitation system for different values of $K_A$, $T_C$ and $T_B$

<table>
<thead>
<tr>
<th>Eigenvalue</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td>$K_A - 0.2K_A$</td>
<td>-7.10×10^4</td>
<td>-51.83</td>
<td>-15.26</td>
<td>-1.42</td>
</tr>
</tbody>
</table>
3.5 Case Study

In this study, the uncertainty in the values of the most critical parameters of the IEEE ST1A excitation system is considered. The uncertainty study is implemented by considering ±10% and ±20% changes in the values of selected parameters from the nominal values given in Table 3-1. The time-domain dynamic stability simulation has been performed using DIgSILENT PowerFactory, using the IEEE ST1A excitation system controller for all generators. The first case is the transient stability analysis of a single machine system given in [162], where there is uncertainty in the value of \( K_A \). In this case, the studies are performed for the conditions where the test system is under high stress (Peak load demand). Figure 3-2 shows the single line diagram of the single-machine test system.

<table>
<thead>
<tr>
<th>Parameter Change</th>
<th>Time-Domain Simulation Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>( T_B - 0.2T_B )</td>
<td>-7.12x10^4 -52.11 -16.11 -1.42</td>
</tr>
<tr>
<td>( T_C - 0.2T_C )</td>
<td>-52.11 -16.11 -1.42</td>
</tr>
<tr>
<td>( K_A - 0.1K_A )</td>
<td>-7.13x10^4 -52.26 -16.53 -1.42</td>
</tr>
<tr>
<td>( T_B - 0.1T_B )</td>
<td>-52.26 -16.53 -1.42</td>
</tr>
<tr>
<td>( T_C - 0.1T_C )</td>
<td>-1.42</td>
</tr>
<tr>
<td>( K_A - 0.05K_A )</td>
<td>-7.15x10^4 -52.56 -17.39 -1.42</td>
</tr>
<tr>
<td>( T_B - 0.05T_B )</td>
<td>-52.56 -17.39 -1.42</td>
</tr>
<tr>
<td>( T_C - 0.05T_C )</td>
<td>-1.42</td>
</tr>
<tr>
<td>( K_A + 0.05K_A )</td>
<td>-7.16x10^4 -52.72 -17.81 -1.42</td>
</tr>
<tr>
<td>( T_B + 0.05T_B )</td>
<td>-52.72 -17.81 -1.42</td>
</tr>
<tr>
<td>( T_C + 0.05T_C )</td>
<td>-1.42</td>
</tr>
<tr>
<td>( K_A + 0.1K_A )</td>
<td>-7.18x10^4 -53.04 -18.66 -1.42</td>
</tr>
<tr>
<td>( T_B + 0.1T_B )</td>
<td>-53.04 -18.66 -1.42</td>
</tr>
<tr>
<td>( T_C + 0.1T_C )</td>
<td>-1.42</td>
</tr>
<tr>
<td>( K_A + 0.2K_A )</td>
<td>-7.19x10^4 -53.38 -19.03 -1.42</td>
</tr>
<tr>
<td>( T_B + 0.2T_B )</td>
<td>-53.38 -19.03 -1.42</td>
</tr>
<tr>
<td>( T_C + 0.2T_C )</td>
<td>-1.42</td>
</tr>
</tbody>
</table>

Figure 3-2: Single line diagram of the single-machine test system.

The influences of the uncertainties of the parameters in the IEEE ST1A excitation system parameters on the voltage profiles of Bus 5 is illustrated in Figures 3-3 and 3-4 for both the unmodified and the modified IEEE ST1A excitation system models, respectively.
Figure 3-3: The influence of uncertainty in the value of $K_A$ without a robust excitation system controller.

The voltage at Bus 3 is studied for a three-phase short circuit initiated at $t = 0.2s$ and cleared at $t = 0.7s$. The disturbance is considered in this study to demonstrate the significant benefit of using the designed optimal robust excitation system in improving the stability of a power grid.

In Figure 3-3, the system is equipped with the classic unmodified IEEE ST1A excitation system controller. It reveals that the variation in the value of $K_A$ can produce different voltage profiles and system characteristics. Besides, it can be seen that the system is stable when the $K_A$ value is set to its nominal value, but when the $K_A$ value is changed to $-20\%$ of its nominal value (i.e. representing $-20\%$ variation in the parameter nominal value), the voltage collapses at $t = 1.4s$ to a value of 0.47pu, which leads to a system collapse at $t = 1.42$. The system is stable for other values of $K_A$. This suggests that the model is not robust to the uncertainty in the $K_A$ value.

However, in Figure 3-4 where the system is equipped with the designed optimal robust IEEE ST1A excitation controller model, the voltage profiles, for the same five levels of uncertainty in the $K_A$ value, do not change significantly. This validates the suitability of the proposed technique to design the optimal robust IEEE ST1A excitation system. Using the robust model of the excitation system in the dynamic stability simulation, the system remains stable even when the $K_A$ value is changed by $-20\%$ of its nominal value.
Figure 3-4: The influence of uncertainty in the values of $K_a$ considering a robust excitation system controller.

Sensitivity studies have also been carried out to investigate the operation of the proposed controller when the controller setpoints are varied [163]; in particular, the impact of varying the generator reference voltage ($V_{\text{ref}}$) from 0.9 to 0.95 and finally 1.0 is investigated. The impact of varying $V_{\text{ref}}$ on the voltage of bus 5 is shown in Figure 3-5. Figure 3-5 shows that despite the significant changes in the values of the voltage at bus 5 after varying $V_{\text{ref}}$, the performance of the control system remains robust to uncertainties in the value of parameters when $K_a$ is varied from −20% to +20% in the zoomed areas. Consequently, it can be concluded that the robustness of the proposed optimal robust excitation system controller is not sensitive to variations in the value of the generator reference voltage.
Figure 3-5: The voltage at bus 5 using the proposed robust excitation system for different generator reference voltages, with the uncertainty in the values of $K_A$.

The second case is the dynamic stability analysis of the IEEE 39-bus New England system, presented in Figure 3-6 and detailed in [98], where there are uncertainties in the values of $K_A$, $T_B$, and $T_C$.

Figure 3-6: Single line diagram of the IEEE 39-buses New England test system.
In this case, it is assumed that all generators are equipped with the IEEE ST1A excitation system controller, where there are uncertainties in the parameter values of $K_A$, $T_B$, and $T_C$. A three-phase solid short circuit is considered at Bus 2 at $t = 0.2s$ which is cleared at $t = 1.4s$. The result for the voltage at Bus 25 in the New England system after the disturbance is presented in Figures 3-7 and 3-8 for the system without and with the optimal robust IEEE ST1A excitation system controller designed using the proposed framework. Figure 3-7 shows that when the $K_A$, $T_B$, and $T_C$ values are changed by $-20\%$ of their nominal values when the classical excitation controller model is used, the system collapses at $t = 1.79s$, while it is stable for other values of $K_A$, $T_B$, and $T_C$. This demonstrates that the ST1A excitation controller is not robust against the uncertainties of $K_A$, $T_B$, and $T_C$.

**Figure 3-7**: The influences of uncertainty in the values of $K_A$, $T_B$, and $T_C$ without a robust excitation system controller at high loading level.

Figure 3-8 represents that when the system is equipped with the optimal robust IEEE ST1A excitation controller, the voltage profiles for all five levels do not change significantly, and even when the values of $K_A$, $T_B$, and $T_C$ are set to $-20\%$ of their nominal values, the system remains stable.
Figure 3-8: The influences of uncertainty in the values of $K_A$, $T_B$, and $T_C$ considering a robust excitation system controller at high loading level.

The results from Figures 3-7 and 3-8 have been summarised in Table 3-5.

Table 3-6: Comparison between the excitation control system performance with and without the robust improvement for IEEE 39 bus network

<table>
<thead>
<tr>
<th>Parameter Variation</th>
<th>Maximum voltage deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>$K_A$, $T_B$, $T_C$</td>
<td></td>
</tr>
<tr>
<td>+20%</td>
<td>1.6%</td>
</tr>
<tr>
<td>+10%</td>
<td>1.1%</td>
</tr>
<tr>
<td>0%</td>
<td>0</td>
</tr>
<tr>
<td>-10%</td>
<td>-1.2%</td>
</tr>
<tr>
<td>-20%</td>
<td>Voltage collapse</td>
</tr>
</tbody>
</table>

In this study, the load demand is high and the system is heavily loaded. The sensitivity of the proposed optimal robust controller to the variation in the load demand of the power system is also investigated for the case of the low and medium load demand conditions of the grid. Table 3-7 presents a summary of the loading levels.

Table 3-7: Different loading conditions considered in the second case study

<table>
<thead>
<tr>
<th>Loading Level</th>
<th>New England Test system</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Load (MW)</td>
</tr>
<tr>
<td>High</td>
<td>6822</td>
</tr>
</tbody>
</table>
Figure 3-9 shows that the robustness of the proposed optimal robust excitation system controller is maintained for different loading levels of the power grid. The optimal robust approach introduced in this study can be easily implemented for any type of excitation system controllers to improve its robustness when the data of the excitation system controllers contains unavoidable uncertainties in its parameters.

<table>
<thead>
<tr>
<th></th>
<th>Medium</th>
<th>6139.8</th>
<th>1372.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>5457</td>
<td>1220</td>
<td></td>
</tr>
</tbody>
</table>

3.6 Summary

This chapter has presented a new optimal robust IEEE ST1A excitation system controller that is robust to the uncertainty in one or more of its parameters. Despite the complex mathematics behind the method, it can be implemented simply and straightforwardly, even though uncertainties in the model parameters exist. This optimal approach has transferred the robust controller problem to an optimal control problem while it has preserved the robustness of the excitation system. The influences of uncertainty in the values of $K_a$, $T_b$, and $T_c$ considering robust excitation system controller – A comparison for high, medium, and low loading levels.
The simulation results from the dynamic stability simulation have demonstrated that the designed robust excitation system controller is capable of being robust to uncertainty in the parameters of an excitation system controller. For the IEEE 39 bus system, simulation results show that when the $K_A$, $T_B$ and $T_C$ values of the IEEE ST1A excitation system controller are changed to $-20\%$ of their nominal values, the system becomes unstable although the system was stable when other values (within the upper and lower limit) were used. However, when the designed optimal robust IEEE ST1A excitation system controller has been applied, the system has become robust to the uncertainties in the parameters of the excitation system controller. Irrespective of the values of the parameters within the boundary of the uncertainties, using the proposed robust controller the power system will not have any variation in its stability.
Chapter 4    Long-term Voltage Stability Improvement

4.1 Foreword

There is always a time gap between a disturbance in the power system and voltage collapse, this time is very critical to the planners to implement reliable and economical countermeasures and resolve voltage related abnormalities. The proposed overexcitation limiter (OEL) extends the time gap between a disturbance in the power system and voltage collapse and allows the synchronous machine to participate in supplying the reactive power deficiency in the grid, which is critical in reactive power mismatch related emergency condition management.

Voltage stability requires the continuing control of the total system’s supply of reactive power during an emergency. The supply of reactive power, however, can be curtailed by the action of rotor over-current protection or OEL in reducing the rotating unit reactive power output. Practical heat run tests show that the timing of the activation of the OEL can be very conservative, resulting in earlier than necessary operation and system voltage collapse. Significant benefit can be achieved if the timing of the OEL activation can be delayed while ensuring enough margin is provided to avoid harming the rotor of the synchronous generator from overheating. This chapter proposes a new thermal-based method to determine the timing of the OEL activation that is based on the thermal capacity of the rotor as the main indicator for limiting the over-rated excitation level of the synchronous generator. The proposed thermal-based method is validated using extensive simulations of a single-machine and the Nordic power system. Simulation studies show that the system voltage collapse can be delayed significantly by delaying the OEL activation without compromising the thermal capacity of the rotor if the proposed OEL setting is used.

4.2 Background

During a catastrophic situation, where the line or generator outages are more than the planned n-1 contingencies, the synchronous generator can provide additional required reactive power by increasing their excitation level for a limited period. To protect the rotor winding from overheating due to high rotor excitation current while simultaneously allowing maximum field forcing for power system voltage stability purposes, the allowed over-excitation period is determined by the OEL. The OEL may reduce the excitation level by instantaneously lowering the reference set point, by ramping or stepping down the reference set point, or by transferring control from the AVR to a lower manually controlled field voltage set point [161]. The timing of this protection is very conservative, without considering the initial and maximum safe rotor temperature. The OEL should be capable of limiting the excitation current before the field over-current protection either place the AVR into the manual mode or trips the exciter to protect the field winding from overheating. Moreover, the field over-current protection should be coordinated with the OEL settings to allow the exciter to effectively provide its full VAr capability during continuous or transient conditions.

According to the stability definition of the IEEE/CIGRE task force [17], 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. This event is characterized by a slow variation of the voltage magnitudes followed by a rapid sharp disruptive phase resulting in voltage collapse [2]. In the first phase of voltage stability with the outages of several transmission lines or generating units beyond planning criteria, the reactive power loss increases rapidly in the remaining transmission lines. The generating units near the most affected region increase the excitation level to produce more reactive power and balance the supply and demand of reactive power [164], resulting in a stable operating condition during the first phase of voltage stability.

However, to protect the rotor from overheating, successive OEL operations progressively reduce the reactive power support causing the imbalance between the supply and demand of reactive power leading to the second fast phase of voltage instability. Much work has been done on ensuring that the load shedding is carried out before the onset of the second phase of voltage instability [84], [165].

However, by investigating the initial rotor temperature and thermal capacity, the OEL protection setting is very conservative; in some cases, the OEL operates even when more than 90% of the rotor thermal capacity is still available to be used [164]. The current OEL systems do not take into consideration the temperature of the rotor winding for rotor over current protection. Consequently, the initial temperature of the rotor (overheated due to a previous disturbance), cooling system performance, and environmental factors are not considered. As all these so-called key factors are neglected in the rotor overcurrent protection, significant risk is involved in using the rotor thermal capability. As a result, traditionally, the OEL systems are tuned in a very conservative manner.

Delaying the OEL operation can delay the onset of the second phase of instability resulting in having more time to consider the best countermeasures to be carried out and such delay can result in better management of voltage instability.

4.3 Automatic Voltage Regulators and Over-Excitation Limiter

Automatic Voltage Regulators (AVRs) can provide a rapid response of the synchronous generator reactive power output to maintain the pre-set voltage. During the normal operating condition, the AVR can vary the voltage between ±5% to ±10% from its nominal condition [17], and during an emergency condition, the AVR can produce higher than rated excitation current, typically up to two times of the rated value [161]. Although the rotor winding is designed for a continuous level of current, higher than rated current can be sustained by the rotor for a limited time; this limited time is usually determined by the OEL in the AVR control system.

4.3.1 Excitation System Perspective

Different strategies have been considered in implementing the OEL system in the AVR control system [161], [80], [165]. In this study, the OEL is used to reduce the excitation level by adding an extra auxiliary input signal for the AVR system that simulates an extra error signal in the voltage regulation process as shown in Figure 4-1 where $V_T$ is generator terminal voltage, $V_{ref}$ is the reference voltage, $V_{pss}$ is the signal from power system stabilizer (PSS), $V_{OEL}$ is the signal from OEL, $V_{Rmax}$ and $V_{Rmin}$ are the maximum and minimum voltage regulator outputs.
When the error signal, $V_{error}$, became negative ($V_T > V_{ref}$), the AVR will ramp down the excitation level to reduce the generator terminal voltage and eliminate the error signal to maintain the reference voltage at the terminal of the generator.

In Figure 4-1, all signals are per unit based on the RMS value of the nominal terminal voltage. The value of $V_{OEL}$ varies between 0 and 1 pu to control the AVR performance. When $V_{OEL} = 0$, the AVR operation is unaffected, but if $V_{OEL} = 1$, the excitation level will decrease significantly. If $V_{OEL}$ remains 0, the rotor excitation current can be increased to inject extra reactive power into the grid. To avoid the rotor winding temperature from reaching its critical value, the OEL system will increase $V_{OEL}$ by ramping it up at a ramping rate set by parameter $K$ as shown in Figure 4-2. This parameter controls the excitation current reduction rate to the rated level.

In Figure 4-2, as $K$ is increased from $K_0$ to $K_1$ and then to $K_2$, the $V_{OEL}$ rate of change decreases as shown in Figure 4-2(a). This decrease in the rate of change of $V_{OEL}$ allows extra reactive power to be supplied while the excitation current is being reduced to its safe level as shown in Figure 4-2(b). The value of $K$ must be designed to be in a pre-specified bound determined by the rotor thermal capacity. In many ways, tuning $K$ gives the flexibility in the AVR operation, where the excitation level may be reduced by instantaneously lowering the reference set point (using $K_0$) or by ramping or stepping down the reference set point (using $K_1$ to $K_2$), or by transferring control from the AVR to a lower manually controlled field voltage set point (using manual control of increasing the value of $K$).

### 4.3.2 Rotor Thermal Capacity

The thermal capacity of the rotor only depends on the manufacturing specifications. Factors such as insulation,
cooling system, and the materials used in building the rotor, directly impact the thermal capability of the rotor in a generating unit. After the manufacturing and installation of the unit, the rotor thermal capability is likely to remain constant unless the environmental conditions change significantly. The OEL system is used to avoid the rotor thermal capability to be exhausted. An ideal OEL system is to monitor the available rotor thermal capacity and reduce the excitation as the thermal capability is close to being exhausted. To reduce the risk of loss of life, a safety margin is normally considered in the operation of the OEL in not using the whole rotor thermal capability. This safety margin should be determined by balancing between the risk of loss of life and a pool of fast-acting reactive power supply.

The available rotor thermal capacity depends on the rotor windings temperature; however, measuring the temperature directly is not a practical option, because, the temperature snapshot of the machine elements is usually only available every 30 seconds [165]. Consequently, different methods to measure the temperature were reported; some use the rotor current and voltage [80], [81], while others use the dependency of the rotor winding resistance to its temperature to calculate the temperature [165], [166].

Generally, for rotor over-heating protection a curve is used indicating the time for OEL activation for each over-excited level in an inverse time function; the higher the rotor current, the sooner the limiter is activated. The rotor capacity curves extracted from [167] are shown in Figure 4-3.

![Figure 4-3: Rotor windings short circuit current capacity.](image)

Figure 4-3 shows that the curve from [167] allows for a longer activation time of the OEL compared to that from the curve from the ANSI C50.13-1989 standard for the same elevated excitation current. The curves in Figure 4-3 use an inverse current-time characteristic very similar to overcurrent protection systems without considering the thermal characteristic of the rotor, the cooling system, and also the environmental factors. To avoid the risk of damage to the machine rotor winding, these factors are normally not considered and a very low-risk OEL setting is used. Taking a very low-risk approach has led to very conservative OEL system settings. Additionally, using the excitation current as an indicator for OEL operation it will be difficult to know the
remaining thermal capacity of the rotor winding.

In this study, rather than current, the thermal energy will be used as the main indicator to determine the OEL activation time.

4.3.3 Over-excitation Limiter

Different types of OEL systems are presented in the literature [82], [86], [161], [168]–[171]; however, all of them are operated through the same sequence of (i) detecting the over-excitation for a specified period and then (ii) reducing it into a safe level. The allowed over-excitation period may be fixed-time or inverse-time. The fixed-time OEL system enables a timer when it detects an over-excitation situation and reduces the rotor current to its rated value when the timer reaches a fixed predetermined value. For the case of inverse-time OEL system, this predetermined value varies inversely with the excitation level as shown in Figure 4-3. Typically, the OEL system uses a combination of the instantaneous and the inverse-time pickup characteristics and switches from an instantaneous limiter with a setting of about 160% of rated excitation current to a timed-limiter with a setting of about 105% of the rated excitation current [80], [172].

4.4 Thermal Based OEL

The proposed method uses the thermal energy of the rotor to determine the auxiliary signal $V_{OEL}$ for the AVR in Figure 4-1 and the ramp rate $K$ to determine the timing for the activation of OEL. This method can be easily implemented on the AVR. Following the recommendation of ANSI C50.13, at least a 20% safety margin must be provided.

The thermal energy of the rotor winding during the over-excitation period needs to be calculated and monitored to ensure that the rotor overheating is safe. The cooling system capability, the initial temperature of the rotor, and the heat transfer from the turbine need to be taken into consideration. To calculate the thermal energy of the rotor winding, the law of conservation of energy for all the components which influence rotor temperature can be calculated as in (4-1),

$$Q_{copper} + Q_{turbine} = Q_{Winding} + Q_{Dissipation}$$  \hspace{1cm} (4-1)

where $Q_{copper}$ is the heat energy due to the copper losses of the current passing through the rotor windings, $Q_{turbine}$ is the indirect heat flow from the steam turbine that passes through the mechanical coupling between the turbine and the generator, $Q_{Winding}$ is the thermal energy of the rotor windings (the absorbed heat by winding) and $Q_{Dissipation}$ is the combination of the energy due to heat dissipation through the pressurized hydrogen flowing in the gap between stator and rotor, and, that due to the radiation and convection of the outer surface of the generator to the surrounding air.

Equation (4-1) is based on the law of the conservation of the energy, so it is valid in both emergency conditions given by (4-3) and normal operating conditions presented by (4-2). For simplicity, let’s consider $E$ and $N$ as the superscripts for emergency and normal conditions of the system respectively.
\[ Q_{\text{Copper}}^E + Q_{\text{Turbine}}^E = Q_{\text{Reading}}^E + Q_{\text{Dissipation}}^E \quad (4-2) \]

\[ Q_{\text{Copper}}^E + Q_{\text{Turbine}}^E = Q_{\text{Reading}}^E + Q_{\text{Dissipation}}^E \quad (4-3) \]

For the next step, let’s subtract (4-3) from (4-2) as given in (4-4),

\[ Q_{\text{Copper}}^E + Q_{\text{Turbine}}^E - Q_{\text{Copper}}^E = Q_{\text{Reading}}^E + Q_{\text{Dissipation}}^E - Q_{\text{Dissipation}}^E \quad (4-4) \]

In (4-4), \( Q_{\text{Turbine}} \) and \( Q_{\text{Dissipation}} \) are equal as that in normal conditions; since, in an emergency condition, neither cooling system capability has changed nor the airflow into the generator. Equation (4-4) can, therefore, be simplified as given in (4-5),

\[ Q_{\text{Copper}}^E - Q_{\text{Copper}}^E = Q_{\text{Reading}}^E - Q_{\text{Dissipation}}^E \quad (4-5) \]

Equation (4-5) can be expressed as (4-6) where \( R, m \) and \( c \) are resistor, mass and the specific heat coefficient of the rotor winding respectively, and \( T_E, T_N, I_E \) and \( I_N \) are the temperature increase and the current during the emergency and the normal voltage condition.

\[ R(I_E^2 - I_N^2)t = mc(T_E - T_N) \quad (4-6) \]

Equation (4-6) describes the relationship between the copper losses in the rotor winding of the generator with the stored thermal energy inside the winding of the generator.

As the rotor current increases, the copper loss becomes greater than the dissipated heat. This excess energy will then be absorbed in the rotor winding as thermal energy and will result in temperature rise. This extra amount of heat energy can be calculated using the integral of the left-hand term of equation (4-6) as shown in (4-7) where \( EAH \) is the Extra Absorbed Heat from \( t_1 \) to \( t_2 \) and, \( R \) is the rotor resistance in per unit.

\[ EAH = \int_{t_1}^{t_2} R(I_E^2 - I_N^2) \, dt \quad (4-7) \]

The maximum amount of rotor current for the steady-state condition, \( I_{en} \), is usually used in OEL to activate the OEL operation. It is generally considered to be about 105% of rated field current. In (4-6), \( I_{en} \) can be used instead of \( I_N \), and \( I_E \), the measured rotor current, can be used instead of \( I_E \), to calculate \( EAH \) since it represents the measured excitation current during emergency condition:

\[ EAH = \int_{t_1}^{t_2} R(I_E^2 - I_{en}^2) \, dt \quad (4-8) \]

The rotor cooling system is responsible for the dissipation of this \( EAH \) in addition to radiation and convection. So, the main objective of our proposed method for the OEL setting is to monitor the value of \( EAH \) and prevent it to go higher than the predetermined rotor thermal capacity, \( E_{\text{cap}} \). The best method to calculate \( E_{\text{cap}} \) is to use the right-hand term of (4-6) by replacing \( T_E \) with \( T_{\text{max}} \) as given in (4-9)
\[ E_{\text{cap}} = mc(T_{\text{max}} - T_N) \]  \hspace{1cm} (4-9)

where, \( T_{\text{max}} \) represents the rotor maximum temperature, and \( T_N \) is the rotor temperature in normal operating conditions. The term \( mc \) is the thermal inertia of the rotor windings and it denotes the quantity of energy required to increase the rotor temperature by 1°C.

The value of \( E_{\text{cap}} \) in (4-9) is dependent on \( mc \), which includes the effects of the cooling system, airflow, rotor material and alloys, environmental condition, etc. and can only be obtained through experiment, such as the heat run tests on the generator. A simple efficient method was proposed in [166] using experimental values to calculate the thermal inertia of the rotor. In [166], heat run tests were carried out on two generators: a 660MW Japanese and a 500MW British coal-fired turbo-generator. The resulting steady-state rotor temperatures against copper losses were plotted corresponding to the five different levels of rotor currents as shown in Figure 4-4.

![Figure 4-4: Actual heat test run results [165].](image)

In this figure, the plots were found to form almost a straight line; because the linear characteristics of the hydrogen rotor cooling system completely swamp other forms of nonlinear heat dissipation such as radiation and convection [165]. The line slope in Figure 4-4 indicates the thermal inertia of each rotor. Once the thermal inertia can be obtained, the rotor thermal capacity, \( E_{\text{cap}} \), can be calculated using (4-9), however, it must be presented in per unit system to ease the comparison. Figure 4-5 shows the flowchart of the proposed thermal OEL operation procedure.
Figure 4-5 shows that the OEL remains inactive while the value of $EAH$ is negative. Whenever it goes positive, it will be compared with a maximum limit or ceiling level for the rotor thermal capability $E_{cap}$. In this specific study, the plan is to use at least 60% of the rotor thermal capability ($0.6E_{cap}$) and avoid exceeding 80% of the rotor thermal capability ($0.8E_{cap}$); consequently, if the level of $EAH$ exceeds $0.8E_{cap}$, $V_{OEL}$ will be set to 1 to sharply ramp down excitation current and avoid using exceeding 80% of the rotor thermal capability. While the level of $EAH$ remains between $0.6E_{cap}$ and $0.8E_{cap}$, the limiter reduces the excitation level gradually by ramping up $V_{OEL}$ as shown in Figure 4-6 to allow the excitation system to inject extra reactive power to the grid while reducing the excitation current to its rated level. The range of $EAH$ (between $0.6E_{cap}$ and $0.8E_{cap}$ used in this study) is left for the users to choose to provide a margin of safety to avoid overheating the coils in the rotor of the machine.

Figure 4-6: The desired characteristics for the OEL system output signal.

Based on Figure 4-6, $V_{OEL}$ must follow the line connecting the two points, $(0.6E_{cap}, 0)$ and $(0.8E_{cap}, 1)$ respectively. The equation of this line determines the value of $V_{OEL}$ when $EAH$ is between $0.6E_{cap}$ and $0.8E_{cap}$ as given below,

$$V_{OEL} = \frac{EAH - 0.6E_{cap}}{0.8E_{cap} - 0.6E_{cap}} = \frac{EAH}{0.2E_{cap}} - 3 \quad (4-10)$$

Equation (4-10) indicates the values of $a$ and $b$ in Figure 4-5 as,
Based on (4-10), the values of $a$ and $b$ are directly dependent on the value of $E_{cap}$ and willingness of the generating unit to use its rotor thermal capability. In this study, we maintained the rotor thermal capability usage between 60% and 80%. Based on proper risk assessment, the generating using can use as much as 100% of the rotor thermal capability in which will lead to different $a$ and $b$ coefficients.

The proposed OEL system model is presented in Figure 4-7. All parameters in this model are in per unit, based on the rated value of the generator. In the diagram shown in Figure 4-7, $y_2$ represents the surplus thermal energy ($EAH$) that was absorbed by the rotor windings due to the over-excitation current. Whenever $y_2$ is not zero, the rotor faces over-excitation, but the OEL system remains disabled, which allows the machine to inject as much reactive power as possible into the system until $y_2$ reaches $0.6E_{cap}$; when the OEL forces the AVR to ramp down the excitation level to $I_m$.

![Figure 4-7: The model of the OEL system with the proposed timing method.](image)

Backup protection is also considered for the safety of the rotor that pushes the AVR to clamp the excitation current to $I_m$ instantly. This backup protection will get activated when $y_2$ reaches $0.8E_{cap}$ and ensure the safety of the rotor in case of any failure in the ramping down procedure.

### 4.5 The Proposed OEL Model Evaluation

To evaluate the proposed method for determining the OEL setting and to compare its performance with that of the conventional OEL systems, a single-machine test system is considered as presented in Figure 4-8.

\[
\begin{align*}
    a &= \frac{1}{0.2E_{cap}} \\
    b &= -3
\end{align*}
\]
The test system in Figure 4-8 is adapted from [162] and its generator is equipped with the proposed thermal-based OEL system and a conventional OEL system introduced by IEEE in [161]. The thermal parameters of the generator are adapted from the available test heat run data from a 660MW Japanese unit [166] with thermal inertia of 10MJ/ºC, and a 500MW British generator unit [165] with thermal inertia of 3MJ/ºC. The simulations are performed using DlgSILENT PowerFactory. The nominal operating range of the rotor temperature of these generators was found to be between 65ºC and 75ºC while the rotor temperature limit lies between 130ºC and 140ºC [165]. Considering 65ºC increase in rotor temperature for the Japanese generator unit from its nominal setpoint, $E_{cap}$ is calculated using (4-9) as given below,

$$E_{cap} = (10MJ/ºC)(65ºC) = 650MJ$$  \hspace{1cm} (4-12)

$E_{base}$ is calculated using (4-13).

$$E_{base} = 660MW \times \left(\frac{1}{100\pi}\right) = 2.1MJ$$  \hspace{1cm} (4-13)

So, the per unit value of $E_{cap}$ can be obtained using (4-14).

$$E_{cap} = \frac{650MJ}{2.1MJ} = 309.52 \text{ pu}$$  \hspace{1cm} (4-14)

The same procedure is performed for the British generator, and the thermal-based OEL parameters for them are presented in Table 4-1.

<table>
<thead>
<tr>
<th>Generator manufacturer</th>
<th>Parameter</th>
<th>Description</th>
<th>value (pu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Japanese</td>
<td>$I_{en}$</td>
<td>OEL enabling current value</td>
<td>2.751</td>
</tr>
<tr>
<td></td>
<td>$R_{rot}$</td>
<td>The resistance of the rotor winding</td>
<td>0.131</td>
</tr>
<tr>
<td></td>
<td>$E_{cap}$</td>
<td>Thermal capacity the rotor</td>
<td>309.5</td>
</tr>
<tr>
<td>British</td>
<td>$I_{en}$</td>
<td>OEL enabling current value</td>
<td>2.604</td>
</tr>
<tr>
<td></td>
<td>$R_{rot}$</td>
<td>The resistance of the rotor winding</td>
<td>0.118</td>
</tr>
<tr>
<td></td>
<td>$E_{cap}$</td>
<td>Thermal capacity the rotor</td>
<td>122.5</td>
</tr>
</tbody>
</table>

The proposed method monitors the absorbed thermal energy of the rotor based on the machine specification and ensures that the rotor is protected against maximum overheating by using the thermal capacity of the rotor minus a pre-specified margin.
As mentioned previously, most of the typical OEL systems are not able to use the thermal capacity of the rotor completely. The performance of the IEEE OEL system, and that of the proposed method for the tripping of one of the transmission lines between Bus 1 and 3 at \( t = 2s \) are presented and compared in Figure 4-9 for both the generator units (as given in Table 4-1).

Figure 4-9 shows that the proposed thermal-based OEL system allows the Japanese units to supply reactive power for an additional 105 seconds by using its thermal capability efficiently. It also takes about 15 seconds for the OEL to ramp down the rotor current during the time in which extra reactive power is still injected into the grid. In the case of the British unit, the IEEE and the thermal-based OEL structure operate with just 60 seconds in time difference. Consequently, the proposed method significantly improves the long-term voltage stability of the system by supplying more reactive power into the grid during an emergency condition and delaying the onset of the second disruptive phase that can lead to voltage collapse. The other advantage of using the thermal-based system is in considering the generator thermal capability in the operation of the OEL systems. As can be seen from Table 4-1, the thermal capability of the Japanese generator is noticeably higher than that of the British one, and this fact influences the OEL operation in the thermal-based OEL system. So, the Japanese generator is permitted to inject more reactive power into the grid for an emergency.

### 4.6 Case Study

A single-machine test system is not capable of showing the advantages of the proposed method completely. In this section, the Nordic power system detailed in [173] and presented in appendix 1, is considered to show the benefit of the proposed method using a large-scale power system considering Load Tap Changing (LTC)
transformers. The single line diagram of the Nordic power system is shown in Figure 4-10. In this system, loads are modelled using the constant current model for active and reactive power. The LTC is also considered for all transformers with the tap changing delay time varying from 8 to 12 seconds from one tap to another. Studies are performed for single and multiple contingency cases to comprehensively show the features of the proposed thermal-based OEL system.

The following assumptions are made for the case study of the Nordic power system:

1. All OEL systems are assumed to be current driven.
2. Conventional OEL systems timing is designed based on the information from [173].
3. The rotor resistor is 0.1 Ω for all generators.
4. The value of E\text{cap} is adapted from the British generator thermal data scaled based on each generator field current rated value and presented in appendix 1.

Case 1: Single contingency, the contingency considered is the 4032-4044 transmission line outage at $t = 2\text{s}$. Initially, it is considered that the Nordic power system is equipped with the IEEE OEL system. So, after the disturbance, the generators try to supply the emergency extra reactive power demand of the system by increasing their excitation level as shown in Figure 4-11.
In Figure 4-11, the closest generators to the short circuit, g7, g11, g12, and g14, initially increase their excitation level right after the disturbance until the OEL system limits their function; at this point g6, g13, g15, and g16 continue the duty of supplying the reactive power of the system by increasing their excitation level. In other words, in a multi-machine power system, after an incident, all generators are participating in supplying the extra reactive power demand of the system based on their distance from the location of the disturbance. The OEL system activation causes voltage dip in the neighbouring bus voltage magnitudes as expressed in Figure 4-12, leading to exhausting of tap operation of transformers and finally the system collapses at $t = 119s$.

Figure 4-11: Changes in the excitation level of the overexcited generator in the Nordic power system for case 1 considering the IEEE OEL system.
Figure 4-12: Voltage profile of selected transmission bus-bars near the location of the disturbance for case 1 considering the IEEE OEL system.

Figure 4-13: Changes in the excitation level of the overexcited generator in the Nordic power system for case 1 considering the thermal-based OEL system.

When the proposed thermal-based OEL system is used, it is possible to supply more reactive power into the system as shown in Figure 4-13. In this case, the system collapses at $t = 184s$ because generators can retain its supply of reactive power for a longer time. This delay is vital for the grid operators since it gives them enough
time to activate voltage related countermeasures.

Table 4-2: OEL systems activation time for case 1

<table>
<thead>
<tr>
<th>Conventional OEL systems</th>
<th>Thermal-based OEL systems</th>
<th>Improvement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen OEL functioning Time (s)</td>
<td>Gen OEL functioning Time (s)</td>
<td></td>
</tr>
<tr>
<td>g12 22.4</td>
<td>g14 73.6</td>
<td>325%</td>
</tr>
<tr>
<td>g14 31.6</td>
<td>g15 135.8</td>
<td>430%</td>
</tr>
<tr>
<td>g7 32.1</td>
<td>g16 154.6</td>
<td>480%</td>
</tr>
<tr>
<td>g11 40.5</td>
<td>g7 154.7</td>
<td>382%</td>
</tr>
<tr>
<td>g16 93.5</td>
<td>g6 Not Limited</td>
<td>∞</td>
</tr>
<tr>
<td>g15 97.2</td>
<td>g11 Not Limited</td>
<td>∞</td>
</tr>
<tr>
<td>g6 Not Limited</td>
<td>g12 Not Limited</td>
<td>0%</td>
</tr>
</tbody>
</table>

Table 4-2 shows the time that OEL systems start reducing generator excitation levels for both IEEE and thermal-based OEL systems. As is evident in Table 4-2, the OEL systems of the same generators get activated in both IEEE and thermal-based cases, but, the order of activation is different; the conventional OEL systems are activated based on their distance from the location of the event while the thermal-based OEL systems are activated based on the thermal capacity of the generator in addition to its distance from the short circuit incident. In this regards the voltage magnitudes of some affected buses are presented in Figure 4-14.

Figure 4-14: Voltage profile of selected transmission bus-bars near the location of the disturbance for case 1 considering thermal-based OEL system.

In Figure 4-14, the voltage magnitudes start reducing after the disturbance with some minor dips mainly because of the operation of LTCs, however, some major voltage dips can be also seen in the profile due to the OEL limiting function in the nearby generators.

The operation of the LTCs has a significant role in the voltage stability of the system. The behaviour of the
LTCs for the Nordic power system in case 1 is presented in Figure 4-15.

Figure 4-15: Operation of LTCs for case 1 with the thermal-based OEL system.

To show the operation of the proposed thermal-based OEL system in case 1 for the Nordic power system, the value of the EAH that the OEL system continuously monitors is presented in Figure 4-16.

Figure 4-16: The value of $EAH$ for the limited generators in case 1.
Case 2: Multiple contingencies, the contingency considered in this case is the outage of two 4044-4045 parallel lines; the first one at \( t = 2s \) and the second one at \( t = 16s \). The excitation level of the generators following the disturbance with conventional OEL system is presented in Figure 4-17.

Figure 4-17 shows that after the first line outage, the rotor currents of some affected generators slightly start increasing until the second line outage, at which the rotor current of \( g7 \) suddenly increases. Because of the significant increase in \( g7 \), its OEL system has functioned quickly and clamped the rotor current after 20 seconds; which leads to the increase in the rotor current of \( g16 \). Sequentially, the OEL systems of \( g6 \) and \( g16 \) also operate and limit the rotor current of the generators.

![Figure 4-17: Changes in the excitation level of the overexcited generator in the Nordic power system for case 2 considering the IEEE OEL system.](image)

Figure 4-18 shows that there is a major voltage dip in the profile when the OEL systems of \( g6 \) and \( g7 \) limit their rotor currents. Another significant voltage drop also occurs at \( t = 82s \); when, the OEL of \( g16 \) limits the excitation current, resulting in the operation of the OLTCs; however, the system collapses at \( t = 135s \).
Figure 4-18: Voltage profile of selected transmission bus-bars near the location of the disturbance for case 2 considering the IEEE OEL system.

Table 4-3 shows the time that the OEL system starts reducing the generator excitation level for both conventional and thermal-based OEL systems.

<table>
<thead>
<tr>
<th>Conventional OEL systems</th>
<th>Thermal-based OEL systems</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen</td>
<td>OEL functioning Time (s)</td>
</tr>
<tr>
<td>g7</td>
<td>36.2</td>
</tr>
<tr>
<td>g6</td>
<td>36.5</td>
</tr>
<tr>
<td>g16</td>
<td>82.8</td>
</tr>
<tr>
<td>g16</td>
<td>Not Limited</td>
</tr>
</tbody>
</table>

Using the proposed thermal-based OEL system, the Nordic system generators can supply more reactive power as shown in Figure 4-19 and delay the voltage collapse of the grid as shown in Figure 4-20.
Figure 4-19: Changes in the excitation level of the overexcited generator in the Nordic power system for case 2 considering the proposed thermal-based OEL system.

Figure 4-20: Voltage profile of selected transmission bus-bars near the location of the disturbance for case 2 considering the proposed thermal-based OEL system.

Figures 4-19 and 4-20 show that considering the thermal-based OEL system, the generators were able to supply reactive power for an extended time and delay the voltage collapse by 30s in the case on an n-1-1 contingency.
4.7 Summary

In this chapter, a new method is proposed for the determination of the timing for OEL activation, which is developed based on available generator rotor thermal capacity. The performance of the proposed method is validated using two test systems. Using the single-machine test system, the simulation result shows that the proposed OEL method can efficiently utilize the thermal capacity of the rotor and inject more reactive power into the system in comparison with that from a conventional OEL equipped generator.

The performance of the proposed method is further validated using the Nordic power system demonstrating its effectiveness in extending the amount of reactive power that can be supplied in a multi-machine network resulting in improved voltage stability of the system. The results from the Nordic power system show that all generators participate in supplying the reactive power after a severe disturbance; the conventional OEL equipped machines participate based on their electrical distance from the incident location while the thermal-based OEL equipped units to participate by considering their thermal capacity in addition to their distance from the disturbance. The generator owners may be able to be persuaded to allow more use of available reactive power contribution of the generators to improve power system performance and voltage stability if incentives are provided through the provision of ancillary and emergency control services in the electric power market.

A system protection scheme (SPS) using operational data from a SCADA system can be used to identify the location and timing of impending voltage instability by observing a sudden increase of generator reactive power outputs and the reduction of voltages in the area of disturbance. The benefit of the proposed thermal-based OEL system is to increase the time for such an SPS to function, by increasing the time so that enough reactive power can be injected into the grid. This will provide the SPS more time to determine the best countermeasure that can be effective to mitigate the emergency condition.
Chapter 5  
Transient Instability Detection

5.1 Foreword

A disturbance near the synchronous generator terminal has the potential to create a huge difference between the mechanical output of the turbine and the electrical output of the generator. This difference in power is stored in the rotor of the generator in the form of kinetic energy during the existence of the disturbance and is released into the grid as a wave of energy after the disturbance is cleared. The presence of the extra energy influences the operation of the grid elements and if it is not damped in time, it can create transient instability. This chapter presents a direct method to accurately detect the risk of transient instability in a power grid. The proposed method can constantly monitor the energy level of each generating unit locally and detects the critical energy level which may lead to a wide-area transient instability. The performance of the proposed method was assessed through comprehensive studies on the Nordic power system and results were found to be promising.

5.2 Background

In modern complex large-scale power systems, a small disturbance near a group of stressed generators can lead to a widespread transient instability. Following the disturbance, energy is being stored in the rotor of the synchronous machines due to the difference in the mechanical output of the turbine and the electrical output of the generator during the fault. After the fault is cleared, the stored energy is passed throughout the network as accelerating energy which must be eliminated for the system to remain stable. Depending on the damping of the synchronous generator, the accelerating energy causes the electrical power to oscillate in a simple one machine infinite bus system. This wave of accelerating energy is typically accompanied by voltage magnitude reductions of the loads and an increase in the frequency respectively. As the voltages in the network are reduced, the load active and reactive powers that are connected to the buses experiencing the voltage reduction will also reduce. Consequently, this will further increase the energy gap between the generated electrical power and the demand, which will cause a secondary accelerating energy wave in the grid.

If the initial accelerating energy and the secondary accelerating energy remain uncontrolled, the rotor angles of the generators will continually increase. If it remains undamped, the increasing rotor angles of the generators may result in transient instability. To keep the rotor angles in a safe range, the so-called primary and secondary accelerating energy waves must be continuously monitored and eliminated when the transient instability is imminent. Once detected, proper countermeasures, such as switching in storage systems must take place to eliminate the increasing secondary accelerating energy waves. The timing of such countermeasures is critical and depends on the fast and accurate detection of the imminent transient instability.

A transient stability study is typically concerned with the ability of the closely interconnected synchronous machines to stay synchronized after being subjected to a disturbance. It strongly depends on the ability of the generator to maintain or restore the equilibrium between the turbine mechanical power and generator electrical power outputs. Nowadays, there is a higher risk of transient instability in today’s heavily-loaded and interconnected power systems [92]. The ability to quickly and accurately predict the potential of an imminent transient instability may allow the grid to be operated with lower transient stability margins [93]. Transient
stability assessment in the power system has always been a major part of the power system analysis [94]. The transient stability of a power system can be assessed through energy methods or time-domain simulations.

The development in parallel computing techniques has improved the efficiency of the time domain simulation-based methods to be able to handle large-scale power system transient stability assessment [95], [96]. In [174] an approach is proposed that indicates the assessment result before the computationally demanding time-domain studies are finished. The trajectory sensitivity methods based on time-domain simulations have also been used in the determination of power flow limits and dynamic VAr planning [175], [176]. Besides, the developments in computation power have also directly impacted the use of pattern recognition methods to predict transient stability issues based on the information provided through PMUs [97]. An innovative online transients stability assessment method based on machine learning that uses PMUs has been presented in [177]. An innovative wide-area supplementary controller that uses a nonlinear Kalman filter to eliminate the local modes as measurement noises using a controllable series compensator is introduced in [100] and then is developed in [101] to use SVCs.

Considering the increasing penetration of the inverter-based generating plants and electric vehicles, a global and innovative method has been proposed that integrates the global transient energy function and re-closer probability distribution functions to provide a quantitative measure of the probability of stability [99]. An efficient transient stability assessment method for inverter-based generation considering the phase lock loop has been introduced in [178].

The transient stability of a multi-machine power system can also be investigated from the distinctive individual machine standpoint [103], [104]. The individual machine energy function method was derived by considering the individual-machine perspective, where the stability of the system is determined by individual machine energy functions [105], [106]. In [108], [109], [179], a detailed transient stability analysis of multi-machine power systems is performed for each individual machine, and the required energy of the selected local countermeasures was calculated using the partial energy function. In [110], the transient stability margin of the system is identified using a combination of equal area criteria of the critical machine and partial energy function. To efficiently determine the transient stability of a power system in the multi-machine environment, a synchronous referred individual machine energy function has also been used [111] and aided in computing the system's critical clearing time during the transients in [112].

The proposed transient instability detection method in the chapter is a direct time-domain method based on the individual machine’s participation in the transient instability of the wide-area power grid. In the proposed method, the excess energy (the gap between the mechanical output of the turbine and the electrical output of the generator) injected into the grid during a contingency is measured online continuously for each critical individual generating unit within the wide-area network at the generating unit terminal. To describe the relationship between the excess energy of each individual generating unit and the wide-area transient stability, two new variables as the Primary Accelerating Energy (PAE) and the Secondary Accelerating Energy (SAE) are defined. The PAE is created by an individual generating unit during the disturbance, then the PAE is injected into the grid and is converted into the SAE. The SAE is then kept spreading into the grid in the post-contingency condition and causes wide-area transient instability. The SAE can be divided into two parts, the first part is caused by PAE, and, the second part that contains a wide-area (wave-like) characteristics. If the first part of the SAE
remains uncontrolled, the second part can cause wide-area transient instability. The proposed method measures the value of PAE at each generating unit terminal and detects if the PAE will lead to an uncontrollable SAE and causes transient instability.

5.3 Accelerating Energy in a Power System

The transient energy of the system after a disturbance in a power grid has been investigated in [81], [98], [103] and presented in (5-1);

\[ E(\omega_i, \delta_i) = E_k - E_p \]  

(5-1)

Where

\[ E_k = \frac{1}{2} M_{eq} \omega_{eq}^2 \]  

(5-2)

And

\[ E_p = \sum_{i=1}^{n_p} P_{ei} (\delta_i - \delta_i^*) + \sum_{i=1}^{n_p} \sum_{j=1}^{n_p} C_{ij} (\cos \delta_i - \cos \delta_j^*) + D_{ij} \frac{\delta_i^* - \delta_i' + \delta_j - \delta_j^*}{\delta_i^* - \delta_j^*} (\sin \delta_i - \sin \delta_j^*) \]  

(5-3)

where, \( E \) is the total accelerating energy, \( \omega_i \) is the \( i^{th} \) generator speed, \( \delta_i \) is the \( i^{th} \) generator angle, \( E_k \) is the kinetic energy, \( E_p \) is the potential energy, \( M_{eq} \) is the equivalent moment of inertia, \( \omega_{eq} \) is the equivalent speed, \( P_{ei} \) is the output electrical power of the \( i^{th} \) generator, \( \delta_i^* \) is the post-contingency equilibrium point angle of the \( i^{th} \) generator and \( \delta_j = \delta_i - \delta_j \) and,

\[ P_{ei} = P_{mi} - E_i^2 G_i \]  

(5-4)

\[ C_{ij} = E_i E_j B_{ij} \]  

(5-5)

\[ D_{ij} = E_i E_j G_{ij} \]  

(5-6)

where \( P_{mi} \) is the output mechanical power of the \( i^{th} \) generator, \( E_i \) is the generator field voltage of the \( i^{th} \) generator, \( B_{ij}, G_{ij} \) is the susceptance and the conductance, between the \( i^{th} \) and the \( j^{th} \) generator.

Based on (5-1), the total energy in the wide-area power grid is formed by the combination of the potential and kinetic energy. The potential energy cannot be directly measured in the network, however, the kinetic energy can be calculated at the generating unit terminals as the generating plants are the only sources of energy in the grid. For the generating units, the kinetic energy difference between the turbine output mechanical energy and the generator output electrical energy at each instance of time is the PAE. The physical concept of the PAE can be simply presented from the classical swing equation expressed in (5-7).
\[ \frac{2H}{\omega_{sys}} \frac{d^2 \delta}{dt^2} + \omega_{sys} D \frac{d \delta}{dt} = P_m - P_e \]  \hspace{1cm} (5-7)

where \( H \) is the system inertia constant, \( \omega_{sys} \) is the system speed, \( \delta \) is the generator rotor angle, \( D \) is the rotor damping constant, \( P_m \) is the turbine output mechanical power and \( P_e \) is the generator output electrical power.

Under a normal operating condition, the right-hand side of (5-7) should be equal to zero, which means that the synchronous machine speed will remain constant (because the acceleration is zero), and there will be no deviations in the rotor angle. Based on (5-7), considering constant mechanical power output from the prime mover, in the case of any deviation in the value of \( P_e \), the right-hand side of (5-7) will become non-zero which means that there would be acceleration \((P_m - P_e > 0)\) or deceleration \((P_m - P_e < 0)\) on the rotor of the synchronous machine.

To assess the impact of the PAE from an individual generating unit on the grid, the dynamic reaction of a synchronous generator connected to a load substation has been investigated prior, during and after a three-phase to ground solid short circuit at the generator terminal as shown in Figure 5-1. In Figure 5-1, \( P_e \) is measured at generator terminal and \( P_L \) and \( V_L \) are measured at the load substation. In Figure 5-1, during pre-contingency, between \( t_0 \) and \( t_1 \); \( P_m \), \( P_e \) and load power demand \((P_L)\) is equal to 1pu. At \( t_1 \), a three-phase to ground solid short circuit happens and \( P_e \) and \( P_L \) become zero, while \( P_m \) remains 1pu until \( t_2 \). The mismatch between \( P_m \) and \( P_e \) during the fault causes the PAE to become non-zero.

The right-hand side of (5-7) indicates the difference between the mechanical power output of the turbine and the electrical power output of the generator. Let us call it \( P_{acc} \), the acceleration power, as shown in (5-8):

\[ P_{acc} = P_m - P_e \]  \hspace{1cm} (5-8)

In the normal operating condition (between \( t_0 \) and \( t_1 \)), the value of \( P_{acc} \) equals to zero; however, between \( t_1 \) and \( t_2 \), the value of \( P_m \) is higher than \( P_e \) producing a positive acceleration power \((P_{acc} > 0)\) increasing the rotor speed and consequently increasing the rotor angle. To obtain the amount of stored energy in the rotor of the generator as a result of the \( P_{acc} \), equation (5-8) should be integrated through time as expressed in (5-9):

\[ \int P_{acc} \, dt = \int (P_m - P_e) \, dt \]  \hspace{1cm} (5-9)

By calling the left-hand side of (5-9) the primary accelerating energy, PAE, it can be expressed as (5-10):

\[ \text{PAE} = \int (P_m - P_e) \, dt \]  \hspace{1cm} (5-10)

The PAE can be simply calculated using (5-10). As indicated in (5-10), the value of the PAE is calculated locally at the generator terminal and only depends on the individual generating unit. The PAE does not represent any wide-area network energy level indication and it only shows how much excess energy has been injected into the wide-area network by the individual generating unit as a result of the disturbance. Monitoring the value of PAE is the first step in identifying if a generating unit injects excess energy into the grid and increases the risk of
transient instability.

After the fault is cleared at \( t_2 \), the electrical power is restored to its initial condition and the PAE becomes zero. In post-contingency (after \( t_2 \)), the excess energy injected into the grid as the PAE increases output electrical power of the generator \( (P_e) \), causes a power gap between, \( P_e \) and the active power demand of the load \( (P_L) \), igniting the first part of the SAE. The first part of the SAE is caused by the individual generating unit response in the post-contingency situation as illustrated in Figure 5-1.

To calculate the first part of the SAE, the accelerating power \( (P_{acc}) \) should be determined as given by:

\[
P_{acc} = P_e - P_L
\]  

By integrating (5-11) for time, the first part of the SAE is calculated in (5-12),

\[
SAE = \int(P_e - P_L) \, dt
\]  

This first part of the SAE is caused by the generator as the generator output power is changing as a response to the disturbance and will return to its pre-contingency value after some time, depending on the damping of the generator; consequently, the first part of the SAE is a temporary characteristic.

The increase in the \( P_e \) due to the PAE (first part of the SAE) has a second negative impact on the transient stability of the network. As \( P_e \) increase, the losses on the transmission line increase and the voltage at the load zone substation decreases. The reduction in the voltage magnitude of the load reduces the maximum electrical
output power of the generator based on (5-13),

\[ P_e = P_e^{\text{max}} \sin \delta \]  

(5-13)

Where

\[ P_e^{\text{max}} = \frac{V_G V_L}{X} \]  

(5-14)

Equation (5-13) indicates that the electric active power output of the synchronous generator; where \( P_e^{\text{max}} \) is the maximum generator active power transfer capacity depends on: (i) \( V_G \), the generator terminal voltage, (ii) \( V_L \), the load voltage and (iii) \( X \) the admittance between the generator and the load. Considering the direct relation between \( P_e^{\text{max}} \) and \( V_L \) as indicated in (5-14), the reduction in \( V_L \) leads to the reduction in \( P_e^{\text{max}} \) (\( V_G \) is constant since it is controlled by the automatic voltage control system) and reduces the first part of the SAE. Reduction in the first part of the SAE improves the transient stability, however, the reduction of the value of \( V_L \) has far more negative impact on the transient stability as it created the second part of the SAE. The reduction of \( V_L \) increases the power gap between \( P_e \) and \( P_L \) at the load terminal as in the interconnected power systems, the load characteristic is highly dependent on the magnitude of the voltage. Equation (5-15) shows the dependency of the load active power demand to the magnitude of the voltage.

\[ P = P_0 \left( \frac{V}{V_0} \right)^e \]  

(5-15)

where \( P_0 \) is the load active power demand when the voltage is \( V_0 \), \( e \) is the exponent coefficient and \( e \) can be any number; however, the values of 0, 1, and 2 for \( e \) indicate constant power, constant current, and constant impedance load respectively.

As indicated in (5-15), the load demand (\( P_L \)) decreases as the value of \( V_L \) reduces. A decrease in \( P_L \) increases the gap between \( P_e \) and \( P_L \) and creates the second part of the SAE as indicated (5-12). As the number of loads is typically more significant than the number of generating units, the second part of the SAE is much more significant than the first part of the SAE. Consequently, total SAE as the summation between the first and second parts of the SAE is expected to be more significant than the PAE. In Figure 5-1, \( e \) in (5-15) is assumed to be 0; however, to assess the significant impact of voltage drop on the load power on the SAE (the second part of the SAE), in Figure 5-2, \( e \) is considered to be 2.
Figure 5-2: Mechanical, electrical and load power, and load voltage subjected to a 3Ph-G fault considering the dependency of load power to voltage magnitude.

As shown in Figure 5-2, when constant impedance load characteristic is considered, the reduction in the voltage after $t_2$ reduces the load demand significantly and increased the power gap between $P_e$ and $P_L$, creating the second part of the SAE based on (5-12) and increasing the total SAE. The second part of the SAE is caused by the load and is increasing as the voltage depression is spread throughout the grid and to other load substations. The second part of the SAE can dramatically increase in a wide-area power grid and lead to transient instability.

As presented in this section, a fault close to a generating unit can develop PAE which is converted to the SAE after the fault clearance. The developed SAE, includes two parts, the first part which is caused by the individual generating unit and produces a temporary negative impact on the transient stability, and, the second part which is caused due to the load zone substation voltage drop and can significantly magnify the power mismatch in the wide-area power grid and cause transient instability. The relationship between the PAE and the total SAE can be used as a key factor to detect any transient instability. The key parameter in the proposed approach is the value of the PAE$_{th}$ (threshold PAE) for each individual generating unit that the wide-area network can absorb without being subjected to a transient instability. The value of PAE$_{th}$ depends on the operating condition of the system, generating unit capabilities, the location of the generating unit, and the dependency of the loads in the wide-area network to the magnitude of the voltage. The value of PAE$_{th}$ can be determined using offline assessment on the wide-area network by the NSP.

Figure 5-3 shows the flowchart of the proposed approach to detect transient instability. The detection is based on the online continuous measuring of the PAE as the generator terminal. After the detection of a Fault Ride Through (FRT) condition, the PAE is measured in real-time at the generator terminal and compared with the
PAE<sub>th</sub> to assess if the disturbance is leading the wide-area network into the transient instability. However, the PAE<sub>th</sub> should be indicated using offline assessment as indicated in this chapter. The proposed method advantages are as follows:

1. The proposed method requires only to monitor the active power output of a generating unit to calculate the PAE. The PAE measurement system can be easily installed in the power plant substation and uses the readings from the circuit breaker connected to the generator terminal. No other real-time information is required to complete the detection process. Parameters such as \( P_m \) and PAE<sub>th</sub> are required, they can be set manually or updated remotely using slow speed communication systems. Other wide-area proposed approaches to detect transient instability normally rely on real-time high-quality measured data from different PMUs located in specific locations of the network. These wide-area transient instability detection systems typically require developed protection grade duplicated ICT infrastructure and wide available bandwidth.

2. The decentralized feature of the proposed approach helps the NSPs to be able to develop the transient stability detection scheme without the requirement of accessing confidential wide-area information and data. Additionally, the generating units are normally privatized, and providing wide-area network data is not legal.

![Flowchart of the proposed transient instability detection approach.](image)

Figure 5-3: Flowchart of the proposed transient instability detection approach.

In the flowchart in Figure 5-3, the key parameter is the value of PAE<sub>th</sub> which needs to be determined by offline assessments. The following section shows how the value of PAE<sub>th</sub> can be determined.
5.4 Accelerating Energy Evaluation for a Single Machine Test System

To evaluate the influence of the PAE and SAE on the transient stability in a power system, a small test system consisting of one synchronous machine rated at 650MVA, connected to an infinite bus through a load substation (500MW demand) is modelled. All transmission lines are modelled simply by considering 10% reactance. As a disturbance, a three-phase short circuit is considered on a transmission line, near the generator terminals as shown in Figure 5-4; the disturbance is initiated at $t = 0s$ and is cleared at $t = 0.1s$.

Figure 5-4: A single machine test system connected to an infinite bus through load substation and transmission lines.

The assessment is mainly focussing on how the PAE leads to the SAE and endangers the transient stability of the network. To have a clear understanding between the first part of the SAE caused by the generator and the second part of the SAE caused by the load, the first presented case study is sequentially performed for constant power load model, showing only SAE caused by the generator, and, the second presented case is performed for constant impedance loads.

Figure 5-5 shows the active power output of the generator, load demand, and load voltage magnitude in the single machine test system presented in Figure 5-4 after a 3Ph short circuit fault. The load model, in this case, is considered to be a constant power load that is independent of the magnitude of the voltage. Consequently, the SAE observed, in this case, is only the first part of the SAE which is caused by the generator. As indicated in Figure 5-5, following the disturbance, the active power output of the generator is reduced significantly, while the output of the turbine (prime mover) remains constant and creates PAE. Figure 5-5 shows the PAE (the dark shaded area) calculated using (5-10), which is the result of the mismatch between the mechanical input (constant) and the electrical output of the generator (calculated using the simulation software, PowerFactory) during the presence of the fault. As the mismatch is integrated during the fault, PAE keeps increasing and is stored in the generator rotor.
Figure 5-5: Generator output and load power of the single machine test system in the stable first swing considering constant power load model.

In Figure 5-6, the energy levels caused by the generating unit during and after the disturbance in the test system is presented. Here, PAE is increased up to 0.1pu during the fault and then is released into the grid as SAE which is increased up to 0.175pu. The SAE in this case caused by the generator only. The system transient stability for this case has been preserved and the network was able to dissipate the PAE injected by the generating unit.

Figure 5-6: Primary and secondary acceleration energy of the single machine test system in the stable first swing
considering constant power load.

The results in Figure 5-7, shows the test system characteristic to the same disturbance as the previous case when the constant impedance load model is considered. Using the constant impedance load model, the load demand is highly dependent on the magnitude of load voltage. After the fault clearance at \( t = 0.1s \), the generator accelerates due to the stored kinetic energy in its rotor as a result of the PAE developed during the fault. The generator rotor angle and the output power are increased which leads to an overloading behaviour in the remaining transmission lines, pushing the angle wider across them and increasing the line current and losses. This leads to a progressive drop in the voltage magnitude of the load substations despite the generator terminal voltage is kept constant by the generator automatic voltage regulator. As the constant impedance load model proportional to the square of voltage magnitude, the second part of the SAE becomes non-zero. In Figure 5-6, SAE is caused due to both reduction of the \( P_{e,\text{max}} \) based on (5-14) as well as the reduction of the load demand caused by voltage depression in the load substation.

![Figure 5-7: Generator output power and load power of the single machine test system in the stable first swing considering constant impedance load.](image)

As shown in Figure 5-6, the load active power demand reduces to zero and then is restored to 96% after the fault is cleared. As the generator rotor angle increases, the generator active power output increases, the voltage decreases furthermore, reducing the load to 88% at \( t = 0.49s \). During the first swing, the voltage is reduced, and the load is diminished consequently leaving a big power gap between the generator output power and the load power as indicated in Figure 5-7 as a shaded area.

Similar to Figure 5-6, Figure 5-8 shows the PAE and the total SAE, but, when the load is modelled as a constant impedance load. As shown in Figure 5-8, in addition to the SAE caused by the generator response to the disturbance, reduction in the load demand has also contributed to the SAE and increased the total SAE.
significantly in comparison with Figure 5-6.

In Figure 5-8, it can be concluded that the SAE from the generator (a temporary impact) is decreasing after the peak at $t = 0.9s$, while the value of SAE caused by the load reduction (permanent impact) is constantly increasing.

Using the same test system, the fault clearance has been extended from 5 cycles to 10 cycles (0.2 seconds). Figure 5-9 shows the characteristics of the single machine test system considering the extended clearance time.
In Figure 5-8, the fault is cleared at $t = 0.2s$, however, the load voltage and the power have been dropped dramatically when compared with Figure 5-7. The PAE and SAE the extended fault clearance time is calculated and presented in Figure 5-10. Increasing the fault clearance time causes the PAE stored in the rotor of the generator to be doubled (0.2pu). After the fault is cleared, the PAE is injected into the network and creates SAE. As SAE passes through the substation, it is multiplied and the second part of the SAE caused by the load voltage reduction increases dramatically.
Figure 5-10: Primary and secondary acceleration energy of the single machine test system in the unstable first swing with the constant impedance load model.

Figure 5-11: Rotor angle of the generator in the stable and unstable first swing transient.

The rotor angles of the generator in both investigated cases are shown in Figure 5-11, which shows that the case with the shorter clearing time produces the stable first swing transient, while the case with a longer clearing time produces the unstable first swing transient.
Technically, it can be stated that the test system in Figure 5-3 is capable of handling the PAE value of 0.1pu and cannot handle the PAE value of 0.2pu. This PAE (0.2pu) can be used as PAE\textsubscript{Th} as indicated in the proposed transient detection approach resented in Figure 5-3. The capability of the system in managing the excess energy can be used efficiently to indicate the risk of transient stability of a network. This indication can also be used to improve the transient stability of a network by considering countermeasures such as using storage systems or increase the capability of the system in eliminating the PAE at the generating unit terminal. The value of PAE\textsubscript{Th} can also be used to select the size of the required countermeasure to be installed.

5.5 Performance Evaluation through Case Studies

The proposed method has been applied to the Nordic power system and its performance investigated. In this section, the Nordic power system has been selected as the test system to assess each generating unit individual impact on the wide-area transient stability. Additionally, the whole grid energy level has been calculated only as an indicator of how each generating unit participates in the Nordic power system energy level. Using the Nordic power system, the PAE injected into the network by each individual generating unit and its impact on the Nordic system are assessed. The disturbance is a solid three-phase short circuit on one of the transmission lines connecting buses 4062 and 4063 in the southern region of the Nordic power system as shown in Figure 5-12.

The disturbance is initiated at \( t = 0\, \text{s} \) and cleared after 5 cycles \( (t = 0.1\, \text{s}) \) and the simulation results show that the system produces stable first swing condition, however when the clearing time is delayed and the fault is...
cleared after 9 cycles ($t = 0.18s$), the system produces unstable first swing condition.

Figure 5-13 shows the deviation in the active power output of G18, G17, G15, and G08, which are the closest generators to the location of the disturbance. Figure 5-13 indicates that the PAE stored in the rotor of G18 during the disturbance was able to push the power output by 33% at $t = 0.72s$ in post-contingency; moreover, the PAE generated by G18 keeps spreading into the grid as a wave of energy, increasing the output power of G17, G15 and G08 by 20%, 9% and 4% at $t = 0.92s$, 1.05s and 1.09. The output powers of the nearby generators keep increasing during the first swing. These generators are selected to be the critical generators in the Nordic power system for this specific disturbance.

Figure 5-13: Selected generators output power of Nordic power system in the stable first swing.

The extra generated power by G17, G15, and G08 will ignite the SAE as presented in Figure 5-14. Figure 5-14 shows the SAE caused by G18, G17, G15, and G08 and the total SAE in the post-contingency condition. The value of the total SAE caused by the generators extra-generated power is 0.27pu, while the total PAE stored during the disturbance is 0.17pu. The value of SAE is more significant that the PAE. The calculated total PAE and SAE are calculated by the summation of G18, G17, G15 and G08 PAE and SAE, consequently, the total PAE and SAE only represents these 4 generating units and not all Nordic system. The total PAE and total SAE have only been presented as indicative values. In the proposed approach to detect transient instability, the total PAE and total SAE are not required. Other factors such as coherent groups also contribute to the transient instability, however, in this work, only the contribution of each generating unit has been considered individually and the interaction between the machines are not considered.
Figure 5-14: Primary and secondary acceleration energy caused by generators of the Nordic power system in the stable first swing.

After the disturbance is cleared, the voltage magnitude of the loads is reduced as presented in Figure 5-15 which leads to a significant reduction in the load demand, since, the load power is directly related to the square of the voltage magnitude.

Figure 5-15: Selected loads voltage magnitude of the Nordic power system in the stable first swing.

The consequent drop in the load power demand following the release of PAE will lead to a significant SAE as presented in Figure 5-16. Figure 5-16 shows that the total SAE for the stable first transient of the Nordic power system in the specific operating condition. In this case, the considered disturbance is 0.59pu which is 3.3 times the value of the PAE.
Figure 5-16: Total primary and secondary acceleration energy caused by the loads in addition to generators after the disturbance in the stable first swing.

When the clearance time is increased to 9 cycles ($t = 0.18s$), the PAE stored in the rotor of the generator becomes higher than the case with the shorter clearance time, since the electrical output of the generator remains at zero for a longer period.

Figure 5-17 shows that after the disturbance is cleared at $t = 0.18s$, the output powers of the close-by generators are increased initially due to the energy stored in the rotors being released into the grids, and then they are reduced, because of the voltage reduction as shown in Figure 5-17.

Figure 5-17: Selected generators output power of Nordic power system in the unstable first swing.

The output power of G18 during the post-contingency is increased by 15%, which is less than half of the G18 power output increase observed in the case with a shorter clearance time (Figure 5-12). This is mainly because
the rotor angles of the generators were already unstable in its first swing as shown in Figure 5-17. The rotor angle of the affected generator is presented in Figure 5-18.

![Figure 5-18: Rotor angle of the generators for the Nordic power system in the stable and unstable first swing.](image)

Due to the longer presence of the disturbance, in the first swing as shown in Figure 5-19, the total PAE value calculated by summation of the PAE’s from G18, G17, G15 and G08 has been increased to 0.33pu. This significant difference between the stable and unstable first swing value of the total PAE was occurred due to the increasing values of the rotor angles of the generators in the unstable swing (shown in Figure 5-18) caused by the delayed fault clearance.

However, the value of the total SAE calculated by the summation of the SAE’s from G18, G17, G15, and G08 was reduced to -0.13pu, and the generators helped the transient stability of the network by reducing the value of their SAE. Since generators’ post-contingency characteristics have contributed to reduce the value of SAE, it is not efficient to use a countermeasure to dissipate more energy at the generator point of connections.
Figure 5-19: Primary and secondary acceleration energy caused by generators after the disturbance in the unstable first swing.

The value of PAE for each generating unit measured in Figure 5-19 can be used as the PAE_{th} for each of the G18, G17, G08, and G15 generating units. Based on the proposed transient instability detection method, when the PAE_{th} for each critical generating unit is reached, transient instability is imminent.

The voltage drops in the load bus-bars after the disturbance in the unstable first swing situation are given in Figure 5-20. As it is evident, the voltage drop is very significant and leads to a significant reduction in the load demand and a significant increase in the SAE caused by the load.

Figure 5-20: Selected loads voltage magnitude of the Nordic power system in the unstable first swing.

Figure 5-21 shows that the negative SAE due to the generators has reduced the total value of SAE from 1.15
(SAE due to the loads) to 1.02. However, the SAE after 1 second is still 3.1 times greater than the PAE and leads to transient instability. By reducing the SAE caused by the loads, transient stability can be maintained.

![Figure 5-21: Total primary and secondary acceleration energy caused by the loads in addition to generators after the disturbance in the unstable first swing.](image)

A comparison between the SAE due to the generators and the SAE due to the loads shows that the SAE due to the load demand reduction impacts the network transient stability more significantly. This fact can be used in developing efficient countermeasures with the idea of increasing the SAE reduction rate at the load zone substations. The developed countermeasures should be located at the load buses to compensate for the reduced load demand and hence to reduce the SAE imposed by load reduction. Ideally, by removing the SAE caused by the load reduction, the system can preserve its stability. Consequently, the reduction in the load (the dependency of the load demand to voltage magnitude) can be used as an indicator to find out how much more energy needs to be eliminated to achieve zero SAE. One of the potential countermeasures is to switch in energy storage systems installed in the load buses to reduce the SAE.

### 5.6 Summary

This chapter has presented a direct method to quickly and accurately detect the potential risk of an imminent transient instability in a power system by monitoring the excess energy injected into the grid by each individual generating unit. The proposed method first calculates the primary accelerating energy for each generator during the fault and then compares it with a threshold to indicate if the injected accelerating energy leads to transient instability. As the wave of energy passes through the network, the secondary accelerating energy keeps increasing and the rotor angles of the generators move further away from the normal operating angles. To facilitate the proposed method, the power gap between the active power at the generator terminal and the active power at the load substation feeder should be assessed offline and the primary accelerating energy threshold determined by the NSP. This can be used to calculate the excess energy created by each generating unit in the grid which makes it practical and simple to implement. The proposed method can be used to assess whether a
network is close to the transient instability. The method can also be used in real time to detect the risk of transient instability and estimate the available time for applying the countermeasures.
Chapter 6  Transient Stability Improvement

6.1 Foreword

In this chapter, a new approach is presented to reduce the nonlinear characteristics of a stressed power system and improve the transient stability of the system by reducing its second-order modal interaction through retuning selected critical parameters of the generator excitation system. To determine the magnitude of the second-order modal interaction within the system, a new index on nonlinearity is developed using normal form theory. Using the proposed index of nonlinearity, a sensitivity function is formed to indicate the most effective excitation system parameters in the nonlinear behaviour of the system. These dominant parameters are tuned to reduce the magnitude of the second-order modal interaction of the system and to reduce the index on nonlinearity. The efficiency of the proposed method is initially validated using a four-machine two-area test system. The IEEE 39-Bus New England test system is then used to investigate the performance of the proposed method for a more realistic system. Simulation results show that a proper tuning of the excitation controller can reduce the magnitude of the second-order modal interaction of the system and can even improve the transient stability margin of the network.

6.2 Background

Today power systems are increasingly stressed due to the continuously growing load as the penetration of plug-in electric vehicles (PEV) is increased; moreover, PEV charging stations and controller are naturally highly nonlinear loads and connecting them to the power grid increases the nonlinearity of the system [180], [181]. Under such a stressed condition, the conventional local linear model tested only at equilibrium points may fail to model the complete system characteristics or may reveal incomplete system performance. Further, as the system becomes more stressed, complicated phenomena involving the interaction between the system modes may occur [115]. As discussed in [117], the interaction between modes plays an important role in the dynamic characteristics of the system and must be considered in comprehensive dynamic studies.

In the late eighties, attempts to consider the nonlinear characteristics and modal interaction of the system were initiated. In [115] and [116], the envelope equation, which governs the aspect of the resonance between two modes, is presented. In [117], the inter-area mode phenomenon in stressed power systems following large disturbances is studied. The importance of adding the second-order terms in a time-domain simulation is presented in [118]. In the same year, the Normal Form (NF) theory is used as a tool to identify the nonlinear aspects of the modal interaction phenomenon [182].

The NF theory is a useful and powerful analytical tool to study the characteristic of a nonlinear dynamical system in the neighbourhood of an equilibrium point. Over the past few years, NF has been widely used to determine the effect of the modal interaction on the controller’s performance [120]–[122]. In [123], [183], some guidelines were presented to design system controllers to reduce the inter-area oscillation of the system using NF. NF has also been used to indicate the effect of modal interactions on machine states, system participation factors, and eigenvectors [124], [125]. In a stressed power system, NF theory is used to study the nonlinear modal interaction [184] and its influence on system controller design and allocation [126], [127]. Most recently,
the effect of the modal interaction with higher than 2\textsuperscript{nd} order in the small-signal analysis is investigated [128]. In [129], [130], an attempt is made to derive the closed-form nonlinear solutions of torques and their modal interactions to nonlinear torsional dynamics.

The main objective of the chapter is to improve the transient stability of the system by reducing the magnitude of the second-order modal interaction between generating units in a realistic nonlinear power grid. The proposed method reduces the second-order modal interaction of a power system by retuning the excitation system parameters. In the proposed method, the NF theory is applied to extract the Taylor series expansion second-order terms from a power system, since these second-order terms represent the second-order modal interaction in the nonlinear system. Using the NF theory, these second-order modal interactions are extracted and linearized. The linearization is necessary to investigate the influence of different power system elements parameters (the excitation system parameters are used in this research) on the magnitude of these second-order modal interactions. To determine the magnitude of second-order modal interaction within the system, a new index of nonlinearity is developed using the NF technique. The index is then used to determine the most effective excitation system parameters, in addition to the direction of their influence in the magnitude of the second-order modal interaction using a sensitivity function. This investigation leads to identifying the significant impact of excitation system parameters on the second-order modal interaction of the power system, which leads to our proposal to modify these parameters to reduce the identified magnitude of these second-order interactions. The new parameters are shown to be successful in reducing the magnitude of the second-order modal interaction through a time-domain simulation. The simulation results also show that the reduction in the second-order modal interaction will increase the transient stability boundary of the network and improve its power transfer and generating capability under a stressed operating condition without requiring any new equipment or devices to be bought or installed. The proposed method can be implemented in any type of excitation systems.

The Khorasan power grid load-ability of power transmission lines was constrained by the transient stability limit. The proposed method provided a practical and economical solution to this limitation by varying the excitation system parameters of the generators to reduce the magnitude of the second-order modal interaction between generating units and hence to expand the transient stability boundaries of the power grid.

6.3 Second-Order Solution Using Normal Form

Consider the following general nonlinear differential equations

$$\dot{x} = f(x)$$ \hspace{1cm} (6-1)

where \(x\) is the vector of system states \([x_1, x_2, \ldots, x_N]^T\) and \(f\) is the real-valued vector field.

Let the system in (6-1) be locally approximated by the Taylor series expansion at the stable equilibrium point \(x_{SEP}\) as given in (6-2).

$$\dot{x} = f(x) = \sum_{n=1}^{\infty} \frac{1}{n!} \left[ \sum_{i=1}^{N} x_i \frac{\partial}{\partial x_i} \right] f(x_{SEP})$$ \hspace{1cm} (6-2)
where $x_i$, the deviation from the equilibrium point, is the $i$th state variable.

Each term of the Taylor series expansion at the equilibrium point of the system, indicate specific characteristics of the nonlinear system. Considering more terms in the series provides more precise and detailed modelling of the nonlinear system.

The abbreviated version of the Taylor series expansion is

$$\dot{x} = Ax + F_2(x) + F_3(x) + \cdots$$  \hspace{1cm} (6-3)

where $F_2(x)$, $F_3(x)$, and so on are the second, third, and higher-order terms of the Taylor series expansion. Using similarity transformation in (6-3) yields

$$\dot{y} = \Lambda y + \hat{F}_2(y) + \hat{F}_3(y) + \cdots$$  \hspace{1cm} (6-4)

For the $j$th mode of the system, we can write $y_i$ derivative as

$$\dot{y}_j = \lambda_j y_j + \sum_{k=1}^{N} \sum_{l=1}^{N} \hat{F}_{kl} y_k y_l + \sum_{k=1}^{N} \sum_{l=1}^{N} \sum_{m=1}^{N} \hat{F}_{klm} y_k y_l y_m + \cdots$$  \hspace{1cm} (6-5)

Equation (6-5) consists of linear first-order, nonlinear second order, nonlinear third order, and nonlinear higher-order terms. The product of two, three, or more modes of the system, represents the second, third, and higher-order modal interaction. Equation (6-5), includes all nonlinearities in the power system model.

Nonlinear characteristics of the system can be simplified using the method of NF. This method provides a simple representation around the local equilibrium point. NF approach uses a sequence of nonlinear transformations, performed usually order by order. In the early twenties, Poincare used this method to transform the local nonlinear equations to linear form. Consider the set of eigenvalues $\lambda_j, j=1,2,\ldots,N$, the resonance of order $r$ exists if we have;

$$\lambda_j = \sum_{i=1}^{N} m_i \lambda_i, \hspace{1cm} r = \sum_{i=1}^{N} m_i$$  \hspace{1cm} (6-6)

where $r$ is the resonance order and $\lambda_j$ is the eigenvalue from the linear term of the nonlinear system.

According to the NF theory, if there is no $r$th resonance order in the nonlinear system, nonlinear terms of up to $r$th order could be eliminated using a nonlinear state-space transformation.

Consider a nonlinear system with no resonance up to the second order. In this case, nonlinear terms could be eliminated up to the second order. The transformed system is given by

$$z = \Lambda z + O(z^3)$$  \hspace{1cm} (6-7)

where $z$ is the new state vector in the Jordan form and $O(z^3)$ represents the transformed third and higher-order terms. Neglecting $O(z^3)$ and solving the linear equation results in
\[ z_j(t) = z_{j0} e^{\lambda t} \]  

(6-8)

The inverse transformation of \( z \) returns the equation to the \( y \) reference. Using inverse similarity transformation, an approximate and closed-form solution of the nonlinear system will appear in the \( x \) reference. This solution contains second-order modal interaction characteristics of the nonlinear system.

There is a simple NF transformation to eliminate the second-order nonlinear term. Consider the expansion with only the first and second-order terms as follows;

\[ \dot{x} = Ax + F_j(x) \]  

(6-9)

Assuming zero as the equilibrium point, we have

\[ \dot{y} = A_i x + \frac{1}{2} x^T H' x \]  

(6-10)

where \( A_i \) is the \( i^{th} \) row of the Jacobian matrix with \( i=1, 2,3, \ldots N \) and \( H' \) is the Hessian matrix of second derivatives.

Using similarity transformation, in term of \( y \) (6-10) yields

\[ \dot{y} = \Lambda y + \frac{1}{2} V \begin{bmatrix} y^T U^T H^U y \\ y^T U^T H^V y \\ \vdots \\ y^T U^T H^N y \end{bmatrix} \]  

(6-11)

For \( j^{th} \) mode of the system we have

\[ \dot{y}_j = \lambda_j y_j + \sum_{k=1}^{N} \sum_{l=1}^{N} C_{jkl} y_k y_l \]  

(6-12)

where

\[ C' = \frac{1}{2} \sum_{k=1}^{N} \sum_{l=1}^{N} y_{\ell} [U^T H' U] = [C_{\ell}] \]

Assuming no second-order resonance, the proper second-order NF transformation is

\[ y = z + h_z(z) \]  

(6-13)

where

\[ h_z^{(2)}(z) = \sum_{i=1}^{N} \sum_{j=1}^{N} h_{ij}^{(2)} z_i z_j \]

and
\[ h_{ij}^l = \frac{C_{ij}^l}{\lambda_i + \lambda_j} \]

Using the transformation (6-13), (6-12) can be represented in the NF space as

\[ z_j = \lambda_j z_j + O(z^3) \]  \hspace{1cm} (6-14)

Neglecting high order terms of \( O(z^3) \), the linear equation in (6-14) is solvable and has a solution identical to (6-8). The approximate solution in Jordan space reference is:

\[ y_j(t) = z_{j0}e^{\lambda_j t} + \sum_{k=1}^{N} \sum_{l=1}^{N} h_{klj}^l z_{j0} z_{klj} e^{(\lambda_k + \lambda_l) t} \]  \hspace{1cm} (6-15)

Using the inverse similarity transformation, an approximated solution in physical space reference is given by

\[ x_j(t) = \sum_{j=1}^{N} u_{ij} z_{ij0} e^{\lambda_j t} + \left[ \sum_{j=1}^{N} \sum_{l=1}^{N} \sum_{k=1}^{N} h_{klj}^l z_{j0} z_{klj} e^{(\lambda_k + \lambda_l) t} \right] \]  \hspace{1cm} (6-16)

Initial conditions are obtained using equations \( y_0 = Vx_0 \) and \( z_0 = y_0 - h_2 \). In the second equation, initial conditions are obtained using numerical solution algorithms. Equations (6-15) and (6-16) give us the ability to calculate the contribution of modes of oscillation to the system states. They allow direct comparison between linear and nonlinear analysis including the second-order interactions. Nonlinear effects are exhibited in the NF solution both in the linear part in the first terms of (6-16), and the second order interactions nonlinear part in the second terms of (6-16).

This solution can be transformed back to the Jordan form as expressed in (6-17),

\[ y_j(t) = z_{j0}e^{\lambda_j t} + \sum_{k=1}^{N} \sum_{l=1}^{N} h_{klj}^l z_{j0} z_{klj} e^{(\lambda_k + \lambda_l) t} \]  \hspace{1cm} (6-17)

In (6-17), the first term represents the individual modes of the system, while the second term shows the system second-order modal interaction. The ratio of the second term magnitude to the first term can be used to express the impact of the second order modal interaction of the system as expressed in (6-18),

\[ I_j = \frac{\sum_{k=1}^{N} \sum_{l=1}^{N} h_{klj}^l z_{j0} z_{klj}}{z_{j0}} \]  \hspace{1cm} (6-18)

Hereafter, \( I_j \) is called the index of nonlinearity. This index approximates the nonlinear characteristics, besides the second-order modal interaction of the system.

Equations (6-18) and (6-9) show that the index can be excited by three main factors as presented below:

1. The Initial conditions (the size of \( z_{j0}z_{klj} \))
2. A large value of \( C_{ij} \) will cause a large value in \( h_{klj}^l \)
3. The location of the eigenvalues of the system ($\lambda_i + \lambda_j = \lambda_k$)

The third factor (the location of eigenvalues in the s-plane) has a tremendous impact on the second-order modal interaction excitation.

### 6.4 Second-Order Modal Interaction Reduction

The significant influence of the system eigenvalues in the value of the index of nonlinearity is determined by (6-18), in which the value of the index of nonlinearity is proportional to the system eigenvalues. However, the location of the system eigenvalues in the s-plane is also highly influenced by the excitation system. So, the excitation system parameters play an important role in the magnitude of the second-order modal interaction and consequently the nonlinear characteristics of the system.

Figure 6-1 shows the model of a classic excitation system. In this model, $T_R$ is the voltage regulator time constant, $T_C$ and $T_B$ are the compensator time constants, $K_A$ and $T_A$ are the amplifier gain and time constant respectively. $V_{PSS}$ is the auxiliary signal from the power system stabilizer (PSS) and $V_{OEL}$ is the protective signal from the overexcitation limiter.

![Figure 6-1](image)

In the proposed method, the main accessible parameters of the excitation system, $K_A$, $T_B$, and $T_C$ are retuned to influence the nonlinear characteristics of the system in a way, which leads to the reduction of the magnitude of the second-order modal interaction. The selected parameters can be accessed and retuned easily in any excitation systems types and models [161]. The selected parameters impact the performance of the excitation system as a control system and do not impact the excitation system capability. The capability of the excitation system in injecting excitation current into the rotor is determined in the manufacturing process. To set the excitation model parameter efficiently, a sensitivity function is defined by,

$$S_{K_A} = \Delta I / \Delta K_A \quad (6-19)$$

$$S_{T_B} = \Delta I / \Delta T_B \quad (6-20)$$

$$S_{T_C} = \Delta I / \Delta T_C \quad (6-21)$$

where $S$ is the sensitivity value and the $\Delta I$ is the change in the index of nonlinearity.

Due to the dependency of the dynamic studies on the operating condition of the system, a set of the most
probable operating scenarios must be considered. Figure 6-2 shows the algorithm of the proposed method. In the first step, the rotor angle stability studies are performed, and if the system is stable, the next scenario will be implemented. In the case of instability, the participation factor analysis is performed, and the speed and the rotor angle related modes are identified. The proposed index of nonlinearity is then calculated for these modes and the mode with the maximum index of nonlinearity is considered as $I_j^\text{max}$. In this step, a threshold value $I_j^\text{Threshold}$ is set. If $I_j^\text{max} < I_j^\text{Threshold}$, this mode will be neglected because of its linear behaviour; otherwise, it will be highly nonlinear.

The approach presented in Figure 6-2, retunes the excitation system parameters in an offline mode to reduce the nonlinear characteristics of these modes. In the algorithm, the excitation parameters are increased gradually to reach the lowest possible index of nonlinearity. The step is 2%. The criteria for the parameters selection are to be within the acceptable range of the parameters indicated by the excitation system manufacturer. The algorithm should be implemented for a selected operating condition which is identified as the most probable operating condition by the network service provider (NSP). If the most probable operating condition is changed due to significant network development, the algorithm should be re-run considering the new operating condition.

The most probable operating condition is normally labelled as the system's normal operating condition by NSP. NSP network is normally expected to be operated in system normal operating conditions unless a contingency or planned outage changes the operating condition of the network.

Figure 6-2: Flowchart of the proposed method.
A proper exciter system design is achieved by calculating the sensitivity of the index of nonlinearity to each parameter as expressed in (6-19), (6-20) and (6-21). If the sensitivity of a parameter is positive, the value of that parameter is decreased by 2% and the index of nonlinearity recalculated and the algorithm enters another iteration to see if the stable excitation system parameters are achieved. If the sensitivity of a parameter is negative, the value of the parameter is increased by 2%. The new stable excitation system parameters are the new tuning parameters.

6.5 Method Evaluation

The developed method is applied to a two-area, four generator test system taken from [12], which is modified to consider different operating conditions according to [127]. The details of the considered two-area four generator test system are presented in the appendix. These two areas are connected through two parallel transmission lines. Each transmission line transfers 400 MW of active power. Figure 6-3 shows a single-line diagram of the test system. For this study, all generators are modelled by the two-axis model and equipped with an exciter [17], and the nominal apparent power for each generator is assumed to be 900 MVA. The output operating voltage of each generator is 20 kV. The loads are modelled as constant impedances with no dynamics; moreover, the generators are equipped with the excitation system. As a disturbance, the generation outage at GEN4 is considered for 300 milliseconds. The simulation is carried out using DlgSILENT PowerFactory with 5 milliseconds simulation time step.

![Figure 6-3: Single line diagram of the test system.](image)

First, the linear and the nonlinear characteristics of the test system are investigated using a time-domain simulation and then the second-order modal interaction of the system is reduced using the new parameters for the excitation system model.

6.5.1 Linear and Nonlinear Characteristics of the System

The behaviour of the linear and the nonlinear model of the test system after the disturbance are presented in Figure 6-4. In Figure 6-4, after the outage clearance, the rotor angles of the GEN1 and GEN3 rise significantly when using the nonlinear system model, but when using the linear system model, they can follow a stable route towards their initial value. This significant difference between the nonlinear and linear modelling of the system arises from the influence of the second-order modal interaction on the nonlinear modelling.
A comparison between the results provided in Figure 6-4 indicated the significance of considering nonlinear terms in the transient stability assessment of a power system. In Figure 6-4 (a) the test system nonlinear model assessment shows that the disturbance causes transient instability while the same test system linear model assessment in Figure 6-4 (b) shows that the system is stable in the presence of the same disturbance. Additionally, it can be concluded that if the nonlinear characteristic of the nonlinear test system is reduced and the system becomes more linear, the system behaviour in the presence of the disturbance will move from Figure 6-4 (a) to Figure 6-4 (b) and the test system transient stability will improve.

To determine the modes which are responsible for the second-order modal interaction in the nonlinear system, a participation factor analysis is used. The participation factor analysis indicates the highest participation modes in both the speed and the rotor angle of the generators. Table 6-1 represents the results of the participation factor analysis for the 3 modes with the highest values of participation factors. These three modes are selected because they were the best candidates to study the modal interaction between the generating units as all non-slack generators were significantly participating to maintain the stability of these modes.

Table 6-1: The participation of each generator in electromechanical modes of the test system

<table>
<thead>
<tr>
<th>Mode #</th>
<th>Eigenvalue</th>
<th>GEN1</th>
<th>GEN2</th>
<th>GEN3</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-0.68 ± j6.68</td>
<td>0.25</td>
<td>0.60</td>
<td>0.47</td>
</tr>
<tr>
<td>2</td>
<td>-0.67 ± j6.65</td>
<td>0.59</td>
<td>0.35</td>
<td>0.14</td>
</tr>
<tr>
<td>3</td>
<td>-0.10 ± j3.24</td>
<td>0.27</td>
<td>0.033</td>
<td>0.49</td>
</tr>
</tbody>
</table>

The results from Table 6-1 show that for the third mode, GEN1 and GEN3 have the highest participation factor while the participation factor of GEN2 is very small; so, mode 3 is originally generated from the interaction between GEN1 and GEN3. To verify this, the proposed index of nonlinearity is also used to indicate the nonlinear characteristics of the system with regards to the presented modes in Table 6-1. Table 6-2 shows the value of the index of nonlinearity considering the mentioned electromechanical modes.

Table 6-2: The index of nonlinearity for the selected electromechanical modes
The results from Table 6-2 verify the significant role of mode 3 in the magnitude of the second-order modal interaction in the system; since mode 3 has the highest value of the index on nonlinearity. In other words, the second-order modal interaction between GEN1 and GEN3 increases the nonlinear characteristics of the system.

### 6.5.2 Reduction in the Magnitude of the Second-order Modal Interaction

To reduce the magnitude of the second-order modal interaction of the test system, the proposed approach is used to redesign the excitation system model parameters. In the first step, the sensitivity of each excitation system model parameter to the index of nonlinearity using (6-19), (6-20), and (6-21) is calculated. If the sensitivity of a parameter is positive, the value of that parameter is decreased, and in case of a negative sensitivity, it will be increased. The magnitude of the change of a parameter is dependent on the sensitivity magnitude. The most sensitive parameter will be the most impacted by the changes.

Table 6-3 show the selected sets of the excitation system model parameter tuning regarding reducing the magnitude of the second-order modal interaction. In Table 6-3, four sets of excitation system model parameters are selected among more than 30 sets of parameters, because they clearly show the gradual decrease in the value of the nonlinearity index. Additionally, Table 6-3 shows the sensitivity of the parameters to the index on nonlinearity for GEN1 and GEN3 and the value of the index of the nonlinearity of the system after implementing the new parameters on the excitation system model. The sensitivity function of the first to third sets is calculated against the fourth set because the fourth set is stable.

<table>
<thead>
<tr>
<th>Set#</th>
<th>GEN#</th>
<th>$K_s$</th>
<th>$T_s$</th>
<th>$T_C$</th>
<th>$S_{K_s}$</th>
<th>$S_{T_s}$</th>
<th>$S_{T_C}$</th>
<th>$i_i$</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>1</td>
<td>220</td>
<td>8</td>
<td>2</td>
<td>-0.0008</td>
<td>0.025</td>
<td>-0.10</td>
<td>0.46</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>210</td>
<td>9</td>
<td>1.5</td>
<td>-0.0000</td>
<td>0.002</td>
<td>-0.10</td>
<td></td>
</tr>
<tr>
<td>II</td>
<td>1</td>
<td>240</td>
<td>7</td>
<td>3</td>
<td>-0.0005</td>
<td>0.019</td>
<td>-0.04</td>
<td>0.33</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>210</td>
<td>9</td>
<td>2.5</td>
<td>0.0000</td>
<td>0.000</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>III</td>
<td>1</td>
<td>250</td>
<td>6</td>
<td>4</td>
<td>-0.0003</td>
<td>0.016</td>
<td>-0.02</td>
<td>0.27</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>210</td>
<td>9</td>
<td>3</td>
<td>0.0001</td>
<td>-0.002</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>IV</td>
<td>1</td>
<td>250</td>
<td>5.5</td>
<td>5</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.24</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>205</td>
<td>10</td>
<td>3</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
</tbody>
</table>

In this test system and the considered operating scenario, GEN1 and GEN3 are responsible for the magnitude of the second-order modal interaction. As a result, the excitation system parameters of these two generators are considered for retuning. Figure 6-5 up to Figure 6-8 shows the rotor angles of test system generators for each set of the excitation system parameters.
Figure 6-5: Rotor angle of the generators for the exciter system parameter set I.

Figure 6-6: Rotor angle of the generators for the exciter system parameter set II.
The time-domain simulation results of the rotor angles of the test system generators presented in Figure 6-5 up to Figure 6-8 show that changes in the excitation system model parameters using the proposed method significantly influence the characteristics of the system by reducing the magnitude of the second-order modal interaction of the system. As is evident from Figure 6-5 up to Figure 6-8, as the index of nonlinearity reduces from the set I to set IV, the nonlinear characteristic of the system reduces. In addition to the reduction of the nonlinearity, the transformation in the nonlinear test system behaviour in the presence of the disturbance from Figure 6-5 up to Figure 6-8 shows that as the nonlinear behaviour reduces, the transient stability of the nonlinear test system improves.
6.5.3 Expansion in the Transient Stability Boundaries

A time-domain analysis is carried out to investigate the influence of the reduction in the magnitude of the second-order modal interaction on the transient stability of the system. In this situation, considering the same disturbance like that of the previous section, the rotor angle behaviour for four different generating operating scenarios is simulated. Table 6-4 presents detailed information about the four selected operating scenarios.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>I</th>
<th>II</th>
<th>III</th>
<th>IV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1: conventional parameters</td>
<td>560</td>
<td>602</td>
<td>607</td>
<td>700</td>
</tr>
<tr>
<td>Case 2: new parameters</td>
<td>560</td>
<td>665</td>
<td>700</td>
<td>707</td>
</tr>
</tbody>
</table>

The studies are carried out for two cases with different excitation system model parameters. In case 1, the excitation system parameter of the set I given in Table 6-4 is considered, in which the index of the nonlinearity of the system is 0.46. In case 2, the exciter system parameters of set IV given in Table 6-4 are considered, in which the index of the nonlinearity of the system is 0.24. Each scenario was obtained by changing the active power output of GEN1 and GEN3. In this study, the active power transfer between Area 1 and Area 2 remains constant; since the inter-area oscillation is heavily dependent on the power transfer between areas.

**Case 1:** In this case, the time-domain simulation results for GEN1 and GEN3 equipped with the set I excitation system model parameters after the disturbance are presented in Figures 6-9 and 6-10.

![Figure 6-9](image)

**Figure 6-9:** Rotor angle of GEN1 after the event for different active power output scenarios with conventional exciter system parameters.

The system can remain stable for scenarios I and II but after a 5MW increase in the output active power of both GEN1 and GEN3 in scenario III, the system exceeds its transient stability boundary and becomes unstable.
Figure 6-10: Rotor angle of GEN3 after the event for different active power output scenarios with conventional exciter system parameters.

**Case 2:** In this case, GEN1 and GEN3 are equipped with the excitation system model parameters of set IV. These parameters are redesigned to reduce the magnitude of the second-order modal interaction.

Figure 6-11: Rotor angle of GEN1 after the event for different output active power scenarios with new exciter system parameters.

Figures 6-11 and 6-12 show that the transient stability boundary of the test system has been increased due to the reduction of the index of nonlinearity by using the new set of excitation system parameters. In other words, the transient stability margin of the system is improved by redesigning the exciter system parameters.
Figure 6-12: Rotor angle of GEN3 after the event for different output active power scenarios with new exciter system parameters.

For this test system, the transient stability boundary of a single generator is increased by about 100 MW. In other words, by using the new set of excitation system parameters, the power generation and transfer capacity of the system may increase by about 15%.

6.6 Case Study

The performance of the proposed method of reducing the magnitude of the second-order modal interaction and improving transient stability of the system by reducing the nonlinear characteristics of the system has been evaluated using the IEEE 39-bus New England system [98]. The New England test system presented in Figure 6-13 includes 10 generators.
Figure 6-13: IEEE 39-bus New England test system.

The disturbance is a severe solid 3 phase to ground short circuit on busbar 6 initiated at \( t = 0.1s \) and cleared at \( t = 0.7s \). In this study, the rotor angle of all generators is monitored carefully for 5 seconds in two different cases with exactly similar operating conditions.

Figure 6-14: System responses to the disturbance including all orders of interactions between modes.

Figure 6-14 shows the results for case 1 for selected generators in which typical excitation system parameters are used. In this case, the magnitude of the second-order modal interaction between generating units has not been reduced and the system is showing significant nonlinear characteristics. Figure 6-15 shows the results for case 2 in which the modified excitation system parameters are used and the magnitude of the second-order modal interaction is reduced using the proposed method.
Figure 6-15: System responses to the disturbance excluding second-order modal interaction.

The clear difference between Figures 6-14 and 6-15 shows the significant influence of the proposed method in improving the transient stability of the system by reducing the magnitude of the second-order modal interaction of the system. After the fault clearance, the rotor angle of SG39 is 152 degrees in Figure 6-14 while in Figure 6-15 it drops to 128 degrees which gives us at least 20 degrees increase in the transient stability boundary.

6.7 Summary

In this chapter, a new method is presented to reduce the magnitude of the second-order modal interaction of the system. A new index of nonlinearity is developed which can indicate the nonlinear characteristics of the system due to the interaction between two pairs of modes. It is shown that by retuning the adjustable parameters of the excitation system, this index can be reduced significantly resulting in moving the behaviour of the system closer toward more linear characteristics. The proposed approach has been initially evaluated on a four-machine, two-area test system and finally on a more realistic IEEE 39-Bus New England test system. Simulation results using DlgSILENT PowerFactory indicate that a proper tuning of the excitation system parameters can reduce the index of nonlinearity and can expand the transient stability margin of the system. For future works, the influence of the third-order terms of the Taylor series expansion in the transient stability of the large scale multi-machine power systems should be investigated carefully.
Chapter 7  Conclusions and Future Works

7.1 Conclusions

In this thesis, the most economical and practical method to improve the characteristic of a power system in a post-contingency operating condition have been developed.

The contributions of this thesis are as follows:

1) An optimal robust excitation system has been developed that improved the performance of the excitation system during the emergency condition by being robust against the uncertainty of the excitation system parameters;

2) A new OEL model is developed that improves the capability of the synchronous generator in supplying reactive power longer to the grid in an emergency condition utilising the full thermal rating capability of the rotor;

3) A novel method has been developed that can track the kinetic energy flow through the grid by monitoring the propagated accelerating energy in the system. This method will indicate the amount of stored energy in the system that may lead to transient instability;

4) A simple method has been introduced that can easily improve the transient stability of the system by retuning the excitation system parameters in the system and reducing the nonlinear characteristic of the network.

In Chapter 3, a new optimal robust IEEE ST1A excitation system controller is presented, which is robust to the uncertainty in one or more of its parameters. Despite the complex mathematics behind the method, it can be implemented simply and straightforwardly, even though the uncertainties in the model parameters exist. This optimal approach has transferred the robust controller problem to an optimal control problem, while at the same time, it has preserved the robustness of the excitation system. The influences of uncertainty in the values of $K_A$ with and without the design of the robust excitation system controller have been investigated for a single machine test system. The simulation results from the dynamic stability simulation have demonstrated that the designed robust excitation system controller is capable of being robust to the uncertainty in the parameters of an excitation system controller. For the IEEE 39 bus system, the simulation results show that when the $K_A$, $T_B$ and $T_C$ values of the IEEE ST1A excitation system controller are changed to $\pm 20\%$ of their nominal values, the system becomes unstable although the system was stable when other values (within the upper and lower limit) were used. However, when the designed optimal robust IEEE ST1A excitation system controller has been applied, the system has become robust to the uncertainties in the parameters of the excitation system controller. Using the proposed robust controller, the power system will not have any variation in its stability irrespective of the values of the parameters within the boundary of the uncertainties.

In Chapter 4, a new method is proposed for the determination of the timing for OEL activation, which is developed based on available generator rotor thermal capacity. The performance of the proposed method is validated using two test systems. Using the single-machine test system, the simulation result shows that the proposed OEL method can efficiently utilize the thermal capacity of the rotor and inject more reactive power.
into the system in comparison with that from a conventional OEL equipped generators. The performance of the proposed method is further validated using the Nordic power system demonstrating its effectiveness in extending the amount of reactive power that can be supplied in a multi-machine network resulting in improved voltage stability of the system. The results from the Nordic power system show that all generators participate in supplying the reactive power after a severe disturbance; the conventional OEL equipped machines to participate based on their electrical distance from the incident location, while the thermal-based OEL equipped units to participate by considering their thermal capacity in addition to their distance from the disturbance. The generator owners may be able to be persuaded to allow more use of the available reactive power contributions of the generators to improve the power system performance and the voltage stability if incentives are provided through the provision of ancillary and emergency control services in the electric power market. A system protection scheme (SPS) using the operational data from a SCADA system can be used to identify the location and the timing of the impending voltage instability by observing the sudden increase of generator reactive power outputs and the reduction of voltages in the area of disturbance. The benefit of the proposed thermal-based OEL system is to increase the time for such an SPS to function, by increasing the time so that enough reactive power can be injected into the grid. This will provide the SPS more time to determine the best countermeasure that can be effective to mitigate the emergency condition.

In Chapter 5, a new algorithm to detect transient instability is presented. This algorithm measures the accelerating energy in two different stages. In the first stage, the accelerating energy created during the disturbance is calculated. This accelerating energy is then called primary accelerating energy. In the next stage, as the wave of energy passes through the grid it causes voltage drops in load busbars, which results in the reductions in the load demands at the specific busbars, the reductions in the load demands add up to the existing primary accelerating energy causing a secondary accelerating energy that keeps increasing as the wave of energy passes through load busbars resulting in much longer transient stability or even transient instability. Finally, the real-time determination of the propagated accelerating energy can be used as an indicator to detect transient instability.

In Chapter 6, a new method is presented to reduce the second-order modal interaction of the system. A new index of nonlinearity is developed which can indicate the nonlinear characteristics of the system due to the interaction between the two pairs of modes. It is shown, that by retuning the adjustable parameters of the excitation system, this index can be reduced significantly resulting in moving the behaviour of the system closer toward more linear characteristics. The proposed approach has been initially evaluated on a four-machine, two-area test system and finally on a more realistic IEEE 39-Bus New England test system. Simulation results using DIgSILENT PowerFactory indicate that a proper tuning of the excitation system parameters can reduce the index of nonlinearity and can expand the transient stability margin of the system.

7.2 Future Works

The concept of the emergency control of a power grid that has been developed in this thesis can be developed further.

The key factors of being practical and efficient in addition to economic consideration should always be the
main aims of any emergency control scheme. In communication with the Australian transmission system operator, it was recommended that the solutions that can be implemented must be cost-effective in its approach. Any economical solution to the emergency control issue is very attractive for the transmission system operators.

The work that has been carried out in this thesis can be extended and continued in the following recommended areas:

1) Similar to the excitation controller, the prime mover and governor can be developed to be robust to any uncertainty in their parameters. The approach can be adapted from the design process introduced in Chapter 3 for the excitation controller. An optimal robust prime mover and governor can improve the capability of the system in dealing with the frequency related contingency, specifically when the power grid is being operated close to its limits. In addition to the excitation system, the prime mover and the governor of the synchronous machine, other synchronous machine controllers and protection systems such as the overexcitation limiter, the under excitation limiter, the rate change of frequency protection system and the passive and active islanding protection systems can be developed to be robust to the variations in the synchronous generator parameters or variations in the operating condition of the network.

2) The proposed OEL method in Chapter 4 extends the capability of the generator in supplying more reactive power in a post-contingency operating condition. Considering this capability, the under-voltage load shedding schemes should be developed to allow more time delays in the operation of the curtailment scheme. Corrective actions can also be implemented in the provided extra time to avoid the activation of load-shedding schemes.

3) The rotor thermal capability concept developed in Chapter 4 can be used for any overcurrent protection system. Using this developed method, the thermal capability of any element can be efficiently used, and the element can operate in the overloaded condition for a longer period without being damaged. This method helps the operators to use the full capability of any element in the overloaded condition without damaging the element. This improvement can also be obtained by considering a direct temperature measurement in the overloaded elements. Thermography based measurement methods can be utilized to directly measure the temperature in an overloaded element without needing to have direct contact. This temperature measurement can be used to avoid damages to any overloaded elements.

4) Transient stability detection has always been a challenging concept in power system security. Using the proposed method in Chapter 5, the propagated accelerating energy in a power system can be measured as a wave of energy spreading throughout the network in time, pattern recognition algorithms can be explored to predict the time that the system will reach the transient instability limit. The pattern recognition methods can be trained offline for a specific large-scale power system and then implemented in real-time to estimate the time in which the transient instability is imminent. This time can be used for the activation of the countermeasure.

5) The concept of the propagated accelerating energy can be used to determine the effectiveness of a
transient stability countermeasure. The countermeasure can be implemented and the amount of energy dissipation after the implementation can be measured and the effectiveness of the countermeasure will be ranked. Moreover, this concept can be used to locate the most effective location for the countermeasure to be installed.

6) As a countermeasure to avoid transient stability in a large power system, storage systems can be installed in the load zone substations to reduce the SAE caused by loads, the size of the storage systems can be selected based on the relationship between the voltage magnitude of the load and the active power load demand as indicated in Chapter 5. Based on the concept of the propagated accelerating energy, the time to actuate the storage systems as a countermeasure can be obtained through recognizing the pattern of the increasing PAE and SAE.

7) The investigation of the influence of the voltage magnitudes of the busbars to the accelerating speed of the propagated energy needs to be investigated. The investigations in Chapter 5 indicated that the dependency between the active and reactive power demand in the load substation to the voltage magnitude of the load determines the speed of the wave of energy passing throughout the grid. For loads that are highly sensitive to the voltage magnitude, the wave of energy will spread much faster than that from the less sensitive loads. The speed of the propagated accelerating energy spreading out through the system can be studied and the critical factors can be identified. This will lead to the identification of the most critical parameters of the system in transient stability and can be used in improving the transient stability of the system.

8) In addition to the second-order modal interaction investigated in Chapter 6, a third-order modal interaction between the different modes of the system can be investigated as well. To study the influence of the third-order interaction between the system modes, the use of a third-order Taylor series expansion terms needs to be studied.
References


A. Vahidnia, G. Ledwich, E. Palmer, and A. Ghosh, “Wide-area control through aggregation of power


Appendix A

A.1 Nordic Power System Excitation System Details

The excitation system model used in the Nordic power system is presented in Figure A-1 and the excitation system parameters are presented in Table A-1.

Table A-1: Excitation system parameters values used in Nordic power system modelling

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$K_{AVR}$</td>
<td>AVR gain</td>
<td>50 pu</td>
</tr>
<tr>
<td>$E_{Max}$</td>
<td>Maximum excitation limit</td>
<td>1 pu</td>
</tr>
<tr>
<td>$E_{Min}$</td>
<td>Minimum excitation limit</td>
<td>-1 pu</td>
</tr>
<tr>
<td>$T_P$</td>
<td>Excitation time constant</td>
<td>0.1 s</td>
</tr>
</tbody>
</table>

Figure A-1: Simplified excitation system model used in Nordic power system modelling.

A.2 Nordic Power System Speed Governor System Details

The speed governing steam turbine system model used in the Nordic power system is presented in Figure A-2 and the speed governing steam turbine system parameters are presented in Table A-2.

Table A-2: Speed governing steam turbine system parameters values used in Nordic power system modelling

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$T_1$</td>
<td>Governor time constant</td>
<td>0 s</td>
</tr>
<tr>
<td>$T_2$</td>
<td>Governor derivative time constant</td>
<td>0 s</td>
</tr>
<tr>
<td>$T_3$</td>
<td>Servo time constant</td>
<td>0.1 s</td>
</tr>
<tr>
<td>$K_1$</td>
<td>Controller gain</td>
<td>25 pu</td>
</tr>
<tr>
<td>$Z'_{Max}$</td>
<td>Max rate of change of the main valve position</td>
<td>0.1 pu/s</td>
</tr>
<tr>
<td>$Z'_{Min}$</td>
<td>Min rate of change of the main valve position</td>
<td>-0.1 pu/s</td>
</tr>
<tr>
<td>$P_{Max}$</td>
<td>Maximum power limit imposed by Valve</td>
<td>1 pu</td>
</tr>
<tr>
<td>$P_{Min}$</td>
<td>Minimum power limit imposed by Valve</td>
<td>1 pu</td>
</tr>
<tr>
<td>$P_0$</td>
<td>Pre-fault mechanical power</td>
<td>1 pu</td>
</tr>
</tbody>
</table>
Figure A-2: Simplified speed governing steam turbine system used in Nordic power system modelling.

A.3 Nordic Power System Steam Turbine System Details

The steam turbine system model used in the Nordic power system is presented in Figure A-3 and the steam turbine system parameters are presented in Table A-3.

Table A-3: Steam turbine system parameters values used in Nordic power system modelling

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$F_{HP}$</td>
<td>High-pressure power fraction</td>
<td>0.4 pu</td>
</tr>
<tr>
<td>$F_{IP}$</td>
<td>Intermediate pressure power fraction</td>
<td>0.3 pu</td>
</tr>
<tr>
<td>$F_{LP}$</td>
<td>Low-pressure power fraction</td>
<td>0.3 pu</td>
</tr>
<tr>
<td>$T_{CH}$</td>
<td>Steam chest time constant</td>
<td>0.2 s</td>
</tr>
<tr>
<td>$T_{RH}$</td>
<td>Reheat time constant</td>
<td>4 s</td>
</tr>
<tr>
<td>$T_{CO}$</td>
<td>Crossover time constant</td>
<td>0.3 s</td>
</tr>
<tr>
<td>$P_{GV}$</td>
<td>Power at Gate or Valve outlet</td>
<td>1 pu</td>
</tr>
<tr>
<td>$P_M$</td>
<td>Mechanical Power</td>
<td>1 pu</td>
</tr>
</tbody>
</table>

Figure A-3: Steam turbine system used in Nordic power system modelling.

A.4 Nordic Power System Overexcitation System Details

The value of $E_{cap}$, the thermal capability of each generator in the Nordic power system is presented in Table A-4.

Table A-4: Thermal capability of the generator OEL system

<table>
<thead>
<tr>
<th>Gen</th>
<th>$R$ (pu)</th>
<th>$I_{d\text{Rated}}$ (pu)</th>
<th>$E_{cap}$ (pu)</th>
<th>Gen</th>
<th>$R$ (pu)</th>
<th>$I_{d\text{Rated}}$ (pu)</th>
<th>$E_{cap}$ (pu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>g1</td>
<td>0.36</td>
<td>1.8087</td>
<td>48.365</td>
<td>g11</td>
<td>0.13</td>
<td>1.8087</td>
<td>48.365</td>
</tr>
<tr>
<td>g2</td>
<td>0.27</td>
<td>1.8087</td>
<td>48.365</td>
<td>g12</td>
<td>0.15</td>
<td>1.8087</td>
<td>48.365</td>
</tr>
</tbody>
</table>
A.5 Two Area Four Machine System Details

Table A-5: Generator data (all four generators)

<table>
<thead>
<tr>
<th>Generator</th>
<th>R</th>
<th>X</th>
<th>X'</th>
<th>X''</th>
<th>I'</th>
<th>I''</th>
</tr>
</thead>
<tbody>
<tr>
<td>g3</td>
<td>0.31</td>
<td>1.8087</td>
<td>48.365</td>
<td>g13</td>
<td>0.13</td>
<td>2.817</td>
</tr>
<tr>
<td>g4</td>
<td>0.27</td>
<td>1.8087</td>
<td>48.365</td>
<td>g14</td>
<td>0.31</td>
<td>2.916</td>
</tr>
<tr>
<td>g5</td>
<td>0.11</td>
<td>1.8087</td>
<td>48.365</td>
<td>g15</td>
<td>0.53</td>
<td>2.916</td>
</tr>
<tr>
<td>g6</td>
<td>0.17</td>
<td>2.916</td>
<td>77.974</td>
<td>g16</td>
<td>0.31</td>
<td>2.916</td>
</tr>
<tr>
<td>g7</td>
<td>0.09</td>
<td>2.916</td>
<td>77.974</td>
<td>g17</td>
<td>0.27</td>
<td>2.916</td>
</tr>
<tr>
<td>g8</td>
<td>0.38</td>
<td>1.8087</td>
<td>48.365</td>
<td>g18</td>
<td>0.53</td>
<td>2.916</td>
</tr>
<tr>
<td>g9</td>
<td>0.44</td>
<td>1.8087</td>
<td>48.365</td>
<td>g19</td>
<td>0.22</td>
<td>1.8087</td>
</tr>
<tr>
<td>g10</td>
<td>0.36</td>
<td>1.8087</td>
<td>48.365</td>
<td>g20</td>
<td>2</td>
<td>1.8087</td>
</tr>
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Table A-6: Generator damping (on machine base)

<table>
<thead>
<tr>
<th>Generator</th>
<th>D</th>
<th>H</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4</td>
<td>6.5</td>
</tr>
<tr>
<td>2</td>
<td>6</td>
<td>6.5</td>
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<tr>
<td>3</td>
<td>11</td>
<td>6.5</td>
</tr>
<tr>
<td>4</td>
<td>10</td>
<td>6.5</td>
</tr>
</tbody>
</table>

Table A-7: Line data (on system base 100 MVA)

<table>
<thead>
<tr>
<th>From Bus#</th>
<th>To Bus#</th>
<th>R</th>
<th>X</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2</td>
<td>0.0025</td>
<td>0.025</td>
</tr>
<tr>
<td>2</td>
<td>5</td>
<td>0.001</td>
<td>0.01</td>
</tr>
<tr>
<td>3</td>
<td>6</td>
<td>0.022</td>
<td>0.22</td>
</tr>
<tr>
<td>4</td>
<td>6</td>
<td>0.0025</td>
<td>0.025</td>
</tr>
</tbody>
</table>

Table A-8: Load data

<table>
<thead>
<tr>
<th>Bus#</th>
<th>Load (MW)</th>
<th>Load (MVAR)</th>
<th>Shunt (MVAR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>967</td>
<td>100</td>
<td>200</td>
</tr>
<tr>
<td>6</td>
<td>1767</td>
<td>100</td>
<td>350</td>
</tr>
</tbody>
</table>

Table A-9: Exciter system data

<table>
<thead>
<tr>
<th>Bus#</th>
<th>KA</th>
<th>TA</th>
<th>TB</th>
<th>TC</th>
<th>TR</th>
<th>VRMIN</th>
<th>VRMAX</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>180</td>
<td>0.01</td>
<td>1</td>
<td>10</td>
<td>0.01</td>
<td>-5</td>
<td>5</td>
</tr>
<tr>
<td>2</td>
<td>100</td>
<td>0.01</td>
<td>1</td>
<td>10</td>
<td>0.01</td>
<td>-5</td>
<td>5</td>
</tr>
<tr>
<td>3</td>
<td>130</td>
<td>0.01</td>
<td>1</td>
<td>10</td>
<td>0.01</td>
<td>-5</td>
<td>5</td>
</tr>
<tr>
<td>4</td>
<td>220</td>
<td>0.01</td>
<td>1</td>
<td>10</td>
<td>0.01</td>
<td>-5</td>
<td>5</td>
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